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Exhibit Number	:	ORA-1
Commissioner	:	Michael Peevey
Admin. Law Judge	:	Douglas M. Long
ORA Project Mgrs.	:	Dexter Khoury, Lee-Whei Tan
ORA Witnesses	:	Robert Levin Valerie Kao Dan Willis Lee-Whei Tan Elise Torres

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Testimony on Pacific Gas and Electric's 2014 General Rate Case Phase II

San Francisco, California
November 15, 2013

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APPENDIX A – QUALIFICATION OF WITNESS

MEMORANDUM

This report was prepared by the Office of Ratepayer Advocates (ORA) of the California Public Utilities Commission (Commission or CPUC) in Pacific Gas and Electric's 2014 General Rate Case Phase II proceeding. In this docket, the applicant presents its marginal cost estimates to develop the revenue responsibilities to be assigned to the customer classes. ORA modifies PG&E's marginal costs. ORA also revises PG&E's cost allocation and rate design to ensure compliance with legal and regulatory requirements as well as improved economic efficiency. As a result, the residential class would see an average 2.1 percent rate reduction and small commercial customers would see a 4.0 percent rate decrease. These compare with PG&E's proposals to increase residential rates by 0.6 percent and small commercial class rates by 2.0 percent.[1]

Dexter Khoury and Lee-Whei Tan served as ORA's project coordinators in this review, and are responsible for the coordination of this report. Mike Campbell (Branch Program Manager) and Chris Danforth (Project and Program Supervisor) oversaw this project and the review of this report. ORA's witnesses' prepared qualifications and testimony are contained in this report.

List of DRA Witnesses and Respective Chapters

Chapter Number	Description	Witness
1	Marginal Generation Cost	Robert Levin
2	Marginal Distribution Capacity Cost	Valerie Kao
3	Marginal Customer Access Cost	Valerie Kao
4	Revenue Allocation	Dan Willis
5	Master Meter Discount	Lee-Whei Tan
6	Small Commercial Rate Design	Elise Torres

[1] PG&E's numbers were taken from its August 2013 update filing, which reflect some residential rate design changes proposed by PG&E while ORA's numbers retain the status quo residential rate structure per the Administrative Law Judge Long's October 18, 2013 e-mail ruling to defer residential rate design changes.

CHAPTER 1
MARGINAL GENERATION COSTS
ROBERT LEVIN

I. SUMMARY AND RECOMMENDATIONS

This Chapter presents the Office of Ratepayer Advocates' (ORA) marginal generation cost recommendations for Pacific Gas and Electric Company's (PG&E) 2014 General Rate Case (GRC) Phase 2 Application (A.) 13-04-012. PG&E presents separate marginal cost components for generation capacity and energy, which has been the practice during most of the Commission's thirty-year history of establishing electric rates based on marginal costs.

For marginal energy costs (MEC), ORA recommends that PG&E's proposed values be reshaped to reflect PG&E's standard time-of-use (TOU) periods. The resulting values are shown in Table 1-1 below. For the marginal generation capacity cost (MGCC), ORA recommends an annual value of $30.89 per kW-year,[2] which is based on a modification of PG&E's proposed methodology to reflect the lack of need for new generating capacity before 2022.

[2] If one were to include a 15 percent resource adequacy adder, ORA's estimate would be $35.52 per kW-year. PG&E's proposed MGCC ($57.17 per kW-year) excludes a 15 percent resource adequacy adder, as does ORA's recommended value of $30.89 per kW-year. However, as PG&E's testimony acknowledges: "…the marginal capacity cost of serving a given customer demand level, as calculated in PG&E's revenue 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." PG&E, A.13-04-012, Prep. Test. of Yumi Oum/PG&E, ch. 2, pp. 2-15: ll. 13-17 (dated April 18, 2013).

Table 1-1

ORA'S Marginal Energy Cost Recommendations
Calculation of 2014 Marginal Energy Costs
by TOU Rate Period and Voltage Level
(¢/kWh)

Line No.	TOU Rate Period	Transmission MEC (Based on 2014 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	5.723	1.0188	5.831	1.0495	6.120
2	Summer Partial-Peak	4.779	1.0188	4.869	1.0495	5.110
3	Summer Off-Peak	3.601	1.0188	3.669	1.0495	3.850
4	Winter-Partial	4.897	1.0188	4.989	1.0495	5.236
5	Winter-Off	3.923	1.0188	3.997	1.0495	4.195

Specifically, ORA recommends:

- Using PG&E's MEC model, but use the appropriate standard PG&E TOU period definitions for all calculations (intermediate and final). ORA's recommended MECs are presented in Table 1-1 above.
- Reducing PG&E's marginal generation capacity costs MGCC to $30.89 per kW-year to reflect a resource balance year of 2022 which would be consistent with the current Long-Term Planning Proceeding (LTPP).
- Adoption of PG&E's general approach to calculating the MGCC, but extended to include a 2022 resource balance year by using a nine-year horizon rather than PG&E's six-year horizon. This reflects a mixed short-run/long-run approach, which the Commission adopted in previous litigated marginal cost proceedings.[3]

[3] *See Southern Calif. Edison (SCE),* D.96-04-050, 65 CPUC2d 362, 1996 Cal. PUC LEXIS 270 (dated April 10, 1996).

- Use of PG&E's pre-tax weighted average cost-of-capital in all marginal cost calculations.

To place both PG&E's and ORA's recommendations in context, it is best to first address general methodological issues and Commission policy regarding marginal generation costs, as discussed in the following section.

II. THE PROPER TIMEFRAME FOR MARGINAL COST DETERMINATION

A. General Methodological Issues

The Commission typically has adopted a short-run marginal cost approach to computing MECs. While MECs depend on load and price shape parameters, as well as the forecast of natural gas prices that can sometimes be disputed, the conceptual framework for determining MEC is usually uncontroversial. ORA proposes only a relatively minor technical shape adjustment to PG&E's MECs.

In contrast, the conceptual framework for determining the MGCC has always been a major contentious issue in marginal cost ratemaking. In nearly every marginal cost proceeding since the 1980s, some parties have argued for a strictly long-run marginal cost approach to determining the MGCC; while other parties favor an intermediate term approach that combines elements of both a short-run and long-run analysis. In the latter approach, the existence of a near-term capacity surplus is reflected in a reduced value of the MGCC.

As discussed below, the Commission has nearly always taken the latter mixed short-run/long-run approach when MGCC methodologies and values have been litigated. However, these issues were last litigated in 1996.[4] Those parties that favor the strict long-run approach to MGCC have not shied away from ignoring the Commission's 1996 findings and continuing to advocate their position.

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[4] *Id.*

In this Application, PG&E has proposed a conceptually correct mixed short-run/long-run approach consistent with the Commission's findings in D.96-04-050.[5] Specifically, PG&E has stated its conclusion that it will need no new generating capacity for system reliability purposes before 2018, and proposes an MGCC value well below the long-run value based on near term lack of capacity need.

While ORA proposes significant changes to PG&E's MGCC proposal, including a delay in the resource balance year until 2022, ORA strongly supports PG&E's use of a mixed short-run/long-run approach for determining MGCC, as adopted in D.96-04-050 and earlier Commission decisions. However, in anticipation that some interveners will propose a much higher long-run MGCC value, ORA explains below why the conceptual approach of D.96-04-050 and PG&E should be adopted and the alternative long-run approach rejected.[6]

B. The Conceptual Framework for Marginal Generation Capacity Costs

As PG&E's testimony states:

> The …Commission has been using marginal costs as the basis for cost allocation and setting electric rates that have evolved from a marginal cost framework originating over 30 years ago, citing the benefits of more economically efficient rates. 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 cost-effectiveness evaluations 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.[7]

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[5] *Id.*

[6] *Id.*

[7] PG&E, A.13-04-012, Prep. Test. of Thomas L. Troup/PG&E , ch. 1, p. 1-1: ll. 16-25 (dated April 18, 2013).

ORA agrees and emphasizes that a major reason for the Commission's reliance on marginal costs is that marginal cost-based pricing promotes economic efficiency.[8,9]

Over the last thirty years the Commission generally has adhered to the correct incremental definition of marginal cost that it adopted in 1981, as articulated in D.92749:

> Marginal costs may be defined as the change in total cost which results from a change in output. The result of using marginal cost in rate setting is that the rate equals the cost of producing one more unit, or the savings from producing one less unit.[10]

However, a fundamental issue in utility marginal cost ratemaking is whether or not marginal costs should reflect the timing of future demand-related investments.[11] In other words, is a long-run perspective (in which timing is irrelevant) appropriate, or should a shorter run perspective (in which timing matters) be adopted?

As a TURN protest in a 2000 SCE rate proceeding stated:

> The Commission's existing marginal cost methodologies generally set rates based upon the answers it determines to the following question:
>
> ***What costs change if the utility adds a kilowatt of demand?***[12]

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[8] The Commission has made its policy preference clear, stating**:**

> 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. [*PG&E*, D.93887, 1981 Cal. PUC LEXIS 1279, at *285(dated Dec. 30, 1981)].

[9] In a later decision, the Commission stated

> First, economic efficiency dictates that rates be based on marginal cost, not embedded cost. D.86-12-009, 22 CPUC2d 443, 456.

[10] OII-Marginal Cost Methodology, D.92749, 5 CPUC2d 620,1981 Cal. PUC LEXIS 597, at *3.

[11] This issue arises for marginal capacity costs when capacity investments are "lumpy": i.e., they tend to be large and occur infrequently, as may be the case for generation capacity. Lumpiness is less a concern for distribution capacity, at least at the utility system level. In the regression method, historical cost data for many small- and medium- sized, demand-related distribution investments are aggregated. For a large utility, the resulting stream of aggregate annual distribution costs is generally "smooth" and the timing of individual capital investments is not an issue.

[12] SCE, A.00-01-009, The Utility Reform Network Protest at p. 3 (dated Feb. 11, 2000), *available at* http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:57:506931079937801::NO/, click on "Documents" tab; then on line: "Feb. 11, 2000; Protest; Utility Reform Network."

The answer to this question depends upon the amount of surplus capacity relative to customer demand. The principles that marginal costs should signal the amount of surplus capacity and the timing of new additions was stated in I.*86-06-005,* D.90-07-055, and again in *PG&E*, D.92-12-057, as follows:

> Prices [based on LRMC] should recognize that some customers cause demand for system additions more than others, and some cause demand for additions sooner than others. To recognize these differences between customer groups, [marginal cost] studies should incorporate an adjustment which takes into account the proximity or distance of actual planned additions…[and]…should reflect the cost of planned capacity additions which occur over time.[13]

> [O]ur goal is to continue to improve our methodology of sending the most accurate marginal cost price signals to PG&E's customers. Because this is our goal, we agree with PG&E's policy principles that marginal cost components should…capture the timing and magnitude of future investment. . . . *PG&E*, D.92-12-057, 47CPUC 2d 143, 276; 1992 Cal. PUC LEXIS 971, at *13 (dated Dec. 16, 1992).

> The economic intuition behind this principle is that MCs should "be low in times of capacity surplus, rising to full cost when capacity is constrained."[14]

Thus, the Commission clearly has found that marginal costs should vary over time depending on the amount of surplus capacity. Immediately before a major investment, which is intended to resolve an anticipated capacity shortage, marginal capacity costs should be high. After the investment, when excess capacity exists, marginal capacity costs reduce to a low level. Accordingly**,** the Commission historically has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity**.**

In D.96-04-050, which is one of the more recently litigated SCE decisions dealing with generation marginal cost issues, the Commission reaffirmed its previous guidance

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[13] D.90-07-055, 1990 Cal. PUC LEXIS 766, at *10-11 (dated July 18, 1990).

[14] *I.86-06-005,* D.92-12-058, 1992 Cal. PUC LEXIS 970, at *43 (dated Dec. 16, 1992) (citing CACD Workshop Rept at 17).

that marginal costs should be reduced at times of near-term capacity surplus. During the 1990s, the Commission used an "Energy Reliability Index" (ERI) to adjust the marginal generation capacity costs to reflect near-term surplus capacity. In its 1995 General Rate Case (GRC), A.93-12-025, SCE proposed an ERI of 1.0, reflecting no adjustment for near-term surplus capacity. In D.96-04-050, which decided A.93-12-025, the Commission rejected SCE's proposed ERI, holding:

> The CT cost is also adjusted by an Energy Reliability Index (ERI). The ERI reflects the actual situation faced by Edison in maintaining reliable generation service. When a utility needs capacity to increase reliability of service, its ERI is 1.0 and marginal costs include all the costs of a CT. As capacity is added and reserve margin increases, the value of incremental capacity declines and the ERI drops below 1.0[15]

Moreover, the same Decision also stated:

> [S]everal parties take issue with Edison's use o f a 1.0 ERI. Edison argues that an ERI of 1. 0 is appropriate because its system is designed to meet customers' needs for reliable firm capacity "for an indefinite period. " Accordingly, Edison believes that marginal generation costs should reflect the long - run need for capacity by including the full cost of a CT.[16]

However:

> ORA, CFBF, and CLECA recommend the use of a six-year average ERI of 0.85. They argue that a six -year average appropriately balances both long-run and short-run considerations, including the near-term market conditions…[17]

The Commission held:

> As discussed above, we believe that marginal costs for use in revenue allocation and rate design should appropriately reflect expected year-to-year price variations during the forecast period. A six-year average ERI is consistent with this approach, and has been adopted by the Commission for the last several PG&E general rate cases and

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[15] *SCE,* D.96-04-050, 1996 Cal. PUC LEXIS 270, at *76.

[16] *Id.* at *78.

[17] *Id.*

> for Edison for use in revenue allocation since its last GRC in D.92-06-020.[18]

Finally, it stated:

> Although Edison apparently believes that we were misguided in our 1992 decision (RT at 7789-7790), we continue to find its arguments for an ERA of 1.0 to be unpersuasive. *Moreover, Edison 's preference to ignore short-term capacity conditions in the valuation of marginal generation costs is inconsistent with how we evaluate the capacity value of new resource additions, such as DSM. We adopt an ERA of 0.85*. [Emphasis added.][19]

Although the ERI methodology of the 1990s is obsolete, the economic principles embodied in D.96-04-050 remain valid and are equally relevant today. Furthermore, they are consistent with mainstream economic thought. Most economists agree that the marginal cost concept most relevant for ratemaking takes into account the near-term existence or lack of surplus capacity.[20] In other words, marginal cost should consider not simply the cost of the next unit of supply, but also should reflect the cost of serving the next unit of customer demand.

D.96-04-050 is not an isolated case; the Commission generally has avoided reliance on long-run marginal costs for use in ratesetting when surplus capacity may exist. For example, an earlier decision stated:

> Long-run marginal cost is simply the incorrect price signal to be sending at a time when available capacity far exceeds demand over the relevant price range.[21]

There is much support in the economics literature for basing marginal cost estimates on demand, considered in conjunction with supply, rather than on supply costs alone. A long-run marginal cost methodology is based solely on supply (i.e., capacity)

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[18] *Id.* at *78–79.

[19] *Id.* at *80 and *273 (Findings of Fact 25) ("An ERI of 1.0 ignores short-term capacity conditions in the valuation of marginal generation costs and is inconsistent with how we evaluate the capacity value of new resource additions, such as demand-side management.").

[20] *See* Alfred Edward Kahn, *The Economics of Regulation*, 70–71 (1970).

[21] D.86-12-009, 22 CPUC2d 443, 458.

costs without regard for demand. Setting prices based on LRMC cannot be consistent with economic efficiency in a period with excess capacity. As stated by Alfred Kahn: "[T]he intensity and elasticity of demand help determine the level of marginal costs."[22]

In a similar vein, Nobel Laureate (in economics) Sir Ronald Coase stated:

> In calculating the costs of an additional supply of a public utility service, it is of course necessary to start with the industry as it is, with whatever assets it possesses and the circumstances in which it finds itself. *Costs are rooted in the actual situation*. [Emphasis added.][23]

This is a clear statement that the marginal cost methodology should be based on real utility investment plans (which consider the timing of need), rather than on the undiscounted cost of capacity when such capacity may not be required for several years into the future.

In the current Application, PG&E has concluded that it will need no new generating capacity for system reliability purposes before 2018, and thus proposes an MGCC value well below the long-run value based on the near term lack of need for capacity. While ORA disagrees that new capacity will be needed as soon as 2018, ORA strongly supports the conceptual basis of PG&E's approach and would oppose any proposed long-run approach to MGCC as detrimental to economic efficiency.

III. PG&E'S MARGINAL GENERATION COST PROPOSALS

A. Marginal Energy Costs

PG&E's methodology for calculating MEC in the current GRC is conceptually similar to the one it used previously in its A.10-03-014,[24] but with some significant differences. Similarities include forecasting hourly energy prices for the three-year test period (2014-2016 in the current case) and grouping and averaging hourly prices into

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[22] *Id.* at 89.

[23] R. H. Coase, *The Theory of Public Utility Pricing and Its Application*, Bell J. Econ. & Mgmt & Sci., vol. 1, no. 1, 1970 at 123.

[24] PG&E, A.10-03-014 (filed Mar. 22, 2010), available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=29590/.

PG&E's TOU periods. Differences between the old and new methodologies primarily consist of the substitution of public data sources and non-proprietary models for the confidential models and inputs previously used. Use of public data and models allows some simplification and much needed transparency in the computations.

PG&E computes MEC values per PG&E TOU periods in the following major steps:[25]

1. Obtain the historical hourly prices in the CAISO Day-Ahead Market for PG&E from CAISO's OASIS website.
2. Compute "Effective Market Heat Rates" (EMHR) for each hour of the historical period.
3. Calculate averages of historical hourly EMHRs for the CAISO on-peak and off-peak periods for each month to derive hourly EMHR multipliers for each month.
4. Develop monthly PG&E Citygate natural gas price forecasts based on publically available sources.
5. Group the hourly prices into PG&E's TOU periods, and average the prices in each TOU period.

As explained further below, ORA disputes only step 3 above and has calculated averages of historical hourly EMHRs for the standard PG&E rate design TOU periods (rather than the CAISO on-peak and off-peak periods) for each month, to derive hourly EMHR multipliers for each month. This more accurately reflects the usual inclusion of all weekend hours as "off-peak" for determining TOU rates.

B. Marginal Generation Capacity Costs

PG&E's MGCC methodology is fundamentally similar to the methods it used previously in A.10-03-014, including the use of an existing generation unit as a proxy plant for years prior to the resource balance year.[26] In both cases, the MGCC for each

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[25] The process described leads to MEC values at the transmission voltage level. Primary and secondary voltage MEC values are obtained by multiplying the transmission MEC values by energy loss factors, as shown in Table 1-1.

[26] In A.06-03-005, PG&E indicated that new capacity could be required as early as 2008, which was the first of the six years averaged to the levelized MGCC. PG&E A.06-03-005, Prep. Test. of Antonio
(continued on next page)

year is the carrying cost of the proxy unit, reduced by any gross profits computed using a "Black Options" model.[27] This calculation is applied to six years of data, and the result is levelized to produce a single MGCC value.

In PG&E's 2011 GRC Phase 2, its testimony stated "[t]he highest cost existing unit will set the capacity cost in the market for existing capacity until a new generation resource is expected to be needed, that is, from 2011 through 2013."[28] PG&E apparently used the same logic in the current proceeding. In this Application, PG&E uses the carrying costs of a combined cycle (CC) plant[29] during an initial four-year (2014 – 2017) time period of the Commission's traditional six-year MGCC analysis period, during which no new capacity will be required. For the last two years (2018 – 2019), PG&E used the carrying costs of a new CT.[30] For all years, gross

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(continued from previous page)

Alvarez/PG&E , ch. 2, pp. 2-3 to 2-8 (dated March 2, 2006). As a result, a new combustion turbine (CT) was used as the proxy unit for all six years of the analysis.

[27] This model computes the "Energy gross margin," which is the expected market revenue net of variable cost. The variable cost includes fuel, start-up, and variable Operations and Maintenance (O&M) costs. According to PG&E's prepared testimony in this proceeding:

> To determine the energy gross margins of a marginal resource, PG&E used a stochastic analysis to reflect uncertainties present in the market prices of power and gas. Variable costs were based on fuel costs, start-up costs and Variable O&M 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.

PG&E, A.13-04-012, Prep. Test. of Yumi Oum/PG&E , ch. 2, pp. 2-12: ll. 8-19 (dated April 18, 2013).

[28] PG&E, A.10-03-014, Prep. Test. of Ronald Helgens/PG&E, ch. 2, p.2-5, ll. 7-9, (dated March 22, 2010).

[29] For existing units, the carrying costs consist of the operating costs of a combined cycle gas turbine (CCGT) including insurance, property tax, and fixed O&M. PG&E, A.13-04-012, Prep. Test. of Yumi Oum/PG&E , ch. 2, p. 2-13: ll. 6-15 (dated April 18, 2013).

[30] Carrying costs are different for existing and new units. For new units, the real economic carrying cost (RECC) of a proxy unit is used, augmented by the cost of insurance, property tax, and fixed O&M. *Id, p.2-14, ll.7-17*

margins are subtracted. Since carrying costs are greater than gross margins for each year of PG&E's analysis, the proxy unit has a net cost rather than a net profit. PG&E levelized MGCC values for all six years (2014 to 2019) to calculate MGCC value of $57.27 at the transmission voltage level.

IV. ORA'S MARGINAL GENERATION COST PROPOSALS

A. ORA recommends adjusting PG&E's MEC calculations to consistently reflect PG&E's standard TOU periods throughout the calculation of the MECs

A key element of PG&E's MEC calculation is the generation of hourly marginal prices. In the 2011 GRC Phase 2, PG&E used a proprietary model to perform this step. Whereas, in the 2014 GRC Phase 2, PG&E has used publicly available inputs and a publicly available model to generate its hourly prices. ORA finds fault only with the use of the CAISO pricing periods as an intermediate step in grouping the hourly prices into time-of-use periods.[31]

Thus, for marginal energy costs, ORA recommends that PG&E's proposed values be reshaped to reflect PG&E's standard TOU periods. Specifically, ORA recommends using PG&E's MEC model, but using the appropriate standard PG&E time-of-use period definitions for all calculations (intermediate and final). ORA's recommended MECs are presented above in Table 1-1.

B. ORA recommends that PG&E's MGCC be based on a 2022 resource balance year.

PG&E's assertion that *new flexible capacity will be needed in 2018,* runs counter to more recent analyses which indicate a lack of PG&E system need for new capacity until at least 2022. PG&E cites CAISO testimony at FERC as indicating a need for

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[31] CAISO pricing period differ from PG&E's standard TOU periods in that certain Saturday hours are considered as peak hours by CAISO. See, PG&E response by witness Yumi Oum, dated June 4, 2013, to DRA data request DRA_002, which stated: PG&E's forecast of hourly prices is based on market heat rates forecast using CAISO hourly prices and the CAISO's definition of the peak period. Please refer to the following link for the CAISO's definition of peak period (i.e., 6 days by 16 hours): http://www.caiso.com/2426/2426c05e14b00.pdf.

capacity in 2018.[32] This CAISO assessment was, however, based on an extremely high demand scenario which was rejected by CPUC staff analysts.[33] ORA's justification for use of a 2022 resource balance year is described in the following section.

C. Track 2 of the 2012 LTPP examined system flexibility needs for 2022. The Commission concluded that system flexibility needs for 2022 may be low or non-existent and canceled Track 2.

Track 2 of the 2012 LTPP, the System Reliability Track, examined renewable integration and the potential need for new resources to meet system flexibility needs. In the *Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and 4 Schedules* (issued September 16, 2013), the Commission canceled Track 2 of the LTPP proceeding, stating that there has been some indication that system flexibility needs may be low or non-existent and that the system flexibility needs would be revisited in the 2014 LTPP proceeding.[34] This conclusion was in agreement with SCE's analysis which shows no additional resources are needed in 2022 at this time to meet system needs when using the Base Case with SONGS Out assumptions.[35] In addition, CAISO's

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[32] PG&E, A.13-04-012, Prep. Test. of Yumi Oum/PG&E , ch. 2, p. 2-12: ll. 2-4 (dated April 18, 2013), citing CAISO, FERC Docket No. ER12-897-000, Waiver Request for Sutter Energy Center and attach. E, decl. of Mark Rothleder, CAISO Exec. Dir. of Market Anal. and Develop't, *available at* http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

[33] See Long Term Procurement Plan (LTPP), R.12-03-014, Scop'g Memo at 8 (dated May 17, 2012), *available at* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULC/166780.PDF/; specifically, in *LTPP Tracks 1 & 3*, D.12-04-046, the Commission stated:

> In looking at the whole record, it would be reasonable to find that there is no need for additional generation by 2020 at this time, and accordingly it is reasonable to defer authorization to procure additional generation based on system and renewable integration need. The proposed settlement is therefore reasonable in light of the whole record. [D.12-04-046, 2012 Cal. PUC LEXIS 192, at *14 (dated Ap. 19, 2012).]

[34] LTPP re Tracks 2 and 4, R.12-03-014, ALJ Rul'g at 6–7 (dated Sept. 16, 2013), *available at* http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=76995686, click on #68004 PDF.

[35] Noushin Ketabi, CPUC, *R.12-03-014: LTPP Track II Workshop – SCE Operating Flexibility Modeling Results & Energy Division ELCC Modeling Efforts* 34 (Concl. 1)(dated Sept. 18, 2013), *available at* http://www.cpuc.ca.gov/PUC/serp.aspx?cx=001779225245372747843:e2wnztai65q&cof=FORID:10&utf=UTF-8&q=R.12-03-014&sa=saSearch/.

analysis in Track 2 of the 2012 LTPP was inconclusive in terms of demonstrating system flexibility needs in 2022.

D. ORA recommends that PG&E's MGCC be based on a nine-year analysis period extended to include the 2022 resource balance year.

ORA's analysis uses a resource balance year of 2022. Thus, with a six-year planning horizon ending in 2019, the cost of a new CT would not be relevant to the calculation of the MGCC in this 2014 GRC Phase 2 proceeding. Using PG&E's MGCC values for an existing CC plant for 2014-2019 would result in a levelized MGCC of $22.40 at the transmission voltage level as shown below in Table 1-2 below.

Table 1-2

Calculation of Marginal Generation Capacity Cost
Based on Existing Capacity Only and A Six-Year Time Horizon
($/kW-year)

Line No.	Year	Residual Capacity Value	
1	2014	22.93	(a)
2	2015	22.18	(a)
3	2016	21.76	(a)
4	2017	21.60	(a)
5	2018	22.55	(b)
6	2019	23.53	(b)
7	PG&E After-Tax WACC	8.06%	
8	Net Present Value (NPV) of Six-Year Sum	103.38	103.38
9	MGCC levelized over 6 years at 8.06% discount rate	22.40	

(a) Per PG&E, based on an existing CCGT
(b) Per PG&E, from PG&E response to DRA DR

However, ORA does not recommend this value, and believes instead that the MGCC should reflect the cost of a new CT discounted to the year of need. Since that

year is 2022, an extended nine-year analysis is needed. Calculation of ORA's recommended MGCC value of $30.89 per kW-year is shown in Table 1-3 below.

Table 1-3

Calculation of Levelized Cost Over 2014-2022 ($/kw-yr)
Calculation of Marginal Generation Capacity Cost
($/kW-year)

Line No.	Year	Residual Capacity Value	
1	2014	22.93	(a)
2	2015	22.18	(a)
3	2016	21.76	(a)
4	2017	21.60	(a)
5	2018	22.55	(b)
6	2019	23.53	(b)
7	2020	24.00	(c)
8	2021	24.48	(c)
9	2022	155.75	(d)
7	PG&E Pretax WACC	8.06%	
8	Net Present Value (NPV) of Nine-Year Sum	208.03	208.03
9	MGCC levelized over 9 years at 8.06% discount rate	30.89	

Notes
(a) Per PG&E
(b) Per PG&E, from PG&E response to DRA DR
(c) Based on escalating 2019 short run capacity value by 2%
(d) Based on escalating 2019 long run capacity value by 2%

While D.96-04-050 and previous decisions adopted a six-year analysis period, this was done with the general understanding that new generation capacity would be needed within the six years. Thus, six years was regarded as a sufficiently long period to encompass both short-run and long-term generation needs, and a six-year term could be described as incorporating a mixed short-run/ long-run perspective. However, as described above, a six-year analysis period is no longer sufficient to include the need for

new generation capacity. Therefore, ORA proposes to use a nine-year planning horizon to estimate MGCC, as the shortest period that will encompass the need for new generating capacity.

As an alternate proposal, should the Commission prefer to retain the traditional six-year analysis period, Table 1-2 *supra* presents the MGCC calculation using a six-year analysis and based on existing capacity only (reflecting a resource balance year beyond 2019).

E. ORA recommends that PG&E's capital-related marginal costs be calculated based on PG&E's pretax weighted capital cost, rather than the after-tax value proposed by PG&E.

Tables 1-2 and 1-3 *supra* reflect cost that are levelized using PG&E's pretax weighted average capital cost as a discount rate (8.06 percent) rather than the 7 percent after-tax rate proposed by PG&E. This has the effect of slightly reducing the MGCC. ORA notes that SCE and SDG&E typically use the higher pre-tax discount rate in their economic analyses, including marginal cost calculations.

In making this recommendation, ORA relies heavily on previous testimony of TURN's witness Dr. William Marcus, in PG&E's 2011 GRC Phase 2, A.10-03-014. Dr. Marcus testified on PG&E's proposed use of its after-tax weighted capital cost as its discount rate as follows:

- PG&E's proposed discount rate, which reflects the tax-deductibility of bond interest, is inappropriate for marginal cost evaluation in this proceeding. The utility's cost of capital without tax effects should be used instead.
- The Commission has, for nearly 30 years, used the utility's cost of capital without tax effects as the discount rate for many of its economic evaluations, including calculation of combustion turbine costs for avoided capacity cost (required almost 28 years ago in D. 82-12-120); new supply; transmission options such as the California-Oregon Transmission Project and Devers-Palo Verde 2;2 and the calculation of marginal distribution costs for rate design by both PG&E in all cases prior to 2007 and by Edison and SDG&E in recent cases. Neither

> Edison nor SDG&E use the low after-tax discount rate for marginal cost or project evaluation.[36]

Further, in D.05-04-051, the Commission explicitly adopted the utility's weighted average cost of capital without tax effects for conservation evaluation, as follows:

> This Commission relies on the Total Resource Cost Test (TRC) as the primary indicator of energy efficiency program cost effectiveness, consistent with our view that ratepayer-funded energy efficiency should focus on programs that serve as resource alternatives to supply-side options. The TRC test measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and non-participants. The benefits are the avoided costs of the supply-side resources avoided or deferred. The TRC costs encompass the cost of the measures/equipment installed and the costs incurred by the program administrator. *The TRC should be calculated utilizing a discount rate that reflects the utilities' weighted average cost of capital, as adopted by the Commission.* [Emphasis added.][37]

The Commission reaffirmed this decision in D. 06-11-018, stating:

> Parties took differing positions on the discount rate that should be used in calculating benefit-cost ratios. Consistent with our determination in D.05-04-051, the applicant's weighted cost of capital, as adopted most recently by the Commission, should be used as the discount rate in evaluating the benefits of a transmission project. Consistent use of the utilities' weighted cost of capital as a discount rate will facilitate our comparison of proposed transmission projects and alternative investments.[38]

As TURN pointed out:

> The Commission should not change almost 25 years of precedent just because PG&E has unilaterally decided that it likes lower discount rates…. The full utility cost of capital makes sense for economic evaluation, given that customers actually pay even higher rates as a return on rate base …. An argument could potentially even

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[36] PG&E, A.10-03-014, Prep. Test. of Dr. W. Marcus/ TURN, pp.3-4, (dated October 6, 2010).

[37] *R.01-08-028*, D.05-04-051, attach. 3, sec. IV(2), at p. 6, available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=193954/, click on hyperlink entitled "D0504051 Gottstein Attachment 3."

[38] *I.05-06-041*, D. 06-11-018, 2006 Cal. PUC LEXIS 487, at *66–67 (dated Nov. 9, 2006).

> be made for a higher rate, but a lower rate such as the one that PG&E proposes here is not reflective of costs actually paid by ratepayers.[39]

ORA concurs with the quoted testimony of Dr. Marcus, and finds that it is equally applicable to calculating the marginal costs for the current PG&E GRC Phase 2 proceeding. Therefore ORA proposes to use PG&E's pretax weighted average capital costs in all capital-related marginal costs in this proceeding.

V. CONCLUSION

ORA believes that PG&E has provided a reasonable methodology to estimate marginal energy costs. But PG&E's MEC calculations should be adjusted to consistently reflect PG&E's standard TOU periods throughout the calculation of the MECs.

ORA agrees with PG&E that marginal generation capacity costs should reflect the current condition of an oversupply of generation capacity, but disagrees on when new capacity will be needed. Recent developments in Track 2 of the Commission's 2012 LTPP strongly support that no additional flexible system capacity will be needed by PG&E before 2022, and ORA therefore recommends using a MGCC of $30.89. This analysis is based on a nine-year analysis period, which combines the existing costs of combined cycle capacity through 2021 and the cost of a new CT in 2022.

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[39] PG&E, A.10-03-014, Prep. Test. of W. B. Marcus/TURN 3-4 (dated October 6, 2010).

CHAPTER 2

MARGINAL DISTRIBUTION CAPACITY COSTS

VALERIE KAO

I. INTRODUCTION

This Chapter addresses PG&E's proposal for marginal distribution capacity costs. Marginal distribution capacity costs are those distribution system costs that vary with changes in customer demand. For ratemaking purposes, marginal distribution capacity costs typically consist of the equipment needed to deliver energy from the substation to the final line transformer, including the cost of the substation itself. PG&E proposes to estimate these costs using its Discounted Total Investment Method (DTIM), which estimates a marginal distribution demand cost at each service level (i.e., primary, new business on primary distribution, and secondary) for each of PG&E's 18 divisions, which are further disaggregated into 245 distribution planning areas.

ORA finds that a different marginal cost methodology, the Regression Method (RM), developed by the National Economic Research Association (NERA), provides more explanatory power and statistically more significant results for estimating marginal distribution demand costs at the system level, when compared with PG&E's DTIM. ORA agrees, however, with the basic notion that distribution investments are highly location- and timing-specific. Therefore, ORA recommends scaling PG&E's division-level estimates based on the DTIM to the system-level estimates based on the RM.

II. ORA RECOMMENDATIONS

Consistent with ORA's testimony in PG&E's 2011 GRC Phase 2 proceeding, ORA recommends "marrying" PG&E's area-specific marginal distribution capacity costs with system-level RM estimates of these costs. The area-specific marginal distribution capacity costs, as estimated by PG&E, can be scaled to the RM results by applying the system-level scalar at each service level as shown in the following table:

Table 2-1

DTIM and RM Estimates of Marginal Distribution Capacity Costs

	A DTIM (PG&E)	*B* RM (ORA)	*C* Scalar [B ÷ A]
Service Level	($/kW)		
Primary Distribution	$27.95	$35.34	126.5%
New Business on Primary Dist.	$8.98	$12.23	136.2%
Secondary Distribution	$1.66	$1.91	114.7%

The above figures also reflect ORA's recommendation, as explained in Chapter 1,[40] to use PG&E's before-tax weighted average cost of capital as the applicable discount rate. This applies to marginal distribution demand costs since, in both the RM and DTIM calculations, the marginal investment must be annualized to convert to a $/kW-year figure.

III. DISCUSSION AND ORA'S PROPOSAL

A. The Regression Method Provides More Accurate Estimates of Distribution Demand-Related Investments at The System Level

The RM combines ten years of historical load and distribution investment data with five years of forecasted load and investment data to develop an estimate of marginal distribution capacity costs (MDCC) at the system level. In its work papers, PG&E provided MDCC estimates based on the RM, which ORA used to develop the scalars in Table 2-1 above.

PG&E proposes that the Commission adopt its MDCC estimates, which are based on DTIM. This methodology develops load forecasts for each Distribution Planning Area (DPA), which are then used to develop six-year investment plans for each DPA. These investment plans and their associated load forecasts in turn become the inputs for PG&E's DTIM calculation. PG&E's testimony states that the DTIM is the only method

[40] *See* Chapter 1, pp. 1-17 to 1-19.

that accounts for both the time value of money and the location-specific nature of demand-related distribution investments. Indeed, the timing and magnitude of distribution investments vary by location, as do the factors that influence the timing and magnitude of peak load growth. But the question is whether the highly disaggregated modeling effort that underlies the DTIM approach, provides results that are as statistically significant as those calculated by the RM approach using aggregate data. In this section, ORA demonstrates that the disaggregated modeling approach proposed by PG&E provides a false precision.

ORA's analysis focused on the robustness of the load forecasting methodology used for each DPA. PG&E's DTIM involves running several regression models to test and estimate the relationship between local load and the following:

- Time (i.e., years);
- Temperature;
- Number of residential customers;
- Product of temperature and the number of residential customers;
- Time (i.e., years) and temperature; and
- Number of residential customers and temperature.[41]

PG&E's testimony states that the most valid statistical model is automatically selected based on the following criteria:

- Reject any model with a negative coefficient for year, temperature or domestic customers;
- Reject any model with an 'F-significance' above 0.05;
- Reject any model with a coefficient 'p-value' greater than 0.05; and
- Select the remaining model with the highest F-statistic.[42]

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[41] The last two regressions and are multivariate regressions. See A.13-04-012 Exhibit PG&E-2 Chapter 5, p. 5-8.

[42] A.13-04-012 Exhibit PG&E-2 Chapter 5, p. 5-8

PG&E's planners may adjust the first-year forecast that comes from this analysis for a given DPA, if the most recent historical year peak plus the calculated annual load growth exceed the forecast peak for the current year by more than 1.5 percent. PG&E further explains that if none of the regression models are statistically valid, "then the most recent peak demands are multiplied by annual percentage growth factors determined by the [Analysis and Rates] Department's econometric models."[43]

ORA examined PG&E's DPA-level regression results and confirmed that for 151 of the DPA-level load forecasts (representing 62 percent of all DPAs), PG&E used the system-wide (Bay Area or non-Bay Area) econometric estimates produced by its Analysis and Rates Department, instead of any of the DPA-specific regression models described in its testimony.[44] This suggests that PG&E's DPA-level regressions do not produce statistically valid results for a majority of its DPAs. Additionally, PG&E indicated that it used one of the regression model results for a number of DPA load forecasts, even though those results did not meet the selection criteria specified in PG&E's testimony.[45]

Separately, ORA made a simple comparison of the coefficient of determination (i.e., the "R squared" values) for the RM to those of the individual DPA-level regression models, for those DPAs where PG&E used one of its regression model results rather than system-wide econometric growth rates. The comparison shows that the RM model produced a higher coefficient of determination than most of those of the DPA models. This means that a linear relationship provides a better "fit" between system-wide

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[43] A.13-04-012 Exhibit PG&E-2 Chapter 5, p. 5-9.

[44] *See* PG&E response to ORA DR 10, Question 3, dated September 6, 2013 (response is marked as confidential).

[45] Most of these DPAs were identified by PG&E, in response to a ORA data request, as "Ag/Oil DPAs." In response to a follow-up data request, PG&E defined "Ag/Oil DPAs" as "DPAs that have significant agricultural irrigation or commercial oil pumping demand that drives the timing and peak of energy consumption in the area. These types of customers do not follow the typical loading or growth patterns associated with other commercial or industrial customers." *See* PG&E response to ORA DR 22, Question 1, dated October 28, 2013.

cumulative load growth and cumulative investments than it does for the assumed relationships between and among year, temperature, the number of residential customers, and load.[46]

Aggregation of the DPA-specific estimates likely introduces some degree of inaccuracy to the system-level estimate, given PG&E's use of either less granular econometric or worse-"fitting" estimates for a majority of DPAs. This can be observed by comparing PG&E's forecast of 2005 – 2009 DPA-loads (submitted as part of its 2007 GRC Phase 2 application) with recorded loads in subsequent GRC Phase 2 filings, and its 2009-2011 forecast of DPA-loads (for its 2011 GRC Phase 2 application) with recorded loads included in its filings in this matter. ORA summarizes the difference between forecast and recorded loads in the tables below:[47]

[46] *See* PG&E response to ORA DR 10, Question 3, dated September 6, 2013 (response is marked as confidential). Additionally, ORA reviewed the confidential workpapers for those DPAs where PG&E found statistically valid results, in order to observe and compare the R squared values of those analyses with the R squared values of the system-level RM results.

[47] ORA computed these differences based on confidential workpapers submitted by PG&E for this [2014] GRC Phase 2 and its 2011 GRC Phase 2.

Table 2-4

Summary Statistics of Forecast Minus Recorded DPA Loads (Kw)

	2007 (forecast) minus 2011 (recorded)				2007 vs 2014	2011 vs 2014		
	2005	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**	**2011**
Maximum	42.20	45.38	40.00	41.74	55.90	73.90	76.20	110.70
Minimum	-32.55	-70.60	-33.10	-33.90	-35.80	-5.00	-6.80	-3.84
Mean	2.86	-3.26	0.17	-0.57	3.84	9.52	10.63	17.42
Median	0.50	-0.50	0.10	0.10	1.30	4.84	5.20	10.05
Number of DPAs where forecast > recorded	147	88	120	118	154	209	217	227
Number of DPAs where recorded > forecast	86	144	109	114	76	27	23	11

Table 2-5

Summary Statistics of Forecast as Percent of Recorded DPA Loads

	2007 (forecast) minus 2011 (recorded)				2007 vs 2014	2011 vs 2014		
	2005	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**	**2011**
Maximum	73.9%	96.1%	74.5%	88.6%	90.9%	151.2%	176.9%	167.4%
Minimum	-72.7%	-75.0%	-75.0%	-75.0%	-70.0%	-33.3%	-24.2%	-42.9%
Mean	4.5%	-1.3%	1.3%	1.7%	6.4%	12.3%	15.6%	24.0%
Median	3.0%	-2.4%	0.8%	0.3%	5.5%	10.7%	13.2%	21.6%

The generally larger differences between PG&E's 2011 forecast and recorded loads may possibly be explained by the unexpected downturn in economic activity that was not accounted for in the forecast. But the information for the years prior to that economic downturn is not much better. For example, the number of DPAs for which the 2005-2008 forecasted load (from 2007 GRC) exceeded the recorded load (from subsequent GRCs) was still higher than the corresponding number of DPAs for which recorded load exceeded forecasted load. This suggests that PG&E's forecasts tend to overestimate loads.

B. Scaling the Discounted Total Investment Method Results to the Regression Method Results Balances the Need for Accuracy with PG&E's Preference for Area-Specific Results

As explained above, the RM results provide a more reliable estimate of marginal distribution capacity costs at the system level than PG&E's proposed DTIM results, which are based in part on its DPA-specific load forecasts and investment plans. ORA agrees, however, that capturing the variation in local-area load growth, and consequently local distribution investments, is useful given that geographically-differentiated distribution demand costs have been used to target economic development rate and energy efficiency programs. ORA's recommendation would reflect both the location-specific nature of distribution investments and the greater accuracy of system-level distribution marginal cost estimation based on the NERA Regression Method.

While the DTIM approach has the potential to better reflect the timing of investments, problems in PG&E's disaggregated load forecasts that underlie the approach can prevent the methodology from actualizing this potential. In contrast, the RM approach combines historical and forecasted data to temper the problems that are inherent in most forecasts. Thus ORA believes that on balance, it is better to "marry" the two approaches to capture the best of both approaches.

IV. CONCLUSION

ORA recommends that the Commission scale PG&E's division-level estimates of marginal distribution capacity costs to the system-level RM results.

CHAPTER 3
MARGINAL CUSTOMER ACCESS COSTS
VALERIE KAO

I. INTRODUCTION

Marginal customer access costs are those distribution system costs that vary with the number of customers in a given customer class, and do not vary by the customers' usage or peak demand. Alternatively, they can be characterized as ***costs that change when the utility adds a customer.***[48] A classic example of a marginal customer access cost would be the cost of providing, maintaining, and reading customers' meters. Such costs vary with the number of customers, but generally do not vary with demand, within a given customer class.[49]

For utility ratemaking, marginal customer access costs typically consist of the capital costs of new customer connection (or "hookup") equipment, plus the ongoing revenue cycle services (RCS) costs. The latter include costs of customer services such as billing, customer inquiry, and meter reading. About 37 percent of PG&E's reported residential marginal customer access costs consist of capital costs.[50]

PG&E proposes to capture the capital costs of new customer connection using the "new customer only" (NCO) methodology adopted by the Commission since the early 1990s. In this methodology, the full cost of new hookup equipment is attributed to new customers only,[51] while ongoing RCS and related costs are attributed to all customers.

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[48] Unlike other marginal costs, customer costs are not symmetric: the costs that a utility avoids on losing a customer are typically less than the costs it incurs by adding a customer.

[49] Here it is assumed that a customer class is reasonably homogeneous and all members have similar meters that are rated for the range of demands that is typical for the class.

[50] According to PG&E's electronic workpapers, residential hookup costs per customer (including loading factors that reflect associated administrative and general costs, and operations and maintenance costs) comprise $29.02 out of a total customer cost of $77.99 in 2014 dollars. Non-residential marginal customer access costs are more heavily weighted toward capital costs.

[51] This is the so-called "new customer only" or "NCO" methodology. NCO was adopted by the
(continued on next page)

PG&E describes the NCO method as a three-step process:

(1) Estimate the cost per new customer of connecting to the grid for each customer class;

(2) Compute the present value of revenue requirements for the new connection; and

(3) Multiply by the class-specific customer growth rate to obtain the marginal customer connection cost attributable to the customer class.

The resulting values are added to the ongoing RCS and related costs to obtain the total class-specific marginal customer access cost.

ORA agrees, in general, with PG&E's conceptual description of marginal customer access costs, and with the broad outline of PG&E's implementation of the NCO methodology. However, at a detailed level, ORA finds significant flaws with the data and methodology supporting PG&E's estimates of both the new connection costs and the ongoing RCS costs.

With respect to the new connection costs, PG&E states that it has replaced the previous methodology of estimating a "typical customer connection" cost with "an analysis of 2010-2012 customer connection cost data obtained from PG&E's Customer Construction Billing System."[52] This more detailed data has the potential to improve the accuracy of the marginal cost estimates. However, the approach involves tabulating field-gathered cost data for thousands of new customer connections, increasing the potential for errors.

II. SUMMARY OF RECOMMENDATIONS

At a summary level, ORA has identified four significant flaws in PG&E's analysis of the marginal costs of new customer connections:

(continued from previous page)

Commission in D.92-12-057

[52] Exhibit PG&E-2 (errata PG&E-5), page 7-6.

- PG&E's data shows numerous customers with zero connection costs; and others with connection costs greater than the class median by a factor of ten or more. PG&E offers no explanation for such outliers, nor excludes outliers from the marginal cost calculation. ORA questions the validity of these outliers, and finds that their inclusion biases the marginal cost results, especially for the residential and small commercial classes. ORA offers a revised computation, which eliminates outliers at both extremes.
- ORA finds fault with the discount rate used in the "present value of revenue requirement" factor that is multiplied by the capital cost of the new connection. As discussed in Chapter 1, ORA believes that PG&E erred by using the after-tax instead of the pre-tax weighted average cost of capital in its marginal cost calculations.
- ORA recommends that the meter operations and maintenance (O&M) costs be captured as a lump sum lifetime cost attributable to new customers only. This would render the approach for meter O&M costs analogous with what PG&E has done for the O&M costs of final line transformers and service lines.
- ORA finds that the interclass variations in the forecast customer growth rates at the class level are poorly explained. ORA proposes to apply a composite growth rate to all nonresidential classes.

ORA also has made adjustments to PG&E's proposed RCS costs, described briefly as follows:[53]

- ORA recommends adjusting PG&E's estimates of SmartMeter opt-out program costs, and including revenues from SmartMeter opt-out customers.

[53] Additionally, ORA identified a calculation error in PG&E's computation of the RCS costs associated with billing and collections. PG&E acknowledged this error and agreed to correct it in a subsequent errata filing. On November 8, 2013, PG&E notified A.13-04-012 parties (those who have requested workpapers) of revised models, which include a correction for the error that ORA identified. PG&E's November 8, 2013 revised models also include corrections to two other errors that PG&E subsequently identified, resulting in a slightly smaller marginal customer access cost than what ORA presents here. Due to time constraints, ORA was unable to adjust its results to account for the two additional corrections that PG&E made.

- ORA disagrees with PG&E's estimate of billing exceptions, and recommends an estimate that better reflects the rate of billing exceptions following SmartMeter deployment.
- Consistent with the recommendation above to attribute meter O&M costs to new customers only, they are removed from the RCS costs.

The results of ORA's recommendation are shown in the following table.

Table 3-1

ORA Recommendations for Marginal Customer Access Costs

Line No.	Group	Revenue Cycle Services	Other Account 903	New Connection Costs	TOTAL [A+B+C]
		($/cust/year)			
1	RESIDENTIAL	$21.14	$7.06	$31.68	$59.88
2	AGRICULTURAL A	$31.25	$55.49	$162.33	$249.07
3	AGRICULTURAL B	$41.58	$55.49	$456.60	$553.67
4	SMALL L&P	$29.87	$29.59	$123.80	$183.26
5	A10 MEDIUM L&P SECONDARY	$120.91	$124.17	$560.14	$805.23
6	A10 MEDIUM L&P PRIMARY	$252.89	$124.17	$637.56	$1,014.62
7	E19 SECONDARY	$189.93	$257.73	$826.37	$1,274.03
8	E19 PRIMARY	$489.30	$257.73	$1,030.06	$1,777.10
9	E19 TRANSMISSION	$445.65	$257.73	$2,719.84	$3,423.22
10	E20 SECONDARY	$796.87	$257.73	$2,220.00	$3,274.60
11	E20 PRIMARY	$777.25	$257.73	$1,889.06	$2,924.05
12	E20 TRANSMISSION	$740.73	$257.73	$2,719.84	$3,718.31
13	STREETLIGHTS	$8.44	$55.29	$19.06	$82.79
14	TRAFFIC CONTROL	$7.40	$29.59	$22.55	$59.53

III. DISCUSSION – HOOKUP EQUIPMENT COSTS AND ASSOCIATED OPERATIONS AND MAINTENANCE COSTS

ORA recommends that the Commission adopt marginal customer access costs (MCACs) based on the NCO methodology, which the Commission has adopted in

nearly all litigated marginal cost decisions since 1992. In more detail, ORA proposes to:

- Exclude the lowest and highest 5% of new customer connection costs when computing the mean for each customer class because some of the lower and upper extreme values of PG&E's connection cost data appear to be invalid.
- Adjust the present value of revenue requirements factor that is multiplied by the class-specific connection costs to reflect PG&E's pretax weighted average capital cost rather than the after-tax discount rate used by PG&E.
- Include the costs of meter operations and maintenance as a lump sum lifetime cost attributable to new customers only, as PG&E has done for the analogous costs of final line transformers and service lines.
- Use the same composite growth rate forecast for all nonresidential customer classes.

A. Methodological issues: Rental versus NCO Approaches

For nearly 25 years, the Commission has defined customer connection costs as consisting of meters, service drops, and final line transformers (FLTs), the latter serving as the boundary between customer-related and demand-related distribution facilities. Establishing a new customer connection normally requires all three of the above elements, sometimes termed the "TSM" equipment (i.e., for transformer, service and meter). Installation of the TSM equipment requires significant labor as well as material costs. These costs are capitalized and included in utility rate base.[54]

As normally defined in economic textbooks, marginal costs are symmetric. For example, in standard marginal cost theory, the costs of serving an additional unit of demand are generally the same as the costs avoided by a unit decrease in demand. This

[54] ORA could have proposed a reduction in the marginal customer hookup costs by excluding some SmartMeter costs, which PG&E justified via expected demand response (DR) benefits. The Commission's adoption of PG&E's SmartMeter business case was based on expected benefits consisting of 28 percent DR benefits and 72% operational benefits. In principle, following the cost-causation principle, 28% of the smart meter costs should not be considered "customer cost-related" and should be included in generation-related costs. ORA did not make this adjustment at this time because the effect on marginal generation cost is difficult to estimate.

symmetry, however, does not hold for customer connection capital costs because such equipment is often dedicated to individual customers rather than shared.

As stated above, establishing a new connection requires material and installation costs of new TSM equipment. If, however, a previously occupied customer premise is abandoned, (or a customer chooses to go "off-the-grid" and surrender his/her connection equipment), only a fraction of the original TSM cost can be recovered by salvage and/or reuse of the meter and FLT. Similarly, if a portion of a utility system is sold (e.g., to a municipal utility district), the selling utility will likely receive only a fraction of the current replacement cost of the facilities.

Thus, the costs of adding a customer and the costs avoided by losing a customer are not symmetric. This lack of symmetry has vexed practitioners of marginal cost based ratemaking since its introduction in the early 1980s. This problem has resulted in the Commission adopting various approaches over the years, including:

(1) Treating TSM costs as entirely sunk (thereby excluding marginal customer-related capital costs altogether from the marginal costs used for ratesetting);

(2) Treating TSM costs as if they always were fully recoverable at their replacement cost new (RCN) value, regardless of the age or depreciation of the facilities. This is the so-called "rental" method.

(3) Including as marginal only TSM costs for new customers (at previously unserved sites) or for customers whose TSM equipment is being replaced in the test year. This is the so-called NCO method.

Approach (1) was abandoned early in the history of CPUC ratemaking because the Commission found that the revenue allocation resulting from this methodology did not capture the role of the customer hookup in cost causation and resulted in skewing costs to large customers.

Approach (2), popular in the later 1980s, essentially was the opposite of Approach (1). Where Approach (1) treated all TSM costs as sunk and none as marginal, Approach (2) treated *none* of the TSM costs as sunk and *all* as marginal, and in addition, it valued all TSM facilities at RCN, regardless of vintage.

Beginning with PG&E's 1993 GRC,[55] the Commission has consistently rejected the rental method (Approach (2)) because it found that the rental method overcharges customers for the cost of their TSM equipment. The revenue allocation that results when the RECC methodology is applied to TSM, overstates the role of the existing customer in cost causation, which skews the costs to small customers.

Thus, beginning with D.92-12-057 in PG&E's 1993 GRC, the Commission has nearly always adopted the NCO method (Approach (3)) when marginal costs were litigated. In doing so, the Commission has judged that the NCO method best reflects cost causation for TSM facilities.

B. Data issues: Questionable validity of extreme values in PG&E's customer cost data

PG&E's testimony states:

> PG&E's 2014 GRC Phase II marginal customer connection cost estimates are based on an analysis of 2010-2012 customer connection cost data obtained from PG&E's Customer Construction Billing System (CCBS)….The use of actual job estimate costs as a data source for this approach to computing marginal costs of connecting new customers … 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… Using actual field-estimated job costs in place of "typical customer connection" costs represents a vast improvement in the methodology and should be adopted.

Generally, ORA concurs with PG&E's use of field data encompassing the wide variety of customer connections. However, as discussed below, ORA has identified data of questionable validity at the extreme ends of the distribution of customer connection costs. These material and installation costs of TSM equipment can vary widely by customer class and within customer classes. But a detailed examination of PG&E's customer connection data reveals the presence of costs that appear unreasonably

[55] D.92-12-057.

low or high, mostly concentrated in the residential and Small Light and Power (L&P) classes. These TSM costs are the major component of marginal customer access costs, which, in turn, influence the allocation of PG&E's distribution revenue requirement among its customer classes.

. PG&E's Residential Connection Cost Data

There are valid reasons to expect a high variability in residential connection costs. For single-family residential connections can range from a single new "infill" residence, connected to an existing FLT, to a subdivision containing hundreds of new homes, requiring the full array of TSM equipment including the FLTs. On a per item basis, the FLT is by far the most expensive of the residential TSM equipment. Additionally, the density of residential developments (number of homes per acre) can have a major impact on the connection cost per home. Because less dense residential developments require more transformers per customer (i.e., fewer customers can be served per transformer) and require longer, more costly service extensions, the variation in TSM costs per customer can be quite significant.

PG&E's testimony and workpapers appear to account adequately for this variability in its residential TSM costs per customer. However, about five percent of new connections cost less than $200. According to PG&E's data, this is the average cost of a residential meter. Since new customer connections require, at a minimum, a meter and service line, connections costing less than the cost of a meter must be considered suspect.

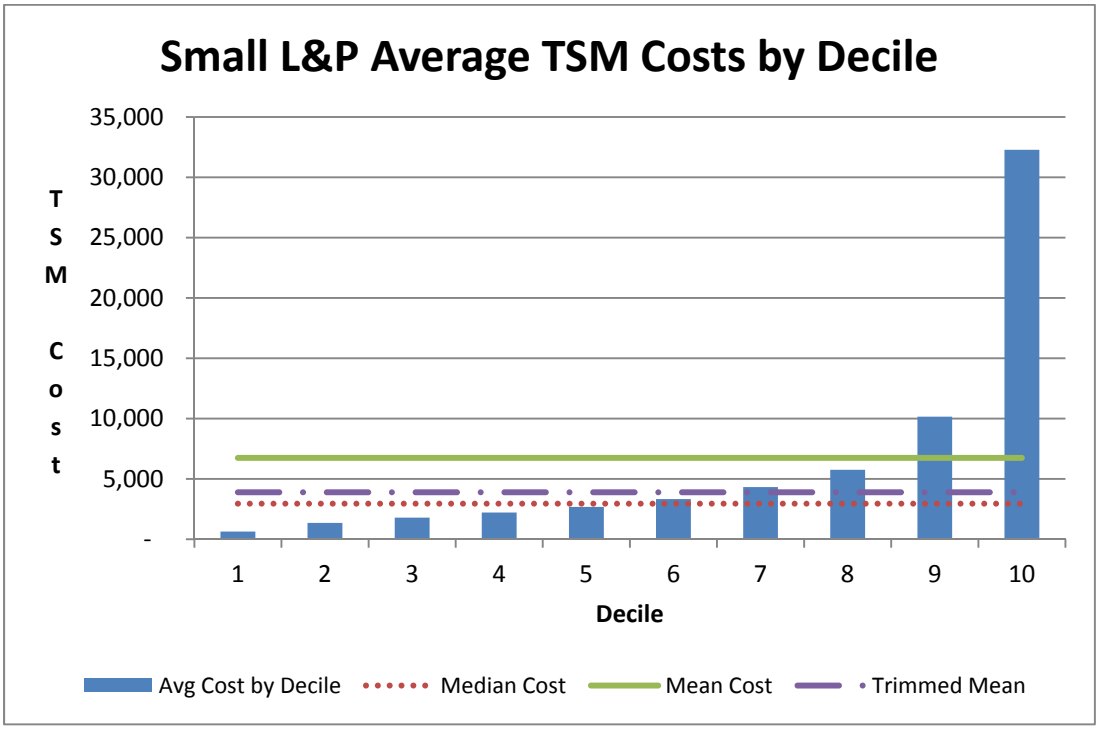
. PG&E's Small Light and Power Connection Cost Data

The extreme variation between high and low cost connections in the Small L&P class is even more suspect than that in in the residential class. To address these data validity concerns without introducing significant bias, ORA proposes to exclude the lowest and highest five percent of the customer connection cost data for each customer class, when calculating the class average connection costs.

The Small L&P class has numerous (167) connections reported to cost $0 and over 200 connections that allegedly cost ten times or more than the class median cost. About four percent of PG&E's Small L&P data consists of connections purportedly costing $30,000 or more, which is ten times the median cost to connect of $2,946. At the extreme high end, 19 customers show connection costs ranging from $100,000 to $340,000. Inclusion of these high cost customers causes the mean to be more than double the median. ORA finds that these high cost connections are of questionable validity. They may have been erroneously included due to a misclassified rate schedule, or by failing to divide the total cost by the correct number of nonresidential units in a multi-unit commercial development.

As Figure 3-1 shows, the Small L&P cost data is strongly skewed by the presence of a relatively few connections which are at a very much higher cost than the median. Thus, the average cost for the highest decile is nearly ten times the median, and the mean is more than double the median. For these reasons, exclusion of extreme outliers is especially critical to a reasonable estimate of the MCAC for this customer class. The "Trimmed Mean" reflects the mean of the Small L&P data after the highest and lowest five percent of new connection costs are excluded.

Figure 3-1



The Commission has defined "Small" commercial customers as those having maximum demands not exceeding 20 kW.[56] However, under a settlement agreement reached in PG&E's 2011 GRC Phase 2, (A.10-03-014), customers with maximum demands between 20 kW and 75 kW are allowed to take service under PG&E's Small Commercial A-1 and related rate schedules in 2011 – 2013. Assessment of whether they should continue to take service on Small Commercial rate schedules is to be

[56] Decision 10-10-032, footnote 1: "A small business customer is defined as a non-residential customer with an annual electric usage of 40,000 kilowatt hours (kWh) or less, or an energy demand of 20 kilowatt (kW) or less, or annual consumption of 10,000 therms of gas or less. Alternatively, a small business customer is a customer who meets the definition of "micro-business" in California Government Code Section 14837 (Section 14837). Section 14837 defines a micro-business as a business, together with affiliates, that has average annual gross receipts of $3,500,000 or less over the previous three years, or is a manufacturer, as defined in Section 14837 subdivision (c), with 25 or fewer employees. The California Department of General Services is authorized to amend the gross receipt amount. In January 2010 DGS increased the gross receipt amount from $2,750,000 to the current amount of $3,500,000. (*see*, California Office of Administrative Law, Regulatory Action Number 2000-1110-01S.)

reviewed in this GRC. ORA's assessment of whether they should be migrated to Medium Commercial rate schedules is discussed further in Chapter 6 of this testimony.

The very high TSM costs for some customers appear to be strongly correlated with maximum demands of over 20 kW. ORA identified 200 customers with maximum demand above 20 kW, which is about 3% of PG&E's total of 5,875 new Small L&P connections. Included are 52 customers with maximum demands above 75 kW. As shown in Table 3-2, the average connection cost for the > 20 kW group was nearly four times the average connection cost for the Small L&P class as a whole. The data in Table 3-2 were developed using the trimmed data that excludes the highest and lowest 5% of connection costs. As can be seen, the resulting data still show significant variability within the Small L&P class.

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Table 3-2

Test Year 2014 Class New Connection Equipment Costs ($/New Connect)[57]

Customer Class	Transformer	Service	Meter*	Total
RESIDENTIAL	293	1,293	172	1,758
AGRICULTURAL A	1,749	4,337	233	6,319
AGRICULTURAL B	7,267	10,048	762	18,077
SMALL L & P (all customers)	1,131	3,328	351	4,809
Customers ≤ 20 kW	1017	2994	315	4326
Customers > 20 kW	7722	9345	1450	18517
A10 MEDIUM L & P SECONDARY	8,818	11,929	1,479	22,226
A10 MEDIUM L & P PRIMARY	0	13,778	10,951	24,729
E19 SECONDARY	13,709	17,649	1,468	32,826
E19 PRIMARY	213	26,616	12,774	39,603
E19 TRANSMISSION	0	90,626	12,228	102,854
E20 SECONDARY	40,624	45,433	2,499	88,556
E20 PRIMARY	69	58,437	13,307	71,814
E20 TRANSMISSION	0	90,626	12,228	102,854
STREETLIGHTS	0	701	14	715
TRAFFIC CONTROL	0	701	155	857

* Streetlight Meter Cost is multiplied by LS3 Metered Streetlight Percentage

C. Present Value of Revenue Requirements Factor

As discussed in Chapter 1, ORA rejects PG&E's proposed use of the after tax weighted average capital cost as its discount rate for marginal cost computations. For marginal customer access costs, the discount rate affects both the present value of revenue requirements associated with customer connection equipment and the calculation of the lifetime O&M cost of such equipment. ORA's proposed marginal costs are based on PG&E's pretax weighted capital cost of 8.06 percent.

[57] Means reflect ORA's recommended exclusion of the top and bottom 5% of the cost distribution, as outliers.

D. Meter O&M Costs

PG&E has proposed a lifetime O&M cost adder for new final line transformers and service lines, but not for meters which are the third element of customer hookup equipment. Instead, PG&E has chosen to reflect meter O&M as an ongoing cost applicable to all customers.

ORA sees no valid reason for this inconsistency of treatment of O&M costs among the categories of TSM equipment.[58] ORA therefore proposes to treat meter O&M costs as a lifetime adder analogous to the treatment of transformer and service line O&M costs. This has the effect of significantly reducing the effect of meter O&M costs on overall marginal customer access costs since they are only counted for new customers rather than for all customers.[59]

E. Customer growth rates

The NCO method computes an expected annual TSM investment by multiplying the fully loaded cost of the TSM equipment, including the present value of associated revenue requirements (return, depreciation, taxes), by the customer growth rates. As shown in Table 3-3, PG&E's proposed residential customer growth rate is 1.12 percent. For non-residential customers, the growth rates vary by an order of magnitude, and range from 0.32 percent for E-19 Secondary to 3.28 percent for the Large Agricultural customer group.

The variation among the various nonresidential classes is poorly explained and is based on a very narrow period and sparse data. ORA recommends, therefore, using a composite growth rate for all non-residential classes. ORA computed a composite

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[58] ORA acknowledges that, during the late 1990s the Commission sought to unbundle revenue cycle services, one of which was meter O&M. ORA believes that PG&E's proposed treatment of meter O&M costs was a holdover from that proceeding. However, as a practical matter, that unbundling did not come to fruition and is no longer being pursued.

[59] Though the lifetime O&M costs used in the NCO calculation is higher than the annual costs used in the RCS cost calculation, this difference is significantly smaller than the effect of counting it only for new customers rather than for all customers.

growth rate of 1.61 percent using PG&E's data. It applied this growth rate to all non-residential classes rather than using the class-specific growth rates proposed by PG&E.

Table 3-3 compares PG&E's and ORA's customer growth rates for use in the NCO calculation. ORA's approach smoothes out the erratic variation in growth that sometimes occurs with smaller customer groups. It also eliminates obvious anomalies such as the large value shown above for Agricultural B, and the very small value for E-19 Secondary. This approach is reasonable because the customer growth rates for the larger nonresidential customers have a relatively minor impact on the overall revenue allocation.

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Table 3-3

New Connection Rate (New Connects/Total Group Accounts)

	PG&E Proposed	ORA Proposed
RESIDENTIAL	1.12%	1.12%
AGRICULTURAL A	1.33%	1.61%
AGRICULTURAL B	3.28%	1.61%
SMALL L & P	1.73%	1.61%
A10 MEDIUM L & P SECONDARY	0.73%	1.61%
A10 MEDIUM L & P PRIMARY	2.45%	1.61%
E19 SECONDARY	0.32%	1.61%
E19 PRIMARY	2.41%	1.61%
E19 TRANSMISSION	2.41%	1.61%
E20 SECONDARY	2.41%	1.61%
E20 PRIMARY	2.41%	1.61%
E20 TRANSMISSION	2.41%	1.61%
STREETLIGHTS	1.03%	1.61%
TRAFFIC CONTROL	1.41%	1.61%

F. Results: NCO Customer connection capital and lifetime O&M costs.

The customer connection capital and lifetime O&M costs are derived by multiplying the present value of revenue requirements of new hookup equipment, including lifetime O&M costs, by the customer growth rate. ORA uses the trimmed data presented in Table 3-2 to calculate the NCO results, as shown in Table 3-4.

Table 3-4

2014 GRC Phase 2: New Customer Only Marginal Costs, $/Customer-Yr (2014$)

	A	B	C	D	E
Group	Total New Connect Loaded Cost	Lifecycle O&M (METER, Transformer & Service)	Total [A + B]	New Connect rate	New Connect Costs [C * D]
	($/New Connect)			(%/yr)	($/cust/yr)
RESIDENTIAL	2,390	445	2,835	1.12%	31.68
AGRICULTURAL A	8,556	1,540	10,096	1.61%	162.33
AGRICULTURAL B	24,383	4,015	28,398	1.61%	456.60
SMALL L&P (All customers)	6,522	1,178	7,700	1.61%	123.80
Customers ≤ 20 kW	5867	1060	6926	1.61%	111.36
Customers > 20 kW	24974	3950	28924	1.61%	465.05
A10 MED. L&P SECONDARY	29,991	4,848	34,839	1.61%	560.14
A10 MED. L&P PRIMARY	33,884	5,769	39,653	1.61%	637.56
E19 SECONDARY	44,258	7,139	51,397	1.61%	826.37
E19 PRIMARY	54,200	9,866	64,066	1.61%	1,030.06
E19 TRANSMISSION	140,534	28,629	169,163	1.61%	2,719.84
E20 SECONDARY	119,228	18,847	138,075	1.61%	2,220.00
E20 PRIMARY	98,177	19,314	117,492	1.61%	1,889.06
E20 TRANSMISSION	140,534	28,629	169,163	1.61%	2,719.84
STREETLIGHTS	976	209	1,185	1.61%	19.06
TRAFFIC CONTROL	1,171	231	1,402	1.61%	22.55

IV. DISCUSSION – REVENUE CYCLE SERVICES COSTS

PG&E's proposed RCS costs increased between the 2011 and 2014 GRCs by more than fifty percent. ORA found this surprising given the expectation that PG&E's smart

meter infrastructure would have reduced or eliminated many marginal costs associated with meter reading, billing, and other customer service-related activities.

In response to ORA's data request regarding this increase, PG&E explained that "the change in MCAC estimates from the 2011 to the 2014 GRC is primarily due to changes in the MCAC calculation method between the two GRCs."[60] PG&E elaborated that, for its 2011 GRC, it estimated total RCS marginal costs based on models that were developed in the 1990s, and then it applied a SmartMeter O&M benefit estimate to that total. In contrast, PG&E's SmartMeter benefits are now embedded in the RCS marginal cost calculation. These benefits primarily are embedded in data derived from PG&E's Field Automation System (FAS) database. PG&E further explained that the increase from 2011 to 2014 also is due to inflation, labor cost increases, unexpected costs associated with the smart meter opt out program, and inclusion of revenue assurance and shutoffs for non-payment activities not previously included.[61] PG&E also claimed that the SmartMeter O&M benefit that it subtracted from its 2011 GRC RCS cost estimate was crude and overly generous. It asserted that removing this O&M benefit from its 2011 GRC RCS cost estimate, and comparing the result with the new 2014 RCS cost estimate, would show that Smart Meters actually have reduced RCS costs.[62] Nevertheless, given the large changes in RCS costs between the two GRCs, ORA determined to investigate more fully some of the larger cost categories within RCS.

ORA found its investigation and analysis of PG&E's RCS costs to be extremely difficult. PG&E concedes that it did not use the same cost categories and identification codes in this 2014 GRC as it did for the 2011 GRC,[63] complicating ORA's effort to assess whether to what extent the costs of specific activities changed. Moreover, PG&E's FAS file uses pivot tables that select certain categories of costs to

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[60] PG&E response to ORA data request 13, Question 1.

[61] PG&E response to ORA data request 13, Questions 1, 3.

[62] See table on page 5 of PG&E's response to ORA data request 13, Question 1.

[63] PG&E response to ORA data request 13 Question 4.

include. PG&E confirmed that the determination of which categories to select involved consultation with "subject matter experts," which ORA does not challenge but nevertheless considers a subjective exercise.[64]

These problems especially impacted ORA's analysis of meter O&M costs. Notwithstanding the difficulty that ORA encountered in verifying the new meter O&M estimate that comes from the FAS data base, ORA proposes to treat meter O&M costs consistent with how PG&E treats transformer and service O&M costs, that is, as part of the NCO calculation. ORA finds that consistent treatment of all TSM O&M costs (i.e., as part of the NCO calculation) is reasonable. Evidently they were previously treated differently because the same RCS data base is used to produce credits to direct access providers who provide their own metering services. But there is no reason why the use of this data base for another purpose should require an inconsistent treatment of the TSM equipment O&M costs for bundled customers.[65] These adjustments are explained in Section D above. As explained in that section, including meter O&M in the NCO calculation significantly reduces their contribution to overall marginal customer access costs than would including them in the RCS calculation.

A. PG&E's RCS model overestimates SmartMeter opt-out and billing exceptions costs

PG&E's 2014 update to its RCS model includes forecasts of certain costs that are based on its GRC Phase I application. ORA finds at least two of these costs – meter reading for SmartMeter opt-out customers and billing exceptions costs – to be substantially overestimated. ORA therefore recommends adjustments to these estimates.

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[64] PG&E response to ORA data request 13 Question 4.

[65] PG&E has included in its NCO model estimates for meter O&M costs that are not carried forward into the final total so as not to double count the same costs that also are captured in the RCS model. ORA merely used those estimates that PG&E placed in its NCO model and omitted them from the totals produced by the RCS model.

. **Meter-reading costs for SmartMeter opt-out customers**

PG&E's "2014 RCS Study Metering Update" model includes the forecasted costs of manual meter reading costs for participants in the SmartMeter opt-out program. ORA adjusted several inputs to develop an estimate that more closely reflects the likely ongoing costs to serve SmartMeter opt-out customers.

First, PG&E forecasted that 200,670 customers would opt out from SmartMeter service in 2014. This figure was based on opt-out participation as of May 3, 2012.[66] In response to an ORA data request in the GRC Phase 1 proceeding, PG&E provided 2012 month-end data of the recorded number of opt-out customers, showing a growth rate of approximately two percent after initial uptake.[67] Based on these updated numbers, ORA in Phase 1 adjusted the forecasted SmartMeter Opt-out program participation to 54,070 by the end of 2014.[68] This lower rate of participation impacts manual meter reading costs, which PG&E estimated in its 2014 RCS update model as $32.58 million. Based on opt-out participation of 54,070, manual meter reading costs instead would be $12.2 million.[69]

Second, PG&E did not account for revenues from SmartMeter opt-out participants in its 2014 RCS update model. ORA estimated these revenues based on the current program participation charges and the lower estimate of program participation discussed above, and netted these out of the estimated meter reading costs in PG&E's RCS model. The net RCS meter reading cost is $5.7.million.

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[66] Exhibit PG&E-5 p. 10-9, footnote 14

[67] PG&E GRC Phase 1, ORA DR 208 Question 11

[68] See ORA testimony in A.12-11-009: Exhibit DRA-13, Customer Care, filed May 3, 2013, p. 55; Ex DRA-13 Workpapers_Customer Care, WP 5-2; and PG&E response to ORA data request 167 Question 2 (ORA rounded the Phase 1 estimate of 53,991 to 54,000 before adding the 2014 forecast of 70 additional customers). In a subsequent data request response (to ORA DR 19 Question 2), PG&E stated that it had over 40,000 opt-out customers as of October 5, 2013, which is approximately 10,000 fewer than it had forecasted.

[69] In ORA's testimony in A.11-03-014 (p. 3-10ff), it was recommended that utilities investigate the possibility of reducing the meter reading frequency from monthly to quarterly. If this recommendation were implemented, the opt-out meter reading costs would be even lower than $9.1 million.

PG&E excludes the SmartMeter opt-out program revenues because it regards these revenues as speculative. In response to a ORA data request, PG&E stated that "the Commission approved only interim fees" in Decision (D.) 12-02-014, and that a proposed decision addressing cost and cost allocation issues has not yet been issued.[70] While the Commission has yet to definitively resolve the issues of cost and cost allocation in the SmartMeter Opt-Out proceeding, ORA submits that, if the Commission were to eliminate or significantly reduce opt-out fees, then program costs would be further socialized. If this were to occur, the SmartMeter opt-out program begins to resemble a public purpose program. Public purpose programs such as the CARE, Energy Efficiency, and Demand Response currently are not included in marginal access customer costs. This is true even though one could make the argument that adding customers potentially increases the number of participants in these other programs just as much as it could add to the number of participants in the SmartMeter opt-out program.

There is strong justification to merely regard the Smart Meter Opt-Out Program as a public purpose program and thus to exclude entirely its associated costs from marginal customer access costs.[71] But ORA instead determined to employ a more conservative approach and to use ORA's own Smart Meter Opt-Out Program costs and revenues that it proposed in Phase 1 of this GRC. This results in a significantly reduced net cost relative to what PG&E has proposed. In the future, ORA may reconsider this position and recommend excluding such costs from marginal customer access costs altogether depending on developments in the SmartMeter opt-out proceeding. ORA notes that PG&E's argument for excluding SmartMeter opt-out revenues because they are speculative ignores the fact that the participation and costs associated with the program

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[70] PG&E response to ORA data request 14 Question 2

[71] ORA notes that the SmartMeter opt-out program fees currently cover about half of the program costs. This is comparable to PG&E's effective CARE subsidy of around 47%. Moreover, pursuant to AB 327, PG&E must decrease its CARE subsidy to between 30% and 35% over time. Yet the SmartMeter opt-out program fees could decrease to zero if the proposals of some parties are adopted. If the opt-out program fees were to decrease even by a small amount, this would render the subsidy level in that program even higher than what it will be in the CARE program in the future.

also are speculative at this time. If SmartMeter Opt-Out program costs are included in the RCS calculation, it is more appropriate to account for some level of participating customer contribution as opposed to using a $0 fee as PG&E has done.

. Billing exceptions costs after SmartMeter deployment

A second forecast input to PG&E's 2014 RCS update model is the anticipated frequency of non-interval billed exceptions, which PG&E estimates at 0.9 percent. This percentage is multiplied by the "Non Interval Billed Population (meters) – Data Exception Processing Only" to produce an estimated volume of daily transactions. As an explanation for this exceptions rate, PG&E's GRC Phase I workpapers state:

> …forecasts the data exception rate applicable to [2014 Non Interval Billed Population (meters) – Data Exception Processing Only]. Currently, when a customer needs to transition to interval billing, PG&E evaluates the meter connectivity and read rate to ensure reliable data is available from that site. Meters with less than acceptable read rates are either serviced, replaced, or other actions are taken to resolve the problem prior to the utilization of interval data for billing. With the overall conversion of all SmartMeters to daily data processing, the estimate of data exceptions requiring manual correction is forecast to be higher than for [2014 Forecast Interval Billed Population (meters) – Data and Billing Exceptions Processing], and PG&E has estimated this at 0.9% for purposes of forecasting the required headcount. [72]

ORA disagrees with using this figure as the basis for estimating ongoing billing exceptions costs because the rate reflects the frequency of exceptions that PG&E anticipates in the process of ***transitioning*** customers from monthly-read data to hourly-read data for billing purposes. As a result of the anticipated work associated with reviewing meter connectivity and read rates, the rate of billing exceptions should be reduced substantially, even beyond the historical level of approximately 500 transactions per day, which is a billing exceptions rate of approximately 0.01 percent.[73]

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[72] A.12-11-009 Exhibit PG&E-5, Chapter 4, WP 4-30, note for Line 17 'Data Exception Rate'

[73] A.12-11-009 Exhibit PG&E-5, Chapter 4, page 4-17.

Moreover, PG&E plans to implement an Interval Data Processing and Exception Management project, which would reduce the need for manual intervention for exception processing. While this project is not anticipated to be operational till late 2015, ORA expects that this project will further reduce the amount of manual exceptions processing work that staff will need to perform on an ongoing basis.

Clearly the 0.9 percent billing exceptions rate is much higher than the historical rate of 0.01 percent, thus ORA asked how the estimate was produced. In response to ORA's request, PG&E stated that it "has not retained the historical data used to derive the Data Exception Rate." Without this data or other substantiation, ORA is unable to assess the accuracy of this estimate. In the same response, PG&E concedes that "billing exceptions are expected to decrease as PG&E completes SmartMeter deployment." PG&E, however, further explains that:

> The Data Exception rate will never be zero. Billing exceptions do not stem solely from a lack of meter connectivity as deployment is completed, but can result from, among other conditions, damaged meters, meter/module communication failures, network transmission failures, and records exceptions, conditions that can occur even with SmartMeter™ deployment.[74]

This statement is somewhat in conflict with PG&E's explanation, in the Phase 1 workpaper WP-40, of what the 0.9% rate represents. That workpaper states that the work performed focuses on transitioning customers to interval data reading and on "[m]eters with less than acceptable read rates [that] are either serviced, replaced, or other actions are taken to resolve the problem prior to the utilization of interval data for billing." It does not state that the 0.9percent estimate relates to ongoing issues that include damaged meters and records exceptions.

Given that PG&E did not retain the data needed to substantiate its forecast, ORA reviewed various SmartMeter status reports filed by PG&E to seek an estimate of billing exceptions that will likely persist after PG&E completes the transition from monthly

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[74] PG&E response to ORA DR 19 Question 2.

reads to hourly reads. Specifically, PG&E's semi-annual assessment reports include a set of "Performance Criteria," including an "Electric billing data collection failure rate." PG&E defines this metric as

> …the number of electric SmartMeters™ from which complete data (complete backhaul data, daily anchor, and complete set of intervals) were not retrieved, divided by the total number of electric SmartMeters™. This measure consists of the percentage of complete daily data sets, one good anchor read and complete good interval reads, averaged over the defined period. Any service point with an estimated anchor and/or estimated interval read(s) fails this measure and is excluded. Failure of this read metric does not lead to an estimated bill; an accurate bill can be generated in most cases."[75]

Although the particular metrics provided in PG&E's AMI reports do not align perfectly with the factors that lead to billing exceptions, as described by PG&E,[76] the billing data collection failure rate reported in PG&E's semi-annual assessment report is a better proxy for the likely rate of billing exceptions that PG&E will experience after it corrects for meter connectivity and/or unacceptable read rates. ORA substituted the most recent data collection failure rate of 0.18 percent (for the July – December 2012 period) in place of PG&E's forecasted 0.9 percent in the RCS update model. ORA's revisions lead to a reduction in billing exceptions costs from $32.6 million per year to $10.2 million per year for residential customers.

ORA noticed that the billing exceptions rate for larger non-residential customers also were quite high. ORA inquired and was told that these costs relate to the retention of 10,077 MV-90 meters, which entail higher exceptions processing costs than the newer SmartMeters. PG&E's response to ORA's Data Request #19, Question 2f, states:

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[75] A.05-06-028 Pacific Gas and Electric Company Advanced Metering Infrastructure Semi-Annual Assessment Report SmartMeter™ Program Quarterly Report, July 1 – December 31, 2012 (CPUC Decisions 06-07-027 and 09-03-026), filed April 2, 2013, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M064/K670/64670664.PDF, pp. 21-22.

[76] PG&E's monthly status reports include a different "performance indicator," on "SM Billing accuracy % (SA)". The most recent monthly status report (for August 2013) shows a year-to-date billing accuracy rate of 99.81%, in other words 0.19% of bills were not accurate. This metric does not seem to relate as directly to billing exceptions as does the billing data collection failure rate.

> PG&E acknowledges that the electric MV-90 meters were originally planned to be replaced by SmartMeters™. In the process of deploying SmartMeter™ technology to these locations, however, PG&E determined for several reasons that it was more customer-friendly and less of a customer impact to allow these customers to keep their MV-90 meters unless they expressed a preference for SmartMeters™.

Given PG&E's intention to retain these older meters, ORA did not adjust the billing exceptions rates for these customers.

B. Calculation error in PG&E's RCS Model

During ORA's examination of PG&E's RCS model, ORA identified a calculation within the Billings and Collections dataset that appeared inconsistent with PG&E's proposed methodology for calculating such costs. Specifically, the totals of the Billings and Collections dataset, as presented in PG&E's August 2013 updated workpapers, were based on total costs rather than electric only costs. ORA inquired about this apparent inconsistency and, in response, PG&E acknowledged the calculation error and stated that it will submit an erratum to correct the error. As part of its response, PG&E confirmed what the correct RCS results should have been, as compared with the results shown in their August 2013 workpapers.[77]

C. Results: Revenue Cycle Services Costs

The effect of ORA's various adjustments to the RCS costs are shown in Table 3-5 below. PG&E's estimates are shown before and after the correction of the error related to billing and collections costs discussed in Section B above.

To these RCS costs PG&E adds Account 903 costs. The Account 903 costs are miscellaneous costs not captured in PG&E's RCS models that include electric safety and reliability outreach, local office and neighborhood payment center transactions, and a number of other cost categories. ORA does not challenge the Account 903 cost

[77] PG&E response to ORA data request 13 Question 15.

estimates. The RCS and account 903 costs both are broken out separately in Table 3-1 above.

Table 3-5

Revenue Cycle Services Results Excluding Account 903 Costs (Before and After Correction of Error in Billing and Collections Cost)

Customer Class	**PG&E's RCS Results – Before Correction**	**PG&E's RCS Results – After Correction**	**ORA's RCS Results**
Residential	$41.90	$33.62	$21.14
Agricultural A	$83.24	$63.06	$31.25
Agricultural B	$124.87	$104.69	$41.58
Small L&P	$66.99	$46.11	$29.87
A10 Medium L&P Secondary	$173.15	$152.96	$120.91
A10 Medium L&P Primary	$615.34	$595.15	$252.89
E19 Secondary	$277.97	$257.79	$189.93
E19 Primary	$774.95	$754.77	$489.30
E19 Transmission	$1,135.62	$1,115.44	$445.65
E20 Secondary	$1,075.27	$1,055.08	$796.87
E20 Primary	$1,174.46	$1,154.27	$777.25
E20 Transmission	$1,145.75	$1,125.56	$740.73
Streetlights	$16.65	$9.15	$8.44
Traffic Control	$66.99	$46.11	$7.40

V. CONCLUSION

ORA recommends that the Commission adopt its recommended modifications to PG&E's NCO methodology for marginal customer access costs, as described in this chapter.

CHAPTER 4
REVENUE ALLOCATION
DANIEL WILLIS

I. SUMMARY AND RECOMMENDATIONS

This Chapter presents the ORA revenue allocation recommendations for PG&E GRC Phase II, A.13-04-012. ORA's revenue allocation in part is based on its marginal cost recommendations that are explained in ORA Chapters 1, 2, and 3. In addition, this Chapter discusses the allocation of miscellaneous costs, such as Demand Response (DR) programs and incentive costs; the allocation of discounts associated with the Family Electric Rate Assistance (FERA) low-income customer program; and the method used to cap customer class revenue changes.

The following list summarizes ORA's recommendations:

- The Commission should adopt ORA's revenue allocation recommendations, which reflect ORA's marginal costs and allocations of miscellaneous revenues and are summarized in tables 4-1 and 4-2.
- Most of the 16 miscellaneous revenue accounts should be allocated to customer classes on either an equal percent of revenue or an equal cents per kWh basis, instead of by PG&E's proposed allocation using distribution marginal cost.[78]
- FERA program costs should be allocated to all customer classes on an equal cents per kWh basis and consistent with the allocation of the CARE program funding.
- ORA supports PG&E's capping proposal to moderate class revenue changes. PG&E caps the rate changes by limiting them to plus or minus three percent for bundled service customers and plus or minus six percent for DA/CCA customers.[79]

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[78] Table 4-3 presents ORA's proposed allocations for each.

[79] Using ORA's marginal cost and revenue allocation methodologies, the amount of revenue that must be reallocated under PG&E's proposed caps of three and six percent is too great to be absorbed by uncapped classes. Thus, ORA caps revenue changes at four and eight percent.

Tables 4-1 and 4-2 compare ORA's recommended revenue allocation for bundled service customers and for DA/CCA customers, respectively. The allocations below reflect capping to mitigate bill impacts. The uncapped allocations are found in section V below at tables 4-7 and 4-8. PG&E explains that the results of this process "reflect only the changes in revenue allocation and rate design proposed in this proceeding such that total revenue is equal to revenue at current rates."[80] That is, the revenue allocation results presented here do not reflect any changes to rates that are expected from Phase I of this GRC proceeding. Thus, any Phase II increases will be on top of the system-wide increase approved therein.

Table 4-1

PG&E'S and ORA'S Revenue Allocation, Bundled Service Customers

Class	Present (May 2013) Revenue ($000)	PG&E Proposal (3% Bundled Cap)[81]		ORA Position (4% Bundled Cap)	
		Proposed Revenue ($000)	Average Percent Change	Proposed Revenue ($000)	Average Percent Change
Residential	5,309,098	5,339,069	0.6%	5,198,224	-2.1%
Small	1,613,897	1,645,378	2.0%	1,549,334	-4.0%
Medium	1,239,675	1,202,485	-3.0%	1,240,055	0.0%
E-19	1,816,598	1,762,100	-3.0%	1,872,203	3.1%
Streetlights	69,902	71,999	3.0%	72,698	4.0%
Standby	57,393	58,800	2.5%	59,606	3.9%
Agriculture	864,360	890,290	3.0%	898,934	4.0%
E-20	1,178,493	1,182,611	0.3%	1,225,434	4.0%
System[82]	12,149,416	12,152,733	0.0%	12,116,488	-0.3%

[80] PG&E, A.13-04-012, Ex. PG&E-4, p.1-10:ll. 10–12 (dated Aug. 16, 2013).

[81] Per ALJ Long's October 18, 2013 Ruling in this proceeding, A.13-04-012, to defer work on residential rate design, ORA's recommendations would maintain the status quo for that class, but PG&E's proposal as presented above would include its changes to residential rate design as originally proposed.

[82] ORA's recommended marginal cost and revenue allocation changes result in different overall revenues being allocated between bundled and DA/CCA customers.

Table 4-2

PG&E'S and ORA'S Revenue Allocation, DA/CCA Customers

Class	Present (May 2013) Revenue ($000)	PG&E Proposal (6% Bundled Cap)		ORA Position (8% Bundled Cap)	
		Proposed Revenue ($000)	Average Percent Change	Proposed Revenue ($000)	Average Percent Change
Residential	85,604	83,225	-2.8%	80,874	-5.5%
Small	32,282	34,219	6.0%	29,699	-8.0%
Medium	53,964	53,195	-1.4%	58,276	8.0%
E-19	223,887	217,581	-2.8%	241,798	8.0%
Streetlights	888	941	6.0%	959	8.0%
Standby	1,708	1,605	-6.0%	1,571	-8.0%
Agriculture	3,111	3,298	6.0%	3,360	8.0%
E-20	221,675	225,701	1.8%	239,409	8.0%
System	623,118	619,764	-0.5%	655,947	5.3%

II. MARGINAL COST REVENUE ALLOCATION

In order to determine each class's revenue responsibility for distribution and generation,[83] PG&E allocates revenue requirements for these functions on an unbundled basis using their separate marginal cost revenues. Within distribution and generation, marginal cost revenues are assigned to each class and then scaled up using Equal Percentage of Marginal Cost (EPMC) allocation factors and then added together to match the total revenue requirement for each. This approach is consistent with Commission policy.

A. Marginal Distribution Cost Revenue

Distribution marginal costs are those associated with providing customer access to and accommodating customer demand on the distribution system. They are composed of marginal customer access costs and marginal distribution capacity costs. To calculate a

[83] Transmission revenue is set separately by the Federal Energy Regulatory Commission (FERC) and thus is not at issue in this proceeding.

class's total marginal customer access cost revenue, the yearly marginal customer costs for each customer class are multiplied by the forecast number of customer-months divided by 12.[84] Marginal distribution capacity costs, or demand-related distribution marginal costs, are estimated for both the primary and secondary distribution systems and then multiplied by aggregate customer maximum demand, measured using class loads at the substation and at the final line transformer levels respectively.

B. Marginal Generation Cost Revenue

Marginal generation cost revenues are composed of those associated with generation capacity costs and generation energy costs. Generation capacity costs represent the cost to serve an additional kW of demand. Marginal cost revenues are developed by multiplying marginal capacity costs by each customer class' average contribution to system peak, measured using their Peak Capacity Allocation Factor (PCAF)[85]. Marginal energy cost revenues for each class are calculated by multiplying a customer class' forecast sales in each TOU period by the marginal energy cost for each period.

ORA agrees with the methodology that PG&E uses to calculate marginal cost revenues, but develops its own values for the marginal cost inputs. These values are the result of various adjustments to the methodologies that are addressed in Chapters 1, 2 and 3 of ORA's testimony. The differences in the marginal cost inputs account for part of the difference between the two parties' respective revenue allocation proposals.

III. MISCELLANEOUS ACCOUNTS IN DISTRIBUTION RATES

As part of the distribution revenue requirement, PG&E's work papers include the allocation of 16 miscellaneous revenue components, including the California Solar

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[84] Ex. PG&E-4, *supra* note 80, at p.2-11:ll. 11–13.

[85] According to Ex. PG&E-4, *supra* note 80, at 2-11:ll. 20–24:

> Using the system PCAF method, PG&E has estimated each class' average contribution to system peak during a recorded three year period. These recorded kW values are converted to forecast system PCAF weighted loads by multiplying them by the ratio given by TY sales divided by recorded sales.

Initiative (CSI), DR Programs, and PG&E's Cornerstone Improvement Project. PG&E proposes that each of these accounts be allocated between customer classes based on each class's contribution to Distribution Revenue after being scaled up using EPMC. ORA does not agree that every one of these accounts should be allocated using this method, as most of them are not primarily caused by customers' use of the distribution system. ORA follows cost-causation principles and divides these accounts into the following groups for purposes of assigning allocation factors:

- Demand Response related accounts should be allocated on an equal percent of revenue (EPR)[86] basis;
- Programs related to enhancing distribution reliability or to meeting increased customer access and demand on the distribution system should be apportioned using PG&E's recommended distribution allocator; and
- Programs providing a broad environmental or social benefit should be allocated to non-exempt classes on an equal cents per kWh basis.

Under ORA's recommendation, these allocation proposals would be used to determine class revenues in this proceeding, as well as to allocate revenue changes between this GRC and PG&E's next GRC. Table 4-3 presents ORA's recommended allocation methods, and table 4-4 shows the percentage of revenues for which each customer class is responsible under each approach.

[86] Equal percentage of revenues including imputed Direct Access generation revenues, identified in PG&E work papers as "Total Revenue w/ DA Gen Imputed." See PG&E, A.13-04-012, Work Papers re ex. PG&E-4, ch. 2 (PG&E CD-ROM 1, Aug. 23, 2013, in file "CONF_RA_Rev Alloc_GRC.xlsx"; tab "CALC_Allocators," and cell E10).

Table 4-3

Miscellaneous Revenue Components

	Estimated Total Revenue ($000)	ORA Proposed Allocator
Demand Response Related		
Demand Response and AC Cycling (DRRBA/ACC)	79,720	EPR
Base Interruptible Program (E-BIP)	24,036	EPR
28 percent of Advanced Metering (AMI/SMBA)[87]	36,747	EPR
Revised Customer Energy Statement (RCESBA)	363	EPR
Customer Energy Efficiency Incentive Account (CEEIA)	18,950	EPR
Compressed Air Energy Storage	2,477	EPR
Dynamic Pricing Memorandum Account (DPMA)	1,278	EPR
Distribution Related		
72 percent of AMI/SMBA	94,493	Dist. EPMC
Cornerstone	45,559	Dist. EPMC
Meter Reading Cost Balancing Account (MRCBA)	35,208	Dist. EPMC
Cost of Capital[88]	(118,267)	Dist. EPMC
Environmental or Social Programs		
California Solar Initiative (CSI)	79,750	Equal Cents[89]
Self-Generation Incentive Program (SGIP)	30,751	Equal Cents
Environmental Enhancement	10,169	Equal Cents
Hazardous Substance Mechanism (HSM)	17,038	Equal Cents
CPUC Fee	20,681	Equal Cents
Non-Tariffed Balancing Account (NTBA)	(341)	Equal Cents
Total	378,619	

[87] Twenty-eight percent of the AMI benefits were expected to come from cost reductions due to Demand Response/ Dynamic Pricing. The remaining seventy-two percent were justified based on expected operational/ distribution cost savings.

[88] As explained below, a portion of this reduction was allocated within generation rates.

[89] Equal cents per kWh, identified in PG&E work papers as "Total Sales." See PG&E, A.13-04-012, Work Papers re ex. PG&E-4, ch. 2 (PG&E CD-ROM 1, Aug. 23, 2013, in file "CONF_RA_Rev Alloc_GRC.xlsx"; tab "CALC_Allocators," and cell F10).

Table 4-4

Miscellaneous Revenue Allocators[90]

Customer Class	After Movement Distribution Revenue (Dist. EPMC)	Total Revenue w/ DA Gen Imputed (EPR)	Total Sales (Equal Cents)
Residential	49.7%	40.1%	36.6%
Small	12.4%	12.3%	10.0%
Medium	8.9%	10.0%	9.2%
E-19	13.4%	17.2%	18.7%
Streetlights	0.6%	0.5%	0.5%
Standby	0.2%	0.4%	0.6%
Agriculture	8.7%	6.4%	6.7%
E-20	6.1%	13.0%	17.8%
Total	100.0%	100%	100%

A. Demand Response Related Revenues

In *PG&E*, D.12-04-045, the Commission defines Demand Response activities and budgets for 2012-2014, stating its objectives as follows:

> The Commission broadly defines Demand Response (DR) as reductions or shifts in electricity consumption by customers in response to either economic or reliability signals. Economic signals come in the form of electricity prices or financial incentives and reliability signals present themselves as alerts during times when the electricity system is vulnerable to extremely high prices or reliability is compromised. We have generally categorized DR programs according to whether their purpose is to address spikes in market prices in the case of price-responsive programs or Dynamic Pricing or to relieve threats to system reliability in the case of reliability programs. Regardless of the category, the intent of the DR programs is to take advantage of these signals to maximize ratepayer benefit.[91]

As explained in D.12-04-045 stated above, in D.10-12-024 the Commission adopted a method for estimating the cost-effectiveness of DR activities. The avoided

[90] These allocation percentages reflect DRA's marginal cost recommendations.

[91] *PG&E*, D.12-04-045, 2012 Cal. PUC LEXIS 193, at *2-3 (dated Ap. 19, 2012).

costs attributable to a DR program that determine its cost-effectiveness, are primarily based on avoided generation capacity costs:

> The Protocols… use the Avoided Cost calculator developed by Energy and Environmental Economics, Inc. (E3) to determine all avoided costs, which are the primary benefits of DR programs.[92]

> The Protocols allow the Utilities to specify five adjustment factors to the avoided costs. These adjust the avoided generation capacity cost for an individual DR program based on the following factors: "A" - availability of the program; "B" - notification times; "C" - trigger flexibility; "D" – distribution; and "E" – energy price.[93]

It is clear that the Commission views DR as an alternative to procuring generation resources. Discussing IOU contracts with third party DR providers, D. 12-04-045 also states:

> We must be consistent in enforcing the loading order articulated in Energy Action Plan II and ensure that the Utilities do not procure or build conventional generation when DR may meet the same system need.[94]

In reference to complying with California's RPS goals, the Commission notes:

> Large amounts of intermittent generation create operational complexities for the grid operator. DR and energy storage should be available for ramp up and ramp down, compensation for over-generation, and balance of the system.[95]

PG&E has characterized Dynamic Pricing-related Demand Response in a similar manner in one of its AMI proceedings:

> Demand Response impacts refer to the change in customer-specific peak demand and energy use, by rate period, resulting from time-varying tariffs. In this chapter, the term "financial benefits" means the monetary value of reductions in both capacity and energy that

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[92] *Id.* at *43.

[93] *Id.* at *43 n.60.

[94] *Id.*at *107.

[95] *Id.* at *269.

> flow from changes in peak demand and energy use induced by new tariffs.[96]
>
> Demand Response benefits largely accrue from system peak load reductions resulting from customer response to Dynamic Pricing. The most significant of the benefits is the avoided cost of procuring incremental electric [generating capacity] or alternative Demand Response capacity resources during summer critical peak hours. A secondary benefit is obtained by the reduction in future costs of transmission and distribution upgrades. A relatively minor benefit results from the reduction in energy procurement costs.[97]
>
> This chapter discusses the financial benefits associated with avoided generation capacity and changes in the total cost of energy needed to meet demand.[98]

While the benefits of Demand Response are predominantly generation-related, they may be able to reduce or defer distribution and transmission investments as well. Thus ORA recommends that DR implementation costs be allocated to all customers using a methodology that reflects total revenues. Using the equal percent of revenues allocation is a balanced approach recognizing that DR benefits primarily accrue to customers in the form of reduced generation costs and secondarily as reduced transmission and distribution costs.

In addition to the Demand Response and Dynamic Pricing accounts, ORA recommends that the following accounts be allocated in the same manner to recognize their similar attributes:

- The Base Interruptible Program (E-BIP), which is clearly identified as a Demand Response Program and funded through D.12-04-045;
- Compressed Air Energy Storage, used for Permanent Load Shifting, which also falls under the umbrella of DR;[99]

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[96] PG&E, A.05-06-028, Ex. PGE-4, ch. 5, p. 5-1:ll. 9-14.

[97] *Id.* at p. 5-2:ll. 14-20.

[98] *Id.* at p. 5-2:ll. 21-23.

[99] In *PG&E*, D.10-01-025, the Commission finds that the Compressed Air Energy Storage Demonstration project "has the potential to improve grid reliability, flexibility, security and interoperability; lower
(continued on next page)

- Revised Customer Energy Statement, developed in large part to provide customers with the information needed to enroll in dynamic pricing options;[100]
- Twenty-eight percent of the Advanced Metering Infrastructure/ Smart Meter Balancing Account, the proportion of AMI benefits meant to be realized through Demand Response and Dynamic Pricing; and
- Allocating the Customer Energy Efficiency Incentive Account by equal percent of revenues would be consistent with the current allocation of the Energy Efficiency costs that are part of Public Purpose Programs.[101]

B. Distribution Related Revenues

ORA allocates the costs of the Cornerstone Improvement Project, Meter Reading Cost Balancing Account, and 72 percent of the AMI Balancing Account based on the distribution EPMC allocator. This is because these costs are associated with distribution functions or programs that will defer distribution investments. In addition, PG&E includes in these accounts a Cost of Capital reduction of $119 million. A portion of the overall reduction has already been allocated to generation,[102] thus ORA agrees that the remaining should be allocated based on distribution revenues.

C. Environmental / Social Program Revenues

The CSI, the Self-Generation Incentive Program (SGIP), Environmental Enhancement and the Hazardous Substance Mechanism (HSM) are programs that exist to

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(continued from previous page)

electric power systems costs and enhance cost effectiveness; and reduce greenhouse gases." *Id.,* 2010 Cal. PUC LEXIS 12, at *2 (issued Jan. 22, 2010).

[100] PG&E's 2011 GRC Phase II Testimony included an exhibit requesting funding for both Dynamic Pricing and its Revised Customer Energy Statement, in which it stated, "PG&E requests the Commission approve a proposal for revisions to PG&E's customer energy statement pursuant to the recently enacted California Assembly Bill 1763, to incorporate dynamic pricing information, and to fulfill the Commission's request that California Investor Owned Utilities implement customer-friendly billing formats" PG&E, A.10-03-014, Ex. PG&E-3, p. 1-1:ll. 11-16.

[101] It is ORA's understanding that PPP revenues not including the CARE surcharge have historically been allocated using a total revenue allocator, and the allocation of these costs in PG&E's work papers most closely aligns with that achieved using the EPR allocator.

[102] PG&E Advice 4096-E-A, p. 11, Table 2 footnote 1. http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4096-E-A.pdf

provide broad environmental benefits for all California ratepayers. The Commission has consistently allocated the costs of these types of programs based on sales, using either an equal cents per kWh or equal cents per therm allocator.

The CSI and SGIP programs offer incentives to IOU customers to install distributed generation as part of California's energy policy goals. In D.06-01-024, which adopted the CSI program, the Commission stated:

> The development of solar energy projects is consistent with state policies generally that support environmentally sound energy resources and an energy infrastructure that is diverse and disbursed.[103]

The Commission also found:

> All solar energy technologies have the potential to reduce demand for fossil fuels and investments in more traditional energy resources and provide environmental benefits.[104]

In addition, the Commission found in its decision adopting the initial SGIP program that, "The self-generation programs … will produce significant public (e.g., environmental) benefits for all ratepayers."[105]

In the past, the Commission has decided to allocate the costs of similar programs on a volumetric basis by sales. Regarding the Natural Gas Vehicle Program (NGV), the Commission concluded,

> The Legislature has declared that the pursuit of cleaner air and relief from global warming is in the public interest. There is nothing in the hearing record which suggests that these benefits, as well as the strategic advantage of lowering our dependence upon foreign oil, will not be realized by the successful implementation of this

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[103] *R. 04-03-017*, D.06-01-024, 2006 Cal. PUC LEXIS 529, at *57 (Find. of Fact 1) (dated Jan. 12, 2006).

[104] *Id.* at *58 (Find. of Fact 5).

[105] *R.98-07-037*, D.01-03-073, 2001 Cal. PUC LEXIS 218, at *57 (Find'g of Fact 3) (dated March 27, 2001).

> program. To the extent that they are, they will be enjoyed by all Californians in their capacity as ratepayers.[106]

The Commission further stated,

> The fixed infrastructure costs associated with the NGV program result in air quality benefits enjoyed by all Californians in their capacity as ratepayers and, as such, should be recovered on an equal cents per therm basis over all volumes sold by PG&E to all customer classes consistent with the intent of Public Utilities Code § 740.3(c).[107]

Furthermore, in a 2007 Biennial Cost Allocation Proceeding, the Commission made a clear determination that gas SGIP costs should be allocated volumetrically:

> Consistent with our view that all customers should pay for programs that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers and adopt PG&E's proposal to allocate the costs on an equal cents per therm basis.[108]

Similarly, the Environmental Enhancement[109] and Hazardous Substance Mechanism budgets should be allocated by equal cents per kWh in recognition of the broad environmental benefit that they provide to PG&E ratepayers. Finally, ORA sees no reason why the CPUC fee revenues should be allocated among customer classes according to their access to and use of the distribution system, as PG&E has proposed. In fact, P.U. Code § 432(b) regarding the CPUC Fee states:

> The commission may establish different and distinct methods of assessing fees for each class of public utility, if the revenues collected are consistent with paragraph (2) of subdivision (a), *except that the commission shall establish a uniform charge per kilowatt hour for sales in kilowatt hours for the class of electrical*

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[106] *PG&E*, D.91-07-018, 40 CPUC2d 722, 1991 Cal. PUC LEXIS 509, at *50–51 (dated July 2, 1991).

[107] *Id*. at *69–70 (Find'g of Fact 13).

[108] *PG&E*, D.05-06-029, 2005 Cal. PUC LEXIS 238, at *25 (dated June 16, 2005).

[109] To ORA's knowledge, this amount funds PG&E's Stewardship Council, which manages watershed lands owned by PG&E for conservation purposes.

corporations and a uniform charge per therm for sales in therms for the class of gas corporations.[Emphasis added.][110]

ORA's changes to the allocation of the miscellaneous revenues are presented in Table 4-5 below.[111]

Table 4-5

ORA Reallocations of Miscellaneous Revenues

Misc. Revenue Allocation by Class (000$)			
Class	**PG&E Allocators**	**ORA Allocators**	**Change in Revenue**
Residential	189,541	151,820	(37,721)
Small	61,368	43,030	(18,338)
Medium	27,900	36,024	8,124
E-19	40,249	65,197	24,948
Streetlights	2,044	1,924	(121)
Standby	778	1,732	954
Agriculture	37,243	26,023	(11,220)
E-20 T	19,497	52,870	33,373
System	378,619	378,619	-

IV. CARE AND FERA DISCOUNT COSTS

PG&E proposes to continue to allocate the revenue requirement caused by the CARE shortfall on an equal cents per kWh basis to all eligible customers, and to recover this shortfall using the CARE surcharge component of Public Purpose Programs (PPP) charges. PG&E explains that this treatment is "consistent with the language in Pub. Util. Code 327(a)(7) established by enactment of Senate Bill 695."[112] ORA continues to support the Commission precedent of allocating the CARE Program costs to all PG&E

[110] Cal. Pub. Util. Code § 432(b) (Deering, LEXIS through Chapter 800 of *** the 2013 Regular Session and through Ch. 5 of the First Extra Session of the 2013-2014 Legislature).

[111] ORA notes that in its most recent Annual Electric True-Up filing, Advice 4278-E, PG&E includes several additional line items under the Distribution heading for pending proceedings. ORA recommends that should these revenue items be approved, parties must be allowed to take a position on their allocation if the specific method is not determined in the respective proceedings.

[112] PG&E, A.13-04-012, Ex. PG&E-4, p. 2-7:ll. 14–18.

customers on an equal cents per kWh basis, and further proposes to allocate the FERA Program costs in the same manner.

The estimated FERA funding for 2014 is $7,867,540, as shown in PG&E's revenue allocation work papers. PG&E proposes to allocate these costs entirely to the residential class. The FERA program provides monthly discounts for income qualified residential households who do not quite qualify for the CARE program. These discounts are generally more moderate than those for CARE, but the reason for the program is the same. The Commission has recognized the need to provide low-income households with affordable electricity service. Moreover, Pub. Util. Code § 382(b) requires this goal to be met, as follows:

> In order to meet legitimate needs of electric and gas customers who are unable to pay their electric and gas bills and who satisfy eligibility criteria for assistance, recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures. Energy expenditure may be reduced through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs.[113]

In *PG&E,* D.05-06-029, the Commission held that all customers should contribute to funding of the CARE subsidy, as follows:

> We are not convinced by PG&E's claim that CARE program benefits inure entirely to residential customers. We believe that all businesses and individuals benefit from the economic welfare of the greater community.[114]

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[113] Pub. Util. Code § 382(b) (Deering, LEXIS through Chapter 800 of *** the 2013 Regular Session and through Ch. 5 of the First Extra Session of the 2013-2014 Legislature). On October 7, 2013, Governor Brown signed Assembly Bill 327, which amended Pub. Util. Code § 382 to give the Commission more authority to tailor residential rate design for low-income ratepayers based on differing income levels. *See* Stats. 2013, ch. 611, § 1, *available at* LEXIS 2013 Bill Text CA A.B. 327. However, the bill maintains the strong commitment to protect California's low-income ratepayers.

[114] *PG&E*, D. 05-06-029, 2005 Cal. PUC LEXIS 238, at *22 (dated June 16, 2005).

Consistent with the Commission's views on the CARE program, it is ORA's position that FERA also provides societal benefits to all ratepayers. Therefore, the costs of providing the two programs should be treated similarly and paid for by all customer classes on an equal cents per kWh basis. Furthermore, Pub. Util. Code § 739.1(e)(2) states:

> The commission shall ensure that an electrical corporation or gas corporation with a commission-approved program to provide discounts based upon economic need in addition to the CARE program, including a Family Electric Rate Assistance program, utilize a single application form, to enable an applicant to alternatively apply for any assistance program for which the applicant may be eligible.[115]

It is clear that California policymakers view the two programs as providing the same type of necessary assistance to ratepayers, and ORA proposes that the costs of the two programs be treated the same way as well.

Table 4-6 presents ORA's reallocation to customer classes of the estimated FERA program revenues, which PG&E allocates to the residential class only.[116]

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[115] Pub. Util. Code § 739.1(e)(2) (Deering, LEXIS through Chapter 800 of *** the 2013 Regular Session and through Ch. 5 of the First Extra Session of the 2013-2014 Legislature).

[116] PG&E's revenue allocation work papers divided the FERA program into both the generation and distribution revenue requirements. ORA has reallocated all FERA revenues among the non-allocated distribution revenues only, which are directly assigned to each customer class, per PG&E's Electric Preliminary Statement Part CZ.

Table 4-6

ORA FERA Reallocation

Customer Class	FERA Program Costs ($000)
Residential	2,879
Small	789
Medium	727
E-19	1,469
Streetlights	36
Standby	44
Agriculture	526
E-20 T	1,398
System	7,868

V. MITIGATION

A. Capping Class Revenue Changes

Table 4-7 and 4-8 show PG&E and ORA's revenue allocation results if no capping mechanism were implemented. That is, the tables present total class revenues if each class were immediately moved to its full cost-based revenue responsibility.

Table 4-7

PG&E'S and ORA'S Revenue Allocation (Based on Full-Cost, Bundled)

Class	Present (May 2013) Revenue ($000)	PG&E		ORA	
		Total Revenue ($000)	Average Percent Change	Total Revenue ($000)	Average Percent Change
Residential	5,309,098	5,252,705	-1.1%	5,155,126	-2.9%
Small	1,613,897	1,644,941	1.9%	1,491,745	-7.6%
Medium	1,239,675	1,166,524	-5.9%	1,229,848	-0.8%
E-19	1,816,598	1,744,465	-4.0%	1,860,946	2.4%
Streetlights	69,902	81,465	16.5%	83,507	19.5%
Standby	57,393	57,108	-0.5%	59,655	3.9%
Agriculture	864,360	1,050,270	21.5%	1,001,247	15.8%
E-20	1,178,493	1,167,474	-0.9%	1,233,518	4.7%
System	12,149,416	12,164,951	0.1%	12,115,592	-0.3%

Table 4-8

PG&E'S and ORA'S Revenue Allocation (Based on Full-Cost, DA/CCA)

Class	Present (May 2013) Revenue ($000)	PG&E		ORA	
		Total Revenue ($000)	Average Percent Change	Total Revenue ($000)	Average Percent Change
Residential	85,604	80,944	-5.4%	79,783	-6.8%
Small	32,282	34,412	6.6%	29,044	-10.0%
Medium	53,964	51,964	-3.7%	57,575	6.7%
E-19	223,887	212,838	-4.9%	239,873	7.1%
Streetlights	888	1,098	23.7%	1,134	27.7%
Standby	1,708	1,473	-13.7%	1,492	-12.6%
Agriculture	3,111	4,077	31.0%	3,709	19.2%
E-20	221,675	221,278	-0.2%	244,936	10.5%
System	623,118	608,085	-2.4%	657,545	5.5%

As shown above, moving immediately to the uncapped revenue allocation would significantly impact some classes. In addition, these tables do not include the effects of implementing PG&E's GRC Phase I revenue requirement request. PG&E proposes an increase to its revenue requirement of over 18 percent in 2014.[117] If a large portion of this request is approved, PG&E's customers will see a significant increase in their rates in 2014 regardless of the results of the revenue allocation process of this phase of the GRC proceeding. The bill impact from the compounding increases of the two phases for some customer groups would be too great.

Thus, ORA supports PG&E's proposal to limit these increases, even though doing so also would require limiting the revenue decreases for some classes, resulting in those customer groups shouldering a greater portion of the revenue requirement relative to the uncapped allocation. Moving classes that would benefit from their full EPMC level immediately to that level should not come at the expense of overwhelming increases for

[117] PG&E, A.12-11-009, Ex. ORA-1, p. 5:l. 6. Increase is over 2011 recorded expenses.

other classes. Thus, PG&E's proposal to cap class level increases is reasonable given that a considerable number of past Commission decisions have limited class-level revenue changes within a similar range.[118]

B. Capping Mechanism

In the first step of its capping mechanism, PG&E caps class level total revenue changes at plus or minus six percent and allocates revenues over or under the cap levels to uncapped classes within distribution rates according to each class' distribution marginal costs. ORA notes that this method has the effect of further muting any changes that ORA has proposed for the allocation of various distribution revenues in favor of those customer classes that have comparatively lower allocation factors for distribution marginal costs. For this reason, ORA has adjusted the mechanism to distribute revenues above or below the cap in the first step based on total distribution revenues (reflecting ORA's recommended changes) rather than by distribution marginal cost revenues.[119]

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[118] *See So. Cal. Edison*, D.96-04-050, 65 CPUC2d 362, 1996 Cal. PUC LEXIS 270, at *128–134 (dated Ap. 10, 1996), for a discussion of Commission policy on capping. Also, in SDG&E's 2000 Rate Design Window (RDW) the revenue allocation was capped at SAPC plus or minus three percent. *SDG&E*, D.00-12-058, 2000 Cal. PUC LEXIS 1013,*44-46 (Dec. 21, 2000). In Pacific Corp's 2003 GRC, the Commission granted an overall system average increase of 4.7 percent plus a cap of 2.5 percent. *See PacifiCorp.,* D.03-11-019, D. 03-11-019, 2001 Cal. PUC LEXIS 1266, at *14–15 (Find'g of Fact 3) (dated Nov. 13, 2003). In Sierra Pacific's 2003 GRC, the Commission granted an increase of 6.2 percent plus a cap of 2.6 percent. *See Sierra Pacific*, D.04-01-027, 2001 Cal. PUC LEXIS 1281, at *12–13 (dated Jan. 8, 2004).

[119] ORA makes this change because a portion of revenues paid for in distribution rates have little or no relationship with customer classes' distribution marginal costs. ORA does not make a similar change to the second step of the capping mechanism, because the issue does not arise for revenues paid for in generation rates.

VI. CONCLUSION

ORA recommends that the Commission adopt its revenue allocation proposals as described above, and adopt the allocations to each customer class shown in Tables 4-1 and 4-2. These results reflect ORA's proposed marginal cost calculations as well as ORA's changes to the allocation methods used for PG&E's miscellaneous revenue accounts, along with a reallocation of the FERA revenues to all customer classes. Lastly, ORA supports PG&E's proposal to cap class level revenue changes for both bundled and DA/CCA customers.

CHAPTER 5
MASTER METER DISCOUNTS
LEE-WHEI TAN

I. INTRODUCTION

This Chapter reflects ORA's master meter discounts based on ORA's marginal customer cost estimates presented in Chapter 3. ORA's master meter discounts differ from those of PG&E's mainly because of different marginal customer cost estimates. It also differs because DRA maintains the current diversity benefit, whereas PG&E's benefit reflects the rate design it proposed in its application and testimony.[120] The following table presents ORA's and PG&E's master meter discounts:

Table 5-1

Master Meter Discounts

				Proposed 2014 Test Year Discount			
		Current Discount *(a)*		ORA (b)		PG&E (c)	
Line	Rate Schedule	Net Discount	Daily Equivalent	Net Discount	Daily Equivalent	Net Discount	Daily Equivalent
1	ET – Mobile Home Park Service	$ 2.35	$ 0.07721	$ 5.83	$ 0.192	$ 4.04	$ 0.133
2	ES – Multi-family Service	$ (0.70)	$ (0.02300)	$ 0.97	$ 0.032	$ 1.38	$ 0.045

(a) Electric Master Meter Discount Rate in effect January 1, 2013

(b) ORA's net discount assumes current diversity benefit per ALJ Long October 18, 2013 ruling, which instructed parties not to change residential rate design from current residential rate/structure.

(c) PG&E's net discount assumes a diversity benefit based on its residential rate design changed filed in August 2014.

II. PROCEDUAL BACKGROUD

On October 18, 2013, the Administrative Law Judge (ALJ), Douglas Long, issued a ruling to modify the existing scoping memo for this proceeding (A.13-04-012)

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[120] Though DRA's marginal costs generally are lower, its diversity benefit is higher, resulting in a higher master meter discount. Under the rental method, ORA's marginal cost is just a bit lower than that of PG&E's.

regarding PG&E's marginal costs, revenue allocation, and rate design for Test Year (TY) 2014. ALJ Long stated:

> Parties are directed to immediately stop all work on residential rate design issues at this time. Residential rate design is hereby deferred pending further direction from the Commission in Rulemaking (R) 12-06-013 to address the Commission's policy preferences for any initial implementation of Assembly Bill 327 or longer-term implementation of changes to residential rate design.
>
> Parties are further directed to continue with all other work pending in A. 13-04-012 related to determining PG&E's marginal costs, revenue allocation, and rate design excluding residential rate design…. All currently scheduled milestones for intervenor testimony, rebuttal, settlement, evidentiary hearings, and briefs, etc., remain intact.

Subsequently, the Western Manufactured Housing Community Association (WMA) sought further guidance from the ALJ on master meter discount issues as master meter discount schedules are part of residential rate schedules. The ALJ clarified that master meter discount issues are sufficiently distinct from other residential rate design issues to allow parties to continue the discovery and testimony according to the current set schedule.[121]

Pursuant to the above-mentioned ALJ directions, ORA presents its proposed master meter discount in this Chapter. ORA notes that one of the master meter discount inputs, diversity benefit, is dependent on residential rates and baseline allowances, which are deferred according to the October 18, 2013 ALJ Ruling. Therefore, ORA develops the master meter discount based on a "status quo" residential rate scenario, which retains the current residential rate structure, and baseline allowances, and assumes the current

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[121] E-mail from ALJ Long to Edward Poole, WMA Attorney, (Oct. 21, 2013, 1655 PST) (on file with ORA).

diversity benefits. When and if the Commission directs parties to move forward with residential rate design, the master meter discounts would have to be updated.[122]

III. MASTER METER DISCOUNTS

PG&E presents master meter discount proposals for its Electric Multifamily Service (Schedule ES) and Electric Mobile Home Park Service (Schedule ET). Under these rate schedules, electricity is delivered to a single master meter at a residential development, and the electricity is then delivered through a private submetered distribution system to individual tenants in mobile home parks (MHP) or other multifamily residential accommodations. The owners of the MHP or master-metered multifamily residential developments take services from PG&E. PG&E provides them a discount to compensate them for the costs that PG&E avoids because they submetered the individual tenant spaces rather than having the utility directly serve those tenants.

A. Utility Avoided Costs/Marginal Costs

In the Order Instituting Rulemaking (OIR) to re-examine the issues involved in the master meter discount for MHP, the Commission adopted a joint recommendation presented by the Western Manufactured Housing Community Association (WMA), the California Investor Owned Utilities (IOU), and The Utility Reform Network (TURN),[123] which identified the electric utility avoided costs as follows:[124]

- Capital Investment Costs: a Utility's cost portion of initial and subsequent capital investment, including capital expenditures for

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[122] In addition, these revenue allocation and rate design processes do not reflect PG&E's GRC Phase 1 revenue requirement changes. If the Commission adopts a Phase 1 decision prior to residential rate design change is completed, that would further change master meter discounts.

[123] The joint recommendation was proposed by WMA, PG&E , So. Cal. Edison, So. Cal. Gas , SDG&E, SWGas, and TURN. There are eight active parties in the proceedings, Submetering MHP Issues,
R.03-03-017 and I.03-03-018. Of those, only the Latino Issues Forum did not join in the joint recommendation. However, the Latino Issues Forum does not oppose it.

[124] *Submetering MHP Issues,* D.04-04-043, 2004 Cal. PUC LEXIS 184, at *7–14 (attach. A) (dated April 22, 2004), which provides a more complete detail list.

replacement and improvement of the distribution system and service facilities.

- Operations and maintenance (O&M) expenses including, but not limited to, meter reading, billing, maintenance, and repair of the distribution system and service facilities, including distribution and service, trenching, distribution and service conduit, distribution and service substructures, and distribution protective structures maintenance, where appropriate, as defined in the applicable utility tariffs, e.g., Electric Rules 15 and 16.
- Administrative and general (A&G) expenses, uncollectibles, and unaccounted for loss of electrical energy.

Even though joint recommendation stated above defined the avoided costs for master meter schedules in the OIR, there were still disputes in the last PG&E general rate case (GRC) for Test Year 2011, A.10-03-014. As a result, in *PG&E*, D.11-12-053, the Commission provided further guidance in developing master meter discounts, which is briefly summarized below:

- Replacement costs implicitly are included in the submeter discount through use of the real economic carrying charge (RECC) factor.[125]
- The Equal Percent Marginal Cost (EPMC) scaler should not be applied to the Master Meter Discount.[126]
- Submeter discount should use PG&E's connection costs for extending new services under Tariff Rules 15 and 16 as "capped" by line extension allowances, consistent with Cal. Public Utilities Code § 739.5.[127]
- Use of multifamily new connection costs is the most reasonable estimate of the connection costs that the utility avoids by not directly serving MHP submetered tenants.[128]

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[6] *PG&E*, D.11-12-053, 2011 Cal. PUC LEXIS 585, at *64 (dated Dec. 15, 2011).

[126] *Id.* at *67.

[127] *See id.* at *70.

[128] *See id.* at *134–135 (Ord. Para. 21).

ORA reviewed PG&E's filing and noted that PG&E has applied the above Commission directives to derive its master meter discounts. However, ORA has made many adjustments to PG&E's marginal customer cost components, including inputs to the RECC factor, which result in different master meter discounts as shown in Tables 5-2 & 5-3.

Table 5-2

Mobile Home Park Master Meter Discount

Line	Schedule ET Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter *
1	Transformer	$ 390.65	$ 8,818.31
2	Service	543.52	11,928.81
3	Meter	305.19	1,478.79
4	Transformer/Service/Meter (TSM) Equip. Cost	$ 1,239.36	$ 22,225.90
5	RECC	8.48%	8.48%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$ 105.08	$ 1,884.41
7	Test Year Secondary Dist. ($/kW-Yr)	$ 1.88	
8	Test Year Ongoing Costs Per Residential Unit		
9	Meter Services	$ 3.11	$ 2.15
10	Transformer Maintenance	2.12	47.77
11	Service Maintenance	5.84	128.26
12	Meter Reading	5.65	4.58
13	Billing & Collections	13.44	19.84
14	Other Account 903 (Adjusted)	4.49	29.59
15	Total Ongoing Costs Per Residential Unit	$ 34.64	$ 232.20
16	Total Connection Cost	$ 141.60	$ 2,116.60
17	Average Number of Residential Units		65
18	Master Meter Connection Cost Per Residential Unit		$ 32.56
19	Net Marginal Connection Cost Per Residential Unit	$ 109.04	
20	Uncollectibles Factor	0.3705%	
21	Uncollectibles	0.40	
22	Net Base Discount Per Residential Unit — Annual	$ 109.44	
23	**Base Master Meter Discount Per Residential Unit — Monthly**	**$ 9.12**	
24	Diversity Benefit Adjustment (Illustrative)	5.20	
25	Line Loss Adjustment	1.91	
26	**Net Discount (Monthly) (Illustrative)**	**$ 5.83**	
27	**Net Discount (Daily) (Illustrative)**	**$ 0.19166**	

Table 5-3

Multi-family Master Meter Discount

Line	Schedule ES Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter *
1	Transformer	$ -	$ -
2	Service	-	-
3	Meter	305.19	1,478.79
4	Transformer/Service/Meter (TSM) Equip. Cost	$ 305.19	$ 1,478.79
5	RECC	8.48%	8.48%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$ 25.88	$ 125.38
7	Test Year Secondary Dist. ($/kW-Yr)	$ -	
8	Test Year Ongoing Costs Per Residential Unit		
9	Meter Services	$ 3.11	$ 2.15
10	Transformer Maintenance	-	-
11	Service Maintenance	-	-
12	Meter Reading	5.65	4.58
13	Billing & Collections	13.44	19.84
14	Other Account 903 (Adjusted)	4.49	29.59
15	Total Ongoing Costs Per Residential Unit	$ 26.68	$ 56.17
16	Total Connection Cost	$ 52.55	$ 181.55
17	Average Number of Residential Units		37
18	Master Meter Connection Cost Per Residential Unit		$ 4.91
19	Net Marginal Connection Cost Per Residential Unit	$ 47.65	
20	Uncollectibles Factor	0.3705%	
21	Uncollectibles	0.18	
22	Net Base Discount Per Residential Unit — Annual	$ 47.82	
23	**Base Master Meter Discount Per Residential Unit — Monthly**	**$ 3.99**	
24	Diversity Benefit Adjustment (Illustrative)	3.02	
25	Line Loss Adjustment	-	
26	**Net Discount (Monthly) (Illustrative)**	**$ 0.97**	
27	**Net Discount (Daily) (Illustrative)**	**$ 0.03185**	

B. Diversity Benefits

In addition to using marginal cost or avoided cost, a diversity benefit is also factored into computing the master meter discounts. As the Commission explains in D.04-11-033, the diversity benefit adjustment reduced the discount paid to the MHP owners to account for the fact that while the MHP owner receives a full baseline

allowance for each space, some tenants use less than the baseline allowance and some spaces may be vacant.[129]

PG&E used a sample of 206 directly served mobile home parks comprised of some 13,400 tenant units based on 2011 and 2013 calendar recorded usage, to determine the diversity benefit. PG&E estimates a $6.83 diversity benefit based on its proposed E-1 rates. These E-1 rates are based on its marginal costs, cost allocation, as well as a 50 percent baseline allowance and a collapsing of tier 3 and tier 4 rates. Because the ALJ instructed parties not to perform residential rate design changes in this Phase, ORA retains the current diversity benefit, which is $5.20 for ET and $3.02 for schedule ES.

These diversity benefits have to be updated once residential rate design results are determined by the Commission either in Phase 2 of the Residential OIR or a later Phase of this GRC.

IV. CONCLUSION

ORA recommends that the Commission adopt ORA's master meter discounts based on ORA's marginal customer costs and that they be updated to reflect residential rates once the latter are determined.

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[129] *Submetering Discounts, R.03-03-017,* D.04-11-033, 10 n.6 (dated Nov. 19, 2004), *available at* http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=All&DocID=184302/.

CHAPTER 6
SMALL COMMERCIAL RATE DESIGN
ELISE TORRES

I. INTRODUCTION

This Chapter analyzes PG&E's rate design proposals for its small commercial customers and presents ORA's recommendations on small commercial rate design. Over 99 percent of PG&E's Small Light and Power (SL&P) customers are served on schedules A-1, A-1 TOU, and A-6. This Chapter primarily focuses on these rate schedules.[130] PG&E proposes several changes to the SL&P rate schedules. As discussed below, ORA supports some of PG&E's proposals and opposes others.

First, ORA opposes PG&E's proposal to substantially increase its basic service fees for schedules A-1, A-1 TOU, A-6, and A-15. This proposal would result in detrimental bill impacts for a majority of customers subject to the SL&P rate schedules, especially the lowest energy users in the customer class. Instead of increasing the customer charge for all customers, ORA recommends a graduated basic service fee, also known as a customer charge, based on a customer's size. Currently there is a broad range of demand levels for customers in the SL&P customer class, making graduated customer charges appropriate.

ORA's proposal also is designed to prevent significant bill increases for the smallest energy users in the SL&P class. Under ORA's proposal, customers using less than 20 kW would pay a lower customer charge than customers using over 20 kW. This structure better aligns the basic service fee that customers pay with their marginal costs, which will be discussed in more detail below.

Second, PG&E proposes to impose a 75 kW cut-off for rate schedules A-1, A-1 TOU, and A-6. This means that customers with maximum demands greater than 75 kW

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[130] In addition, PG&E's SL&P includes rate schedules: A-15 and Traffic Control-1 (TC-1). Currently SL&P sales are broken down as follows: 47 percent in schedule A-1; 35 percent in schedule A-1 TOU; and 18 percent in schedule A-6. *See* PG&E, A.13-04-012, Ex. PG&E-4, vol. 1, ch. 4, p. 4-2, tbl. 4-1.

would not be allowed to remain on those rate schedules. In contrast, ORA believes a smaller kW cut-off should be adopted for all SL&P rate schedules to create a more appropriate demarcation between SL&P customers[131] and Medium Light & Power (ML&P) customers. However, due to limitations of the customer data provided by PG&E, ORA is not proposing a lower kW cut-off in this GRC. Rather, ORA proposes to work with PG&E to implement a more appropriate cut-off for the 2017 GRC.[132]

Finally, bill impact studies provided to ORA in response to a data request indicate that some SL&P customers would benefit from transferring to ML&P rate schedules.[133] Some E-CARE customers also would benefit from transferring to the Residential CARE rate. Accordingly, ORA proposes that PG&E contact all A-1, A-1 TOU, and A-6 customers whose annual usage exceeds 60,000 kWh and who would save money if they switched to either the A-10 TOU or E19V schedule, and all E-CARE customers to discuss which rate schedule would result in the greatest bill savings for them. This proposal will save some customers money and will help ensure that customers are placed in the appropriate customer class.

As a matter of context for SL&P rates, ORA notes that PG&E is currently in the process of phasing-out its flat rate schedule A-1 and transferring all A-1 customers to its mildly time-differentiated schedule A-1 TOU, as directed by the Commission in PG&E, D.11-11-008.[134]

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[131] *See PG&E,* D.08-07-045, 2008 Cal. PUC LEXIS 290, at *139 (Concl. of Law 11:

> It is reasonable to subdivide commercial and industrial customer with maximum load less than 200 kW into two subgroups: those with maximum demand between 20 kW and 200 kW, referred to as medium C&I, and those with maximum demand below 20 kW, referred to as small commercial.)

(dated July 31, 2008)

[132] Specific details of ORA's proposal are set forth in the next section.

[133] PG&E Response October 21, 2013, to ORA Data Request 21, Questions 1–4.

[134] *PG&E*, D.11-11-008, 2011 Cal. PUC LEXIS 516, at *2. *See* Ex. PG&E-4, *supra* note 130, at p. 4-8.

II. ORA RECOMMENDATIONS

ORA proposes various changes to PG&E's SL&P rate design proposals that will reduce some of the harsh bill impacts created by PG&E's proposals. Accordingly, ORA recommends that PG&E be directed to:

- Implement a two-level customer charge, maintaining the current monthly customer charge of $10 for single-phase customers and $20 for polyphase customers on SL&P rate schedules[135] who are 20 kW or below, and adding a monthly customer charge of $40 for all customers who are larger than 20 kW.
- Begin collecting usage data separately for SL&P customers with maximum demands 20 kW and less (and those exceeding 20 kW), and with maximum demands up to 50 kW (and those exceeding 50 kW), with the goal of computing billing determinants for the redefined SL&P class, with a cut-off threshold of 20 kW or 50 kW, for use in the 2017 GRC.
- Meet and confer with ORA at least nine months prior to the filing of its Testimony and Workpapers in the 2017 GRC Phase II to discuss an appropriate kW cut-off to qualify for SL&P rate schedules.
- If no agreement is reached, make a good faith effort to analyze the 20kW and 50kW cut-off thresholds in parallel with PG&E's proposed cut-off threshold and to provide ORA with the necessary revenue allocation models, bill impact studies, and billing determinants to evaluate the effects of instituting a lower kW threshold cut-off for SL&P rate schedules.
- Contact customers on SL&P rate schedules, who are eligible for service on other rate schedules (either ML&P or E-CARE customers eligible for Residential rates), to discuss the different tariff options available to them and if they would benefit from switching to a different customer class.

[135] Excluding A-15 and TC-1.

III. COMPARISON OF PG&E'S PROPOSED RATES AND ORA'S PROPOSED RATES

The following table compares PG&E's and ORA's proposed rates:

Table 6-1

Comparison of Current, PG&E and ORA Proposed Rates

Rate Schedule A-1	**Current PG&E Rates** (cents/kWh)	**PG&E Proposed Rates** (cents/kWh)	**ORA Proposed Rates** (cents/kWh)
Energy Charge: Summer	0.21366	0.20004	0.19684
Energy Charge: Winter	0.15022	0.15812	0.14960
Basic Service Fee	Single-phase: $10 Polyphase: $20	Single-phase: $20 Polyphase: $30	Single-phase ≤ 20 kW: $10 Polyphase ≤ 20 kW: $20 All customers > 20 kW: $40

Rate Schedule A-1 TOU	**Current PG&E Rates**	**PG&E Proposed Rates**	**ORA Proposed Rates**
Energy Charge: Summer	Peak: 0.23120 Part-Peak: 0.22358 Off-Peak: 0.20041	Peak: 0.21975 Part-Peak: 0.19512 Off-Peak: 0.17172	Peak: 0.21989 Part-Peak: 0.19168 Off-Peak: 0.16630
Energy Charge: Winter	Peak: 0.15892 Off-Peak: 0.14216	Peak: 0.18226 Off-Peak: 0.16607	Peak: 0.17590 Off-Peak: 0.15723
Basic Service Fee	Single-phase: $10 Polyphase: $20	Single-phase: $20 Polyphase: $30	Single-phase ≤ 20 kW: $10 Polyphase ≤ 20 kW: $20 All customers > 20 kW: $40

Table 6-1

Comparison of Current, PG&E and ORA Proposed Rates Continued

Rate Schedule A-6	**Current PG&E Rates**	**PG&E Proposed Rates**	**ORA Proposed Rates**
Energy Charge: Summer	Peak: 0.49008 Part-Peak: 0.24064 Off-Peak: 0.14119	Peak: 0.40099 Part-Peak: 0.20273 Off-Peak: 0.14916	Peak: 0.41922 Part-Peak: 0.19964 Off-Peak: 0.14016
Energy Charge: Winter	Peak: 0.15885 Off-Peak: 0.13119	Peak: 0.16780 Off-Peak: 0.15392	Peak: 0.16141 Off-Peak: 0.14529
Basic Service Fee	Single-phase: $10 Polyphase: $20	Single-phase: $20 Polyphase: $30	Single-phase ≤ 20 kW: $10 Polyphase ≤ 20 kW: $20 All customers > 20 kW: $40

DRA's proposals reflect its marginal cost and revenue allocation proposals. Due to the fact that DRA allocates less revenues to small commercial customers, its energy rates are slightly lower than PG&E's. For Schedule A-6, ORA's recommended on-peak to off-peak energy rate differentials are slightly higher than PG&E's because ORA's underlying marginal energy costs are somewhat more time-differentiated than PG&E's.

IV. DISCUSSION

A. Overview of PG&E's rate proposals

ORA supports some of PG&E's recommendations for the SL&P rate schedules and opposes others. PG&E's application shows that it continues to transition customers on schedule A-1 to the A-1 TOU rate schedule, as directed in Decision 11-11-008.[136] PG&E also proposes to increase the differential between on and off-peak rates for schedule A-1 TOU and ORA agrees with this recommendation. PG&E proposes to

[136] D.11-11-008, *supra* note 134, at *2.

slightly moderate the on- and off-peak differential for schedule A-6 but still maintain a 25 cent differential between on- and off-peak periods. ORA is neutral on this proposal.

PG&E proposes to impose a 75 kW cut-off for customers on schedule A-6 and to maintain a 75 kW cut-off for A-1 and A-1 TOU. According to PG&E's proposal, a customer whose maximum energy demand exceeds 75 kW for three consecutive months will be transferred to a ML&P demand-metered tariff.[137] ORA supports PG&E's proposal to institute a 75 kW cut-off but would like to see a lower kW cut-off for the SL&P class adopted in PG&E's next GRC Phase II.

PG&E recommends increasing the basic service fee by $10 for all customers in the SL&P rate class.[138] Specifically, PG&E proposes to increase the monthly basic service fee from $10 to $20 for single-phase customers and from $20 to $30 for polyphase customers. This would result in small reductions to the volumetric rates for SL&P customers. PG&E's SL&P rate design proposal would give rise to bill increases for a majority of SL&P customers on the A-1 and A-6 rate schedules. The increases are especially high for low-usage customers, and thus ORA opposes this proposal.

The E-CARE rate for SL&P customers is designed to have the same average discount as the average residential CARE discount. The Residential Rate Design portion of this GRC has been deferred pending further direction from the CPUC in Rulemaking 12-06-013. Thus, the E-CARE rate should be updated after the Residential Rate Design portion of this GRC is completed.

B. PG&E's A-1 Rate Schedule

. Introduction

The large majority of PG&E's small commercial customers are currently on schedules A-1 and A-1 TOU. PG&E is in the process of transferring all A-1 customers to schedule A-1 TOU. This transition takes place once a customer has 12 months of

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[137] Ex. PG&E-4, *supra* note 130, at p. 4-5.

[138] Excluding schedule TC-1.

interval data, and it should be fully completed by November 2013. According to PG&E's Testimony, as of April 18, 2013, there were 224,000 customer accounts on schedule A-1 and 202,000 accounts on schedule A-1 TOU.[139]

. Schedule A-1

Schedule A-1 is PG&E's simplest small commercial rate schedule consisting of a seasonal single flat energy rate and a monthly basic service fee (often referred to as a customer charge). PG&E proposes to increase the schedule A-1 customer charge by 100 percent for single-phase and 50 percent for polyphase customers. This increase will have significant bill impacts on smaller usage customers on schedule A-1. The smallest users, those who use up to 2,400 kWh per month, comprise 25 percent of A-1customers, and this group will experience bill increases of 20 percent or more.[140] To address this problem, ORA proposes to adopt a graduated customer charge by usage level for rate schedules A-1, A-1 TOU, and A-6, as will be discussed in greater detail below

. Schedule A-1 TOU

Schedule A-1 TOU is the default SL&P rate schedule.[141] It has three TOU periods over the summer season (May through October) and two TOU periods over the winter season (November through April). PG&E proposes to increase the summer peak/off-peak differential for schedule A-1 TOU from three cents to five cents. ORA agrees with increasing this differential.

PG&E also proposes to increase the schedule A-1 TOU customer charge by 100 percent for single-phase and by 50 percent for polyphase customers. PG&E's proposal will negatively impact small usage customers, and cause bill increases of approximately 15 percent or higher for the A-1 TOU customers who use up to 3,800 kWh per year, who

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[139] Ex. PG&E-4, *supra* note 130, at p. 4-2 & tbl.4-1.

[140] PG&E Response August 30, 2013, to ORA Data Request 4, Question 1.

[141] Ex. PG&E-4, supra note 130, at p. 4-4.

in turn constitute 20 percent of A-1 TOU customers.[142] Approximately 50 percent of all A-1 TOU customers will experience bill increases of at least 10 percent.[143] ORA's proposal for a graduated customer charge will help mitigate these increases, as will be explained in more detail below.

C. PG&E's Schedule A-6

Schedule A-6 is a TOU rate with three TOU periods over the summer season and two TOU periods over the winter season. Schedule A-6 has a much greater peak/off-peak differential (over 25 cents) than schedule A-1 TOU. Slightly more than five percent of SL&P customers are on schedule A-6. PG&E's proposed schedule A-6 distribution and energy charges are designed to be cost based.

As with schedule A-1, PG&E proposes to increase the customer charges for this rate schedule by 100 percent for single-phase customers and by 50 percent for polyphase customers. PG&E's proposal will result in approximately 20 percent of A-6 customers experiencing bill increases of 10 percent or more. ORA proposes the same graduated customer charge by customer size for schedule A-6 as ORA recommends for A-1 and A-1 TOU. ORA's proposal would avoid the large bill increases for low usage customers that would result if PG&E's recommendation to increase fixed charges for all SL&P customers were implemented.

D. PG&E's E-CARE Schedule

Schedule E-CARE is a rate for non-profit group living facilities served on non-residential rates.[144] Schedule E-CARE is intended to provide a comparable level of discount as that afforded to residential CARE customers and ORA supports this goal. An E-CARE customer's bill is equal to its otherwise applicable commercial charges,

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[142] PG&E Response, *supra* note 140.

[143] PG&E Response, *supra* note 140.

[144] Ex. PG&E-4, *supra* note 130, at p. 4-7.

"less a discount equal to the product of its total kWh usage and the schedule E-CARE discount rate per kWh."[145]

The E-CARE discount is unbundled into three parts: (1) a Public Purpose Programs component for the waiver of the CARE surcharge; (2) a distribution discount component; and (3) a component reflecting the CARE exemption for the California Department of Water Resources Bond Charges.[146] PG&E provides the majority of the E-CARE discount in the distribution component so that Community Choice Aggregation and Direct Access customers receive the same E-CARE discount, which ORA supports.

The Residential Rate Design portion of this GRC has been appropriately deferred pending further direction from the CPUC in Rulemaking 12-06-013.

E. ORA's Basic Service Fee Proposal for Small Commercial Schedules

ORA proposes a two-level customer charge that would provide a monthly charge of $10 for single-phase customers and a $20 basic service fee for polyphase customers on SL&P rate schedules whose customer size is 20 kW or below. ORA proposes a monthly customer charge of $40 for all SL&P customers whose size exceeds 20 kW. ORA's proposed graduated customer charge reflects the much greater costs of the customer "hookup" for customers with maximum demands above 20 kW, relative to the costs imposed by SL&P customers 20 kW or below.[147]

ORA has determined the class average small commercial marginal customer access costs to be $15.27 per customer-month.[148] As explained in Chapter 3 of ORA's

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[145] Ex. PG&E-4, *supra* note 130, at p. 4-7.

[146] Ex. PG&E-4, *supra* note 130, at pp.4-7 – 4-8.

[147] As explained in Chapter 3 of this Testimony, hookup equipment consists of the final line transformer, the service connection, and the meter. The Commission has previously defined a "Small" commercial customer as having a maximum demand not exceeding 20 kW. Note that the revenue cycle services costs for customers over 20 kW also might be different from those under 20 kW, but DRA does not have data on this difference. Thus it is proposing differences in customer charges based on the relative costs of the hookups alone.

[148] ORA-1, ch. 3, p.3-5, tbl 3-1. Table 3-1 presents annual Marginal Customer Access Costs. The Small L&P Marginal Customer Access Cost is $183.26; this was divided by 12 in order to determine the cost (continued on next page)

Testimony, marginal customer costs consist of the capital costs of new customer connection equipment, together with ongoing revenue cycle services (RCS) costs.[149] RCS costs include costs of customer services such as billing, customer inquiry, and meter reading.[150]

According to ORA's Customer Access Marginal Cost Testimony, "High TSM costs appear to be strongly correlated with maximum demands of over 20 kW."[151] Furthermore, ORA's marginal customer access cost analysis in Chapter 3 shows that the average new connection costs, for SL&P customers who are above 20 kW, are almost four times greater than new connection costs for the SL&P customer class in general.[152]

For these reasons, a SL&P customer whose demand size exceeds 20 kW should pay a higher customer change than SL&P customers who are 20 kW or below. ORA proposes that customers with loads exceeding 20 kW receive a customer charge equal to four times that of the smaller customers served on single-phase service.[153] ORA's proposal for a graduated customer charge is supported by ORA's marginal cost analysis as well as by CPUC precedent. In Decision 08-07-045, the Commission stated:

> It is reasonable to subdivide commercial and industrial customer[s] with maximum load less than 200 kW into two subgroups: those with maximum demand between 20 kW and 200 kW, referred to as medium C&I, and those with maximum demand below 20 kW, referred to as small commercial.[154]

(continued from previous page)

per customer month.

[149] *Id*.

[150] *Id*. at 3-1.

[151] *Id.* at 3-14.

[152] *Id.* at 3-14 & tbl. 3-2.

[153] A majority of customers with loads not exceeding 20 kW take single-phase service. In contrast, all customers with loads over 20 kW are served on polyphase service. All customers who take polyphase service currently pay a customer charge double that paid by single-phase customers.

[154] D.08-07-045, *PG&E,* D.08-07-045, 2008 Cal. PUC LEXIS 290, at *139 (Concl. of Law 11).

ORA's proposed graduated customer charge also would help mitigate the negative bill impacts of PG&E's proposed rates on small usage SL&P customers. For these reasons, ORA recommends the adoption of its proposed two-level customer charge. It provides for a monthly charge of $10 for single-phase customers and $20 for polyphase customers whose maximum demand is 20 kW or below, and a monthly customer charge of $40 for all SL&P customers larger than 20 kW.

F. Eligibility for Small L&P Rates

ORA believes that a lower kW threshold should be established to create a more appropriate demarcation between SL&P and ML&P customers. The Commission has previously set 20 kW as a cut-off for "small" commercial customers, arguing that such customers are qualitatively different from medium and large commercial customers and merit special rate treatment.[155] However, due to bill impacts,[156] ORA is willing to accept PG&E's proposed 75 kW eligibility threshold for SL&P rate schedules for the 2014 GRC Phase II. But ORA proposes that further reductions in the kW cut-off threshold be considered in PG&E's 2017 GRC Phase 2 proceeding. Limitations of PG&E's Workpapers and a lack of information make it difficult to change the current demarcation between SL&P and ML&P at this time. Thus, to facilitate such consideration, PG&E should begin collecting usage data separately for SL&P customers with maximum demands not exceeding 20 kW and with demands not exceeding 50 kW with the goal of computing billing determinants for the redefined SL&P class for use in the 2017 GRC. Specifically, PG&E should collect usage data for customers with demands up to and including 20 kW and those exceeding 20 kW; and for customers with demands up to and including 50 kW and those exceeding 50 kW. ORA proposes to meet with PG&E approximately nine months in advance of the filing date of PG&E's

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[155] *Id.*

[156] The implementation of a 20 kW threshold cut-off for SL&P rate would have resulted in 15% of A-1 customers experiencing bill increases of 50% or higher and 10% of A-6 customers experiencing bill increases of 54% or higher. PG&E Response to DRA Date Request 4, Questions 3 and 4.

2017 GRC Phase 2 application to discuss an appropriate kW cut-off for the SL&P customer class. ORA will confer with PG&E and attempt to reach an agreement on a lower cut-off kW threshold.

If no agreement is reached, ORA proposes that PG&E be required to make a good faith effort to analyze the 20 kW and 50 kW cut-off thresholds in parallel with whatever cut-off threshold PG&E will propose. PG&E should be required to perform a study showing the results of instituting a cut-off for SL&P at both 20 kW and 50 kW. This study should show how customers would be impacted by this change, examining at minimum, customer bill impacts and changes to the average rates for the impacted rate schedules. ORA also proposes that PG&E be required to provide the following information to ORA, within 60 days after PG&E files its 2017 GRC Phase 2 application:

- An alternate revenue allocation, reflecting at most two lower (20 kW and/or 50 kW) maximum kW thresholds, or kWh proxies for A-1 TOU and A-6 eligibility, as may be proposed by ORA in the 2017 GRC Phase 2, and assuming the customers migrating from A-1 TOU and A-6 will move to A10-TOU;
- Billing determinants needed to compute correct rates for A-1 TOU, A-6, and A10-TOU, and related classes affected by a proposal (if any) by ORA to reduce the maximum allowable kW demand to be eligible for A-1 TOU and A-6 service;
- Bill impact studies to determine the impacts of setting at most two lower (20 kW and/or 50 kW) kW cut-off thresholds.

G. PG&E Should Contact all Customers on SL&P Rate Schedules to Discuss the Different Tariff Options for the SL&P Customer Class

Some SL&P customers would experience substantial bill savings if they transferred off of their current SL&P tariff to a ML&P rate. For this reason, ORA proposes that PG&E be required to contact all A-1, A-1 TOU, and A-6 customers whose annual usage exceeds 60,000 kWh and who would save money if they switched to either the A-10 TOU or E19V schedule. According to bill impacts provided by PG&E in

response to an ORA data request, this would be approximately 12,990 customers, or 2.8 percent of all SL&P customers.[157]

Many E-CARE customers also are eligible for service on the Residential CARE rate. In some instances, E-CARE customers could achieve bill savings if they switched to the Residential CARE rate.[158] There are approximately 548 E-CARE customers in total.[159] ORA proposes that PG&E be required to contact all E-CARE customers who would benefit from switching to a residential CARE schedule. PG&E should discuss the other SL&P rate schedules for which they are eligible and any residential rates for which they are eligible, and explain the potential bill impacts of switching to another rate, and recommend the best rate schedule for each customer.

V. CONCLUSION

The Commission should adopt ORA's small commercial rate design proposals including, the lower customer charges recommended by ORA for SL&P customers whose maximum demand is 20 kW or lower. The Commission also should require PG&E to begin collecting usage data separately for SL&P customers at different maximum demand levels. PG&E should be required to meet and confer with ORA at least nine months prior to filing its Testimony and Workpapers in the 2017 GRC Phase II to discuss an appropriate kW annual cut-off for the SL&P rate class and to provide ORA with the necessary information and bill impacts to assess the impacts of up to two alternative SL&P cut-off thresholds. If adopted, the above mentioned ORA commercial rate design proposals will ensure both ORA and PG&E provide meaningful analysis of what an appropriate usage cut-off for the SL&P rate class should be in the future.

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[157] PG&E Response October 21, 2013, to ORA Data Request 21, Questions 1-4.

[158] This could be due to a variety of factors: the customer's load profile, the specific rate design of each rate, etc. The E-CARE discount is set at the same level as the average residential CARE discount.

[159] PG&E Response September 4, 2013, to ORA Data Request 4, Question 5; PG&E, A.13-04-012, Ex. PG&E-4, vol. 2, Apps. to Ex. PG&E-4 vol. 1, app. D, pp. D-16 & D-19 (dated Aug. 16, 2013).

APPENDIX A

WITNESS OF QUALIFICATIONS

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ROBERT LEVIN

Q.1 Please state your name and business address.

A.1 My name is Robert Levin. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates (ORA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I have a Ph.D. in Operations Research and an M.A. in Mathematics from the University of California, Berkeley, and a B.A. in Mathematics from U.C.L.A.

I was employed by PG&E for 24 years in various professional capacities in the areas of resource economics, capacity planning, marginal cost studies, and project cost-effectiveness evaluation.

I joined the Commission staff early in 2008. Since then, I have worked primarily on gas AMI and electric marginal cost and rate design proceedings. I sponsored policy and economic analysis testimony in the SoCalGas AMI proceeding (A.08-09-023) and in PG&E's, SCE's, and SDG&E's GRC Phase 2 proceedings (A.10-03-014, A.11-06-007, and A.11-10-002, respectively), as well as PG&E's 2009 and 2010 Rate Design

Window proceedings (A.09-02-022 and A.10-02-028, respectively). I also sponsored testimony in PG&E's 2012 Economic Development Rate proceeding (A.12-03-001).

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 1, Marginal Generation Cost.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
VALERIE KAO

Q.1 Please state your name and business address.

A.1 My name is Valerie Kao. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By Whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates (ORA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I have a Master's in Pacific and International Affairs from the University of California, San Diego, and a Bachelor of Arts in Peace and Conflict Studies from the University of California, Berkeley.

I joined the staff of the California Public Utilities Commission in 2007 and have worked in the Policy Analysis Branch of Communications Division, the Administrative Services Division, the Demand-Side Analysis Branch of Energy Division, and The Electricity Pricing and Customer Programs Branch of DRA. I have worked on numerous electric rate design and demand-side management (i.e., energy efficiency, demand response and customer-side distributed generation) proceedings.

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 2, Marginal Distribution Demand Costs, and Chapter 3, Marginal Customer Access Costs.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
DAN WILLIS

Q.1 Please state your name and business address.

A.1 My name is Dan Willis. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates (ORA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I hold a Bachelor of Science degree in Environmental Economics and Policy from the University of California Berkeley, with a minor in Conservation and Resource Studies. I joined ORA in July of 2012 and testified before the Commission in the Smart Meter Opt-Out Proceeding, A.11-03-014. In addition, I have conducted detailed analysis on several other Commission proceedings on rate design, including the Residential Rates Order Instituting Rulemaking (RROIR) and PG&E's Application for an Economic Development Rate.

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 4, Revenue Allocation.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

LEE-WHEI TAN

Q.1. Please state your name and business address.

A.1. My name is Lee-Whei Tan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst V in the Electric Pricing and Consumer Program Branch of the Office of Ratepayer Advocates (ORA).

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Science Degree in Chemistry from National Tsing Hua University in 1979 (Taiwan) and a Master of Arts Degree in Economics in 1986 from San Francisco State University.

In July 1986, I joined the Fuels Branch of the Division of Ratepayer Advocates where I sponsored testimony relating to utilities fuel management practices. I transferred to the Special Economics Branch in July 1987 and was involved in the benchmarking of computer programs (ELFIN, PCAM, PROMOD). In April 1988, I joined the Economics and Energy Rate Design Branch where I was assigned marginal costs and rate design for gas and electric cases. In 2001, I was assigned to the Telecommunications Branch of ORA, where I was assigned to work on telephone utility cases, such as New Regulatory Framework proceedings, mergers, and Public Utilities Code §851 proceedings.

I joined the Electric Pricing and Consumer Program Branch in July, 2009, and have been assigned to work on the revenue allocation and project coordination for San Diego Gas and Electric (SDG&E) Critical Peak Pricing Application, SDG&E 2012 GRC Phase2, and Pacific Gas and Electric Company's (PG&E) 2011 GRC Phase 2 Filing.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 5 on "Master Meter Discount" of ORA's prepared testimony in PG&E's 2014 GRC Phase 2 Filing.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ELISE TORRES

Q.1 Please state your name and business address.

A.1 My name is Elise Torres. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By Whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates (ORA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I have a J.D. from the University of California, Hastings College of the Law, and a B.S. in City and Regional Planning from the California State Polytechnic University.

I had a legal fellowship prior to joining the CPUC and I worked on a Commission proceeding concerning the siting of a transmission substation. I joined the staff of the California Public Utilities Commission in June of 2012, in the Electricity Pricing and Customer Programs Branch of ORA. I have worked on several electric rate design proceedings. I served as a witness for ORA in PG&E's 2012 Economic Development Rate proceeding. I sponsored testimony for the case and testified on behalf of ORA in evidentiary hearings. I review Petitions for Modification and other utility filings related to electric rate design and customer programs and respond on behalf of ORA.

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 6, Small Commercial Rate Design.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.