Docket:	:	A.19-07-004
Exhibit Number	:	Cal PA - ____
Commissioner	:	Genevieve Shiroma
Administrative Law Judge	:	Gerald F. Kelly
Cal PA Witness	:	Jayne Parker

REPORT AND RECOMMENDATIONS ON RATES AND SURCHARGES

Application 19-07-004

San Francisco, California
February 14, 2020

TABLE OF CONTENTS

Contents

MEMORANDUM

The Public Advocates Office at the California Public Utilities Commission ("Public Advocates Office") examined requests and data presented by California American Water Company ("Cal Am") in Application ("A.") 19-07-004 ("Application") to provide the California Public Utilities Commission ("Commission") with recommendations that represent the interests of ratepayers for safe and reliable service at the lowest cost. Mukunda Dawadi is the Public Advocates Office's project lead for this proceeding. Richard Rauschmeier is the oversight supervisor and Kerriann Sheppard and Robyn Purchia are legal counsels.

Although every effort was made to comprehensively review, analyze, and provide the Commission with recommendations on each ratemaking and policy aspect presented in the Application, the absence from the Public Advocates Office's testimony of any particular issue does not necessarily constitute its endorsement or acceptance of the underlying request, methodology, or policy position related to that issue.

A. INTRODUCTION

Cal Am's general rate case establishes customers' base rates for water service for a three-year period. Base rates include the monthly service charge that is assessed for a customer's meter size and quantity rates that are assessed for the volume of water consumed. Base rates are calculated to meet a utility's revenue requirement and should provide the basic information necessary to evaluate the impacts of requests made by a utility in a general rate case on customers' bills .[1] However, over the past decade more than one-fifth of Cal Am's average residential bill has consisted not of base rates, but rather surcharges that are the result of alternative ratemaking mechanisms.[2]

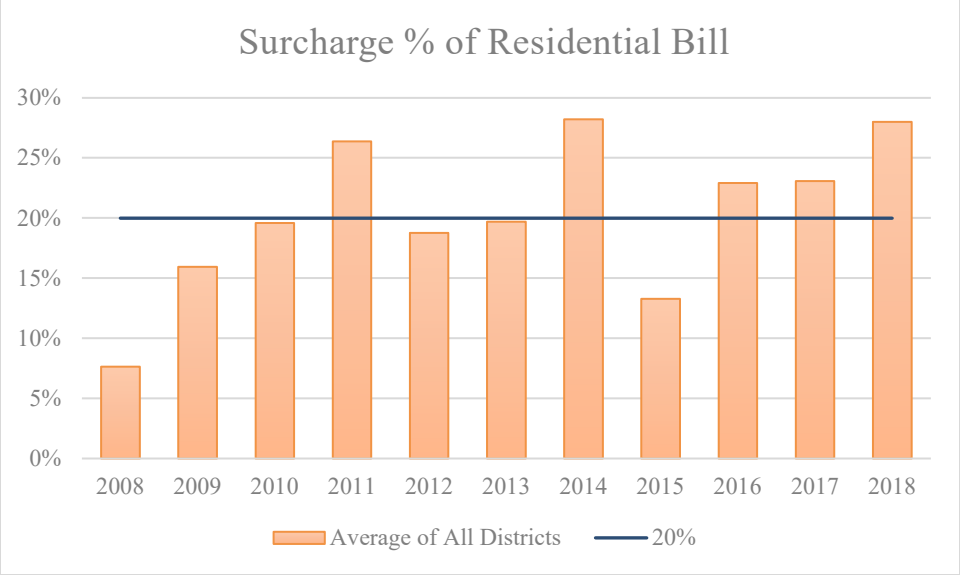
As shown below in Figure 1, surcharges have averaged approximately 20% of the total residential bill across all of Cal Am's districts over the past decade. In Cal Am's Monterey District, surcharges have totaled as much as 53% of the average residential bill in 2011, 2014 and 2016.[3]

[1] A "revenue requirement" is the authorized budget that is established to cover both operating costs and provide the utility an opportunity to earn a reasonable rate of return on the property devoted to the business. *The Regulation of Public Utilities*, C.F. Phillips, Jr., 1993

[2] Alternative Ratemaking Mechanisms (ARMs) or Alternative Revenue Programs (ARPs) "adjust future tariffs (usually as a surcharge applied to future billings) in response to past activities or completed events." *Revenue for Power and Utilities Companies*, KPMG, US GAAP, 2018

[3] See Attachment 2: Monterey District tariff pricing from 2008-2018.

Figure 1: Surcharge Percentage of Residential Bill-Territory Wide



The full impact of surcharges over the three-year period that general rate cases establish rates is not known at the time of the general rate case because surcharges can be added to customer bills between general rate cases. For example, Cal Am's surcharges jumped from being 20% of the average residential bill in 2013 to being 28% in 2014 partly because of surcharges that were approved and added to customers' bills outside of Cal Am's general rate case.

Surcharges that are approved during a general rate case are not included in the overall revenue increases proposed by the utility.[4] For example, Cal Am's current general rate case Application proposes to increase revenue by "$25,999,900 or 10.60% in the year 2021, by $9,752,500 or 3.59% in the year 2022, and by $10,754,500 or 3.82% in the year 2023."[5] However, none of these

[4] Cal Am's proposed revenue increase percentage is calculated as the difference between total revenues at present rates and total revenues at proposed rates, excluding surcharges. See the Public Advocates Office's Executive Summary and Results of Operations Report.

[5] Cal Am Final Application 2019 GRC, p. 1.

proposed revenue increases include the surcharges that Cal Am is requesting be approved in the general rate case.[6]

As of May 31, 2019, Cal Am had an outstanding balance of approximately $199,000,000 in surcharge accounts, which are known as Memorandum and Balancing Accounts in California.[7] If Cal Am's outstanding balance of surcharge accounts was collected over the three-year period that is addressed in this general rate case (2021-2023), customer bills would increase by an additional 24.5% on top of the base rate revenue that Cal Am proposes.[8]

Surcharge accounts were first created to address unforeseen circumstances and, therefore, be temporary in nature.[9] However, surcharges for Cal Am's average residential customer have been remarkably persistent over the last ten years. More concerning, the forecasting methodologies and Special Requests proposed by Cal Am in the current general rate case appear deliberately designed to obfuscate the impacts to customer bills by shifting an increasing amount of base rates into surcharge accounts and applying a shareholder return to the account balances.[10]

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[6] Refer to the testimony of Mukunda Dawadi for the Public Advocates Office

[7] Direct Testimony of Jeffrey M. Dana, Attachment 1.

[8] $199,252,617 from Cal PA ANU 16 Q005 Attachment 1 / 3 years = $66,417,539. $66,417,539 / $271,241,000 (Sum of the Revenue Requirements for Cal Am's Northern, Southern, Central and Wastewater Districts. See the Public Advocates Office's Executive Summary and Results of Operations Report) = 24.5%.

[9] Cal. P.U.C., Water Div. Res. W-4294 (Nov. 29, 2001).

[10] Refer to the testimony of witnesses, Anusha Nagesh and Mukunda Dawadi for the Public Advocates Office

B. SUMMARY OF RECOMMENDATIONS

To increase transparency for all customers, including low-income residents, incentivize Cal Am to operate more efficiently, and reduce the potential for abuse of surcharge accounts, the Commission should:

- Prevent the continued proliferation of surcharge accounts;
- Limit surcharges to 20% of a residential customer's total bill; and
- Reinstate an earnings test prior to authorizing surcharge recovery to ensure Cal Am is not earning above its authorized rate of return.

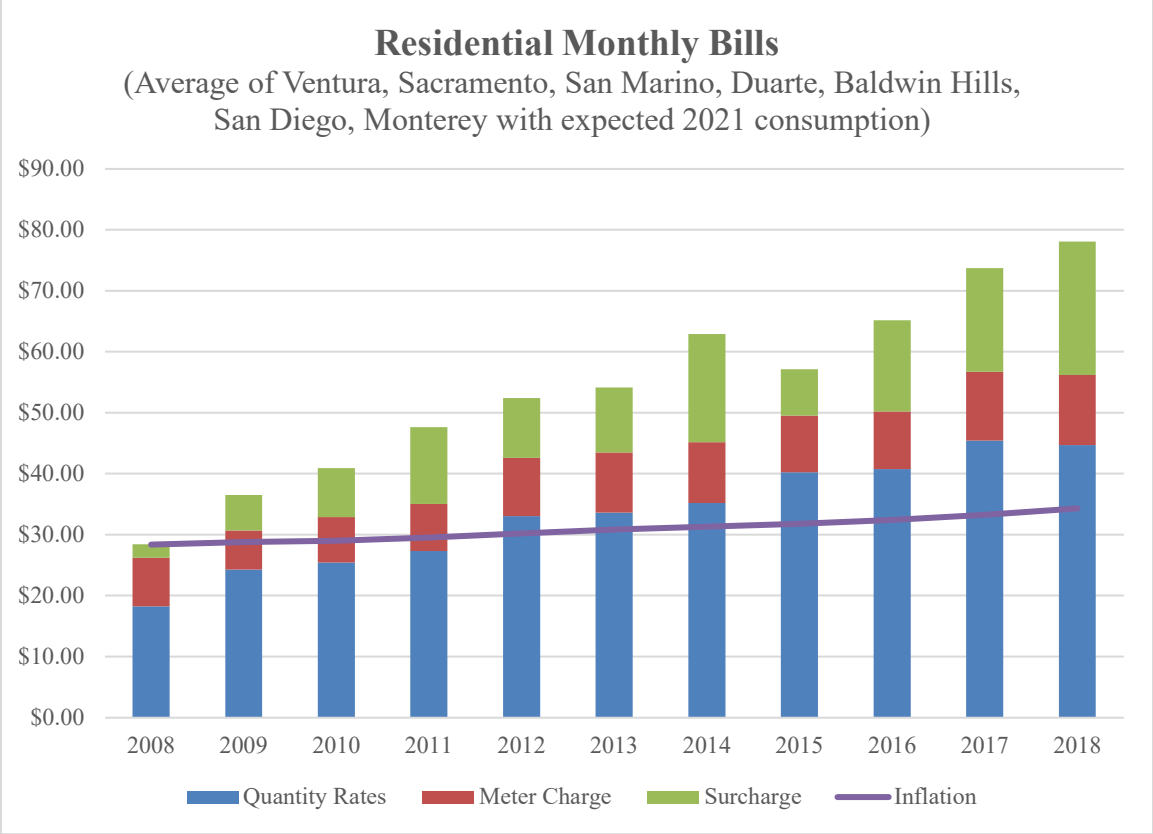
C. DISCUSSION

As depicted in Figure 2, Cal Am's residential customers have experienced increases in water bills averaging 9.3% per year for the last ten years.[11] Over the same period, however, inflation increased at an average rate of just 1.92% per year.[12]

[11] Attachment 1

[12] Attachment 3

Figure 2: Average Residential Monthly Bills



In its current general rate case Application, Cal Am proposes increases in base rates totaling 18% between 2021 and 2023.[13] Additionally, Cal Am requests recovery of surcharge accounts that would add another 15% to the average residential customer's bill.[14] While Cal Am attributes its surcharge accounts to numerous external factors allegedly beyond its control,[15] many of the forecasting methodologies and Special Requests proposed by Cal Am in this general rate case undoubtedly will grow the balances of its surcharge accounts.[16]

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[13] Cal Am Application 10.6% (2021) + 3.59% (2022) + 3.82% (2023) = 18.01%

[14] Proposed surcharges % from CAW 2019 GRC Final Application Exhibits A, CD, pp. pgs: 612, 616, 621, 626, 630, 271.

[15] Direct testimony of Jeffrey T. Linam, p. 60, lines 15-24.

[16] Refer to the testimony of Anusha Nagesh for the Public Advocates Office

1. The Commission Should Stop the Proliferation of Surcharge Accounts and Mitigate the Potential for Abusive Surcharge Practices

The Commission has explained that the purpose of surcharge accounts is to protect utilities from "unforeseen expenses, of a substantial nature, beyond the utilities' management or regulatory control."[17] However, the steady presence of surcharges on Cal Am's customer bills for at least the past decade suggests something different has occurred. Instead of being temporary additions, surcharges seem to have become a permanent fixture on Cal Am's customer bills.

According to its most recent Annual Report submitted to the Commission, Cal Am was operating a total of 97 separate surcharge accounts at the end of 2018.[18] Since filing its general rate case in July 2019, the Commission has authorized Cal Am to create an additional five surcharge accounts[19] and has pending requests for five more in separate proceedings.[20] In the current general rate case Application, Cal Am is requesting at least 1 additional surcharge

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[17] Cal. P.U.C., Water Div. Res. W-4294 (Nov. 29, 2001).

[18] Cal-Am's 2018 Annual Report, Schedule E-1.

[19] New Surcharges created since July 2019: D.19-04-014: Rio Plaza Transaction Surcharge Account (1); AL 1250 A: Rio Plaza Groundwater Extraction Surcharge Account (1); D.19-12-038: Meter Installation Memorandum Account (1); D.19-12-038: Environmental improvements and Compliance Memo Account (1); D.19-12-038: Transaction Memorandum Account (1)

[20] Pending Surcharges: AL 1275: Public Safety Power Shut-Offs Memorandum Account (1); A.19-12-003: Consumer Privacy Memo Account (1); A.18-09-013: Bellflower Surcharge Accounts (3). New Surcharge Accounts Created Since July GRC Filing: D.19-04-014: Rio Plaza Transaction Surcharge Account (1); AL 1250 A: Rio Plaza Groundwater Extraction Surcharge Account (1); D.19-12-038: Meter Installation Memorandum Account (1); D.19-12-038: Environmental improvements and Compliance Memo Account (1); D.19-12-038: Transaction Memorandum Account (1)

account[21] and is proposing significant modifications to the process by which its current surcharge accounts operate.

In particular, Cal Am is proposing to raise the recovery cap on its most comprehensive surcharge accounts[22] and to begin applying its authorized rate of return (which currently includes a shareholder return of 9.2%)[23] to the outstanding balance of many of its existing surcharge accounts.[24]

The proliferation of surcharge accounts and Cal Am's proposals for new and expanded uses of surcharge accounts should not be surprising. In 1985, the then Executive Director of the Commission warned that, "[w]e can expect utilities to continually press for the comfort of more [surcharge accounts] and the green light to file a variety of [surcharges] between general rate proceedings…it is the [Commission's] task to recognize that desire and pressure and weigh it against the need to have management incentive working to minimize costs."[25]

In 2012, a report by the American Association of Retired Persons ("AARP Report") on the increasing use of utility surcharges detailed how surcharge accounts diverge from traditional ratemaking methods.[26] The AARP Report explained how these alternative ratemaking mechanisms can diminish a utility's incentive to control or reduce expenses. "Since the utility is passing the cost on to customers [via surcharges], it has less incentive to seek ways to reduce the expense." In fact, the use of surcharge accounts is nearly the opposite of

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[21] Acquisition Contingency Memorandum Account (1)

[22] Special Request No. 5: Modification of 15% Cap on WRAM/MCBA Amortization CAW 2019 GRC Final Application at p. 11

[23] D.18-03-035 at p. 2

[24] Refer to the testimony of Mukunda Dawadi for the Public Advocates Office

[25] Attachment 4: Balancing Accounts History, p. 6

[26] Attachment 5: AARP at p. 3

traditional ratemaking which establishes reasonable budgets called "revenue requirements" that a utility must manage to achieve profits between rate cases.[27]

The AARP Report also explains that a review of surcharges "is typically conducted on an expedited basis, as opposed to the thorough review that would typically occur in a full rate case."[28] In California, the Commission can authorize surcharges in as quickly as one month through the informal advice letter process. This process can operate without customer notice or consideration within an evidentiary record.[29]

Even when consideration of surcharges occurs within the evidentiary record of a general rate case, the proliferation of surcharge accounts complicates the Commission's review and increases the likelihood of customers paying the same costs twice. As Commission staff previously noted, the process of reviewing surcharge accounts "has essentially shifted the burden of proof to staff and intervenors to show expenditures were not prudent."[30] This situation actually arose in Cal Am's previous general rate case when the Public Advocates Office demonstrated that the exact same invoices used by Cal Am previously to generate surcharges on customers' bills were being resubmitted by Cal Am to increase customers' base rates.[31]

Although Cal Am indicates that it makes a "good faith" effort to remove from its ratemaking proposals those items being tracked or recovered elsewhere,[32]

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[27] Under a traditional approach to ratemaking, a utility cannot adjust its rates outside a rate case. No matter what happens to a utility's costs or revenues between rate cases, rates remain fixed. National Regulatory Research Institute Report No. 16-08 at p. 10

[28] Attachment 5: AARP Report, p. 9

[29] See General Order 96B (reducing notice requirements for advice letters increasing rates and granting evidentiary hearings only in limited circumstances).

[30] Attachment 4: Balancing Accounts History, p. 4.

[31] D.18-12-021, pp. 182-83.

[32] Direct testimony of Stephen W. Owens, p. 5, lines 6-7.

it has made mistakes. Ultimately, the Commission should reverse the proliferation of surcharge accounts to restore incentives for utilities to control costs.

However, to reduce the possibility that customers pay the same costs in both base rates and surcharges, the Commission should require Cal Am to implement a more systematic process of identifying and categorizing costs as they are incurred.[33] The Commission should also deny Cal Am's requests in this general rate case for additional surcharge accounts[34] and enforce the following additional limitations on the operation of Cal Am's surcharge accounts to further mitigate the potential for abuse.

2. The Commission Should Limit Cal Am's Surcharges to No More than 20% of a Residential Customer's Bill

Surcharges can mask the overall impact of utilities' proposals in general rate cases. For example, Cal Am is requesting recovery of about $14,626,618 from surcharge accounts in the current general rate case.[35] However, this amount is in addition to the $46.5 million increase in base rates that Cal Am is also requesting.[36] Because of this, the full impact of Cal Am's requests on customers' bills is not transparent.

A similar lack of transparency exists for surcharges that Cal Am may request outside the general rate cases through informal advice letter proceedings. The Commission's standard practice does not require customer notification for recovery of any individual surcharge account that is less than 10% of gross utility

[33] Refer to the testimonies of Anusha Nagesh and Daphne Goldberg for the Public Advocates Office

[34] Refer to the testimony of Anusha Nagesh for the Public Advocates Office

[35] Refer to the testimony of Anusha Nagesh

[36] $25,999,900 in 2021, $9,752,500 in 2022, and $10,754,500 in 2023.

revenue.[37] However, there is no upper limit to the total number of individual accounts or surcharges that Cal Am can request between general rate cases.[38]

Although more detailed customer notices would improve the transparency of Cal Am's requested recovery of surcharge accounts in the future, many of Cal Am's proposals and forecasting methodologies in the current general rate case appear deliberately designed to manipulate the notification process.

For example, Cal Am's Special Request #4 proposes to remove from base rates and recover through surcharges the cost of providing customer leak adjustments. This proposal results in a 10% decrease to Cal Am's proposed base rates.[39] However, the cost to customers will not be 10% less. Despite giving the appearance of lower rates, Cal Am's proposal ensures that the actual cost will become a surcharge that is collected outside of base rates and customer noticing requirements. As detailed in the testimony of the Public Advocates Office's witness, Suzie Rose,[40] the Commission should not allow Special Request #4 to mask the actual customer impacts of Cal Am's proposals.

Similarly, several of Cal Am's forecasting methodologies also provide customers and the Commission with the appearance of impacts smaller than what customers will actually experience. This occurs when Cal Am underestimates its budget for items that are included in base rates with corresponding surcharge accounts.[41] Because these corresponding surcharge accounts track the variance between the budgeted amount and the actual cost incurred, an underestimated

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[37] Cal. P.U.C. Standard Practice U-27-W, p. 5.

[38] Surcharge account that exceeds 2% of a utility's gross revenue can be requested via an advice letter outside of a general rate case (Cal. P.U.C. Standard Practice U-27-W).

[39] Retaining the estimated $2.7 million of leak adjustments in base rates would increase Cal Am's proposed increase in 2021 base rate revenue from $25.9 million to $28.6 million

[40] Refer to the testimony of Suzie Rose for the Public Advocates Office

[41] Refer to the testimony of Anusha Nagesh for the Public Advocates Office

budget gives the illusion of lower costs even though customers eventually experience the actual cost through additional surcharges.

Cal Am's underestimated costs of purchased water and purchased power are especially egregious examples of masking the impacts of its general rate case requests.[42] In addition to artificially lowering its proposed and noticed revenue increase by roughly $10 million per year, the corresponding surcharge accounts that track this underestimated amount are the same accounts on which Cal Am proposes to begin earning a shareholder return. [43] This means, customers are paying hidden profits for the benefit of shareholders.

Furthermore, Cal Am's Special Request #5 proposes to lift the existing cap on recovery of these accounts.[44] If granted, Cal Am will be able to collect more surcharges, more quickly, and with more profit while providing notice of only a fraction of the actual bill impacts customers will experience over the next three years.

To provide greater certainty and transparency, the Commission should limit the surcharges Cal Am can collect on residential customer bills to 20% of the total bill. This is approximately the same average percentage of surcharges appearing on Cal Am's residential customer bills over the last ten years.

3. The Commission Should Reinstitute an Earnings Test to Prevent Cal Am from Using Surcharges to Exceed its Authorized Rate of Return

In 2003, the Commission re-affirmed its practice of applying an earnings test to the recovery of surcharge accounts to prevent a utility from implementing surcharges that would result in exceeding its authorized rate of return and

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[42] Refer to the testimony of Anusha Nagesh for the Public Advocates Office under Chapter 1, Table 1-1

[43] Refer to the testimony of Anusha Nagesh

[44] Refer to the testimony of Suzie Rose for the Public Advocates Office

achieving "an unanticipated windfall at ratepayer expense."[45] The Commission explained:

> The original purpose of these [surcharge] accounts was to allow the utilities to recover unanticipated expenses within the normal rate case cycle to prevent financial injury, and . . . to serve as insurance to utilities that certain uncontrollable expenses would not affect their ability to achieve authorized earnings. A utility that exceeds its authorized rate of return is not in financial peril; thus, there is no need for recovery of the [surcharge] account amounts in excess of its authorized rate of return.[46]

Two years later and under a different set of commissioners, the industry association that represents California's investor-owned water utilities successfully petitioned the Commission to modify its decision and eliminate the earnings test.[47] However, the Commission's modified decision left intact the original conclusion of law that, "[t]he Commission has the discretion to modify the existing procedure when the procedure is producing unintended results."[48]

The demonstrated and increasing potential for abusive practices related to surcharge accounts requires the Commission to modify existing procedure. Similar to the earnings test that was required when surcharge accounts were first created in 1977, the Commission should re-establish an earnings test to ensure that surcharges do not result in Cal Am exceeding its authorized return. Prior to authorizing recovery of any surcharge account, the Commission should be assured

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[45] D.03-06-072, p. 7.

[46] D.03-06-072, p. 17.

[47] See D.06-04-037 (eliminating annual advice letter filing and application of the earnings test).

[48] Compare D.03-06-027, p. 18 (finding Commission has discretion to modify existing procedure when it is producing unintended results), with D.06-04-037, pp. 9-10 (eliminating only annual advice letter filing and application of the earnings test).

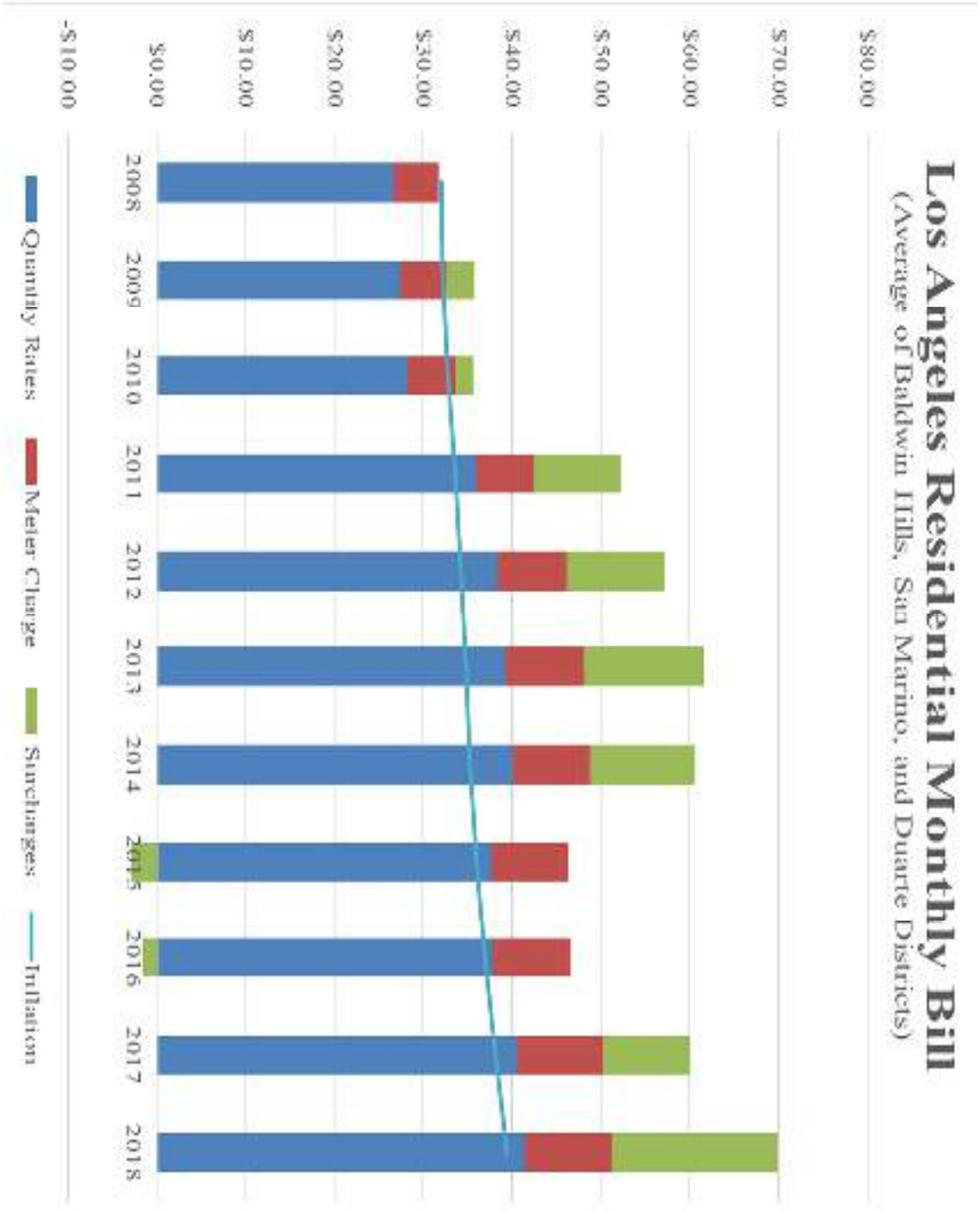
that recovery of the account balance would not produce a rate of return higher than authorized for the period during which the balance in the account was recorded.

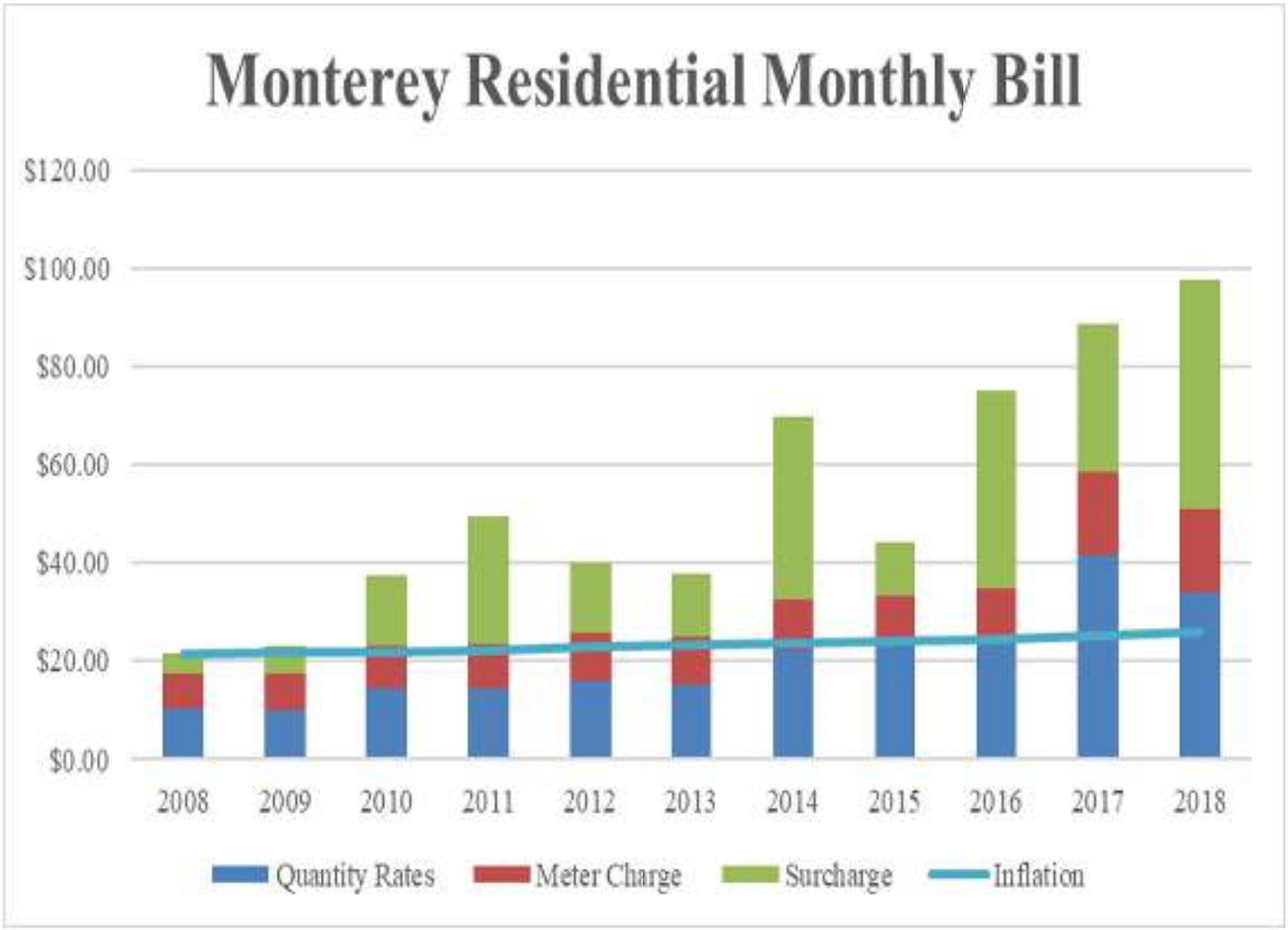
D. CONCLUSION

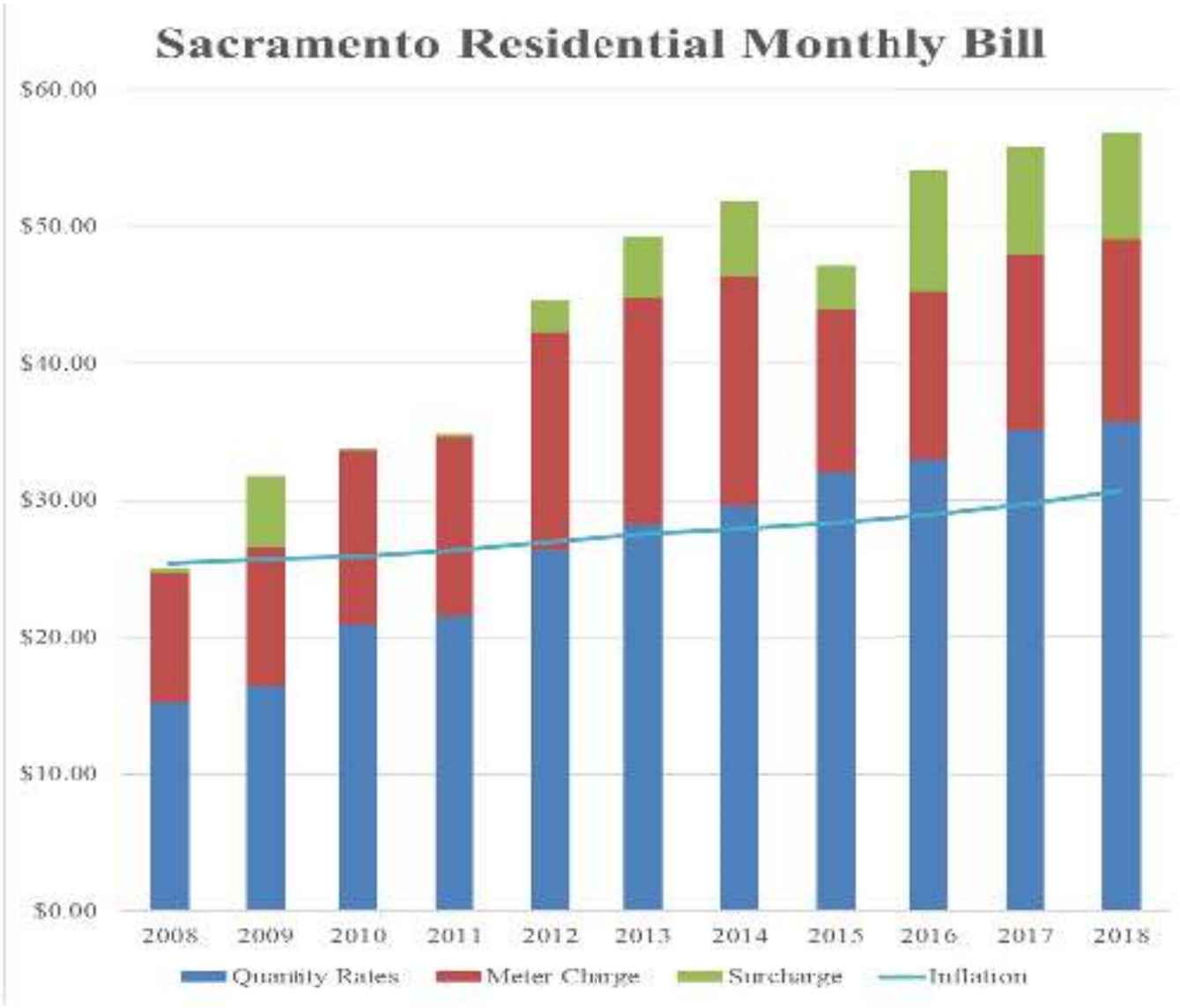
The pervasive nature of surcharge accounts in Cal Am's general rate case illustrates that an unintended consequence of these accounts includes the ability to move funds out of base rates and, therefore, obfuscate the impacts for customers and decision makers. The Commission should place a 20% cap on surcharges as a portion of customer's total bill and reinstitute an earnings test for Cal Am to ensure that the approved surcharges do not allow for a rate of return that exceeds Cal Am's authorized rate of return. These two changes will encourage Cal Am to operate more efficiently and transparently and will enable a more equitable billing system for customers.

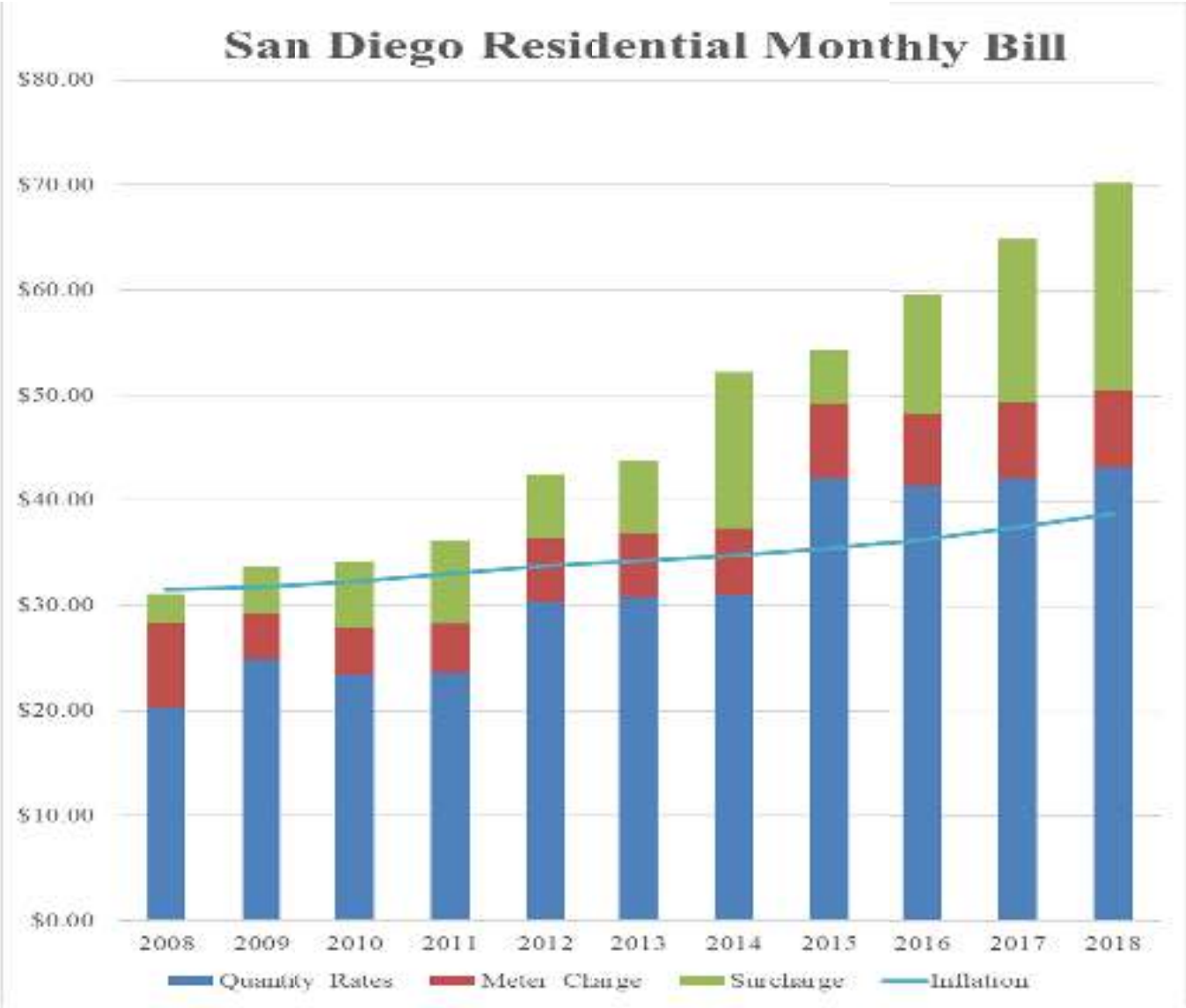
ATTACHMENTS

Attachment 1: Residential Monthly Bills




Monterey Residential Monthly Bill
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Quantity Rates
Meter Charge
Surcharge
Inflation


Sacramento Residential Monthly Bill
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Quantity Rates
Meter Charge
Surcharge
Inflation


San Diego Residential Monthly Bill
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
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2008
2009
2010
2011
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2016
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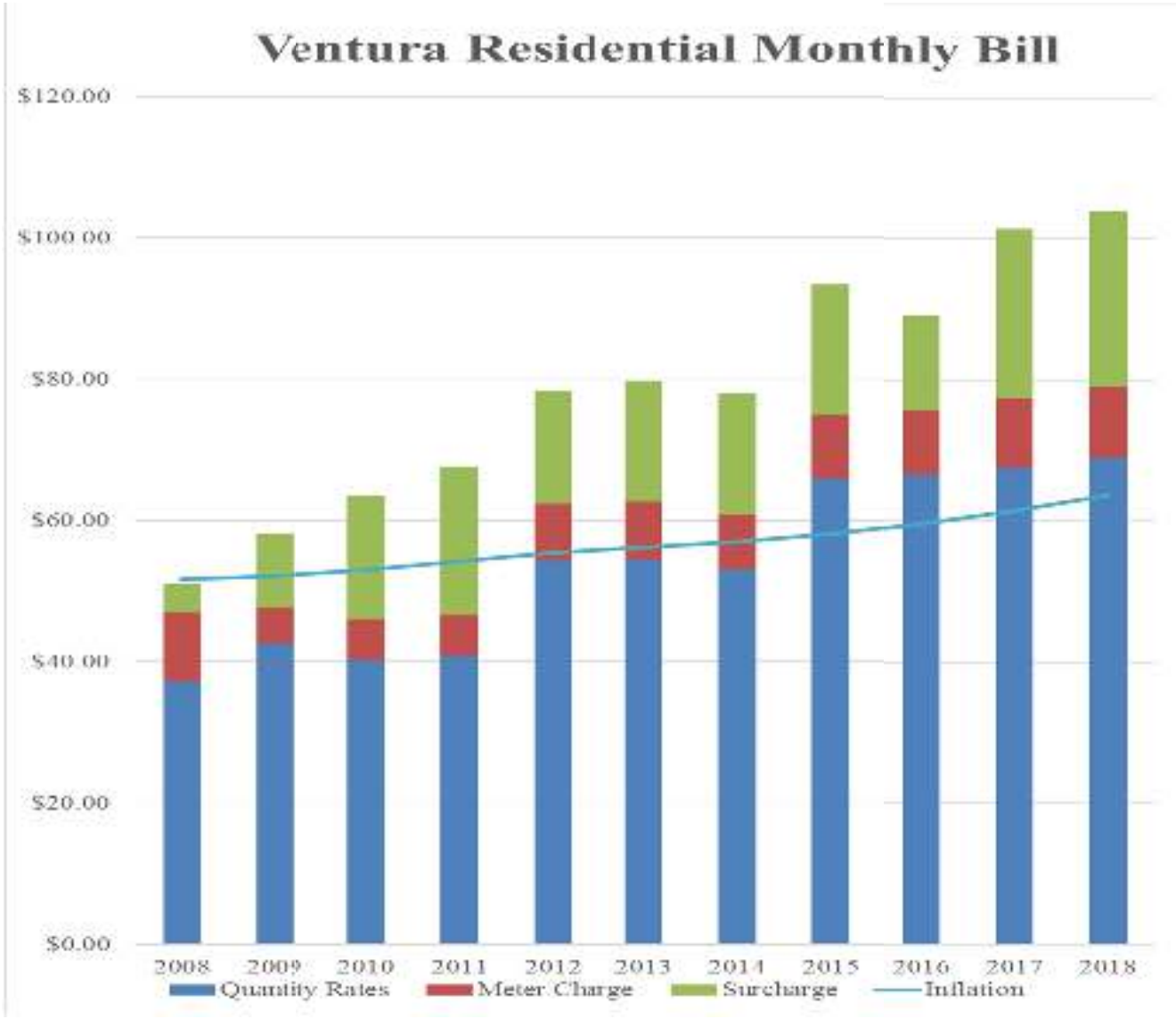
2018
Quantity Rates
Meter Charge
Surcharge
Inflation


Ventura Residential Monthly Bill
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Quantity Rates
Meter Charge
Surcharge
Inflation

Attachment 2: Residential Surcharge Percentage of Total Bill

Year	Sacramento	Ventura	Los Angeles	San Diego	Monterey	**Average of All Districts**
2008	1%	8%	0%	9%	19%	**8%**
2009	16%	18%	9%	13%	25%	**16%**
2010	1%	27%	6%	18%	38%	**20%**
2011	1%	31%	19%	22%	53%	**26%**
2012	5%	20%	19%	14%	36%	**19%**
2013	9%	21%	22%	16%	34%	**20%**
2014	11%	22%	20%	28%	53%	**28%**
2015	7%	20%	-7%	10%	25%	**13%**
2016	16%	15%	-3%	19%	53%	**23%**
2017	14%	24%	16%	24%	34%	**23%**
2018	14%	24%	27%	28%	48%	**28%**
Average	**9%**	**21%**	**14%**	**19%**	**41%**	**20%**

Attachment 3: Consumer Price Indices For All Urban Consumers (CPI-U)

Year	California % Change
2008-09	1.32%
2009-10	0.75%
2010-11	1.73%
2011-12	2.40%
2012-13	2.09%
2013-14	1.42%
2014-15	1.55%
2015-16	2.04%
2016-17	2.54%
2017-18	3.33%
2018-19 f/	3.45%
2019-20 f/	3.83%
2020-21 f/	2.83%

http://www.dof.ca.gov/Forecasting/Economics/Indicators/Inflation/

Attachment 4: Balancing Accounts History

State of California

Memorandum

OFFSETS, ETC.

Date : September 23, 1985

To : Commissioners

From Public Utilities Commission—San Francisco – JOSEPH E. BODOVITZ
Executive Director

File No.:

Subject :

As you may have seen in the notes of the Friday Committee senior staff discussion, we thought it might be useful for you to have some background information as you review ALJ Patrick's draft decision on second-year attrition for energy utilities. That draft will soon be circulating, and will contain discussion of, for example, the interaction of ERAM and attrition. We therefore thought it would be useful for you and your advisors to have a brief history of balancing accounts, attrition allowances, and other regulatory mechanisms now in place.

Attached, therefore, is a summary that was prepared in mid-1982 as an introduction to what was then planned as a larger policy document on various regulatory strategies. Much of the strategy discussion found its way into other documents, and the introduction is still surprisingly current and clear.

There is, however, one significant change: The attached summary refers to the GEDA and EEDA programs, which were still in place in 1982. EEDA has now been concluded in accordance with a Commission order, with the proposed sale of EEDA properties discussed in a consultant's report. GEDA is the subject of a draft decision by ALJ Johnson which is soon to be circulated for review. The draft recommends, among other things, project-by-project review of the current GEDA projects of utilities, to determine which should be kept and which should be sold.

The Advisory Branch of the Evaluation and Compliance Division (headed by Ida Goalwin) will be glad to try to answer any questions you or your advisors may have with regard to the various regulatory mechanisms described in the attached paper.

Attachment

cc: Commissioners' Advisors
Agenda Distribution List
All ALJs
All Attorneys

BACKGROUND ON MAJOR ELEMENTS OF CPUC REVENUE REQUIREMENT REGULATION - THE CONDITIONS LEADING TO THEIR ADOPTION AND WHETHER CONDITIONS HAVE CHANGED

This paper is an overview of conditions and assumptions to objectively describe the major elements of CPUC's revenue requirement regulations. It describes the dynamics and forces behind where we are today and whether they have changed; it does not reach ultimate conclusions on whether or how the components of CPUC's revenue requirement should be changed.

The major elements of CPUC's program for energy utility revenue requirement regulation are:

1. Fuel/energy cost offsets coupled with balancing accounts.
2. A prospective estimated normal test year results of operations in general rate proceedings.
3. Sales-supply adjustment mechanisms.
4. Attrition allowances annually between general rate decisions.
5. Ratemaking repercussions from having utilities promote conservation.
6. The use of balancing accounts to cover utility costs for new programs to fianance conservation measures, solar deomonstration programs, and RCS audits.
7. Gas Exploration and Development Adjustment (GEDA) and Electric Energy Development Adjustment (EEDA).

These programs are addressed in that order:

I

Fuel/Energy Cost Offsets Coupled With Balancing Accounts

Prior to the 1970s utilities' fuel/energy costs were relatively stable - and compared to today, cheap. During the 1960s CPUC allowed advice letter "PGA trackers" to process direct pass-through of FPC tracking pipeline company rate increases; CPUC set up this mechanism shortly after the FPC established its corresponding cost tracking procedure.

When the interstate pipeline suppliers received a general rate increase from the FPC, CPUC required gas cost applications to be filed, as contrasted to the PGA trackers. CPUC did not have balancing accounts.

On the electric side, prior to 1974 fuel-energy costs were reviewed in general rate proceedings (which were relatively infrequent). In 1974, after the oil embargo and costs started their dramatic rise, a fuel clause adjustment (FCA) procedure was set up. AT first these adjustments were done by advice letter. About 1975 they were done through formal applications as hearings were required. The FCA procedure involved using the recorded-current fuel-energy cost and a projected fuel burn and/or energy mix; at first a 12-month forecast test period was used, but by the end of the FCA a 6-month test period was used. There was no balancing account.

In 1976 the standard Energy Cost Adjustment Clause* (ECAC) was adopted. CPUC started removing more and more direct energy-fuel cost components from base rates, moving toward what was termed "zero fuel costs base rates." A separate billing factor, called "ECAC billing factor" or ECACBF, is used. This was necessary because a balancing account was used, where billing factor revenues were credited and energy-fuel costs were debited. Electric utilities filed ECAC applications twice each year. CPUC's activity on ECAC involved reviewing reasonableness of recorded ECAC expenses and adopting a forecast energy mix and sales. In the eventual decision the ECACBF was changed to: amortize any over- or undercollection in the balancing account (a 12-month amortization period was generally used) and to prospectively recover current expense for the projected energy mix. In December 1980 current ECAC procedures were adopted:

1. Three ECAC filings annually, with one selected to review the reasonableness of the previous 12 months of recorded expense (called the record period).

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* Called "clause" because the procedure and details were placed in the utilities' tariffs as part of their Preliminary Statement.

2. Over- or undercollections would bear interest at the commercial rate.
3. Gains and losses from oil sales and 2% of estimated ECAC expense was, in essence, made part of the base rate by removing these costs from the balancing account.

Conditions and Assumptions That Led CPUC to Present ECAC/GAC Ratemaking

1. Changes in gas and energy costs do not coincide with general rate proceedings and, in fact, occur far more frequently.
2. Energy cost offset matters must be processed very expeditiously since utilities may unavoidably be paying higher prices and, absent a balancing account, will never recover the shortfall.
3. CPUC is inadequately staffed to thoroughly analyze, hold and conclude public hearings, and issue a decision within a few weeks when utilities file fuel-energy cost offset applications.
4. Gas-energy prices started rising so frequently that forecasting these expenses was virtually impossible.
5. The rise in fuel-energy prices, coupled with any deviation from an average-year energy mix, meant the economic repercussions to either the utility or ratepayers could be gigantic.
6. Use of balancing accounts and periodic review of recorded expenditures for prudency would allow CPUC and its staff time to completely review utility operating decisions and conditions.
7. Reduced risk to utilities (from balancing account protection from revenue shortfall) could be reflected in setting rate of return.

CPUC's Experience With ECAC/GAC Balancing Account Ratemaking

Retrospective balancing account review to determine if utilities pursued lowest cost courses is difficult but CPUC has no choice; its statutory function is to serve as juror deciding whether an increase in rates is justified and reasonable (P.U. Code Sections 451 and 454). Thus,

balancing account ratemaking is not premised on the ability to move retrospective decisions on prudency and reasonableness; CPUC always has the obligation to judge prudency and reasonableness before any rate changes irrespective of the ratemaking procedures.

ECAC meant CPUC staff needed to continuously monitor and review utility operations (e.g. mix, contracts, and operating choices). This was a new role, and a real change from regulation in the 1960s and early 1970s. Staff is still trying to get organized; given the nature of such review; it's an activity where the battle to get "really organized" will always be present. Also, it's been difficult for CPUC to make prudency disallowances because "the money has been spent"; it takes a compelling showing to make a disallowance.*/ The result is balancing account review has essentially shifted the burden of proof to staff and intervenors to show expenditures were not prudent.

Conditions and Assumptions Which have Changed

None of the underlying conditions have changed. Some claim utility risk and incentive has been drastically reduced through balancing account offset ratemaking. It is debatable whether this is due to the ratemaking procedures themselves or how they are administered, applied, and viewed. The key for present procedures to be effective is to have ongoing and aggressive staff review to stay abreast of what options the utility had to minimize cost and to evaluate whether the lowest cost options were pursued; balancing cost with supply considerations is part of the ongoing analysis. There can never be any clear formulistic approach to evaluating prudency and reasonableness; otherwise the expertise of CPUC and its professional staff would not be needed. Prudency issues are always challenging, but as long as CPUC regulates monopoly utilities under the existing statutory scheme these issues must be grappled with and resolved.

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* The showing expected of utilities should be a detailed explanation of options, the choices selected and why. Staff should analyze the known or reasonably foreseeable options with a skeptical professional eye toward determining if the utility's management made the most economical choice.

This means a big commitment of personnel/positions. Given that general rate proceeding work has intensified, it is impossible for staff to do "hindsight" ECAC and GAC review thoroughly. Remember, balancing account ratemaking is a new and demanding ratemaking activity that is continuous, and which is undertaken in addition to general rate proceedings.

II

Prospective Estimated Test Year Results
Of Operations in General Rate Proceedings

CPUC may only set or change rates to cover prospective conditions. The exception is where a balancing account is established, and even then the balancing account cannot start retroactively. The test year constitutes a normal or typical period of operation, representative of conditions over the future period for which rates are set. The most difficult variables have been isolated out for balancing account treatment (e.g. sales-revenues and fuel-energy costs). Use of a future test year has significantly helped lend credibility to utility regulation in California. It means no rate can be raised without a showing future conditions reasonably justify an increase. This contrasts with states where rates are periodically adjusted simply on recorded or historical costs. Adopting a prospective test year results of operations, and CPUC's evidentiary and burden of proof process that goes with it, has been a rebuff to those that allege regulation simply fosters cost plus utilities and rates (this assumes staff does more than accept utility data and simply trend it).

It is recognized that actual costs may vary either way from those adopted when rates are set, but this gives utility management an incentive to keep costs as low as possible to maximize profits. In turn, efficient operations that maximize profits can be a benefit that ultimately accrues to ratepayers because the presumably efficient operations are the base everyone estimates from the next time rates are set.

Conditions and assumptions that affect the extent to which test year ratemaking is used, instead of to balancing account-offset ratemaking are:

1. Volatility of inflation and utility costs that are beyond the control of utility management.
2. The degree to which CPUC wishes to impose ratemaking constraints in the interest of providing incentive to utility management to maximize productivity and cut costs.

We can expect utilities to continually press for the comfort of more balancing account ratemaking and the green light to file a variety of offset applications between general rate proceedings. Utility management wants the best of all worlds; high earnings and a high rate of return but as little risk as possible; it's CPUC's task to recognize that desire and pressure, and weigh it against the need to have management incentive working to minimize costs. The degree with which test year ratemaking is used depends largely on the policy orientation of CPUC.

III

Sales-Supply Adjustment Mechanisms

In 1978 CPUC adopted a Supply Adjustment Mechanism (SAM) for gas utilities. The purpose was to ensure gas utilities neither lost money nor made excess profits when supplies-sales went under or over estimated sales adopted when general rates are set. The condition leading to SAM was supply uncertainty; this was in the era of gas supply gloom and doom preceding enactment of NGPA (when interstate pipelines were curtailing supplies). The consensus was that given the bleak uncertain supply picture, it was impossible to forecast sales (which are a function of supply to serve lower priority customers). A result could, for example, be if no low priority sales were assumed when adopting sales in general rate cases and supply became available to serve P-4- and P-5-customers, the utility had a windfall profit.

About the same time CPUC started its efforts to get utilities to encourage and achieve customer conservation as a means of prolonging

gas supply. SAM fit well as a means of ensuring significant conservation results would not penalize utilities by eroding earnings. Critics of SAM argued it was a "guaranteed rate of return," which is not true. It works with a balancing account as follows: From the base sales estimate adopted in the most recent general rate decision the utility is made whole for the margin it would have had on sales if recorded sales are less than the base; if it sells more than the base amount, the margin on those incremental sales goes to the ratepayer as a credit to the SAM balancing account. As SAM evolved it was procedurally rolled into gas offset proceedings.

On the electric side, CPUC had an OII into an Electric Sales Adjustment Mechanism. Given outlandish proposals by utilities and staff resistance, nothing was adopted; that was in 1979. However, in 1980 the issue of forecasting sales in SoCal Edison's general rate case became acute. Reduced customer use, either from rising rates or conservation programs-awareness, started being noticeable. Edison was nervous. Hearings were reopened shortly before CPUC's decision was due to update sales forecasts. Likewise PG&E shortly afterward filed an offset application based on, among other things, a changed sales picture. Interest in the SAM concept for electric utilities was rekindled. In December 1981 CPUC adopted an Electric Rate Adjustment Mechanism (ERAM) for PG&E and SDG&E; ERAM for Edison is probably on the way.

Now, both ERAM and SAM are premised on the assumptions and conditions that:

1. It is too difficult to project and estimate sales 1-2 years ahead.
2. Sales-supply fluctuations are largely ratemaking elements beyond the control of utility management.
3. The mechanisms ensure utilities cannot resist promoting conservation because their successful conservation efforts would erode shareholder earnings; a potential disincentive is removed.

Have Conditions Changed Since SAM and ERAM Were Set Up?

Supply for gas utilities is not the fearful problem it once was--at least for now. But forecasting customer use is getting more difficult. Both mechanisms bring some comfort to regulators and utilities. However, they reduce both risk and opportunity. Utilities won't lose their shirts if sales drop, but they won't make it big if they increase. Utilities and the investment community seem to like certainty. Having the mechanisms ensures no financial loss to utilities for pursuing "vigorous and innovative" conservation programs as mandated by CPUC. So, SAM and ERAM suit needs of utilities and regulators. They are criticized by some as meaning the ratepayer will never see economic benefits from conservation; however, at most, they give the utility recovery of fixed costs (or the margin) when sales decline (albeit the fixed costs are spread through a smaller quantity of sales). Over the long term ratepayers realize their savings from conserving because variable costs are avoided. SAM and ERAM have never been really well-explained.

IV

Attrition Allowance on Step Rates Between General Rate Decisions

For many years there was steady growth in customers and sales which largely offset rising utility costs. Thus, general rate cases were much more infrequent than today. With inflation, rising cost of capital, and less customer growth and consumption came more frequent rate proceedings, culminating in the present rat-race cycle of general rate decisions every two years for energy utilities.

The assumptions and conditions leading to step rates through attrition adjustments were:

1. In an inflationary period it is too difficult, if not impossible, to set rates for a prospective adopted test year which will reasonably allow utilities the opportunity to realize CPUC's authorized return.
2. Swings in earnings (e.g. higher the year following a rate decision and lower the second year) unavoidably

caused by inflation would alarm the financial community,[*] lead to downrating, and ultimately increase utility debt costs.

3. There is not room for utility management to further spur productivity gains on savings to offset rising costs during the second year after a rate decision. This assumption is premised on the belief utility management is continually and highly motivated to maximize profits.

Have conditions changed? There are still fairly dramatic swings in the cost of capital. Inflation may be on the decline. Whether attrition allowances will survive, given the pressure for the regulator to ensure utility management has maximum incentive to minimize costs, is a big question at this juncture. The answer will probably depend on what course inflation takes and the degree to which CPUC can evaluate whether utility management is taking all reasonable steps to maximize profits through productivity gains and cost-cutting despite attrition allowances.

V

Ratemaking Repercussions from
Having Utilities Promote Conservation

CPUC has, since the 1973-74 Arab oil embargo, increasingly stressed the importance of conservation. Consumer conservation means high variable costs associated with incremental new demand can be avoided. Avoiding highest cost peaking generation saves all ratepayers. Likewise, long-term fixed costs that result when new generation facilities are built can be reduced by conservation as the need for new facilities can be slowed. Conservation by gas customers prolongs gas supply and may eventually tend to create economic supply-demand pressures to keep gas supplier prices down.

Traditionally utilities promoted more consumer use of energy; gas and electric utilities competed in promoting their respective energy product. There were economies of scale; and if customer use went up between

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* These people thrive on predictability.

relatively infrequent rate cases earnings went up and the stockholders could benefit. Having utilities actively promote conservation seemed by many to be inconsistent with the utilities' interests; it was said funding their conservation programs through ratemaking expense could only result in halfhearted inefficient use of ratepayer funding. However, it was for want of any other in-place organization or entity to start statewide conservation programs that CPUC chose to direct utilities to have "vigorous and imaginative" conservation programs funded from operating expense. A hindsight test was to be applied, with potential return penalties, to ensure adequate efforts were taken.

Revenue or sales protection ratemaking mechanisms (SAM and ERAM) ensure utilities have no disincentive or penalty if conservation occurs. Issues surrounding the level of conservation program funding, effectiveness of proposed programs and of past efforts became bigger and bigger issues in general rate proceedings.

The asumptions leading to CPUC's current program and approach having utilities promote conservation with ratepayer funding are:

1. Conservation can reduce the need for expensive new generating capacity and incremental variable costs; it can prolong gas supply.
2. No other means of getting programs in place and developing statewide awareness of the need and benefits of conservation existed; utilities were the only in-place entities with resources to carry out programs.
3. Particularly early in CPUC's efforts, utility rates had not reached the painful economic level that would lead to consumer conservation efforts due to price alone.
4. CPUC had the staff to analyze proposed programs, funding levels, economic benefits, and past utility efforts.

Have these underlying conditions or assumptions changed? Much of the effort spent analyzing proposed programs and their funding have centered around cost-effectiveness. From the regulator's standpoint there is no

comfort in funding programs that are not clearly cost-effective; direct utility involvement in promoting conservation remains controversial and, of course, it is CPUC's obligation to ensure this nontraditional ratepayer-funded activity is in the economic interest of all ratepayers. In reaction to concern that utility management might not apply the utmost in management acumen to devise and carry out the most effective programs possible, there were efforts to devise incentives. But devising an incentive-penalty program depends on being able to set reasonable goals and to objectively measure results; this, of course, is almost full circle and leads back to a task as difficult as evaluating cost-effectiveness of individual programs. Regulatory complexity and ratesetting nightmares continue with either approach. The changed assumptions and conditions are:

1. If CPUC allocates from limited staff resources to analyze, devise, and monitor utility conservation programs (either program by program or an overall reward and penalty program), tremendous staff resources are diverted from the traditional never-ending revenue requirement ratesetting issues of greater dollar magnitude.
2. Utility rates have reached a level where consumers are aware of the benefits of conservation and are starting to scramble in search of ways to conserve; given NGPA and gas deregulation this will, over the long run, intensify.

The question for CPUC is now whether utility conservation efforts should start scaling back as rates increase. Should efforts concentrate on load management vis-a-vis conservation generally? Either way the greatest problem remains: CPUC took on a huge complex program area with essentially the same overall staff recources that existed for periodic revenue requirement proceedings. CPUC has not been able to regulate conservation efforts with an eye toward cost-effectiveness and positive payoffs to the degree and confidence it would like, given the fiscal and resource limitations it faces as an agency.

The Use of Balancing Accounts to Cover New Utility Programs

Balancing account ratemaking was extended from ECAC and GAC as a means of covering utility costs for certain load management programs (which arose between general rate proceedings), the demonstration solar financing program, and, most recently, weatherization financing. For the latter, it has evolved into a "full cost of service tariff" to guarantee recovery and satify project financing lenders.

The conditions and assumptions leading to this were:

1. The programs were relatively novel and specific annual expenditures were hard to estimate.
2. The most rapid way to promote the programs and not peg their pace to annualized cost recovery was to establish a balancing account.
3. Implementing the programs could not, in CPUC's view, wait for inclusion in a general rate proceeding.
4. Actual costs could be adequately reviewed for reasonableness later during balancing account adjustment proceedings.

It was largely convenience and expediency which led to these balancing accounts. As with ECAC, for the staff they mean catchup ratemaking, or auditing and reviewing to see if unreasonable costs are recorded in the balancing account.

The use of balancing account-offsets to start up and fund new high priority programs will probably continue; they reduce utility resistance since the guarantee of recovering reasonable dollar-for-dollar expenditures is extended. It's fair to say that new balancing accounts are fostered by the perceived need for expediency to meet novel circumstances. To a great degree balancing account or hindsight ratemaking is the antithesis of prospective test year ratemaking. This is pretty widely recognized. The distinctions and ramifications should be kept firmly in mind by CPUC when weighing whether to launch new balancing accounts.

Gas Exploration and Development Adjustment (GEDA)
And Electric Energy Development Adjustment (EEDA)

These are ratepayer-funded cost-plus programs that were originally undertaken when it appeared California could be without energy sources to meet its needs. The largest program is GEDA. The keynote is that GEDA moves gas utilities (PG&E and SoCal) into ratepayer-funded gas supply activity. This is a departure from the traditional distribution role. Utility affiliates do the actual investment, exploration, and development activity under CPUC authorization that sets the geographic scope and funding levels. The affiliate, when it's all said and done, gets all costs recovered from the utility's ratepayers and an after-tax rate of return (that is granted to the utility) on its capitalized GEDA rate base. Needless to say, GEDA can be a little gold mine for utilities.

In 1981 CPUC reviewed GEDA and continued it under some new ratemaking groundrules. It was continued because of the prospect of cheap gas and economic benefit to ratepayers, not because it's essential to secure supply. Under CPUC's latest groundrules shareholders bear 20% of the risk-investment (50% in Cook Inlet). SoCal Gas is winding down its GEDA program. PG&E may pursue new GEDA projects with its Rocky Mountain leasehold options and in California.

GEDA and EEDA are reversals of the traditional shareholder-ratepayer roles. GEDA was last modified to instill some shareholder risk. These programs are aberrations in the broad view of CPUC's regulation and in time will probably be phased out. These mechanisms illustrate how the specter of serious supply problems can lead regulators to reverse the traditional shareholder-ratepayer role and relationship.

Conclusion

CPUC's procedures and approach to energy utility ratemaking have significantly evolved over the past 15 years. We now have essentially two types and almost parallel tracks for ratemaking:

1. General rate proceedings always underway (with a decision every 2 years for the large utilities).

2. Balancing account ratemaking which is continuous.

Has this changed utility risk and incentive? Does it necessarily lead to less efficient operations and equate to higher rates? The answers are clouded. In the sense that balancing account ratemaking has more potential for abuse and, almost by nature, the burden of proof to show reasonableness is essentially shifted to staff and intervenors. CPUC was and is not staffed to vigorously cover all the ratemaking bases; we have continuous ratemaking and we are still staffed to do periodic general rate cases. Balancing account or hindsight ratemaking is the toughest and most demanding ratemaking if it's vigorously pursued. If CPUC staffing and resources continues at present levels, it is impossible to do a thorough and vigorous job on all fronts. The degree to which CPUC resources are inadequate to stay abreast of balancing account ratemaking directly equates into reduced risk for utility management (e.g. less risk of vigorous regulatory oversight). Does this mean the large balancing accounts should be phased out? Again the staff resource question haunts us. Most of the conditions and forces (including inadequate staffing) that led to balancing account ratemaking still exist. Whichever course CPUC takes, until it is equipped to aggressively engage in balancing account ratemaking, or to do a credible job the economic forces would demand in the absence of balancing accounts, it's going to continue to be a far less than perfect or satisfying regulatory process.

Different ratemaking approaches can all be made credible in theory; it's the logistics of putting them into practice which plague us. The lesson, then, is before things are changed further, the ramifications and realities for staffing must be carefully thought through; otherwise progress, done with the best of intentions, will be illusory.

Attachment 5: Increasing Use of Surcharges in Consumer Utility Bills

Increasing Use of Surcharges on Consumer Utility Bills

PREPARED BY LARKIN & ASSOCIATES, PLLC FOR AARP | MAY 2012

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. The imposition of these surcharges are a departure from the traditional utility rate setting process, and regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of meeting utility needs and assuring ratepayer protections.

A surcharge is an additional fee imposed on a ratepayer's utility bill in addition to the base rate charge for utility service. In the past, surcharges were only approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if *not* addressed outside of a base rate case, could threaten to harm a utility's financial health. Examples of such surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for other types of surcharges and tracking mechanisms by utilities have significantly increased.[1] Indeed, the National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[2]

Utilities have requested surcharge rate mechanisms as a means to accelerate the recovery of a variety of costs, many of which are not volatile or uncontrollable. In some instances, the use of surcharges and other tracking mechanisms have proliferated so as to be baffling and expensive for consumers and burdensome for regulators to monitor.

Utilities say the surcharges are needed so they can make investments in aging infrastructure and comply with environmental regulations, among other claims, without compromising their financial health. Utilities also claim that the surcharges will result in smaller and less frequent rate increases as well as reduce the frequency of their general rate cases, which can be time consuming and costly to process.

But the increasing imposition of surcharges and other alternative ratemaking mechanisms can also defeat some of the primary principles of the rate-setting and regulatory review process. Besides increased costs to consumers, surcharges can also result in such additional undesirable consequences as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.

Regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of utility and ratepayer needs. If the regulator decides to approve a utility's request to impose new surcharges on ratepayers, adequate safeguards to protect consumers are a must.

INTRODUCTION

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. Not only are these charges often confusing and frustrating to consumers, they also represent a shift from the traditional utility ratesetting process. A surcharge is an additional cost added to utility customers' bills. Surcharges are also referred to by other terms such as riders, adjustment clauses, recovery mechanisms, and cost trackers. The proliferation of additional fees and surcharges generally shifts risks away from utility investors and onto consumers. This report describes why consumers should be concerned about the shift toward utilities collecting more costs outside of the traditional rate structure. Descriptions of some types of fees and surcharges proposed and/or collected by the nation's major utilities are outlined in Appendix I of this report.

HOW FEES AND SURCHARGES DIVERGE FROM THE TRADITIONAL METHOD OF SETTING UTILITY RATES

Utilities must petition state regulators to increase utility rates. Utilities submit a formal request to regulators containing their proposed rates to charge customers. The utility's request is reviewed in a formal proceeding, which is called a "rate case." Interested parties, such as representatives of residential or business customers, are allowed to intervene and review the utility's documentation to determine if the utility's request is reasonable. The case is resolved by a hearing and the regulators issue a formal decision.

The utility's requested rate is called a "revenue requirement" which is the amount necessary for the utility to cover its financial obligations associated with providing safe, reliable service to customers, along with earning a reasonable "return." Basic accounting and ratemaking principles serve as the foundation in setting rates to be charged by utilities to provide safe, reliable service. The primary purpose of utility ratemaking is to establish rates that allow a utility to recover its prudently[3] incurred operating and maintenance expenses, plus a fair return on its investment in assets that are used and useful[4] in providing utility service. Rates are calculated based on a "test-year" which is a 12-month period to be representative of operating conditions when the rates being established will be in effect.[5] Utilities are generally required to "net" all costs and benefits of operation at the time rates are set to avoid "cherry-picking" individual cost increases that may be offset by other cost decreases.[6] Under traditional ratemaking, utilities cannot change rates charged to customers outside of a rate case.[7]

Consumers are most familiar with seeing the "base rate" charge on their bills. The base rate is defined as the rate gas and electric utilities charge customers for the cost of providing safe and reliable service, which includes an opportunity for the utility to earn a fair return on its prudently incurred utility plant investment. The base rates are set by state regulators in a rate case, and are often segregated between the basic service charge, distribution, transmission and, for electric service, generation.[8]

In addition to base rates, most utilities assess a fuel surcharge (gas cost adjustment or fuel and purchased power adjustment) and revenue-based taxes in addition to the base rate charge. Typical "standard" charges that appear on a customer's electric utility bill may include:

- Customer Charge: The basic charge to recover costs for billing, meter reading, equipment, maintenance, etc. (state regulated)

- Generation Charge (or Commodity Charge): Charges for the production of electricity, based on usage (state regulated in non-deregulated states)

- Transmission Charge: Charges for moving high voltage electricity from a generation facility to the distribution lines of an electric distribution company [regulated by the Federal Energy Regulatory Commission ("FERC")]

- Distribution Charge: Charges for the use of local wires, transformers, substations, and other equipment used to deliver electricity to end-use consumers from the high voltage transmission lines (state regulated, only shown as a separate charge in deregulated states)

- Fuel and Purchased Power Charges
- State Taxes

Typical standard charges that appear on a customer's gas utility bill may include:

- Customer Charge
- Gas Transmission or Distribution charge
- Commodity Charge
- Purchased Gas Adjustment (true-up)
- State Taxes

Other fees and surcharges fall into the category of "single issue ratemaking," which is a deviation from traditional ratemaking. Single issue ratemaking involves "singling out" specific expenditures from a company's base rates and allowing a utility to separately recover those costs from ratepayers. Singling out specific costs can make the traditional ratemaking formula unbalanced. For example, if a utility replaces a large piece of equipment at its plant, the new equipment will affect multiple aspects of the business. The utility's rate base plant will increase, and revenues may increase, if the plant addition is to serve new customers. Future maintenance expenses may decrease if the addition improves efficiency. The lower maintenance costs, which would reduce rates for ratepayers, may not be reflected within a surcharge that focuses only on the new investment.

In the past, single issue ratemaking was typically approved by regulators only in limited situations for costs that were considered:

1. Largely outside the control of the utility,
2. Unpredictable and volatile, and
3. Substantial and reoccurring, and which would have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a traditional rate case.

Examples of such volatile and unpredictable costs traditionally include fuel costs and purchased power costs for electric utilities, and purchased gas costs for gas utilities. In contrast, capital investments for plant additions or replacing aging infrastructure are not generally considered to be highly volatile, uncontrollable and/or unpredictable. Management can control these costs to some extent by comparison shopping materials and contractors. The timing of projects can also be adjusted based on availability of funds.

Yet in recent years, many other types of costs are being proposed by utilities to be recovered through surcharges that do not meet the above criteria.[9] The National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[10]

Allowing a utility to recover lost revenues or discrete increased costs through a surcharge can also diminish the utility's incentive to control or reduce expenses because the utility is assured of full cost recovery. Since the utility is passing the cost on to customers, it has less incentive to seek ways to reduce the expense. Furthermore, in a rate case, the utility's costs are carefully scrutinized, whereas cost increases recovered in surcharges can become part of utility rates on an expedited basis, without being subjected to the same degree of review. In rate cases, utilities must provide documentation justifying its requested costs or they may be disallowed. Reviews of costs recovered via surcharges are usually done on a much more limited basis. By allowing a utility to recover cost changes through a surcharge, rider or balancing account, the utility is assured of the recovery of such costs, therefore diminishing the utility's incentive to control expenses, and reducing the utility's financial risk.

SURCHARGES, TRACKERS AND OTHER COST RECOVERY MECHANISMS

DEFINITIONS

There are different types of "single issue ratemaking" which include surcharges, trackers, riders, and other cost recovery mechanisms.[11]

Surcharge: A surcharge allows a utility to separately charge customers for costs that would have otherwise been part of the utility's standard base rates. This means the utility recovers dollar-for-dollar the level of costs incurred or estimated to be incurred. A surcharge appears as an additional charge on a ratepayer's utility bill, above and beyond the base rates, fuel surcharge and taxes. Some surcharges are a flat rate while others fluctuate, either based on usage or changes in the surcharge rate.

Surcharges are also referred to as riders, adjustment clauses, recovery mechanisms, and cost trackers, etc. Many utilities use the term "rider" in their tariffs with respect to surcharges. However, some utilities use the term "rider" to designate rates for a particular class of service. For example, Georgia Power defines "rider" as a modification to an existing tariff rate.[12] In these instances the "rider" is a type of rate on a customer's bill associated to that type of specific utility service, rather than an additional "surcharge". Therefore, one must read the Company's applicable tariff sheet to understand what the rider or surcharge actually represents. Utility tariff sheets may be written in technical language, and this may be hard to understand for many consumers.

Sometimes the entire cost recovered by a surcharge is excluded from base rates and recovered separately through the surcharge (e.g., fuel costs). In other instances, only the incremental portion or the difference between what is included in the base rates and the changes in the cost (e.g., in some states vegetation management or storm damage costs) are recovered through the surcharge. For instance, if a utility is allowed to recover $10 million in base rates for tree trimming expenses, but actually spends $11 million, and the utility has a surcharge mechanism in place for such costs, the $1 million difference would be assessed as a surcharge to ratepayers.

A surcharge can either be a fixed rate or adjusted periodically as the cost element it covers changes (i.e., monthly, quarterly or annually). Changes in costs addressed by the surcharge are typically reviewed by regulators periodically (e.g., annually or quarterly). However, the level of review of utility costs charged to customers through surcharges is usually more informal, expedited and less rigorous than in contrast to the in-depth review that would typically be conducted in a full utility rate case.

For example, in a recent utility case in Nebraska the utility requested three adjustment mechanisms (weather normalization, a billing adjustment factor and an inflation factor). However, the state regulator denied the surcharges:

> Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operative efficiently.
>
> ...
>
> Therefore the rate mechanisms should be denied.[13]

Balancing Accounts: Another form of single issue ratemaking, referred to as "balancing accounts," also can result in new surcharges on bills for utility service. A balancing account tracks the difference in a certain cost allowed in base rates and the actual cost.[14] California is one state regulatory jurisdiction that makes extensive use of balancing accounts.[15] The ratemaking regime in California has become particularly complex. The extensive use of balancing accounts and cost trackers has made it challenging and difficult for the regulators to adequately audit the proliferation of special mechanisms being used by utilities. California utilities have a traditional three-year General Rate Case ("GRC") cycle, though the cycle has been extended beyond that in some instances. The utility's base rates are developed using

forecasted amounts and typically are adjusted annually for inflation. An added complexity is that many issues affecting the utility's base rates may also be addressed separately in other dockets. The California utilities also utilize a variety of mechanisms to recover costs separately from base rates: surcharges, adjustment mechanisms, balancing accounts and memorandum accounts.[16]

Some believe that the use of balancing (and memorandum accounts) by California utilities has become excessive. A recent California American Water Company ("CalAm") General Rate Case demonstrates how the use of surcharges and other alternative rate mechanisms can get out of control. In Application No. A.10-07-007, CalAm had 79 existing balancing and memorandum accounts. CalAm had requested six additional balancing and memorandum accounts, which if approved, would bring the total to 84. The Department of Ratepayer Advocates ("DRA"), which is charged with looking out for the consumer interest, acknowledged that it did not have the resources to fully review the Company's numerous accounts:

> These advice letters are generally approved without audit. There is little opportunity to review the recorded amounts for reasonableness before the balances are recovered, unless DRA requests the opportunity to audit the balances or request for a suspension of the advice letter.[17]

Exhibit 1 is a table summarizing the number of balancing and memorandum accounts utilized by some of the larger California utilities:[18]

EXHIBIT 1

UTILITY	BALANCING ACCOUNTS	MEMO ACCOUNTS	OTHER ACCOUNTS	TOTAL
Southern California Edison (SCE)	21	24	16	61
Southern California Gas Co. (SoCal)	22	24	10	56
San Diego Gas & Electric (SDG&E)	22	33	7	62
Pacific Gas & Electric (PG&E)	32	35	15	82
California American Water Company	*	*	*	79
Golden State Water Company	9	29		38
Total Accounts for Regulators to Review	106	145	48	299

* Information regarding the breakdown of the different accounts was not located; as noted above, CalAm's requests, if approved, would increase the total to 84.

Trackers: Another single issue ratemaking mechanism is a "tracker" which involves recording or "tracking" costs in a specified account, which are later reviewed by regulators. The costs are not initially included in the utility's base rates, but are accumulated or "set aside" for future review. They may be incorporated into the development of the utility's base rates in its next base rate case or may show up as a separate charge on ratepayers' bills. This type of mechanism is sometimes utilized to "track" whether the authorized level is being spent. In some situations, underspending by a utility of a "tracked costs" is eventually returned to ratepayers.

An example of utility expenses that have been "tracked" are vegetation management (tree trimming) costs. For example, a utility may have issues with its reliability and regulators may decide to monitor the level of the utility's tree trimming expenditures as a means of assessing whether the utility is conducting an adequate level of maintenance near its wires and poles.

Another example of a cost that has been "tracked" and deferred by a utility for future review are storm damage costs. A utility may incur substantial repair costs to its distribution system as a result of a catastrophic storm. Some utilities have petitioned regulators to accumulate and defer the extraordinary storm repair costs for review and inclusion in rates at a later date, rather than merely recording such costs as expenses in the current period, which may result in utility investors bearing the risk of such costs if they result in the utility reporting lower earnings for that accounting period.

Depending on the definition of "tracker" in a particular jurisdiction, by allowing a utility to recover costs through a tracker account, the utility may effectively be guaranteed recovery of the tracked expense. Sometimes the deferrals are limited to a pre-specified level; in other cases, the subsequent recovery by the utility of the tracked cost may be subject to an "earnings test". An earnings test may prevent the utility from subsequently charging all of the tracked/deferred costs to ratepayers if it would result in excess earnings.

SURCHARGES HAVE BEEN IMPOSED THROUGH REGULATION AND LEGISLATION

A utility must obtain permission from its state regulator to apply an additional surcharge to customers' bills. Typically, a utility will present the mechanics for its proposed surcharge to the regulator for approval. Consumer advocates and intervenors may participate in the proceeding and make recommendations to adjust or modify the utility's proposal. The regulator will weigh the information and make its decision. Again, if a surcharge mechanism is approved, there are time and resource limits to the review of the costs, making it difficult for intervenors to participate. Once cost categories are approved for recovery in a surcharge, the categories can no longer be questioned, and the only aspect that can be disputed is whether the level of such costs are reasonable and prudently incurred to provide utility service. Some jurisdictions allow use of surcharges consistently between utilities, while others approve surcharges on a case-by-case basis.

In several states, surcharges have been adopted through legislation, often requiring the use of a surcharge and limiting the discretion of regulators. An example of where legislation now limits what the state utility regulatory commissions can do is the state of Virginia. Virginia has passed legislation allowing utilities to recover many types of costs through surcharges, includ-

ing environmental costs, costs for constructing new generation, generation and demand side management, and other types of costs.

In Utah, legislation has been passed allowing gas or electric utilities to recover the costs of major plant additions by filing an application for approval of a major plant addition within 150 days from the capital addition's scheduled in-service date. The statute defines "major plant addition" as "any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1% of the gas corporation's or electrical corporation's rate base."[19]

On October 26, 2011, the Illinois legislature overrode the Governor's veto of Senate Bill 1652, which became effective as Public Act 97-0616. Among those changes was the addition of a new Section 16-108.5 entitled "Infrastructure Investment and Modernization; Regulatory Reform." This legislation provides for utilities to file for a performance based formula rate plan process. On November 8, 2011 Commonwealth Edison Company, the state's largest utility, filed for a new tariff called Rate DSPP (Delivery Service Pricing and Performance), pursuant to that legislation. A formula rate plan is a mechanism or "formula" which resets a utility's rates annually, and is used in place of a rate case.

Due to the utility mergers and acquisitions over the years, many local utilities are now subsidiaries of large holding companies that have utility operations in multiple state jurisdictions. These large corporations have the resources to effectively lobby their positions to benefit their operations.

American Electric Power Company ("AEP"), one of the nation's largest electric utilities, affirms this by stating in its 2010 Form 10-K:

> Given the long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process.

As another example, Xcel Energy, stated in its 2010 Form 10-K that:

> Xcel Energy files periodic rate cases and establishes formula rate or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations.

A utility's proposal for cost recovery under the legislatively authorized mechanisms are typically reviewed via the regulatory process, albeit on a limited basis, as described above. The review may be primarily performed by utility commission staff as active participation in reviewing a proliferation of utility surcharges by resource constrained consumer advocate groups is difficult to sustain.

Exhibit 2 is a table summarizing types of costs utilities are charging customers through surcharges. This is not a comprehensive listing, but rather a summary to illustrate various types of surcharges that were identified in the process of preparing this report.

EXHIBIT 2: EXAMPLES OF SURCHARGES	
DESCRIPTION	STATES
Aging infrastructure	GA, KY, MO, NJ, OH
Decoupling/Weather Normalization	CA, GA, KS, KY, LA, MD, MS, NJ, NV, TN, TX, VA
Energy Efficiency/DSM/Conservation	CA, OR, MD, MA, SC, NC, IN, AR, KY, MI, OH, OK, TX, CO, IA, GA, FL, IL, MO
Environmental Compliance	WA, DE, NJ, IA, IN, KY, MN, SD, MI, OH, TN, TX, VA, GA, NJ, IL
Franchise Fees	MN, TX, AR, KY, LA, MI, VA, WV, GA, NJ, TN, IL, CO
New Plant (Coal, Nuclear)	AL, AR, GA, IN, MS
Pension/OPEB	MA, SC
Property Taxes	KS, MS
Renewable Energy	IL, NC, OH, MA, CA, IA, OR, UT, WA, CO, MN, NM
Smart Meters/Smart Grid	CO, OH, TX
Storm Damage	MA, OH, OK
Stranded Costs	CT, NH, NJ, MA
System Reliability/Vegetation Management	KS, OH, OK, TN, TX
Transmission Investment	OH, TX, VA
Uncollectibles	IA, IL, OH, NV
Universal Service/Low Income	AZ, CA, CO, DC, TX, GA, IL, OH, OR, UT, WA, MD

WHY DO SURCHARGES, RIDERS AND ADJUSTMENT MECHANISMS PUT CONSUMERS AT RISK?

In many instances surcharges are unnecessary and are not beneficial to ratepayers. Surcharges are costs added to utility customers' bills in addition to the basic charge for providing safe and reliable utility service. Surcharges can effectively guarantee utilities recovery of their fluctuating costs, thereby, shifting financial risk away from the investors and onto consumers. The surcharge is often applied to consumers' bills without first being subject to a thorough review by regulators and consumer groups. Additionally, some surcharges may recover costs that are not necessary for providing basic safe and reliable service. Surcharges may put consumers are at risk for being overcharged by utilities for basic utility service.

Reasons why surcharges pose a risk for consumers include:

REDUCES THE UTILITY'S INCENTIVE TO CONTROL COSTS

In a rate case a utility is allowed a reasonable level of revenues to recover its operating expenses as well as an opportunity to earn a fair return on its prudently incurred investment in used and useful plant. In between rate cases, the benefit of any cost reductions would flow back to the utility as higher profits. For costs that are to be "tracked" through a surcharge, the utility is usually required to return any under-spending to ratepayers, so the utility is not benefitted by cost-cutting efforts. The surcharge can thus remove or reduce the utility's incentive to reduce costs. Guaranteeing recovery of a specific expense reduces the utility's incentives to control costs, and thus shifts the burden of cost increases between rate cases from shareholders onto ratepayers.

REVIEW OF SURCHARGES IS TYPICALLY MORE LIMITED

Utilities typically submit reports to regulators for costs recovered via a surcharge on an annual or quarterly basis. This usually involves submitting some calculations and workpapers identifying and supporting the amounts. The review by regulators is typically conducted on an expedited basis, as opposed to the thorough review that would typically occur in a full rate case. In rate case, a thorough review of costs can also be conducted by intervening parties, and the utility must adequately support its costs or they risk being disallowed.

VIOLATION OF THE MATCHING PRINCIPLE, A FUNDAMENTAL ACCOUNTING AND RATEMAKING PRINCIPLE

A key concept in accounting and ratemaking is the matching principle. The matching principle involves matching revenues with related expenses and investments in the time period they occur. Accounting and ratemaking require the cost of capital investments to be spread over the period in which they will be used. Capital investments, such as replacement of equipment at the utility's plant can produce efficiencies such as reducing future O&M costs or enable new revenues. If the cost of the capital expenditure is recovered through a surcharge, these efficiencies may not be captured in the surcharge. Recovering capital investments via a surcharge can thus violate the matching principal.

UTILITY MAY OVER-COLLECT THESE COSTS

In some cases, the utility may overestimate the costs to be recovered. Therefore, it may over-collect these costs from ratepayers. For example, if a utility collects a surcharge to fund

the cost of a new plant or a large piece of equipment while it is still being constructed, the amount being collected from customers may be more than the actual cost. While the funds should ultimately be returned to ratepayers, until then, these funds can be used by the utility and represent a source of cost-free capital to the utility.

For example, San Diego Gas & Electric Company stated in its current 2012 general rate case ("GRC"), in its direct testimony, that its Advanced Metering Infrastructure Balancing Account (AMIBA) was forecasted to be $48.546 million overcollected on the electric side and $6.33 million overcollected on the gas side at December 31, 2011. This means that the utility collected $54.876 million more from customers than it needed. The Company also stated that it forecasted its Distribution Integrity Management Program Balancing Account (DIMPBA) and Research Development & Demonstration Expense Account (RDDEA) to be over-recovered by $3.304 million and $0.191 million, respectively. The RDDEA was authorized in D. 08-07-046 and went into effect on January 1, 2008. The Company was collecting the surcharge from customers for most of the year; however, the Company stated the related R&D program spending did not begin until late in 2008.[20]

There is also the risk that overpayment of costs may be not be returned to customers, because if the surcharge costs are reviewed only on a cursory basis, any errors or overcharges may not be detected and/or returned to customers.

JUSTIFICATIONS FOR SURCHARGES DO NOT HOLD UP

Below are some reasons utilities may use to justify the use of surcharges, along with a comment concerning why the reasoning may be invalid.

FREQUENCY OF GENERAL RATE CASES

Utilities may cite reduced frequency of general rate cases, which can be costly to litigate, as a reason for surcharges. The purpose of general rate cases is to thoroughly evaluate the utility's rates and costs for reasonableness. Eliminating or bypassing that opportunity to review the utility's costs may result in costs being charged to ratepayers without adequate regulatory scrutiny. Implementation of surcharges may also result in burdening regulators with additional work, as they will need to review these surcharges between general rate cases.

"RATE SHOCK"

Utilities will sometimes argue that surcharges and trackers reduce "rate shock" because the surcharge produces smaller, more frequent rate increases, rather than a future sharp hike in rates from a base rate case. In a rate case, many factors comprise a utility's base rates: capital structure, capital investments, and operating expenses. While some costs may increase, they could be offset by decreases in other expenses. A rate case review may not necessarily result in a rate increase. A utility may be found to be over-earning and rate decrease may be ordered. Therefore, one cannot assume that utility base rate cases will always result in larger rate increases.

AGING INFRASTRUCTURE

Many utilities have requested surcharges to recover the costs of investments to upgrade aging infrastructure. However, utility capital expenditures are not volatile or outside the control of a utility. Management is able to influence the timing and extent of these costs. Utilities, similar to

other non-regulated companies, issue bids for large scale projects to evaluate the most cost-effective options. Maintaining and upgrading the utility infrastructure is a normal aspect of operating a utility. Also, cost efficiencies may result from the improvements, but such savings may not be recognized as an element that reduces the surcharge.

COMPLIANCE WITH ENVIRONMENTAL REGULATIONS

Similarly, a utility might cite expenditures that it must make to comply with environmental regulations as a reason to implement a surcharge. This is not a new concept. Environmental regulations have been in existence for many years and are continuously evolving. Complying with environmental regulations is also a normal aspect of operating a utility. How best to deploy capital and O&M resources to comply with these regulations is not entirely outside the control of a utility. Also, cost efficiencies associated with the environmental investment may not be recognized as an offsetting element that reduces the surcharge.

SITUATIONS WHERE TRACKING MECHANISMS BENEFIT CUSTOMERS

There have been limited situations where surcharges have benefited customers. As one example of this, in the 1980s, Entergy implemented a return sharing mechanism in Arkansas which was primarily weather driven. The effects of the hot summer weather that had not been captured in the base rate case generated higher revenues for the Company and customers received credits on their bills.

RECOMMENDED CONSUMER SAFEGUARDS

When regulators are considering whether to allow certain expenditures to be recovered via a surcharge or other special rate mechanism the following consumer protections should be considered, and included, if a surcharge is approved:

COST RECOVERY SHOULD BE SPECIFIC

If a surcharge is approved, it should be strictly for the specific expenditure. The surcharge should not contain multiple types of costs or be vaguely defined, which will make reviews difficult. The surcharge should not be allowed to be expanded at a later date to include additional items. As an example, of surcharge coverage expansion, Atlanta Gas Light was permitted to implement a pipeline replacement surcharge to recover costs associated with implementing an aging pipeline replacement program over a ten year period. The need to replace aging pipe to address safety issues resulted from an investigation of the utility's alleged violations of minimum federal safety standards. Years later, the utility proposed and was allowed to expand this surcharge to include other types of capital costs associated with installing new distribution pipeline and infrastructure upgrades that were not strictly related to addressing the public safety concerns that were the basis for allowing the original surcharge.

NUMBER OF SURCHARGES SHOULD BE LIMITED

A utility should not be permitted to have a complex myriad of surcharges and trackers. This defeats the purpose of reducing rate cases and the rate setting process in general and places a bigger burden on the regulator to have to monitor numerous surcharges outside of rate cases.

The extensive use of surcharges, trackers, memorandum accounts, and other recovery mechanisms by California utilities has resulted in an almost overwhelming burden on regulators and consumer advocates.

TIME PERIOD OF SURCHARGE SHOULD BE DEFINED, NOT INDEFINITE

The surcharge or tracker should be for a set time period rather than indefinitely. For example, some states have implemented revenue decoupling as a pilot. After the pilot period, regulators can then review the results to determine the cost-effectiveness of implementing the special rate mechanism and determine whether it should continue.

MECHANICS OF SURCHARGES SHOULD BE STRUCTURED TO BENEFIT THE RATEPAYER

The surcharge should be structured so that cost overruns are absorbed by the utility and under-spending is returned to ratepayers. Some of the utility cost tacking accounts used by California utilities have this feature. A "one-way" balancing account, for example tracks and returns utility under-spending for the tracked cost (such as tree-trimming) to ratepayers.

RELATED COST SAVINGS AND EFFICIENCY IMPACTS SHOULD BE INCORPORATED

If the surcharge is to recover costs associated with replacing plant equipment, or for investments which improve efficiency, an efficiency factor to reflect lower O&M costs should be considered.

LOWER RETURN ON EQUITY ("ROE") TO REFLECT REDUCED RISK

A utility's ROE is the return investors expect, or require, in order to invest in the Company. In a rate case, utilities request a specific ROE percentage which is reviewed by the parties and a fair and reasonable ROE is authorized by the Commission. While a utility's ROE is based on several factors, depending on the utility's specific circumstances, a reduction in ROE may be appropriate if a surcharge is approved. A portion of the Company's business risk has been transferred from investors and is now being borne by ratepayers.

REDUCE FREQUENCY OF RATE CASES

Many utilities allege that surcharges will reduce the frequency of rate cases or large rate increases. A possible condition for approving a surcharge could be that the utility agrees to not file for a base rate increase for a specified period. Conversely, if a utility has annual rate cases or multi-year rates, a surcharge may not be necessary as the utility's rates are already being adjusted more frequently.

AVOID APPROVAL OF NEW SURCHARGES IN A SETTLEMENT

Although settlements are typically non-precedential (i.e., non-authoritative) if a surcharge is approved in a settlement, it may be unlikely or difficult to have it reversed or denied in future proceedings. Also, other utilities may imitate and cite the use by the existing utility as justification for their proposed surcharges for similar costs.

AUDIT/REVIEW FOR PRUDENCE AND REASONABLENESS

If a surcharge is approved to recover costs associated with a substantial project such as construction of a new power plant, significant environmental retrofits, or Smart Grid, a recommendation could be made that a full audit or a detailed review of the prudence and reasonableness of the costs should be conducted. For example, the Mississippi PSC is conducting

a prudence review of the costs associated with Mississippi Power Company's (MPCo) Integrated Coal-Gasification Combined Cycle ("IGCC") Plant that is currently under construction in Kemper County. MPCo is proposing to recover the Construction Work In Progress ("CWIP") financing costs associated with the Kemper Project through a surcharge.

RECENTLY PROPOSED SURCHARGES THAT HAVE BEEN DENIED

Regulators are still relying on traditional ratesetting and have not been persuaded by utilities' requests to implement surcharges. Below is a brief discussion of some recent instances:

PENSION/OTHER POST RETIREMENT BENEFITS (OPEB)

Narragansett Electric (d/b/a National Grid), Rhode Island; Docket No. 4065 (2010). The Company proposed a mechanism to recover pension and other post employment benefits expense incurred each year over the amount included in base rates. The Rhode Island Commission denied Narragansett's request. The Order stated:

> ...the Commission finds that this expense is a business risk that should be managed by the Company like any other business risk facing a business enterprise. Also important to note is that the State of Rhode Island, whose pension fund is severely underfunded, has not proposed that the Rhode Island taxpayers be burdened with a reconciling mechanism to ensure adequate funding of the state pension program. The General Assembly has proactively modified the existing plan to address this underfunding by changing the benefit eligibility, increasing the level of employee contributions, among other options under consideration.

Delmarva, Maryland; Docket No. 9093 (2007). The Company requested a Pension and Other Post-Employment Benefits ("POPEB") rider, to capture yearly differences between the pension and OPEB costs embedded in the Company's base rates and the actual expenses properly chargeable to the Company's distribution operating costs. The Maryland Commission denied the Company's request. The final Order stated:

> Implementation of a tracker mechanism is an extraordinary form of ratemaking usually reserved for very large expense items that have the potential to impair seriously a utility's financial well-being, which is not the case here for OPEB and pension costs. We therefore deny the Company's request for a POPEB rider.

Delmarva, Delaware; Docket No. 09-414 (2011). Delmarva proposed a surcharge mechanism called a Volatility Mitigation Rider ("Rider VM") to collect a rolling three-year average of pension, OPEB and uncollectible expenses, which it claimed were volatile and largely beyond its control. The Delaware Commission denied the Company's request and stated in its Decision:

> These are normal utility expenses; allowing dollar for dollar recovery of them would depart from traditional ratemaking practices and would reduce Delmarva's incentive to try to control them. We also note that our sister commissions in Maryland and

> the District of Columbia rejected the same proposal when Delmarva and its affiliates presented it to them, and we find their reasoning convincing. Thus, for the reasons advanced by Staff and the DPA, we reject Delmarva's request to implement Rider VM.

ENVIRONMENTAL COMPLIANCE COSTS

Kansas City Power & Light, (KCPL) Case No. 11-KCPE-581-PRE (2011)

KCPL requested recovery of environmental upgrade costs at its La Cygne Plant through a surcharge. The Commission's decision to deny the surcharge was based in part on an observation that "the potential future cost that utility companies will undoubtedly expect customers to bear is presently unforeseeable or speculative at best, but undoubtedly will be significant."

DECOUPLING

Many utilities have claimed that they require "revenue decoupling" in order to eliminate disincentives which prevent them from vigorously promoting energy-efficiency.

Despite the utility industry's attempt to convince regulators that decoupling is the latest concept, several states are still reluctant to implement decoupling mechanisms.[21] For example, Connecticut denied two utilities' requests for decoupling, despite legislation enacted permitting decoupling (Connecticut Light & Power; Docket No. 09-12-05; 2010, and Connecticut Natural Gas; Docket No. 08-12-06; 2009).

The following states have also rejected decoupling mechanisms:

- Indiana, Southern Indiana Gas; Cause No. 43839 (2011)
- Montana, Northwestern Energy; Docket No. D2009-0-129 (2011)
- Tennessee, Piedmont Natural Gas; Docket No. 09-00104 (2010)
- Rhode Island, Narragansett Electric (d/b/a National Grid), Docket No. 3493 (2009)

In the above cases, the regulators decided to reject decoupling because benefits to customers were speculative and the risk was shifted away from the company and onto customers.

Notably, the regulator's order in the Narragansett case stated:

> Revenue decoupling would protect the Company from revenue declines attributable to any causes, not only conservation and efficiency efforts. . . . Over the last four years, decoupling would have resulted in an additional $34 million payment to the Company.

One of the concerns about decoupling is that it insulates utilities from economic conditions such as the impacts of a recession. As Dr. David Dismukes has explained:

> Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times of, or alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for

> revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risk of these economic contractions, just like many other types of businesses and industries.[22]

On January 26, 2009, Detroit Edison Company ("DTE") filed an application with the Michigan Public Service Commission ("MPSC"), Case No. U-15768. Among other things, DTE requested that the MPSC approve an electric rate decoupling mechanism and an advanced metering infrastructure ("AMI") program. Both of those requests were approved by the MPSC in its January 11, 2010 order. On April 10, 2012, DTE's electric rate decoupling mechanism and the AMI program funding mechanism were rejected by the Michigan Court of Appeals.[23] The Court ruled that the MPSC did not have the authority to direct or approve decoupling for electric utilities, but only had authority to conduct research and report on the operations of a decoupling mechanism with electric utilities. Michigan Statute MCL 460.1097(4) states that:

> [T]he commission shall submit a report on the potential rate impacts on all classes of customers if the electric providers whose rates are regulated by the commission decouple rates. . . . The commission's report shall review whether decoupling would be cost-effective and would reduce the overall consumption of fossil fuels in this state.

The Court also ruled that DTE's AMI program funding that had been approved by the MPSC "was unreasonable, because it was not supported by 'competent, material and substantial evidence on the whole record'".[24] The Court noted that the Manager of the Energy Efficiency Section in the Electric Reliability Division of the MPSC had agreed that the AMI was not commercially tested, and required large amounts of capital, which could result in great economic risk and highly impact rates. No alternative considerations were discussed, nor were the needs for AMI or the net-benefits (if any) to the affected customers. The Court also stated that in reviewing the MPSC's decision, it "will not rubber stamp a decision permitting such a substantial expenditure—a cost to be borne by the citizens of this state—that is not properly supported."[25]

CAPITAL ADDITIONS

In New Mexico, in a 2011 decision, the commission rejected a stipulated capital additions rider for Public Service New Mexico Company, stating such a rider would represent "a major departure from and violation of the Commission's long-standing policy against piecemeal ratemaking."

In a recent Washington Gas Light Company ("WGL") rate case (Case No. 9267) the Maryland Public Service Commission's order issued on November 14, 2011 rejected WGL's request for an automatic surcharge on all customers to improve its distribution system. In denying that request, the Commission found that WGL was capable of carrying out a pipeline replacement program and ensuring the safety and reliability of its distribution system without getting automatic cost recovery through a surcharge:

> Although we agree fully with the Company that safe and reliable infrastructure is its highest priority and that it should accelerate its program to replace pipe, we decline to authorize a surcharge for the recovery of future pipe replacement expenses. Based on the record in this case, we find that the Company has historically demonstrated the ability to replace its

infrastructure when necessary to ensure safety and reliability, and that it can do so using traditional ratemaking procedures without compromising its ability to earn an appropriate return. The Company's witnesses confirm that WGL has the operational and financial ability to accelerate its existing pipe replacement program, and we authorize the Company to do so. But the mere fact that the Company plans increased infrastructure investments does not justify a surcharge, which would represent a fundamental shift from long-standing rate-making principles. To the contrary, the record in this case demonstrates that the Company can invest significant amounts in infrastructure and can readily recover those costs in rates with an appropriate return. . . . We recognize that accelerating its pipe replacement program may require the Company to file somewhat more frequent rate cases than it would prefer. That is not, in our view, a negative outcome—rate cases afford all parties, and this Commission, the opportunity to ensure that rates are just and reasonable, and we understand that accelerated infrastructure investment may require more frequent adjustments. But ratepayers and the Company are better served if base rates are adjusted more frequently in smaller increments, and waiting longer between rate cases could lead to other undesirable results, including greater mismatches between costs and rates.

CONCLUSION

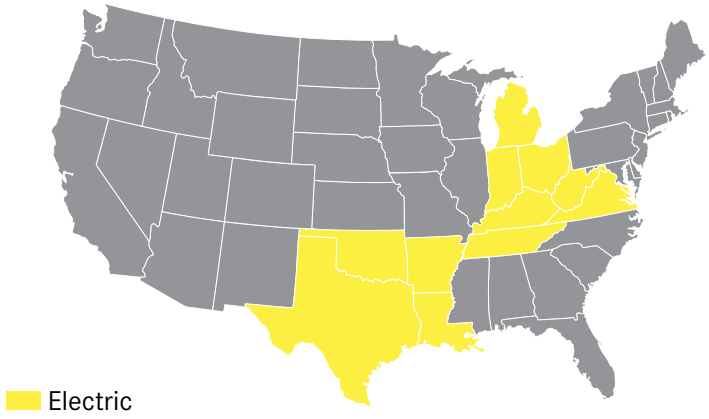
In the past, surcharges were only permitted in limited circumstances for costs that were substantial, volatile and uncontrollable, and that could harm the utilities' financial health. Examples of such traditional surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for surcharges and tracking mechanisms by utilities have significantly increased, for many different types of costs, including capital investments, for specific operating and maintenance expenses and even for revenue losses. In some instances, the use of special ratemaking mechanisms such as surcharges and other tracking mechanisms have proliferated to the point of becoming excessive and burdensome for regulators to monitor. The use of surcharges is a deviation from traditional ratemaking and puts customers at risk for overpaying for safe and reliable utility service. The use of numerous alternative ratemaking mechanisms and surcharges can defeat some of the primary principles of the rate-setting and regulatory review process. Surcharges can also result in undesirable consequences, such as reducing utility incentives to control costs, and shifting utility business risks away from investors and onto customers.

COMPARISON OF SURCHARGES USED BY COMPANIES WITH MULTI-STATE UTILITY OPERATIONS

Many of the larger utility companies serve customers in multiple states. The following section illustrates the surcharges assessed by these companies to residential customers in the states in which the utility provides service. As can be seen from the tables, the use of surcharges for most utilities varies among the states it serves. Some companies have similar surcharges for the states they serve, while the use of surcharges varies among jurisdictions for others. Whether specific surcharges are approved by regulators appears to be based on the regulatory regime in the state, not whether the company has similar existing surcharges in other states.[26] The following sections contain maps illustrating the states in which the utility serves customers.[27]

AMERICAN ELECTRIC POWER (ELECTRIC)

American Electric Power ("AEP") Company is headquartered in Columbus, Ohio. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. AEP has approximately 5.3 million retail customers. AEP serves customers in the following states:



The public utility subsidiaries and jurisdictions of AEP Company include:

- Appalachian Power Company
- Columbus Southern Power Company
- Indiana Michigan Power Company
- Ohio Power Company
- Public Service Company of Oklahoma
- Southwestern Electric Power Company

Exhibit 3 is a comparison of costs recovered through surcharges in AEP's jurisdictions:

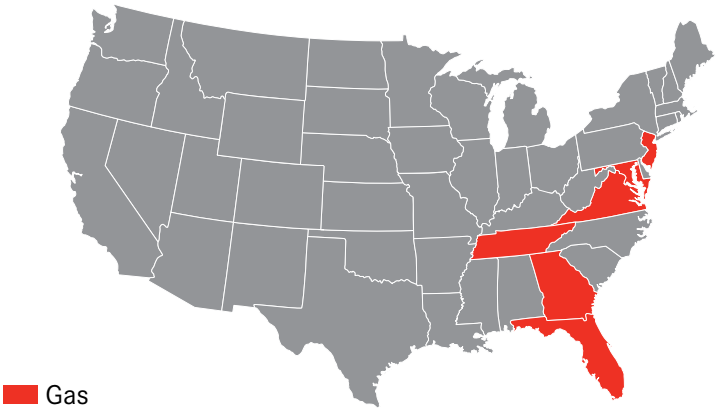
EXHIBIT 3

DESCRIPTION	AR	IN	KY	LA	MI	OH	OK	TN	TX	VA	WV
Advanced Metering (Voluntary)									●		
Alternative Generation	●										
Capital Expenditures											●
Capacity Charge			●								
Clean Coal Technology		●									
Energy Efficiency/DSM	●	●	●		●	●	●		●		●
Environmental Investment/ Compliance		●	●		●	●		●	●	●	
Federal Litigation Consulting Fees	●					●					
Franchise/Municipal Taxes	●		●	●	●					●	●
Inspection Fee								●			
Off System Sales		●									
PJM Cost		●									
Rate Case Expense									●[1]		
Reliability Expenditures/ Vegetation Management	●					●	●	●	●		
Sales & Use Tax			●					●		●	
Smart Grid						●					
Storm Expenses							●				
System Benefits/Universal Service									●		
Transmission Cost Recovery						●			●	●	
True-Up Case Expense									●		

[1]Two rate case expense surcharges
Source: 2010 Form 10-K and tariffs

AGL RESOURCES (GAS)

AGL is headquartered in Atlanta.[28] AGL Resources is an energy services company whose principal business is the distribution of natural gas in six states. AGL's six utilities serve approximately 2.3 million end-use customers.[29] AGL serves customers in the following states:



The public utility subsidiaries of AGL Resources include:

- Atlanta Gas Light
- Chattanooga Gas
- Elizabethtown Gas
- Elkton Gas
- Virginia Natural Gas
- Florida City Gas

Exhibit 4 is a comparison of revenues and costs recovered through surcharges in AGL's jurisdictions.

EXHIBIT 4

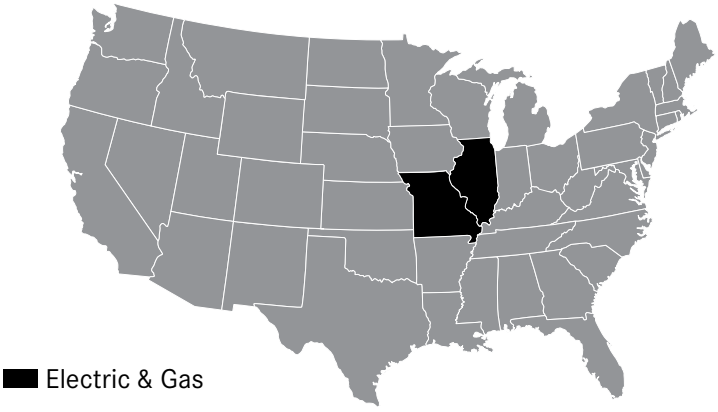
DESCRIPTION	FL	GA	MD	NJ	TN	VA
Conservation	●					
Environmental/Green House Gas Initiative		●		●		
Franchise Fees		●		●	●	
Pipeline Replacement/Utility Infrastructure Enhancement		●		●		
Revenue Normalization			●		●	●
Social Responsibility/Societal Benefits		●		●[1]		
Transitional Energy Facility Adj.				●		
Weather Normalization				●	●	●

[1]In NJ, Societal Benefits includes costs for clean energy program, environmental remediation and universal service

Source: 2010 Form 10-K and tariffs

AMEREN CORPORATION (ELECTRIC & GAS)

Ameren is a public utility holding company headquartered in St. Louis, Missouri. Ameren's subsidiaries operate rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant generation businesses.[30] Ameren has approximately 2.4 million electric customers and 900,000 natural gas customers.[31] Ameren serves customers in Missouri and Illinois.



The public utility subsidiaries of Ameren include:

- Union Electric Company (electric & gas)
- Ameren Illinois (electric & gas)

Exhibit 5 is a comparison of costs recovered through surcharges in Ameren's jurisdictions.

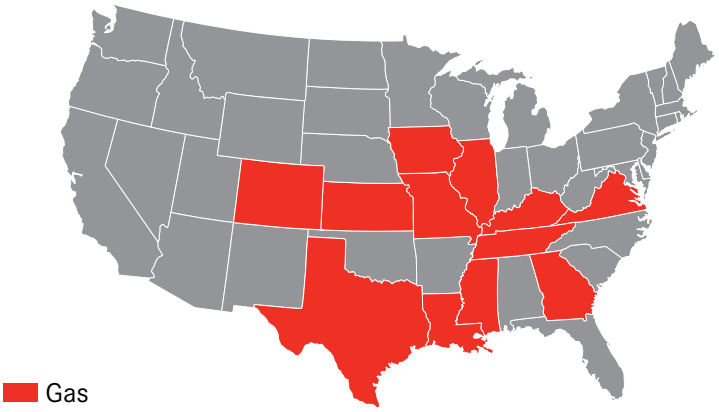
EXHIBIT 5

	ILLINOIS		MISSOURI	
DESCRIPTION	Electric	Gas	Electric	Gas
Coal Tar Cleanup[1]		•		
Energy Efficiency Costs	•	•		
Environmental Costs	•	•		
Excess Franchise Fees	•	•		
Government Compliance Costs	•	•		
Hazardous Materials (Asbestos)	•			
Infrastructure Maintenance	•			
Infrastructure Replacement				•
Uncollectibles	•	•		

[1]Zone 3 customers only
Source: 2010 Form 10-K and tariffs

ATMOS ENERGY CORPORATION (GAS)

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other non-regulated natural gas businesses. The Company's primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. It also has more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, Atmos transports natural gas for others through its distribution system. Atmos has approximately three million residential, commercial, public authority and industrial customers in 12 states located primarily in the South. Atmos serves customers in the following states:



Atmos' natural gas distribution segments include:

- Mid-Tex Division
- Kentucky/Mid-States Division
- Louisiana Division
- West Texas Division
- Colorado-Kansas Division
- Mississippi Division

Exhibit 6 is a comparison of costs recovered through surcharges in Atmos' jurisdictions:

EXHIBIT 6

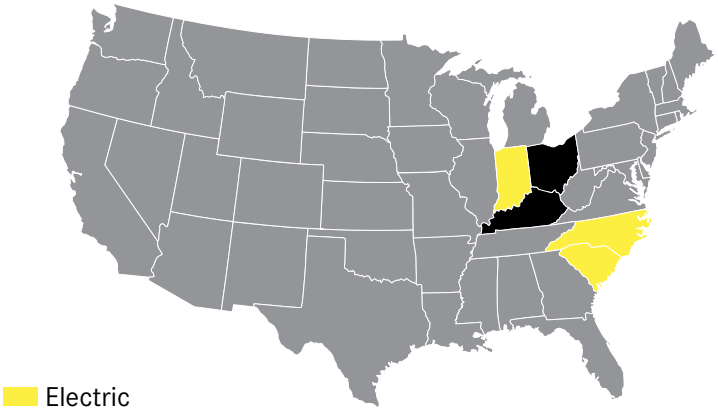
DESCRIPTION	CO	GA	IA	IL	KS	KY	LA	MO	MS	TN	MID TX	WEST TX	VA
Ad Valorem					●								
Automated Metering Incentive	●												
Demand Side Management	●					●							
Energy Efficiency			●								●	●	
Environmental										●			
Franchise Fee	●	●											
Low Income				●									
Municipal Fee											●		
Performance Based Rate Mechanism (experimental)						●							
Pipe Replacement		●				●							
Rate Case Expense											●		
Rate Stabilization/ Rate Review[1]							●		●			●	
Renewable Energy				●									
Research & Development[2]						●							
System Reliability					●								
Taxes				●							●		
Transportation Service Cost	●												
Uncollectibles			●										
Weather Normalization		●			●	●	●		●	●	●	●	●

[1]Atmos' Louisiana and Mississippi jurisdictional base rates are based on Formula Rates, which are adjusted annually, as opposed to a rate case.
[2]Voluntary participation by the Company in R&D funding for Gas Technology Institute or other research facilities.
Source: 2010 Form 10-K and tariffs

DUKE ENERGY (ELECTRIC AND GAS)

Duke Energy Corporation is an energy company that operates in the United States primarily through its direct and indirect wholly-owned subsidiaries. The Company is headquartered in North Carolina. Duke Energy supplies and delivers energy to approximately 4 million customers in the U.S.

Duke serves customers in the following states:



Electric
Electric & gas

Duke has created a "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, which has been approved in the Carolinas and Ohio. Duke has proposed similar mechanisms in Indiana.

The public utility subsidiaries of Duke Energy currently include:

- Duke Energy Carolinas (electric)
- Duke Energy Indiana (electric)
- Duke Energy Ohio (electric and gas)

On January 8, 2011, Duke Energy Corporation ("Duke Energy") entered into a Merger Agreement and Plan of Merger between and among Diamond Acquisition Corporation, a North Carolina corporation and Duke Energy's wholly-owned subsidiary (Merger Sub) and Progress Energy, Inc., a North Carolina corporation.[32] Progress Energy includes two major electric utilities that serve about 3.1 million customers in the Carolinas and Florida.[33] The merger is still pending.

Exhibit 7 is a comparison of costs recovered through surcharges in Duke's jurisdictions:

EXHIBIT 7

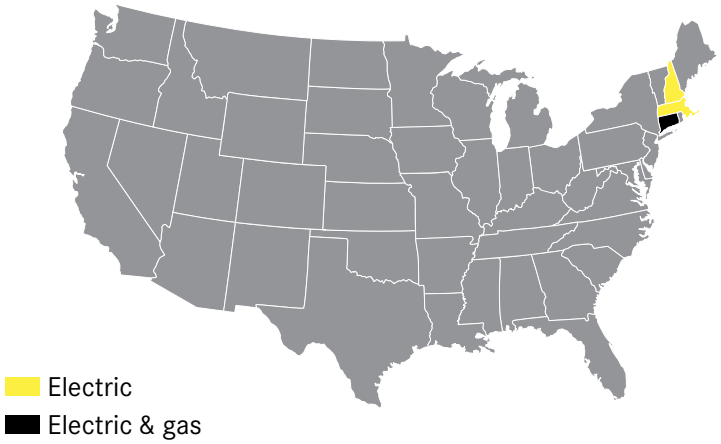
	KY		IN	NC	OH		SC
DESCRIPTION	ELEC	GAS	ELEC	ELEC	ELEC	GAS	ELEC
Accelerated Main Replacement						•	
Annually Adjusted Component					•		
Clean Coal Operating Cost Revenue Adjustment			•				
Demand Side Management	•	•	•	•			
Economic Competitiveness					•		
Emmission Allowances			•				
Energy Efficiency				•	•		•
Excise Tax					•	•	
Franchise Fee	•	•					
Infrastructure Modernization					•		
New Generation			•				
Non-fuel purchased power				•			
Off-system Power sales & Emission Allowance Sales Profit Sharing	•						
Pension Costs							•
Pollution Control			•				
Regulatory Transition Charge					•		
Reliability Adj (Capacity)			•				
Renewable Energy				•	•		
State Tax					•		
Storm Recovery					•		
System Reliability Tracker					•		
Transmission Cost					•		
Uncollectible					•	•	
Universal Service					•		

Source: 2010 Form 10-K and tariffs

NORTHEAST UTILITIES (ELECTRIC AND GAS)

Northeast Utilities ("NU") is a public utility holding company headquartered in Connecticut. The Company is engaged primarily in the energy delivery business through its wholly-owned utility subsidiaries.

NU serves customers in Connecticut, Massachusetts and New Hampshire.



The public utility subsidiaries of NU include:

- Connecticut Light & Power
- Public Service Company of New Hampshire
- Western Massachusetts
- Yankee Gas

On October 18, 2010, NU and NSTAR announced a Merger Agreement to combine the two companies. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England. The merger is still pending.

Exhibit 8 is a comparison of costs and revenues recovered through surcharges in NU's jurisdictions:

EXHIBIT 8

	CT		NH	MA
DESCRIPTION	ELEC	GAS	ELEC	ELEC
Competitive Transition Assessment[1]	●		●	●
Decoupling				●
Electricity Consumption Tax			●	
Energy Efficiency Programs				●[2]
Exogenous Costs				●
FERC Congestion Charge	●			
Low Income				●
Pension/PBOP				●
Renewable Energy				●
Storm Recovery Costs				●
System Benefit			●	

[1]Stranded investment, conservation load management, renewable energy
[2]Two separate charges for energy efficiency & DSM
Source: 2010 Form 10-K and tariffs

MIDAMERICAN ENERGY HOLDINGS COMPANY (ELECTRIC AND GAS)

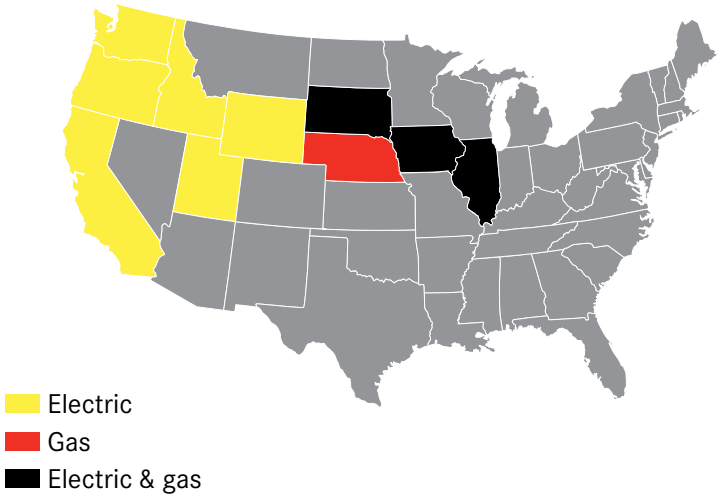
MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC, Northern Natural Gas Company, Kern River Gas Transmission Company, CE ElectricUKFunding Company, CalEnergy Philippines, CalEnergy U.S. and HomeServices of America, Inc. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

As of December 31, 2010, MEHC's electric and natural gas utility subsidiaries served 6.2 million electricity customers and end-users and 0.7 million natural gas customers. MEHC's natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States during 2010.

PacifiCorp, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric utility company headquartered in Oregon that serves 1.7 million retail electric customers. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity.

MEHC serves customers in:



The public utility subsidiaries of MEHC include:

- PacifiCorp
- Pacific Power (electric)
- Rocky Mountain Power (electric)
- MidAmerican Energy (electric & gas)
- Northern Natural Gas (gas-regulated by FERC)

Exhibit 9 is a comparison of costs recovered through surcharges in MEHC's jurisdictions:

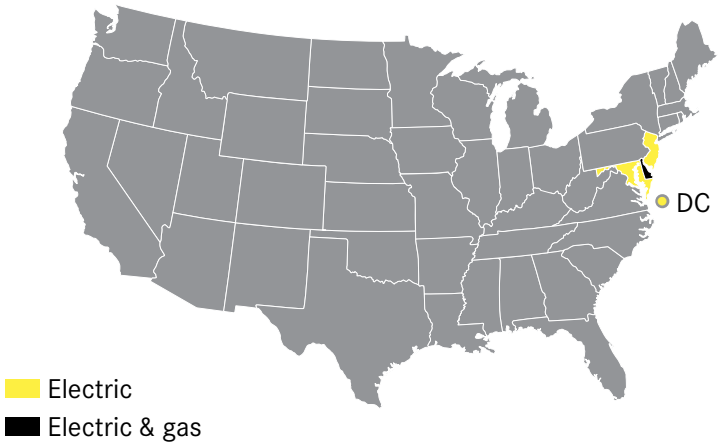
EXHIBIT 9

	CA	IA		ID	IL		NE	OR	SD		UT	WA	WY
DESCRIPTION	Elec	Elec	Gas	Elec	Elec	Gas	Gas	Elec	Elec	Gas	Elec	Elec	Elec
Alternate Energy Producer Cost Recovery		●											
Btu Adjustment			●				●			●			
Capital Investments		●											
Carbon Reduction Costs			●									●	
CARE Program	●												
Catastrophic Event Memo Account	●												
Commission Fees/ Government Fees	●	●											
Energy Efficiency/DSM [2,3]	●	●	●		●	●		●	●	●	●	●	●
Franchise Fees						●						●	
GridWest Regulatory Asset								●					
Hydro Cost Deferral												●	
Independent Evaluator Cost								●					
Intervenor Funding								●					
Klamath Dam Removal								●					
Klamath Rate Reconciliation Adjustment								●					
Low Income	●					●		●			●	●	
Nuclear Decommissioning					●								
Property Sales								●					
Public Purpose Charge								●					
Rate Mitigation Adjustment			●					●					
Renewable Energy/Solar Energy Programs/Research[1]	●	●			●	●		●			●	●	
Severance-Regulatory Asset								●					
Taxes		●	●		●	●	●	●	●	●		●	
Transition Balancing Account (includes franchise fees & uncollectibles)	●											●	●

[1]Voluntary in IA, IL and UT
[2]DSM charge in SD does not apply to all customers
[3]DSM suspended in Wyoming
Source: 2010 Form 10-K and tariffs

PEPCO HOLDINGS, INC. (ELECTRIC AND GAS)

Pepco Holdings Inc. ("PHI") is a diversified energy company that through its operating companies is engaged primarily in two businesses: the distribution, transmission and default supply of electricity and the delivery and supply of natural gas (power delivery), conducted through its regulated public utility companies. PHI has approximately 1.9 million customers in the following jurisdictions: Delaware, Maryland, New Jersey, and the District of Columbia.



The public utility subsidiaries of PHI include:

- Potomac Electric Power Company (electric)
- Atlantic City Electric (electric)
- Delmarva Power & Light (electric & gas)

Exhibit 10 is a comparison of revenues and costs recovered via surcharges in PHI's jurisdictions:

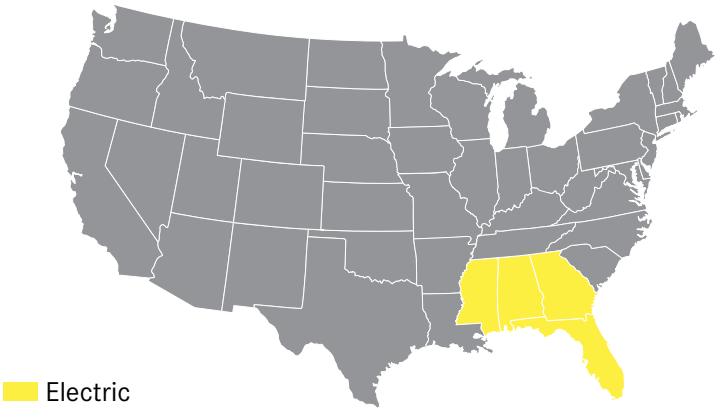
EXHIBIT 10

	DC	DE		MD	NJ
DESCRIPTION	ELEC	ELEC	GAS	ELEC	ELEC
Bill Stabilization	●			●	
Corporate Business Tax					●
Delivery Tax	●				
Demand Side Management				●	
Energy Assistance Fund[3]	●				
Environmental Expenses			●		●
Infrastructure Investment					●
Public Space Occupancy Fees	●				
Regulatory Assets Recovery[1]					●
Sales and Use Tax					●
Securitization of Stranded Costs					●
Societal Benefits[3]	●				●
Sustainable Energy Fund	●				
Transitional Facility Assessment					●
Universal Service Costs	●			●	

[1]Asbestos removal, FAS 106 Costs and other regulatory assets
[2]A new Reliability Investment Recovery Mechanism (RIM) surcharge is currently being proposed in all of PHI's regulated electric utility operating jurisdictions.
[3]Customer will pay either Societal Benefits Charge or the Energy Assistance Fund Charge, not both
Source: 2010 Form 10-K and tariffs

SOUTHERN COMPANY (ELECTRIC)

Southern Company was incorporated under the laws of Delaware on November 9, 1945 and is headquartered in Atlanta. Its traditional operating companies (which are also referred to as the Southern Company System) supply electric service to approximately 4.4 million customers, in four southeastern states: [34]



The public utility subsidiaries of Southern Company include:

- Alabama Power Company
- Georgia Power Company
- Gulf Power (serves utility customers in the Florida panhandle)
- Mississippi Power

Exhibit 11 is a comparison of costs recovered via surcharges in Southern Company's jurisdictions:

EXHIBIT 11

DESCRIPTION	AL[1]	FL	GA	MS
Ad Valorem				●
Demand Side Management/ Conservation		●	●	
Environmental Compliance		●	●	●
New Plant Construction Costs	●		●	●[2]
Performance Evaluation Plan				●
Regulatory Taxes				●
System Restoration				●
Taxes (franchise, gross receipts, etc.)	●	●	●	

[1]Alabama Power's rates are adjusted annually by the Rate Stabilization and Equalization Factor (a formula rate plan) since 1982, as opposed to setting rates based on the traditional rate case process
[2]Rider CNP to recover Construction Work In Progress costs associated with the Kemper Plant, is pending in Mississippi.
Source: 2010 Form 10-K and tariffs

SOUTHWEST GAS CORPORATION (GAS)

Southwest Gas ("SWG") is engaged in the business of purchasing, distributing and transporting natural gas in portions of Arizona, Nevada, and California. SWG is the largest distributor of natural gas in Arizona and Nevada. As of December 31, 2010, SWG purchased and distributed or transported natural gas to 1,837,000 residential, commercial and industrial customers.[35]

Exhibit 12 a comparison of revenues and costs recovered though surcharges in SWG's jurisdictions:

EXHIBIT 12

DESCRIPTION	AZ	CA	NV
California Alternate Rates for Energy Balancing Account		•	
Catastrophic Event Memorandum Account		•	
Customer Owned Yard Line (COYL) Cost Recovery Mechanism	•		
CPUC Reimbursement Fee		•	
Decoupling	•	•	•
Demand Side Management (DSM) Surcharge	•		
Energy Efficiency/Renewable Energy Tariff Plan	•		
Facilities Surcharge		•	
Fixed Cost Adjustment		•	
Intrastate Transportation Cost Balancing Account		•	
Low Income	•		
Low Income Energy Efficiency Balancing Account		•	
Public Interest R&D Balancing Account		•	
Research and Development Surcharge	•		
Taxes (not included in rates)			•
Transportation Franchise Fee		•	
TRIMP Surcharge	•		
Uncollectibles			•

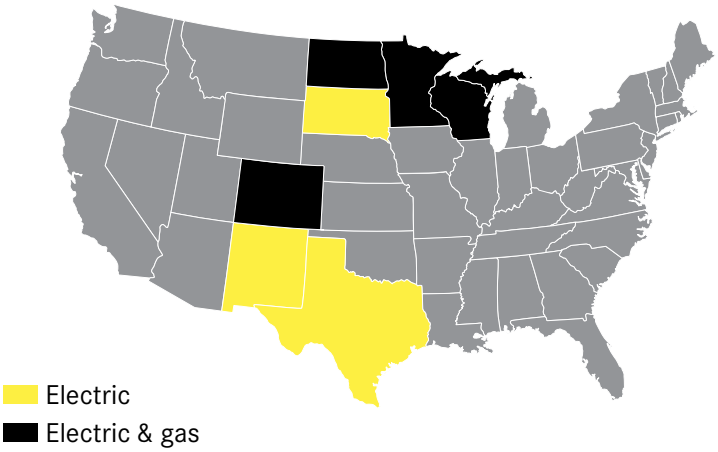
Source: 2010 Form 10-K and tariffs. In SWG's most recent rate case, Docket No. G-01551A-10-0458 before the Arizona Corporation Commission, a full revenue decoupling mechanism alternative was adopted from a settlement agreement that had been reached by most of the parties to the rate case.

Some consumer safeguards adopted in Docket No. G-01551A-10-0458 require SWG to:

- Starting April 30, 2012, file quarterly reports regarding the decoupling mechanism's performance.
- Starting April 2013, file annual reports permitting the Commission and all parties the opportunity to review the decoupling mechanism's performance.
- Be subject to an annual earnings test that would prohibit SWG from recovering any decoupling deferral amounts to the extent that the deferral recovery would increase its earnings above the authorized return on common equity.
- Provide $75,000 for the hiring of an independent consultant to conduct the annual Staff review of SWG's annual filing.
- Cap at 5 percent any surcharge developed through the decoupling mechanism that would result in a non-gas revenue surcharge of greater than 5 percent, and SWG will carry the deferral account balance forward for recovery in the following and subsequent years with no carrying charge; however, there will be no cap on annual surcharge decreases.
- Not to file a general rate application prior to April 30, 2016, with a test year ending no earlier than November 30, 2015.
- Submit a proposed customer outreach/education plan to Staff for review and approval, to outline how SWG intends to explain decoupling to customers.[36]

XCEL ENERGY (ELECTRIC AND GAS)

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2010, Xcel Energy's continuing operations included the activity of four wholly-owned utility subsidiaries that serve electric and natural gas customers in eight states. Along with WYCO, a joint venture formed with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.[37] Xcel Energy serves 1.36 million electricity customers and 1.3 million natural gas customers.[38] Xcel serves customers in the following states:



The public utility subsidiaries of Xcel include:

- Northern States Power
- Public Service Company of Colorado
- United Water
- SPS

Exhibit 13 is a comparison of costs recovered thorough surcharges in Xcel's jurisdictions:

EXHIBIT 13

	CO		MI		MN		ND		NM	SD	TX	WI	
DESCRIPTION	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Elec	Elec	Elec	Gas
Conservation/Energy Efficiency Program					●	●			●				
Demand Side Management	●	●											
Energy Optimization			●	●									
Environmental Improvement					●					●			
Facilities Fees					●								
Franchise Fees	●	●			●	●					●		
General Rate Schedule Adjustment	●	●											
Interim Rate					●		●						
Low Income (Pilot)	●	●											
Mercury Emmissions Reduction					●								
Other Taxes/Fees	●	●			●	●	●	●		●			
Pipeline System Integrity Adjustment		●											
Renewable Development					●								
Renewable Energy Standard	●				●				●				
State Energy Policy					●	●							
Transmission Capital Costs	●				●					●			

Source: 2010 Form 10-K and tariffs

APPENDIX I – DESCRIPTIONS OF TYPES OF COSTS BEING ASSESSED AS SURCHARGES

The following discussion focuses on proposed surcharges which would appear as an additional charge on ratepayers' bills, above and beyond the basic service charge and charges for fuel and taxes. Below are examples of various surcharges proposed and employed by utilities and a brief description of the costs being recovered through surcharges.

LOST REVENUES

Lost revenue surcharges are an added charge to ratepayers' bills which serve to compensate the utility for loss of revenue due to various factors. Some lost revenue surcharges include:

REVENUE DECOUPLING

Revenue decoupling helps assure that the utility's actual earnings will be at the level of authorized earnings. Under some forms of full decoupling, customers' rates are automatically adjusted to insulate the utility's earnings from fluctuations in sales. The rational for this that it removes existing disincentives which make utility management reluctant to aggressively promote energy conservation. Revenue decoupling can take on different approaches, including: decoupling true up plans, lost revenue adjustment mechanisms, and fixed/variable pricing rate design, which shifts costs into the "fixed" portion of the customer's bill and out of the "variable" portion of the bill.

Straight Fixed Variable or (SFV) is a rate design where fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges. This approach would require very high basic service charges.[39]

Fixed costs are the portion of utility costs that do not change with the level of energy consumption. Within each rate class that does not have a demand charge, each customer is charged the same amount for fixed costs. Variable costs are those costs that differ depending on the amount a customer consumes (e.g., the volumetric charge per kilowatt-hour). Some items that would be considered a variable charge include fuel, some maintenance, and often purchased power. By separating these two charges, a utility's ability to recover its revenue requirement is completely separated from sales volume. By ensuring the recovery of all fixed charges, the revenue level of the company under SFV remains fairly consistent, providing a high level of certainty for investors. Additionally, SFV insulates the utility company from feeling the effects of external forces such as loss of sales due to poor weather or customer investment in energy efficiency would typically have on revenues. Alternatively, the utility company's upside from increased sales is limited.

The use of SFV can reduce savings experienced by customers from energy efficiency investments as presented in the following example[40]:

Reduction of Monthly Customer Usage from 1,000 to 900 Units Energy Efficiency Investment of $200

	STANDARD TWO-PART TARIFF	SFV
	$15 Fixed Charge	$50 Fixed Charge
	$0.075/kWh	$0.04/kWh
1,000 Units	Fixed: $15.00	Fixed: $50.00
	Variable: $17.00	Variable: $40.00
	Total: $90.00	Total: $90.00
900 Units	Fixed: $15.00	Fixed: $50.00
	Variable: $67.50	Variable: $36.00
	Total: $82.50	Total: $86.00
Savings	$7.50/month	$4/month
	$90/year	$48/year

WEATHER NORMALIZATION ADJUSTMENT (PARTIAL FORM OF DECOUPLING)

A weather normalization adjustment ("WNA") applies a surcharge to ratepayers' bills so that the bills reflect an amount that would be billed for utility services under normal weather conditions. For example, if gas utility customers use less gas for space heating because winter is warmer than normal, their savings are limited to the avoided gas commodity charges, and the rest of their utility bill effectively reflects the higher usage that is based on "normal" weather. Similarly, if electric customers use less air conditioning during a cooler than normal summer, what would have been their savings is reduced by having to pay the utility as if the normal hot summer weather had occurred. The opposite is also true; higher utility bills from extreme weather can be somewhat mitigated by a WNA surcredit. Weather normalization is a regulatory procedure that removes weather-related volatility from customer bills; that is, adjusts the non-gas (or distribution) charges on customers' bills to reflect normal weather instead of actual weather which may be colder or warmer than normal.[41]

EARNINGS SHARING MECHANISM/RATE OF RETURN TRACKER

An earnings sharing mechanism is a single adjustment based on the utility's rate of return. Adjustments are made outside of rate cases when actual costs deviate from test year costs and/or actual revenues deviate from test year revenues, in a manner that affects utility earnings.[42] Some earnings sharing mechanisms are based upon whether the utility earns within a band

around its authorized rate of return. As an illustrative example, if a utility's authorized return on equity was 10%, an earnings sharing mechanism could have a "band" of 50 basis points (plus or minus) around that authorized ROE, earnings above a 10.5% ROE are "shared" with ratepayers via the earnings sharing mechanism as a credit, while earnings below 9.5% would result in a surcharge.

TRANSITION ADJUSTMENT

A transition or stranded cost surcharge recovers revenues lost to utilities when customers purchase their energy supply through independent marketers. The rationale for this type of surcharge is that the migration to another supplier creates "stranded costs" for the utility.

CAPITAL EXPENDITURES

GAS PIPELINE/AGING INFRASTRUCTURE REPLACEMENT

Infrastructure surcharges provide for utility recovery of capital investments made to upgrade a utility's aging electric distribution infrastructure or gas distribution pipeline system.

ATLANTA GAS LIGHT

In 1998, AGL was permitted to implement a surcharge to recover prudently incurred costs associated with a ten-year pipe replacement program ("PRP") to address specific pipeline safety violations. The PRP was scheduled to be completed but was extended to 2013 as part of a settlement in Docket No. 85616-U. The residential surcharge was $1.29 per month in years 7-9 of the PRP and increased to $1.95 in years 10-13. In 2009, the Company filed a request to rename the existing surcharge to the Strategic Infrastructure Development and Enhancement ("STRIDE") Program surcharge so that it would include the PRP costs as well as the Integrated System reinforcement Program ("i-SRP") costs and costs for expanding the distribution system. The Commission approved the Company's request for the STRIDE surcharge in its final decision dated in Docket No. 29950, dated January 20, 2010.

In contrast, Washington Gas Light ("WGL") recently sought, as part of its rate base increase, approval of an Accelerated Pipe Replacement Plan ("APRP") and a related cost recovery mechanism ("Rider") to accelerate the replacement of aging pipes, increase safety and reliability and provide environmental benefits through the reduction of greenhouse gas emissions. The APRP was approved by the regulators but the surcharge was denied by regulators because it departed from traditional ratemaking. In its order, the Maryland PSC stated it would rather review these costs in the context of a rate case, even if the filing of rate cases would be more frequent.

NEW GENERATION PLANT INVESTMENT (COAL FIRED, SOLAR, RENEWABLE, NUCLEAR GENERATION)

Some utilities have been authorized surcharges to recover investments made for the purposes of adding generation or capacity to serve more customers or meet increased demand, or for the investments in specific types of generation such as renewables or solar. For example, Progress Energy Florida ("PEF") obtained regulators' approval this year to recover $86 million from ratepayers for the costs of constructing nuclear Units Levy 1 and 2. The estimated 2012 monthly cost to ratepayers is about $2.93 for the first 1,000 kilowatt hours (kwh) for PEF customers.

Florida Power & Light Company ("FP&L") also received regulators' approval to recover $196 million for costs associated with construction of two new units at its Turkey Point Plant and adding capacity to existing units at Turkey Point and St. Lucie Plants.[43]

SMART METERS/SMART GRID

"Smart Meters"[44] and "Smart Grid" generally refer to technology to convert and automate utility electricity delivery systems, and enable new functions, such as grid monitoring and time-of-use metering. Many utilities are proposing to rapidly implement these technologies, but some utilities and regulators have found that the costs are much higher than anticipated and/or ratepayer benefits were not commensurate. There have been requests by electric utilities for surcharge recovery of costs for Advanced metering Infrastructure ("AMI"). In 2010, regulators in Texas allowed Oncor Utilities to implement a monthly surcharge of $2.19 per customer for 11 years to pay for the costs associated with installing smart meter as well as a public education campaign.[45]

The New York PSC authorized Con Edison to recover Smart Grid costs through a surcharge. While the monthly surcharge averages about 28¢/customer, or less than 0.3% of the average monthly bill, the surcharge will collect over $145 million for the company. The surcharge continues at least until Con Edison's next rate case, in April 2013, when it may be reset.[46]

However, other states have disallowed surcharges to recover these substantial and speculative costs:

MARYLAND

Baltimore Gas & Electric Proposed a SmartGrid Plan in Case No. 9208, Order 83410, and requested that the $835 million cost to implement be recovered from customers via a surcharge. The Commission denied the company's Smart Grid Plan and surcharge recovery. The Commission's decision stated:

> The Proposal asks BGE's ratepayers to take significant financial and technological risks and adapt to categorical changes in rate design, all in exchange for savings that are largely indirect, highly contingent and a long way off. We are not persuaded that this bargain is cost-effective or serves the public interest, at least in its current form.
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> ...
>
> The Proposal is a 'no-lose proposition' for the Company and its investors.[47]

BGE submitted a modified SmartGrid plan in Case No. 9208. The Commission approved BGE's modified SmartGrid plan, but again did not permit recovery of the project through a surcharge. The Commission supported intervenor, the Maryland Energy Administration's (MEA), position that AMI deployment is analogous to an investment in a power plant, an investment of similar (or greater) magnitude that historically would be recovered through traditional ratemaking.[48]

RENEWABLE ENERGY

Renewable energy surcharges recover costs related to capital expenditures or purchased power contracts associated with a utility's renewable energy program. Renewable energy is defined as

energy that can be replenished, such as wind, solar, geothermal, hydro, photovoltaic, wood and waste. Renewable energy typically also has environmental benefits. To encourage the development of renewable energy, many jurisdictions provide for utility cost recovery via surcharges. Non-renewable energy sources are finite, such as coal, oil, and gas.[49]

TRANSMISSION INFRASTRUCTURE

Transmission surcharges can include provisions for utility recovery of capital expenditures to upgrade a utility's aging transmission infrastructure and/or transmission cost increases which the utility incurs based on transmission costs approved by the FERC. Some state regulatory commission prefer to isolate the impacts on utility customer bills resulting from federal mandates, including FERC decisions, so those impacts are transparent to customers and are distinguished from state regulatory decision impacts.

OPERATION AND MAINTENANCE EXPENSES

PIPELINE SAFETY PROGRAM FEES

Utilities have proposed surcharges to recover costs associated with inspecting gas distribution pipelines and safety related issues.

VEGETATION MANAGEMENT

Vegetation management activities can include: tree pruning (trimming), right-of-way mowing and clearing, and herbicide application.[50] A major cause of power outages can be due to improperly maintained vegetation or trees that can come in contact with power lines during severe storms.

ENVIRONMENTAL COMPLIANCE

Environmental compliance costs can include remediation costs associated with site investigation and removal of pollution or contaminants from soil or groundwater[51] or costs to implement environmental controls mandated by state and federal regulations.[52] A common example of environmental compliance costs is the emission control equipment that electric generation utilities are required to install on coal-fired plants to meet air quality standards.

UNCOLLECTIBLE CHARGES

Some utilities have requested surcharges to collect customers' bad debts. Some surcharges allow a utility to collect from (or refund) the difference between the uncollectible (or bad debt) expense allowed in base rates and the utility's actual prior calendar year uncollectible expense. Some utility uncollectible surcharges recover only the fuel or gas cost portion of uncollectible accounts.[53] In some cases, the uncollectible expense may be collected though the utility's fuel or gas clause.

PENSION/OTHER POST RETIREMENT BENEFITS ("OPEB")

Prior to 2008, many utilities' defined benefit pension plans were well funded. However, due to the sharp decline of the stock market in late 2008 with the onset of the world-wide financial crisis, many utilities' pension plans suffered substantial losses. In the following

years, some utilities requested substantial increases to their pension expense to replenish the funding of their pension plans, some via a surcharge. The stock market has since stabilized.

STORM DAMAGE

A catastrophic storm may cause significant damage to a utility's infrastructure (wires, poles, substations, etc.). Some utilities have petitioned regulators to recover the costs associated with repairing its infrastructure via a surcharge mechanism. Traditionally, utility storm damage repair costs have been addressed in base rates.

ENERGY EFFICIENCY/CONSERVATION/DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

Costs associated with implementing energy efficiency, conservation and demand side management programs are increasingly being addressed for ratemaking purposes in utility surcharge mechanisms.

UNIVERSAL SERVICE COSTS (LOW INCOME PROGRAM COSTS)

A universal service cost is a fee paid by users of a utility service in some states to support the provision of providing utility service for low-income users. The fees help eligible customers pay their electricity bills and may also provide for energy conservation measures and weatherization.[54]

MUNICIPAL FEES/FRANCHISE FEES

Some utilities pass through fees imposed on the utility by the municipality for franchise, occupation taxes/fees, or any other tax/fee imposed on the company by the municipality to conduct business within the city limits and on the cities' rights-of-way to its customers.[55] Typically, special surcharges for municipal fees or taxes would be applicable to utility customers residing within the municipality that is imposing such surcharges on the utility.

AD VALOREM TAXES

Ad Valorem taxes are taxes based on assessed value of property (i.e., property taxes).

OTHER TAXES

Some utilities impose a surcharge to collect other taxes such as sales and use tax, gross receipts tax, etc.

STRANDED COSTS

Costs incurred by utilities to serve their customers that potentially may be unrecoverable in a newly-created market.[56] Stranded costs can be defined as the estimated decline in the value of electricity-generating assets due to restructuring of the industry.[57]

SOCIETAL BENEFITS CHARGE OR SYSTEM BENEFITS CHARGE

In some jurisdictions, such as New Jersey and Arizona, utilities collect from customers a "societal benefits charge" which allows the utility to recover a combination of costs: e.g., clean energy program costs, manufactured gas plant remediation expenses, universal service fund and other allowed costs.[58]

REGULATORY FEES

These fees can include rate case costs, regulator fees, etc.

LITIGATION COSTS

Legal fees and costs associated with a trial, if significant or unusual, would be the subject of a special surcharge request by a utility. Traditionally, utility legal costs are addressed in the determination of the utilities' base rates.

CAPITAL/O&M COMBINED

ECONOMIC STIMULUS PROGRAM ("ESP")

In some jurisdictions, such as New Jersey, costs and associated carrying costs incurred on behalf of the utility for reliability focused and energy efficiency focused infrastructure projects are within the Economic Stimulus Program ("ESP"), which is a specific utility cost recovery mechanism. ESP Costs include: (1) the carrying costs (depreciation and return on net investment, including tax effects) on capital investments and (2) the incremental operation and maintenance expenses associated with the infrastructure programs.

ENVIRONMENTAL COMPLIANCE

Capital expenditures and O&M associated with installing environmentally compliant plant equipment that reduces or removes the level of harmful substances being emitted into the atmosphere. This can include costs for environmental remediation (i.e., clean-up).

SYSTEM HARDENING/RELIABILITY COSTS

Proactive measures to increase a utility's transmission and distribution system to withstand the effects of high winds and storms. This can also include investments to upgrade or underground the infrastructure.

SECURITY COSTS

Security costs include proactive measures to protect a utility's infrastructure from security threats. After the September 11, 2001 terrorist attacks on the World Trade Center, some utilities began requesting special cost recovery for the increased costs for security threats to water supply and treatment facilities and to other potential terrorist targets such as nuclear generating plants.

ABOUT THE AUTHORS

Ralph Smith is a senior regulatory consultant with Larkin & Associates, PLLC. His professional credentials include being a Certified Financial Planner™ Professional, a licensed certified public accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. He received a Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979; a Master of Science in Taxation, Walsh College, Michigan, 1981. His Master's thesis dealt with investment tax credit and property tax on various assets. He also graduated,

cum laude, with a Juris Doctor from Wayne State University Law School, Detroit, Michigan, 1986, and received an American Jurisprudence Award for academic excellence. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving water and sewer, telephone, electric, and gas utilities.

Over the past 31 years, Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors, including AARP, on several occasions.

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Input for this report was also provided by Hugh Larkin, Jr., senior partner of Larkin & Associates; Helmuth W. Schultz, III, and Donna Ramas, senior regulatory analysts; Mark Dady and John Defever, regulatory analysts, and Kerry Niemiec, administrator.

END NOTES

[1] Public Utilities Commission of Minnesota, Utility Rates Study, 2010, Talking Points on Cost Trackers, The National Regulatory Research Institute Presentation, November 2009.

[2] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[3] The International Accounting Standards Board (IASB) Framework lists prudence as a sub-quality of reliability, calling prudence "the inclusion of a degree of caution in the exercise of the judgments needed in making the estimates required under conditions of uncertainty, such that assets or income are not overstated and liabilities or expenses are not understated" (paragraph 37). Also, Financial Accounting Standards Board ("FASB") Concepts Statement 2 discusses conservatism—meaning prudence—at length in paragraphs 91–97.

[4] Used and useful is defined by the Edison Electric Institute's 2005 Glossary of Electric Terms as "A regulatory specification typically used to determine whether an item of "Plant" may be included in a utility's rate base.

[5] http://nrri2.org/index.php?option=com_content&task=view&id=97&Itemid=48. Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[6] Cost Recovery Mechanisms for Smart Grid Investment, Carl Peterson, Center for Business and Regulation, University of Illinois Springfield.

[7] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[8] http://www.nj.gov/bpu/residential/glossary/ In states which have restructured their retail electric markets, the transmission and distribution rates remain regulated.

[9] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[10] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[11] The terms used may vary slightly between different jurisdictions and are not used uniformly by utility regulators.

[12] http://www.georgiapower.com/pricing/glossary.asp#rider

[13] Aquila, Order in Application No. NG-0041

[14] Balancing accounts are usually classified as "one way" (or "asymmetrical") where underspending is returned to ratepayers, but overspending is absorbed by company. Under a two-way ("or symmetrical") balancing account, the impact of underspending and overspending, if deemed to be prudent, is ultimately passed on to the ratepayer.

[15] A balancing account may be recorded as a regulatory asset or a deferred asset on the utility's books. Qualifying costs are charged to the balancing account and the surcharge revenues collected are credited to the account. Balances in some balancing accounts earn the 90-day commercial payment rate.

[16] Memorandum ("memo") accounts are used extensively by California utilities, with more limited or no use in other jurisdictions. The costs being tracked may later be converted to a balancing account upon approval by the regulator. In California, information regarding memorandum accounts are reported by filing "Advice Letters".

[17] A.10-07-007

[18] This information was obtained from the tariffs on the utilities' websites during the time-frame of this report.

[19] Utah Code Annotated Section 54-7-13(4)

[20] Direct Testimony of Greg Shimansky, GDS-1, A. 10-12-005

[21] Direct Testimony of Jodi Jerich, on behalf of RUCO, Docket No. G-04204A-11-0158

[22] Testimony of David Dismukes, Docket No. 09-00183, Testimony of Jodi Jerich, G-04204A-11-0158

[23] http://coa.courts.mi.gov/documents/OPINIONS/FINAL/COA/20120410_C296374_47_296374.OPN.PDF

[24] *Id.*, at 8

[25] *Id.*, at 8

[26] The array of surcharges being proposed and implemented by utilities is continuously evolving. Information for the utilities listed is believed to be accurate at the time the research was conducted, but is subject to change as new regulatory developments occur.

[27] It should be noted that the utility may only serve customers in a portion of the states shown.

[28] http://www.aglresources.com/about/about_us.aspx

[29] AGL Resources 2010 Form 10-K p. 4

[30] 2010 Form 10-K

[31] http://www.ameren.com/aboutameren/pages/aboutus.aspx

[32] 2010 Form 10-K

[33] https://www.progress-energy.com/company/about-us/index.page?

[34] http://www.southerncompany.com/aboutus/home.aspx

[35] Southwest Gas Corporation, Form 10-K, 2010

[36] Proposed Decision dated November 28, 2011

[37] 2010 Form 10-K

[38] http://www.metrodenver.org/investor-center/2011/xcel-energy.html

[39] Direct Testimony of Leland Snook on behalf of APS, Docket No. E-01345A-11-0224

[40] Source: https://aep.com/about/IssuesAndPositions/Financial/Regulatory/AlternativeRegulation/StraightFixedVariable.aspx

[41] Ralph Miller Direct Testimony, Brooks Congdon, on behalf of Southwest Gas Corp., Docket No. G-01551A-07-0504

[42] Utility Rates Study, July 22, 2010 by the Minnesota Public Utilities Commission to the Senate Energy, Utilities, Technology & Communications Committee.

[43] http://citrusdaily.com/psc-approves-nuclear-cost-recovery-progress-energy-fpl/2011/10/25/87681.html

[44] Also referred to as "Advanced Meters".

[45] http://www.greentechmedia.com/articles/read/smart-grid-cost-recovery-make-the-consumer-care/

[46] www.smartgridtoday.com/public/2174print.cfm, Order in Case 09-E-0310, http://www.coned.com/documents/elec/159-164a.pdf

[47] MD PSC Order No. 83410, pp. 1,3, dated June 21, 2010.

[48] MD PSC Order No. 83531, pp. 32-41.

[49] 2005 EEI Glossary.

[50] http://www.oncor.com/community/vegetation/default.aspx

[51] http://en.wikipedia.org/wiki/Environmental_remediation

[52] http://www.georgiapower.com/pricing/glossary.asp#r1

[53] Atmos Energy

[54] http://www.nj.gov/bpu/residential/glossary/

[55] http://www.georgiapower.com/pricing/glossary.asp#r2

[56] 2005 EEI Glossary

[57] http://www.cbo.gov/doc.cfm?index=976&type=0

[58] South Jersey Gas

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Attachment 6: Methodology

Monthly water prices were calculated using the tariffs from the last advice letter of the year (Figure 3) for the following districts: Monterey, Los Angeles (average of San Marino, Baldwin Hills, and Duarte), Sacramento, San Diego, and Ventura. Details regarding the meter size and consumption are found in Figure 4. Summer and winter pricing was averaged when present, and Monterey Main District was utilized with the assumption that the household had three people, ¼ acre of land, and 0 large animals.

Figure 3: Advice Letters Utilized

Year	Cal Am Territory				
	Los Angeles	**Monterey**	**Sacramento**	**San Diego**	**Ventura**
2008	710	691	708	714	714
2009	763	819	787	789	788
2010	821	868	849	852	841
2011	906	915	907	899	894
2012	974	971	966	974	974
2013	996	944	999	1004	998
2014	1023	1061	1060	1039	1022
2015	1082	1075	1106	1087	1090
2016	1126	1128	1127	1108	1131
2017	1159	1185	1187	1179	1148
2018	1217	1213	1209	1212	1215

Figure 4: Meter Size Used and Monthly Consumption

District	Revenue Description	Meter Size	Monthly Consumption (CCF)
LAC Baldwin Hills	Residential	5/8 x 3/4"	13.7
LAC Duarte	Residential	5/8 x 3/4"	16.5
LAC San Marino	Residential	5/8 x 3/4"	19.1
Monterey County Main	Residential	5/8 x 3/4"	5.1
Sacramento	Residential	5/8 x 3/4"	11.5
San Diego County	Residential	5/8 x 3/4"	8.9
Ventura County	Residential	5/8 x 3/4"	16.9

Attachment 7: Witness Qualifications

QUALIFICATIONS AND PREPARED TESTIMONY OF JAYNE PARKER

Q.1 Please state your name and business address.

A.1 My name is Jayne Parker and my business address is 505 Van Ness Ave, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am a Public Utility Regulatory Analyst in the Communication and Water Policy Branch of the Public Advocates Office of California Public Utilities Commission (Cal PA).

Q.3 Briefly describe your pertinent educational background.

A.3 I have a Bachelor of Arts degree from Loyola Marymount University and a Master of Science in Energy Policy with Johns Hopkins University.

Q.4 Briefly describe your professional experience.

A.4 I joined the Communications and Water Policy branch of the Public Advocates Office as a Public Regulatory Analyst after working for Tesla Motors for 6 years where I analyzed data including customer energy tiers and production, payments, and savings. I have submitted comments and/or testimony for several proceedings.

Q.5 What is your responsibility in this proceeding?

A.5 I am responsible for the testimony on Cal Am's Consumer Bills presented in this report.

Q.6 Does that conclude your direct testimony?

A.6 Yes, it does.