Q. **Reference: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 21 (77 pdf)**

Citation:

> Marginal cost-based allocation of embedded costs may seem to be novel, but variants of this approach have been in use for many years in a number of regulatory jurisdictions. West coast U.S. utilities have used this approach for twenty years.

Please provide copies of or links to documents from these West Coast utilities describing their approach to marginal cost-based allocation of embedded costs.

A. This response has been provided by Christensen Associates Energy Consulting.

Attached are three documents demonstrating the use of Marginal Cost-based Cost of Service. LAB-NLH-015, Attachment 1 is a full Marginal Cost-based Cost of Service study from Portland General Electric. LAB-NLH-015, Attachment 2 and LAB-NLH-015, Attachment 3 are presentation-style documents. LAB-NLH-015, Attachment 2 indicates the use of marginal costing by Pacific Gas & Electric; and LAB-NLH-015, Attachment 3 indicates the use of marginal costing by the State of California, generally, as indicated by the state's Division of Ratepayer Advocates.

UE 262 / PGE / 1400
Garity - Macfarlane - Werner

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bonnie Gariety
Robert Macfarlane
Bruce Werner

February 15, 2013

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Bonnie Gariety. I am responsible for the Customer Service Marginal Cost Study, which are in Section IV.

My name is Robert Macfarlane. I am responsible for the Generation Marginal Cost Study in Section II.

My name is Bruce Werner. I am responsible for the Distribution Marginal Cost Study in Section III.

We are Pricing and Tariffs Analysts in the Rates and Regulatory Affairs Department for PGE. Our qualifications are described in Section V.

Q. What is the purpose of your testimony?

A. The following testimony and accompanying exhibit describe our Marginal Cost Studies including: Generation, Distribution, and Customer Service marginal cost estimates. Our testimony is organized in the order listed above, and PGE Exhibit 1401 is a summary of these marginal costs by component. The summary consists of generation energy and capacity costs, and costs by PGE rate schedule for; subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs.

Q. How are the results of these studies used?

A. Witnesses Cody and Macfarlane (PGE Exhibit 1500) use the results of this study to spread PGE's proposed revenue requirement across the relevant customer classes as described in their testimony.

II. Generation Marginal Cost Study

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity and long-run marginal energy costs. This marginal cost methodology is consistent with our most recent Integrated Resource Plan (IRP), which identifies a need for capacity resources for both the winter and summer periods. This methodology is similar to the long-run methodology we used in UE 215.

Q. Please describe the methodology used in UE 215.

A. In UE 215 we defined the long-run marginal generation resource as a combined cycle combustion turbine (CCCT) for baseload purposes. We used the fixed costs of an LMS 100 simple cycle combustion turbine (SCCT) to estimate the portion of CCCT fixed costs to assign to capacity. We estimated marginal energy costs using the weighted values of the energy portion of the CCCT and a wind plant. We based the weightings on the expected energy from each resource as identified in the then draft 2009 IRP.

Q. What changes do you propose to the methodology used in UE 215?

A. We propose to average the real levelized costs from two models. The first model is similar to the one used in UE 215. The difference is that we use the fixed costs of a reciprocating engine capacity resource to estimate the portion of CCCT fixed costs to assign to capacity. This resource cost is the lesser of the two capacity resources presented in the 2011 IRP Update dated November 23, 2011 (2011 IRP Update)[1].

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[1] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_nov2011.pdf.

The second model defines the long-run marginal generation resource as a CCCT for baseload purposes. We use the fixed costs of an F-frame SCCT to estimate the portion of CCCT fixed costs to assign to capacity. No further adjustment is made.

Q. Please describe the steps you used to develop the long-run generation allocation in the first model.

A. The first model of generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a CCCT used for baseload purposes.
2. From this analysis, separately estimate the capacity and energy components as follows:
    a) Estimate the marginal cost of future capacity as the fixed cost of a reciprocating engine capacity resource.
    b) Use the capacity resource fixed costs, inclusive of fixed gas transportation, as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
    c) To the reciprocating engine capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP and associated 2011 and 2012 IRP updates.
3. Estimate the fully allocated cost of a generic wind farm as identified in the IRP.
4. Calculate the weighted average real levelized price of the energy portion from step 2 and the entire cost in step 3. The result provides the long-run marginal energy cost in real levelized terms.

5. Finally, express the capacity value from step 2.c. in real levelized terms.

Q. Please describe the steps you used to develop the long-run generation allocation in the second model.

A. The second model of generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a CCCT used for baseload purposes.
2. From this analysis, separately estimate the capacity and energy components as follows:
    a) Estimate the marginal cost of future capacity as the fixed cost of an F-frame SCCT.
    b) Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
    c) To the SCCT capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP and associated 2011 and 2012 IRP updates.
3. Finally, express the capacity and energy values in real levelized terms.

Q. How do you derive the generation marginal costs from the two models?

A. For energy, we take a simple average of the real levelized energy values from step 4 of the first model and the energy value in step 3 of the second model. For the capacity, we take a simple average of the real levelized capacity values from step 5 of the first model and the capacity value in step 3 of the second model.

Q. What are the sources of the overnight capital costs for the resources used in the two models?

A. For the CCCT, reciprocating engines capacity resource, and the wind resource; we used the values provided on page 33 of the 2011 IRP Update. For the F-frame SCCT we reviewed the IRPs of several other northwest utilities and used a value of $700 per kW (2014$), a rounded value based on the most typical overnight capital cost.

Q. How did you calculate the 2014 test-period marginal capacity costs?

A. We multiplied the real levelized annual capacity cost described above by the projected 2014 cost-of-service (COS) test-period, peak-hour load. This peak-hour load is projected to occur in January.

Q. How did you allocate the marginal capacity costs to each rate schedule?

A. We allocated the total 2014 test period marginal capacity costs described above on the basis of each schedule's relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-coincident peak, or 4-CP).

Q. Why did you choose these four monthly peaks?

A. We chose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2009 IRP. Additionally, we chose these months because PGE's highest annual peak hour occurred during one of these four months in nine out of the past ten years and the seasonal peak occurred during one of these four months in 19 out of the 20 seasons.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We used the proportion of new gas and renewable resources proposed for the year 2020 as identified on page 10 of the 2012 IRP Update dated November 21, 2012 (2012 IRP Update)[2]. This resulted in an attribution of 80% of marginal energy costs to the energy costs of a CCCT as defined above, and 20% to the fully allocated costs of a generic wind farm.

Q. What is the source of your long-term gas price forecast?

A. We used the long-term gas price forecast contained in our 2012 IRP Update dated November 21, 2012 for the Sumas and AECO hubs. We equally weighted the projected burnertip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. Yes. We include compliance costs consistent with the environmental assumptions in the 2012 IRP Update.

Q. What is the fully allocated cost of a generic wind farm as specified in the IRP?

A. The cost of a fully allocated wind farm exclusive of wheeling is estimated at $64.31/MWh in real levelized 2014 dollars, consistent with the capital costs on page 33 of the 2011 IRP Update.

Q. How did you shape these energy costs into hourly values?

A. We shaped the weighted marginal energy costs described above into hourly intervals based on the energy price shaping used in PGE's production cost model, Monet.

Q. How did you estimate each rate schedule's marginal energy cost?

A. We performed the following steps to calculate the 2014 hourly load profile and marginal energy cost of each rate schedule:

[2] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_nov2012.pdf.

1. For each schedule and each month, calculate a typical weekday, Saturday, and Sunday load shape using 2011 hourly load profiles.
2. Use these day-type hourly profiles and the projected monthly peak hour loads to shape each schedule's monthly test-period load forecast into hourly values.
3. By hour, sum each schedule's loads from 2 above and compare these hourly sums to the hourly system load forecast. Assign hourly differences between the two quantities on the basis of each schedule's monthly standard deviation of hourly shaped loads in 2 above. These standard deviations are differentiated by weekday, Saturday, and Sunday.
4. Multiply each schedule's shaped hourly load forecast by the corresponding hourly long-term energy cost described above.

Q. How does this projection of hourly interval loads compare to the monthly load forecast submitted in this docket?

A. The energy values by schedule match precisely. However, inserting the projected monthly peak hour loads to smoothed hourly loads, the monthly peak load hours and the hourly loads immediately proximate to the peak load hours can sometimes appear to be somewhat less than smooth. Nevertheless, the hourly interval data yields a more granular basis to allocate the marginal cost of energy relative to simply using monthly energy values and monthly loads.

Q. Does this conclude your description of generation marginal costs?

A. Yes.

III. Distribution Marginal Cost Study

Q. Please summarize how you calculate marginal distribution costs.

A. We separately calculate marginal distribution costs for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers, service laterals, and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate subtransmission and substation marginal unit costs by first summing growth-related capital expenditures over the five-year period 2013-2017. We then annualize these capital expenditures and divide by the growth in system non-coincident peak (NCP). Customers served at subtransmission voltage supply their own substation and are excluded from this calculation.

Q. How do you calculate the marginal unit distribution feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kV, or feeders that serve downtown core areas.
3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.

4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each rate schedule based on the rate schedule's proportionate contribution to NCP. Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each schedule's NCP.
6. For each feeder, allocate the tapline cost responsibility of each rate schedule based on the rate schedule's proportionate design demand (estimated peak at the line transformer). Calculate a unit cost per kW for both poly- and single-phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.
8. Separately estimate the unit costs of customers greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, multiply this average distance by two, resulting in a per-customer average of 8,200 feet of dedicated feeders. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per customer costs of customers served at subtransmission voltage. This is done by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation. Then multiply this average distance by the current cost per wire mile and annualize these costs.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. Therefore, we exclusively used the current cost of underground facilities in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal line transformer and service costs?

A. We calculate each schedule's marginal line transformer and service lateral costs by estimating the cost of providing the average customer within a class with a service lateral and a line transformer (secondary delivery voltage only). We also include the service design costs and any wire costs not captured in the feeder portion of the study. For smaller customers, such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to appropriately calculate the per customer share of service and transformer costs.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the installed cost of a new Advanced Metering Infrastructure (AMI) meter for each customer and then apply an annual carrying charge.

Q. How do you allocate distribution O&M to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage times its marginal capital cost.

Q. Does this conclude your description of distribution marginal costs?

A. Yes.

IV. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. PGE uses the study to guide the allocation of the customer service functional revenue requirements in the ratespread process as specified in ORS 757.652. The customer service marginal costs are separately estimated by metering, billing, and other services.

Q. Is there a new Chart of Accounts by FERC account numbers?

A. Yes. In 2011, PGE replaced its financial system and established new PGE accounts, which are FERC based.[3] In previous rate cases costs were allocated by PGE ledger.

Q. What PGE account numbers are included in the customer service cost?

A. PGE accounts 9020001, 9030001, 9050001, 9080001, and 9090001.

Q. Are descriptions and titles provided for each of the account numbers?

A. Yes. Descriptions and titles for the account numbers listed above are shown in Table 1 below. Account numbers 9020001, 9030001 and 9050001 are customer account expenses and account numbers 9080001 and 9090001 are customer service and informational expenses.

Table 1
Customer Accounts Expense

Account	Title	Description
9020001	Meter Reading Expense	Labor and expenses associated with on- and off-cycle customer meter reading.
9030001	Customer Records & Collections	Includes the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.
9050001	Misc. Customer Account Expense	Labor and expenses associated with answering residential and non-residential general account questions

[3] See page 4 of PGE Exhibit 1000 regarding the financial system replacement project.

Table 1, continued
Customer Service and Informational Expense

Account	Title	Description
9080001	Customer Assistance Expense	Labor and non-labor expenses associated with market research, promoting safe, efficient and economical use of electricity, managing energy efficiency programs and energy service supplier relationships and maintaining and enhancing customer program technology systems.
9090001	Information and Advertising Expense	Labor and non-labor expenses associated with informational and instructional advertising that conveys information to customers to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

Q. Other than the change in PGE's account numbering system, is the methodology of the study the same?

A. Yes. As with the PGE ledgers, we allocated the PGE account categories directly on the basis of cost causation and a few are allocated based on sub-allocation of the other accounts. After the allocations occur, the total allocations are divided by the projected 2014 customer counts by Schedule. The result is the marginal costs for each rate schedule.

Q. Are the customer marginal costs divided into three categories?

A. Yes. There are metering, billing, and other services marginal costs, which is the same approach as in our previous general rate case.

Q. Are the marginal costs for metering, billing and other services provided?

A. Yes. PGE calculates the marginal customer costs by PGE Standard Service Rate Schedule for metering, billing and other expenses. It also provides the total customer expense, which is the total of the metering, billing and other expenses.

Q. Briefly describe how you calculate the marginal cost of metering, billing and other services.

A. We calculate the marginal cost expected to occur in 2014 by dividing the 2014 allocated amounts by projected 2014 customer counts to derive the marginal cost per customer for each rate schedule.

Q. Are marginal costs allocated based primarily on number of customers, number of meter reads, and write-off dollar amounts?

A. Yes. As with billing, we allocate certain support costs based on sub-allocations within the functional category.

Q. How do you calculate the percentage of write-offs by rate schedule?

A. We total the dollar amount of write-offs for the past three years (2009-2011), and then divide the dollar amount per rate schedule by the total write-off amount to arrive at the percent of write-offs by rate schedule. We use an adjusted write-off amount, excluding Schedules 85 and 89. Therefore, the largest portion of write-offs is allocated to residential customers.

Q. How do you calculate the percentage of meter reads by rate schedule?

A. By 2014 some manual meter reads may still occur, but the number of manual reads will be minimal as we have fully transitioned to AMI. The decline in metering expenses in 2014 reflects this transition. To allocate the remaining metering costs, we use the number of manual meter reads from January 2011 through October 2012. The number of manual meter reads on an annual basis is grouped by meter type (kWh, demand, kvar, time of use, and net meters) and by rate schedule. We estimate how many reads are attributed to the rate schedules and then calculate a percentage by rate schedule. Then the percentage of meters reads is weighted with number of customers (less unmetered and signals) to arrive at a weighted percentage.

Q. What is the basis of the weighted customer counts?

A. We applied a weighting methodology for billing and other services. The weights are based on 2011 costs per customer. The 2011 weight is then multiplied by the projected 2014 number of customers, resulting in an adjusted 2014 customer count. Then the adjusted 2014 customer count is divided by the total number of customers to arrive at a percentage. Finally, that percentage is multiplied by the 2014 costs.

A. Metering

Q. Briefly describe how you calculate marginal costs of metering?

A. Metering costs consist of PGE accounts 9020001. We calculate the marginal cost of metering by allocating the cost to the rate schedules based on various cost-causation principles. For example, we allocate the PGE account 9020001 - "field collections" to metering. We use a weighted percentage of customers (less unmetered lighting and signals) and the most recent meter study. The total allocations are divided by customer counts to arrive at the marginal cost by schedule. Because PGE will have completed its network upgrades for AMI, fewer costs are attributed to metering than the previous GRC.

B. Billing

Q. How do you calculate the marginal costs of billing?

A. Billing costs consist of PGE accounts 9030001. We allocate the collection-related cost on the same basis as the uncollectible accounts. We allocate some of the cost directly on the basis of cost-causation and we allocate some of the other accounts on sub-allocations of the other accounts within billing. For example, "retail receivables" and "field collections" are allocated based on percentage of adjusted write offs by rate schedule. "Specialized billing" costs are allocated by the number of customers on direct access. "Business services group" is allocated by customer. "CIS billing" is allocated by the number of customers, except streetlights and signals. After we allocate the various PGE accounts, we divide the total allocations by the projected customer counts by schedule. This result is the billing marginal cost for each rate schedule.

C. Other Services

Q. How do you calculate the marginal costs of other services?

A. Other services costs consist of PGE accounts 9050001 and 9080001. We calculate the marginal cost of other services by allocating the individual cost to the rate schedules based on various cost-causation principles. For example, we allocate "customer contact operations" by the number of customers on rate schedules using up to 200 kW. The "key customer group" (RC 527) is allocated to all schedules except for residential. However, the allocation is based on a weighting between number of customers and usage. The key customer group is PGE account 9030001, but we have placed it in other services, since this department provides customer service and manages relationships with large customers. After we allocate the individual cost to the individual rate schedules we divide the allocations by the test period customer count to obtain a per customer marginal cost.

Q. Does this conclude your description of customer service marginal costs?

A. Yes.

V. Qualifications

Q. Ms. Gariety, please state your educational background and qualifications.

A. I received a Bachelor of Science and a Master of Science degree in Economics from the University of Wyoming. Since joining PGE in 2007, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on power costs, solar, load curtailment, electric vehicle, and various regulatory issues. Previously, I was an analyst with Iowa Utilities Board and the Office of Consumer Advocate under the Iowa Department of Justice. Also, I was an economist for the State of Oregon Employment Department.

Q. Mr. Macfarlane, please state your educational background and qualifications.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on pricing and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Mr. Werner, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree with an emphasis in Fine Arts from Montana State University in 1977. Since joining PGE in 1999 I have worked as an analyst on a variety of pricing issues in the Regulatory Affairs Department. From 1979 to 1999 I worked at PacifiCorp in several different capacities starting in energy efficiency and finishing in regulatory affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1401	Marginal Cost Study

PORTLAND GENERAL ELECTRIC
MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,162,952	$398,808,672
Schedule 15	25,007	$1,085,126
Schedule 32	1,712,854	$81,886,302
Schedule 38	32,797	$1,610,351
Schedule 47	23,120	$1,126,022
Schedule 49	73,893	$3,543,605
Schedule 83	3,032,861	$145,785,900
Schedule 85	2,391,879	$114,100,025
Schedule 89 1-4 MW	1,010,377	$48,037,390
Schedule 89 GT 4 MW	2,525,314	$117,581,291
Schedule 91	111,372	$4,832,703
Schedule 92	4,803	$222,413
Schedule 93	615	$29,437
Totals	19,107,843	$918,649,238

PORTLAND GENERAL ELECTRIC
MARGINAL CAPACITY COSTS

Model One - SCCT Proxy Capital Cost $/kW (F Frame)

1	SCCT Installed Cost	$/kW	$766
2	Real Carrying Charge		10.04%
3	Annualized SCCT Cost	$/kW-yr	$76.90
4	Fixed O&M	$/kW-yr	$5.29
5	Fixed Gas Transport	$/kW-yr	$0.00
6	Reserve Margin (12%)	$/kW-yr	$9.86
7	Total	$/kW-yr	$92.05

PORTLAND GENERAL ELECTRIC
MARGINAL CAPACITY COSTS

Model Two - Reciprocating Engines Proxy Capital Cost		
1 Recip Eng Installed Cost	$/kW	$1,311
2 Real Carrying Charge		10.04%
3 Annualized Recip Eng Cost	$/kW-yr	$131.63
4 Fixed O&M	$/kW-yr	$3.59
5 Fixed Gas Transport	$/kW-yr	$34.17
6 Reserve Margin (12%)	$/kW-yr	$20.33
7 Total	$/kW-yr	$189.73

PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	FEEDER BACKBONE COSTS	FEEDER TAPLINE COSTS	SERVICE & TRANSFORMER COSTS	METER COSTS	CUSTOMER COSTS
	($/kW)	($/kW)	($/kW)	($/kW)	($/Customer)	($/Customer)	($/Customer)
Schedule 7 Residential							
Single-phase	$10.99	$10.12	$24.23	$17.10	$82.61	$20.19	$72.42
Three-phase	$10.99	$10.12	$24.23	$17.10	$147.47	$55.45	$72.42
Schedule 15 Residential	$10.99	$10.12	$25.26	$17.81	$8.66	N/A	$60.40
Schedule 15 Commercial	$10.99	$10.12	$25.26	$17.81	$8.66	N/A	$100.17
Schedule 32 General Service							
Single-phase	$10.99	$10.12	$28.14	$24.77	$123.07	$19.37	$115.53
Three-phase	$10.99	$10.12	$28.14	$9.44	$264.80	$68.38	$115.53
Schedule 38 TOU							
Single-phase	$10.99	$10.12	$33.47	$20.26	$195.06	$57.76	$106.54
Three-phase	$10.99	$10.12	$33.47	$13.09	$527.62	$82.42	$106.54
Schedule 47 Irrigation							
Single-phase	$10.99	$10.12	$70.23	$52.32	$9.70	$53.83	$105.21
Three-phase	$10.99	$10.12	$70.23	$27.08	$25.26	$81.81	$105.21
Schedule 49 Irrigation							
Single-phase	$10.99	$10.12	$71.65	$44.06	$27.36	$57.76	$119.93
Three-phase	$10.99	$10.12	$71.65	$27.46	$132.97	$99.76	$119.93
Schedule 83 Secondary General Service							
Single-phase	$10.99	$10.12	$24.68	$20.63	$426.41	$46.44	$178.23
Three-phase	$10.99	$10.12	$24.68	$9.00	$1,093.60	$108.37	$178.23
Schedule 85 Secondary General Service	$10.99	$10.12	$21.13	$7.00	$1,732.11	$151.34	$878.76
Schedule 85 Primary General Service	$10.99	$10.12	$21.13	$7.00	$727.44	$1,382.27	$878.76
Schedule 89 Secondary 1-4 MW	$10.99	$10.12	$21.14	$4.66	$4,581.85	$164.19	$3,605.21
Schedule 89 Primary 1-4 MW	$10.99	$10.12	$21.14	$4.66	$867.23	$1,382.27	$3,605.21
Schedule 89 Secondary GT 4 MW	$10.99	$10.12	$73,144	N/A	$11,054.47	$164.19	$41,225.61
Schedule 89 Primary GT 4 MW	$10.99	$10.12	$73,144	N/A	$2,548.39	$1,382.27	$41,225.61
Schedule 89 Subtransmission	$10.99	N/A	$83,464	N/A	N/A	$16,556.61	$41,225.61
Schedules 91 & 95 Streetlighting	$10.99	$10.12	$25.26	$17.81	$5.01	N/A	$770.25
Schedules 92 Traffic Signals	$10.99	$10.12	$25.26	$9.09	$12.09	N/A	$624.90
Schedule 93 Field Lighting	$10.99	$10.12	$25.26	$9.09	$72.37	$1,296.40	$175.03

STATE OF CALIFORNIA Edmund G. Brown Jr., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

January 22, 2016

Advice Letter 4708-E

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Subject: Submit Study Plan for Approval as Directed by D.15-08-005, O.P.10

Dear Mr. Jacobson:

Advice Letter 4708-E is effective January 19, 2016 per Resolution E-4756.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

Pacific Gas and Electric Company®

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-7226

September 28, 2015

Advice 4708-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> **Submit Study Plan for Approval as Directed by Decision 15-08-005, Ordering Paragraph 10**

<u>Purpose</u>

This advice letter is in compliance with Decision (D.) 15-08-005, in which the California Public Utilities Commission (Commission or CPUC) ordered Pacific Gas and Electric Company (PG&E) to submit a study plan by September 29, 2015, for approval by the Commission's Energy Division.

<u>Background</u>

Ordering Paragraph 10 of D.15-08-005 requires that:

PG&E shall file a data-rich analysis of the Small and Medium Commercial classes in its upcoming General Rate Case Phase 2 application. PG&E shall (1) schedule a "meet and confer" session with parties to this proceeding, to take place within 30 days of the effective date of this decision, and (2) file a Tier 2 Advice Letter 45 days from the effective date of this decision, providing a detailed plan for the study, including a description of the data that will be analyzed. PG&E shall not proceed with its proposed study until the Advice Letter is approved by the Commission's Energy Division.

On August 27, 2015, PG&E notified the service list of the required "meet and confer" session, which was subsequently held on September 14, 2015. SEIA, CALSEIA, PG&E, CLECA, CFBF and ORA participated in the "meet and confer" session which was offered via webcast or in-person meeting.

In this advice letter, PG&E submits for Energy Division approval its study plan as directed by Ordering Paragraph 10.

Study Plan

PG&E's proposed Study Plan, including a description of the data to be analyzed, is provided as Attachment A to this advice letter. PG&E will be filing the final study with its 2017 General Rate Case Phase II Application on March 31, 2016, and respectfully requests prompt approval of this study plan so that it can begin the work as soon as possible.

The proposed Scope of this Study is to examine the (1) cost of service by segment and class definitions, and (2) relevant and appropriate demand charges, if any, that should be imposed on small and medium commercial customers depending on their level and pattern of demand.

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than October 19, 2015, which is 21 days[1] after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

[1] The 20-day protest period concludes on a weekend. PG&E is hereby moving this date to the following business day.

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 advice filing become effective on regular notice, October 28, 2015, which is 30 calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.13-04-012. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

Attachments

cc: Service List A.13-04-012

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

Utility type:	Contact Person: Kingsley Cheng
☑ ELC ☐ GAS	Phone #: (415) 973-5265
☐ PLC ☐ HEAT ☐ WATER	E-mail: k2c0@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **4708-E** **Tier: 2**

Subject of AL: **Submit Study Plan for Approval as Directed by Decision 15-08-005, Ordering Paragraph 10**

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.15-08-005

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ____

Resolution Required? ☐Yes ☑No

Requested effective date: **October 28, 2015** No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 21 days[1] after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division
EDTariffUnit
505 Van Ness Ave., 4th Flr.
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Erik Jacobson
Director, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

[1] The 20-day protest period concludes on a weekend. PG&E is hereby moving this date to the following business day.

Attachment A: Small and Medium Commercial Customer Rate Study Plan

Contents

Attachment A: Small and Medium Commercial Customer Rate Study Plan

1. Introduction

This Study Plan is provided to describe the detailed analysis and comprehensive review of Pacific Gas and Electric's (PG&E) small and medium-sized commercial customer class as it relates to cost allocation and rate design. In Decision 15-08-005 dated August 18, 2015, on page 26, the Commission stated that "we expect an exhaustive examination of the question of relevant and appropriate demand charge or charges, if any, that should be imposed on small and medium commercial customers depending their level and pattern of demand" and that "this study must also justify the appropriate limit for Schedule A-6." In Ordering Paragraph 10, the Commission also stated that "PG&E shall (1) schedule a "meet and confer" session with the parties to this proceeding, to take place within 30 days of the effective date of this decision, and (2) file a Tier 2 Advice Letter 45 days from the effective date of this decision, providing a detailed plan for the study, including a description of the data that will be analyzed" and that "PG&E shall not proceed with its proposed study until the Advice Letter is approved by the Commission's Energy Division."

On September 14, 2015, PG&E conducted a meet and confer workshop to discuss the study parameters of the segmentation, cost allocation and rate design applicable to the small and medium-sized commercial customer class. Attendees of the workshop included:

a. California Large Energy Consumers Association (CLECA) – Cathy Yap
b. California Farm Bureau Federation (CFBF) – Laura Norin
c. Small Business Utility Advocates (SBUA) – James Birkelund
d. Solar Energy Industries Association (SEIA) – Tom Beach
e. California Solar Energy Industries Association (CalSEIA) – Brad Heavner
f. Office of Ratepayer Advocates (ORA) – Chris Danforth; Dexter Khoury; Nathan Chau

g. Pacific Gas & Electric Rates Staff

In the sections below, the study plan is described. Once approved, PG&E will develop the study. The results of the study shall be filed with PG&E's 2017 General Rate Case (GRC) Phase II application.

2. Scope of the Study

The scope of this study is to examine (1) cost of service by demand segments and class definitions, and (2) relevant and appropriate demand charges, if any, that should be imposed on small and medium commercial customers depending on their level and pattern of demand. Accordingly, the planned analysis is described separately for these two studies.

3. Cost of Service by Demand Segment and Class Definition

The first study is intended to review cost of service for various segments of small and medium commercial customers. This work was initially proposed by ORA as part of the Small Commercial Settlement agreement. ORA requested 'filing quality' cost allocation for the commercial sector segmented at 20, 50 and 75 kW. This portion of the study will also address SBUA's request to segment customers by their North American Industry Classification System (NAICS) code. PG&E proposes the following research.

3.1 PG&E will initially develop an analysis of Small and Medium Commercial customers (less than 500 kW) in fixed increments of demand: 0 to 20 kW, 20 to 50 kW, 50 to 75 kW, 75 to 200 kW and 200 kW to 500 kW. This customer count (frequency) analysis will be conducted to make an initial assessment of whether there is any "natural grouping" of customers based on customer size or any other characteristics of the customers in the group.[1] This analysis will be conducted separately for Net Energy Metering (NEM) and non-NEM customers and will track current rate schedule. In addition, customers will be categorized by their NAICS codes up to the first three (3) digits to the extent such data is available in PG&E's billing system.[2]

Data Requirements: Recorded billing data will be used in conjunction with Smart-Meter interval data (i.e., integrated kW demands measured over 15-minute periods) available for the class.[3]

Accounts without NAICS code information in PG&E's billing system will be identified and reported as having missing data.

3.2 PG&E will assign customers and develop cost allocation results (based on marginal costs) for class divisions at 20 kW, 50 kW, and 75 kW and over.

Data Requirements by Segment Studied:

- System Peak Cost Allocation Factors (PCAF) based on adjusted net loads (i.e., gross loads net of solar, wind and hydro generation)[4] for allocation of generation capacity costs based on load research data and information for migrating (across demand thresholds) customers;

- Distribution PCAF loads for allocation of primary voltage marginal distribution capacity costs based on load research data and information for migrating customers;

[1] If there is a clustering of customers at one of the identified break points, that is, 20 kW, 50 kW, 75 kW, etc., it may be appropriate to modify that particular break point.
[2] A NAICS code is a six-digit code identifying sector and sub-sector industrial classifications, where each successive digit subdivides an industry sector into progressively more detailed categories.
[3] If necessary to preserve the confidentiality of customer data, some customer information may be aggregated to mask the identities of specific customers.
[4] PG&E used this methodology in its 2015 Rate Design Window proceeding, to develop its proposal for new time-of-use (TOU) period definitions for residential customers, to reflect the changing pattern of generation costs.

Attachment A: Small and Medium Commercial Customer Rate Study Plan

- Distribution Final Line Transformer loads for allocation of New Business Primary and Secondary marginal cost based on load research data and information for migrating customers;

- Recorded monthly kWh sales;

- Marginal Customers Access Costs;

- Locational marginal costs for primary marginal costs, new business primary marginal costs and secondary marginal costs; and

- Annual marginal generation capacity cost and hourly marginal energy cost.

PG&E plans to use its load research sample for 2012, 2013 and 2014 for this analysis. The table below shows the number of Small and Medium Commercial customers in PG&E's load research sample for 2012, 2013 and 2014.

Table 1.0 – Population and Load Research Sample Counts for 2012, 2013 and 2014

	2012		2013		2014	
Customer Class	Population Count	Sample Count	Population Count	Sample Count	Population Count	Sample Count
Small Commerical (A-1 & A-6)	462,624	14,239	479,184	13,446	486,560	10,859
Medium Commercial (A-10)	47,257	10,230	48,579	4,161	49,447	4,367
Medium C&I E-19 (All)	20,651	7,310	22,208	4,796	24,984	5,510
Total	530,532	31,779	549,971	22,403	560,991	20,736

PG&E will perform a "filing quality" cost of service study by demand segment using the data described above. The flow chart detailed in Framework 1.0 describes the segmentation and class definitions. Specifically, the flow chart describes the input, analyses and output in order to segment the small and medium-sized commercial class and to determine appropriate thresholds for the application of rates.

4. Rate Design

In Decision 15-08-005, at page 26, the Commission states ”we expect an exhaustive examination on the question of the relevant and appropriate demand charge or charges, if any, that should be imposed on small and medium commercial customers depending on their level and pattern of demand. We reiterate that this study should comprehensively analyze cost allocation and rate design within the small and medium commercial classes.” In order to evaluate the most appropriate rate designs for Small and Medium Commercial classes, PG&E proposes to develop samples of customers representing a range of different operating characteristics taken from PG&E’s class load research sample. PG&E will estimate the annual cost of service for each sample. PG&E will then test the cost recovery of a variety of different rate designs by billing each sample customer under each rate design and comparing the cost recovery achieved (i.e., annual revenue collected versus cost to serve) by each rate design over the range of sample customers. PG&E will identify the the rate design that best recovers the cost of service for the sample customers. In this analysis, too, customers in the samples will be segmented by NEM versus non-NEM.

A limited sensitivity analysis will also be performed on various cost-based time-of-use (TOU) periods, that is peak, peak, partial-peak and off-peak, used for rate design.

Data Requirements (Cost):

- Customer load profiles

- Generation capacity cost allocated to hours based on net loads

- Distribution capacity cost allocated to hours based on PCAF loads

- Non-coincident costs

Attachment A: Small and Medium Commercial Customer Rate Study Plan

- Hourly energy costs

Data Requirements (Alternative Rate Structures):

- Allocated Cost

- Forecast Billing Determinants

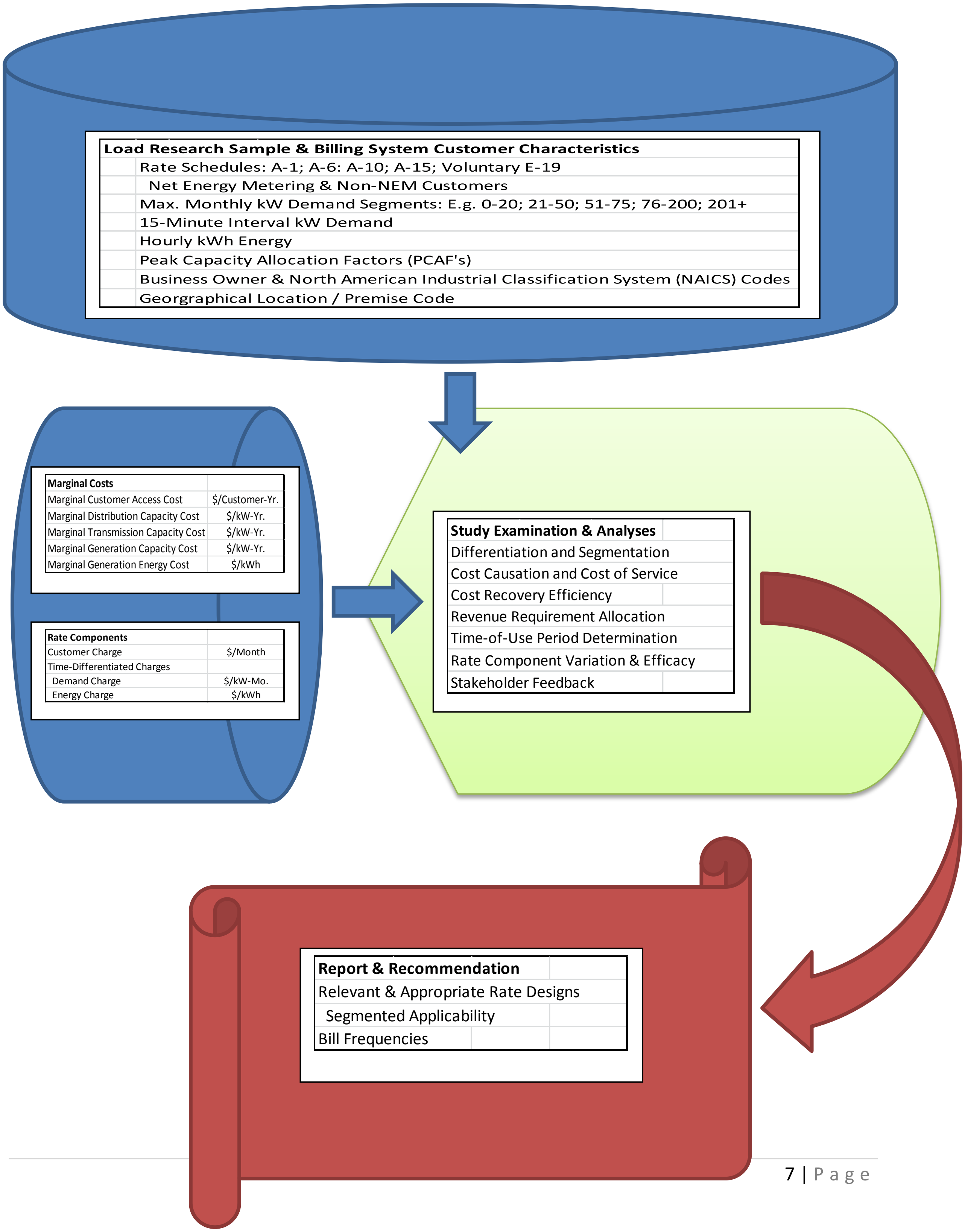
- Alternative Rate Structures to include fixed, maximum demand, peak demand, and energy charges.

The flow chart detailed in Framework 1.0 describes the cost allocation and rate design analysis. Specifically, the flow chart describes the input, analyses and output in order to allocate marginal costs for small and medium-sized commercial class and to design fair and reasonable rates.

PG&E will present the results of this data-rich analysis of the Small and Medium- Commercial classes in its upcoming 2017 General Rate Case Phase II application.

Attachment A: Small and Medium Commercial Customer Rate Study Plan

Framework 1.0 – Class Segmentation, Cost Allocation and Rate Design



PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Braun Blaising McLaughlin, P.C.
CENERGY POWER
CPUC
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine
Casner, Steve
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Coast Economic Consulting
Commercial Energy
Cool Earth Solar, Inc.
County of Tehama - Department of Public Works
Crossborder Energy
Davis Wright Tremaine LLP
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Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates
Don Pickett & Associates, Inc.
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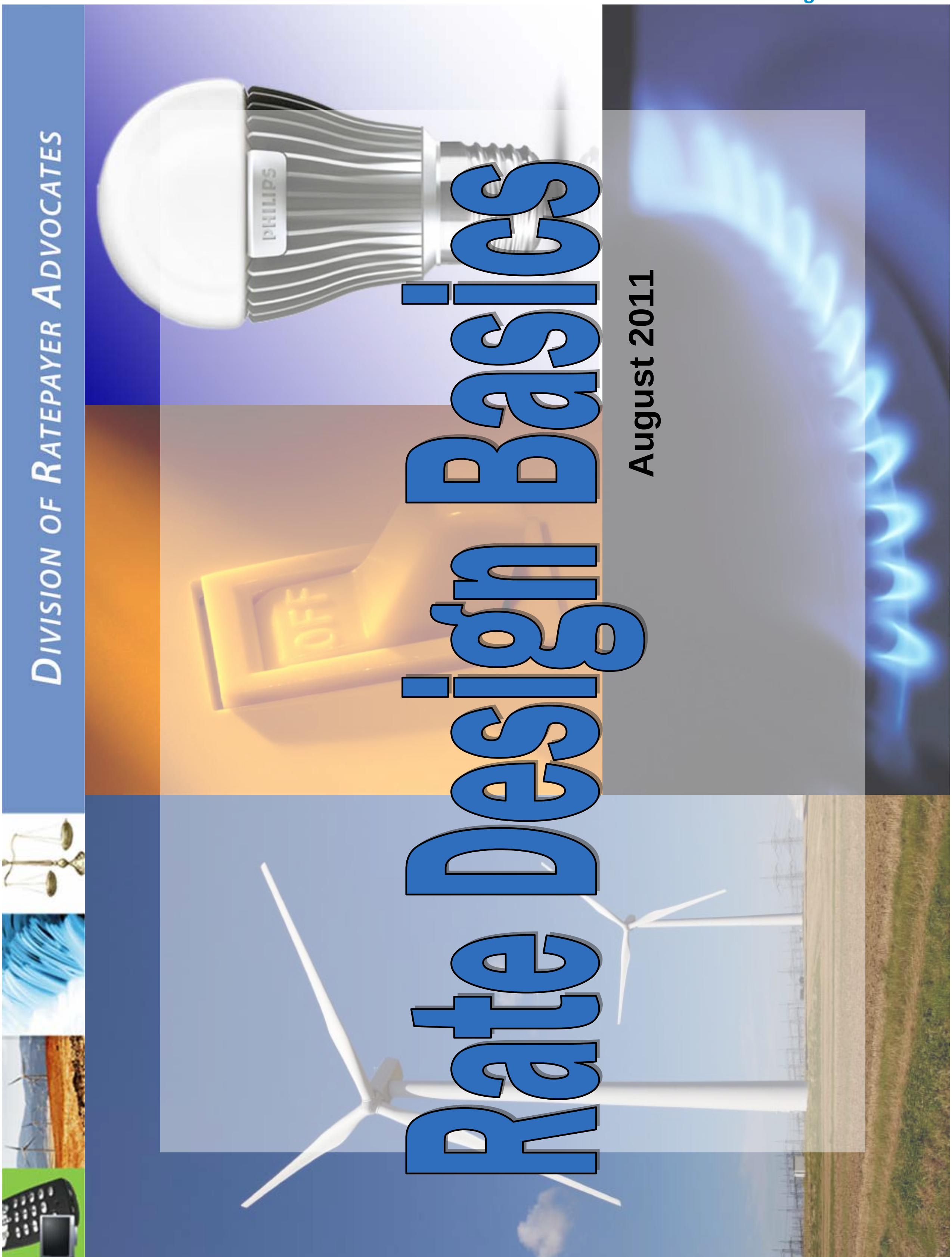
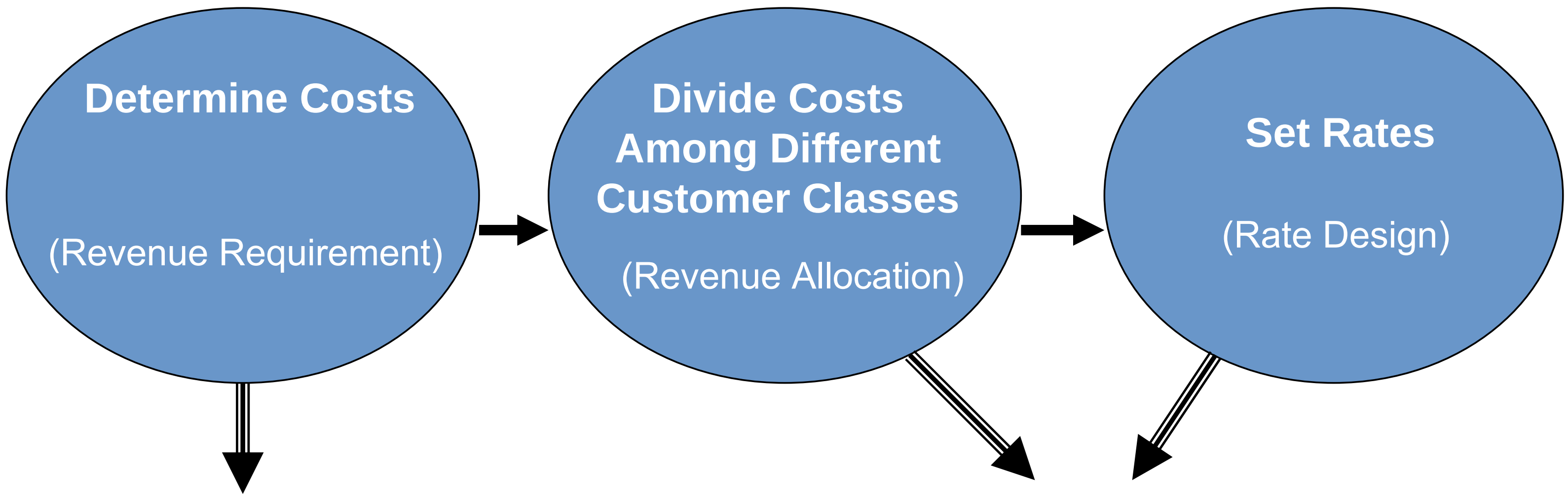
Hanna & Morton
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Leviton Manufacturing Co., Inc.
Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.
ORA
Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SDG&E and SoCalGas
SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Energy (Socal Gas)
Sempra Utilities
SoCalGas
Southern California Edison Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
YEP Energy


Division of Ratepayer Advocates
Rate Design Basics
August 2011

Presentation Overview

- Ratemaking -- The Big Picture
- Marginal Cost Determination
- Revenue Allocation
- Basic Rate Design
  - Residential Rates
  - Time-varying Rates

CPUC Electricity Ratemaking Process



Proceedings:

- General Rate Cases ("GRC"), Phase I
- Energy Resource Recovery Account (ERRA)
- Other Cost Recovery Applications, i.e. AMI, Energy Efficiency, Low-Income

Proceedings:

- General Rate Cases, Phase II
- Rate Design Windows ("RDW")
- Other Proceedings
  - Recently, utilities have included cost recovery proposals in other proceedings

Marginal Cost

Revenue Allocation & Rate Design
are based on the utility's Marginal Costs

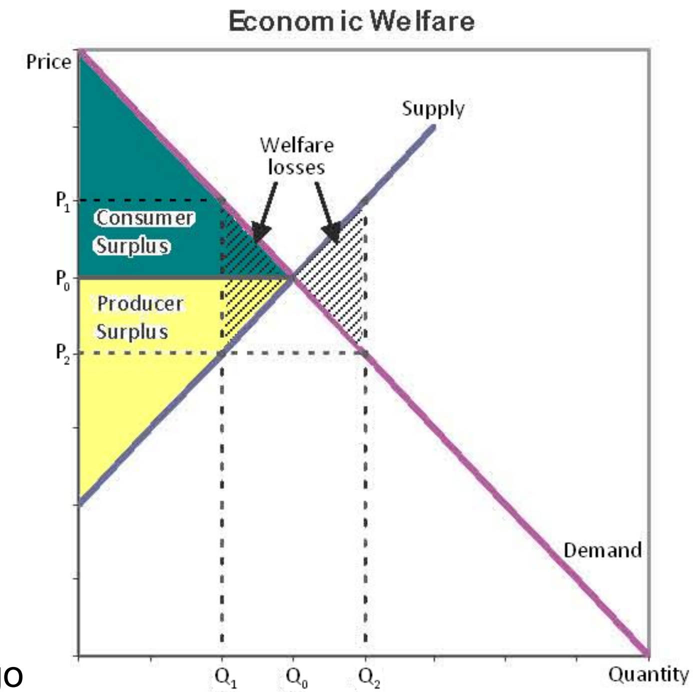
- **What is a Marginal Cost?:** The cost of providing an additional unit of electricity

Type of Marginal cost	Type of Charge
Energy (Generation)	Energy / Usage (kWh)
Capacity (Generation, T&D)	Demand (kW) and / or Volumetric (kWh)
Customer (Facility Costs, Meter Reading, Billing, Customer Service)	Customer and / or Volumetric (kWh)

Marginal Cost

Why do we base Revenue Allocation and Rate Design on Marginal Costs?

- Producing at a level of Q_O and charging a price of P_O maximizes **Economic Welfare**
  - **Economic Welfare =**
    Consumer Surplus + Producer Surplus
  - **Consumer Surplus =**
    Consumer Value – Retail Price
  - **Producer Surplus =**
    Retail Price – Marginal Production Cost
- Any departure from Q_O produces a **Welfare Loss**
- CPUC first implemented marginal cost-based ratemaking in the late 1970's after the oil embargo
  - To promote energy conservation when fuel prices were skyrocketing
  - Before that, CPUC used an embedded cost allocation



Marginal Cost

Marginal Generation Capacity Costs

A hot topic in Marginal Cost ratemaking

- In theory, market prices tend towards short-run marginal costs so that surpluses and shortages can be mitigated
- In ratemaking, the goal is a middle ground between long-run and short-run marginal costs in order to:
  - Promote rate stability over time
  - Encourage purchases of energy consuming products that will reflect what electricity will cost over the entire product lifecycle (up to 15 years)
- In the current environment of generation capacity surpluses, the appropriate length of time is greatly debated in GRCs

Marginal Costs in Revenue Allocation

Reflecting Marginal Costs in ratemaking requires adjustment:

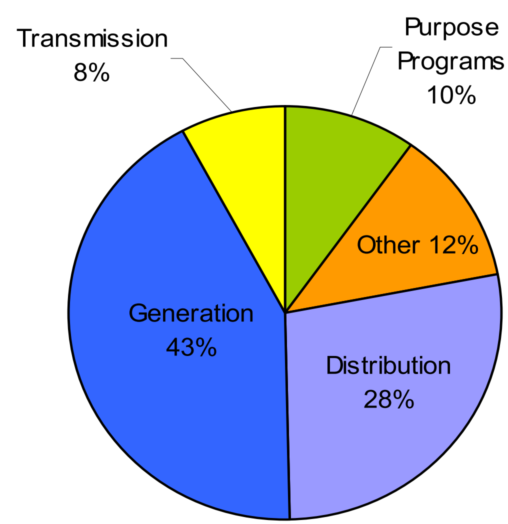
- Utilities are allowed to collect the authorized revenue requirement, which reflects average costs, not marginal costs
- Charging marginal costs could yield a revenue requirement over- or under-collection
- In electric ratemaking, unlike unregulated markets, it is difficult to correct for under- and over-collections through product differentiation, market segmentation, and price discrimination
- CPUC devised a revenue allocation process known as "equal percentage of marginal costs" aka *EPMC revenue allocation*
  - *How it works:* Revenues allocated to each customer class are equal to the percentage of the total costs they would be responsible for if all customers were charged marginal costs
  - *In rate design:* Marginal costs must be scaled up or down so that they collect the revenues allocated to the class

Revenue Allocation

Categories of Costs

Allocation of Generation, Distribution and other Revenue Requirements

- **Generation** and **Distribution:** Separately allocated using EPMC
- **Transmission:** FERC jurisdictional and allocated by embedded costs
- **Public Purpose Programs:** Allocated mostly by equal cents/kWh
- **Other Costs (i.e. SGIP, CSI):** Allocated by various methods



Reflects Revenue Req's. for PG&E in 2011 Annual Electric True-Up filing

**errors due to rounding*

Revenue Allocation

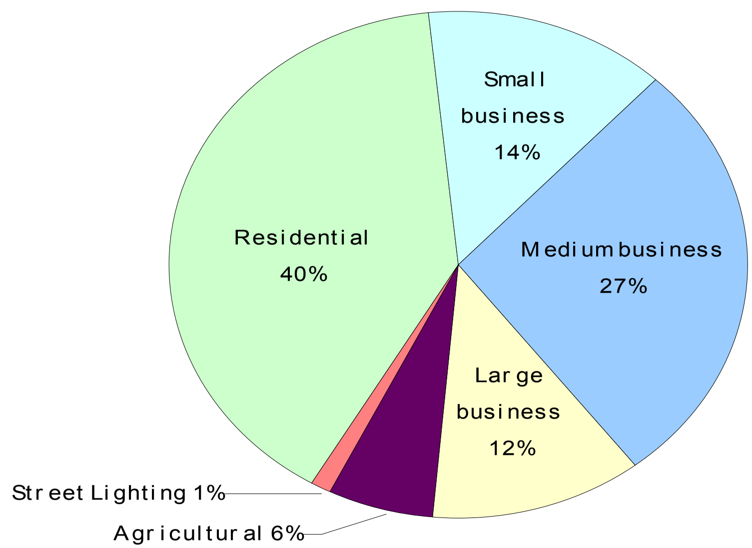
Public Purpose Programs (PPP)

- PPP costs are determined by state statutes or CPUC proceedings:
  - **California Alternate Rates for Energy (CARE):** Rate discount program for low-income residential customers
  - **Energy Savings Assistance Program (ESAP):** Provides low-income households with weatherization and energy efficiency services
  - **Energy Efficiency (EE):** Provides subsidies to residential and business customers designed to support energy efficiency
  - **Research and Development (R&D):** Provides funds to conduct research on science or technology for providing or improving utility services
- Additional PPP costs are determined in GRCs and other proceedings on a program basis

Revenue Allocation

Impact on Customer Classes

Example: Percent of PG&E Total Electric Revenue Requirement Allocated to Various Customer Classes



Reflects Costs for PG&E in 2011 Annual Electric True-Up

Rate Design

Once Revenue Allocation is determined,
Rates are developed for each customer class

- **Rate Design:** Typically involves balancing several competing goals
  - Fair and Equitable to all Customers
  - Stable and Predictable
  - Stable Revenue Collection
  - Reflective of Social Costs of Energy Production and Consumption
  - Affordable Universal Services
  - Understandable
  - Incentive to Conserve
  - Economically Efficient

- **Residential Rates**: Increasing block tiered volumetric rates established since the Energy Crisis, which promote conservation and ensure affordable basic usage

- **Commercial, Industrial, Agricultural Customers:** Fixed charges and volumetric rates

Rate Design – Residential

- **Prior to 2001 Energy Crisis:** Only 2 tiers of residential rates:
  - Baseline
  - Above Baseline

- **Baseline Rates:** Designed to provide affordable rates for basic uses of energy

- **Increasing Block** or **Inverted Rate Structure:** Designed to promote conservation for usage above Baseline

Rate Design – Residential

Baseline Allowances

- Baseline Program approved by the Legislature in 1988:

  "The Commission shall designate a baseline quantity of gas and electricity which is necessary to supply a significant portion of the reasonable energy needs of the average residential customer" [P. U. Code §739]

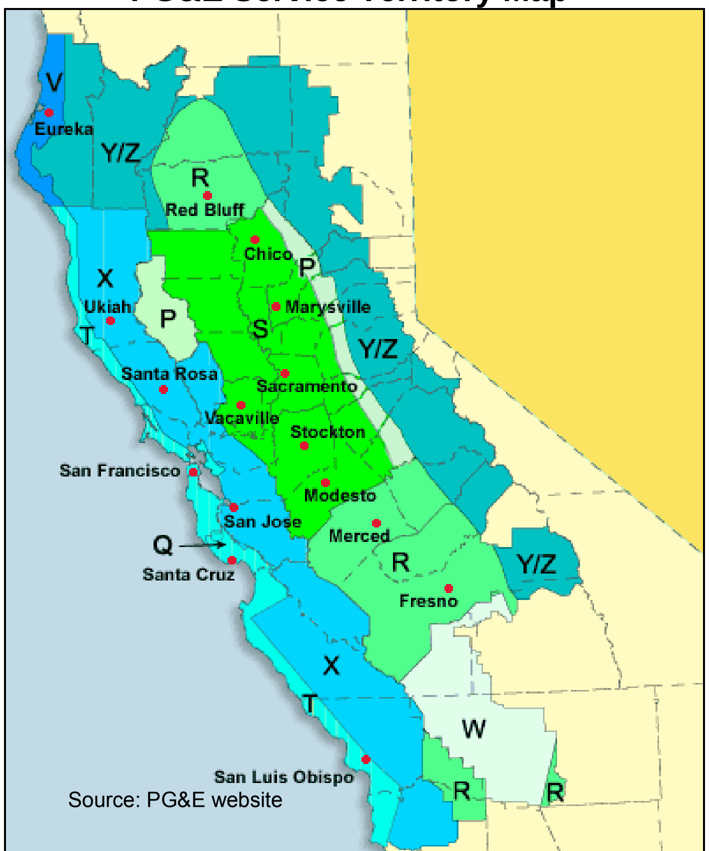
- Baseline Allowance calculation:
  - Quantity is set at 50% - 60% of average consumption in a given climate zone
    - During the 2001 Energy Crisis they were set at the upper end of this range
  - Different quantities calculated for summer and winter seasons
    - Higher baseline quantities are available for customers with defined medical needs

Rate Design – Residential

Baseline Quantities by Zone

PG&E Example

PG&E Service Territory Map



Source: PG&E website

Baseline Quantities (kWh Per Month)

San Francisco (Baseline Area "T")

	Summer	Winter
Electric	249	298
All-Electric	341	614

Stockton (Baseline Area "S")

	Summer	Winter
Electric	484	380
All-Electric	599	982

- Baseline quantities vary by average consumption, geography, and season
- Baseline quantities adjusted in GRCs

Rate Design - Residential

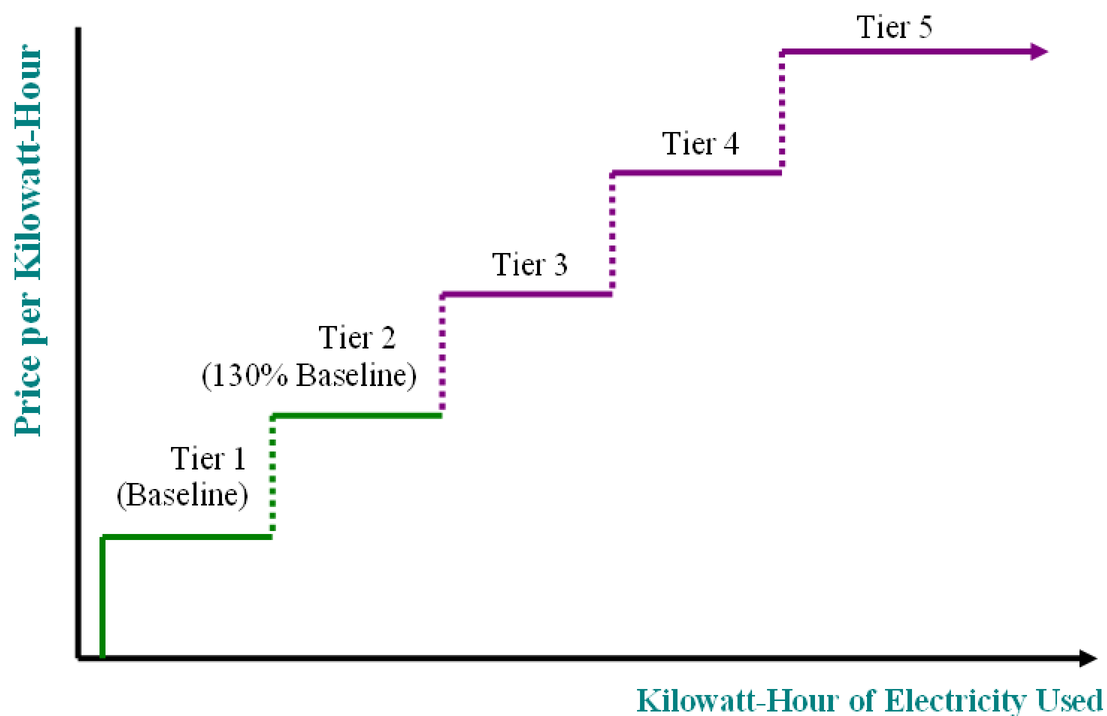
Impact of 2001 Energy Crisis

- Electricity Crisis started in 2000 and was characterized by skyrocketing electricity costs and rotating outages
- IOUs could not sufficiently recover the high cost of electricity under the rate freeze instituted by electric restructuring statute AB 1890
- Legislature required the Department of Water Resources to purchase electricity for utility ratepayers
- In 2001, the Legislature passed AB 1X, which protected residential customers from the worst impacts of the energy crisis
- AB 1X prohibited increases in rates for usage up to 130% of baseline usage

Rate Design - Residential

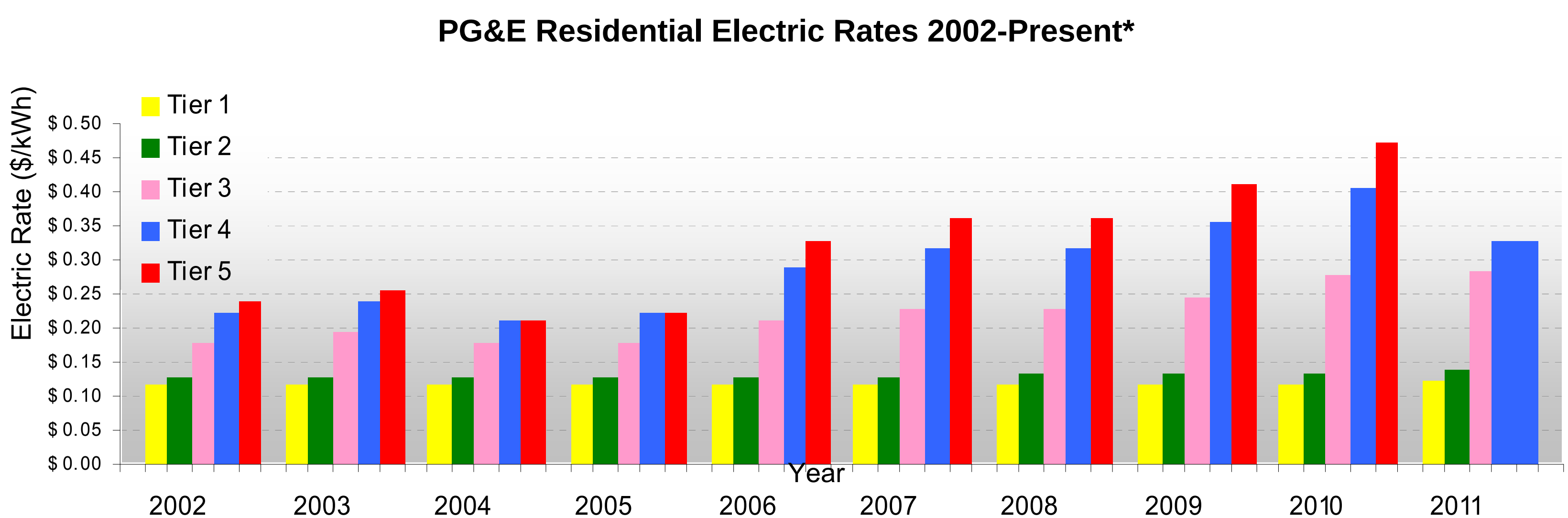
Increasing Block Rates

- The higher the usage, the higher the price per unit
- Similar to marginal tax bracket system



Rate Design - Residential

Historical View of Rates



*Source: PG&E historical tariffs

- CPUC enacted rate surcharges and created 5 tiers of increasing block rates for residential customers
- Tier 3, 4, and 5 rates were increasing due to increased revenue requirements

Rate Design – Residential

Senate Bill 695 Reforms to AB 1X

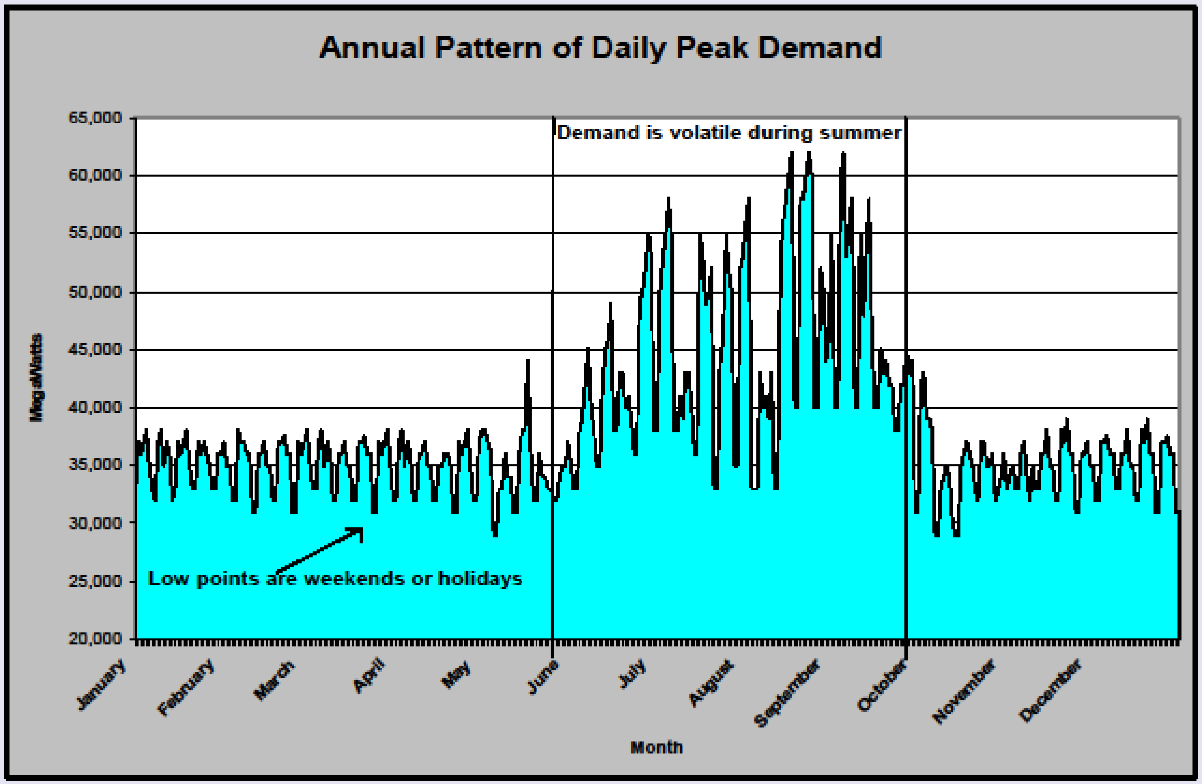
SB 695 enacted in 2009 to moderate rate increases in tiers 3–5:

- Allows 3 – 5% increases per year to non-CARE Tiers 1 & 2 (Tier 5 recently eliminated)
- Allows increases to CARE rates of up to 3% per year based on the annual percentage increase in benefits of the CalWORKS program
  - Permits PG&E to introduce a new CARE Tier 3 rate with a capped introductory rate
- Imposes an overall cap on residential non-CARE Tier 1 rates of 90% of system average rates (including fixed customer charge revenues)
- Addresses Time Variant Pricing (TVP) for residential customers:
  - Does not allow mandatory TVP for residential customers
  - Permits default (opt out) TVP without bill protection starting in 2014
  - Allows default (opt out) real time pricing without bill protection starting in 2020
  - Prohibits penalties for opting out of TVP
- Parties have argued whether SB 695 puts limitations on a residential customer charge

Rate Design – Time Variant Pricing

The Basis for Time Variant Pricing

Demand is Volatile During Summer



Source: California Energy Commission

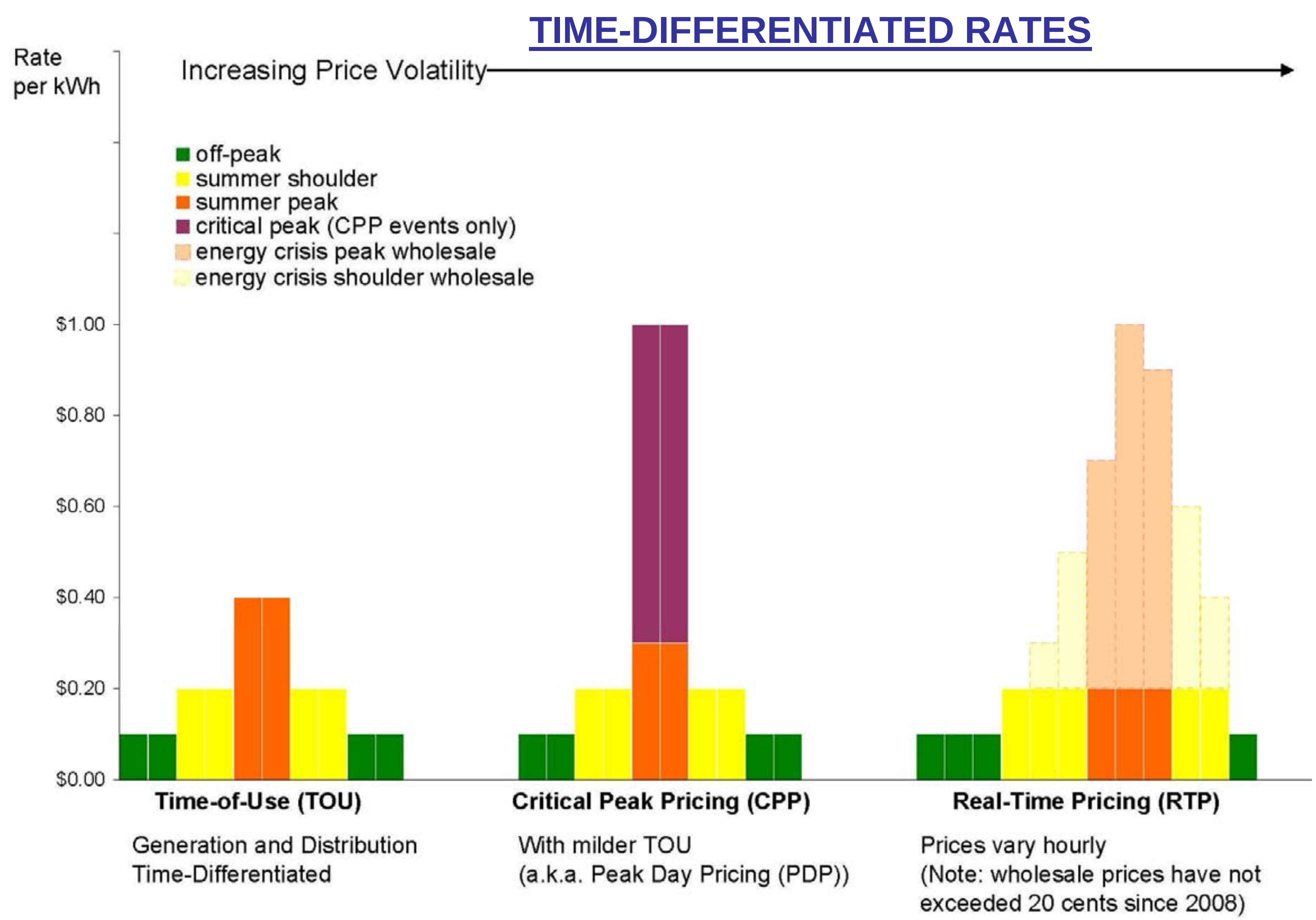
Rate Design – Time Variant Pricing

Types of Time Variant Pricing

- **Time Variant Pricing (TVP):**
  - Customers are charged varying prices depending on when they use electricity
  - Includes time-of-use pricing and dynamic pricing
- **Time of Use (TOU) Pricing:**
  - Pre-determined rates that apply to pre-determined time periods (on-peak, mid-peak, or off-peak)
  - Does not reflect market or electric system conditions on a day-ahead or near real-time basis
- **Dynamic Pricing:**
  - Rates are allowed to vary to reflect market / system conditions
  - *Critical Peak Pricing (CPP):* A dynamic rate that allows a predetermined short-term price increase to reflect system conditions expected on the following day
  - *Real Time Pricing:* A dynamic rate that allows price itself to be adjusted typically on an hourly basis to reflect near real-time system conditions

Rate Design – Time Variant Pricing

Time Variant Pricing Rate Design



Rate Design - Time-Variant Pricing

CPUC Timetable for Dynamic Pricing

PG&E Schedule for Implementing Dynamic Pricing

	Current Rate Design	New Default Rate Design	New Optional Rate Design	Current Default Implementation Date
Large Commercial & Industrial	Mandatory TOU	TOU w/ CPP Overlay	TOU Only	May 1, 2010
Small & Medium Commercial	Most on Flat Rates	TOU w/ CPP Overlay	TOU Only	Nov. 1, 2012 (originally May 2011)
Residential	Tiered, non-TOU	N/A (same as current)	TOU or CPP	

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