MEETING AGENDA – NOVEMBER 14, 2017

COMMUNITY ROOM
4000 EAST RIVER ROAD NE
ROCHESTER, MN 55906

4:00 PM

Call to Order

1. Approval of Minutes

1. Public Utility Board - Regular Meeting - Oct 24, 2017 4:00 PM

NEW BUSINESS

Open Comment Period

(This agenda section is for the purpose of allowing citizens to address the Utility Board. Comments are limited to 4 minutes, total comment period limited to 15 minutes. Any speakers not having the opportunity to be heard will be the first to present at the next Board meeting.)

****Total comment period has been extended to 30 minutes total for this meeting.***

2. Consideration Of Bids

1. Customer Service Center Building Expansion Project - Bid Award
2. Resolution: CSC Building Expansion Project - Bid Award

3. Regular Agenda

1. 2018 Water Utility Budget Approval

   Resolution: 2018 Water Utility Capital and Operating Budget
2. 2018 Electric Utility Rate Adjustment

   Resolution: 2018 Electric Utility Rate Adjustment
3. 2018 Electric Utility Budget Approval

   Resolution: 2018 Electric Utility Capital and Operating Budgets

4. Adjourn

The agenda and board packet for Utility Board meetings are available on-line at www.rpu.org and http://rochestercitymn.iqm2.com/Citizens/Default.aspx

MEETING MINUTES – OCTOBER 24, 2017

RPU SERVICE CENTER
4000 EAST RIVER ROAD NE
BOARD ROOM
ROCHESTER, MN 55906

4:00 PM

Call to Order

Attendee Name	Title	Status	Arrived
Mark Browning	Board President	Present	
Tim Haskin	Board Member	Present	
Melissa Graner Johnson	Board Member	Present	
Brian Morgan	Board Member	Present	
Michael Wojcik	Board Member	Absent	

1. Approval of Agenda

1. **Motion to:** approve the agenda as presented

RESULT:	**ADOPTED [UNANIMOUS]**
MOVER:	Tim Haskin, Board Member
SECONDER:	Brian Morgan, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

2. Approval of Minutes

1. Public Utility Board - Regular Meeting - Sep 26, 2017 4:00 PM
2. **Motion to:** approve the minutes as presented

RESULT:	**ADOPTED [3 TO 0]**
MOVER:	Brian Morgan, Board Member
SECONDER:	Tim Haskin, Board Member
AYES:	Mark Browning, Tim Haskin, Brian Morgan
ABSTAIN:	Melissa Graner Johnson
ABSENT:	Michael Wojcik

3. Approval of Accounts Payable

1. A/P Board Listing
2. **Motion to:** approve the A/P Board Listing

Board Member Melissa Graner Johnson asked if Mastec North America Inc, which appears on a couple of line items, is a corporation that does housing. General Manager Mark Kotschevar replied that it is a company that does trenching and cabling work.

RESULT:	**ADOPTED [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Member
SECONDER:	Tim Haskin, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

NEW BUSINESS

Open Comment Period

(This agenda section is for the purpose of allowing citizens to address the Utility Board. Comments are limited to 4 minutes, total comment period limited to 15 minutes. Any speakers not having the opportunity to be heard will be the first to present at the next Board meeting.)

President Browning opened the meeting for public comment. Two people came forward to speak.

Brett Ostby, of Rochester, spoke regarding fixed costs.

Rick Morris, of Rochester, spoke regarding the UMR Connects event, Rochester's Energy Future: A Community Forum, on Thursday, November 2, 2017, at 7:00 p.m. Mr. Morris invited Board members to attend and distributed event flyers.

4. Consideratoin of Bids

1. Underground Cable Puller

   Supervisor of Facilities Steve Monson presented a request to the Board to purchase an underground cable puller. The utility received two bids that were opened on October 16, 2017, from Sherman + Reilly, Inc. and Wesco. Sherman + Reilly was the low bidder at $174,355. Mr. Monson explained that the utility had a major failure with its existing cable puller this year and was unsuccessful in attempting to get repair parts, so the item, which is part of an ongiong equipment replacement plan, was moved up for replacement this year and is included in the 2017 contingency funds.

RESULT:	**COUNCIL APPROVAL [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Member
SECONDER:	Brian Morgan, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

2. Resolution: Underground Cable Puller

   BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a contract with Sherman + Reilly, Inc. for:

   One Underground Cable Puller

   The amount of the purchase order to be ONE HUNDRED SEVENTY-FOUR THOUSAND, THREE HUNDRED FIFTY-FIVE AND 00/100 DOLLARS ($174,355.00).

Minutes Acceptance: Minutes of Oct 24, 2017 4:00 PM (Approval of Minutes)

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of October,

5. Regular Agenda

1. Compliance Policy Approval

The draft Compliance Policy was initially presented to the Board for review and comment at its September 26, 2017 meeting by Director of Compliance and Public Affairs Steven Nyhus and the Board's communication committee. The Board requested that the RPU Board members be added to the scope. The policy was amended as requested.

RESULT:	**COUNCIL APPROVAL [UNANIMOUS]**
MOVER:	Tim Haskin, Board Member
SECONDER:	Melissa Graner Johnson, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

Resolution: Compliance Policy Approval

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the

Compliance Policy

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of October, 2017.

2. Cayenta Customer Care Implementation Change Order

Manager of Marketing and External Affairs Patty Hanson presented a request to the Board to approve a change order for additional funds to support the utility's implementation of the Cayenta Customer Care software. The go-live date for the project has been extended to March 28, 2018 from its original intended November 13, 2017 go-live date, due to delayed deliveries of interfaces and configurations by Cayenta, and a conflict with the utility's annual audit process. The utility has negotiated to bring the costs down, Ms. Hanson said. The utility underestimated the impact of a travel policy in the contract with Cayenta that charges RPU for Cayenta employees' compensation for travel time while en route, she said, which comprises a bulk of the new charges associated with the extension. Additional charges include the extension of project management services, backfill resources and unforeseen third party interface expenses. The total cost impact, including a 20 percent contingency, is $563,583.

Board Member Tim Haskin asked if the Vancouver-based Cayenta employees are flying into the Minneapolis airport and renting a car to travel to Rochester, which sounds more expensive. Ms. Hanson said they are. Mr. Haskin inquired about the City of Rochester travel policy which strongly encourages the use of the Rochester International Airport, however, Ms. Hanson replied that these are not City employees, but she will follow up with Cayenta to ensure they are using the lowest cost option.

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Board Member Brian Morgan asked if the change order were not approved, would it stop the project? Yes, the project has to keep moving forward to align with RPU's customer service goals, Ms. Hanson replied.

Board Member Melissa Graner Johnson asked how confident the utility is with the accuracy of the amount of additional funds needed? Director of Finance Peter Hogan responded that the utility is confident and has provided for contingencies that may occur.

Missing on a single item like budget, schedule or quality is one thing, but if you miss on two or possibly three, a review of the process or a root cause analysis is in order, said Mr. Morgan.

Mr. Hogan said that the utility is currently in phase one of the implementation, and next will be phase two. Lessons learned from phase one will be included in phase two.

General Manager Mark Kotschevar clarified that the added costs are included expenditures in the utility's 2018 budget.

RESULT:	**COUNCIL APPROVAL [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Member
SECONDER:	Brian Morgan, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

3. Resolution: Cayenta Customer Care Implementation Change Order

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the RPU Change Order 001 to the Software Implementation Services Agreement with Cayenta, a Division of N. Harris Computer Corporation, for the Cayenta customer care implementation, project management services, backfill resources, unforeseen 3rd party interface expenses, and additional 20% contingency, in the amount of $563,583.00, contingent upon approval of the 2018 budget, and authorize the Mayor and the City Clerk to execute the change order.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of October, 2017.

4. Billtrust Contract Extension

Accounting Manager Bryan Blom presented a request to the Board to extend a contract with Billtrust for bill printing, mailing and credit card processing services. Services are being extended another six months due to the delay in the implementation of the utility's new customer care software system, Cayenta, until March 2018, which will include a new payment processing service. RPU has contracted with Billtrust for these services for the past seven

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years, with the current contract expiring on October 31, 2017. The six month extension of the contract is valued at $252,000, and includes delegation of any future extensions to the General Manager.

RESULT:	**COUNCIL APPROVAL [UNANIMOUS]**
MOVER:	Tim Haskin, Melissa Graner Johnson
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

Resolution - Billtrust Contract Extension

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a

six-month extension with

Billtrust for Web Portal Services, IVR Services to include Pay-by-Phone

and Bill Print & Mail Services

The amount of the extension to be TWO HUNDRED FIFTY-TWO THOUSAND AND 00/100 DOLLARS ($252,000.00) with 2018 expenses contingent upon budget approval. The Board also delegates to the General Manager approval of additional extensions and subsequent funding of this contract as needed should there be further delays of the Cayenta implementation.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of

October, 2017.

5. Risk Property, General Liability and Automotive Insurance Renewals for 2018

Purchasing and Materials Manager Joe Mauss presented insurance quotations to the Board for the annual renewal of the utility's risk property, general liability, automobile insurance and excess general liability insurance policies for 2018. The risk property insurance is a $250 million policy with Wortham Insurance/ARGUS; West Side Energy Station is not yet included in coverage, but will be added when it is put into service.

The liability and auto insurance is a $1.5 million policy with the League of Minnesota Cities Insurance Trust. The excess general liability insurance is provided through Associated Electric and Gas Insurance Services Ltd. (AGEIS) with blanket coverage from $1 million to $20 million.

The coverage period for all policies is from November 1, 2017 to October 31, 2018.

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RESULT:	**COUNCIL APPROVAL [UNANIMOUS]**
MOVER:	Brian Morgan, Board Member
SECONDER:	Melissa Graner Johnson, Board Member
AYES:	Mark Browning, Tim Haskin, Melissa Graner Johnson, Brian Morgan
ABSENT:	Michael Wojcik

6. Resolution: All Risk Property Insurance Renewal for 2018

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a contract agreement with Wortham Insurance/ARGUS and that the Common Council authorize the Mayor and the City Clerk to execute the agreement for

ALL RISK PROPERTY INSURANCE

The insurance agreement to be for a twelve month policy period commencing November 1, 2017, and expiring October 31, 2018.

The amount of the contract agreement not to exceed TWO HUNDRED FORTY-SIX THOUSAND FIVE HUNDRED THIRTY-SEVEN AND 00/100 DOLLARS ($246,537.00).

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of October, 2017.

Resolution: Commercial Automobile and General Liability Insurance Renewals for 2018

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a contract agreement with the League of Minnesota Cities Insurance Trust and that the Common Council authorize the Mayor and the City Clerk to execute the agreement for

COMMERCIAL AUTOMOBILE AND GENERAL LIABILITY INSURANCE

The amount of the contract agreement to be ONE HUNDRED THIRTY-ONE THOUSAND FIVE HUNDRED AND 00/100 DOLLARS ($131,500.00).

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th day of October, 2017.

7. Resolution: Excess General Liability Insurance Renewal for 2018

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a contract agreement with Associated Electric and Gas Insurance Services, Ltd. (AEGIS) and that the Common Council authorize the Mayor and the City Clerk to execute the agreement for

EXCESS GENERAL LIABILITY INSURANCE

The insurance agreement to be for a twelve month policy period commencing November 1, 2017 and expiring October 31, 2018.

The amount of the contract agreement not to exceed THREE HUNDRED ONE THOUSAND TWO HUNDRED NINETY-NINE AND 00/100 DOLLARS ($301.299.00).

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 24th *day of October, 2017.*

6. Informational

1. CSC Building Expansion and Renovation Project - Update

Facilities Project Manager Patricia Bremer provided an update to the Board on the RPU Customer Service Center building expansion project. Ms. Bremer said there have been no changes to project scope, and the utility is on target for budget. The total project budget is estimated at $15.3 million.

The project is currently in the bidding phase. A pre-bid meeting was held on October 12, 2017 with prospective contractors, and construction bids are due on November 2, 2017. Facilities staff will return to the Board to seek approval of the construction contracts at its November 14, 2017 meeting.

There will be two construction contracts; an owner-contractor agreement for the labor, and a purchasing agent agreement for the materials, said Ms. Bremer. The intent of this contract structure is to save sales tax dollars. Five deduct alternatives will be offered.

Construction is slated to begin on December 1, 2017, with an anticipated completion date of February 15, 2019.

2. Review Proposed Change to Load Management Credit Rate Tariff

RPU Controller Bryan Blom spoke to the Board regarding a proposed change to the current Load Management Credit Rate Tariff, which offers credit amounts to residential customers having a combination of qualifying air conditioners and qualifying electric water heaters controlled by load management devices. The current tariff program is voluntary and means that RPU can shut down the customer units at peak energy times. It was established in 2002.

Under the existing program, customers with one qualifying air conditioner and one qualifying electric water heater would receive an annual credit of $60. With the proposed new rate tariff, the same customer would receive an annual credit of $51. There would be no change to the credit amount for those customers who have just one qualifying air conditioner, which comprises a majority of the customers in the program, said Mr. Blom.

The utility is seeking to simplify the process of crediting customer accounts using its new customer care software system, which is expected to be launched in March 2018. The simplified rate tariff would credit customers $3.00/month per qualifying air conditioner from May through September, and $3.00/month per qualifying electric water heater for all twelve months of the year.

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The Board reached a consensus to advertise the proposed rate tariff in the newspaper of record to provide public notice.

This was presented as an informational item only. Staff will request approval of the change at the Board's November 14, 2017 meeting, to provide time for public input. If approved, the effective date will align with the go-live date of the new customer account/billing system.

3. Preliminary 2018 Electric and Water Budgets and Rates

Director of Corporate Services Peter Hogan shared with the Board the 2018 electric and water capital and operating budgets that were presented in a separate meeting to the Board's finance committee on October 17, 2017. The proposed budgets take into consideration the electric cost of service study conducted for the utility by Utility Financial Solutions, LLC, and presented previously to the Board.

The budget includes a rate increase of 1.5% for the electric utility in 2018 and 1.9% in 2019, followed by a 2.5% rate increase for each year 2020 through 2022. The first two years of the proposed rate increase was advertised in the newspaper of record to provide public notice.

Also included is a rate increase for the water utility of 6% in 2018. The increase is part of a previously-approved three-year rate track adopted by the Board in 2015.

No action was being requested at this time; the budgets were being presented as informational only.

Board Member Brian Morgan asked if the Board needed to continue the ongoing rates discussion that began in August with the introduction of the cost of service study findings.

President Browning replied that since advertising the rates in the newspaper, the utility has only received two to three letters in response.

Board Member Tim Haskin pointed out that on the bottom of the newspaper ad, in very small print, is a statement indicating that the rate increase may be absorbed by installing two LED bulbs. This should be in larger print, he said.

The Board members were asked to bring any questions they may have regarding the proposed budget and rates to the November 14, 2017 meeting.

7. Board Liaison Reports

Minutes Acceptance: Minutes of Oct 24, 2017 4:00 PM (Approval of Minutes)

1. Board Liaison Reports: RCA Rochester Home Rule Charter Amendment and Notice of Public Hearing

The RPU Board is currently revising several of its Board policies. The Board Organization Policy is in the process of being revised by the Board's policy committee after a request was made to the Rochester Home Rule City Charter committee for a language change that will revise the timing of the election of Board officers from the January meeting to the May meeting. The language change has not yet been approved by the Rochester City Council but is in process.

President Browning remarked that while waiting for the approval, the Board will hold the election of officers in January as usual. City Attorney Terry Adkins confirmed that the new policy will not be in place in time for the January 2018 meeting.

Also currently being drafted by the operations and administration committee is the revised policy for Acquisition and Disposal of Real Property. Next in line for revision by the communications committee is the RPU Cold Weather Disconnect policy, said General Manager Mark Kotschevar.

8. General Managers Report

General Manager Mark Kotschevar congratulated Communications Coordinator Tony Benson and Residential Account Representative Stephanie Humphrey for coordinating the public power event at the Minnesota Children's Museum Rochester on October 7, 2017. Over 600 visitors were in attendance for the event, which offered free admission, a bucket truck display, RPU exhibits and free giveaways.

Mr. Kotschevar met with the new Rochester City Administrator Steve Rymer, and said that Steve is excited to come out and visit the RPU service center.

Board Member Brian Morgan asked about the new Tesla electric car charging station at the Hyvee located at 500 Crossroads Drive SW. Director of Core Services Sidney Jackson said that this is the first high capacity car charging station in Rochester (480 volt DC), and is only for Tesla vehicles.

Mr. Kotschevar shared that Proterra brought an electric bus, the "Proterra Catalyst Bus" as a demo to the Rochester Public Works Operations Center and provided round-trip rides to downtown Rochester. The zero-emission electric buses are becoming more common, he said.

9. Division Reports & Metrics

10. Other Business

11. Adjourn

The agenda and board packet for Utility Board meetings are available on-line at www.rpu.org and http://rochestercitymn.iqm2.com/Citizens/Default.aspx

Submitted by:

____

Secretary

Approved by the Board

____
Board President

____
Date

Minutes Acceptance: Minutes of Oct 24, 2017 4:00 PM (Approval of Minutes)

ROCHESTER ENERGY COMMISSION
Working Toward a Sustainable Community

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•

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•

Raymond Schmitz

•

Cory Rubin

September 18th, 2017

Dear RPU Board Members,

The Rochester Energy Commission (REC) is tasked with various obligations by ordinance, including an obligation to, "Research and adopt position documents on issues affecting energy usage and sustainability." For this reason, the REC kindly requests that the Board of Rochester Public Utilities carefully evaluate the amount of the fixed Customer Charge for Residential Service. The REC believes reducing the fixed Customer Charge and increasing the variable Energy/kWh rate would provide additional economic incentive for energy conservation and would enhance the sustainability and economic vitality of our City.

Our residential utility rate should send an appropriate economic signal to end-users which allows them to make wise decisions on energy use. If more of the electric utility bill varied with the amount of energy used customers would have increased opportunity to influence the monthly bill and those customers with the lowest energy usage would have more control over their household budget. Over the long term a more conservation-minded customer set would reduce the need for additional electric utility investment.

Two items are attached for your consideration. The first is a comparison of fixed residential charges in place at Minnesota investor owned utilities and at the ten largest Minnesota municipal utilities. The comparison shows Rochester's fixed charge to be an outlier, the largest in that group.

The second attachment is an analysis from Synapse Energy Economics and the Consumer's Union which provides a national perspective on and an economic examination of fixed versus variable costs and rates. The article reviews traditional cost-of-service ratemaking, discusses the appropriate means to recover various costs, and reviews the thinking of other utilities and jurisdictions setting rates. The article also addresses the negative impact of fixed charges on low-income customers. It is the REC's belief that pricing should be sympathetic to low-income customers while still providing incentive for all customers to conserve, perhaps by using income-based tiers or rebates.

We thank you for your attention and consideration and stand ready to provide any assistance you might require.

The Rochester Energy Commission

ROCHESTER
Minnesota

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On Tue, Aug 1, 2017 at 9:40 AM, Will Nissen <nissen@fresh-energy.org> wrote:

For additional context, here are the customer charges for the three investor-owned utilities and other large municipal utilities in MN:

RPU (largest municipal utility) = $18.76/month

Xcel = $8/month

Minnesota Power = $8/month

Otter Tail Power = $9.75/month

Marshall Municipal Utilities (2nd largest municipal) = $20/month

Moorhead Public Service (3rd largest) = $14.40/month

Shakopee Public Utilities (4th largest) = $8/month

Owatonna Public Utilities (5th largest) = $9/month

City of Chaska (6th largest) = $9.40/month

Austin Municipal Utility (7th largest) = $13/month

Will Nissen

Director, Energy Performance

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Caught in a Fix

The Problem with Fixed Charges for Electricity

Prepared for Consumers Union

February 9, 2016

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Acknowledgements: This report was prepared by Synapse Energy Economics, Inc. for Consumers Union. We are grateful for the information, suggestions, and insights provided by numerous colleagues, including Consumers Union and John Howat of the National Consumer Law Center. We also relied heavily upon the data on recent fixed charges proceeding provided by other colleagues working to address fixed charges in rate proceedings nationwide, and information provided by Kira Loehr. However, any errors or omissions are our own. The views and policy positions expressed in this report are not necessarily reflective of the views and policy positions of the National Consumer Law Center.

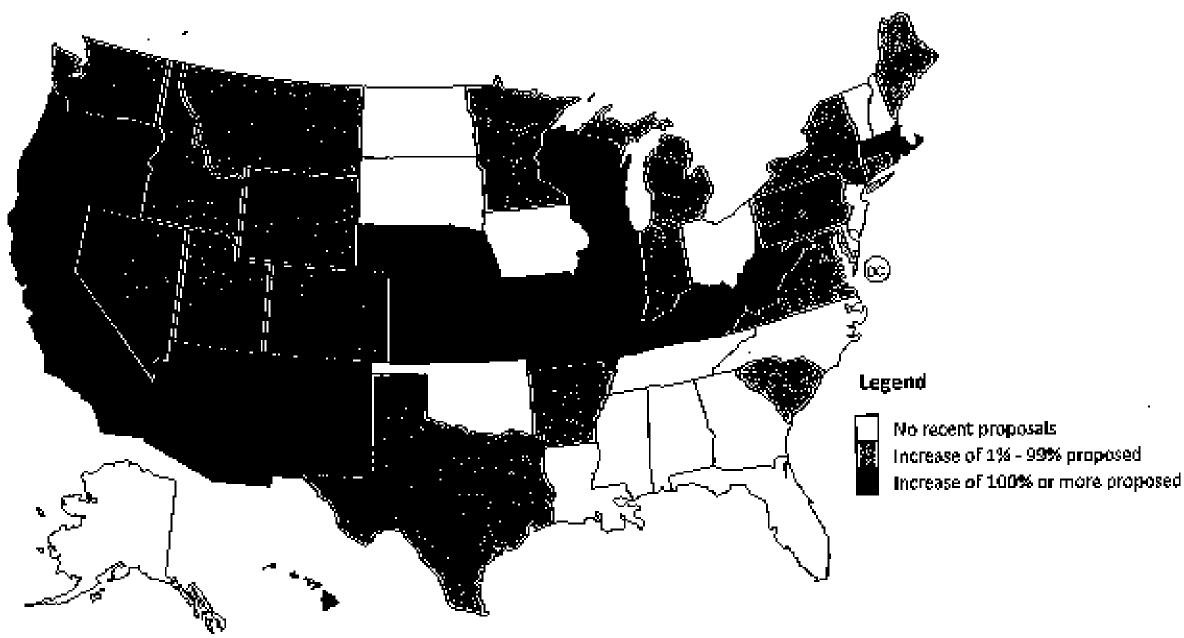
CONTENTS

EXECUTIVE SUMMARY

Recently, there has been a sharp increase in the number of utilities proposing to recover more of their costs through mandatory monthly fixed charges rather than through rates based on usage. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales (from energy efficiency, distributed generation, weather, or economic downturns) will reduce its revenues.

However, higher fixed charges are an inequitable and inefficient means to address utility revenue concerns. This report provides an overview of (a) how increased fixed charges can harm customers, (b) the common arguments that are used to support increased fixed charges, (c) recent commission decisions on fixed charges, and (d) alternative approaches, including maintaining the status quo when there is no serious threat to utility revenues.

Figure ES 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Fixed Charges Harm Customers

Reduced Customer Control. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charges reduce the ability of customers to lower their bills by consuming less energy.

Low-Usage Customers Hit Hardest. Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised. There are many reasons a customer might have low energy usage: they may be very conscientious to avoid wasting energy; they may simply be located in apartments or dense housing units that require less energy; they may have small families or live alone; or they may have energy-efficient appliances or solar panels.

Disproportionate Impacts on Low-Income Customers. Data from the Energy Information Administration show that in nearly every state, low-income customers consume less electricity than other residential customers, on average. Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, fixed charges raise bills most for those who can least afford the increase.

Reduced Incentives for Energy Efficiency and Distributed Generation. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to invest in energy efficiency or distributed generation. Customers who have already invested in energy efficiency or distributed generation will be harmed by the reduced value of their investments.

Increased Electricity System Costs. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer. With little incentive to save, customers may actually increase their energy consumption and states will have to spend more to achieve the same levels of energy efficiency savings and distributed generation. Where electricity demand rises, utilities will need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

Common Myths Supporting Fixed Charges

"Most utility costs are fixed." In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the long-term planning horizon. Over this timeframe, most costs are variable, and customer decisions regarding their electricity consumption can influence the need to invest in power plants, transmission lines, and other utility infrastructure. This longer-term perspective is what is relevant for economically efficient price signals, and should be used to inform rate setting.

"Fixed costs are unavoidable." Rates are designed so that the utility can recover past expenditures (sunk costs) in the future. Utilities correctly argue that these sunk costs have already been made and are unavoidable. However, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be based on forward-going costs to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The fixed charge should recover distribution costs." Much of the distribution system is sized to meet customer maximum demand – the maximum power consumed at any one time. For customer classes without a demand charge (such as residential customers),[1] utilities have argued that these distribution costs should be recovered through the fixed charge. This would allocate the costs of the distribution system equally among residential customers, instead of according to how much energy a customer uses. However, customers do not place equal demands on the system – customers who use more energy also tend to have higher demands. While energy usage (kWh) is not a perfect proxy for demand (kW), collecting demand-related costs through the energy charge is far superior to collecting demand-related costs through the fixed charge.

"Cost-of-service studies should dictate rate design." Cost-of-service studies are used to allocate a utility's costs among the various customer classes. These studies can serve as useful guideposts or benchmarks when setting rates, but the results of these studies should not be directly translated into rates. Embedded cost-of-service studies allocate *historical* costs to different classes of customers. However, to provide efficient price signals, prices should be designed to reflect *future* marginal costs. Rate designs other than fixed charges may yield the same revenue for the utility while also accomplishing other policy objectives, such as sending efficient price signals.

"Low-usage customers are not paying their fair share." This argument is usually untrue. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Further, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed charges are necessary to mitigate cost-shifting caused by distributed generation." Concerns about potential cost-shifting from distributed generation resources, such as rooftop solar, are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. This power is often provided to the system during periods when demand is highest and energy is most valuable, such as hot summer afternoons when the sun is out in full force. The energy from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will significantly reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

Recent Commission Decisions on Fixed Charges

Commissions in many states have recently rejected utility proposals to increase mandatory fixed charges. These proposals have been rejected on several grounds, including that increased fixed charges

[1] There are several reasons that demand charges are rarely assessed for residential customers. These reasons include the fact that demand charges introduce complexity into rates that may be inappropriate for residential customers; residential customers often lack the ability to monitor and respond to demand charges; and that residential customers often do not have more expensive meters capable of measuring customer demand.

will reduce customer control, send inefficient prices signals, reduce customer incentives to invest in energy efficiency, and have inequitable impacts on low-usage and low-income customers.

Several states have allowed utilities to increase fixed charges, but typically to a much smaller degree than has been requested by utilities. In addition, there have been many recent rate case settlements in which the utility proposal to increase fixed charges has been rejected by the settling parties. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason.

Alternatives to Fixed Charges

For most utilities, there is no need for increased fixed charges. Regulators who decide there is a need to address utility revenue sufficiency and volatility concerns should consider alternatives to increased fixed charges, such as minimum bills and time-of-use rates.

1. INTRODUCTION

In 2014, Connecticut Light & Power filed a proposal to increase residential electricity customers' fixed monthly charge by 59 percent — from $16.00 to $25.50 per month — leaving customers angry and shocked. The fixed charge is a mandatory fee that customers must pay each month, regardless of how much electricity they use.

The utility's fixed charge proposal met with stiff opposition, particularly from seniors and customers on limited incomes who were trying hard to save money by reducing their electricity usage. Since the fixed charge is unavoidable, raising it would reduce the ability of customers to manage their bills and would result in low-usage customers experiencing the greatest percentage increase in their bills. In a letter imploring the state commission to reject the proposal, a retired couple wrote: "We have done everything we can to lower our usage... We can do no more. My wife and I resorted to sleeping in the living room during the month of January to save on electricity."[2]

Customers were particularly opposed to the loss of control that would accompany such an increase in the mandatory fixed charge, writing: "If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."[3]

Unfortunately, customers in Connecticut are not alone. Recently, there has been a sharp uptick in the number of utilities that are proposing to recover more of their costs through monthly fixed charges rather than through variable rates (which are based on usage). Some of these proposals represent a slow, gradual move toward higher fixed charges, while other proposals (such as Madison Gas & Electric's) would quickly lead to a dramatic increase in fixed charges of nearly $70 per month.[4]

> *"If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."*

The map below shows the prevalence of recent utility proposals to increase the fixed charge, as well as the relative magnitude of these proposals. Proposals to increase the fixed charge were put forth or decided in 32 states in 2014 and 2015. In 14 of these states, the utility's proposal would increase the fixed charge by more than 100 percent.

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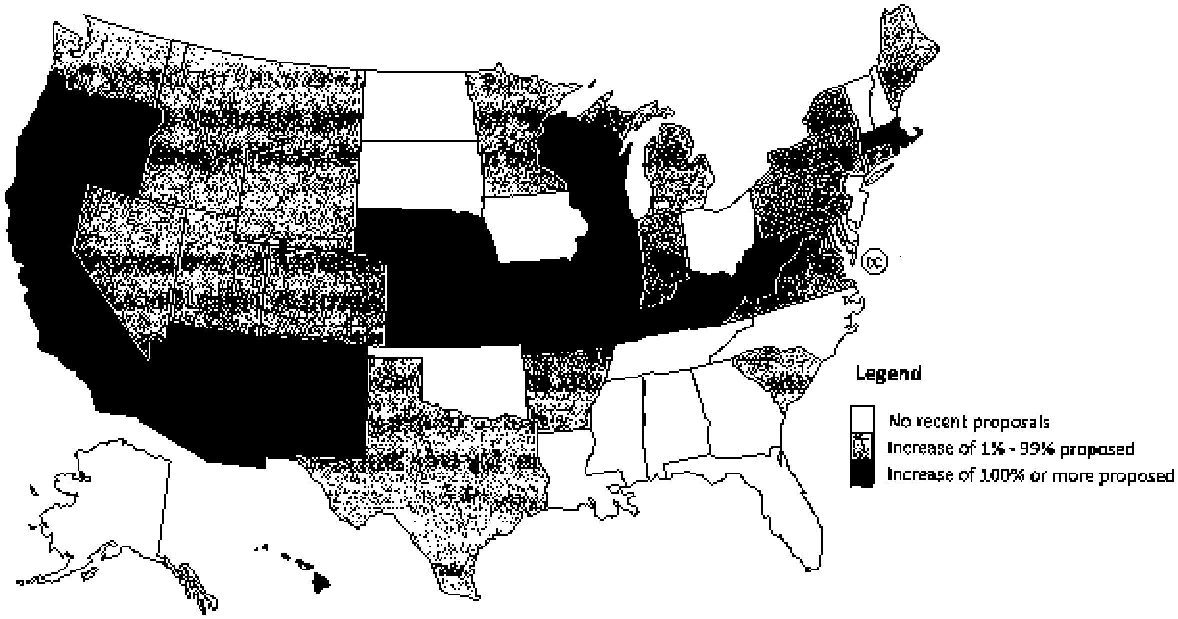
[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[3] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

[4] Madison Gas & Electric's proposal for 2015/2016 offered a preview of its 2017 proposal, which featured a fixed charge of $68.37. Data from Ex.-MGE-James-1 in Docket No. 3270-UR-120.

Figure 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Although a fixed charge may be accompanied by a commensurate reduction in the energy charge, higher fixed charges have a detrimental impact on efficiency and equity. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales resulting from energy efficiency, distributed generation, weather, or economic downturns will reduce its revenues. However, higher fixed charges are not an equitable solution to this problem. Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

As the frequency of proposals to increase fixed charges rises, so too does awareness of their detrimental impacts. Fortunately, customers in Connecticut may soon obtain some relief: On June 30, 2015, the governor signed into law a bill that directs the utility commission to adjust utilities' residential fixed charges to only recover the costs "directly related to metering, billing, service connections and the

Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

provision of customer service."[5] However, not all policymakers are yet aware of the impacts of fixed charges or what alternatives might exist. The purpose of this report is to shed light on these issues.

Chapter 2 of this report examines the trends and drivers behind fixed charges, while Chapter 3 provides an assessment of how fixed charges impact customers. In Chapter 4, we explore many of the common technical arguments used to support these charges, and explain the flaws in these approaches. Finally, in Chapter 5, we provide an overview of some of the alternatives to fixed charges and the advantages and disadvantages of these alternatives.

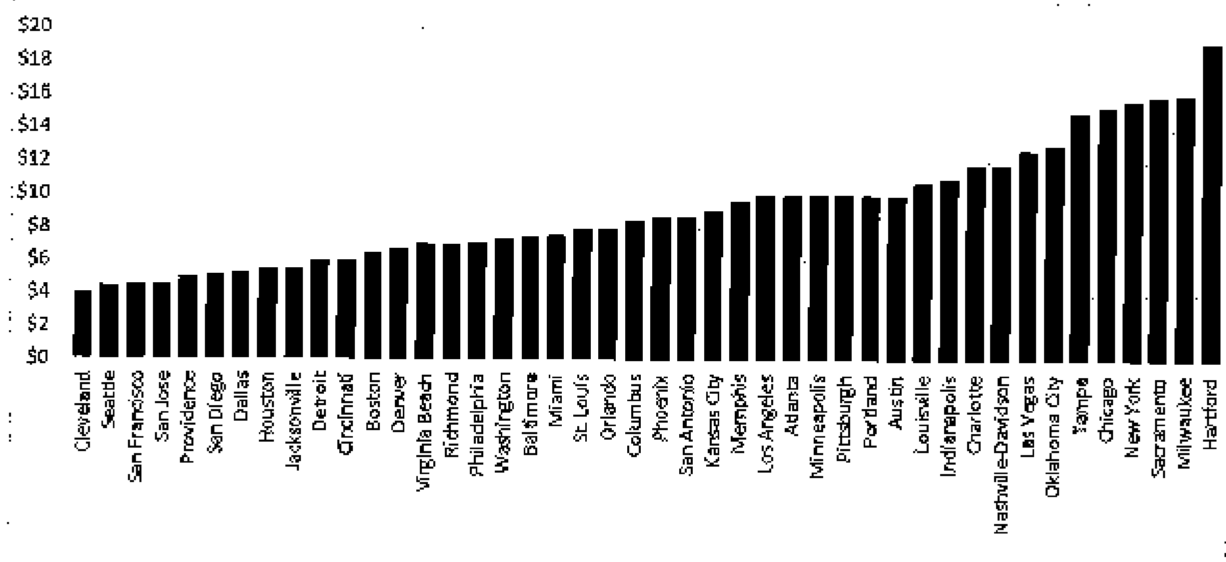
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

2. Troubling Trends Toward Higher Fixed Charges

What's Happening to Electric Rates?

Sometimes referred to as a "customer charge" or "service charge," the fixed charge is a flat fee on a customer's monthly bill that is typically designed to recover the portion of costs that do not vary with usage. These costs may include, for examples, costs of meters, service lines, meter reading, and customer billing.[6] In most major U.S. cities, the fixed charge ranges from $5 per month to $10 per month, as shown in the chart below.[7]

Figure 2. Fixed charges in major U.S. cities



Source: Utility tariff sheets for residential service as of August 19, 2015.

Although fixed charges have historically been a small part of customers' bills, more and more utilities across the country—from Hawaii to Maine—are seeking to increase the portion of the bill that is paid through a flat, monthly fixed charge, while decreasing the portion that varies according to usage.

[6] Frederick Weston, "Charging for Distribution Utility Services: Issues in Rate Design," Prepared for the National Association of Regulatory Utility Commissioners (Montpelier, VT: Regulatory Assistance Project, December 2000).

[7] Based on utility tariff sheets for residential service as of August 2015.

Connecticut Light & Power's proposed increase in the fixed charge to $25.50 per month was significantly higher than average,[8] but hardly unique.

Other recent examples include:

- The Hawaiian Electric Companies' proposal to increase the customer charge from $9.00 to $55.00 per month (an increase of $552 per year) for full-service residential customers, and $71.00 per month for new distributed generation customers (an increase of $744 per year);[9]

- Kansas City Power and Light's proposal to increase residential customer charges 178 percent in Missouri, from $9.00 to $25.00 per month (an increase of $192 per year);[10] and

- Pennsylvania Power and Light's March 2015 proposal to increase the residential customer charge from approximately $14.00 to approximately $20.00 per month (an increase of more than $70 per year).[11]

Figure 3 below displays those fixed charge proposals that are currently pending, while Figure 4 displays the proposals that have been ruled upon in 2014-2015.

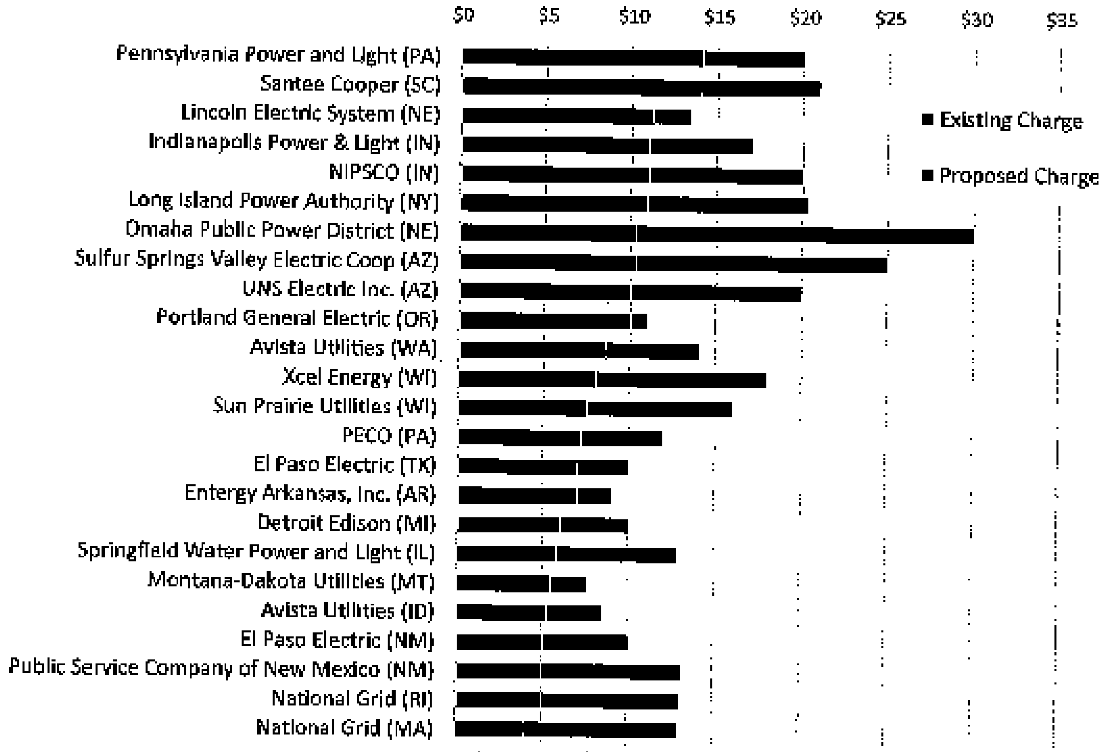
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[9] Hawaiian Electric Companies' Distributed Generation Interconnection Plan, Docket 2011-0206, submitted August 26, 2014, at http://files.hawaii.gov/puc/3_Dkt 2011-0206 2014-08-26 HECO PSIP Report.pdf.

[10] Kansas City Power and Light, Case No.: ER-2014-0370.

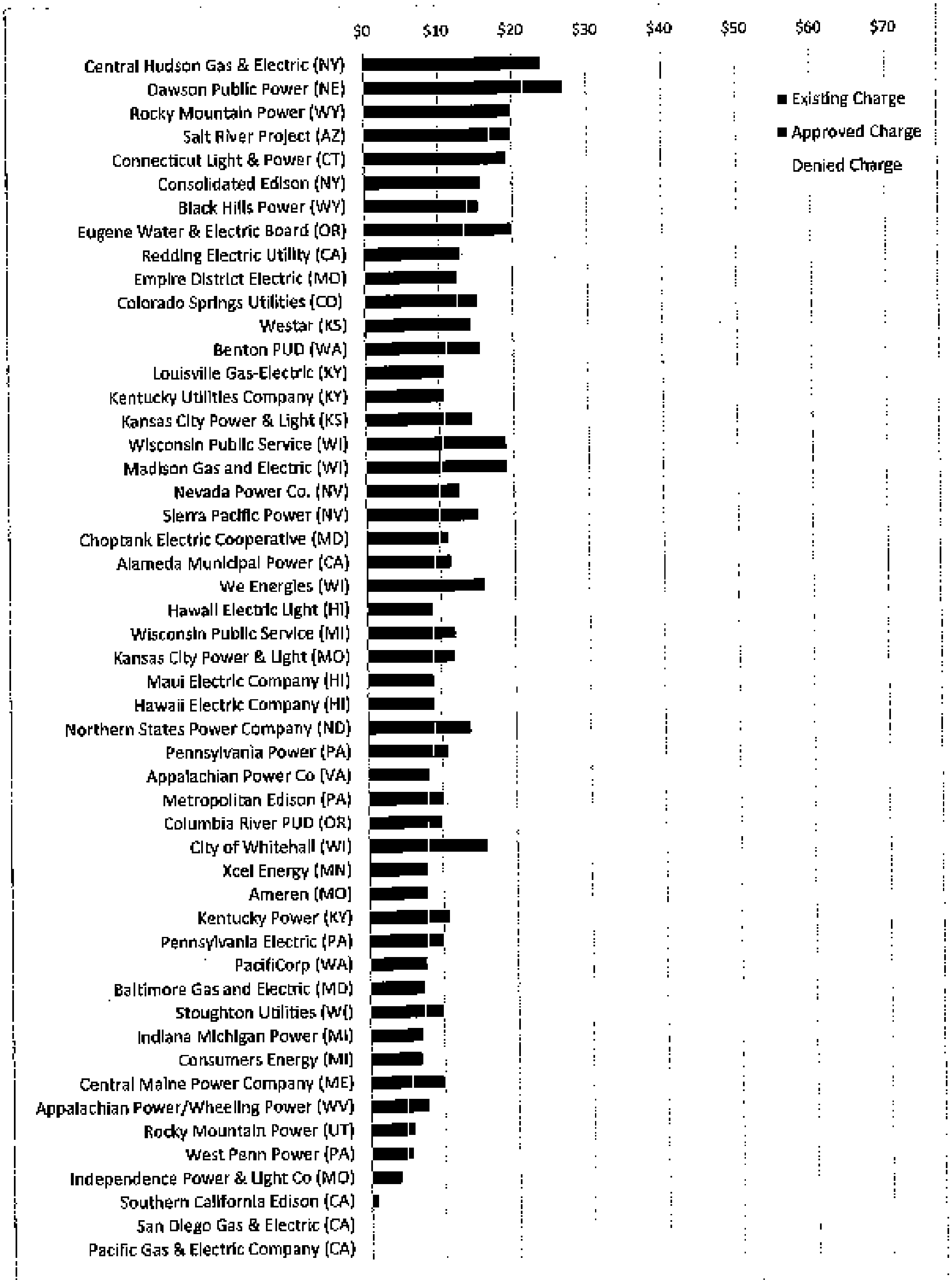
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



Source: See Appendix B

Figure 4. Recent decisions regarding fixed charge proposals



Notes: "Denied" includes settlements that did not increase the fixed charge. Source: See Appendix B

What is Behind the Trend Toward Higher Fixed Charges?

It is important to note that the question of whether to increase the fixed charge is a rate design decision. Rate design is not about how *much* total revenue a utility can collect; rather, rate design decisions determine *how* the utility can collect a set amount of revenue from customers. That is, once the amount of revenues that a utility can collect is determined by a commission, rate design determines the method for collecting that amount. However, if electricity sales deviate from the predicted level, a utility may actually collect more or less revenue than was intended.

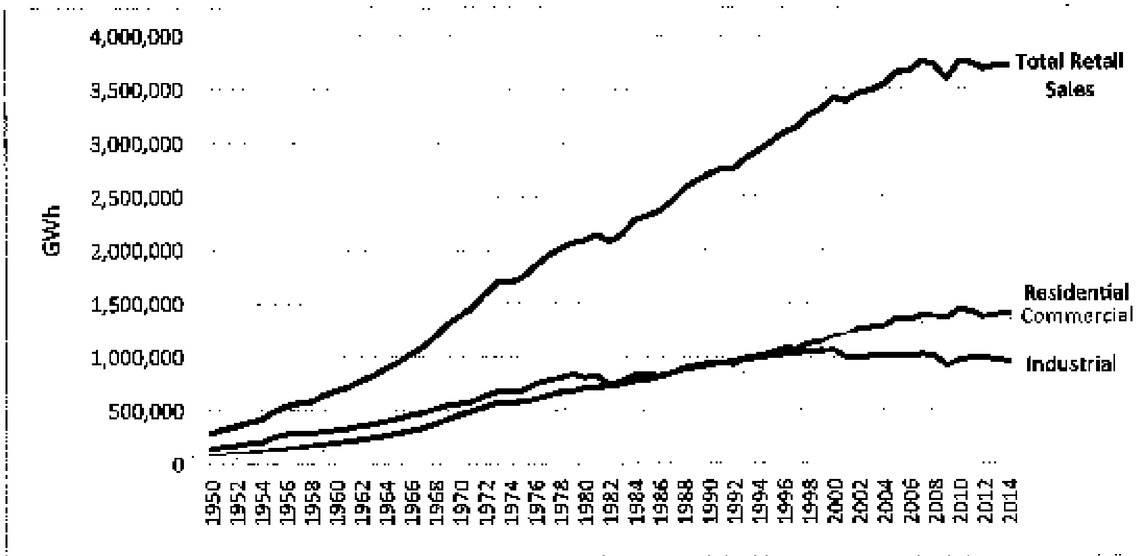
Rates are typically composed of some combination of the following three types of charges:

- Fixed charge: dollars per customer
- Energy charge: cents per kilowatt-hour (kWh) used
- Demand charge: dollars per kilowatt (kW) of maximum power used[12]

Utilities have a clear motivation for proposing higher fixed charges, as the more revenue that a utility can collect through a fixed monthly charge, the lower the risk of revenue under-recovery. Revenue certainty is an increasing concern for utilities across the country as sales stagnate or decline. According to the U.S. Energy Information Administration, electricity sales have essentially remained flat since 2005, as shown in Figure 5 below. This trend is the result of many factors, including greater numbers of customers adopting energy efficiency and distributed generation—such as rooftop solar—as well as larger economic trends. This trend toward flat sales is in striking contrast to the growth in sales that utilities have experienced since 1950, and has significant implications for utility cost recovery and ratemaking.

[12] Demand charges are typically applied only to medium to large commercial and industrial customers. However, some utilities are seeking to start applying demand charges to residential customers who install distributed generation.

Figure 5. Retail electricity sales by sector



Source: U.S. Energy Information Administration, September 2015 Monthly Energy Review, Table 7.6 Electricity End Use.

Reduced electricity consumption—whether due to customer conservation efforts, rooftop solar, or other factors—strikes at the very heart of the traditional utility business model, since much of a utility's revenue is tied directly to sales. As Kansas City Power and Light recently testified:

> From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery.[13]

At the same time that sales, and thus revenue growth, have slowed, utility costs have increased, as much utility infrastructure nears retirement age and needs replacement. The American Society of Civil Engineers estimates that $57 billion must be invested in electric distribution systems by 2020, and another $37 billion in transmission infrastructure.[14]

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[13] Direct Testimony of Tim Rush, Kansas City Power & Light, Docket ER-2014-0370, October 2014, page 63.

[14] American Society of Civil Engineers, "2013 Report Card for America's Infrastructure: Energy," 2013, http://www.infrastructurereportcard.org.

3. How Fixed Charges Harm Customers

Reduced Customer Control

As technology advances, so too have the opportunities for customers to monitor and manage their electricity consumption. Many utilities are investing in smart meters, online information portals, and other programs and technologies in the name of customer empowerment. "We think customer empowerment and engagement are critical to the future of energy at Connecticut Light & Power and across the nation," noted the utility's director of customer relations and strategy.[15]

The fixed charge reduces customer control, as the only way to avoid the charge is to stop being a utility customer.

Despite these proclamations of support for customer empowerment and ratepayer-funded investments in demand-management tools, utilities' proposals for raising the fixed charge actually serve to disempower customers. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charge reduces the ability of customers to lower their bills by consuming less energy. Overall, the fixed charge reduces customer control, as the only way to avoid the fixed charge is to stop being a utility customer, an impossibility for most customers

Low-Usage Customers Hit Hardest

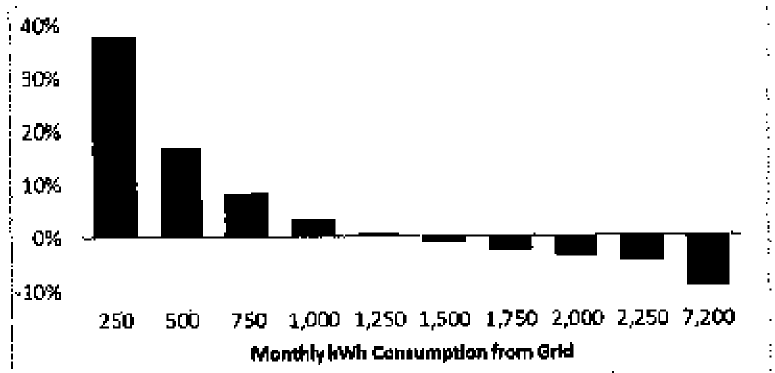
Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage customers may have invested in energy-efficient appliances or installed solar panels, or they may have lower incomes and live in dense housing.

Figure 6 illustrates the impact of increasing the fixed charge for residential customers from $9.00 per month to $25.00 per month, with a corresponding decrease in the per-kilowatt-hour charge. Customers who consume 1,250 kilowatt-hours per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kilowatt-hours per month would see their bill rise by nearly 40 percent. High usage customers (who tend to have higher incomes) would see a bill decrease. The data presented in the figure approximates the impact of Kansas City Power & Light's recently proposed rate design.[16]

[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

[16] Missouri Public Service Commission Docket ER-2014-0370.

Figure 6. Increase in average monthly bill

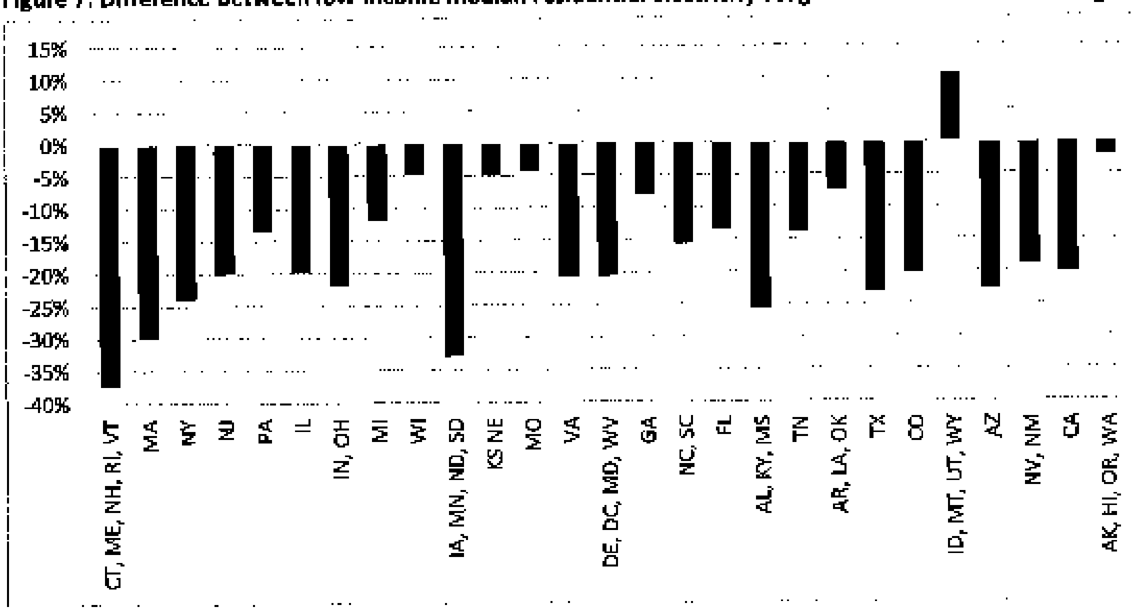


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

Low-income customers are disproportionately affected by increased fixed charges, as they tend to be low-usage customers. Figure 7 compares median electricity consumption for customers at or below 150 percent of the federal poverty line to electricity consumption for customers above that income level, based on geographic region. Using the median value provides an indication of the number of customers above or below each usage threshold—by definition, 50 percent of customers will have usage below the median value. As the graph shows, in nearly every region, most low-income customers consume less energy than the typical residential customer.

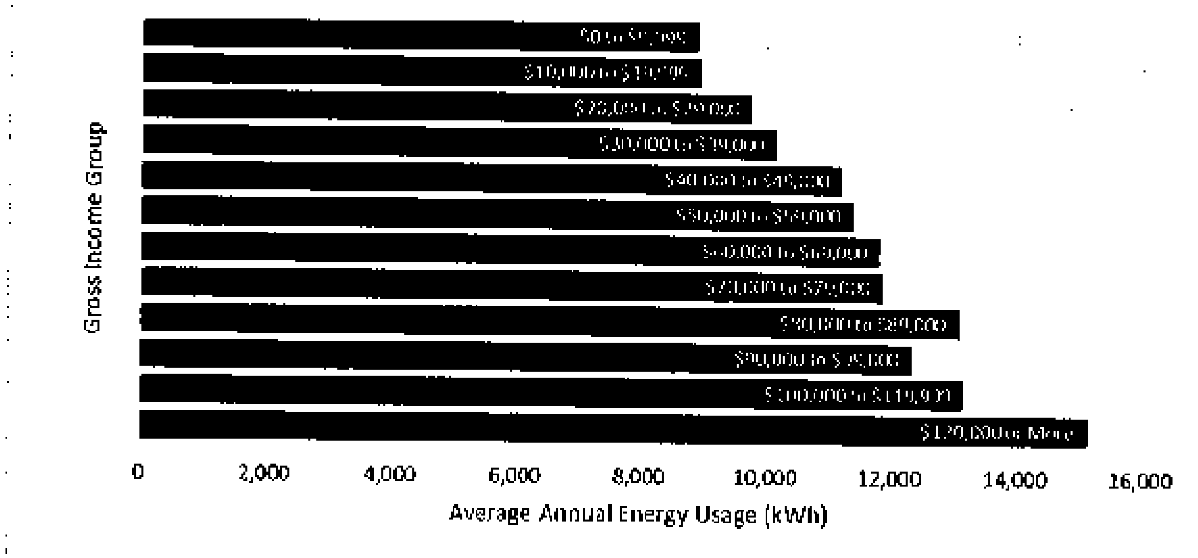
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



Source: Energy Information Administration Residential Energy Consumption Survey, 2009. http://www.eia.gov/consumption/residential/data/2009. Developed with assistance from John Howat, Senior Policy Analyst, NCLC.

The same relationship generally holds true for average usage. Nationwide, as gross income rises, so does average electricity consumption, generally speaking.

Figure 8. Nationwide average annual energy usage by income group



Source: Energy Information Administration Residential Energy Consumption Survey, 2009 *http://www.eia.gov/consumption/residential/data/2009.*

Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, higher fixed charges tend to raise bills most for those who can least afford the increase. This shows that rate design has important equity implications, and must be considered carefully to avoid regressive impacts.

Reduced Incentives for Energy Efficiency and Distributed Generation

Energy efficiency and clean distributed generation are widely viewed as important tools for helping reduce energy costs, decrease greenhouse gas emissions, create jobs, and improve economic competitiveness. Currently, ratepayer-funded energy efficiency programs are operating in all 50 states and the District of Columbia.[17] These efficiency programs exist alongside numerous other government policies, including building codes and appliance standards, federal weatherization assistance, and tax incentives. Distributed generation (such as rooftop solar) is commonly supported through tax incentives and net energy metering programs that compensate customers who generate a portion of their own electricity.

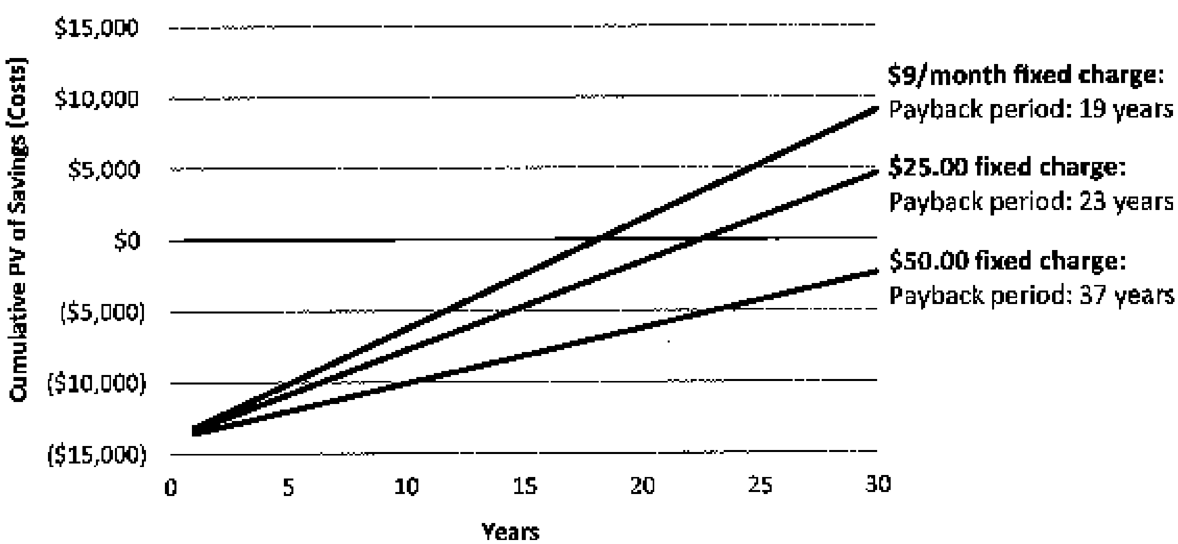
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

Increasing fixed charges can significantly reduce incentives for customers to reduce consumption through energy efficiency, distributed generation, or other means. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to lower their bills by reducing consumption. Customers who are considering making investments in energy efficiency measures or distributed generation will have longer payback periods over which to recoup their initial investment. In some cases, a customer might never break even financially when the fixed charge is increased. Increasing the fixed charge also penalizes customers who have already taken steps to reduce their energy consumption by implementing energy efficiency measures or installing distributed generation.

"When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?"

Figure 9 illustrates how the payback period for rooftop solar can change under a net metering mechanism with different fixed charges. Under net metering arrangements, a customer can offset his or her monthly electricity usage by generating solar electricity—essentially being compensated for each kilowatt-hour produced. However, solar customers typically cannot avoid the fixed charge. For a fairly typical residential customer, raising the fixed charge from $9.00 per month to $25.00 per month could change the payback period for a 5 kW rooftop solar system from 19 years to 23 years – longer than the expected lifetime of the equipment. Increasing the fixed charge to $50.00 per month further exacerbates the situation, causing the project to not break even until 37 years in the future, and virtually guaranteeing that customers with distributed generation will face a significant financial loss.

Figure 9. Rooftop solar payback period under various customer charges



All three scenarios assume monthly consumption of 850 kWh. The $9.00 per month fixed charge assumes a corresponding energy charge of 10.36 cents per kWh, while the $25 fixed charge assumes an energy charge of 8.48 cents per kWh, and the $50 fixed charge assumes an energy charge of 5.54 cents per kWh.

In Connecticut, customers decried the proposed fixed charge as profoundly unfair: "When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?" noted one frustrated customer. "Where is the incentive to spend hard-earned money to improve your appliances, or better insulate your home or more efficiently set your thermostats or air conditioning not to be wasteful, trying to conserve energy for the next generation - when you will allow the utility company to just turn around and now charge an additional fee to offset your savings?"[18]

Increased Electricity System Costs

High fixed charges may actually encourage customers to leave the system, leaving fewer and fewer customers to shoulder the costs of the electric system.

Because higher fixed charges reduce customer incentives to reduce consumption, they will undermine regulatory policies and programs that promote energy efficiency and clean distributed generation, leading to higher program costs, diminished results, or both. Rate design influences the effectiveness of these regulatory policies by changing the price signals that customers see. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer.

The flip side of this is that customers may actually increase their energy consumption since they perceive the electricity to be cheaper. Under such a scenario, states will have to spend more funds on incentives to achieve the same level of energy efficiency savings and to encourage the same amount of distributed generation as achieved previously at a lower cost. Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

In extreme cases, high fixed charges may actually encourage customers to leave the system. As rooftop solar and storage costs continue to fall, some customers may find it less expensive to generate all of their own electricity without relying on the utility at all. Once a customer departs the system, the total system costs must be redistributed among the remaining customers, raising electricity rates. These higher rates may then lead to more customers defecting, leaving fewer and fewer customers to shoulder the costs.

Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

The end result of having rate design compete with public policy incentives is that customers will pay more—either due to higher energy efficiency and distributed generation program costs, or through more investments needed to meet higher electricity demand. Meanwhile, customers who have already invested in energy efficiency or distributed generation will get burned by the reduced value of their investments and may choose to

[18] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

leave the grid, while low-income customers will experience higher bills, and all customers will have fewer options for reducing their electricity bills.

4. Rate Design Fundamentals

To understand utilities' desire to increase the fixed charge—and some of the arguments used to support or oppose these proposals—it is first necessary to review how rates are set.

Guiding Principles

Rates are designed to satisfy numerous objectives, some of which may be in competition with others. In his seminal work, *Principles of Public Utility Rates,* Professor James Bonbright enumerated ten guiding principles for rate design. These principles are reproduced in the appendix, and can be summarized as follows:

1. Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.
2. Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.
3. Efficiency: Rates should provide efficient price signals and discourage wasteful usage.
4. Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

Different parts of the rate design process address different principles. First, to determine sufficient revenues, the utility's revenue requirement is determined based on a test year (either future or historical). Second, a cost-of-service study divides the revenue requirement among all of the utility's customers according to the relative cost of serving each class of customers based on key factors such as the number of customers, class peak demand, and annual energy consumption. Third, marginal costs may be used to inform efficient pricing levels. Finally, rates are designed to ensure that they send efficient price signals, and are relatively stable, understandable, and simple.

Cost-of-Service Studies

Cost-of-service study results are often used when designing rates to determine how the revenue requirement should be allocated among customer classes. An *embedded* cost-of-service study generally begins with the revenue requirement and allocates these costs among customers. An embedded cost-of-service study is performed in three steps:

- First, costs are functionalized, meaning that they are defined based upon their function (e.g., production, distribution, transmission).
- Second, costs are classified as energy-related (which vary by the amount of energy a customer consumes), demand-related (which vary according to customers' maximum energy demand), or customer-related (which vary by the number of customers).

- Finally, these costs are allocated to the appropriate customer classes. Costs are allocated on the principle of "cost causation," where customers that cause costs to be incurred should be responsible for paying them. Unit costs (dollars per kilowatt-hour, per kilowatt of demand, or per customer-month) from the cost-of-service study can be used as a point of reference for rate design.

A *marginal* cost study differs from an embedded cost study in that it is forward-looking and analyzes how the costs of the electric system would change if demand increased. A marginal cost study is particularly useful for informing rate design, since according to economic theory, prices should be set equal to marginal cost to provide efficient price signals.

One of the challenges of rate design comes from the need to reconcile the differences between embedded and marginal cost-of-service studies. Rates need to meet the two goals of allowing utilities to recover their historical costs (as indicated in embedded cost studies), and providing customers with efficient price signals (as indicated in marginal cost studies).

It is worth noting that there are numerous different approaches to conducting cost-of-service studies, and thus different analysts can reach different results.[19] Some jurisdictions consider the results of multiple methodologies when setting rates.

Rate Design Basics

Most electricity customers are charged for electricity using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed charge (e.g., $9 per month) plus an energy charge based on usage (e.g., $0.10 per kilowatt-hour).[20] The fixed charge (or "customer charge") is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, while the energy charge reflects the cost to generate and deliver energy.

Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, an energy charge, and a demand charge, because they are large users and have meters capable of measuring demand as well as energy use. The demand charge is designed to reflect the maximum amount of energy a customer withdraws at any one time, often measured as the maximum demand (in kilowatts) during the billing month. While the fixed charge is still designed to recover customer costs that are largely independent of usage, the cost to deliver energy through the transmission and distribution system is recovered largely through the demand charge, while the energy charge primarily reflects fuel costs for electricity generation.

[19] Commonly used cost-of-service study methods are described in the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Utility Commissioners.

[20] There are many variations of energy charge; the charge may change as consumption increases ("inclining block rates"), or based on the time of day ("time-of-use rates").

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

Utilities commonly argue that most of their costs are fixed, and that that the fixed charge is appropriate for recovering such "fixed" costs. For example, in its 2015 rate case, National Grid stated, "as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible."[21]

Response

This argument conflates the accounting definition with the economic definition of fixed and variable costs.

- In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. In this sense of the term, fixed costs can include poles, wires, and power plants.[22] This definition contrasts with variable costs, which are the costs that are directly related to the amount of energy the customer uses and that rise or fall as the customer uses more or less energy.

- Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the planning horizon—perhaps a term of 10 or more years for an electric utility. Over this timeframe, most costs are variable.

Because utilities must recover the costs of the investments they have already made in electric infrastructure, they frequently employ the accounting definition of fixed costs and seek to ensure that revenues match costs. This focus is understandable. However, this approach fails to provide efficient price signals to customers. As noted above, it is widely accepted in economics that resource allocation is most efficient when all goods and services are priced at marginal cost. For efficient electricity investments to be made, the marginal cost must be based on the appropriate timeframe. In *Principles of Public Utility Rates*, James Bonbright writes:

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant

[21] National Grid Pricing Panel testimony, Book 7 of 9, Docket No. D.P.U. 15-155, November 6, 2015, page 36.

[22] Many of these costs are also "sunk" in the sense that the utility cannot easily recover these investments once they have been made.

> marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[23]

A fixed charge that includes long-run marginal costs provides no price signal relevant to resource allocation, since customers cannot reduce their consumption enough to avoid the charge. In contrast, an energy charge that reflects long-run marginal costs will encourage customers to consume electricity efficiently, thereby avoiding inefficient future utility investments.

"Fixed Costs Are Unavoidable"

<u>Argument</u>

By classifying some utility costs as "fixed," utilities are implying that these costs remain constant over time, regardless of customer energy consumption.

<u>Response</u>

Past utility capital investments are depreciated over time, and revenues collected through rates must be sufficient to eventually pay off these past investments. While these past capital investments are fixed in the sense that they cannot be avoided (that is, they are "sunk costs"), some future capital investments can be avoided if customers reduce their energy consumption and peak demands. Inevitably, the utility will have to make new capital investments; load growth may require new generating equipment to be constructed or distribution lines to be upgraded. Rate design has a role to play in sending appropriate price signals to guide customers' energy consumption and ensure that efficient future investments are made.

In short, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be analyzed to some degree on a forward-going basis to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The Fixed Charge Should Recover Distribution Costs"

<u>Argument</u>

The electric distribution system is sized to deliver enough energy to meet the maximum demand placed on the system. As such, the costs of the distribution system are largely based on customer peak demands, which are measured in kilowatts. For this reason, large customers typically face a demand charge that is based on the customer's peak demand. Residential customers, however, typically do not have the metering capabilities required for demand charges, nor do they generally have the means to

[23] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). P. 336.

monitor and reduce their peak demands. Residential demand-related costs have thus historically been recovered through the energy charge.

Where demand charges are not used, utilities often argue that these demand-related costs are better recovered through the fixed charge, as opposed to the energy charge. Similar to the arguments above, utilities often claim that the costs of the distribution system—poles, wires, transformers, substations, etc.— are "fixed" costs.[24]

Response

While the energy charge does not perfectly reflect demand-related costs imposed on the system, it is far superior to allocating demand-related costs to all residential customers equally through the fixed charge. Recent research has demonstrated that there exists "a strong and significant correlation between monthly kWh consumption and monthly maximum kW demand," which suggests that "it is correct to collect most of the demand-related capacity costs through the kWh energy charge."[25]

Not all distribution system costs can be neatly classified as "demand-related" or "customer-related," and there is significant gray area when determining how these costs are classified. In general, however, the fixed charge is designed to recover customer-related costs, not any distribution-system cost that does not perfectly fall within the boundaries of "demand-related" costs. Bonbright himself warned against misuse of the fixed charge, stating that a cost analyst is sometimes "under compelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."[26]

Where it is used at all, the customer (fixed) charge should be limited to only recovering costs that vary directly with the number of customers, such as the cost of the meter, service drop, and customer billing, as has traditionally been done.[27]

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[24] For example, in UE-140762, PacifiCorp witness Steward testifies that "Distribution costs (along with retail and miscellaneous) are fixed costs associated with the local facilities necessary to connect and serve individual customers. Accordingly, these costs should be recovered through the monthly basic charges and load size charges (which are based on demand measurements)." JRS-1T, p. 17. Another example is provided in National Grid's 2015 rate case application. The utility's testimony states: "the distribution system is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand, and, once constructed, distribution system costs are fixed in nature. In other words, reducing energy consumption does not result in a corresponding reduction in distribution costs. Therefore, as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible." D.P.U. 15-155, Pricing Panel testimony, November 6, 2015, page 36.

[25] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," *Fortnightly* 27, no. 4 (May 2014).

[26] *Principles of Public Utility Rates*, Dr. James Bonbright, Columbia University Press, 1961, p. 349.

[27] Weston, 2000: "there is a broad agreement in the literature that distribution investment is causally related to peak demand" and not the number of customers; and "[t]raditionally, customer costs are those that are seen to vary with the number of customers on the system: service drops (the line from the distribution radial to the home or business), meters, and billing and collection." Pp. 28-29.

"Cost-of-Service Studies Should Dictate Rate Design"

Argument

Utilities sometimes argue that adherence to the principle of "cost-based rates" means that the unit costs identified in the cost-of-service study (i.e., dollars per kilowatt-hour, dollars per kilowatt, and dollars per customer) should be replicated in the rate design.

Response

The cost-of-service study can be used as a guide or benchmark when setting rates, but by itself it does not fully capture all of the considerations that should be taken into account when setting rates. This is particularly true if only an embedded cost-of-service study is conducted, rather than a marginal cost study. As noted above, embedded cost studies reflect only historical costs, rather than marginal costs. Under economic theory, prices should be set equal to marginal cost in order to provide an efficient price signal. Reliance on marginal cost studies does not fully resolve the issue, however, as marginal costs will seldom be sufficient to recover a utility's historical costs.

> *"I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."*

Further, cost-of-service studies do not account for benefits that customers may be providing to the grid. In the past, customers primarily imposed costs on the grid by consuming energy. As distributed generation and storage become more common, however, customers are increasingly becoming "prosumers"—providing services to the grid as well as consuming energy. By focusing only on the cost side of the equation, cost-of-service studies generally fail to account for such services.

Cost-of-service study results are most useful when determining *how much* revenue to collect from different types of customers, rather than *how* to collect such revenue. Clearly, rates can be set to exactly mirror the unit costs revealed by the embedded cost-of-service study (dollars per customer, per kilowatt, or per kilowatt-hour), but other rate designs may yield approximately the same revenue while also accomplishing other policy objectives, particularly that of sending efficient price signals. Indeed, most products in the competitive marketplace—whether groceries, gasoline, or restaurant meals—are priced based solely on usage, rather than also charging a customer access fee and another fee based on maximum consumption.

This point was echoed recently by Karl Rabago, a former Texas utility commissioner: "I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."[28]

[28] Rabago direct testimony, NY Orange & Rockland Case 14-E-0493, p. 13.

As a final note, utility class cost of service studies are just that. They are performed by the utility and rely on numerous assumptions on how to allocate costs. Depending on the method and cost allocation chosen, results can vary dramatically, and represent one party's view of costs and allocation. Different studies can and do result in widely varying results. Policymakers should view with skepticism a utility claim that residential customers are not paying their fair share of costs based on such studies.

"Low-Usage Customers Are Not Paying Their Fair Share"

Argument

It is often claimed that a low fixed charge results in high-usage customers subsidizing low-usage customers.

Response

The reality is much more complicated. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Thus, many low-usage customers impose lower demands on the system, and should therefore be responsible for a smaller portion of the distribution system costs. Furthermore, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed Charges Are Necessary to Mitigate Cost-Shifting Caused by Distributed Generation"

Argument

Several utilities have recently proposed that fixed customer charges should be increased to address the growth in distributed generation resources, particularly customer-sited photovoltaic (PV) resources. Utilities argue that customers who install distributed generation will not pay their "fair share" of costs, because they will provide much less revenue to the utility as a result of their decreased need to consume energy from the grid. This "lost revenue" must eventually be paid by other customers who do not install distributed generation, which will increase their electricity rates, causing costs to be shifted to them.

While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power.

The utilities' proposed solution is to increase fixed charges—at least for the customers who install distributed generation, and often for all customers. The higher fixed charges are proposed to ensure that customers with distributed generation continue to pay sufficient revenues to the utility, despite their reduced need for external generation.

Response

Concerns about potential cost-shifting from distributed generation resources are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. The power from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will dramatically reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

This is a critical element of distributed generation resources that often is not recognized or fully addressed in discussions about alternative ratemaking options such as higher fixed charges. Unlike all other electricity resources, distributed generation typically provides the electric utility system with generation that is nearly free of cost to the utility and to other customers. This is because, in most instances, host customers pay for the installation and operation of the distributed generation system, with little or no payment required from the utility or other customers.[29]

One of the most important and meaningful indicators of the cost-effectiveness of an electricity resource is the impact that it will have on utility revenue requirements. The present value of revenue requirements (PVRR) is used in integrated resource planning practices throughout the United States as the primary criterion for determining whether an electricity resource is cost-effective and should be included in future resource plans.

The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

Several recent studies have shown that distributed generation resources are very cost-effective because they can significantly reduce revenue requirements by avoiding generation, transmission, and distribution costs, and only require a small increase in other utility expenditures. Figure 10 presents the benefits and costs of distributed generation according to six studies, where the benefits include all of the ways that distributed generation might reduce revenue requirements through avoided costs, and the costs include all of the ways that distributed generation might increase revenue requirements.[30] These costs typically include (a) the utility administrative costs of operating net energy metering programs, (b) the utility costs of interconnecting distributed generation technologies to the distribution grid, and (c) the utility costs of integrating intermittent distributed generation into the distribution grid.

[29] If a utility offers some form of an incentive to the host customer, such as a renewable energy credit, then this will represent an incremental cost imposed upon other customers. On the other hand, distributed generation customers provided with net energy metering practices do not require the utility or other customers to incur any new, incremental cost.

[30] Appendix C includes citations for these studies, along with notes on how the numbers in Figure 10 were derived.

Figure 10. Recent studies indicate the extent to which distributed generation benefits exceed costs

As indicated in the figure, all of these studies make the same general point: Distributed generation resources are very cost-effective in terms of reducing utility revenue requirements. In fact, they are generally more cost-effective than almost all other electricity resource options. The results presented in Figure 10 above indicate that distributed generation resources have benefit-cost ratios that range from 9:1 (New Jersey and Pennsylvania) to roughly 40:1 (Colorado, Maine, North Carolina) to as high as 113:1 (Arizona). These benefit-cost ratios are far higher than other electricity resource options, because the host customers typically pay for the cost of installing and operating the distributed generation resource.

Rate designs should be structured to encourage the development of very cost-effective resources, not to discourage them.

This point about distributed generation cost-effectiveness is absolutely essential for regulators and others to understand and acknowledge when making rate design decisions regarding distributed generation, for several reasons:

- The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may possibly even eliminate, any cost-shifting that might occur between distributed generation host customers and other customers.[31]
- When arguments about cost-shifting from distributed generation resources are used to justify increased fixed charges, it is important to assess and consider the likely magnitude of cost-shifting in light of the benefits offered by distributed generation. It is quite possible that any cost-shifting is *de minimis*, or non-existent.
- The net benefits of distributed generation should be considered as an important factor in making rate design decisions. Rate designs should be structured to encourage the

[31] This may not hold at very high levels of penetration, as integration costs increase once distributed generation levels hit a certain threshold. However, the vast majority of utilities in the United States have not yet reached such levels.

development of very cost-effective resources; they should not be designed to discourage them.

Again, policy makers should proceed with caution on claims regarding cost shifting. Where cost shifting is analyzed properly and found to be a legitimate concern, it can be addressed through alternative mechanisms that apply to DG customers, rather than upending the entire residential rate design in ways that can negatively affect all customers.

6. Recent Commission Decisions on Fixed Charges

Commission Decisions Rejecting Fixed Charges

Commissions in many states have largely rejected utility proposals to increase the fixed charge, citing a variety of reasons, including rate shock to customers and the potential to undermine state policy goals. Below are several reasons that commissions have given for rejecting such proposals.

Customer Control

In 2015, the Missouri Public Service Commission rejected Ameren's request to increase the residential customer charge, stating:

> The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control.[32]

Energy Efficiency, Affordability, and Other Policy Goals

The Minnesota Public Utilities Commission recently ruled against a relatively small increase in the fixed charge (from $8.00 to $9.25), citing affordability and energy conservation goals, as well as revenue regulation (decoupling) as a protection against utility under-recovery of revenues:

> In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation. The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory" and the utility's need for revenue sufficient to enable it to provide service.
>
> The Commission concludes that raising the Residential and Small General Service customer charges... would give too much weight to the fixed customer cost calculated in Xcel's class-cost-of-service study and not enough weight to affordability and energy conservation. ... The Commission concurs with the OAG that this circumstance highlights the need for caution in making any decision that would further burden low-income, low-usage customers, who are unable to absorb or avoid the increased cost.

[32] Missouri Public Service Commission Report and Order, File No. ER-2014-0258, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service, April 29, 2015, pages 76-77.

> The Commission also concludes that a customer-charge increase for these classes would place too little emphasis on the need to set rates to encourage conservation. This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability.[33]

Similarly, in March of 2015, the Washington Utilities and Transportation Commission rejected an increase in the fixed charge based on concerns regarding affordability and conservation signals. The commission also reaffirmed that the fixed charge should only reflect costs directly related to the number of customers:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic changes should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.[34]

In 2012, the Missouri Public Service Commission rejected Ameren Missouri's proposed increase in the customer charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[35]

In 2013, the Maryland Public Service Commission rejected a small increase in the customer charge, noting that such an increase would reduce customers' control of their bills and would be inconsistent with the state's policy goals.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the

[33] Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota; Findings of Fact, Conclusions, and Order; Docket No. E-002/GR-13-868, May 8, 2015, p. 88.

[34] Washington Utilities and Transportation Commission, Final Order Rejecting Tariff Sheets, Resolving Contested Issues, Authorizing And Requiring Compliance Filings; Docket UE-140762, March 25, 2015, p. 91.

[35] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

> reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[36]

Commission Decisions Approving Higher Fixed Charges

Higher fixed charges have been rejected in numerous cases, but not all. In many cases, a small increase in the fixed charge has been approved through multi-party settlements, rather than addressed by the commission. Where commissions have specifically approved fixed charge increases, they often cite some of the flawed arguments that are addressed in Chapter 5 above. Below we provide some examples and briefly describe the commission's rationale.

Fixed Charges and Recovery of Distribution System Costs

Over the past few years, Wisconsin has approved some of the highest fixed charges in the country, based on the rationale that doing so will "prevent intra-class subsidies... provide appropriate price signals to ratepayers, and encourage efficient utility scale planning...."[37] This rationale is largely based on two misconceptions: (1) that short-run marginal costs provide an efficient price signal to ratepayers and will encourage efficient electric resource planning, and (2) that recovering certain distribution system costs through the fixed charge is more appropriate than recovering them through the energy charge.[38]

As discussed above, a rate design that fails to reflect long-run marginal costs will result in inefficient price signals to customers and ultimately result in the need to make more electric system investments to support growing demand than would otherwise be the case. Not only will growing demand result in the need for additional generation capacity, it may cause distribution system components to wear out faster, or to be replaced with larger components. Wrapping such costs up in the fixed charge sends the signal to customers that these costs are unavoidable, when in fact future investment decisions are in part determined by the level of system use.

Further, using the fixed charge to recover distribution system costs that cannot be readily classified as "demand-related" or "customer-related" exemplifies the danger that Bonbright warned of regarding using the category of customer costs as a "dumping ground" for costs that do not fit in the other

36 In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

37 Docket 3270-UR-120, Order at 48.

38 For example, Wisconsin Public Service Corporation argued that the fixed charge should include a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors, rather than only the customer-related costs.

categories. Use of the fixed charge for recovery of such costs tends to harm low-income customers, as well as distort efficient price signals.

Despite generally approving significantly higher fixed charges in recent years, in a December 2015 order the Wisconsin Public Service Commission approved only a slight increase in the fixed charge and signaled its interest in evaluating the impacts of higher fixed charges to ensure that the Commission's policy goals are being met. Specifically, the Commission directed one of its utilities to work with commission staff to conduct a study to assess the impacts of the higher fixed charges on customer energy use and other behavior.[39] This order indicates that perhaps the policy may be in need of further study.

Demand Costs Not Appropriate for Energy Charge

In approving Sierra Pacific Power's request for a higher fixed charge, the Nevada Public Service Commission wrote:

> If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable.[40]

Despite declaring that demand-related costs are inappropriately recovered in the energy charge, the commission makes no argument for why the fixed charge is a more appropriate mechanism for recovering such costs. Nor does the commission recognize that customer demand (kW) and energy usage (kWh) are likely correlated, or that recovering demand-related costs in the fixed charge may introduce even greater cross-subsidies among customers.

Settlements

Many of the recent proceedings regarding fixed charges have ended in a settlement agreement. Several of these settlements have resulted in the intervening parties, including the utility, agreeing to make no change to the customer charge or fixed charge. For example, Kentucky Utilities and Louisville Gas & Electric requested a 67 percent increase in the fixed charge, from $10.75 to $18.00 per month. The case ultimately settled, with neither utility receiving an increase in the monthly fixed charge.[41] While

[39] Wisconsin Public Service Commission, Docket 6690-UR-124, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, December 17, 2015.

[40] Nevada Public Service Commission, Docket 13-06002, *Application of Sierra Pacific Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto*, Modified Final Order, January 29, 2014, Page 176.

[41] Kentucky Public Service Commission Order, Case No. 2014-00372, *In the Matter of Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, page 4; Kentucky Public Service Commission Order, Case No. 2014-00371, *In the Matter of Application of Kentucky Utility Company for an Adjustment of its Electric and Gas Rates*, page 4.

settlements seldom explicitly state the rationale behind such decisions, it is safe to expect that many of the settling parties echo the concerns stated by the Commissions above.

In conclusion, the push to significantly increase the fixed charge has largely been rejected by regulators across the country as unnecessary and poor public policy. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason. In addition, in late 2015, it appeared that some utilities were beginning to propose new demand charges for residential customers instead of increased fixed charges.

7. ALTERNATIVES TO FIXED CHARGES

Utilities are turning to higher fixed charges in an effort to slow the decline of revenues between rate cases, since revenue collected through the fixed charge is not affected by reduced sales. In the past, costs were relatively stable and sales between rate cases typically provided utilities with adequate revenue, but this is not necessarily the case anymore. The current environment of flat or declining sales growth, coupled with the need for additional infrastructure investments, can pose financial challenges for a utility and cause it to apply for rate cases more frequently.

Higher fixed charges are an understandable reaction to these trends, but they are an ill-advised remedy, due to the adverse impacts described above. Alternative rate designs exist that can help to address utility revenue sufficiency and volatility concerns, as discussed below. Furthermore, in many cases, utilities are reacting to perceived or future threats, rather than to a pressing current revenue deficiency. Simply stated, there is no need to increase the fixed charge.

Rate Design Options

Numerous rate design alternatives to higher fixed charges are available under traditional cost-of-service ratemaking. Below we discuss several of these options, and describe some of the key advantages and disadvantages of each. No prioritization of the options is implied, as rate design decisions should be made to address the unique circumstances of a particular jurisdiction. For example, the rate design adopted in Hawaii, where approximately 15 percent of residential customers on Oahu have rooftop solar,[42] may not be appropriate for a utility in Michigan.

[42] As of the third quarter of 2015, nearly 40,000 customers on Oahu were enrolled in the Hawaiian Electric Company's net metering program, as reported by HECO on its website: http://www.hawaiianelectric.com/heco/_hidden_Hidden/Community/Renewable-Energy?cpsextcurrchannel=1#05

Status Quo

One option is to simply maintain the current level of fixed charges and allow utilities to file frequent rate cases, if needed. This option is likely to be most appropriate where a utility is not yet facing any significant earnings shortfall, but is instead seeking to preempt what it views as a future threat to its earnings.

By maintaining the current rate structure rather than changing it prematurely, this option allows the extent of the problem to be more accurately assessed, and the remedy appropriately tailored to address the problem. Maintaining the current rate structure clearly also avoids the negative impacts on ratepayers and clean energy goals that higher fixed charges would have, as discussed in detail above.

However, maintaining the status quo may have detrimental impacts on both ratepayers and the utility if the utility is truly at risk of significant revenue under-recovery.[43] Where a utility cannot collect sufficient revenues, it may forego necessary investments in maintaining the electric grid or providing customer service, with potential long-term negative consequences.

In addition, the utility may file frequent rate cases in order to reset rates, which can be costly. Rate cases generally require numerous specialized consultants and lawyers to review the utility's expenditures and investments in great detail, and can drag on for months, resulting in millions of dollars in costs that could eventually be passed on to customers. Because of this cost, a utility is unlikely to file a rate case unless it believes that significantly higher revenues are likely to be approved.

Finally, chronic revenue under-recovery can worry investors, who might require a higher interest rate in order to lend funds to the utility. Since utilities must raise significant financial capital to fund their investments, a higher interest rate could ultimately lead to higher costs for customers. However, such chronic under-recovery is unlikely for most utilities, and this risk should be assessed alongside the risks of overcharging ratepayers and discouraging efficiency.

Minimum Bills

Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. For example, if the minimum bill were set at $40, and the only other charge was the energy charge of $0.10 per kWh, then the minimum bill would only apply to customers using less than 400 kWh, who would otherwise experience a bill less than $40. Given that the national average residential electricity usage is approximately 900 kWh per month, the minimum bill would have no effect on most residential customers.

[43] Of course, the claim that the utility is at risk of substantially under-recovering its revenue requirement should be thoroughly investigated before any action is taken.

A key advantage claimed by proponents to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, without significantly distorting price signals for the majority of customers. The threshold that triggers the minimum bill is typically set well below the average electricity usage level, and thus most customers will not be assessed a minimum bill but will instead only see the energy charge (cents per kilowatt-hour). Minimum bills also have the advantage of being relatively simple and easy to understand.

Minimum bills may be useful where there are many customers that have low usage, but actually impose substantial costs on the system. For example, this could include large vacation homes that have high usage during the peak summer hours that drive most demand-related costs, but sit vacant the remainder of the year. Unfortunately, minimum bills do not distinguish these types of customers from those who have reduced their peak demand (for example through investing in energy efficiency or distributed generation), and who thereby impose lower costs on the system.[44] Further, minimum bills may also have negative financial impacts on low-income customers whose usage falls below the threshold. For these reasons, minimum bills are superior to fixed charges, but they still operate as a relatively blunt instrument for balancing ratepayer and utility interests. Further, utilities will have an incentive to push for higher and higher minimum bill levels.

To illustrate the impacts of minimum bills, consider three rate options: (1) an "original" residential rate structure with a fixed charge of $9 per month; (2) a minimum bill option, which keeps the $9 fixed charge but adds a minimum bill of $40; and (3) an increase in the fixed charge to $25 per month. In all cases, the energy charge is adjusted to ensure that the three rate structures produce the same amount of total revenues. The figure below illustrates how moving from the "original" rate structure to either a minimum bill or increased fixed charge option would impact different customers.

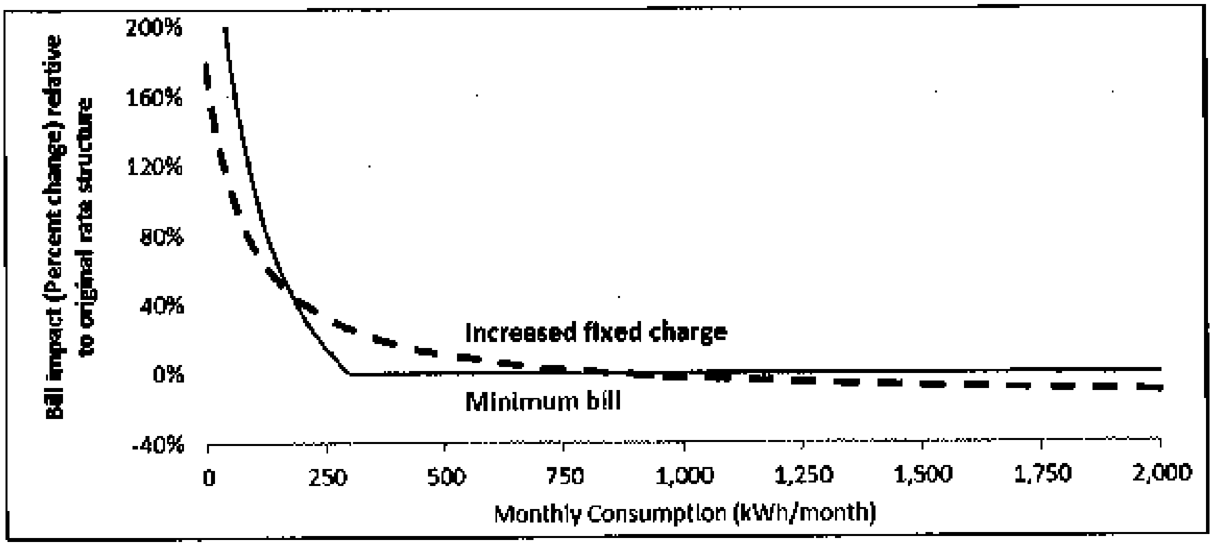
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

In contrast, under the $25 fixed charge, all customers using less than approximately 875 kWh per month (about half of residential customers) would see an increase in their electric bills, while customers using more than 875 kWh per month would see a *decrease* in their electric bills.

[44] In the short run, there is likely to be little difference in the infrastructure investments required to serve customers with high peak demands and those with low peak demands. However, in the long run, customers with higher peak demands will drive additional investments in generation, transmission, and distribution, thereby imposing greater costs on the system. A theoretically efficient price signal would reflect these different marginal costs in some manner in order to encourage customers to reduce the long-run costs they impose on the system.

Figure 11. Impact of minimum bill relative to an increased fixed charge

Rate Structure	Energy Charge	Fixed charge	Minimum bill
Typical rate structure	10.36 cents / kWh	$9 / Month	$0 / Month
Minimum bill	10.34 cents / kWh	$9 / Month	$40 / Month
Increased fixed charge	8.48 cents / kWh	$25 / Month	$0 / Month



Source: Author's calculations based on data from a representative Midwestern utility.

Time-of-Use Rates

Electricity costs can vary significantly over the course of the day as demand rises and falls, and more expensive power plants must come online to meet load.[45] Time-of-use (TOU) rates are a form of time-varying rate, under which electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have separate rates for peak and off-peak periods, but intermediate periods may also have their own rates.

Time-varying rate structures can benefit ratepayers and society in general by improving economic efficiency and equity. Properly designed TOU rates can improve economic efficiency by:

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;
2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

[45] Electricity costs also vary by season and weekday/weekend.

3. Providing appropriate price signals for customer investment in distributed energy resources that best match system needs.

Time-varying rates are also capable of improving equity by better allocating the costs of electricity production during peak periods to those causing the costs.

Despite their advantages, TOU rates are not a silver bullet and may be inappropriate in the residential rate class. They may not always be easily understood or accepted by residential customers. TOU rates also require specialized metering equipment, which not all customers have. In particular, the adoption of advanced metering infrastructure (AMI) may impose significant costs on the system.[46] Residential consumers often do not have the time, interest or knowledge to manage variable energy rates efficiently, so TOU blocks must be few and well-defined and still may not elicit desired results. Designing TOU rates correctly can be difficult, and could penalize vulnerable customers requiring electricity during extreme temperatures. Some consumer groups (such as AARP) urge any such rates be voluntary. Finally, even well-designed TOU rates may not fully resolve a utility's revenue sufficiency concerns.

Value of Solar Tariffs

Value of solar tariffs pay distributed solar generation based on the value that the solar generation provides to the utility system (based on avoided costs). Value of solar tariffs have been approved as an alternative to net metering in Minnesota and in Austin, Texas. In both places, a third-party consultant conducted an avoided cost study (value of solar study) to determine the value of the avoided costs of energy, capacity, line losses, transmission and distribution.

Value of solar tariffs are useful in that they more accurately reflect cost causation, thereby improving fairness among customers. They also maintain efficient price signals that discourage wasteful use of energy, and improve revenue recovery and stability.

However, value of solar tariffs are not easily designed, as there is a lack of consensus on the elements that should be incorporated, how to measure difficult-to-quantify values, and even how to structure the tariff. Value of solar rates are also not necessarily stable, since value-of-solar tariff rates are typically adjusted periodically. However, there is no reason that the tariff couldn't be affixed for a set time period, like many long-term power purchase agreements.

Alternatively, if the value of solar is determined to be less than the retail price of energy, a rider or other charge could be implemented to ensure that solar customers pay their fair share of costs. Regardless of the type of charge or compensation mechanism chosen, a full independent, third-party analysis of the costs and benefits of distributed generation should be conducted prior to making any changes to rates.

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[46] AMI also allows remote disconnections and prepaid service options, both of which can disadvantage low-income customers. See, for example, Howat, J. *Rethinking Prepaid Utility Service: Customers at Risk.* National Consumer Law Center, June 2012.

Demand Charges

Generation, transmission, and distribution facilities are generally sized according to peak demands—either the local peak or the system peak. The peak demands are driven by the consumption levels of all electricity customers combined. Demand charges are designed to recover demand-related costs by charging electricity customers on the basis of maximum power demand (in terms of dollars per kilowatt), instead of energy (in terms of dollars per kilowatt-hour).

Designing rates to collect demand-related costs through demand charges may improve a utility's revenue recovery and stability. Proponents claim that such rates may also help send price signals that encourage customers to take steps to reduce their peak load. These charges have been in use for many years for commercial and industrial customers, but have rarely been implemented for residential customers.

Demand charges have several important shortcomings that limit how appropriate they might be for residential customers. First, demand charges remain relatively untested on the residential class. There is little evidence thus far that demand charges are well-understood by residential customers; instead, they would likely lead to customer confusion. This is particularly true for residential customers, who may be unaware of when their peak usage occurs and therefore have little ability or incentive to reduce their peak demand.

Second, depending on how they are set, demand charges may not accurately reflect cost causation. A large proportion of system costs are driven by system-wide peak demand, but the demand charge is often based on the customer's maximum demand (not the utility's). Thus demand charges do not provide an incentive for customers to reduce demand during the utility system peak in the way that time of use rates do. Theoretically, demand charges based on a customer's maximum demand could help reduce local peak demand, and therefore reduce some local distribution system costs. However, at the residential level, it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Since a customer's maximum demand is typically triggered by a short period of time in which that customer is using numerous household appliances, it is unlikely that this specific time period coincides exactly when other customers sharing the same transformer are experiencing their maximum demands. This averaging out over multiple customers means that a single residential customer's maximum demand is not likely to drive the sizing of a particular piece of distribution-system equipment. For this reason, demand charges for the residential class are not likely to accurately reflect either system or local distribution costs.

Third, few options currently exist for residential customers to automatically monitor and manage their maximum demands. Since customer maximum monthly demand is often measured over a short interval of time (e.g., 15 minutes), a single busy morning where the toaster, microwave, hairdryer, and clothes dryer all happen to be operating at the same time for a brief period could send a customer's bill skyrocketing. This puts customers at risk for significant bill volatility. Unless technologies are implemented to help customers manage their maximum demands, demand charges should not be used.

Fourth, demand charges are not appropriate for some types of distributed generation resources. Some utilities have proposed that demand charges be applied to customers who install PV systems under net energy metering policies. This proposal is based on the grounds that demand charges will provide PV customers with more accurate price signals regarding their peak demands, which might be significantly different with customer-sited PV. However, a demand charge is not appropriate in this circumstance, because PV resources do not provide the host customer with any more ability to control or moderate peak demands than any other customer. A PV resource might shift a customer's maximum demand to a different hour, but it might do little to reduce the maximum demand if it occurs at a time when the PV resource is not operating much (because the maximum demand occurs either outside of daylight hours, or on a cloudy day when PV output is low).

Fifth, demand charges may require that utilities invest in expensive metering infrastructure and in-home devices that communicate information to customers regarding their maximum demands. The benefits of implementing a customer demand charge may not outweigh the costs of such investments.

In sum, most residential customers are very unlikely to respond to demand charges in a way that actually reduces peak demand, either because they do not have sufficient information, they do not have the correct price signal, they do not have the technologies available to moderate demand, or the technologies that they do have (such as PV) are not controllable by the customer in a way that allows them to manage their demand. In those instances where customers cannot or do not respond to demand charges, these charges suffer from all of the same problems of fixed charges: they reduce incentives to install energy efficiency or distributed generation; they pose an unfair burden on low-usage customers; they provide an inefficient price signal regarding long-term electricity costs; and they can eventually result in higher costs for all customers. For these reasons, demand charges are rarely implemented for residential customers, and where they have been implemented, it has only been on a voluntary basis.

8. CONCLUSIONS

In this era of rapid advancement in energy technologies and broad-based efforts to empower customers, mandatory fixed charges represent a step backward. Whether a utility is proposing to increase the fixed charge due to a significant decline in electricity sales or as a preemptive measure, higher fixed charges are an inequitable and economically inefficient means of addressing utility revenue concerns. In some cases, regulators and other stakeholders have been persuaded by common myths that inaccurately portray an increased fixed charge as the necessary solution to current challenges facing the utility industry. While they may be desirable for utilities, higher fixed charges are far from optimal for society as a whole.

Fortunately, there are many rate design alternatives that address utility concerns about declining revenues from lower sales without causing the regressive results and inefficient price signals associated with fixed charges. Recent utility commission decisions rejecting proposals for increased fixed charges suggest that there is a growing understanding of the many problems associated with fixed charges, and that alternatives do exist. As this awareness spreads, it will help the electricity system continue its progression toward greater efficiency and equity.

APPENDIX A – BONBRIGHT'S PRINCIPLES OF RATE DESIGN

In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[47]

[47] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES

The tables below present data on recent utility proposals or finalized proceedings regarding fixed charges based on research conducted by Synapse Energy Economics. These cases were generally opened or decided between September 2014 and November 2015.

Table 1. List of finalized utility proceedings to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Alameda Municipal Power (CA)	AMP Board vote June 2015	$9.25	$11.50	$11.50	
Ameren (MO)	File No. ER - 2012-0166 Tariff No. YE-2014-0258	$8.00	$8.77	$8.00	Company initially proposed $12.00. Settling parties agreed to $8.77. Commission order rejected any increase, citing customer control
Appalachian Power Co (VA)	PUE-2014-00026	$8.35	$16.00	$8.35	
Appalachian Power/Wheeling Power (WV)	14-1152-E-42T	$5.00	$10.00	$8.00	
Baltimore Gas and Electric (MD)	9355, Order No. 86757	$7.50	$10.50	$7.50	Settlement based on Utility Law Judge
Benton PUD (WA)	Board approved in June 2015	$11.05	$15.60	$15.60	
Black Hills Power (WY)	20002-91-ER-14 (Record No. 13788)	$14.00	$17.00	$15.50	
Central Hudson Gas & Electric (NY)	14-E-0318	$24.00	$29.00	$24.00	
Central Maine Power Company (ME)	2013-00168	$5.71	$10.00	$10.00	Decoupling implemented as well
City of Whitehall (WI)	6490-ER-106	$8.00	$16.00	$16.00	
Columbia River PUD (OR)	CRPUD Board vote September 2015	$8.00	$20.45	$10.00	
Colorado Springs Utilities (CO)	City Council Volume No. 5	$12.52	$15.24	$15.24	
Connecticut Light & Power (CT)	14-05-06	$16.00	$25.50	$19.25	Active docket
Consolidated Edison (NY)	15-00270/15-E-0050	$15.76	$18.00	$15.76	Settlement
Consumers Energy (MI)	U-17735	$7.00	$7.50	$7.00	PSC Order
Choptank Electric Cooperative (MD)	9368, Order No. 86994,	$10.00	$17.00	$11.25	PSC approved smaller increase
Dawson Public Power (NE)	Announced June 2015	$21.50	$27.00	$27.00	Based on news articles
Empire District Electric (MO)	ER-2014-0351	$12.52	$18.75	$12.52	Settlement
Eugene Water & Electric Board (OR)	Board vote December 2014	$13.50	$20.00	$20.00	
Hawaii Electric Light (HI)	2014-0183	$9.00	$61.00	$9.00	Part of "DG 2.0"
Maui Electric Company (HI)	2014-0183	$9.00	$50.00	$9.00	Part of "DG 2.0"
Hawaii Electric Company (HI)	2014-0183	$9.00	$55.00	$9.00	Part of "DG 2.0"
Independence Power & Light Co (MO)	City Council vote September 2015	$4.14	$14.50	$4.14	Postponed indefinitely
Indiana Michigan Power (MI)	U-17698	$7.25	$9.10	$7.25	Settlement
Kansas City Power & Light (KS)	15-KCPE-116-RTS	$10.71	$19.00	$14.50	Settlement
Kansas City Power & Light (MO)	File No. ER-2014-0370	$9.00	$25.00	$11.88	
Kentucky Power (KY)	2014-00396	$8.00	$16.00	$11.00	Settlement was $14/month; PSC reduced to $11
Kentucky Utilities Company (KY)	2014-00371	$10.75	$18.00	$10.75	Settlement for KU LGE
Louisville Gas-Electric (KY)	2014-00372	$10.75	$18.00	$10.75	Settlement for KU LGE

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Madison Gas and Electric (WI)	3270-UR-120	$10.29	$22.00	$19.00	
Metropolitan Edison (PA)	R-2014-2428745	$8.11	$13.29	$10.25	Settlement
Nevada Power Co. (NV)	14-05004	$10.00	$15.25	12.75	Settlement
Northern States Power Company (ND)	PU-12-813	$9.00	$14.00	$14.00	Under previous rates, customers with underground lines paid $11/month
Pacific Gas & Electric Company (CA)	R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
PacifiCorp (WA)	UE-140762	$7.75	$14.00	$7.75	Commission order emphasized customer control
Pennsylvania Electric (PA)	R-2014-2428743	$7.98	$11.92	$9.99	Settlement
Pennsylvania Power (PA)	R-2014-2428744	$8.86	$12.71	$10.85	Settlement
Redding Electric Utility (CA)	City Council Meeting June 2015	$13.00	$42.00	$13.00	Postponed consideration until 2/2017
Rocky Mountain Power (UT)	13-035-184	$5.00	$8.00	$6.00	Settlement
Rocky Mountain Power (WY)	20000-446-ER-14 (Record No. 13816)	$20.00	$22.00	$20.00	
Salt River Project (AZ)	SRP Board vote February 2015	$17.00	$20.00	$20.00	Elected board of SRP voted Feb. 26 2015
San Diego Gas & Electric (CA)	A.14-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
Sierra Pacific Power (NV)	13-06002, 13-06003, 13-06004	$9.25	$15.25	$15.25	
Southern California Edison (CA)	A.13-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.94	$10.00	$0.94	$10 minimum bill adopted instead
Stoughton Utilities (WI)	5740-ER-108	$7.50	$10.00	$10.00	
We Energies (WI)	5-UR-107	$9.13	$16.00	$16.00	
West Penn Power (PA)	R-2014-2428742	$5.00	$7.35	$5.81	Settlement
Westar (KS)	15-WSEE-115-RTS	$12.00	$27.00	$14.50	Settlement
Wisconsin Public Service (MI)	U-17669	$9.00	$12.00	$12.00	Settlement
Wisconsin Public Service (WI)	6690-UR-123	$10.40	$25.00	$19.00	
Xcel Energy (MN)	E002 / GR-13-868	$8.00	$9.25	$8.00	Commission order emphasized customer control

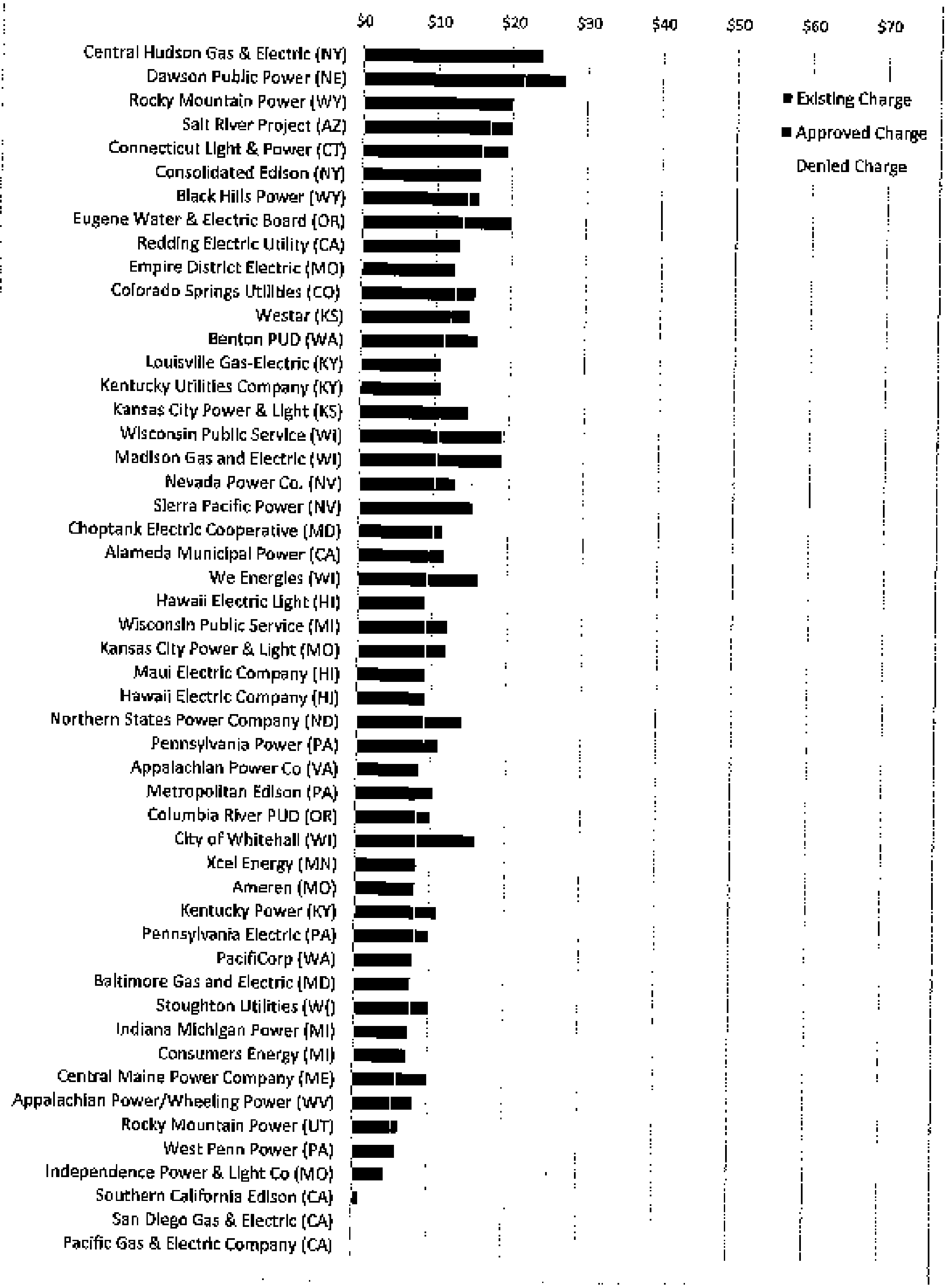
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Avista Utilities (ID)	AVU-E-15-05	$5.25	$8.50		Active docket
Avista Utilities (WA)	UE-150204	$8.50	$14.00		
Detroit Edison (MI)	U-17767	$6.00	$10.00		Proposed order has rejected residential increase
El Paso Electric (TX)	44941	$7.00	$10.00		Public hearings ongoing
El Paso Electric (NM)	15-00127-UT	$5.04	$10.04		Public hearings ongoing
Entergy Arkansas, Inc. (AR)	15-015-U	$6.96	$9.00		Active docket
Indianapolis Power & Light (IN)	44576/44602	$11.00	$17.00		Active docket, values reflect proposal for customers that use more than 325 kWh
Lincoln Electric System (NE)	City council proceeding	$11.15	$13.40		City council decision is pending
Long Island Power Authority (NY)	15-00262	$10.95	$20.38		Rejected by PSC, LIPA Board has ultimate decision
Montana-Dakota Utilities (MT)	D2015.6.51	$5.48	$7.60		BSC based on per day not per month, values converted to monthly
National Grid (MA)	D.P.U. 15-120	$4.00	$13.00		Proposed as part of Grid Mod plan, presented as "Tier 3" customer, for use between 601 to 1,200 kWh per month
National Grid (RI)	RIPUC DOCKET NO. 4568	$5.00	$13.00		Presented as "Tier 3" customer, for use between 751 to 1,200 kWh per month
NIPSCO (IN)	44688	$11.00	$20.00		Active Docket
Omaha Public Power District (NE)	Public power	$10.25	$30.00		Based on news coverage of stakeholder meetings. No specific number submitted, $20, $30, $35 where floated past stakeholders
PECO (PA)	R-2015-2468981	$7.12	$12.00	$8.45	Settlement not yet ratified
Public Service Company of New Mexico (NM)	15-00261-UT	$5.00	$13.14		Public hearings ongoing
Portland General Electric (OR)	UE 294	$10.00	$11.00		Proposed
Pennsylvania Power and Light (PA)	R-2015-2469275	$14.09	$20.00	$14.09	Settlement not yet ratified
Santee Cooper (SC)	State utility	$14.00	$21.00		Pending, expected decision in December 2015
Springfield Water Power and Light (IL)	Municipal board	$5.76	$12.87		Pending as of Oct 1 2015
Sulfur Springs Valley Electric Coop (AZ)	E-01575A-15-0312	$10.25	$25.00		Active docket
Sun Prairie Utilities (WI)	5810-ER-106	$7.00	$16.00		
UNS Electric Inc. (AZ)	E-04204A-15-0142	$10.00	$20.00		Active docket, hearings in March 2016
Xcel Energy (WI)	4220-UR-121	$8.00	$18.00		

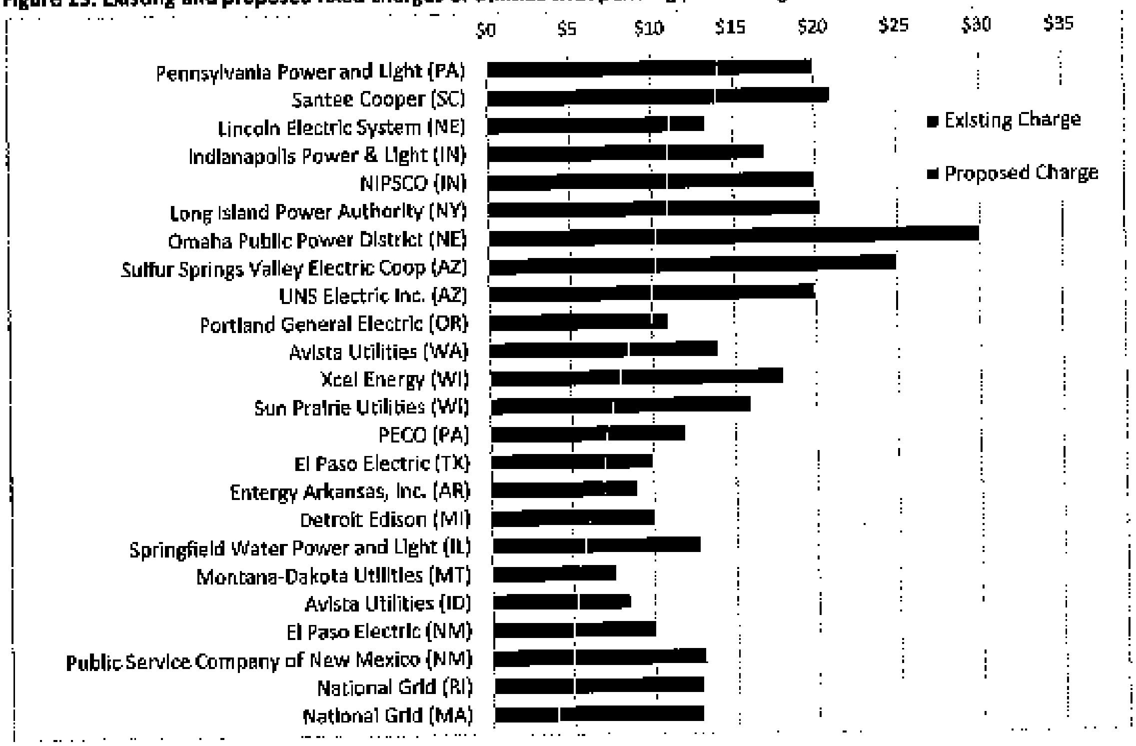
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Figure 13. Existing and proposed fixed charges of utilities with pending proceedings to increase fixed charges

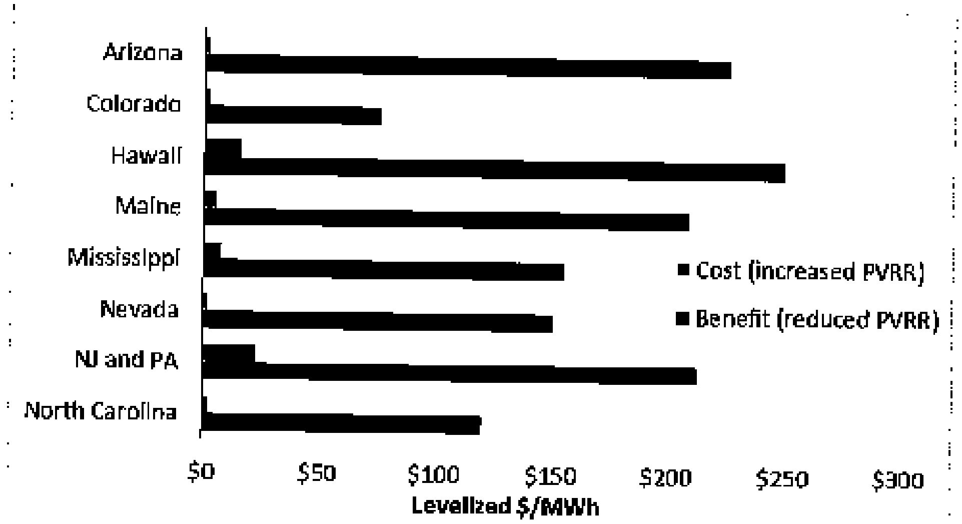


APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS

A utility's revenue requirement represents the amount of revenue that it must recover from customers to cover the costs of serving customers (plus a return on its investments). Customers who invest in distributed PV may increase certain costs while reducing others. Costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost. At the same time, a NEM system will avoid other costs for the utility, such as energy, capacity, line losses, etc. These avoided costs will reduce revenue requirements, and thus are a benefit. These costs and benefits over the PV's lifetime can be converted into present value to determine the impact on the utility's present value of revenue requirements (PVRR).

Over the past few years, at least eight net metering studies have quantified the impact of NEM on a utility's revenue requirement. Key results from these studies are summarized in the table and figure below. Note that only those costs and benefits that affect revenue requirements are included as costs or benefits. If a study included benefits that do not affect revenue requirements (such as environmental externality costs, reduced risk, fuel hedging value, economic development, and job impacts), then they were subtracted from the study results. Similarly, the costs presented below include only NEM system integration, interconnection, and administration costs.[48] Other costs that are sometimes included in the studies but do not affect revenue requirements, such as lost revenues, are not included.

Figure 14. Recent studies indicate extent to which NEM benefits exceed costs



[48] Historically, some utilities have offered incentives to customers that install solar panels (or other NEM installations). While these incentive payments do put upward pressure on revenue requirements, the incentives themselves are removed from Figure 14 and Table 3 to help compare costs and benefits when utility-specific incentives are taken out of the equation.

Table 3. Net metering studies that report PVRR benefits and costs

Year	State	Funded / Commissioned by	Prepared by	Benefit ($/MWh)	Cost ($/MWh)	Benefit-Cost Ratio
2013	Arizona	[illegible]	Crossborder Energy	226*	2	113
2013	Colorado	Xcel Energy	Xcel Energy	75.6	1.8	42
2014	[illegible]	[illegible]	[illegible]	260*	[illegible]	16
2015	Maine	Maine Public Utilities Commission	Clean Power Research, et. al.	209	5	42
2014	Mississippi	Mississippi Public Service Commission	[illegible] Economics	[illegible]	[illegible]	19
2014	Nevada	State of Nevada Public Utilities Commission	E3	150	2	75
[illegible]	[illegible]	[illegible] Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association	Clean Power Research	213*	23*	9*
2013	North Carolina	NC Sustainable Energy Association	Crossborder Energy	120*	3	40

**Indicates that the value displayed in the table is the midpoint of the high and low values reported in the study.*

Source: Synapse Energy Economics, 2015.

Arizona

The Arizona study, performed by Crossborder Energy, presents 20-year levelized values in 2014 dollars.[49] Benefits include avoided energy, generation capacity, ancillary services, transmission, distribution, environmental compliance, and costs of complying with renewable portfolio standards. The avoided environmental benefits account for non-CO_2 market costs of NO_X, SO_X, and water treatment costs, and thus are included as revenue requirement benefits. The benefits range from $215 per MWh to $237 per MWh. Figure 14 and Table 3 present the midpoint value of this range: $226 per MWh. The report estimates integration costs to be $2 per MWh.

Colorado

The Colorado study, performed by the utility Xcel Energy, presents 20-year levelized net avoided costs under three cases in the report's Table 1.[50] The benefits include avoided energy, emissions, capacity, distribution, transmission and line losses. The benefits also include an avoided hedge value, which does not affect revenue requirements. Removing the hedge value from the benefits yields a revenue

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[49] Crossborder Energy. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Page 2. Table 1.

[50] Xcel Energy. 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. Executive Summary, page V.

requirement benefit of $75.6 per MWh. The study estimates solar integration costs to be $1.80 per MWh.

Hawaii

The Hawaii study, performed by E3, presents the 20-year levelized costs and benefits of NEM on the various Hawaii utilities (HECO, MECO, HELCO, and KIUC). The base case NEM benefits are $213 per MWh for KIUC,[51] $234 per MWh for MECO,[52] $242 per MWh for HELCO,[53] and $287 for HECO.[54] Figure 14 and Table 3 present the midpoint of these values: $250 per MWh. The NEM revenue requirement costs are estimated to be $16 per MWh, which includes integration costs ($6 per MWh) and transmission and distribution interconnection costs ($10 per MWh).[55]

Maine

The Maine study, prepared by several co-authors, presents the 25-year levelized market and societal benefits for Central Maine Power Company.[56] The revenue requirement benefits, including avoided costs and market price response benefits, are $209 per MWh. The study estimates the NEM revenue requirement costs to be $5 per MWh, reflecting NEM system integration costs.

Mississippi

The Mississippi study, prepared by Synapse Energy Economics, presents base case 25-year levelized benefits associated with avoided energy, capacity, transmission and distribution, system losses, environmental compliance costs, and risk.[57] The total revenue requirements benefit is $155 per MWh, which excludes the $15 per MWh risk benefit. The NEM administrative costs are estimated to be $8 per MWh.

Nevada

The Nevada study, conducted by E3, presents costs and benefits on a 25-year levelized basis in 2014 dollars. The study estimates the costs and benefits for several "vintages" of rooftop solar. Figure 14 and Table 3 present the vintage referred to as "2016 installations," because this is most representative of

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[51] E3, Evaluation of Hawaii's Renewable Energy Policy and Procurement, January 2014, page 53, Figure 26.

[52] Ibid. Page 50, Figure 23.

[53] Ibid. Page 47, Figure 20.

[54] Ibid. Page 43, Figure 17.

[55] Ibid. Pages 55 and 56.

[56] Clean Power Research, Sustainable Energy Advantage, & Pace Law School Energy and Climate Center for Maine PUC. 2015. *Maine Distributed Solar Valuation Study*. Page 50. Figure 7.

[57] Synapse Energy Economics for Mississippi PSC. 2014. *Net Metering in Mississippi*. Pages 33 and 38.

costs and benefits in the future. The revenue requirement benefits, including avoided costs and renewable portfolio standard value, are estimated to be $150 per MWh. The E3 study also reports the "Incentive, program, and integration costs" to be $6 per MWh.[58] This value includes the integration costs, which were assumed by E3 to be $2 per MWh.[59] Customer incentive costs are not included in any of the results presented in Figure 14 and Table 3, so the revenue requirement costs for Nevada include only the integration costs of $2 per MWh.

New Jersey and Pennsylvania

The New Jersey and Pennsylvania study, prepared by several co-authors, presents the 30-year levelized value of solar for seven locations.[60] The benefits include energy benefits (that would contribute to reduced revenue requirements), strategic benefits (that may not contribute to reduced revenue requirements), and other benefits (some of which would contribute to reduced revenue requirements). To determine the revenue requirement benefits, the benefits associated with "security enhancement value," "long term societal value," and "economic development value" are excluded. The highest reported benefit value was in Scranton ($243 per MWh) and the lowest value was reported in Atlantic City ($183 per MWh). Figure 14 and Table 3 present the midpoint of these two values: $213 per MWh. Similarly, they present the midpoint of the solar integration costs ($23 per MWh).

North Carolina

The North Carolina study, prepared by Crossborder Energy, presents 15-year levelized values in 2013 dollars per kWh. The benefits are presented for three utilities separately. A high/low range of benefits were presented for each benefit category (energy, line losses, generation capacity, transmission capacity, avoided emissions, and avoided renewables). The low avoided emissions estimate reflects the costs of compliance with environmental regulations, which will affect revenue requirements, but the high avoided emissions estimate reflects the social cost of carbon, which will not affect revenue requirements. Therefore, the low avoided emissions value ($4 per MWh) is included, but the incremental social cost of carbon value ($18 per MWh) is excluded. The lowest revenue requirement benefit presented in the study is $93 per MWh for DEP, and the highest one is $147 per MWh for DNCP (after removing the incremental social cost of carbon). Figure 14 and Table 3 present the midpoint between the high and low values, $120 per MWh, as the revenue requirement benefit. The study also identifies $3 per MWh in revenue requirement costs.

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[58] E3 for Nevada PUC. 2014. *Nevada Net Energy Metering Impacts Evaluation*. Page 96.

[59] Ibid. Page 61.

[60] Clean Power Research for Mid-Atlantic & Pennsylvania Solar Energy Industries Associations. 2012. *The Value of Distributed Solar Electric Generation to NJ and PA*. Page 18.

GLOSSARY

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. (See Marginal Cost Pricing, Value-Based Rates.)

Capacity: The maximum amount of power a generating unit or power line can provide safely.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility (see Value-Based Rates).

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or Critical Peak Pricing (CPP): Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer Charge: A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.

Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a certain period. The charge may be designed in many ways. For example, it may be based on a customer's maximum demand during a monthly billing cycle, during a seasonal period, or during an annual cycle. In addition, some demand charges only apply to a customer's maximum demand that coincides with the system peak, or certain peak hours. Typically assessed in cents per kilowatt.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. (See Marginal Cost.)

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed (i.e., cents per kilowatt-hour).

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

Flat Rate: A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Inverted Rates/Inclining Block Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Load Shape: The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Long-Run Marginal Costs: The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. (See Embedded Cost.)

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

Rate Case: A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs.

Straight Fixed Variable (SFV) Rate Design: A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Time-of-Use Rates: A form of time-varying rate. Typically the hours of the day are segmented to "off-peak" and "peak" periods. The peak period rate is higher than the off-peak period rate.

Time-Varying Rates: Rates that vary by time of day in order to more accurately reflect the fluctuation of costs. A common, and simple form of time-varying rate is time-of-use rates.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. (See Short Run Marginal Cost.)

Volumetric Rate: A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the customer (e.g., cents/kWh, or cents/kW). May also be referred to as the "variable rate." If referring to cents per kilowatt-hour, it is often referred to as the "energy charge."

Adapted from Lazar (2011) "Electricity Regulation in the US: A Guide." Regulatory Assistance Project.

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MEMORANDUM

DATE: September 19th 2017

TO: RPU Board Members

FROM: Mark Kotschevar

SUBJECT: Customer Charge Research

In preparation for continued discussion regarding the proposed rate changes I have assembled some additional information for the Board to consider. I believe you have received a spreadsheet listing the customer charges currently in effect for many Municipal, Cooperative, and Investor Owned utilities in Minnesota. There is a wide range in the figures which begs the question of why.

Both Xcel Energy and Minnesota Power have had recent rate cases before the Minnesota Public Utilities Commission and as part of that process supplied written testimony in support of their proposed rate changes. In Xcel's case while they proposed a $2.00 per month increase in the customer charge they made it clear that their actual cost of service customer charge should be $18.65 for 2016 and $19.74 for 2017. They state "*The objective of this proposal is to improve fairness between all customers and to provide more appropriate and economically effective price signals.*"

In Minnesota Power's rate case they proposed an increase of $1.00 per month to the customer charge and testified to a cost of service based customer charge of $26.35 per customer per month. They state "*The proposed $9.00 monthly Service Charge does not come close to recovering residential customer-related service connection costs.*" Minnesota Power goes on to discuss how their customer charge compares to the cooperatives they serve with wholesale power and energy. They note the lowest being $18.00 per month and the highest being $43.00 per month. They conclude those charges to be a good proxy for the level of service charge Minnesota Power customers could reasonably afford given they live in the same region and are subject to the similar economic conditions and challenges as the cooperative members.

I have included the relevant pages from both utilities testimony for reference. Xcel's testimony goes on to discuss the fairness of pricing based on cost responsibility and how accurate pricing helps customers make decisions. One key point they make is it becomes increasingly important that the economic value of future energy usage and supply options not be distorted by large differences between electric pricing and electric service costs.

It is clear from the research that the Minnesota Public Utilities Commission has adopted a practice of deviating from cost of service principles and is keeping the investor owned utilities customer charge artificially low.

The cooperative utilities have had a unified effort to align their customer charge with the true cost of service for some time. As you can see from the spreadsheet the majority have customer charges above RPU's proposed charge and above most municipals. They are governed similar to municipals with rates being set by a board of directors elected from their membership. One could conclude the cooperatives have adopted a cost of service rate setting policy similar to the RPU Board.

The adoption of cost based rates for the municipals has been on a slower pace. I did discuss customer charges with the Austin, Owatonna, and New Prague general managers. They all confirmed they currently charge less than the true cost of service. All three noted their actual cost of service customer charge is in the $20.00 to $24.00 per month range. Austin has been working to slowly increase their customer charge by applying all of their last rate increase to the customer charge. Owatonna will be conducting a cost of service study in the near future and intends to work towards true cost of service. This is consistent with conversations I have had with other municipal utilities at recent MMUA meetings. Mark Beauchamp, our rate consultant, also affirmed the average cost of service customer charge he sees in his work nationally is in the $20.00 range. Both the Minnesota Municipal Utilities Association and the American Public Power Association encourage public power utilities to align their rates with actual costs. RPU is ahead of the majority of municipals in setting the customer charge at true cost of service. Many years ago the Board made the commitment to have cost based rates and chose to work that direction slowly over time. The current Board reaffirmed that policy this year with the revised rate policy. Based on the small increases to the customer charge proposed for the next two years we are very close to accomplishing this important goal.

A concern has been expressed that increasing the customer charge creates a negative impact to conservation. While intuition may lead you to that conclusion, our data does not support that outcome. We have increased our customer charge from $14.50 in 2009 to $17.40 in 2016. During that same time frame we were able to more than double our residential kilowatt hours saved through the Conserve and Save program from 2,438,175 kWh in 2009 to 5,276,136 kWh in 2016. In addition to kWh savings, the number of residential rebates processed during this time frame increased by over 10,000. This supports a conclusion that the customer charge does not adversely impact our customer's decisions regarding conservation or our ability to comply with the State's conservation improvement program.

I hope this information helps you understand the reason for differences in customer charges across Minnesota and provides you with some background as discussion continues on the proposed rate changes. Please feel free to contact me if you have questions or need additional information.

Table 5
Base Program Surcharges – TY 2016

Customer Class	Present	Proposed
Residential	$0.53	$0.75
C&I Non-Demand	$0.71	$0.90
C&I Demand	$2.13	$1.94

D. Rate Design Proposals

Q. IS THE COMPANY PROPOSING ANY SIGNIFICANT RATE DESIGN CHANGES IN THIS CASE?

A. No. We are proposing to maintain the current rate design structure. Proposed rates generally include only minor changes to the relationship between rate components. More significant changes are described in the follow sections.

1. *Residential and Small Commercial Customer Charges*

Q. DOES THE COMPANY PROPOSE TO INCREASE THE CUSTOMER CHARGE FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Yes. We propose a $2.00 increase to the fixed monthly customer charge for residential and small commercial customers. This proposal is for the following rate schedules: Residential Service, Residential Time-of Day Service, Small General Service, and Small General Time-of Day Service. This is a moderate proposal for pricing that more precisely represents the different types of electric service costs, including fixed customer related costs and variable energy related costs. The objective of this proposal is to improve fairness between all customers and to provide more appropriate and economically effective price signals.

Q. WHY IS ACCURATELY REPRESENTING THE DIFFERENT TYPES OF ELECTRIC SERVICE COSTS AN IMPORTANT CONSIDERATION FOR PRICING?

A. In addition to the basic fairness of having prices that more closely distribute cost responsibility, accurate pricing gives customers the necessary information to make the energy usage and supply decisions that minimize system costs and extract the maximum value from energy resources. The need for accurate cost information through pricing is growing as customers are increasingly able to respond to electric pricing. Improving technology, such as for renewable distributed generation resources and battery storage, gives customers more options for making decisions about energy usage and supply options. As customers have more options, it becomes increasingly important that the economic value of those options not be distorted by large differences between electric pricing and electric service costs.

Q. WHY ARE SUCH DISTORTIONS HARMFUL?

A. When energy prices exceed variable cost, as required to recover fixed costs excluded from customer charges, customers have an economically unsupported extra incentive for purchasing their own generation sources. However, what is good for the individual customer in this case is not good for other customers and does not lead to minimizing system costs. Rather than contributing to the recovery of fixed costs included in energy prices, such customers have an incentive and often the ability to respond to their over allocation of fixed costs from a below cost customer charge, which simply ends up unnecessarily raising the cost to all other customers.

Energy prices that overly subsidize fixed customer related costs also overburden customers with above-average energy usage that occurs not from a lack of conservation, but from unavoidable individual circumstances such as an above-average household size or a reliance on electric appliances such as water heaters or clothes dryers that more commonly operate with natural gas.

Q. DOES ADDING FIXED COST TO THE ENERGY PRICE PROVIDE A CONSERVATION INCENTIVE?

A. Yes. That much is clear, but the larger issue is the reasonable extent of that extra conservation incentive. As a policy issue, some non-cost-based addition to energy prices can be reasonable, but there are also disadvantages of such an approach that should be acknowledged. These include disincentives to minimizing total system costs and reducing equity between customers. An added conservation incentive can be reasonable, but it should not rise to the level of punitively reducing the value of electricity to conservation minded customers with unavoidable individual circumstances that result in above-average electric energy usage.

Q. DOES THE CUSTOMER CHARGE PROPOSAL RETAIN A SUBSTANTIAL CONSERVATION INCENTIVE IN ENERGY PRICES?

A. Yes. Residential Service has four customer charge levels based on service distinctions, with a weighted average present customer charge of $8.72. This average is $10.72 with the proposed $2.00 increase, which is only 57 percent of the $18.65 fixed customer-related cost shown in the Company's proposed test year 2016 CCOSS, and 54 percent of the $19.74 cost for plan year 2017. For residential customers, this $8.00 per month cost differential would transfer over $96 million of fixed customer-related costs to be recovered through proposed energy prices.

Similar to the Residential Service cost relationship, the Small General Service present customer charge of $10.00 is proposed to change to $12.00, which is [redacted] Company's proposed test [redacted]

Q. IS REVENUE STABILITY THE REASON FOR THE PROPOSED CUSTOMER CHARGE INCREASE?

A. No. Revenue stability, while providing benefits to utilities and its customers, is not a primary reason for the Company's proposal. Although the proposal would increase revenue stability, the main purpose of the proposal is to more precisely recognize electric service costs and to improve equity between customers. Ultimately, the ability to minimize future system costs through more accurate pricing is a significantly more important consideration than revenue stability. Although the Company has a new decoupling rate provision that helps to stabilize revenues, that provision does not address customer equity or reduce the need for accurate pricing.

Q. WHAT IS THE NET IMPACT OF PROPOSED ENERGY CHARGES AND THE $2.00 PROPOSED CUSTOMER CHARGE INCREASE?

A. The incremental customer impact of the proposed customer charge is $2.00 per month only for a customer with no energy usage. The $2.00 increase is fully offset by the energy charge at the customer average usage of 620 kWh for standard residential customers. At relatively low monthly usage of 310 kWh, the net incremental customer charge impact is a $1.00 monthly increase.

Q. DO THE PROPOSED PERCENT INCREASES FOR JUST THE CUSTOMER CHARGE COMPONENT INDICATE ITS REASONABLENESS?

conservation, we increased the rate for the second/higher block by more (compared to the average of the three existing blocks being combined) than we increased the first block (compared to the average of the two existing blocks being combined).

Q. Please explain Minnesota Power's proposed modification to the standard Residential Service Charge.

A. Because Minnesota Power is proposing a reduction in the number of energy charge blocks in its inclining block rates, which will flatten the rates and cause customers in the existing smallest usage block (0 to 300 kWh) to pay more for that usage, we are requesting only a modest increase to the monthly service charge. Minnesota Power proposes to increase the Residential monthly service charge by $1.00 per month, from $8.00 per month to $9.00 per month. This proposed increase of approximately 13 percent is similar to the rate of inflation over the past seven years since Minnesota Power's last rate case. As illustrated below, it is also a much smaller increase than neighboring distribution cooperatives, some of which serve customers literally across the street from Minnesota Power customers, have experienced over the past seven years since Minnesota Power's last rate case.

The proposed $9.00 monthly Service Charge does not come close to recovering residential customer-related service connection costs. The Company's test year cost-of-service study indicates residential customer costs of $26.35[12] per customer per month. However, recognizing the historical opposition to significant increases in the monthly service charge for Minnesota utilities that are regulated by the Commission, Minnesota Power has chosen to moderate the proposed increase at this time.

Q. How does Minnesota Power's proposed Residential Service Charge of $9.00 per month compare to neighboring electric utilities in northeastern Minnesota?

A. It is extremely low in comparison. While preparing its last retail rate case in 2009 and in 2016 for purposes of this filing, Minnesota Power researched the monthly

[12] Volume IV, Schedule E-2, page 104 of 104.

service charges of several distribution cooperatives that provide electric service to customers adjacent to Minnesota Power's service territory. Minnesota Power considers these service charges to be a good proxy for the level of service charge Minnesota Power customers could reasonably afford because the customers/members of cooperatives live in the same region as Minnesota Power customers and are subject to similar economic conditions and financial challenges. In addition, the distribution cooperatives' service charge is essentially approved by its members through their member-elected Boards of Directors. Monthly service charge information was gathered for the following cooperatives:

Table 4

Cooperative (headquarters and service center locations shown in parentheses)	**2009 Monthly Service Charge**	**2016 Monthly Service Charge**
Cooperative Light & Power (Two Harbors)	$16.00	$27.00
Crow Wing Power (Brainerd)	$12.00	$18.00
East Central Energy (Braham)	$16.00	$28.75
East Itasca-Mantrap (Park Rapids)	$16.50	$33.00
Lake Country Power (Grand Rapids, Virginia, and Kettle River)	$20.00	$42.00
Mille Lacs Energy Cooperative (Aitkin)	$24.00	$25.00
North Itasca Electric Cooperative (Bigfork)	$31.50	$43.00

Among these seven distribution cooperatives, the lowest current residential customer charge is $18.00 per month (Crow Wing Power), and the highest is $43.00 per month (North Itasca), with an average of $30.96 per month. Minnesota Power's proposed monthly Service Charge of $9.00 is less than one-third of the average level and only half of the lowest of the group of neighboring cooperative utilities.

Q. How would these proposed changes to Residential rates affect low-income customers on the CARE Rider?

A. First, Minnesota Power proposes no change to the $7.00 per month service charge for our CARE customers. Second, Minnesota Power proposes to reduce the number of energy charge blocks in the CARE Rider rates, to match the proposed two-block block structure for standard Residential rates. Along with this restructuring of the CARE Rider rates, we also propose to revise the "RATE MODIFICATION" section

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October 20, 2017

Rochester Public Utilities Board members,

As you know, the Rochester Public Utilities Board is considering a total revenue increase from the residential customer class of 4.2 percent over the next two years to cover expenses for providing service. Part of this rate increase proposal includes raising the residential customer charge from $18.76 per month to $20.50 per month. While the customer charge is necessary to recover some costs incurred specifically by individual customers, the current and proposed amounts of the residential customer charge are unjustifiably high and reduce the incentive for customers to use less.

The customer charge under consideration by the Board is supported by a Class Cost of Service Study. In this study, all the costs incurred and revenues collected by the utility are added up and spread across all the customers on the utility's system. Some of those costs are related to how much energy customers use and some are related to the cost to connect a customer to the system, called "customer-related" costs. These customer-related costs are recovered through the customer charge. While Class Cost of Service Studies are common in utility ratemaking processes, alternative methodologies can be used and different approaches yield different results. At some point it's more art than science, more a policy decision than a concrete analytical answer.

This is the case when it comes to customer-related costs and customer charges. Some costs, like meters and the connection from a customer's home to the utility system, are widely considered customer-related costs and appropriately included in the customer charge. But other costs, like distribution and transformer costs, are not considered customer-related in some methodologies and are regularly debated in utility ratemaking processes.

Guidance issued by the National Association of Regulatory Utility Commissioners (the association of officials in all U.S. states and provinces that regulate privately-owned utilities) defines customer-related costs as the "costs of billing and collection, providing service information, and advertising and promotion of utility services,"[1] and costs that are related solely to adding or removing one customer from the system.[2] Meters and service connections correctly fall under the category of costs directly related to the addition or removal of one customer from the system.

Notably, this guidance does not include distribution, substation, or transformer costs as customer-related. Importantly, these costs are often shared by numerous customers, and do not necessarily

[1] National Association of Regulatory Utility Commissioners. *Electric Utility Cost Allocation Manual.* January 1992. Page 102. https://efile.mpsc.state.mi.us/efile/docs/17689/0078.pdf.
[2] *Id* at 144.

change with the addition or removal of one customer on the utility system. Yet the Class Cost of Service Study used to develop the recommended increases to the residential customer charge for Rochester Public Utilities' residential customers classifies some distribution, substation, and transformer costs as customer-related. In fact, these costs make up $10.30, nearly 50 percent, of the total $21.60 suggested customer-related costs in the study. Removing these costs, while keeping all the customer-related costs recommended by the National Association of Regulatory Utility Commissioners, results in a recommended customer charge amount of $11.30.

As mentioned above, the final decision on the appropriate amount of the customer charge often comes down to policy rather than analytically determining the perfect number. One main policy driver to consider is preserving the economic incentive for customers to use less energy. Minnesota statute codifies this policy in regulating privately-owned utilities, stating that "to the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use."[3] An important part of achieving this goal is the customer charge.

The interplay between the customer charge portion of your bill, which doesn't change from month to month, and the energy charge portion, which depends on how much energy you use, is a zero-sum game. If the customer charge goes up, the energy charge goes down. In this case the customer has less influence over their bill through how much energy they use, and thus less to gain from reducing energy use through investing in energy efficiency or changing behavior. This can have implications in month-to-month bills, but is also important when a customer is considering the payback of purchasing an energy efficient appliance over a non-efficient one.

There are other reasons to avoid raising the customer charge for Rochester Public Utilities' residential customers, but the two reasons laid out above offer strong arguments for at least keeping the customer charge at its current level. Based on alternative but widely used interpretations of customer-related costs the current customer charge is too high, and raising the customer charge reduces the economic benefits for customers who save energy and reduce waste.

I encourage you to consider these arguments as you discuss and vote on the residential customer charge proposal in this ratemaking process. Please feel free to contact me with any questions.

Sincerely,

Will Nissen
Director, Energy Performance
Fresh Energy
651-294-7143
nissen@fresh-energy.org

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[3] Minn. Stat. § 216B.03. https://www.revisor.mn.gov/statutes/?id=216B.03

22 October 2017

Rochester Public Utilities
400 E. River RD. NE
Rochester MN 55906

Attn. Tony Benson (tbenson@rpu.org

Re: 2017-2018 rate setting

Thank you for the opportunity to comment, as a customer and advocate, on the proposed rates. These are a continuation of comments made at the rate setting in 2014 for the 2014-2017 three year period.

Municipal utilities enjoy the absence of rate approval processes involving the Public Utilities Commission. This has been supported by the legislature because, it is said, municipal utilities have a direct responsibility to their customers rather than to stockholders as in for profit utilities. While this distinction may be true in the abstract, it does not necessarily hold true in the real world. The PUC process has the advantage of input from advocates on behalf of the customer base, in the RPU rate setting process, this year and in 2014, the suggested rates are advanced by a retained consultant and it is difficult for customers to intelligently review them, let alone comment appropriately. The customers then are dependent on the utility board for their protection, however, again you, the board, do not necessarily have access to alternative rate suggestions. This year three of the board were new and two held over from the previous, 2014, setting. Two of the new members, we were told, were trained at a conference sponsored by the national municipal utility organization, customers do not have access to those materials so there is no way to understand the arguments advanced. The third was briefed by the rate consultant whose proposal is now before the board.
During the 2014 - 2017 period I furnished members with materials reflecting expert concern about the impact of utility rates on low income customers and on the rate impact on conservation.
The Consumers Union report prepared by Synapse Energy Economics clearly demonstrated that low income consumers were "hit hardest by fixed customer charges", 'that they caused a loss of control by customers, reduced incentives for energy efficiency, and ultimately increased the costs of energy".
I would add that taxpayers ultimately shoulder the costs of high energy bills via programs that support low and moderate income rate payers.
I have also sent you a report on the "Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives" prepared by the Lawrence Berkley National Laboratory, June 2016. This document has the advantage, as the title indicates, of not being an advocacy paper but rather tries to present the, possibly, conflicting points of view.
You have also had access to positions of the NAACP on utility costs and shutoff policies, and AARP advocacy for low income and other fixed income users.

Fresh Energy, the Minnesota group, has submitted comments and details on the position of RPU consumer charges near the highest among municipal utilities, and comparing them to charges by the large utilities regulated by the PUC.
I have not attached these large files since they have been furnished to you, I will be glad to do so if asked.
In your role as advocate for RPU customers, in particular those of low and fixed income, you may consider the evidence presented that those individuals are disproportionally harmed by the fixed charges, and conclude that less reliance on those charges is in the best interests of your customers.
Staff has argued that your newly established policy requires you to adopt rates that reflect the equality of users, it is unfortunate that when you adopted this earlier this year that we did not have the impact of it on rates. However, the idea that you are now prevented from looking at all aspects of our rates is not logical or appropriate.
Obviously increasing any portion of rates will have an impact on customers, and the impact will be greatest on those least able to pay them, moving income from the "customer charge" to the unit cost will increase those costs and the bill of customers, however, it does give many consumers the opportunity to reduce usage and their bill.
You also have the opportunity to modify your proposed rate structure to ameliorate the impact on those users. You know friends and neighbors who close off rooms, both RPU and the gas company participate in cost saving upgrades. The fixed rates that do not support conservation are not logical.
The argument of the utility group that fixed customer charges are necessary for the survival of the utility, is dramatic but hardly supported by facts. The industry is changing, use is being reduced, distributed generation is increasingly becoming standard, renewable energy, time of use pricing, tiered pricing, and other measures are part of the package. Fixed charges based on actual costs may be appropriate, but Fresh Energy has shown that the proposal includes charges that are not appropriately categorized; equally decoupling, which simply guarantees that income will cover costs, may be better.

Again thank you for the opportunity to comment.

Raymond F. Schmitz
210 14th St NE
Rochester MN 55906

FUTURE ELECTRIC
Utility Regulation

RECOVERY OF UTILITY FIXED COSTS: UTILITY, CONSUMER, ENVIRONMENTAL AND ECONOMIST PERSPECTIVES

Lisa Wood, Institute for Electric Innovation and The Edison Foundation, and **Ross Hemphill**, RCHemphill Solutions

John Howat, National Consumer Law Center

Ralph Cavanagh, Natural Resources Defense Council

Severin Borenstein, University of California, Berkeley

*With a literature review by **Jeff Deason and Lisa Schwartz**, Lawrence Berkeley National Laboratory*

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Ralph Cavanagh is co-director of the Natural Resources Defense Council's energy program, which he joined in 1979. Cavanagh has been a Visiting Professor of Law at Stanford and University of California, Berkeley, Law School and a Lecturer on Law at the Harvard Law School. He also has been a faculty member for the University of Idaho's Utility Executives Course for more than 20 years. From 1993 to 2003 he served on the U.S. Secretary of Energy's Advisory Board. His current board memberships include the Alliance to Save Energy, the Bipartisan Policy Center, the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, and Renewable Northwest. Ralph has received the Heinz Award for Public Policy and the National Association of Regulatory Utility Commissioners' Mary Kilmarx Award.

John Howat has been involved with energy programs and policies since 1981, including the past 17 years at National Consumer Law Center (NCLC). He manages projects in support of low-income consumers' access to affordable utility services, working with clients in 30 states on design and implementation of low-income energy affordability and efficiency programs, utility consumer protections, rate design and metering technology. He has testified as an expert witness in 14 states and is a contributing author of NCLC's treatise, *Access to Utility Service*. Previously, he served as Research Director of the Massachusetts Joint Legislative Committee on Energy, Economist with the Electric Power Division of the Massachusetts Department of Public Utilities, and Director of the Association of Massachusetts Local Energy Officials. Howat has a master's degree from Tufts University's Graduate Department of Urban and Environmental Policy and a Bachelor of Arts degree from The Evergreen State College.

Ross C. Hemphill is an independent consultant on regulatory and energy policy issues. His career over more than 35 years has been devoted to energy and regulatory policy with a primary focus on ratemaking theory and practice. Hemphill has worked for utilities, research institutions and regulatory agencies, both directly and as a consultant, including on the staff of the Illinois Commerce Commission, with AEP Service Corp., the National Regulatory Research Institute, Argonne National Laboratory and Niagara Mohawk Power. Most recently, he was vice president of Regulatory Policy & Strategy for Commonwealth Edison.

Lisa Wood is Vice President of The Edison Foundation and Executive Director of the Institute for Electric Innovation (IEI). At IEI she collaborates with a Management Committee of over 20 electric utility CEOs and provides thought leadership on current issues and innovation in the electric power industry. Under Wood's leadership, IEI released its fourth book in December 2015, *Key Trends Driving Change in the Electric Power Industry*. Wood is a Nonresident Senior Fellow in the Energy Security and Climate Initiative at The Brookings Institution and an Adjunct Professor at Johns Hopkins University's School of Advanced International Studies. She serves on several boards including the Advisory Board of *Current*, GE's new energy business. Prior to launching IEI, Wood was a principal with *The Brattle Group*, a principal with PHB Hagler Bailly, and a Program Director at RTI International. Wood holds a Ph.D. in Public Policy and Management from the Wharton School of the University of Pennsylvania and an M.A. from the University of Pennsylvania.

Jeff Deason is a Program Manager in the Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory (Berkeley Lab). He focuses on energy efficiency research and technical assistance projects in the areas of policy, program design, implementation and evaluation. Prior to joining Berkeley Lab he spent five years as principal and senior analyst at the Climate Policy Initiative, leading its energy efficiency practice, including a variety of projects at the state, national and international levels. He also provided advice to policymakers and foundations, analyzed impacts of policies, and produced publications and journal articles. He is in the final stages of a Ph.D. program in public policy at University of California, Berkeley, where he completed degrees in resource economics and behavioral economics.

Lisa Schwartz leads Berkeley Lab's energy efficiency team and utility regulation work in the Electricity Markets and Policy Group. Before that, she was director of the Oregon Department of Energy, where earlier in her career she served as a senior policy analyst. At the Oregon Public Utility Commission for seven years, she led staff work on resource planning and procurement, demand response, and distributed and renewable resources. She also worked for several years with the Regulatory Assistance Project, a global, nonprofit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing assistance to government officials on a broad range of energy and environmental issues.

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Chair Audrey Zibelman, New York State Public Service Commission
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Other reports in this series

Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future (November 2015)

Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight (October 2015)

Performance-Based Regulation in a High Distributed Energy Resources Future (January 2016)

Distribution System Pricing With Distributed Energy Resources (May 2016)

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Reports are available at **feur.lbl.gov**. Additional report topics will be announced.

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in magnitude to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity related to implications are similar. The U.S. Department of Energy (DOE) played a useful role by sponsoring a series of in-depth papers on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues to inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of challenges and opportunities created by new and improved technologies, changing customer and societal expectations and needs, and structural changes in the electric industry. Some technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To provide future reliable and affordable electricity, power sector regulatory approaches may require reconsideration and adaptation to change. Historically, major changes in the electricity industry often came with changes in regulation at the local, state or federal levels.

DOE is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Introduction to This Report

Utilities recover costs for providing electric service to retail customers through a combination of rate components that together comprise customers' monthly electric bills. Rates and rate designs are set by state regulators and vary by jurisdiction, utility and customer class. In addition to the fundamental tenet of setting fair and reasonable rates, rate design balances economic efficiency, equity and fairness, customer satisfaction, utility revenue stability, and customer price and bill stability.[1]

At the most basic level, retail electricity bills in the United States typically include a fixed monthly customer charge — a set dollar amount regardless of energy usage — and a volumetric energy charge for each kilowatt-hour consumed.[2] The energy charge may be flat across all hours, vary by usage level (for example, higher rates at higher levels of usage), or vary based on time of consumption.[3]

While some utility costs, such as fuel costs, clearly vary according to electricity usage, other costs are "fixed" over the short run — generally, those that do not vary over the course of a year. Depending on your point of view, and whether the state's electricity industry has been restructured or remains vertically integrated, the set of costs that are "fixed" may be quite limited. Or the set may extend to all capacity costs for generation, transmission and distribution. In the long run, all costs are variable.

In the context of flat or declining loads in some regions, utilities are proposing a variety of changes to retail rate designs, particularly for residential customers, to recover fixed costs.

In this report, authors representing utility (Chapter 1), consumer (Chapter 2), environmentalist (Chapter 3) and economist (Chapter 4) perspectives discuss fixed costs for electric utilities and set out their principles for recovering those costs. The table on the *next page* summarizes each author's relative preferences for various options for fixed cost recovery, some of which may be used in combination.[4] The specific design of any ratemaking option matters crucially, so a general preference for a given option does not indicate support for any particular application.

A literature review at the end of the report (Chapter 5) defines each of these options and highlights current practices, potential pros and cons, and the diversity of views held by a wide range of energy experts.

[1] See, for example, Hledik and Lazar (2016), report #4 in the Future Electric Utility Regulation series: feur.lbl.gov.
[2] Large customers also have a demand charge based on their highest electricity demand during a specified time interval, typically not limited to coincidence with the utility system peak, such as any 15-minute period over the course of the billing period.
[3] Several other charges may be separately shown on electric bills, such as taxes, franchise fees, rate credits and public purpose charges (also called system benefit charges, a percentage-based fee on electric bills that provides stable funding for energy efficiency programs and sometimes additional programs — for example, to support renewable resources and services for low-income households).
[4] The order in which these options are addressed varies among authors.

Table i. Summary of Authors' Preferences on Approaches to Fixed Cost Recovery

	Wood/Hemphill (utility)	Howat (consumer)	Cavanagh (environmental)	Borenstein (economist)
Higher fixed charges	Good	Poor	Poor	Better[1]
Minimum bills	Poor	Preferred	Preferred	Poor
Demand charges	Good	Poor	Good[2]	Poor
Time-varying rates	Poor	Preferred	Preferred	Preferred[3]
Tiered rates	Poor	Preferred	Preferred	Poor
Revenue decoupling	Poor	Preferred[4]	Preferred[5]	Poor
Frequent rate cases	Good[6]	Better	Poor	Poor
Formula rate plans	Preferred	Good[7]	Good	Poor
Lost revenue adjustment mechanisms	Poor	Poor	Poor	Poor

○ Poor ◒ Better ◓ Good ● Preferred

[1] First set volumetric price to reflect actual social marginal costs, including costs of externalities whether or not the utility has to pay those costs.
[2] Linked to periods of coincident peak and subject to negotiated resolution of important technical issues.
[3] Reflecting full social marginal cost, with the remaining revenue requirement balanced between higher volumetric rates and higher fixed charges.
[4] Assuming a number of safeguards are implemented (see report).
[5] Necessary but not sufficient.
[6] In combination with a formula rate plan and only for setting revenue requirements; rate design issues to be addressed less frequently (e.g., every three years).
[7] Implementation of formula rates should not deny utility customers and other stakeholders the ability to periodically review and litigate a utility's cost structure.

Poor - Poorly address fixed cost recovery

Better - Somewhat better way to address fixed cost recovery but may not be sufficient

Good - Address fixed cost recovery reasonably well

Preferred - Preferred way to address fixed cost recovery

1. Utility Perspective: Providing a Regulatory Path for the Transformation of the Electric Utility Industry

By Lisa Wood, Executive Director, Institute for Electric Innovation, and Vice President, The Edison Foundation

Ross Hemphill, President, RCHemphill Solutions, and Former Vice President of Regulatory Policy & Strategy, Commonwealth Edison

The electric utility industry is in the midst of a profound transformation. This transformation, more evolutionary than revolutionary, is being driven largely by:

- technological innovation;
- federal and state policies; and
- changing customer needs and increasing expectations.

Key Trends Driving Change in the Electric Utility Industry

Three "megatrends" are at the core of this transformation.

The Transition to a Clean Energy Future
The portfolio of energy resources we use to meet our electricity needs is changing. As a nation, we are investing increasingly in renewable energy, transitioning from coal to natural gas, continuing to generate electricity using nuclear energy and pursuing energy efficiency. At the same time, modernization and digitization of the grid enable the integration of more carbon-free renewable resources, both large-scale and distributed. In fact, we expect continued growth in wind and exponential growth in solar over the next decade.[5] Projected solar growth is a mix of utility solar — the dominant market segment — followed by private residential solar and nonresidential solar.[6]

A More Digital and Distributed Grid
The power grid itself is changing, becoming "smarter" by virtue of a digital communication overlay with millions of sensors that will make the grid more controllable and potentially self-healing. The electric utility industry is investing more than $20 billion per year in the distribution grid alone, which will enable the connection of distributed energy resources, as well as new devices in our homes and businesses.[7] Many of these resources and devices will interact with the grid, resulting in more reliable, resilient and efficient grid operations. The digital grid is evolving into a multi-path network of power and information flows that will use data analytics for grid management and optimization from end to end.[8]

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[5] Greentech Media and SEIA (2016).
[6] Ibid.
[7] Edison Electric Institute (2015).
[8] While the digital power grid offers many benefits, it also raises cyber security risks which the utilities are addressing through a variety of measures, often with government cooperation, and which will add to the costs of maintaining the grid.

Individualized Customer Services
As the grid becomes increasingly digital and distributed, customization of services for electricity customers will continue to grow. Large commercial customers, for example, increasingly want renewable energy to meet their corporate sustainability goals; cities and towns are requesting customized services, such as help with microgrids, smart city services or renewable energy; and some residential customers want greater control over their energy use and/or renewable power or private rooftop solar to generate their own electricity. But, some customers simply want plain vanilla electricity at an affordable price.

Although these megatrends are driving change, the speed of transformation to a great extent will depend on whether regulation evolves to accommodate these changes. The business model of electric utilities must change to reflect the changing generation mix. At the same time, the grid is more complex and customers have different expectations and needs, meaning that the regulatory model also must change.[9] The utility business model can only change to the extent that regulation adjusts to facilitate these changes.

Over the next decade, regulation will have to provide a way for utilities to achieve new corporate and policy goals that meet the needs of their customers. That means meeting the traditional goals of providing safe, reliable and affordable electricity, as well as the new goals of providing even cleaner electricity and individualized customer services, while also integrating and connecting more distributed energy resources and devices.[10]

Value of the Distribution Grid
In the United States, the movement toward a more digital and distributed power grid is well underway. The need for more reliable and resilient grid operations, for greater efficiency and control, and for the connection and interaction with the "Internet of Things" (IoT) — every device with an IP address — creates new challenges, roles and opportunities. The deployment of more than 60 million digital smart meters to U.S. households is one key building block.[11] The integration of ever more distributed energy resources is another. Utilities are playing a central role as the integrators and enablers of the evolving Grid of Things™.

Given recent trends, the utility industry's current $20 billion annual investment in the distribution grid is expected to continue over the next several years.[12] But for the grid to continue to evolve to provide the services that customers want, and to integrate an increasing number of "things," all customers who use the grid will need to continue to share in the cost of maintaining and operating it. This will entail moving toward a services model rather than a throughput model, which requires regulatory change.

For example, a distributed generation (DG) retail customer or a microgrid that is connected to the host utility's distribution system utilizes grid services around the clock on a continuous, ongoing basis.[13] Figure 1.1 shows how a DG customer is using grid services continuously throughout a 24-hour period to import power, to export power and to continuously balance

[9] Rather than changing rates for all customers, we may see the development of rates for specific customized services.
[10] A similar discussion is included in the Introduction to the Institute for Electric Innovation's recent book, *Thought Leaders Speak Out: Key Trends Driving Change in the Electric Power Industry*. Institute for Electric Innovation (2015).
[11] Ibid, pages 24 and 25.
[12] Edison Electric Institute (2015). Table 9.1. 2014 data.
[13] We are discussing a retail customer connected to a utility under a retail rate, not a power purchase agreement.

supply and demand throughout the day. The utility's cost of providing grid services consists of at least four components — the typical fixed costs associated with: (1) transmission, (2) distribution, (3) generation capacity and (4) ancillary and balancing services that the grid provides throughout the day. How should the customer pay for these grid services?[14]

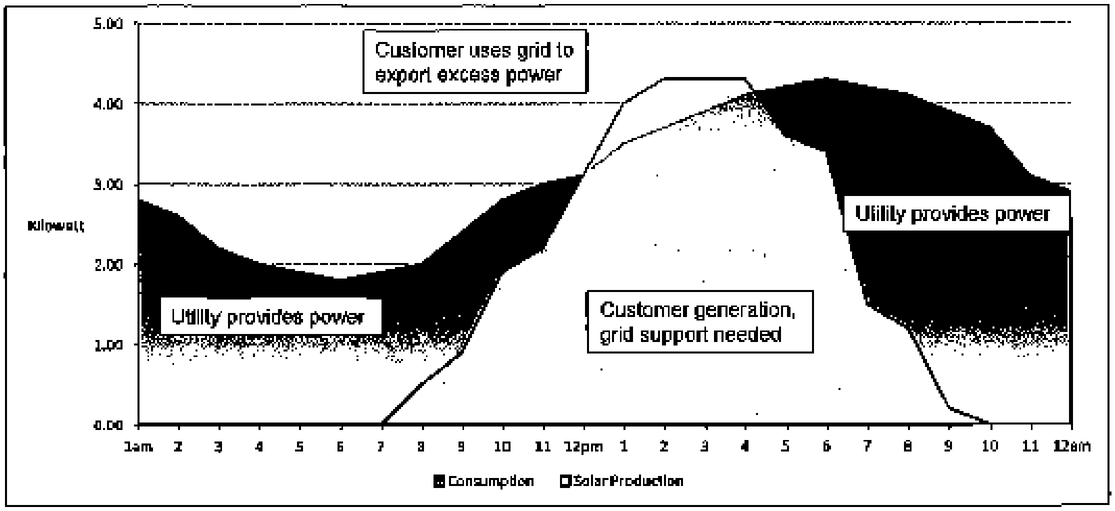

Figure 1.1 A Typical Private Rooftop Solar Photovoltaic (PV) Customer Interacts With the Grid Continuously Throughout the Day to Import Power, Export Power and Balance Supply and Demand.

Table 1.1 shows an example of actual non-energy or fixed charges as a percent of a residential customer's monthly bill; the actual percentage will vary from utility to utility. However, today, most of a utility's fixed charges are collected indirectly via a volumetric usage charge rather than directly via a fixed charge. Despite the fact that actual fixed charges comprise a very large percentage of a typical residential customer monthly bill, only a small percentage of this amount is collected via a fixed or customer charge. The result is that today's electricity customers have little idea of the actual fixed costs incurred to provide non-energy (e.g., grid and customer) services to them. We describe alternative approaches for customers to pay for grid services (without unnecessarily shifting costs onto other customers) and recommend a few specific ways forward. In light of the rapid growth in distributed energy resources, it is critical that all customers who use the grid continue to pay for the cost of grid services provided.

[14] From an economist's perspective, a "fixed cost" does not change as the quantity consumed (and produced) changes during some defined time increment. With respect to the subject matter discussed in this paper, the time increment is month-to-month and year-to-year.

Table 1.1 Example of Non-energy Charges as a Percent of Monthly Bill

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	911
Average Monthly Bill ($)*	$114
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**53%**

*Usage and bill are based on Energy Information Administration (EIA) 2014 data.
^The charge for capacity varies depending upon location. This is just an estimate.

Guidelines for Pricing Grid Services

The transformation of the power sector that is well underway requires both regulatory and policymaker support, including modifying cost-recovery allocation and pricing mechanisms.

The term "transformation" aptly describes what is happening in the electric utility industry today. It is the beginning of a journey rather than a known destination. This journey is being taken by electric utilities, their customers, regulators, legislators and other stakeholders. The journey begins with utilities providing customers new options and services that they want and that technology and policy allow. With a transformation afoot but uncertainty as to the outcome, it is important to think about providing guidance to both utilities and their regulators.

Bonbright's "Criteria of a Desirable Rate Structure," first printed in 1961, has been held tightly as a regulatory doctrine by many.[15] The manuscript captures much of what should have been taken into consideration when setting rates historically. However, utility ratemaking has never been a static process. Wholesale rate practices have changed considerably in the past 20 years to emphasize competitive market principles. Retail regulation also has evolved and changed, although more slowly, to respond to new technologies, policies and changing customer needs. Given the transformation underway in the electric utility industry, rigid adherence to historical retail ratemaking policies and practices is not adequate to ensure the provision of robust grid services in the future.

We offer the following guidance to shape future regulatory policies and practices. Electric utility regulation should be designed to:

1. *Rationalize rate designs.* The age-old regulatory principle of assigning costs to cost causers grows ever more important as customers of all sizes have new opportunities to generate and store electricity. Customers increasingly are differentiated by how they use and even generate power. And more accurate cost allocation is becoming possible through smart

[15] Bonbright, Danielsen and Kamerschen (1988), pp. 377–407.

meters and information technology advances. We must carefully examine rate designs, and to the extent possible, move toward economically efficient rates. Any changes should be publicly acceptable in terms of average bills, year to year increases, and other social considerations.

2. *Provide a fair return consistent with the utility's cost of capital and ensure the maintenance of adequate cash flow.* This principle has always been part of the regulatory compact. Financially healthy utilities remain essential for providing safe, reliable and increasingly clean electricity at an affordable price.

3. *Provide opportunities for utilities to offer additional services that benefit customers and enhance revenue.* Regulators should look at the needs and desires of customers for new services and new technologies, and should give utilities flexibility to offer different options to customers. If these are potentially competitive services, rules to prevent cross subsidies and unfair advantages are necessary. But in each case regulators should consider whether customers are well-served by having the opportunity to choose a utility-provided option.

4. *Create more satisfied and empowered customers.* Some customers may want to understand and play a role in their own energy choices and usage patterns. On the other hand, some customers may want to know nothing more about electricity other than how to flip a switch. Customers are very capable of making good choices and managing energy usage, but there is a big educational task ahead. Regulators should support utilities playing a key role in this education process.

5. *Align policies, rate designs and business models with public policy objectives,* such as protection for low-income customers, development of low-carbon resources, development of distributed energy resources, enhanced system resilience and reliability and cybersecurity.

6. *Create affirmative incentives or other mechanisms to optimize outcomes and utility performance.* Well-designed incentive mechanisms can be valuable tools to align utility, customer and regulatory objectives, but they must have symmetry — the utility should be rewarded for superior performance and penalized for poor performance. Performance may be related to several outcomes including policy goals.

7. *Maintain a manageable level of regulatory risk but avoid undue regulatory review and unduly prescriptive oversight.* New regulatory models should encourage the innovation that will enable utilities to remain forward-looking and responsive to the challenges and opportunities associated with the evolving energy landscape and ever-changing technology. When rapid changes in circumstances or technology occur, both utilities and their customers will benefit from management that has the flexibility to adapt and respond to risk (on both the upside and the downside).

How these recommendations are translated into regulatory policy will vary by state and by region. Using the same guidance, regulatory policy in a state with competitive generation and retail sales may look very different than regulatory policy in a state with a vertically integrated utility system.

Paying for the Evolving Grid

Today's utilities are providing safe, reliable, affordable and increasingly clean electricity. In addition to this, tomorrow's utilities will be providing even cleaner electricity, providing more individualized customer services, integrating and connecting more and more distributed energy resources and providing greater reliability and resilience. The fundamental question is this: How do we change current ratemaking and rate design practices to accommodate the increasingly important role of the distribution grid and the grid services it provides? A recent report by the Edison Electric Institute addresses this issue in some length.[16] Here, we first discuss two approaches that we recommend (if implemented properly): formula ratemaking and appropriate cost-based approaches (i.e., fixed charges and demand charges) that satisfy the recommendations specified in the prior section. Then, we briefly discuss additional approaches for recovery of fixed costs that have been discussed by others, and we identify their shortcomings.

Recommended Approaches for Recovery of Fixed Costs

Alternative approaches can lead to the appropriate recovery of a utility's fixed costs; there is no "one size fits all." Ultimately, the agreed upon approach will depend upon the utility, state regulators, state legislators and other stakeholders. First we discuss the concept of using more frequent rate cases to recover fixed costs through the formula ratemaking process. Then we discuss two cost-based rate approaches: full recovery of fixed charges and demand charges. Each of these approaches — if implemented properly — will lead to the appropriate recovery of a utility's fixed costs.

Regular Rate Cases Through Formula Ratemaking

One approach to improving the recovery of fixed costs is to increase the frequency of rate cases through formula ratemaking. Formula ratemaking is an approach to setting the appropriate level of revenue recovery on an annual (or other time period) basis in a streamlined regulatory process. This approach provides the utility with more stability regarding cost recovery, as opposed to periodic rate cases, and results in larger customer benefits with regular, needed investments in the utility's infrastructure. This concept was applied in Alabama during the 1980s with "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas.[17] Most recently, the approach was codified into public utility law in Illinois as described by Hemphill and Jensen.[18] The Illinois law, which was enacted in 2011, put into place a process where the legislature authorized a number of investments (including smart meters, cable replacement and poles) and required an annual process to determine the distribution utility's revenue requirement. The formula requires the electric utility to file a revenue requirement in May for setting rates starting January 1 of the following year (i.e., a May 2016 filing would set rates for calendar year 2017).

The filing is for setting only the revenue requirement and does not include any aspects of rate design (cost of service allocations or intraclass rate design issues). Separately, rate design issues are addressed every three years.

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[16] EEI (2016).
[17] See Lowry et al. (2013).
[18] Hemphill and Jensen (2016).

In addition, the allowed return on equity (ROE), which is a major part of the revenue requirement formula, is a simple calculation based on components outside of the control of the utility or the regulator. The allowed ROE for Illinois, for example, is the 30-year Treasury bond rate plus 580 basis points (e.g., the ROE is set as 8.64 percent in the 2016 filing that sets 2017 rates). The calculated revenue requirement experienced for a given year is reconciled with the revenue requirement forecasted for that year, one year hence, to assure that the utility is fully compensated for costs prudently incurred.

In Illinois, a number of consumer benefits metrics must be met, including improvements in reliability and efficiency gains related to the deployment of smart meters. If the utility does not achieve the target levels, up to 38 basis points can be reduced on the calculated ROE.

The results have been striking in Illinois. Smart grid investments are being made even ahead of schedule. Customer reliability is at historically high levels. Storm response to outages that do occur (resiliency) has improved. And customer satisfaction is growing. The process of determining the utility's revenue requirement is very much like an annual budget approval process, with an assessment of whether the previous budget was appropriate.

In Illinois, rate design issues are determined every three years. The benefit of this approach is that it separates the determination of an annual revenue requirement from the determination of what pricing is best for each of the distribution services.

The annual performance-based formula ratemaking process provides stability for the recovery of distribution system costs, which allows the utility to plan and execute investments that benefit customers in many ways, including enhanced reliability and infrastructure that enable other beyond-the-meter services. At the same time, it holds the utility accountable for delivering these consumer benefits.

Cost-Based Rate Approaches

Cost causation has always been a linchpin of appropriate electric utility rate design. When rate structures are not reflective of the cost structure, customers receive signals that lead them to behave in inefficient and costly ways, which result in a misallocation of resources. The issue we are discussing in this paper is about providing grid services to customers and recovering the fixed costs associated with providing those grid services. The issue is not about the price of energy. As the transformation of the electric utility industry proceeds, the independence of the cost of grid services and energy supply is underscored.

What is the appropriate role of time-varying rates, as some have suggested this as an approach to recovering grid costs?[19] It is well known from dozens of pilot programs over the past few decades that residential customers respond to time-varying rates.[20] Time-varying rates are usage-based and provide no signal to customers about the cost of the distribution system that is

[19] For example, see Rubin (2015).
[20] Despite this finding, few utilities have a significant percentage of their customers on time-varying rates. One notable exception is OGE Energy, whose goal is to enroll and maintain about 20 percent of its residential customers on a time-varying rate program called SmartHours.

designed to meet their needs, including instantaneous demand for electricity as well as the integration of distributed energy resources.[21]

The drivers of the costs of distribution grid services are almost completely independent of energy supply costs. We know that customers respond to price signals, as well as to their total bill. Hence, rate designs that misallocate costs send customers inaccurate price signals. We support time-varying rates and believe such rates are appropriate to implement in addition to a truly cost-based distribution or grid charge. However, time-varying rates alone do not address the issue of paying for the cost of the grid since these rates reflect only the cost of energy.[22]

Two cost-based approaches that properly reflect and recover the costs of grid services are (1) increasing fixed charges and (2) implementing demand charges.

Fixed Charges

The most straightforward approach to cost-based rate design for distribution or grid services is to support rate design with cost causation by properly aligning the fixed and variable price signals sent by delivery rates with the fixed and variable costs imposed by customers' demand of the delivery system. At the extreme, this is sometimes called a straight fixed-variable rate design.

These types of rates establish fixed and variable charges that are commensurate with the fixed and variable costs of serving each customer or customer class.[23] For residential customers in the United States, delivery or fixed costs range from about 40 percent to 65 percent of a customer's total bill.[24] Yet today, the highest fixed charge on a residential monthly electric utility bill in the United States is about $25 per month, and the average fixed charge is about $10 per month.[25] Currently, most of a utility's fixed charges are collected via a usage charge rather than directly via a fixed charge.

Recognizing the growing importance of the grid and the need to pay for grid services, many utilities are proposing increases to their monthly fixed charges. Recently, state regulators in several states have approved higher fixed charges for residential customers.[26] In some cases,

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[21] Although many fixed costs associated with grid services in the United States are recovered today via a usage charge, we believe that separating energy charges from grid charges in the future is a sensible way forward.

[22] Another approach, the tiered rate, has occasionally been discussed. This approach has been used to incent electricity conservation. As with time-varying rates, tiered rates alone do not address the issue of paying for the cost of the grid. We of course recognize that rates can be "designed" to capture more than just the price of energy, but we fundamentally believe that the cost of the grid and the cost of energy should be separated and that educating customers about these two distinct electricity services is critically important.

[23] Some argue against this approach. However, the fundamental concept of separating fixed and variable costs is a sound concept. We believe that the current approach of embedding fixed costs in a usage or volumetric charge, which is widespread in electricity pricing in the United States, is flawed.

[24] This range is based on conversations with individual investor-owned utilities. At Commonwealth Edison, a distribution utility, fixed costs comprise over 90 percent of the cost of distribution, which is roughly 47 percent of the total customer bill.

[25] Institute for Electric Innovation, internal document showing fixed costs for each of its member utilities.

[26] There are also a number of jurisdictions that have considered and rejected this approach.

utilities are proposing specific fixed charges for DG customers based on the size of a customer's DG system because such customers use the grid differently than non-DG customers.[27]

Today's fixed charges are far below the utility's cost of providing grid services, which includes transmission, distribution, generation capacity, and ancillary and balancing services.[28] We believe that educating customers about what they are paying for when they purchase electricity — both grid services and energy — is critically important. Yet, the public does not understand this distinction because we — utilities, regulators and other stakeholders — have made electricity pricing far from transparent. We also recognize that a utility's fixed costs may be difficult to allocate because some costs are customer-specific and some are systemwide.[29]

Some are opposed to billing customers directly for the fixed costs associated with providing grid services:

- Consumer advocates express concerns about bill impacts on low-usage and low-income customers. We understand this concern but do not believe it should be resolved via rate design. In our view, issues related to low-income customers should be treated through specific programs.
- Environmental advocates express concerns about reducing the marginal price signals to customers, thereby reducing incentives for energy efficiency. Since a large percentage of each residential customer's bill still would be based on usage, we believe there are ample opportunities to incent efficiency.
- And most recently, rooftop solar industry advocates have expressed concerns about DG customers paying directly for the grid services that they use around the clock on a continuous ongoing basis.[30] We believe that DG customers should share in the cost of the grid services that they use and that these costs should not be shifted onto non-DG customers. Current net energy metering practices result in a "subsidy" to DG customers specifically because these customers are not paying fully for the grid services that they use. The simple solution to this is to charge DG customers directly for the grid services they use via a fixed charge.

Increasing fixed charges to cover the cost of grid services and letting customers know what they are paying for makes the purchase of electricity — both energy and grid services — more transparent to customers. This is long overdue, and we believe that increasing fixed charges is a step in the right direction.

[27] It is well known that the load shape for a DG customer is different than for a non-DG customer; in particular, energy usage from the utility is typically low during afternoon hours, and the peak demand occurs at a different time of day. This is often referred to as the "duck curve." For a good explanation, see California ISO (2013), pp. 6–7.
[28] See Table 1.1 for an example, and also Wood and Borlick (2013). We recognize that not all utilities will provide all of these services. Utilities in deregulated wholesale markets will provide different services than vertically integrated utilities, for example.
[29] Severin Borenstein discusses this issue in a blog post, "What's so Great about Fixed Charges?" Energy Institute at Haas, Nov. 3, 2014, https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.
[30] Much of the controversy surrounding net energy metering for rooftop solar is related to the cost shift that occurs because private solar customers with rooftop PV do not pay their fair share of the cost of grid services that they use due to a rate structure where much of the cost of grid services is collected via volumetric rates. For a discussion of this issue, see Borlick and Wood (2014a,b). See also Energy and Environmental Economics, Inc. (2013), p. 6.

Demand Charges

Another cost-based alternative for pricing distribution services is adding demand-based rates or demand charges (e.g., a demand charge is a kilowatt (kW) charge that is added to existing rates which typically have a fixed charge and an energy charge).[31] Demand charges have been used for commercial and industrial customers for decades. With the deployment of advanced metering infrastructure (AMI, or smart meters) to more than half of all U.S. households, demand charges are now feasible for many residential customers. Demand charges result in an allocation of distribution costs based on the facilities required to meet each customer's peak demand during a specific period of time (e.g., one month). This is consistent with a longstanding method of allocating distribution facility costs across the different classes of customers. In this case, under current rate structures, without demand charges customers with low demand (typically smaller customers) subsidize customers with high demand (typically larger customers).[32]

Demand charges have many positive attributes:

- Demand charges ensure that customers with a higher load factor will face a lower bill. Under volumetric rates, a customer with high kilowatts but very few kilowatt-hours pays very little compared to a customer with the same level of kilowatts but a commensurate level of kilowatt-hours.
- Demand charges incentivize more demand response and energy efficiency because customers can respond and reduce their electricity bills. This ultimately reduces the costs of the entire electricity system because load factors increase across the system, and the need to build peaking plants is reduced.
- Demand charges are a reasonable way to recover system-specific grid costs since some portion will vary with peak demands on the system.

Demand charges have not been used widely in the United States for residential customers. A handful of utilities have optional demand charges for residential customers.[33] And a few utilities are now proposing a demand charge as part of a three-part rate (i.e., a demand charge, a fixed charge and an energy charge) for DG customers. We believe that adding a demand charge as part of a three-part rate is a step in the right direction.[34] However, this will require educating customers about what they are paying for when they purchase electricity.

Other Approaches for Recovery of Fixed Costs

As utilities provide even cleaner electricity, provide more individualized customer services, integrate and connect more and more distributed energy resources, and provide greater

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[31] A demand charge can be designed in a number of ways: the customer's maximum kW during each month; the customer's maximum kW during a specified (peak) period or periods of each month; the maximum kW during a year; the kW during the system peak of the year; and so forth. This design element matters — it impacts the bill as well as customer incentives. However, for the discussion in this paper, most practicable designs of a demand charge will have the attributes discussed in this section.

[32] A description of the process of allocating distribution facility costs by coincident and non-coincident demand can be found in National Association of Regulatory Utility Commissioners (1992).

[33] Dominion, Duke Energy, Georgia Power, and Xcel Energy are some of the utilities that have optional demand charges for residential customers.

[34] We recognize that this is not a perfect solution; however, flattening customer load profiles via a demand charge, a critical peak price, or another mechanism has a positive impact on the power system. Hence, demand charges are a step in the right direction.

reliability and resilience, the role of the distribution grid and grid services is becoming increasingly important. As discussed throughout this chapter of the report, the fundamental question is how do we pay for this evolving power grid? In the prior section, we discussed different approaches that we believe could lead to the appropriate recovery of a utility's fixed costs for developing an increasingly dynamic grid that empowers customers.

Non-cost-based approaches that attempt to recovery a utility's fixed costs (and that have worked in other settings) — revenue decoupling, lost revenue adjustment mechanisms (LRAMs) and minimum bills — have serious shortcomings given the major transformation of the electric utility industry that is underway.

Decoupling has worked well for energy efficiency, and over half the states in the United States have adopted decoupling or some type of lost revenue adjustment mechanism.[35] However, given the significant growth in distributed energy resources (including energy efficiency, demand response, DG and distributed storage) expected over the next decade, decoupling, LRAM and minimum bill approaches have serious shortcomings as a means for recovering a utility's fixed costs. Each of these approaches is discussed briefly below.

Revenue Decoupling

Revenue decoupling (or simply, "decoupling") is an adjustment mechanism that separates (or decouples) the recovery of a utility's fixed costs from the volume of its sales. Under decoupling, an external "true-up" mechanism is used to ensure that the utility collects revenues based on its regulatory-determined revenue requirement and, thereby, recovers its fixed costs. Decoupling is one method to recover a utility's fixed costs (to the extent they are not recovered under ratemaking practices that tie the recovery of fixed costs to volumetric consumption charges).

Today, revenue decoupling is used in many states to "true-up" utility net revenues that otherwise would be lost due to declining electricity sales resulting from utility investments in energy efficiency.[36] Although revenue decoupling makes the utility whole, it does so explicitly by shifting costs from participating energy efficiency customers to nonparticipating customers using a public or system benefits charge (which is typically visible and transparent to customers as a charge on their utility bills).

Decoupling causes a cost-shifting problem that is similar in concept to the cost shift created by distributed generation customers under net metering.[37] However, a fundamental difference is that the magnitude of the "cost shifting" from DG to non-DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are extremely small — about 2 percent to 3 percent of the retail rate.[38] In contrast, as described in a prior Institute for Electric Innovation paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers and, unlike

[35] For details on how decoupling works in each state, see Cooper (2014).
[36] In total, 32 states have some type of fixed-cost recovery mechanism in place – 14 with revenue decoupling and 19 with LRAMs. See Cooper (2013); also see Cooper and Smith (2015).
[37] Borlick and Wood (2014a,b).
[38] Morgan (2013).

efficiency charges which are transparent (to both customers and regulators), the DG cost shifting is essentially invisible under a net metering scheme.[39]

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. State regulators will only approve utility-funded energy efficiency programs that pass a cost-benefit test. This means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs — particularly for private rooftop solar PV — are expected to decline over time, and forecasts show increasing amounts of distributed energy resources in the United States over the next decade.

Decoupling has worked well for utility investments in energy efficiency, and the associated cost shift has been relatively minor (about 2 percent to 3 percent of rates, on average, as described above). Neither regulators nor customers should be willing to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless fundamental reforms to net energy metering are put into place. In fact, recognizing this need for reform, regulatory proceedings are underway in several states to address the cost shifting associated with net energy metering.

As distributed energy resources grow and the role of the distribution grid becomes increasingly important, the ability of a utility to recover its fixed costs associated with providing grid services is a significant issue. We do not support decoupling as a solution to recovering fixed costs given the transformation underway. Decoupling will only exacerbate the cost shifting issue.

Lost Revenue Adjustment Mechanism

An LRAM is another general approach to recover a utility's fixed costs. Whereas a decoupling mechanism operates to recover lost revenue due to changes in all utility sales — thereby decoupling the utility's revenue and profit from sales, an LRAM applies specifically to revenue lost due to energy efficiency measures or programs. An LRAM approach requires more sophisticated measurement. An LRAM causes the same cost-shifting problem that was described earlier under decoupling, and this is not a solution to recovering fixed costs given the transformation underway in the electric power industry. As with decoupling, an LRAM will exacerbate the cost shifting issue.

Minimum Bill

Under this approach, the fixed-variable price signals remain the same (presumably a high kilowatt-hour charge) but the customer is required to pay a minimum bill amount. This is sometimes viewed as a compromise approach because the utility is assured a specific level of fixed-cost recovery, but, at the same time, customers see relatively high price signals and still are incented to use energy efficiently. This approach is not transparent because the customer is not shown the full cost of the grid services provided. In addition, it is highly unlikely that the minimum bill amount actually would recover the full cost of grid services, which could range from 40 percent to 65 percent of a typical residential electricity bill (e.g., for a typical residential bill of $114 per month as Table 1.1 shows, the fixed costs associated with the grid might range

[39] Wood and Borlick (2013).

from $46 to $74 per month).[40] We believe that it is critically important to provide transparency to customers regarding the purchase of electricity services. A minimum bill lacks transparency because it still does not show the customer the full costs of the different services being provided — energy and grid services.

In a nutshell, electricity pricing in the United States is confusing, and we support greater transparency going forward. One way to do this is to simply recognize the different electricity services being provided to customers and create rates for different types of services.

Conclusion

Change is afoot in the electric utility industry, driven by technology, policy and customers. There are varied opinions on the exact course and timing of the change. Still, many of us would agree that a decade from now the industry will look something like the following:

- We will have a cleaner electricity generation mix, with lower carbon emissions.
- The power grid increasingly will integrate a mix of central and distributed resources.
- The grid will become more digital, more controllable and more interconnected. Pacific Gas and Electric (PG&E) aptly calls this the Grid of Things™.
- A mix of entities — both utilities and other companies — will provide both supply-side and demand-side distributed energy resources.
- Utilities and others will offer customers a wide range of individualized and customized services.

Technology innovation also requires business and regulatory innovation. Because electric utilities are trustees of essential infrastructure and service, the business model must be sustainable as well as nimble and efficient, and it must be able to earn the support of long-term investors.

Both technology and business innovation require regulators and policymakers to support the transition, including modified cost recovery and pricing mechanisms, and also to support more collaborative ways to make decisions and provide guidance. Wholesale regulation has changed considerably in the past two decades. Retail regulation similarly now must change to allow utilities the ability to adjust to technological innovations, provide customers more choices, and improve the overall delivery system. As we have advocated in this paper, this means adopting regulatory approaches that will lead to the appropriate recovery of a utility's fixed costs, and that make the purchase of electricity — both energy and grid services — more transparent to customers.[41]

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[40] As noted in Table 1.1, the typical residential bill of $114 is based on Energy Information Administration data for 2014. The range of fixed costs is based on conversations with individual utilities around the United States.

[41] Some argue that pricing grid services separately from energy services could drive customers off the grid. This is only true if the power grid does not provide a cost-effective essential service. Our view is that the power grid is becoming increasingly important and is critical to our economy and our way of life, and that its value and essential nature will increase in the future.

Collaboration, good public policy and appropriate regulatory policies are critical for the successful transformation of the regulated electric utility industry. Ultimately, as this transition unfolds, it is about balancing affordability, reliability, clean energy and individualized customer services. This is largely the job of regulators and other policymakers. But the ultimate challenge is to make the transition of the electric utility industry affordable to all Americans! And this is the job of all stakeholders.

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2. A Consumer Advocate's Perspective on Electric Utility Rate Design Options for Recovering Fixed Costs in an Environment of Flat or Declining Demand

By John Howat, Senior Energy Analyst, National Consumer Law Center

Introduction

Context

While technological advances and energy resource economics are driving sweeping change across the electric utility industry, one constant from the residential consumer's perspective is that home energy service remains a basic necessity of life. Generation, end-use technologies, advanced communication capabilities, and utility business model assumptions may be in flux, but reliable, affordable home energy service is still required to meet basic heating, cooling, lighting and refrigeration needs. Without uninterrupted access to these end uses, health, safety and effective participation in society are undermined.

Amidst this sweeping industry change — indeed as a result of the confluence of several of its component parts — electricity usage and sales to end-use customers in the United States have flattened out after decades of strong, sustained growth. From 1949 through 2007, electricity usage among residential, commercial and industrial end-use consumers grew at an average annual rate of 4.9 percent. From 2008 through 2014, usage grew nationally at an average of 0.1 percent.[42] Looking ahead, the U.S. Energy Information Administration projects total electricity usage to grow at a rate of just 0.7 percent annually between 2015 and 2040, with variability among Census Divisions ranging from 0.1 percent in the Mid Atlantic Division to 1.0 percent in the West South Central and Mountain Divisions.[43]

The 21st century energy system, including electric utility rates, must be designed and implemented to accommodate a broad range of public policy objectives, including those related to affordability, reliability, consumer protection, fairness and carbon emission mitigation. While these consumer and environmental objectives sometimes conflict, regulators, policymakers, advocates and utilities can work creatively to ensure that both sets of objectives are achieved, particularly during this transitional period when access to energy saving, load management, storage and small-scale generation technologies is anything but universal.

This chapter of the report examines from a consumer advocate's perspective a range of options available to electric utilities for recovering fixed costs in an altered usage and sales environment.

Underlying Assumptions

At the outset it is appropriate to identify the assumptions and biases that inform this discussion. From the perspective of an advocate concerned with residential consumers' access to affordable, uninterrupted home energy service, it is paramount to control costs that affect consumers' rates and bills, preserve the long-term viability of utility distribution companies that retain an obligation to serve all residential electricity service customers, and retain effective

[42] Calculated from U.S. Energy Information Administration (EIA) (2015a), Table 7.6.

[43] Calculated from EIA (2015b), Table A.2.

regulatory oversight of distribution utility procurement, pricing, billing, customer service, and credit/collections operations.

This bias is steeped in the belief that many residential consumers will not fare well if the role of the existing utility is compromised, service obligations are diminished, and the resulting distribution company void is filled by nonregulated vendors, competitive suppliers and others aiming to sell their wares. The potential to benefit from many energy resource technologies marketed outside of the utility sphere is often dependent upon a consumer's access to upfront capital or financing on favorable terms. Further, detailed knowledge of energy markets, emerging energy resource technologies, and financial analysis are often required for individual consumers to make prudent energy investment decisions. Clearly, not all customers fit this new energy investor profile. "The market" at the distribution level will not serve all customers well, so utility rates should be designed to provide the sufficient, stable revenues required to ensure that the company will continue in its role as a full service provider for those customers not inclined to go elsewhere.

It is important to note that concerns related to secure access to basic electric service are not limited to those households with income so low that they qualify to participate in means-tested programs such as the Low Income Home Energy Assistance Program (LIHEAP).[44] A report issued as the country was emerging from the Great Recession demonstrated that in 2011, 45 percent of U.S. residents lived in households that lacked sufficient income to pay for basic necessities. The report further demonstrated for that many family types, income sufficient to pay for necessities far exceeded LIHEAP income-eligibility guidelines.[45] Thus, the need for a well-functioning utility franchise, regulatory oversight and effective consumer protection extends well beyond households that are typically considered to be "low income."

An additional bias that informs the rate design commentary in this chapter is that energy efficiency is the least-cost resource and the "throughput incentive"[46] should cease to exist. The comparative costs and benefits of energy efficiency are well documented. Comparing the unsubsidized costs of the full range of "conventional" and "alternative" energy resources, energy efficiency is reflected as the cheapest of all available resources, with the levelized cost of efficiency estimated at $0 to $50/megawatt-hour (MWh), versus natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52 to $78/MWh.[47] Further, under appropriate rate design models, energy efficiency improvements provide a relatively low-cost means for utility consumers to control their usage and their bills, assuring payments that are more affordable. In addition, energy efficiency brings a range of other benefits, including those related to greenhouse gas emission reductions, employment and other macroeconomic metrics, and health. Thus, rate design options that undermine energy efficiency incentives should be avoided.

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[44] The U.S. Department of Health and Human Services caps LIHEAP income-eligibility at 200 percent of the Federal Poverty Guidelines or 60 percent of the State Median Income, whichever is higher. Many state programs limit eligibility to 150 percent of the Federal Poverty Guidelines.
[45] McMahon (2013), p. 3.
[46] The term "throughput incentive" refers to the interest of the utility in traditional ratemaking to maximize sales to recover authorized costs, increase revenues and maximize profits.
[47] Lazard (2015).

Discussion of Rate Design Options

High Fixed Charges

Since 2014 proposals to increase fixed charges have been the predominant utility rate design response to changes in revenues and sales. In the past two years, electric utilities in at least 34 states have proposed to shift recovery of revenue requirements from the volumetric portion of customer bills to the monthly, fixed charge.[48] While shifting cost recovery to non-bypassable fixed charges may reduce utility sales risk and stabilize revenues, the shift penalizes low-volume consumers within a rate class and raises equity and social justice concerns. Further, high fixed charges undermine price incentives for energy efficiency and usage reduction while limiting the ability of customers to control their bills. Finally, high fixed charges that undermine usage reduction incentives may lead to the need for greater investment in large-scale generation and transmission, imposing higher rates and bills on all customers and imposing the greatest harm on those residential customers already strapped with the highest home energy burdens.[49]

Regulators over the past 30 years have typically limited fixed charges to cover those costs that are directly related to the number of customers served, including metering, billing and customer assistance. Historically, customer charges have comprised a small fraction of the total bill — $5 to $10 per month for a residential customer.[50] However, many recent utility proposals would increase the existing fixed charge by 100 percent or more. For example, in 2014 Madison Gas and Electric Company proposed to increase the monthly residential fixed charge from $10.44 to $19, with an eye toward raising the monthly non-volumetric charge to $70 over a period of a few years to resolve its revenue stability concerns and eliminate "subsidies" to low-volume consumers.[51]

1. The Cost Shift

As indicated above, providing for utility cost recovery through rate modifications that increase fixed charges while reducing cost recovery from volumetric charges causes disproportionate harm to low-volume consumers. Dramatic increases in fixed charges with reductions, or only moderate increases, in energy charges increases the total monthly bill of low-volume consumers by a higher percentage than that of higher-volume consumers. Table 2.1 shows a bill impact example applicable to Madison Gas and Electric Company's 2014 proposal.

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[48] Regulatory and legislative developments in fixed charge rate design are tracked closely by the "Nix the Fix Network," a collaboration among consumer, environmental and distributed generation advocates.
[49] The term "energy burden" refers to the proportion of household income devoted to home energy and utility service.
[50] Lazar (2015), p. 36.
[51] Content (2014). The proposal is typical in scope and structure to others that have been filed over the past year.

Table 2.1 Comparative Bill Impact for Madison Gas and Electric Company's Proposal to Increase Fixed Charges: Low-Volume, Average and High-Volume Residential General Service Customers[52]

	Low-Volume Customer	Average-Volume Customer	High-Volume Customer
Monthly Usage (kWh)	450	900	1,400
Initial Monthly Customer Charge	$10.44	$10.44	$10.44
Revised Monthly Customer and Grid Connection Charge	$19.00	$19.00	$19.00
Initial Volumetric Charge	$0.13992	$0.13992	$0.13992
Revised Volumetric Charge	$0.12986	$0.12986	$0.12986
Initial Monthly Bill	$73.40	$136.37	$206.33
Revised Monthly Bill	$77.44	$135.87	$200.80
$ Increase (Decrease)	$4.03	($0.49)	($5.52)
Percent Increase (Decrease)	5.5 percent	(0.4 percent)	(2.7 percent)

In this example, an increase in monthly fixed charges from $10.44 to $19.00, along with a decrease in volumetric charges from $0.13992 per kWh to $0.12986 per kWh, produces a 5.5 percent bill increase for a low-volume consumer using 450 kWh monthly, in contrast to a slight decrease for an average-volume consumer using 900 kWh per month. For a high-volume consumer using 1,400 kWh per month, the adjusted bill declines by nearly 3 percent. The hypothetical low-volume consumer in this example experiences a monthly bill increase of just over $4, while the high-volume consumer saves over $5.50. Obviously, the cost shift under a $70 monthly customer charge would be far more dramatic.

2. Equity and Social Justice Concerns

The fixed charge increase penalty to low-volume consumers raises profound equity and social justice concerns. Data from the Energy Information Administration's Residential Energy Consumption Survey (RECS) demonstrates that in states and regions across the United States, median household electricity usage among low-income, elderly and African-American headed households is lower than that of their respective counterparts. As an example, comparative median electricity usage from the Indiana and Ohio "reportable domain"[53] is reflected in the following tables.[54]

Results of these analyses clearly demonstrate that in the Indiana-Ohio reportable domain — on average — low-income, African-American and elderly households use less electricity than their counterparts. As Tables 2.2 through 2.4 indicate, fixed charge increase proposals, by penalizing low-volume consumers, will disproportionately harm these groups of ratepayers.

[52] Monthly bill calculations are based on the following equation: Customer and Grid Connection Charge + (Monthly Usage x Volumetric Charge).
[53] See Table 2.5 for national data, which demonstrate consistent patterns in all regions surveyed.
[54] Tables were generated by tabulating microdata from the U.S. Department of Energy, Energy Information Administration's 2009 Residential Energy Consumption Survey (RECS; EIA 2009). The 2009 RECS includes detailed residential energy consumption and expenditure information from 27 U.S. geographic areas referred to as "reportable domains." Indiana and Ohio comprise one of the reportable domains.

Table 2.2 2009 Median Household Electricity Usage by Poverty Status — Indiana and Ohio

Household Income	Usage (kWh)	Percent Difference
At or Below 150 Percent Poverty	7,831	-21.7 percent
Above 150 Percent Poverty	9,999	
Total All Households	9,365	—

Table 2.3 2009 Median Household Electricity Usage by Race of Householder — Indiana and Ohio

Householder's Race	Usage (kWh)	Percent Difference
Black or African-American	7,900	-19.8 percent
Caucasian	9,846	

Table 2.4 2009 Median Household Electricity Usage by Elder Status — Indiana and Ohio

Householder's Age	Usage (kWh)
65 or More	6,976
Less than 65	10,351

Some utilities have asserted that low-income residential customers use more electricity than other residential customers.[55] Utility companies generally base this assertion on billing and consumption distribution data from utility customers participating in energy assistance programs. However, such programs cannot be used to reliably approximate the entire universe of low-income households. With reported consumption levels based on utility program participants, a concern arises that the low-income results are biased on the high side, assuming that utility programs are often targeted toward high-use/high-bill customers, and in the case of low-income energy efficiency programs, to homeowners rather than renters and multifamily dwellers whose electricity usage tends to be relatively low. Therefore, to better understand low-income usage, it is critical to look at samples that include both program participants and nonparticipants. The only national data set that reflects such sampling is the Residential Energy Consumption Survey (RECS). The RECS includes detailed usage data, as well as information

[55] See, e.g., Indiana Utility Regulatory Commission, Cause No 44688, NIPSCO Direct Testimony Exhibit No. 2, Attachment 2.C.

regarding household income, age, race, ethnicity and numerous other characteristics. All of this is broken into 27 geographic areas.

Analysis of the RECS data shows that in 26 of 27 regions surveyed, average electricity consumption among households living at or below 150 percent of the federal poverty guidelines is less than that of higher-income households. Table 2.5 shows median electricity consumption in each of the RECS reportable domains. Given the consistency of the regional RECS consumption data and the restricted universe of low-income customers utilities rely on to conduct consumption comparisons, it is appropriate to conclude that, on average, low-income customers use less electricity than their counterparts.

Table 2.5 Median 2009 Site Electricity Usage (kWh), by Poverty Status and for All Households

	At or Below 150% Poverty Guideline	Above 150% Poverty Guideline	All Households
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	4,708	7,468	6,961
Massachusetts	4,222	6,056	5,686
New York	4,544	5,969	5,355
New Jersey	4,969	7,497	7,231
Pennsylvania	8,402	9,690	9,306
Illinois	7,350	9,116	8,432
Indiana, Ohio	7,831	9,999	9,365
Michigan	7,073	8,190	7,764
Wisconsin	7,449	7,889	7,727
Iowa, Minn., N. Dakota, S. Dakota	6,241	9,285	8,940
Kansas, Nebraska	8,808	9,402	9,302
Missouri	11,705	12,232	11,991
Virginia	10,997	13,859	13,231
Delaware, District of Columbia, Maryland, West Virginia	10,381	13,063	12,848
Georgia	12,727	13,816	13,499
North Carolina, South Carolina	12,105	14,343	13,651
Florida	11,905	13,760	13,212
Alabama, Kentucky, Mississippi	11,802	15,847	14,656
Tennessee	12,537	14,480	13,782
Arkansas, Louisiana, Oklahoma	12,628	13,646	13,421
Texas	10,602	13,799	12,878
Colorado	5,216	6,516	6,231
Idaho, Montana, Utah, Wyoming	10,665	9,588	9,804
Arizona	10,088	13,056	12,105
Nevada, New Mexico	7,637	9,434	9,164
California	4,739	5,939	5,628
Alaska, Hawaii, Oregon, Washington	10,597	10,799	10,754
Total	8,432	10,072	9,687

Source: U.S. Department of Energy, Energy Information Administration's 2009 Residential Energy Consumption Survey.

3. The Energy Efficiency Incentive, Customer Control Over Bills and Consumer Concerns

Increasing fixed charges undermines the price incentive for consumers to reduce usage through energy efficiency or conservation and handicaps the customer's role in in the industry transformation. Holding the revenue requirement constant, increasing the fixed charge reduces volumetric charges and reduces the value of a kilowatt-hour saved. Customers considering efficiency improvement investments will be faced with longer payback periods, and those who have already made such investments will be penalized. Devaluation of the energy efficiency incentive inherent in volumetric pricing presents the real threats of increasing systemwide usage, expanding investment in more expensive generation resources, increasing greenhouse gas emissions, and undermining the viability of programs and policies intended to promote efficiency.[56] On a very basic level, increased fixed charges diminish the ability of consumers to assert control over utility bills. For many of the reasons outlined here, the National Association of State Utility Consumer Advocates adopted a resolution unequivocally opposing increases in electric and natural gas utility fixed charges.[57]

Revenue Decoupling

In the traditional utility ratemaking process, a company's revenue requirement — based on approval by regulators of a company's demonstrated level of expenses, recovery of allowable capital investments and a reasonable rate of return — is allocated among rate classes according to the cost of delivering service to the class. Rates for each class, usually comprising a combination of fixed and volumetric charges, are designed to generate revenue equal to each class' allocated revenue requirement. After rates are set through this process, a company's revenues and earnings fluctuate according to the level of sales to customers.

Under revenue decoupling, cost of service determinations are initially set in the same manner. Subsequently, rates are adjusted periodically, usually through application of a revenue-per-customer mechanism, to stabilize utility revenues and reconcile for changes in sales. Rates are adjusted upward under declining sales scenarios and downward if sales increase. Decoupling mechanisms are intended to make utilities indifferent to changes in the level of sales and to stabilize revenues. When a utility can demonstrate conclusively that it faces a long-term decline in revenue, a well-designed decoupling mechanism, as long as it includes the safeguards identified below, is a ratemaking option that provides revenue stability without undermining customer incentives to use less and without penalizing low-volume consumers.

1. The Debate

Proponents of revenue decoupling argue that such a mechanism is required to remove the incentive for utility companies operating under traditional cost-of-service ratemaking to increase sales between rate cases (the throughput incentive) and remove the revenue loss disincentive to implement effective energy efficiency initiatives.[58]

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[56] For a thorough analysis of fixed charge impacts and regulatory proceeding, see Whited, Woolf and Daniel (2016).
[57] See NASUCA (2015), https://nasuca.org/customer-charge-resolution-2015-1/.
[58] See, e.g., New Mexico Public Regulatory Commission (2016).

Many consumer advocates' concerns regarding revenue decoupling are that the mechanism results in rate increases under declining sales scenarios irrespective of whether the decline is attributable to utility energy efficiency investment. In addition, advocates have stated that decoupling serves to lock in revenue for the utility and shift sales risk to ratepayers, and is not required as a policy to promote energy efficiency. Finally, consumer advocates have argued that decoupling reflects a piecemeal, automated rate-setting mechanism and deprivation of the regulatory process.[59]

2. Safeguards

A well-designed decoupling mechanism can play a pivotal role in stabilizing utility revenues while mitigating the incentive to increase sales between rate cases. Further, research shows that 37 percent of electric and natural gas utility rate adjustments between 2005 and 2013 resulted in refunds to consumers; some providing a modicum of relief to consumers after a period of extreme weather and high bills.[60]

A well-designed revenue decoupling mechanism should include a number of safeguards to protect against realization of concerns raised by consumer advocates. Approval of decoupling should include a requirement that the utility implement meaningful energy efficiency programs. The utility should also be directed to file a full rate case periodically — allowing regulators and stakeholders to review any changes in the company's cost structure and risk profile. Time between required rate case filings should strike a balance between safeguarding against autopilot cost recovery and creation of undue litigation burden on regulatory agencies, intervenors and utilities. In addition, limiting rate increases in any annual adjustment period to 3 percent will safeguard against excessive price spikes and bill volatility. Finally, revenue decoupling should be implemented in conjunction with an inclining block rate structure, with adjustment surcharges applied to the high-volume "tail block" (last tier of energy consumption) and refunds to the "head block" (first tier of energy consumption).

In addition to incorporation of the safeguards referenced above, it is important to consumers that implementation of revenue decoupling only occur in conjunction with or subsequent to regulatory approval of distributed generation pricing that does not inappropriately shift costs from distributed generation participants to nonparticipants. Getting this pricing "right" is necessary to ensure against the potential for a significant cost shift to renters and other consumers lacking the ability to benefit economically from distributed generation technology. Approval of revenue decoupling prior to implementation of appropriate distributed generation pricing reduces the utility incentive to push back against such a cost shift.

Time-Varying Rates

Time-varying rates, if properly designed and implemented, may allow individual consumers to reduce their energy bills, improve system utilization and reduce peak demand. If consumers respond to the price signals that time-varying rates provide, time-varying rates can also reduce supply and delivery costs for all consumers. However, time-varying rates can have adverse impacts on consumers, especially on those who may have less ability to shift their usage and obtain any benefits from time-varying rates. Low-income consumers, already faced with

[59] See, e.g., Public Service Commission of the State of Missouri (2015).
[60] Morgan (2013).

disproportionately high home energy burdens and rates of service disconnection, should not be further burdened by penalties that may come from time-varying rate design.

Because advanced metering is a prerequisite to offering time-varying rates, it is important to identify guiding principles with regard to both advanced metering infrastructure deployment, as well as time-varying rate design. Following are recommended principles:[61]

- All existing consumer protections, including a customer premise visit prior to involuntary disconnections and the full value of existing low-income discount rates, must be retained.
- Prepaid electric service poses health and safety risks to vulnerable and low-income customers and should be prohibited.[62]
- Cost-benefit analysis should be used to determine the scope and design of time-varying rate programs. Distribution utilities should compare the costs and benefits of different rate structures and implementation scenarios. Sensitivity analysis should capture the uncertainty associated with highly variable factors, such as the level of customer response, behavior change and persistence. The cost-benefit analysis should also provide a comparison of how different approaches or technologies may achieve the same objectives.
- The design of time-varying rates should be sector-specific and informed by cost-benefit analysis and evaluation results, while being thoughtful to minimizing customer confusion.
- Simple and clear consumer education is key to achieving the individual and systemic benefits of time-varying rates, and will help avoid customers being unintentionally harmed due to lack of information. Distribution utilities should be required to provide consumer education, and the existing (utility energy efficiency program) platform should be leveraged.
- Reductions in peak demand can reduce the cost of the energy delivery system, as well as lowering the average supply cost. Thus, time-varying rates should be applied to both supply and distribution rates.

In addition, time-varying rates should be optional for non-distributed generation residential customers: "Customers should have the ability to select a time-varying rate offered by the utility in response to customer education, while others may choose to remain on flat rates because of their own assessment of bill impacts, need for price stability, and convenience trade-offs."[63]

In addition, safeguards for time-varying rates should also include a "shadow billing" component, where customers are informed in advance of implementation what their billing would be under each of the available rates offered by the utility. This would enhance consumer understanding of time-varying rates and provide guidance on whether to choose a different rate.

[61] Anthony and Howat (2014).
[62] As documented in Howat and McLaughlin (2012), deployment of residential advanced metering infrastructure has coincided with an increase in utility proposals to implement prepaid service. The report further documents that prepaid service results in increased rates of service disconnections and is concentrated among lower-income residential consumers.
[63] Anthony and Howat (2014).

Finally, from the perspective of residential consumers, it is important to distinguish between time-of-use (TOU) rates, critical peak pricing (CPP) and real-time pricing (RTP). TOU rates are pre-set in the tariff and vary predictably by time of day or by season. CPP is characterized by pre-set pricing for a specified number of days or hours during peak months. Critical peak periods are announced by the utility when it anticipates high wholesale prices or strained power system conditions. Under CPP, customers lack certainty as to the timing of critical peak events and pay substantially higher prices during those events. RTP is tied to volatile wholesale power markets and therefore brings considerable uncertainty and lack of predictability.

With effective outreach, education and access to energy management resources, many residential consumers may adapt to predictable, modest TOU price differentials. CPP and RTP spikes during heat waves and other peak events are less predictable and bring more severe penalties for those consumers without the ability to safely reduce usage during such events. Making peak-time rebates available to residential consumers is a less punitive approach to providing price signals to these customers.

Other Rate Design Options for Fixed Cost Recovery

1. The Status Quo or Frequent Rate Cases

As indicated previously, consumption and sales have leveled out in recent years and are forecast to remain flat into the foreseeable future. However, electric utility revenues from sales reached an all-time high in 2014 and approached 2014 levels in 2015.[64] From these data it may be inferred that not all utilities face an immediate revenue sufficiency or stability crisis. In cases where no such crisis is demonstrated and a utility company is implementing a robust portfolio of effective energy efficiency programs, sweeping changes to rate design may not be warranted.

2. Lost Revenue Adjustment Mechanisms

These mechanisms are intended to make utilities whole for loss of revenues that can be attributed to energy efficiency program sales. They are viewed by some as an alternative to revenue decoupling. They often involve data-intensive litigation, with utilities striving to demonstrate high levels of energy savings and intervenors working to refute the utility data. In addition, they provide utilities with an incentive to overstate savings and provide the perverse incentive to undermine efficiency program effectiveness so that sales between full rate cases increase. Under this scenario, a utility double-collects through the lost revenue adjustment mechanism and retained sales revenue.

3. Minimum Bills

A minimum bill structure is intended to obtain a minimum payment from customers whose usage is very low, but who nonetheless are dependent on the utility system. A minimum bill bears some resemblance to a high customer charge, with the notable distinction that it does not apply to customers who consume more than the preset minimum bill threshold. In essence it is a high customer charge that is only applicable to very low-volume consumers. Because

[64] "Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions," Energy Information Administration, https://www.eia.gov/electricity/data/eia826/.

minimum bills only apply to a very small number of customers, they are unlikely in most service territories to effectively address pressing fixed-cost recovery problems.

4. Residential Demand Charges

Large commercial and industrial customers have long been subject to paying a demand charge in addition to a fixed customer charge and volumetric charges. Demand charges are based on a customer's peak usage during a billing period or over a longer period — e.g., over the previous 12-month period. Recently, some utilities that have deployed advanced meters have proposed demand charges on residential customer bills. In theory, demand charges send consumers a price signal to reduce peak consumption. However, there is little evidence indicating that large numbers of residential consumers have the wherewithal to respond to demand charge price signals. It is also reasonable to expect that considerable time and effort will be required to build a broad understanding of demand charges among residential customers who have not dealt with the concept in the past. In addition, because advanced metering is required to implement demand charges, the advanced metering infrastructure principles that are pertinent to the time-varying rates discussion are applicable to residential demand charges.

5. Tiered Fixed Charges

At least one large investor-owned utility has proposed to implement a tiered fixed charge structure. National Grid proposed the structure to regulators in its Rhode Island and Massachusetts Service territories. Proposals in both states entail imposing a fixed charge based on maximum usage during the previous 12-month period. Proposed changes to the Massachusetts general residential tariff are reflected in Table 2.6.

Table 2.6 National Grid's Proposed Tiered Fixed Charge Structure — Massachusetts

Current Customer Charge (all bills)	$4.00
Revised Monthly Customer Charge	
For maximum bill 0–250 kWh	$4.20
For maximum bill 251–600 kWh	$8.15
For maximum bill 601–1,200 kWh	$13.00
For maximum bill over 1,200 kWh	$18.00

Even though they are tiered, the proposed fixed charge increases, combined with concomitant reductions in volumetric charges, will infringe on customers' ability to control their bills, and will have the most adverse impacts on customers with average usage but a slightly higher peak usage. The rate design suffers from some of the same defects as high, flat fixed charges, but will be more difficult for customers to understand. In the midst of its rate case in Rhode Island, National Grid filed a motion to withdraw its rate design proposal, stating that it was aware of lack of support for the proposal among intervenors.[65]

[65] Rhode Island Public Utilities Commission (2015).

6. Formula Rates

Formula rate plans, after regulatory approval, provide utilities with a mechanism to adjust base rates outside of a fully litigated general rate case when earnings fall outside of a predetermined band.[66] Formula rates can provide utilities with enhanced revenue stability and reduce operational and sales risk. In approving formula rates, regulators should establish clear performance standards to address reduced utility incentive to control costs and deliver reliable service under this rate design. In addition, similar to revenue decoupling, implementation of formula rates should not deny utility customers and other stakeholders the ability to periodically review and litigate a utility's cost structure.

Conclusion

All of the options addressed in this report have some potential to at least partially stabilize utility revenues. However, none of the rate design options addressed is without the potential to bring adverse impacts to large groups of residential consumers. Some options, particularly the high fixed-charge approach, move the fairness and equity needle in the wrong direction and also erode customer control over bills. Among the rate design options explored as a means to provide for cost recovery in the face flat or declining sales, a revenue decoupling mechanism that includes the full complement of safeguards and consumer-minded design features identified in this chapter of the report has potential to provide a degree of revenue stability without undermining the potential for continued growth of energy efficiency resources. However, in the case of a utility that delivers effective energy efficiency programs, and where no threat to revenue stability is demonstrated, the status quo may be just fine.

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3. Environmentally Preferred Approaches for Recovering Electric Utilities' Authorized Costs of Services: Options for Setting and Adjusting Electricity Rates

By Ralph Cavanagh, Energy Program Co-Director, Natural Resources Defense Council

Statement of the Problem

In the United States, electricity production contributes more greenhouse gas emissions than any other sector of the economy (more than 30 percent).[67] Utilities also are by far the nation's largest investors in energy technology and infrastructure; electric utilities alone will commit $1.5 to $2 trillion over the next two decades, exceeding analogous federal expenditures by an order of magnitude.[68]

It is important to acknowledge at the outset that the United States has many flavors of "regulated utilities." They come in both investor-owned and publicly owned varieties, with a host of in-state and regional differences regarding the extent to which distribution systems own transmission and generation assets. Fully integrated behemoths like the Southern Company and Florida Power & Light coexist with distribution-only utilities like Oncor, National Grid and most of the membership of the National Rural Electric Cooperatives Association (NRECA). A vast intermediate category of distribution companies with competitively procured portfolios of generation and energy efficiency resources includes the likes of giant municipal systems in Seattle, Austin and Los Angeles, along with Western and MidWestern investor-owned utilities like Pacific Gas & Electric, Southern California Edison, Idaho Power, Ameren and Kansas City Power & Light. But in every state and every electricity system, core functions associated with integrating and distributing power from diverse sources remain subject to price regulation and critical to clean energy progress.

If, as many believe, climate stability requires the decarbonization of power generation, utilities will need to be able to invest with confidence and recover their authorized costs. The decisionmakers will be state regulators and (for publicly owned utilities) local boards; as a practical matter, the federal government's ability to influence these decisions is limited to Congress's periodic efforts, upheld by the Supreme Court in FERC v. Mississippi, to get state regulators to consider particular ratemaking options within a specified time, without dictating the outcome.[69]

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[67] The most recent economy-wide EPA emissions data are in "Sources of Greenhouse Gas Emissions," U.S. Environmental Protection Agency, https://www3.epa.gov/climatechange/ghgemissions/sources.html.

[68] The Brattle Group (2008), p. 2.

[69] *FERC v. Mississippi*, 102 S. Ct. 2126 (1982) (rejecting Tenth Amendment challenge to the ratemaking agenda-setting sections of the Public Utility Regulatory Policies Act of 1978 by a 5-to-4 vote). According to the Court, if the federal government wanted to dictate ratemaking outcomes, it would have to "preempt the states completely in the regulation of retail sales by electric and gas utilities," an outcome unlikely enough to eliminate any need for further exploration here. See 102 S. Ct. at 2137.

Utilities' ability to recover their authorized costs of service has been complicated by a shift since 2000 in a longstanding trend of robust growth in retail electricity sales. Prior to that year, for decades, electricity use consistently increased at a rate at least double that of the U.S. population, but since 2000, the average rate of sales growth has lagged consistently behind population growth, and total consumption in 2014 was actually lower than that in 2007[70] (Figure 3.1).

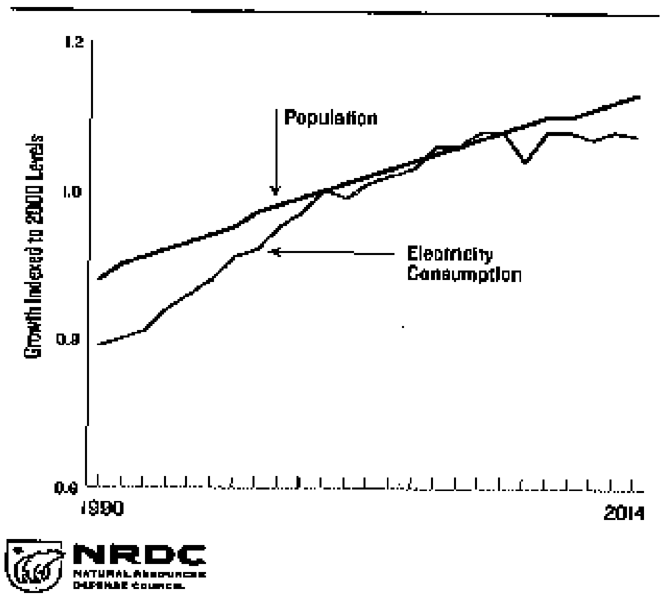

Figure 3.1 Growth in National Electricity Consumption and Population

This trend has helped ensure increased attention to broader aspects of utility business model reform and rate design that are critical to maintaining a clean energy transition. Many are captured in a February 2014 joint statement issued by the Natural Resources Defense Council (NRDC) and the Edison Electric Institute (EEI).[71] The statement notes that net metering programs in wide use across the United States have helped valuable distributed technologies such as solar power gain traction and improve performance, but additional approaches are needed now. Although such generation can reduce a grid's needs for central station generation and other infrastructure, it typically does not eliminate its owners' needs for grid services. When they use distribution and transmission systems to import and export electricity, owners and operators of onsite/distributed generation should provide reasonable cost-based compensation for the utility services they use, while also being compensated fairly for the services they provide. EEI and NRDC also note and endorse a longstanding tradition of utility investment in cost-effective energy efficiency resources, in coordination with upgrades in state and federal efficiency standards, yielding significant reductions in customer and environmental costs, but reinforcing a declining trend in electricity sales growth.

[70] This conclusion and the graph in the text (created by my colleague Sierra Martinez) are based on data from U.S. Department of Energy, Energy Information Administration, Monthly Energy Review.

[71] See "EEI/NRDC Joint Statement to State Utility Regulators," Edison Electric Institute and NRDC, http://docs.nrdc.org/energy/files/ene_14021101a.pdf.

These recommendations are entirely consistent with a core ratemaking principle that regulatory expert Scott Hempling recently summarized as follows:

> Economic efficiency comes first. Economic efficiency requires that we allocate costs to those who cause the costs, while allocating benefits to those who take the risks and bear the burdens. Economic efficiency comes first; allocating the gains from efficiency comes second. Inevitably we will fight over who gets the biggest slice. Let us first cooperate to make the biggest pie.[72]

Three crucial questions emerge, for purposes of this paper: (1) given declining growth in commodity sales, how do utilities secure the reasonable revenue certainty required to make enduring provision for clean, reliable and affordable services, without reducing customers' incentives to use electricity efficiently or to generate it themselves in ways that provide economic and environmental benefits; (2) how can regulators allocate the costs of enhanced electricity grids equitably among all who use them; and (3) how can rate designs best signal to customers the actual costs of the electricity services they use, to encourage efficient choices? And are there ratemaking approaches that can advance all of these objectives, or are zero-sum trade-offs inevitable? The EEI/NRDC statement is optimistic on all counts, but lacking in specifics. This chapter aims to provide them.

Summary of Recommendations

I begin with a procedural observation that may be more important than any substantive recommendation: The most promising ratemaking solutions will emerge from collaborative discussions in open settings among regulators, their utilities, and diverse groups of stakeholders. As regards major changes in utility business models, regulatory fiat is an unpromising course with few if any successful U.S. precedents.

In devising consensus-based solutions, I recommend starting with what is characterized below as a "necessary but not sufficient" element of any successful package: revenue decoupling. It does not affect rate design (it can work with any rate design), but it serves the crucial purpose of freeing regulated utilities from an outdated commodity business model that links financial health to robust growth in retail kilowatt-hour sales. As the most promising rate design options, individually or in combination, I advance three basic approaches: minimum bills, time-varying rates (which can take many forms) and tiered rates. All are responsive to concerns about equity, efficiency and customers' incentives to embrace energy efficiency and distributed generation. I then address options that I view as far inferior, including more frequent rate cases, increased fixed charges, and lost revenue adjustments. These are likely to be ineffective, counterproductive, and/or costly for many if not most customers.

[72] Hempling (2016). This passage is in part a homage to the field's classic work, James C. Bonbright's *Principles of Public Utility Rates* (1961), which suffers in contemporary application from the author's then understandable obsession with increasing the utilization rates of utility-owned baseload power plants.

The Curse of Throughput Addiction

For the past century, regulated utilities have recovered most of their costs of service through volumetric charges on electricity consumption and demand. Since the provision of reliable electricity service is dominated by utility expenditures that do not vary with short-term consumption shifts, this means that utilities' financial health is tied directly to their retail sales volumes, with every drop in consumption bringing a corresponding reduction in recovery of the utilities' authorized costs, and the reverse resulting whenever sales increase, for whatever reason.[73] This means that utilities gain by promoting increased electricity use and are punished automatically for investing successfully in energy efficiency programs, peak load reductions and distributed generation that reduces electricity throughput. Utilities are discouraged from investing in the best-performing and lowest-cost resource — energy efficiency — because it hurts them financially. Utilities' interest in increasing sales conflicts with customers' interest in reducing their energy costs. The problem was highlighted more than four decades ago by a prescient utility regulator, Leonard Ross, of California:

> At present, the financial incentives for utilities are for increased sales, not for conservation. Whatever conservation efforts utilities undertake are the result of good citizenship, rather than profit motivation. We applaud these efforts, but we think the task will be better accomplished if financial and civic motivations are not at cross purposes.[74]

A straightforward solution to this dilemma was filed at the California Public Utilities Commission (PUC) in 1981 by a consumer advocate (still active today) named William Marcus.[75] Marcus proposed the use of modest annual rate adjustments to prevent fluctuations in sales (either up or down) from resulting in over- or under-recovery of utilities' previously approved nonfuel costs. Without this "revenue decoupling," utilities and their customers would have automatically conflicting interests on even the most cost-effective energy efficiency.

A Necessary But Partial Solution: Revenue Decoupling

Revenue decoupling makes utilities indifferent to retail energy sales without abandoning the tradition of volumetric pricing and its incentives for customers to use energy efficiently. More than half the states have now adopted this approach for at least one electric or natural gas utility, and a comprehensive order by the Washington Utilities and Transportation Commission is a primer on how to do it effectively, using modest annual true-ups in rates that few if any customers even notice.[76] Revenue decoupling results in very modest rate adjustments that go both ways and do not materially affect rewards to consumers for reducing their use of electricity and natural gas. As the Oregon Public Utility Commission found when it adopted a decoupling mechanism for Portland General Electric in January 2009, responding to claims that decoupling would rob customers of the rewards of conservation: "We believe the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling

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[73] Sometimes the retail sales reduction results in a wholesale transaction, if the utility can resell the unused power, but wholesale rates typically are well below retail rates, and often utilities are required to refund to customers any wholesale revenues exceeding the cost of production (on the theory that customers paid for the generation used in making the sales and should reap any gains).

[74] California Public Utilities Commission, D. 84902 (September 16, 1975), quoted in Barkovitch (1987), pp. 134–35.

[75] See Marcus (1981, Revised July 1981), cited and summarized in Cavanagh (2009), p. 89, n. 14.

[76] Washington Utilities and Transportation Commission (2013).

adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient."[77]

In January 2008, five states had adopted revenue decoupling for at least one electric utility and 13 states had done so for natural gas. The count of decoupled electric utilities stood at seven; the count for natural gas utilities was approximately 20. National campaigns to expand the model were beginning under the joint sponsorship of NRDC, the Edison Electric Institute and the American Gas Association. Just starting to emerge was a worrisome countervailing trend to displace decoupling with rate designs that moved increasing fractions of utility customers' bills into fixed charges, reducing rewards for efficiency improvements (discussed further below).[78]

As of January 2016, the state revenue decoupling counts were 15 for electric utilities and 23 for natural gas utilities, and the number of utilities covered stood at 33 and 53, respectively (more than a three-fold increase in the total from five years earlier). [79] The past year saw Minnesota adopt electricity decoupling for Xcel Energy (March 2015), New York adopt electricity decoupling for the Long Island Power Authority (March 2015), and Idaho adopt electricity and natural gas decoupling for Avista (December 2015). Additional electricity decoupling proposals are pending in Louisiana (Entergy New Orleans), New Mexico (PNM), Oregon (Avista) and Washington (PacifiCorp), with preliminary proceedings also underway before the Missouri and Pennsylvania Commissions, and a filing likely soon from Xcel in Colorado. Currently decoupled investor-owned and publicly owned utilities account for about 25 percent and 12 percent, respectively, of regulated retail electricity revenues for the two sectors.[80]

Extensive empirical evidence attests the minimal rate and bill impacts of revenue decoupling in practice. Based on 1,269 separate rate adjustments produced by decoupling mechanisms from 2005 to 2013, an exhaustive assessment concluded that annual rate changes were "mostly small." The adjustments did not exceed 2 percent for 85 percent of the electricity and 75 percent of the gas rate adjustments. Some 37 percent of the adjustments involved refunds from the utilities to their customers.[81] Put another way, the typical electricity rate adjustment averaged about seven cents a day (up or down); for natural gas utilities it was less than five cents a day.[82]

Revenue decoupling does not guarantee profits or affect a utility's incentive to control costs. The Regulatory Assistance Project has observed that, "[i]n fact, precisely the opposite is true."[83,84] Decoupling provides assurance to a utility and its customers that the utility will recover only authorized revenues (that is, the amount that regulators have already determined is necessary and prudent in order to deliver energy services to customers). A utility's profit will

[77] Oregon PUC Order No. 09-020, p. 28 (Portland General Electric, Jan. 2009).
[78] The 2008 and 2015 state and utility numbers reflect my own annual assessments, prepared and circulated internally, since 2008; a full list of all decoupling orders since 2005 appears in Morgan (2013), pp. 3–4.
[79] Within the past six years, 18 states have approved electricity decoupling, but three of those (Arizona, Michigan and Montana) do not currently have mechanisms in place. The count of decoupled electric utilities does not include three in Michigan with what I expect to be temporarily expired mechanisms; remedial legislation overturning an anomalous court decision is pending.
[80] I am indebted for these calculations to my NRDC colleague Amanda Levin.
[81] Morgan (2013).
[82] Morgan (2013).
[83] Lazar, Weston and Shirley (2011), p. 45.
[84] Lazar, Weston and Shirley (2011), p. 45.

continue to be driven by both its revenues and its costs. Without decoupling, profit is tied both to sales growth and cost control. With decoupling, controlling costs takes on even greater importance, since the utility can no longer increase profits by increasing sales.

A barrier to decoupling for many investor-owned utilities has been a concern that their regulators might link its adoption to a reduction in their authorized return on equity, on the ground that decoupling somehow generates a significant net reduction in utilities' overall financial risks, reducing the cost of equity. Few Commissions have actually done this, however, and none since 2010.[85] The best available empirical evidence, assembled by The Brattle Group in 2014, argues strongly against such prospective reductions. Brattle conducted a rigorous assessment of the effect of revenue decoupling on electric utilities' cost of capital, following up on two earlier studies involving natural gas distribution companies. The authors concluded that decoupling has not had a statistically significant impact on electric utilities' cost of capital.[86]

Most revenue decoupling mechanisms also address an issue that arises in the context of formula rates: How should regulators deal with predictable increases in utilities' costs in the period following the establishment of an authorized annual revenue requirement in a rate case? Many decoupling mechanisms allow annual increases in cost recovery based on changes in utilities' customer counts or other indices.

The Washington Utilities and Transportation Commission recently incorporated anticipated annual escalation in Puget Sound Energy's grid costs in the utility's decoupling mechanism, in the form of a 3 percent annual increase called a "K Factor."[87] Formula rates are another way of providing assurance that authorized multi-year utility costs will be recovered, independently of kilowatt-hour sales. The utility tracks revenue recovery for the cost categories specified in the "formula" and regularly adjusts rates up or down to ensure full (but not excessive) recovery of authorized revenues on a schedule specified by the regulator.[88] The Puget Sound Energy decision is an illustration of what I view as a reasonable integration of the revenue decoupling and formula rate approaches, in a way that eliminates "throughput addiction" while providing reasonable assurances that the utility will recover escalating multi-year costs of grid enhancement.

Decoupling does not moot all rate design issues, although it solves the problem of revenue volatility associated with sales fluctuations. Utilities and other stakeholders still worry, appropriately, about equitable allocation of costs among all grid users, a problem not automatically solved by uniform true-ups in rates to correct for sales fluctuations.

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[85] For a comprehensive overview of these precedents, see Morgan (2013).
[86] Vilbert et al. (2014).
[87] See Washington Utilities and Transportation Commission (2013).
[88] See Chapter 5 of this report.

The Most Promising Rate Design Reforms

Time-Varying Rates

The category of "time-varying rates" includes numerous variants; included for purposes of this discussion are "time-of-use" rates, critical peak pricing and demand charges linked to a customer's peak usage coincident with system peak usage. The core issue is whether all or part of an electric bill should reflect the higher cost to the system of consumption at certain times. Historically, advocates for residential and business interests sparred fiercely over this question, because residential users tended to have "spikier" daily consumption patterns than larger users, causing them to face potentially higher bills as a class if utility rates included significant time-of-use features.

Revenue decoupling can be used, however, to ensure that each customer class pays only its assigned share of revenues[89] and, if so, the real question is whether reflecting time-varying electricity costs in electricity rates is in the public interest. The scholarly consensus in favor (on economic efficiency grounds) is overwhelming, although there are numerous disputes over details (e.g., what time intervals should be used in applying time-varying charges, how steep should the differentials be across time periods, how should time-varying charges be calculated, and how often should the calculations be revised to reflect changing market conditions?). As advanced metering technology expands its deployment, utilities will be able to test multiple approaches with all customer classes; today, many residential customers lack the digital meters needed to determine their time-varying electricity use, but "smart" meters will soon become the norm. EEI estimates that by the close of 2015, 60 million had been installed across the United States (out of about 140 million).[90]

From the perspective of energy efficiency and distributed resources, there are significant upsides potentially associated with time-varying rates, and certainly no cause for reflexive opposition. Evidence has been accumulating that diversified energy efficiency portfolios tend on balance to yield disproportionately positive impacts during periods of peak system use, and the Northwest Power and Conservation Council has recently published findings that reinforce this conclusion in its draft Regional Plan (Figure 3.2).[91] But these same findings counsel against demand charges not linked to systemwide peak periods, which would also lack a comparable grounding in cost and reliability considerations, and could impede beneficial shifts in demand such as off-peak charging of electric vehicles.

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[89] If any given rate design proves to extract more or less revenue from a customer class than expected and authorized, the decoupling mechanism will correct the anomaly within a year through a modest rate adjustment for the affected class.

[90] Communication with T.D. Smith, Edison Foundation, Jan. 6, 2016.

[91] See "Seventh Northwest Conservation and Electric Power Plan, Chapter 12: Conservation Resources," The Northwest Power and Conservation Council, p. 12-6, https://www.nwcouncil.org/media/7149675/7thplandraft_chap12_consvres_20151020.pdf. ("Using best-available load shapes, the Council estimates the 5,100 average megawatts of [long-term cost-effective regional energy efficiency potential] translates to 10,000 megawatts of capacity savings during the regional peak winter hour (6 pm on a weekday in December, January, and February) and 6,200 megawatts of capacity savings during the regional peak summer hour (6 pm on a weekday in July)." The Council is widely recognized as among the nation's most experienced and credible evaluators of energy efficiency potential and results.

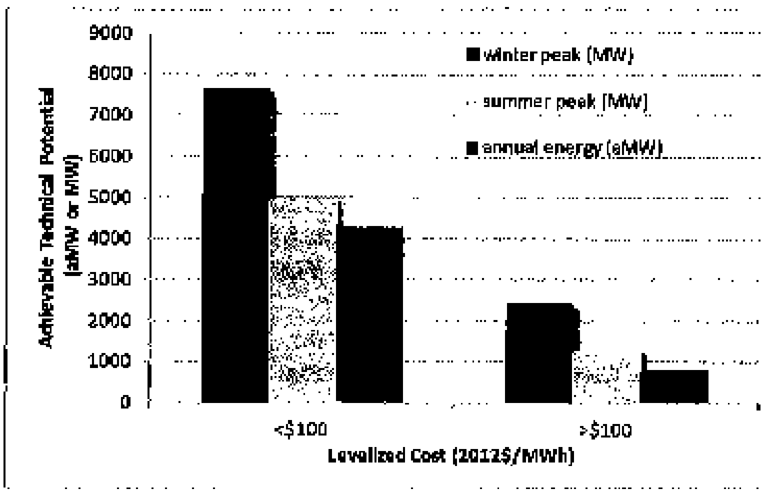

Figure 3.2 Peak and Energy Impacts by Levelized Cost Bundle for 2035 — Northwest Power and Conservation Council

For their part, DG proponents like to emphasize rooftop solar's potential contributions to meeting on-peak system needs.[92] All of this yields optimism about the potential for including a strong time-varying dimension in consensus-based rate design proposals for all customer classes. An excellent starting place for participants in such discussions is the comprehensive rate design manual published recently by the Regulatory Assistance Project.[93,94]

Tiered Rates

Commodity prices in unregulated markets reflect the marginal cost of an additional unit of product, whereas regulated electricity rates are based on the average cost of service. (The average U.S. cost of electricity at the beginning of 2016 was about 11 cents per kilowatt-hour.[95]) In a dialogue that has endured for decades,[96] advocates have sparred over whether to charge different amounts for different levels of consumption within a customer class, yielding either a promotional incentive ("the more you use, the less you pay") or the reverse.

[92] See, e.g., Ho (2016).
[93] See "Smart Rate Design," Regulatory Assistance Project, http://www.raponline.org/featured-work/smart-rate-design.
[94] Lazar and Gonzalez (2015).
[95] The U.S. average electric rate (based on most recent available data) is 10.44 cents/kWh. US EIA, Average Price by State by Provider (EIA-861), January 2016, https://www.eia.gov/electricity/data/state/.
[96] See, e.g., Northwest Conservation Act Coalition (1982), pp. 364–377 (reviewing the debate over how to "promote equitable and resource-conservative rate structures" in terms that remain strikingly relevant in 2016).

With a national average electricity rate of roughly 11 cents per kilowatt-hour for residential customers, and less for nonresidential customers, a tiered structure that raises rates as consumption increases will enhance energy efficiency and DG prospects among those with the largest opportunities to save electricity. As Rich Sedano of the Regulatory Assistance Project points out:

> If the long run marginal cost of electricity is higher than the average rate, a tiered rate is an excellent way to associate marginal use for higher consuming customers with the cost of serving additional energy needs over time. This will tend to promote dynamic efficiency — meaning a sound price signal to promote investment by customer and utility in the proper balance to minimize societal costs, which should be a goal we all share. States can include [various] externalities in their calculation of LRMC [long-run marginal cost] if that is their priority.[97]

Such "tiered rates" also increase revenue volatility for utilities, since they accentuate the revenue impact of consumption increases or reductions at the margin. Here again, revenue decoupling is an important potential source of reassurance that progressive rate design will not come at the expense of utilities' recovery of their authorized costs of service.[98]

Minimum Bills

Minimum utility bills are often confused with monthly fixed charges on utility bills, but in fact they provide a compelling alternative way of ensuring that all grid-connected customers make a reasonable contribution to maintaining the critical infrastructure that they are using. Fixed charges reduce all customers' reward for saving energy and installing distributed generation, by moving revenue out of volumetric charges; minimum bills have this effect only on those who use little or no electricity in a given month (e.g., owners of vacation homes or exceptionally large rooftop solar arrays). Once consumption rises above a predetermined threshold, full volumetric pricing resumes and minimum bills cease to have any adverse effect on incentives to reduce consumption.

For their part, utilities sometimes worry that setting a minimum bill at a small fraction (say, 10 percent to 20 percent) of a customer class's average bill won't yield much incremental revenue or revenue certainty, since most customers in the class are already paying more than the minimum — so why bother with instituting a minimum bill that is irrelevant to most bill payers?

But if one takes seriously the prospect of dramatic increases in both energy efficiency and distributed generation, the number of grid-connected customers potentially at or below the "minimum" threshold could increase significantly before long. The minimum bill would then serve the important function of ensuring that everyone who uses the grid is contributing a guaranteed amount to its maintenance. It may be mostly an insurance policy for the time being, but in an era of concerns about possible utility "death spirals," the policy is very much worth acquiring. The California PUC, long a bastion against any fixed charges in ratemaking, is warming

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[97] The quote comes directly from Sedano's review of the initial draft of this paper (March 2016).

[98] An example of a settlement agreement pairing revenue decoupling with tiered rates is the 2010 submission to the Montana Public Service Commission by the Natural Resources Defense Council, Human Resources Council District XI, and Northwestern Energy, for which the author supplied expert testimony, along with Professor Thomas Power of the University of Montana.

now to minimum bills for residential customers, albeit at a low initial level ($10 per month).[99] The Hawaii PUC has also recently approved the concept, at a higher level ($25 per month for residential customers and $50 for small commercial customers).[100] Those paying these minimum bills are not rewarded for reducing consumption further, but given the small quantity of kWh they are drawing from the grid (10 percent to 20 percent of the typical residential customer's needs), their relative environmental and grid impacts are already modest.

Ineffective or Counterproductive Reforms

Frequent Rate Cases

Some have contended that utilities can be made whole for reduced growth in electricity sales by frequently adjusting rates to reflect changes in demand. Putting aside the nontrivial expense to both public agencies and utility customers of more frequent adversarial clashes over electricity rates, the premise is wrong. Rate regulation never makes utilities whole for losses since the previous rate case; the best it can do is to readjust assumptions in an attempt to avoid such losses in the future. And once the rates are reset, any subsequent reduction in commodity sales costs utilities an increment of fixed cost recovery, with no hope of compensation. No matter how often rate case decisions occur, utilities will spend most of their time between them, and without revenue decoupling, utilities' throughput addiction will continue undiminished.

Higher Customer Fixed Charges

One way of ensuring recovery of authorized costs would be to stop charging for electricity service based on volumetric electricity use, and to make all or most of an electricity bill independent of consumption. This pricing model may work well in some sectors of the U.S. economy, but none have environmental and equity dimensions comparable to electricity service. An extreme version of fixed charge mania has surfaced in Texas, where Reliant's "Predictable 12" plan charges customers a predetermined monthly amount (based on historical consumption) regardless of their electricity use. In the words of NRDC's Amanda Levin:

> Reliant designed this plan to give ultimate bill security to customers, but this new plan has quickly been dubbed the "all you can eat plan." There is no incentive for customers to invest in energy efficiency and no penalty for keeping the AC on at 60 F all summer — even if not at home. During peak summer hours, this plan provides an almost perfectly perverse price signal.[101]

The argument for higher fixed charges is often made on economic efficiency grounds: If much of an electricity bill represents fixed charges, critics argue, using volumetric pricing overstates the short-term cost of meeting demand and makes additional consumption look more costly than it should. This amounts to contending that most utilities today are suppressing beneficial increases in electricity use through their rate designs. Yet the rationale for efficiency programs and standards rests in part on the conclusion that extensive market failures continue to block energy

[99] See id.
[100] See "Hawaii PUC ends net metering program," Utility DIVE, http://www.utilitydive.com/news/hawaii-puc-ends-net-metering-program/407328/.
[101] Levin's findings will appear in a forthcoming chapter of a Fereidoon Sioshansi-edited book on utility business model issues, Utilities of the Future (in press, 2016).

savings that are much cheaper than additional energy production at today's electricity prices. The last thing we need, under those circumstances, is rate designs that encourage additional electricity waste.

Raising fixed charges improves revenue certainty for utilities (although not as effectively as decoupling, unless scaled to the level achieved by Reliant in Texas). But it adversely affects customers with below-average use and is a particularly sensitive issue for low-income advocates.[102] And, unlike minimum bills, it effects an across-the-board reduction in all customers' rewards for saving energy and installing distributed generation. The past year saw the emergence of a nationwide campaign to fight fixed-charge increases, co-chaired by NRDC, Vote Solar and the National Consumer Law Center. The success of that campaign in 32 of 38 cases over its first year adds another reason to rethink any infatuation with higher fixed charges as a promising business model strategy.[103]

Lost Revenue Adjustment Mechanisms

The theory behind lost revenue adjustment mechanisms (LRAMs) sounds benign: Regulators can regularly calculate the "lost revenue" associated with electricity savings delivered by utility programs and incentives, and restore them through rate increases, eliminating the financial penalties that such measures otherwise would inflict on the utilities involved. In that sense LRAMs, if perfectly designed and executed, would partially substitute for revenue decoupling.

But unlike decoupling, LRAMs create a powerful and perverse new incentive for the company to promote programs that look good on paper but deliver little or no savings in practice (because then the company would get a double recovery).[104] For example, poorly designed efficiency measures that customers later replaced or disconnected might well result initially in lost revenue recovery, while allowing the utility also to gain later from higher energy sales after the measures ceased to function. By contrast, revenue decoupling removes any prospect of that wholly inappropriate upside opportunity for the utility when efficiency measures fall short for any reason. Moreover, an LRAM leaves unimpaired strong utility incentives to promote increased electricity use, since (unlike revenue decoupling) it allows utilities to keep any non-fuel revenues secured in excess of those authorized by the commission. Paying a utility bonuses for both increases in its retail electricity sales and its programmatic electricity savings is the metaphorical equivalent of encouraging the CEO to drive with one foot on the brake and the other on the accelerator. Finally, an LRAM yields an automatic rate increase whenever it is applied, whereas rate adjustments under revenue decoupling can be (and have been) either positive or negative.

LRAMs also are unlike decoupling in that they result in automatic utility penalties, in the form of reduced fixed-cost recovery, for all cost-effective electricity savings not directly associated with the load-reducing impacts of utility-sponsored energy efficiency. Cost-effective savings in this

[102] See, e.g., Direct Testimony of John Howat on behalf of Coalition for Clean Affordable Energy, New Mexico Public Regulation Commission, Case No. 1500261-UT (January 2016), and sources cited therein.

[103] Data on fixed-charge increase results were supplied to the author in a personal communication from Devra Wang of the Energy Foundation, November 2015.

[104] See, e.g., Washington Utilities and Transportation Commission (1991), p. 10: "Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor. The company would have an incentive to artificially inflate estimates of sales reductions while actually achieving little conservation."

category include those from efficiency standards administered by government agencies, which can benefit greatly from utility support;[105] informal intervention by utility staff to encourage customer patronage of independent energy efficiency contractors; and effective public education campaigns with multiple participants, including utilities.

Conclusion

In order to fulfill their crucial role in a national (and global) clean energy transition, utilities need and deserve reasonable assurances that recovery of their authorized costs will not vary with fluctuations in electricity use and will reflect appropriate contributions by all grid users. This does not require rate designs that reduce rewards to all or most customers for using less electricity. Alternatives include minimum bills that convert to volumetric charges if the customer exceeds a monthly consumption threshold, time-varying rates that increase with stresses on grids, and inverted rates that raise energy efficiency incentives for the largest electricity users.[106]

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[105] In the Pacific Northwest, over the past 30 years, efficiency standards have achieved results comparable in aggregate to all utility programs combined. See p. 8 of the most recent assessment by the Northwest Power and Conservation Council (Charles and Eckman 2011): http://www.nwcouncil.org/energy/rtf/consreport/2010/2011_10presentation.pdf.

[106] An excellent resource on the "minimum bill" concept is http://www.raponline.org/document/download/id/7361. For a discussion of variable demand charges, see http://www.brattle.com/news-and-knowledge/news/778.

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4. The Economics of Fixed Cost Recovery by Utilities

By Severin Borenstein, Professor of Business Administration and Public Policy in the Economic Analysis and Policy Group of the Haas School of Business, Co-Director of the University of California Energy Institute

Among the many claims about the lessons that economics teaches for fixed-cost recovery, the most common is that fixed costs should be recovered with fixed charges. Standard microeconomics, however, has very little to say directly about how utilities should recover fixed costs, and certainly nothing as simple as this claim. Rather, microeconomics has fairly clear direction on how volumetric prices for electricity should be set to maximize efficiency, that is, to generate the greatest total value for the economy.

The simple guidance on volumetric pricing of electricity is that the retail price of a kilowatt-hour (kWh) should reflect society's full short-run marginal cost of supplying it. To be clear, "Society's" cost includes not just the marginal fuel, labor, capital and other production costs of the utility, but also the externalities caused by generating and selling that incremental kWh of power. Those externalities include greenhouse gas emissions, local air pollution, and other disamenities from the presence of generating stations, as well as transmission and distribution lines.[107] The focus is on short-run social marginal cost, because at any point in time price should reflect the incremental cost of producing one more unit, which will likely be higher when production capacity is strained than when there is plenty of excess capacity.

Largely because of the existence of fixed costs, however, setting the volumetric price of electricity equal to its full social marginal cost in many cases won't raise sufficient revenue to cover the utility's total costs, though the size of the shortfall will depend on many attributes of costs and demand.[108] The shortfall raises the critical question of the most efficient and equitable way for the utility to raise additional revenue. In this chapter of the report, I present an economist's view of a number of alternatives that have been proposed to allow a utility to recover its costs, including fixed going-forward costs that the utility incurs each period, as well as sunk costs that result from past decisions and actions.

In the next section, I briefly outline the foundational principle of economic efficiency in market transactions, which underlies all economic analyses of pricing. In the second section, I apply this principle to electricity pricing and explain why it is likely to lead to a revenue shortfall. The third section then analyzes an array of alternative proposals that allow utilities to recover additional revenue. Though the focus is primarily on economic efficiency, I also discuss equity considerations and impact on lower-income customers. My conclusion is that there is no perfect approach to increasing revenue, but some approaches make much more sense than others.

[107] Of course, the true cost of pollution is itself controversial, but any policy to address externalities confronts this issue, either implicitly or explicitly, when costly actions are taken to reduce pollution. Addressing the externality cost question directly is critical to arriving at transparent and credible environmental and energy policy.

[108] It is worth noting that because economic efficiency starts with setting price equal to short-run marginal cost, it avoids the debate about which costs are fixed. Rather, the focus of revenue collection is on covering total costs (a much less controversial figure), and the question becomes how much additional revenue must be raised to do so starting from the point at which price equals short-run social marginal cost.

Once the options are narrowed, policymakers face a fundamental trade-off between economic efficiency and equity.

The Economic Efficiency of Pricing

The idea that economic efficiency is maximized when price reflects full short-run social marginal cost (SMC) is a bedrock principle of microeconomics, because it is straightforward to show that any departure from SMC is likely to reduce the economic value that the industry can create. Producing a good requires inputs — labor, fuel, machinery, land, etc. — and those inputs have alternative uses. The price of an input is generally a good indicator of its value in its next best use, so economics suggests that the inputs should only be brought together to produce this good if the value of this good to whoever consumes it exceeds the value of all the inputs necessary to make it. Setting price equal to short-run SMC creates the incentive to consume an incremental unit of the good if and only if one values it more than the value that the inputs would create in their next best use.[109] At the same time, customers who are considering an investment in energy efficiency receive a price signal that accurately reflects the social value of the savings such an investment would create.

To illustrate, let's say the incremental input costs of producing one additional unit of a hypothetical good add up to $7.25, but the production process also creates a negative externality (some sort of pollution, for instance) that imposes an additional cost of $1.75. If one sets the price for this good at $9, then everyone who buys it values it more than $9. As a result, there is no unit purchased that is valued less than the collection of inputs (including pollution) that went into making it and every unit valued more than the collection of inputs is purchased.

But what if the price for the good were set at $12? Then anyone who valued an additional unit of the good more than $9, but less than $12, would not buy it. This would be value-destroying, because the value that could have been created by putting together inputs with a cost to society of $9 in order to create a good that gives some specific buyer with a value of, say, $11 would not be created. The failure to make that deal is a loss of $2 of value to society.[110] And there are likely to be many such losses among customers who value the good more than $9 and less than $12. To economists, these losses — illustrated in Figure 4.1 by the upper (pink) triangle — are known as "deadweight loss" or, equivalently, a loss in economic efficiency.

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[109] Some analysts have argued that price should reflect *long-run* marginal cost (LRMC) in order to reflect the capital costs of production. This would not in general yield economic efficiency. For instance, if a system is underbuilt and has a shortage of capacity, economic efficiency dictates that price increase to reflect the scarcity value of the electricity at each moment, regardless of the cost of capital to expand the system's capacity in the longer run. LRMC is appealing as a rough guideline for financing capital expansion, but it is not a good guide to economic efficiency of pricing. Precise economic analysis starts with pricing efficiently, which then makes clear the size of the revenue shortfall. The question of how to make up that shortfall is the subject of this volume. Electricity also differs from many markets due to the need to balance supply and demand with no storage. Borenstein (2000), particularly footnote 1, discusses application of the concepts to that case.

[110] Who bears that loss depends on the price at which a particular deal would have been made. The point is that when the buyer values the good more than it would cost the seller to supply it, there are gains from trade, and failure to make such deals imply a failure of anyone to capture those gains.

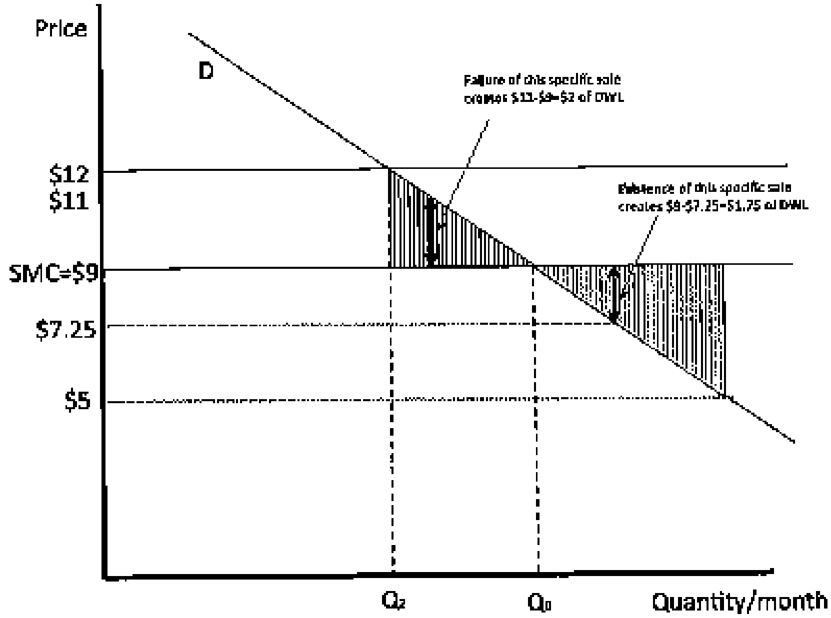


Figure 4.1 Illustration of Deadweight Loss (DWL) From Pricing Above or Below Social Marginal Cost

In practical terms, for example, if we price electricity at $0.22 per kWh when its true SMC is $0.12 (including all pollution externalities), then we might discourage someone from purchasing an electric vehicle when they would have done so had they been able to buy electricity at the true SMC.

Deadweight loss also is created if a good is priced below its SMC. If the hypothetical good illustrated in Figure 4.1 were priced at $5, then anyone who valued the good above $5 would purchase it. But if they valued it less than $9, the value they would be getting from the good would not be great enough to justify all the inputs (including pollution) that went into making it. The deadweight loss created by such underpricing is illustrated by the lower (blue) triangle in Figure 4.1. For instance, if there is a buyer who values the good at $7.25, that purchase of the good would generate $1.75 in deadweight loss or, put differently, would lower the total value created in the economy by $1.75. In practical terms, for example, if the true SMC of electricity is $0.12 per kWh and the price is set at $0.08 per kWh, then we will encourage people to leave some lights on when the value they are getting from doing so is less than the cost they are imposing on society.

Efficient Pricing of Electricity

In textbook competitive markets, price equals marginal cost, and all gains from trade are realized. But the relationship can break down for at least three reasons:

1. *Externalities.* If sellers in the market are highly competitive, but producing the good generates negative externalities, then competition will set a price below the social marginal cost to reflect only the marginal cost that the sellers have to bear. Because

those sellers don't internalize the cost of externalities (by definition), the price will be too low, and too many sales will occur.

2. *Market power of sellers.* If the market is not highly competitive, then sellers may be able to make greater profit by raising prices above competitive levels. Because sellers have such "market power," prices will be too high, and too few sales will occur. Some transactions that would have created economic value will be stifled.

3. *Failure to cover costs when price is equal to marginal cost.* In some cases, generally ones in which firms have significant fixed costs, competitive pricing might not be sustainable because it does not generate enough revenue to cover a firm's total costs. In economics, these situations are referred to as "natural monopoly," because the presence of large fixed costs suggest that it would be more economically efficient to have one firm do all production. Standard examples include local distribution lines for electricity or telephones, because it is widely agreed that it does not make economic sense to have duplicate wires running down the street.

All three of these potential distortions exist in regulated electric utility markets. There are clearly large fixed costs and natural monopoly tendencies in local distribution, and probably also transmission, of electricity. As a result of this tendency toward monopoly, electric utilities are either regulated by a state agency or owned by a local government or consumer-owned cooperative, in part to prevent the electricity provider from exercising market power and raising price above competitive levels. At the same time, generation and distribution of electricity creates negative externalities.

So then what does economics bring to the question of how to recover fixed costs? The answer begins by recognizing the ideal scenario, in which the price of each kWh is set to reflect the social marginal cost of providing it, and customers understand that price and optimize their consumption in response to it. This would involve the price changing second by second, and consumers — or their "smart" devices — responding to those second by second changes.[111] And it would involve price reflecting not just the utility's marginal cost of production, but also the cost of all externalities created.

In this scenario, the price would be very high at times when demand is strong, and there is a high probability of a supply shortage so that the marginal cost of producing one more kWh is potentially very high and would be much lower at low demand times. It has long been known that such pricing could produce more or less revenue than the firm needs to cover its costs.[112] But if there are fixed costs — which don't scale up with peak or total quantity sold — then there will be a tendency toward a revenue shortfall. That is, true fixed or sunk costs tend to create a revenue shortfall problem when electricity is priced to reflect marginal cost.

There is a countervailing effect, however, which is the failure to price externalities. Utilities seldom have to pay for the negative externalities that their business creates, but in order to

[111] Though we are institutionally quite far from this scenario, all the technology for it exists and is, in fact, already used for trading financial instruments. It would also be straightforward to offer alternatives to customers who don't want to be exposed to such price volatility (Borenstein 2013).
[112] Borenstein (2000) presents a more technical version of this argument. Boiteaux (1949) and Steiner (1957) first made these points.

create appropriate incentives for consumption they should still be adding those social costs to the volumetric price of electricity. Doing so would increase their revenues without increasing costs and bring them closer to breaking even, including covering their fixed costs. There is no logical or theoretical reason that the net effect of fixed costs and pricing-in externalities would necessarily cause efficient volumetric pricing of electricity to generate either positive or negative profits for the utility. But realistic calculations suggest that charging efficient volumetric prices would likely still lead the utility to lose money.[113] And if society ever requires utilities to pay for the externalities they create, that will increase utility costs further and move utilities further from being able to recover their total costs while charging economically efficient prices.

Of course, utilities depart from this ideal pricing scenario in many ways, most importantly by charging prices that vary little, if at all, over time. Commercial and industrial customers typically face just a two-tier peak/off-peak pricing structure, while the vast majority of residential customers face no time variation in price at all. Absent a strong reason to think demand is more or less elastic at peak times, the most efficient time-invariant price is the average of the prices that would be charged in the ideal scenario (in which prices change minute by minute), which yields the same total revenue as under time-varying pricing.[114] So the fact that utilities actually charge prices that vary little or not at all over time doesn't change the fundamental issue of how to recover fixed costs. Nor would appropriate time-varying pricing solve the problem.

In recent years, the fixed cost recovery problem has grown as more costs have been added to utility operations that are not directly tied to providing an incremental kWh of electricity. For instance, energy efficiency programs, discounts to low-income customers, and subsidies for installing distributed generation are now all costs that the utility must recover, but are not part of the social marginal cost of providing a kWh to a specific customer. In addition, energy efficiency programs and distributed generation have reduced demand and thus required that the revenue shortfall from marginal-cost pricing be made up over a smaller number of kWh. More generally, declining demand, regardless of the cause, is likely to increase the revenue shortfall that utilities (and regulators) will face if volumetric prices are set efficiently to equal SMC.

The variety of fixed costs that a utility incurs raises a distinction between customer-specific fixed costs and systemwide fixed costs. Customer-specific fixed costs vary according to whether the customer receives service from the utility, regardless of how many kWh the customer consumes. These include incremental metering and billing costs for that customer, and maintaining the connection from the distribution system to the customer's meter. Systemwide fixed costs cannot be attributed to a specific customer and are independent of the kWh consumed on the system. These include construction and maintenance of the local distribution networks, the corporate structure and public purpose programs, such as energy efficiency and distributed generation programs. The distinction has particularly important implications for discussions of equity or cost causality.

[113] See Borenstein and Bushnell (2015), footnote 26.
[114] Borenstein and Holland (2005), p. 475.

Variable Costs: Costs that vary with the quantity of output the firm produces within a period of time

Fixed Costs: Costs that do not vary with output within a period of time

Sunk Costs: Costs that have already been incurred (even if not yet paid) and for which no refund is possible

Short-Run Marginal Cost (or Incremental Cost): The additional cost a firm incurs when it increases production by one unit within a period of time, recognizing that some inputs (typically capital) cannot be adjusted within the period

Total Costs: All costs that the firm has attributed to production within a period of time. Some fixed and sunk costs are amortized over multiple periods, with only a part attributed to production in each period.

Alternative Approaches to Covering a Revenue Shortfall

Departures from pricing at SMC have implications for both economic efficiency and equity concerns. In discussing utility rate structures, the term "equity" can have two different meanings — the first consistent with some notion of fairness across customers with different consumption levels and patterns, and the second consistent with some notion of fairness across customers of different levels of income or wealth. For clarity, I will use "equity" for the first concept and "distributional effects" for the second.

I will assume from this point forward that efficient pricing, price set equal to SMC, results in a revenue shortfall. However, the opposite situation, excess revenue from setting price equal to SMC, can also occur.[115] So I will focus on the question of how to increase revenues to the point that the utility can break even, including a fair return on capital invested.

Average-cost Pricing

For most of the history of utilities, the answer to such a revenue shortfall has been to raise the volumetric price of the electricity. Because utilities are generally monopolies facing fairly inelastic demand, it is almost always possible to raise the price enough to allow the firm to break even. This approach is often referred to as "average-cost pricing" because the price is set at a level to cover the average cost per kWh, where that average is inclusive of both variable costs and fixed costs. As the example in Figure 4.1 demonstrated, however, setting price above SMC creates deadweight loss by impeding some consumption that is socially valuable. Much of the economic analysis of regulatory pricing and taxation over the last 90 years has attempted to

[115] For instance, utilities that have a large supply of hydroelectric power from dams built many decades ago, but still must generate incremental power from fossil-fuel plants, may very well have a SMC that now exceeds their average cost per kWh.

improve economic efficiency by developing alternate ways to raise the needed additional revenue while creating less deadweight loss.

Still, average-cost (AC) pricing remains widespread because it is so attractive on equity grounds. In its simplest implementation, AC pricing implies charging every customer — rich or poor, heavy user or light, residential or commercial — the same price per kWh. Equally important, it means that all customers make payments above marginal cost to help cover the fixed costs, and that a customer's contribution to the extra revenue needed to cover fixed costs is proportional to that customer's usage.[116]

For instance, assume the marginal cost is $0.12 per kWh, but there are significant fixed costs so the utility must charge $0.22 per kWh — an extra $0.10 per kWh — to break even. Then a customer who consumes 100 kWh is making a $10 contribution toward the additional required revenue, while a customer who consumes 400 kWh is making a $40 contribution. Many people and policymakers find this allocation equitable.

Even on equity grounds, however, it is not obvious that one customer consuming four times as much electricity as another customer should make a four times larger contribution to the additional required revenue, when that additional revenue is needed to cover costs that are independent of the level of consumption by an individual or even by all customers in aggregate. For instance, it might be the case that the customer consuming only 100 kWh receives a very high value from those units of consumption, while the heavier consumer might have a readily available alternative (e.g., self-generation), so is getting much less value from the utility.

"Ramsey" Pricing — Differentiated Pricing Based on Demand Elasticity

The earliest contribution on the issue of raising revenue while minimizing deadweight loss[117] pointed out that if a consumer has more elastic (i.e., price-sensitive) demand, raising the price charged to that consumer creates greater deadweight loss relative to the amount of additional revenue it creates compared to another consumer with less elastic demand. Raising the price to customers with more elastic demand simply causes them to cut back their consumption substantially even though they value those units greater than SMC, creating more deadweight loss while purchasing fewer units and thus contributing less to the revenue requirement. Figure 4.2 illustrates that both D1 and D2 consume Q0 when the price is set equal to SMC. But if the price is raised to AC, much more additional revenue is extracted from D1, and less deadweight loss is created, than when price is raised for D2.

[116] AC pricing can also be implemented in a time-varying context by imposing either a constant dollar adder to price in each period or a constant proportional markup. See Borenstein (2005).
[117] Ramsey (1927).

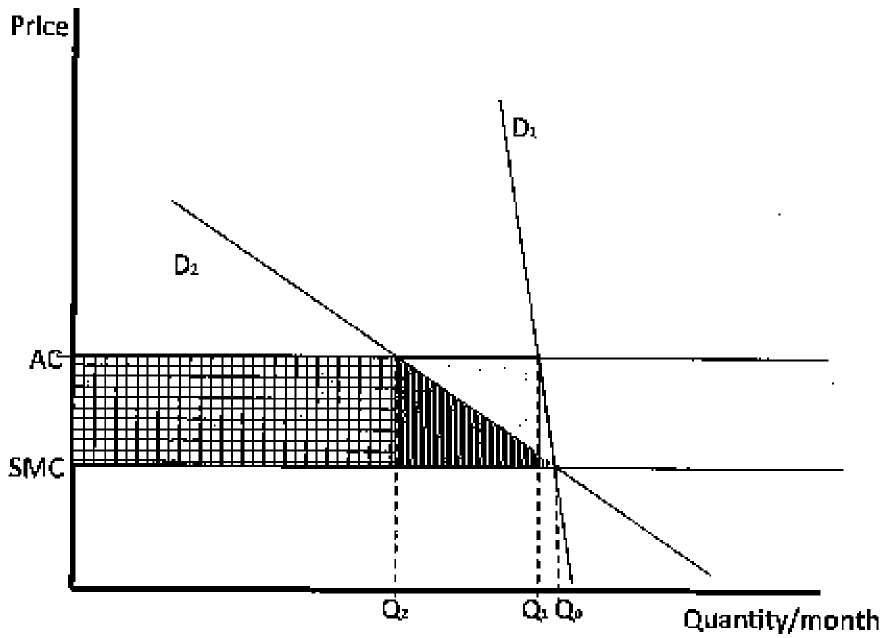


Figure 4.2 Illustration of the Impact of Demand Elasticity on DWL From Raising Price

The resulting "Ramsey pricing rule" says that in order to minimize deadweight loss while meeting the breakeven revenue requirement for the utility, groups of consumers with very inelastic demand should pay higher markups over marginal cost than groups of consumers with very elastic demand. This is much more than an abstract theoretical result. In fact, it describes well the outcome in which a utility gives special rates to commercial and industrial (C&I) customers who credibly argue that they would otherwise locate elsewhere. The willingness of businesses to locate elsewhere if electricity rates are too high demonstrates high demand elasticity and implies that raising the rate to these customers will do more to reduce their demand than to actually bring in greater revenue. That resulting deadweight loss manifests as fewer jobs and less economic value created by these C&I customers.[118]

Application of the Ramsey pricing rule, however, nearly always raises significant equity concerns. Customers with very inelastic demand, who receive higher prices under the rule, are those who have few alternatives and "need" the good. Charging those customers higher prices conflicts with many notions of equity.

Fixed Charges

In most of the United States, residential electricity customers pay a fixed charge each month that is independent of the quantity they consume, though the size of the charge ranges across utilities from just a couple of dollars to $20 or more. Fixed charges are a very attractive way to minimize deadweight loss while raising additional revenue, because they give customers no incentive to change their electricity consumption choices. Thus, if setting the volumetric price of

[118] C&I customers that are willing to relocate demonstrate that elasticity comes not just from a customer changing quantity consumed, but also from the customer relocating to purchase from a different seller.

electricity at SMC yields insufficient revenue, one common suggestion is to set a fixed charge that raises sufficient additional revenue to cover the revenue requirement.

A fixed monthly charge of $10, $20 or $30 is unlikely to lead any customers to disconnect from the utility, because at least a basic level of electricity consumption is a necessity.[119] And once customers decide to pay the fixed charge, they rationally would consider it no more relevant to how much electricity they consume than the same increase in rent, medical insurance, food or any other expense. The decision of how much to consume would still be based on the incremental price of electricity.

Still, questions about the economic efficiency of such an approach have also been raised if customers base their decisions on imperfect information. If consumers don't pay much attention to their bills, they may not distinguish between the marginal price of electricity and their average price, inclusive of the fixed charge, or understand the impact on their overall bill. Convincing evidence of a similar information failure has been presented for more complex tiered billing structures that I will discuss below. Research, however, has not determined whether or not consumers are generally able to sort out a monthly fixed charge from the marginal price of electricity when making consumption decisions. Nonetheless, this is an area deserving of further study.

Practical concerns have also been raised about how the fixed charge concept might be applied beyond residential customers. A fixed monthly charge for commercial or industrial customers is rarely suggested. The reason for this distinction is clear: While households do range substantially in size, most still have between one and 10 individuals and a similar range in square footage of living space and other determinants of electricity demand. In contrast, C&I customers have a much wider range of employees, sales, square footage and other demand determinants. It would seem arbitrary and objectionable to impose the same fixed charge on an auto assembly plant as on a corner store, or a family living in a small apartment.

Some have suggested using a fixed charge that increases when the customer crosses certain consumption thresholds. If no customers are near the thresholds, then this approach could potentially segment customers into different fixed charge categories without creating perverse incentives for changing behavior. In reality, however, the distribution of customer usage is smoothly populated across nearly all consumption levels found among household customers, and the distribution among small commercial customers overlaps significantly with household customers. So such graduated fixed charge tariffs would create incentives for many consumers to reduce usage in order to drop down to a lower fixed charge. Effectively, the thresholds are points at which the price for an incremental kWh is drastically greater than SMC and is thus likely to create substantial deadweight loss.

Applying a uniform fixed charge even among residential customers nearly always raises objections on equity and distributional grounds. The equity argument is just the flip side of the

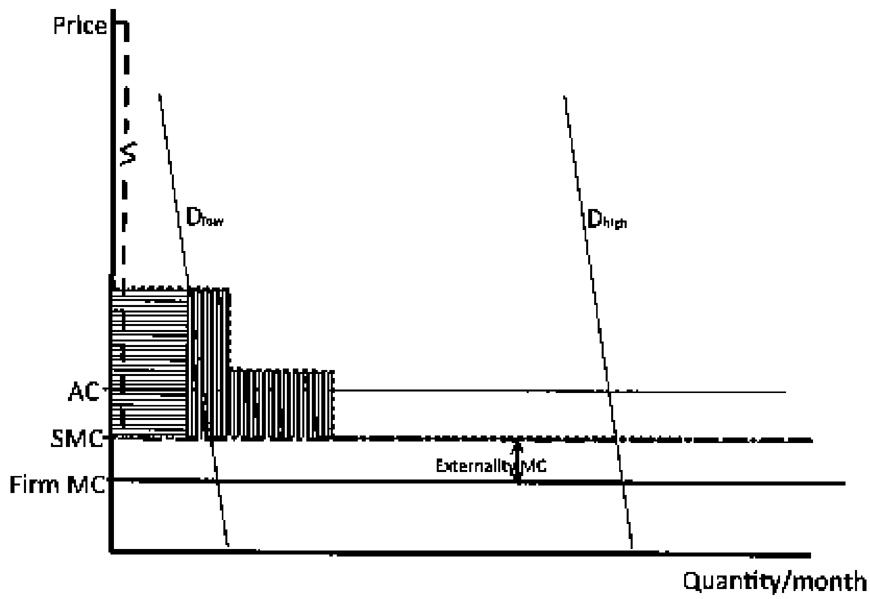
[119] The argument is not as convincing in natural gas distribution, because some households could indeed be on the margin of disconnecting from the utility and using only electricity or liquefied petroleum gas, as discussed by Borenstein and Davis (2012). Virtually all U.S. households are customers of an electric utility, but only about half of households are customers of a natural gas utility. If distributed electricity storage becomes more cost-effective, however, high fixed monthly charges for electric service might one day also lead to "cutting the cord."

discussion in favor of AC pricing: Why should a customer who consumes very little have to make as large a contribution toward covering fixed costs as a customer who consumes much more? The distributional argument is based on the accurate, but sometimes overstated, claim that wealthier households consume more electricity. For example, while this is true for customers of the three large investor-owned California utilities, most low-income customers are already on a separate tariff targeted specifically at the poor.[120] Among moderate- and high-income customers, there is still a difference in average consumption, but it is much more modest.

Tiered Pricing

Under tiered pricing the marginal price a customer faces changes with the quantity consumed. It also is often referred to as increasing-block or decreasing-block pricing, depending on whether the marginal price rises or falls with the customer's consumption. For example, an increasing-block price schedule might charge the customer $0.12 for each of the first 300 kilowatt-hours (kWh) the customer consumes during the month, $0.18 for each additional kWh between 300 kWh and 500 kWh, and $0.30 for each kWh above 500 kWh.

Tiered pricing was originally introduced in the decreasing-block form. That can be seen as a compromise of sorts between AC pricing and a fixed charge with lower constant pricing. As shown by the dashed vertical line in Figure 4.3, a fixed charge is just a very high price for the first tranche of kWh consumed during the billing period, and then a lower price for all additional kWh, while AC pricing charges the same price for all kWh. Under AC pricing, the additional revenue above SMC is raised proportionally to consumption, while with a fixed charge it is equally allocated among all customers regardless of consumption. Declining-block pricing (the dotted line in Figure 4.3) allocates more of the additional revenue needed to higher-demand consumers (the vertically striped area plus the horizontally striped area, for D_{high}) than to lower-demand consumers (just the horizontally striped area, for D_{low}), but not proportionally more.



[120] Borenstein (2011).

Figure 4.3 From Fixed Charges to Decreasing-Block Pricing to Flat Rates

At the same time, because decreasing-block pricing implies above-AC pricing for lower-quantity units of consumption, the marginal price for higher-quantity units can be closer or equal to SMC, and can thus generate less deadweight loss for those units. Compared to fixed charges, however, decreasing-block pricing has the drawback that lower-consuming customers will face a very high marginal price and will respond by inefficiently cutting back consumption. To the extent that there are few or no customers on the lower-quantity tiers (if all customers have demand around D_{high} or greater), the impact is very similar to a fixed monthly charge, because nearly all customers contribute the same amount toward the additional revenue requirement. In that case, nearly all customers face the lowest marginal price.

In the last 20 years, increasing-block pricing has become much more prevalent in residential U.S. electricity tariffs than decreasing-block pricing. Arguments for increasing-block pricing are based on both distributional concerns and conservation goals. The distributional argument is that low-income households are more likely to be consuming more of their electricity at low tier rates, and therefore increasing-block structures redistribute the revenue burden to wealthier households on average. Analysis suggests that the redistribution is quite modest if the utility also has a separate tariff for low-income households, as most utilities do. Furthermore, many lower-income households are made worse off by the increasing-block structure, and many higher-income households benefit from it. Overall, if the goal is to help lower-income households, programs that are more accurately targeted at them are likely to be more effective.[121]

The foundational economic analysis I present earlier demonstrates that reducing consumption creates net benefits to society only if the value of that consumption is less than the full social marginal cost. Thus, charging a price that includes the cost to society of externalities makes sense, but charging a price that is substantially above the full SMC will cause some consumption to be discontinued for which the customer values the service more than marginal cost, even inclusive of the external marginal costs it imposes. Put differently, reduction of consumption that is not valued highly enough to justify the external costs it imposes on society is a worthy goal, but not all conservation is beneficial. Electricity regulators almost always recognize this reality even when they adopt increasing-block pricing, resulting in a plethora of special rates (or special baseline quantities that determine the quantities at which the increasing-block steps occur) for favored activities, such as electric heating or charging electric vehicles. That approach, however, puts the regulator in the position of trying to discern the consumer's value of each electricity use, a task that market economies eschew in general, because they recognize how poorly the government performs that task.

It is also not clear that increasing-block pricing actually lowers aggregate consumption among residential customers. While it does raise the marginal price for high-use customers above a revenue equivalent AC price, it also lowers it for low-use customers below the revenue equivalent AC price. If all customers are well-informed and respond efficiently to marginal price, then aggregate consumption is likely to fall. But customers' response to complex, multi-step, increasing block tariffs corresponds more closely to a model in which they use a heuristic that

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121 Borenstein (2012).

reflects the average price they face.[122] If the increasing-block tariff is revenue neutral with the AC price schedule, then the average price across all units consumed must be the same, and increasing-block pricing would generate no net reduction.[123] Analysis of a very steep increasing-block tariff in place for a large California utility yielded an estimated 2.3 percent reduction in residential consumption assuming customers responded efficiently, but in practice the tariff probably causes an *increase* of about 0.3 percent.[124]

The economic efficiency of increasing-block pricing, compared to AC pricing, depends on the reduction in deadweight loss for customers who respond to a price that is less than AC (but still presumably above SMC) versus the increase in deadweight loss for customers who respond to a price that is greater than AC. The net effect on economic efficiency will almost surely be negative.[125] Analysis for one California utility estimates that compared to AC pricing, the increasing-block tariff the utility uses increases deadweight loss by an amount equal to about 3 percent of revenues received from residential customers.

Finally, for the same reason as with monthly fixed charges, tiered pricing makes very little sense in the context of C&I customers. Because there is a much wider range of electricity demand across companies than across residential customers, it is hard to see how a common tiered pricing structure could be applied to all C&I customers, or even large subsets of them. Some have suggested that the baseline quantities on which the tiers are based could be a function of past usage by the customer, but this creates incentives for distorting consumption in order to alter the baseline.[126]

Minimum Bills

The mathematics of a minimum bill is simple, but frequently ignored: A minimum bill is a combination of a fixed charge and a certain quantity of free electricity. For instance, if the price of electricity is $0.10 per kWh and there is a minimum bill of $8 per month, that is identical to a fixed charge of $8 per month plus receiving the first 80 kWh for free. Thus, a minimum bill is the combination of a fixed charge and an extreme version of increasing-block pricing, as illustrated in Figure 4.4. If the minimum bill is small enough, implying a quantity of free electricity that is less than nearly every customer uses, then the fixed charge and free electricity exactly offset, and the minimum bill has no impact on either the bills of the customers or the finances of the utility.

[122] Ito (2014).

[123] This argument assumes that the average demand elasticity is the same for lower-consuming customers as for higher-consuming customers. Ito tests that assumption and finds no statistical difference between the groups.

[124] Ito (2014).

[125] Borenstein (2012). The reason for this is that the amount of deadweight loss generated by pricing above SMC goes up approximately with the square of the P-SMC differential. In that case, a simple mathematical proof shows that the minimum deadweight loss results from charging all customers the same differential — that is, AC pricing.

[126] Borenstein (2014) discusses a similar issue in which the baselines used to determine what customers are paid for reducing consumption in a billing period are based on each customer's past usage.

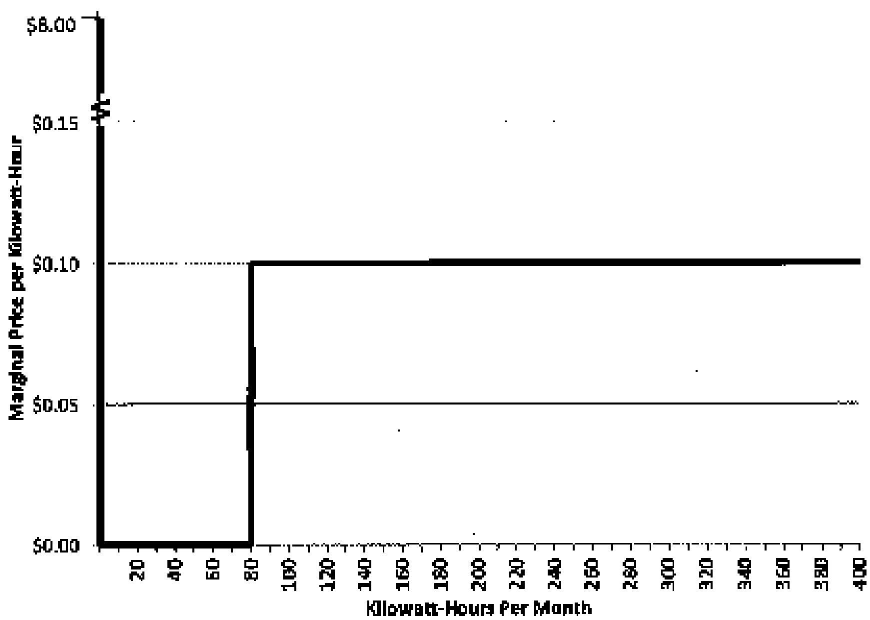

Illustration of Rate Structure with Minimum Bill (Min Bill $8, p=$0.10/kWh)

Figure 4.4 Illustration of Effective Marginal Price of Electricity Under Minimum Bills

If the minimum bill is high enough to actually raise the amount owed to the utility by a significant number of customers, then it creates very perverse incentives for those customers, reducing their cost of incremental consumption to zero until they hit the minimum bill. Zero is well below the SMC for nearly every unit of electricity a utility sells, so a minimum bill has the effect of encouraging electricity consumption from which the customer gets much less value than is imposed on society by its production.

Thus, from both an efficiency and equity point of view, minimum bills are inferior to the alternative of setting price equal to SMC for the equivalent quantity and then charging a fixed charge that is smaller than the minimum bill. For instance, returning to the example above with a minimum bill of $8 and marginal price of $0.10 per kWh, let's say the true SMC is $0.06 per kWh. In that case, it would be more economically efficient and more equitable to charge $0.06 per kWh for the first 80 kWh plus have a fixed charge of $3.20. That would have no impact on the bills of customers consuming more than 80 kWh. It would lower the bill of customers consuming less than 80 kWh, but it would still give them an efficient incentive not to waste electricity.[127]

[127] The fact that some customers use less than 80 kWh and the volumetric price is above marginal cost implies a slight revenue shortfall. This could be offset by a small increase in either the fixed charge or the lower-tier volumetric price. To be concrete, in this example if 10 percent of customers were below 80 kWh and that group of customers consumed an average of 50 kWh, then this alternative tariff would require either setting the fixed charge (for all

Demand Charges

It is unclear why demand charges still exist. Charging customers for their peak usage during a billing period has been supported as an approximation to a customer's demand during system peak periods, but it was never a very good approximation, as the customer's peak may not be coincident with the system peak.[128] Furthermore, the single highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission and distribution capacity.

In any case, the value of such approximations has been mostly eliminated with smart meters that record usage in hourly or shorter intervals. Smart meters permit time-varying price schedules that can easily be designed to more effectively capture the time-varying costs that a customer imposes on the system. Demand charges could be justified when "dumb" meters could only record aggregate consumption and peak consumption, but could not even log information on when that peak occurred.[129]

An additional explanation for demand charges is that they capture the customer-specific fixed cost of providing a certain level of service capacity to the customer's site. Such capacity, however, is established by making up-front and largely sunk investments in the local distribution network and the final connection to the customer. These may constitute a substantial share of the fixed costs that create the concerns addressed in this report, but the cost of such capacity is determined by the attributes of the connection, not by the customer's peak usage after the connection is established. A monthly fixed charge based on the customer's service capacity would more appropriately capture these costs.

The use of demand charges has also created a large market of consultants advising customers on how to reduce their peak demand that is wasteful from a societal point of view. Customers faced with demand charges place high private value on reducing their very highest hour of usage, even if there are other hours in which usage is nearly as high, and even if none of those hours are coincident with system peak times.

At their very best, demand charges may not do a bad job of capturing some customer-specific fixed costs and may quite imperfectly reflect the time-varying costs of the customer's consumption. But customer-specific fixed charges that reflect service levels, and time-varying pricing, accomplish these goals much more effectively, so why would one use demand charges?[130]

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customers) at $3.32 instead of $3.20 or setting the volumetric charge at about $0.0616 instead of $0.06 for quantities up to 80 kWh. Either would leave the utility with the same profits as the proposed minimum bill.

[128] Recently, some have started using "demand charge" to refer to a fee that is based on a customer's use during the systemwide peak demand. This is a form of time-varying pricing similar, though inferior, to what is known as "critical peak pricing." The discussion of demand charges here does not apply to that newer definition.

[129] Most C&I customers now have meters that can record time-varying consumption. The majority of residential customers do not yet have such "smart" meters, but the meters they have also cannot record peak consumption needed for a demand charge. Switching them to the technology for a demand charge would cost nearly as much as the technology for time-varying pricing.

[130] Berg and Tschirhart (1988) propose a system under which customers purchase fuse capacities from the utility, which limits their maximum power consumption. With the progress in technology over the last few decades, this could no doubt be done in a more sophisticated way, but still only makes sense to the extent it reflects real costs imposed by the customer's peak usage.

Frequent Rate Cases, Formula Rate Plans and Decoupling
Infrequent rate adjustments, especially when a utility's costs and sales quantities are highly uncertain, create a mismatch between actual revenues and targeted cost recovery.[131] If the regulatory commission is forward looking and attempts to equalize actual with targeted revenues on average, then the errors will cancel out over time.[132] But if the commission systematically underestimates cost increases or overestimates quantities demanded, then infrequent resetting of rates will create a perpetual revenue shortfall. Although this is a concern for utilities and the regulatory process, it is quite apart from the problem of recovering utility fixed costs. Even if rates were reset daily, the presence of significant fixed costs would mean that economically efficient electricity prices would still likely fail to raise sufficient revenue to cover all of the utility's costs, for the reasons discussed above.

One mechanism for addressing the revenue and cost uncertainty a utility faces is known as a Formula Rate Plan (FRP). FRPs provide for an automatic adjustment of rates when revenues deviate from either target revenue or some formula for pro forma costs. In this way, rate adjustments can be made between formal rate cases in a way that is transparent and can be debated ex ante. While FRPs can help to align revenues with costs, like frequent rate cases they do not address the fundamental conflict between marginal-cost pricing and full-cost recovery. Even if costs and revenues could be predicted perfectly, the tension between economic efficiency and utility cost recovery presented earlier in this chapter of the report would remain.

FRPs are related to "decoupling," which has been adopted in electricity rate setting to align utility incentives with the goals of energy efficiency programs. If sales fall short of expectations due to improved energy efficiency, or generally due to weak demand, the utility will suffer a shortfall, because its costs will decline by less than revenues. This shortfall is caused by the fact that volumetric prices are generally set above the utility's marginal cost in order to recover fixed costs. Decoupling assures the utility that it will be able to recover the lost revenue through price adjustments going forward. In doing so, it reduces or eliminates the incentive of a utility to oppose, or drag its feet on, energy efficiency programs. But as with frequent rate cases and FRPs, the problem that decoupling is meant to solve is quite apart from the general problem of recovering utility fixed costs. Even if decoupling works perfectly, and utilities make all-out efforts to promote energy efficiency, economically efficient volumetric electricity prices would still likely raise insufficient funds without other measures to address the revenue shortfall.

Conclusion
In the end, there is no good answer to the question of how a utility should recover fixed costs, but there are less bad ones. Ratemaking should begin by setting prices to reflect the full time-varying short-run social marginal cost of generating and delivering electricity. These prices should include "adders" for the externalities created, even if the utility is not required to make explicit payments for those social costs, as is the case for most externalities today. As a result, the revenue from these adders can be used to close the gap between the revenue collected from efficient pricing and the revenue the utility needs to cover its costs.[133]

[131] Frequent rate cases could be full-blown rate cases or smaller rate-adjustment filings.
[132] Even in those cases, short-term revenue shortfalls can still create financial stresses that end up raising the costs of the utility and, eventually, the prices to customers.
[133] Even if regulators are unwilling to, or restricted from, imposing explicit adders to reflect externalities, this still suggests that when they mandate markups of volumetric prices above the utility's marginal cost — as virtually all

In general, however, efficient pricing that reflects full social marginal cost will still not cover all fixed and variable costs of the utility. Increasing the volumetric price of electricity has appeal on equity grounds, because it allocates the revenue shortfall across users based on the quantity they consume. However, it also raises the marginal price of electricity above social marginal cost and therefore distorts consumption choices. As customers have more choices of energy supply — e.g., between electrified and liquid fuel-based transportation or between distributed generation and grid supply — the deadweight loss from sending distorted price signals is likely to rise.[134] While raising the volumetric price has been the most common policy choice for many decades, it is particularly important now to consider alternatives.

The leading alternative is higher fixed charges, but they can lead to significant equity concerns and even some potential efficiency issues. Recovering customer-specific fixed costs through fixed charges — calibrated to reflect cost differences in service levels — is quite appealing on both equity and efficiency grounds. But a fixed charge that is the same for customers with massively different demands will violate a common sense of equity, and a so-called "fixed charge" that is based on past or current usage is effectively volumetric and creates deadweight loss.

Objections to any level of fixed charge based on distributional consequences ignore the fact that the alternative of recovering all revenues through volumetric charges arbitrarily harms many low-income customers and benefits many high-income customers. Targeted means-tested programs that help low-income households are a more appropriate response to these concerns.

The more difficult fixed cost recovery issue results from systemwide fixed costs that cannot be attributed to any one customer. Because such costs are substantial, pricing electricity at social marginal cost and having a fixed charge that reflects customer-specific fixed costs is still likely to leave a revenue shortfall. There is no ideal policy for recovery of the additional needed revenue, but the least bad from both an efficiency and equity point of view is almost surely a combination of higher fixed charges and an adder to time-varying volumetric rates. For the reasons I have discussed, it is very difficult to justify demand charges, tiered rates or minimum bills as part of the solution. Nor would frequent rate cases, formula rate plans or decoupling solve the fixed cost recovery problem.

While it may be unsatisfying that economics and policy analysis does not yield a clear solution, it does yield valuable guidance. Incorporating that guidance in electricity ratemaking would be a very useful first step in rationalizing prices.

regulators do — those markups would be more economically efficient if they were calibrated to reflect variations in the externalities created by incremental generation.

[134] See Borenstein (2015).

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5. Literature Review

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This chapter briefly describes the ratemaking options discussed in this report through a review of publications by a wide range of energy experts to highlight current practices, potential pros and cons, and the diversity of views. The references cited provide additional information.

Higher Fixed Charges

A fixed charge, also called a customer charge or basic service charge, is a fee each billing period that does not vary with the consumer's energy usage. Typically, fixed charges for electric utilities cover metering, meter reading and billing costs. Fixed charges also may cover other costs, such as the utility's customer call center and a portion of distribution costs.[135]

Increasing the fixed charge is one way to ensure utilities have more stable revenues to cover fixed costs, and fixed charges have increased over time. Raising fixed charges also is one response to concerns about revenue loss from higher levels of distributed energy resources (DERs), particularly associated with customers with onsite solar photovoltaic (PV) systems (typically rooftop). Solar PV customers with net-zero consumption from the grid still pay the fixed charge portion of their electricity bills.[136]

A major change in the level of the fixed charge is under consideration in many jurisdictions. Utilities in 25 to 30 states have proposed increasing fixed charges for all customers, only for customers with onsite distributed generation, or only for net metering customers.[137] Many of the proposed increases have been significant — more than doubling previous fixed charges. Utility regulators have allowed some of these proposed increases, often modified downward, but have disallowed more proposals than they have allowed.[138]

Higher fixed charges stabilize utility revenues[139] and customer bills[140] because a smaller share of costs varies based on weather and other uncontrollable factors. Higher fixed charges also reduce the need for more frequent rate cases to resolve utility cost recovery shortfalls because more of a utility's fixed costs are recovered through the fixed charge.[141] And, unlike revenue decoupling or lost revenue adjustment mechanisms (discussed later in this chapter), higher fixed charges preserve utility revenues while reducing, rather than enhancing, cross-subsidies from energy efficiency or distributed energy program participants to nonparticipants.[142]

However, when fixed charges are raised substantially, volumetric energy prices often are lowered in order to collect the revenue requirement from the combination of rate components.

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135 Lazar (2013); Costello (2014).
136 Bird et al. (2015).
137 Stanton (2015); NC Clean Energy Technology Center and Meister Consultants (2016).
138 Stanton (2015); Kind (2015).
139 Blank and Gegax (2014); Faruqui et al. (2012); Whited et al. (2015).
140 Testimony of Greg Bollom, Madison Gas and Electric (2014).
141 Lowry et al. (2015).
142 Kind (2013).

Reducing the volumetric price weakens customer incentives for energy efficiency.[143] For the same reason, potential cost savings from distributed generation and other distributed energy resources are lower, reducing their attractiveness[144] and leading the rooftop solar industry to oppose higher fixed charges.[145] On the other hand, higher fixed charges mitigate a disincentive for utilities to promote energy efficiency, since their revenues are less dependent on variable sales,[146] although the disincentive related to fewer investment opportunities persists.

In addition, customers will demand more electricity if volumetric prices are reduced. The extent of this impact depends on the longevity of the price change. In the short run, customers may run their air conditioners and other electric appliances more, but the effect is likely limited. In the longer run, however, customers would tend to switch to electric devices from devices directly fueled by natural gas or other fuels, leading to larger changes in electricity consumption.[147]

Higher fixed charges may disproportionally burden low-income households, which also tend to be lower-usage customers.[148] Depending on how much the fixed charge increases, moderate-income households that live paycheck to paycheck also may be significantly impacted. Service may be unaffordable for these households, particularly when electricity bills increase regardless of how much energy they consume, resulting in disconnections.[149] Other industries (e.g., telephone and cable services) have witnessed customer attrition in response to raising fixed charges.[150] Concerns over impacts on low-income households generally have led consumer advocates to favor low fixed charges.[151] Some proponents of high fixed charges recommend offering optional rate structures more similar to current rate designs for lower-income customers to opt into.[152]

The principle of economic efficiency dictates that, in general, goods and services should be priced according to the true cost of their production, delivery and consumption.[153] However, this principle leads different observers to different conclusions regarding the appropriate level of fixed charges. Importantly, views also vary as to what costs should be considered "fixed."

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[143] Hledik (2014); Bird et al. (2015); Whited et al. (2015).
[144] Bird et al. (2015); Whited et al. (2015).
[145] Hledik (2014); Lazar and Gonzalez (2015).
[146] Costello (2014).
[147] In the short run, a 10 percent reduction in the residential retail price of electricity could be expected to increase consumption by 2 percent to 4 percent. If such a reduction persisted over the long run, we would expect increases from 3 percent to 10 percent. See Paul et al. (2009).
[148] Bird et al. (2015); Lazar et al. (2011); Whited et al. (2015); Kind (2015).
[149] Lazar (2015).
[150] Lazar and Gonzalez (2015); Graffy and Kihm (2014).
[151] Blank and Gegax (2014); Hledik (2014); Lazar and Gonzalez (2015); National Association of State Utility Consumer Advocates (2015); also see https://nasuca.org/customer-charge-resolution-2015-1/.
[152] Testimony of Greg Bollom, Madison Gas and Electric (2014).
[153] Ackerman and De Martini (2013); Braithwait et al. (2007); Testimony of Greg Bollom, Madison Gas and Electric (2014); Lazar and Gonzalez (2015); Parmesano (2007).

Utilities generally view investments in generation, transmission and distribution infrastructure as fixed, in that they are not sensitive to how much energy an individual customer consumes.[154] Most of these costs are currently recovered through variable rates, and utilities are increasingly seeking to correct what they see as a pricing mismatch.[155]

Others note that in the long run, all or almost all of a utility's costs other than direct customer service (metering, billing, accounting) are variable.[156] Some argue that high fixed costs push variable prices below the long-run marginal cost of supplying electricity.[157] If retail rates are below long-run marginal cost, utility customers may not make all of the energy-saving investments that are optimal from a societal point of view because the payoffs will be too low, and utilities will make more costly investments to meet higher customer demand. Moreover, even costs that are fixed in the short run may be dependent on customer usage.[158] For example, according to this view, it may be appropriate to recover power plant and transmission investments in proportion to usage.[159] Firms in competitive industries generally recover all costs through variable pricing even when a portion of their costs is fixed. A basic role of utility regulation is to better approximate such markets.[160] Thus, high fixed charges "are a poor method to recover utility system costs,"[161] "have the most adverse impacts" among various options to recover utility fixed costs,[162] and "provide utilities with stable revenues, but have many adverse impacts on electric[ity] consumers and energy policy."[163]

While revenue stability is an overarching reason for utilities' interest in higher fixed charges, utilities also are concerned that current levels of fixed charges may fall short of the actual cost of providing grid services to distributed generation customers.[164] Some utilities have proposed different rate classes for distributed generation customers.[165] For example, utilities in at least eight states have proposed fixed charge increases for solar PV customers, all distributed generation customers, or all customers who are net-metered.[166] McLaren et al.[167] state that these charges may be appropriate for customers whose systems exceed a certain size threshold or a certain percentage of load.

In addition, utilities are concerned about spreading fixed costs over a shrinking base of retail electricity sales, as penetration of customer-hosted distributed generation (and energy efficiency) increases. That could create a feedback loop: Utilities raise volumetric rates, which in turn makes distributed generation (and energy efficiency) more attractive, causing increased

154 Blank and Gegax (2014).
155 Ackerman and De Martini (2013); Testimony of Greg Bollom, Madison Gas and Electric (2014); Lazar and Gonzalez (2015).
156 Lazar (2013); Whited et al. (2015).
157 Lazar et al. (2011).
158 Blank & Gegax (2014); Lazar (2013); Whited et al. (2015).
159 Lazar (2015).
160 Bonbright (1961).
161 Lazar (2013).
162 Lazar and Gonzalez (2015).
163 Lazar (2015).
164 Borlick and Wood (2014); see also Satchwell et al. (2014), which shows that two "prototypical" U.S. utilities experience increasing cost recovery shortfalls as PV penetration increases.
165 Ackerman and De Martini (2013).
166 Bird et al. (2015); Stanton (2015).
167 Bird et al. (2015).

deployment and further revenue shortfalls.[168] Alternatively, increasing fixed charges also could create a feedback loop: Higher fixed charges increase customers' incentive to defect from utility services entirely. Fewer utility customers means that each remaining customer must bear a greater share of system costs, which could cause fixed charges to rise further, leading to greater defection and so on.[169]

Minimum Bills

A minimum bill sets a lower limit that a customer will pay the utility each billing period, even if the customer's energy usage is zero. Under common proposals for a minimum bill, the fixed charge plus energy charges will typically exceed the minimum for the majority of customers. Thus, a minimum bill structure would have no impact on most customers, who would effectively continue to pay a volumetric rate to cover both power supply and distribution costs. However, customers that reduce their energy usage to very low levels, particularly through the use of distributed energy systems that provide for most or all of their electricity needs, could trigger the minimum bill.[170]

Minimum bills are not currently widespread. However, a few utilities have implemented them, notably in California.[171]

Minimum bills are more targeted than fixed charges, as they apply only during months when energy usage is low (for example, for vacation homes and vacant property) or where rooftop solar generation is high.[172] Customers most likely to trigger minimum bills are households that are strongly seasonal in their electricity usage and households with distributed generation systems.[173] Because a minimum bill will rarely be triggered if the minimum is set low, it will result in much less utility revenue, and therefore a much smaller decrease in volumetric rates, compared to a fixed charge of the same amount.[174]

Therefore, minimum bills do not discourage energy efficiency or increase electricity consumption as much as equal-sized fixed charges. Minimum bills may better align electricity prices with the long-run marginal cost of consumption, because nearly all costs vary in the long run. In months when usage dips below the minimum bill amount, consumers have poor incentives for energy efficiency as the cost of electricity consumption becomes zero. However, this would apply to relatively few customers.[175]

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[168] Darghouth et al. (2015).
[169] Graffy and Kihm (2014).
[170] Lazar (2014); Bird et al. (2015).
[171] Stanton (2015).
[172] Bird et al. (2015).
[173] Lazar and Gonzalez (2015).
[174] Lazar (2014).
[175] Lazar (2014).

Solar PV users who offset their consumption completely would still pay the minimum bill, which would reflect at least in part the value of the grid services they receive.[176] However, minimum bills may reduce solar PV system sizing, as customers will attempt to avoid reducing their usage below the minimum bill amount.[177]

Demand Charges

A demand charge is based on the customer's highest energy usage in a specified time interval — for example, 15 minutes or an hour — over the course of the billing period, typically a month. Some demand charges include a "ratchet," meaning that the highest demand a customer registers in a billing period may apply over the course of the following year. The rationale for a demand charge is that the utility must maintain available capacity (for distribution at a minimum, and generation and transmission as well in vertically integrated regions) to meet the customer's peak demand at all times. The demand charge is measured in kilowatts (demand), rather than kilowatt-hours (energy usage). Rate structures with demand charges have a relatively lower energy charge than rate structures without demand charges because they work in combination to collect the utility's revenue requirement.

Demand charges have typically been applied to the individual peak demand of each customer, regardless of whether that occurs during peak periods for the utility system. However, demand- (capacity-) related costs are primarily associated with the peak demand of the utility system, not the individual customer's peak demand. Only highly local components of the distribution system (e.g., service drop, line transformer) are sized to the individual customer load.[178] Therefore, under a typical demand charge — based on *non*-coincident usage — customers who use the most electricity at times that are not coincident with the system peak pay to offset system peak costs nonetheless.

Demand charges already are in place for large commercial and industrial customers. Demand charges are currently offered in optional residential rate structures by at least nine utilities, though most have not seen significant enrollment,[179] and have recently been proposed for solar PV customers in a handful of states.[180]

[176] Lazar (2015).
[177] Bird et al. (2015).
[178] Lazar and Gonzalez (2015); Bird et al. (2015).
[179] Hledik (2014).
[180] Bird et al. (2015).

Demand charges have historically been unpopular with residential customers.[181] They may find demand charges difficult to understand[182] and are generally less equipped to monitor and shift load than commercial and industrial customers.[183] On the other hand, demand charges provide customers an incentive to reduce utility system costs through improved load management[184] — if the charge is based on demand that is coincident with the utility system peak. Utilities also would avoid a potential cost recovery shortfall due to customers who reduce their overall energy consumption but not their peak consumption.[185]

Implementing demand charges requires metering that can measure demand. Smart meters have been deployed in about half of U.S. homes.[186] In the absence of metering capable of measuring residential demand, some recommend charging all customers in a rate class (for example, all residential customers) according to the average peak customer demand in that class (which is effectively a higher fixed charge) because costs to serve customers are similar across the class.[187] Others argue that, due to the high correlation between usage and peak demand, in the absence of smart meters it is more appropriate to recover most demand-related costs through variable rates.[188]

Compared to high fixed charges, demand charges are less likely to discourage energy efficiency[189] or distributed solar PV[190] and are not as burdensome on low-income households.[191]

Perspectives differ on the relationship between traditional demand charges (charges based on the customer's own peak demand, as opposed to the customer's usage during the utility system's peak demand) and the drivers of actual costs. According to Lazar, demand charges "track cost causation very poorly"[192] as the only costs driven by a customer's individual peak usage are transformer costs.[193] In contrast, other energy experts point out that 50 percent or more of a typical customer's bills are due to capacity-related costs.[194]

Much of the literature on demand charges is coincident with discussion of time-varying rates (discussed next). Some energy experts find time-varying rates more appropriate than demand charges.[195] Others support rates that include both a charge based on customer peak demand and a time-varying rate structure.[196]

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181 Braithwait et al. (2007).
182 Lazar and Gonzalez (2015); Lazar (2013).
183 Glick et al. (2014); Bird et al. (2015).
184 Testimony of Greg Bollom, Madison Gas and Electric (2014); Hledik (2014).
185 Hledik (2014).
186 Wood (2016).
187 Testimony of Greg Bollom, Madison Gas and Electric (2014).
188 Blank and Gegax (2014).
189 Bird et al. (2015).
190 Glick et al. (2014); Hledik (2014).
191 Hledik (2014); Bird et al. (2015).
192 Lazar (2013).
193 Lazar and Gonzalez (2015); Lazar (2015).
194 Blank and Gegax (2014); Testimony of Greg Bollom, Madison Gas and Electric (2014); Electric Power Research Institute (2014).
195 Lazar and Gonzalez (2015); Lazar (2015); Parmesano (2007).
196 Glick et al. (2014).

Time-Varying Rates

Time-varying rates encompass both traditional time-of-use rates, such as daily on- and off-peak rates and rates that vary by season (typically higher in summer or winter, depending on the time of utility system peak), as well as newer dynamic pricing rates such as critical peak pricing and real-time pricing.[197]

While time-varying rates have been the default rate design for many years for large commercial and industrial customers,[198] who are equipped with meters that can measure energy usage in short time intervals, only about 5 million U.S. households participated in dynamic pricing programs of any kind as of 2014.[199] However, more utilities have begun offering optional residential rate schedules that vary by time of day. And some utilities are moving toward a default time-of-use tariff for residential customers.[200]

Most energy experts note the significant mismatch between static electricity rates and the dramatic temporal variation in the actual cost of electricity production — and the poor price signals static rates send to customers.[201] Time-varying rates can partially or even fully remedy this problem.[202] Many experts identify time-varying pricing as a best practice for rate design.[203] Well-designed time-varying pricing encourages customers to minimize electricity use during high cost periods, helping to reduce utility system costs over time.

Time-varying rates may offset cost recovery issues caused by deployment of solar PV technology: As solar PV deployment rises, it will shift the utility's peak system demand to times when solar PV output is lower, thus dampening the impacts of solar deployment on cost recovery.[204] This shift already has occurred, for example, in California at certain times of year, when afternoon solar PV production is offsetting enough load that system peak demand has shifted into the evening — the so-called "duck curve" load profile.[205]

Consumer advocates tend to be skeptical of time-varying rates in part because low-income households, households with older or very young members or with medical conditions, and some shift workers may have limited ability to shift load.[206] In addition, some time-varying rate designs make customer bills less stable and shift price risk from the utility to consumers.[207] That's particularly the case with real-time pricing, where electricity rates fluctuate frequently (e.g., every hour) to reflect changes in market prices. Recent studies have found that residential consumers can adjust their usage effectively under other forms of time-varying rates, such as

[197] Faruqui et al. (2012); U.S. Department of Energy (2010).
[198] Faruqui et al. (2012).
[199] EIA (2014).
[200] For example, see the statement by the Sacramento Municipal Utility District (https://www.smud.org/en/residential/customer-service/rate-information/rates-2016-2017/) and the California Public Utilities Commission's decision on rate reform for residential customers. (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF).
[201] Braithwait et al. (2007); Glick et al. (2014).
[202] Costello (2014).
[203] Lazar (2013); Parmesano (2007); Glick et al. (2014); Kind (2015); Hledik (2014).
[204] Darghouth et al. (2015).
[205] Lazar (2016).
[206] Lazar and Gonzalez (2015).
[207] Testimony of Greg Bollom, Madison Gas and Electric (2014).

traditional time-of-use rates with on- and off-peak periods — and critical peak pricing variations that add a very high price during a very limited number of hours of the year.[208]

Another consideration is that under flat rate pricing, "peaky" customers — who use more electricity when it is most expensive for the utility to acquire — are subsidized by less "peaky" customers who use more off-peak, inexpensive electricity.[209]

Noting the variation in customer tolerance for this price risk, some recommend maintaining different rate options that allow customers to choose depending on their tolerance.[210] Some consumer advocates question the overall cost-effectiveness of the advanced metering infrastructure required to support time-varying rates, and some public utility commissions have disallowed proposed charges to support the purchase of such equipment.[211] Other observers hold that time-varying rates are "cost-effective for virtually all customers" due to falling costs of advanced metering.[212]

Time-varying rates may cause their own problems for fixed cost recovery. Depending on the details of the rate structure, this might occur if fewer peak price events occur than expected or if customers reduce consumption in response to time-varying rates.[213] Studies have shown that time-of-use rates reduce overall consumption by as much as 5 percent.[214] Decoupling, discussed further below, could help address this issue.[215] However, Braithwait et al.[216] note the problem of adverse selection: Customers who can save money on time-varying rates are more likely to enroll in them, where enrollment is optional. Increasing rates for default flat pricing structures, which can be justified by the extra cost and risk to the utility in maintaining such static pricing, may address this issue.[217] Opt-out, time-varying pricing also may mitigate this problem, as enrollment rates in recent studies have been 3.5 times higher than for opt-in enrollment (93 percent versus 24 percent),[218] so the pool of time-varying customers would include most "typical" users.

Tiered Rates

Inclining (or increasing) block rate structures charge a higher rate for each incremental block of electricity consumption. Conversely, under declining (decreasing) block rates, prices decrease as usage increases. Declining block rates have largely fallen out of favor because they do not reflect the increased utility costs associated with greater energy usage.

Inclining block rates are common for residential customers. They can be justified on several grounds. Since air conditioning use is a large component of electricity usage and also is a driver of peak consumption, inclining block rates serve as a proxy for time-varying rates to some

[208] Cappers et al. (2015).
[209] Hledik and Lazar (2016).
[210] Braithwait et al. (2007).
[211] AARP (2012); also see Baltimore Gas and Electric Company (2015) for denial of the requested surcharge.
[212] Parmesano (2007).
[213] Faruqui et al. (2012).
[214] King and Delurey (2005).
[215] Faruqui et al. (2012).
[216] Braithwait et al. (2007).
[217] Braithwait et al. (2007).
[218] Cappers et al. (2015).

extent.[219] Inclining block rates also lower costs for low-usage customers, providing an allocation of low-cost electricity to meet basic needs.[220] Consumer advocates favor them for this reason.[221] On the other hand, steeply inclining rates may create poor price signals on one or both ends of the tiering (in other words, the head block and tail block) and may place undue burden on the subset of low-income households with higher consumption.[222]

Many favor inclining block rates as a strategy to promote energy efficiency by deterring high levels of electricity usage.[223] However, some evidence suggests that they may not do so in practice.[224] Evidence does suggest that inclining block rates redistribute cost from small to large volume users; usage correlates weakly with income.[225]

Declining block rates are more rare today, but can be justified on the bases of declining economies of scale to serve larger users and as a substitute for higher fixed charges to ensure that customers pay closer to their share of system costs.[226]

Tiered rates can be combined with other rate structures presented here. For example, utility rate structures can combine inclining blocks with time-varying features and low fixed charges.[227]

Forward test years involve a forecast of utility revenues and costs for a future time period, rather than relying on a historical test year to set rates. In an environment where utility costs are rising, using a forward test year in a general rate case to determine the utility's revenue requirement and billing determinants can help alleviate under-recovery of utility costs. Forward test years also can anticipate energy efficiency efforts and thereby alleviate under-recovery of costs from the remaining sales, reducing utility disincentives to pursue these programs. Forward test years raise the evidentiary burden on utility rate-setting processes, though well-understood methods have developed. Forward test years are only an option where authorized by state law and utility regulators; they are not currently an option in all states.

For more information, see Lowry et al. (2015); Lowry et al. (2010).

[219] Lazar and Gonzalez (2015); Lazar (2013); Parmesano (2007).
[220] Lazar (2013); Orans et al. (2009).
[221] Lazar and Gonzalez (2015).
[222] Costello (2014).
[223] Kind (2015); Orans et al. (2009).
[224] Ito (2014).
[225] Borenstein (2012).
[226] Lazar (2013).
[227] Lazar (2013); Kind (2015).

Decoupling

Decoupling is a regulatory tool that breaks the link between utility revenues and energy sales. Specifically, it is a price adjustment mechanism that ensures the utility recovers its allowed revenue for fixed costs, as determined by the state public utility commission, regardless of the utility's actual energy sales. Under a typical revenue-per-customer allowance, decoupling tends to lead to small annual increases in revenues. Whether prices increase or decrease under decoupling depends on whether average energy consumption by customers is declining or rising as the number of customers changes.[228]

About a third of U.S. states have decoupled one or more of the electric utilities they regulate. Additional proposals for decoupling are underway and expected in the future,[229] though some states have turned down decoupling proposals.[230]

According to Lazar and Gonzalez, "a well-designed revenue regulation framework [i.e., decoupling] is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause."[231] The authors point out that, under decoupling, rates are still predominantly volumetric, customer bills are predictable, cost recovery is not regressive, and fewer rate cases are necessary. Further, decoupling can focus utility management efforts on cost control, which provides benefits both for utility customers and shareholders. Decoupling also reduces the utility's disincentive to embrace energy efficiency and other distributed resources as a cost-effective strategy.[232] Braithwait et al.[233] note that decoupling can ameliorate cost recovery concerns brought on by time-varying pricing. According to Costello, decoupling does "not seriously violat[e] any core regulatory objective" and reduces the risk of excessive utility returns.

However, others note that decoupling reduces risk to utilities and therefore should be accompanied by lower authorized rates of return.[234] Moreover, decoupling reduces revenue risk from lost sales regardless of whether the cause is energy efficiency improvements or other factors, some of which may not be a desirable reason for adjustments.[235] Costello finds that customer benefits are less clear than utility benefits, which has led consumer advocates to oppose decoupling in some cases.[236]

An issue raised against decoupling is that it insulates a utility from some risks — such as macroeconomic shocks — that have nothing to do with the policy rationales decoupling is intended to address.[237] If poorly designed, decoupling can create perverse incentives, potentially causing greater rate instability and additional cross-subsidies among consumers.[238] Kihm notes that utilities whose regulated rate of return exceeds their cost of capital will wish to

[228] Moskovitz et al. (1992); Eto et al. (1994); Lazar et al. (2011).
[229] Costello (2014).
[230] AARP (2012).
[231] Lazar and Gonzalez (2015), p. 20.
[232] Lazar et al. (2011).
[233] Braithwait et al. (2007).
[234] AARP (2015).
[235] Testimony of AARP (2013).
[236] Costello (2014); AARP (2012).
[237] AARP (2012); Parmesano (2007); Meehan and Olson (2006).
[238] Meehan and Olson (2006).

increase energy sales even in the presence of decoupling because volume of electricity sales, not earned rate of return, will remain the primary driver of their valuation.[239]

Decoupling can cause rates to fluctuate year to year due to conditions in the previous year, such as weather, that cause utilities to over- or under-recover their fixed costs. Morgan[240] shows that these adjustments have generally been small.

Lost Revenue Adjustment Mechanisms

Under these mechanisms, rates are adjusted periodically, such as annually, to specifically address revenue loss resulting from energy efficiency and potentially other distributed energy resources. In so doing, lost revenue adjustment mechanisms (LRAMs) improve utility revenue stability, reduce utility disincentives related to energy efficiency, and protect against under-recovery of utility costs due to utility energy efficiency programs. According to the Institute for Electric Innovation, 19 states had LRAMs as of December 2014.[241] These mechanisms are currently the most popular mechanism, ahead of decoupling, for "relaxing the link between revenue and system use in the U.S. electric utility industry."[242]

LRAMs are accompanied by their own challenges. They are strongly dependent on estimated impacts of energy efficiency programs, which may not match actual load impacts and related revenue shortfalls, as well as other controversial assumptions such as avoided costs and discount rates.[243] These mechanisms encourage optimistic estimates of impacts from utilities. They also tend to force activity into utility programs and away from other viable energy efficiency mechanisms.[244] The adjustments may not receive the same scrutiny as utility costs considered during a general rate case, thus diminishing incentives for utilities to control costs.[245] If rate cases are infrequent, LRAM adjustments relative to old baselines can result in windfall gains to utilities.[246]

[239] Kihm (2009). Kihm shows that about half of utilities fell into this category during the period of his analysis. Such utilities remain averse to energy efficiency, distributed generation and other measures that decrease sales, although decoupling would still preserve utility revenues in the face of these deployments.
[240] Morgan (2013).
[241] Institute for Electric Innovation (2014).
[242] Lowry et al. (2015), p. 17.
[243] Gilleo et al. (2015).
[244] Lazar (2013); Lazar et al. (2011).
[245] AARP (2012).
[246] Gilleo et al. (2013).

Performance incentives for shareholders of investor-owned utilities are mechanisms that provide rewards for reaching goals specified by utility regulators. Some mechanisms also impose a penalty for performance below these goals. Performance incentives for energy efficiency or other distributed energy resources may allow utilities to earn a return on these resources, in a manner similar to the return on investments in capital assets such as distribution substations or generating plants.[247]

Some 29 states had some form of performance incentive for energy efficiency in place as of 2014.[248] Most, though not all, of these states also had either decoupling or a lost revenue adjustment mechanism.

Performance-based incentives for energy efficiency and other distributed energy resources are an option to recover revenue shortfall caused by adoption of those resources.[249] Analysis has shown that utility incentives for energy efficiency can lower customer bills[250] and improve a utility's business case for energy efficiency.[251] Correct calibration of these incentives is a regulatory challenge.[252] Careful incentive design is necessary to avoid unintended consequences such as disputes around performance measurement[253] and potential strategic behavior or gaming on the part of utilities.[254]

Going beyond performance-based incentives, comprehensive performance-based regulation also includes multiyear rate plans. Instead of filing a rate case every year or two, the utility operates under a rate plan that generally lasts four to five years. Formulas (attrition relief mechanisms) trigger automatic adjustments to the utility's allowed revenues between rate cases without linking these adjustments to a utility's actual cost, encouraging utility management efficiency and cost containment. Performance incentives may apply to such measures as service quality and customer service, as well as energy efficiency. This is the topic of another report in the Future Electric Utility Regulation series.[255]

[247] Institute for Electric Innovation (2014).
[248] Institute for Electric Innovation (2014).
[249] Lazar and Gonzalez (2015); Lazar (2015); Nowak et al. (2015).
[250] Satchwell et al. (2011).
[251] Cappers et al. (2009).
[252] Lazar and Gonzalez (2015); Lazar (2015).
[253] Chandrashekeran et al. (2015); Kaufman and Palmer (2012).
[254] Costello (2014).
[255] Lowry and Woolf (2016).

Frequent Rate Cases

Frequent rate cases are another option for ensuring utility revenue stability. However, most stakeholders view frequent rate cases as an incomplete and generally undesirable solution. In addition, if there is only a small change in underlying costs but a large change in retail sales, a general rate case may not be an appropriately targeted tool. Decoupling and formula rate plans can reduce the frequency of general rate cases, a point cited in support of these options.[256] Further, even annual rate cases may not solve cost recovery problems.[257]

Formula Rate Plans

Mark Newton Lowry and Matthew Makos, Pacific Economics Group Research, drafted this section of the literature review.

A cost-of-service formula rate plan (FRP) allows a utility to reset rates to better recover its cost of service without a rate case when its earnings fall above or below a predefined earnings "deadband."[258] Unanticipated changes in revenues or costs that result in earnings surpluses or deficits that exceed the deadband trigger true-up mechanisms that adjust rates so that earnings variances are reduced or eliminated.[259] An FRP can thus serve as both a revenue tracker and a broad-based cost tracker.[260]

FRPs are often implemented as substitutes for cost of service regulation in situations where frequent rate cases are likely due to a tendency for costs to grow more rapidly than delivery volumes and other billing determinants.[261] Conditions that cause earnings attrition include a surge in system modernization investment and slow growth in the delivery volume per customer.[262] While FRPs can address the problem of declining average use of the electric system that other states address through revenue decoupling, FRPs often are accompanied by revenue decoupling or LRAMs.[263]

FRPs do not always address major plant additions.[264] In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost often is recovered through a separate tracker.[265]

Key issues in the design of an FRP include the design of the earnings true-up mechanism, performance standards and monitoring, the duration of the plan, treatment of major capital expenditures, the frequency of rate adjustments, and the procedure under which the plan and utility's performance would be assessed by the regulator during the FRP period.[266] Earnings true-up mechanisms in FRPs commonly move the return on equity all, or almost all, of the way

256 Lazar and Gonzalez (2015); Lowry et al. (2013).
257 Lowry et al. (2013).
258 Costello (2010).
259 Lowry et al. (2015).
260 Lowry et al. (2013); Costello (2011).
261 Edison Electric Institute (2011).
262 Costello (2014).
263 Lowry et al. (2015).
264 Lowry et al. (2015); Entergy Mississippi (2015).
265 Lowry et al. (2015); Schlissel and Sommer (2013).
266 Costello (2014).

to its regulated target *without* sharing variances in earnings.[267] This is an important distinction between the earnings true-up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans under performance-based regulatory approaches.

Proponents of FRPs cite some of the same benefits that are attributed to multiyear rate plans.[268] Regulatory cost is markedly lower than frequent rate cases.[269] Formula rates can mitigate rate shock.[270] Senior utility management can devote more attention to their basic business. Operating risk is reduced, and utilities are less likely to experience significant over- or under-earning.

A common argument against FRPs is that they reduce incentives for a company to operate efficiently.[271] Costello emphasizes that the design of the earnings true-up mechanism is essential to the efficacy of an FRP, as it significantly impacts cost-containment incentives for the utility and the distribution of risks between utility stakeholders and utility customers.[272] For example, Costello notes that an FRP that reduces rates too quickly in response to cost reductions eliminates incentives for the utility to improve efficiency, while an FRP that allows a utility with poor cost management to immediately adjust rates upward to meet its target return on equity rewards the utility with essentially "cost plus" regulation. In some FRPs, the rate of return on equity is not updated and can become stale if the FRP operates for an extended period of time, leading to rates being reset to a point that is too high or too low.[273]

This concern is exacerbated by provisions in some FRPs that provide insufficient opportunity to review the causes of variances in earnings. Limits sometimes are placed on the review of formula rate filings that are far more restrictive than those in general rate cases.[274] In retail jurisdictions, time periods for the review of filings are sometimes limited to two months or less, and intervenors are sometimes excluded from the review process.[275] Review is sometimes limited to verification that the formula has been correctly implemented.[276] This situation can lead to the recovery of imprudent costs that would be disallowed in general rate cases.[277]

To address these concerns, mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its operation and maintenance expenses may be limited by a formula tied to an inflation index.[278] FRPs in Illinois and Mississippi contain several targeted performance incentive mechanisms.[279]

Formula rates have been used by the Federal Energy Regulatory Commission (FERC) and its predecessor agency the Federal Power Commission to regulate interstate services of energy

[267] Lowry et al. (2015).
[268] Costello (2014).
[269] Hemphill and Jensen (2016).
[270] Lowry et al. (2015); Entergy Mississippi (2015). In practice, however, major plant additions are often subject to alternate ratemaking treatments.
[271] Costello (2014).
[272] Costello (2011).
[273] Schlissel and Sommer (2013).
[274] Costello (2014); Schlissel and Sommer (2013).
[275] Entergy Mississippi (2015); Schlissel and Sommer (2013).
[276] Entergy Mississippi (2015); Schlissel and Sommer (2013).
[277] Costello (2014); Hempling (2012).
[278] Mobile Gas Service (2015).
[279] Aggarwal (2014).

utilities for decades.[280] Lowry et al. provides a detailed list of precedents for retail formula rates.[281] Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s.[282] Formula rates also are used for Illinois power distributors. The use of formula rates to regulate natural gas distributors has grown rapidly in the Southeast and South Central States.[283]

[280] Lowry et al. (2013).
[281] Lowry et al. (2015).
[282] Edison Electric Institute (2011).
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Utility Financial Solutions, LLC

October 24, 2017

Mr. Mark Kotschevar
General Manager
Rochester Public Utilities

Dear Mr. Kotschevar,

It is a pleasure to submit additional information on the industry and specifically customer charges.

The industry has been changing because of energy efficiency technologies and customer installed generation. Residential customers classes were once considered a homogenous class, meaning customers usage patterns were all similar. Today that is no longer the case. Residential customers usages vary substantially and many electric utility rate structures do not reflect the fixed and variable cost of providing electric services. This results in cost shifting between customers, with some customer paying above cost of service and others below cost. A critical component of prevent cost shifting is the establishment of appropriate customer charges. The industry standard components used to identify the customer charge as directed by the National Association of Regulatory Utility Commissioners includes:

1. Costs to install and maintain metering
2. Cost to bill the customer
3. Cost of the customer service department
4. Cost of the service drop to the customer
5. Minimum sizing on distribution system

The minimum system identifies the sizing requirements and costs to provide a minimum amount of usage to a customer. In other words, the cost of extending a minimum size wire between the utilities substation and the home or facility.

I hope this letter, the information provided by Fresh Energy, and the attached information provides the Board of Directors with information to make the rate design decisions in the best interest of the City of Rochester ratepayers.

It is a pleasure to provide this information and if any questions arise please do not hesitate to call.

Sincerely,

Mark Beauchamp, President
Utility Financial Solutions

B.28k

Undertaking 32 - Attachment

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current-carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

Christina Bailey

From: Patty Hanson
Sent: Wednesday, November 01, 2017 9:15 AM
To: Mark Kotschevar
Cc: Christina Bailey
Subject: FW: General Message - 10-31-17, 7:40PM

Hi Mark –

The message below came in through our website for the Board members re: the rate increase.

Patty

Patty Hanson | Manager of Marketing and Energy Services
Rochester Public Utilities (RPU) | 4000 E River Rd NE | Rochester, MN 55906
p. 507.280.1615 | c. 507.261.4994 | phanson@rpu.org | www.rpu.org

we pledge, we deliver

RPU is an environmentally responsible company. Please consider the environment before printing this e-mail

From: Rochester Public Utilities [mailto:do-not-reply@client-emailer.com]
Sent: Tuesday, October 31, 2017 7:40 PM
To: RPU Customer Service
Subject: RPU: General Message - 10-31-17, 7:40PM

This "General Message" from: James Rentz (rpljrentz@yahoo.com)

Contact Information:
Name: James Rentz
Email: rpljrentz@yahoo.com
Home Address: (507) 289-0665

Message:
Dear Board Members, I would encourage you all to think outside the box when reviewing the new rate structure. Hopefully, instead of relying so heavily on the use of regressive customer charges, you can find more progressive policies to maintain a financially healthy public utility. While the proposed $0.74 in 2018 and $1.00 in 2019 increases are not that large in an absolute sense, when you consider that brings the charges to $19.50 ($234/year) and $20.50 ($246/year) you begin to realize the impact on low and fixed income households. To put this in perspective, if you were working at the current state minimum wage, the proposed 2019 customer charge represents 1.3% of your total income. While some fixed amount of revenue is obviously useful for budgetary purposes, a better rate schedule would have a greater factor for actual energy usage and spread the fixed charges in a more equitable manner. Some possibilities would be: 1. Base customer charges on assessed property value. 2. Have a two tier rate. Higher for buried utilities since they are more expensive to install and ultimately maintain. 3. Base customer charges on lot size or length of street frontage because the cost of providing service for larger houses and developments is greater. 4. Implement customer charges for medium and large general and

industrial sites in 2018. 5. Reduce, or eliminate, transformer ownership credits. 6. Reduce customer charge increases and make up any difference with energy usage charges. These are just a few possible options that could be used. I am sure that with more information even better alternatives could be devised. Thank you for the opportunity to express these ideas. James Rentz

ROCHESTER

Minnesota

Greetings RPU Board & Staff;

I would like to see RPU set a goal of reducing customer charges for residential electric customers of at least $100 per year starting in 2019. We have been told by our customer base that they overwhelmingly want us to lead on clean energy, so let's do it. I look forward to discussing this at an upcoming meeting.

I am headed to Charlotte for the National League of Cities but wanted to share my thoughts on the setting of rates in 2018 and beyond. I am also interested in spurring on discussion related to smart grid infrastructure in 2018. I would also like to express my desire to help RPU grow the business in 2018 and beyond by using targeted incentives to promote the electrification of vehicle fleets and building HVAC systems.

Reconsidering Residential Rate Structures:

The RPU policies of fiscal sustainability and treating all user groups fairly are critical to who we are and should remain unchanged. However, by a preponderance of evidence, there are many industry accepted practices that can result in different balances between customer and energy charges. A list industry acceptable rate analysis tools include would also include "basic customer" and "peak and average" models. These would result in lower customer charges than the method we have chosen.

We happen to be using a philosophy that results in more items being included in the customer charge. As such in 2018 we will have a customer charge that is substantially higher than that of Xcel Energy. We understand that higher customer charges are a financial disincentive to conservation and the creation of local generation. We also understand that the total amount paid for by residential customers is not likely to change, but the net contributions from energy and customer charges would.

I believe that the proposed rates for 2018 should go forward. I believe that it is too late to switch strategies now. I would request that we revisit policies related to these rates in 2018 for 2019 and beyond. I have set a personal goal of reducing customer charges for RPU residential electric customers of $100 per year in 2019.

While the idea of residential demand charges is both innovative and could achieve an unprecedented level of fairness, we don't have anywhere near the technology in place to pursue this yet. I would also suggest that minimum energy bills could be a compromise method of addressing the infrastructure needs of very low use customers such as "snowbirds" or local generators such as myself.

Advancing Smart Grid:

Smart Grid can mean many different policies and technologies but when I use the term I speak to having the policies and technologies in place to accomplish 3 goals.

1. Enable reliable real-time bidirectional communications between energy supply and load.
2. Enable the dissemination of energy availability, cost, and percent renewable.
3. Remotely control loads, especially HVAC and vehicle charging.

RPU's smart grid business case is complicated by the SMMPA contract which really does allow us or our consumers to financially benefit by using energy when it is plentiful and cheap. This may continue to be the case until 2030. That said I do believe we need to begin the process of building out smart infrastructure in anticipation of 2030 or opportunities to collaborate with SMMPA in the intervening years.

Growing RPU Electric Customers:

Despite the current availability of relatively inexpensive fossil fuel resource, there is a strong desire in the community to reduce our carbon emissions. Prospects for efficient combined heat & power plants in the future are exciting. In the short run I believe we should create incentive programs and rate structures to encourage the installation of heat pumps in homes and small businesses as well as the electrification of vehicle fleets. In 2017, the city of Rochester purchased 11 diesel buses. It is my goal that these are the last non-electric transit vehicles we ever purchase.

By aggressively promoting efficient electric heating and vehicles we and secure new energy revenue into the future. This is particularly exciting because these same customers also offer us the potential to significantly adjust our load to maximize the use of abundant, cheap clean energy.

Locally we produce no coal, oil, natural gas, or uranium. We to have tremendous access to wind, solar, biomass, and hydro power in our region. As rely on electricity to fuel an increasingly flexible load demand we also boost the fortunes of RPU and the region.

Thank you to RPU Board and Staff for your service,

Michael Wojcik,

Rochester City Council, RPU Board of Directors, Rochester Energy Commission

FOR BOARD ACTION

Agenda Item # **(ID # 8113)** **Meeting Date: 11/14/2017**

SUBJECT: Customer Service Center Building Expansion Project - Bid Award

PREPARED BY: Patricia Bremer

ITEM DESCRIPTION:

The RPU Customer Service Center (CSC) was designed and constructed in 1987-1988, with the original intent of meeting RPU's space needs for staff and equipment for 25-30 years. Through routine master plans, facilities assessments and a recent space needs analysis, it became clear that RPU would meet or exceed the available space for staff and equipment at the CSC facility in 2017.

In October 2016, the RPU Board approved agreements for staff to work with a consultant team consisting of RSP Architects and CPMI to develop this project. Over the course of the last year, RPU has worked diligently with this consultant team to design and develop this project to meet RPU's space needs for the next 10-20 years. The resultant project was issued for public bidding on October 2, 2017.

RPU elected to separate the project into two construction contracts. This includes one Owner-Contractor Agreement for the construction labor, and one Purchasing Agent Agreement for the materials. The MN Department of Revenue requires this type of contracting in order to realize a savings on the sales tax of the materials used in construction. By the Purchasing Agent Agreement, RPU is authorizing the contractor to act on its behalf in the purchase of the materials. RPU remains responsible for payment, risk of loss and title to the materials.

Sealed bids were received on November 2, 2017, which included bids from eight general contractors. The bid tab showing the results is included for reference. Staff recommends awarding both contracts to Knutson Construction Services Rochester, Inc., as they were the combined low bid for both portions of work. This approval request is broken down as follows: $5,009,000 for the Owner-Contractor Agreement (labor), $3,827,000 for the Purchasing Agent Agreement (materials). Total approval request for the two contracts is $8,836,000.

A project budget of $15.3M was approved for this expansion and the high level project budget is listed below:

FOR BOARD ACTION

Agenda Item # (ID # 8113) Meeting Date: 11/14/2017

	Estimated Cost
Consultants	$ 1,187,000
Fees (permits, advertising)	$ 46,000
Construction	$ 9,636,000
10% Contingency	$ 963,000
Builder's Risk Insurance	$ 50,000
Fixtures, Furniture & Equipment	$ 800,000
Temp Conditions (moves, storage)	$ 15,000
Total	$12,697,000

An approval for an additional low voltage contract which is included in the construction estimate above will be brought to the board at the next meeting.

Construction is expected to run from December 2017 to December 2018, with final close out and occupation by February 2019. RPU will continue to occupy the facility so construction efforts will be completed through a phased approach.

UTILITY BOARD ACTION REQUESTED:

Staff requests approval of two contracts with Knutson Construction Services Rochester, Inc. in the amount of $5,009,000 for the Owner-Contractor Agreement (labor), and $3,827,000 for the Purchasing Agent Agreement (materials) following final contract review from the General Manager and City Attorney. Staff also requests approval of a $963,000 contingency fund, including granting authorization for the RPU Project Manager to perform the acts to execute the project.

RPU Customer Service Center - Expansion and Renovation

Rochester, Minnesota

BID SUBMITTAL TABULATION

Submitting Contractor		Total Base Bid	Alt. A-1	Alt. A-2	Alt. A-3	Alt. A-4	Alt. E-1	Alt. E-2
A.E. Benike Construction	Labor Bid LP-1	$ 4,778,661	$ (21,570)	$ (20,574)	$ (471)	$ (88,913)	$ (5,735)	$ (512)
	Material Bid MP-1	$ 4,799,313	$ (49,024)	$ (58,432)	$ (2,069)	$ (25,259)	$ (10,138)	$ (246)
	Total Combined Bid	$ 9,577,974						
Boldt Construction	Labor Bid LP-1	$ 5,625,400	$ (25,600)	$ (16,100)	$ (800)	$ (426,000)	$ (5,600)	$ (500)
	Material Bid MP-1	$ 3,967,000	$ (26,750)	$ (32,530)	$ (1,960)	$ (63,300)	$ (9,900)	$ (240)
	Total Combined Bid	$ 9,592,400						
Joseph Company	Labor Bid LP-1	$ 4,925,000	$ (30,618)	$ (24,650)	$ (200)	$ (78,000)	$ (4,300)	$ (300)
	Material Bid MP-1	$ 4,278,000	$ (31,467)	$ (23,675)	$ (2,650)	$ (30,000)	$ (10,600)	$ (100)
	Total Combined Bid	$ 9,203,000						
Kraus-Anderson Construction	Labor Bid LP-1	$ 5,035,875	$ (19,000)	$ (16,000)	$ (200)	$ (86,000)	$ (4,300)	$ (300)
	Material Bid MP-1	$ 4,028,820	$ (5,600)	$ (8,000)	$ (4,000)	$ (46,000)	$ (10,000)	$ (100)
	Total Combined Bid	$ 9,064,695						
Knutson Construction	Labor Bid LP-1	$ 5,009,000	$ (29,500)	$ (7,000)	$ (200)	$ (82,000)	$ (5,600)	$ (500)
	Material Bid MP-1	$ 3,827,000	$ (29,000)	$ -	$ (12,100)	$ (19,700)	$ (9,900)	$ (240)
	Total Combined Bid	$ 8,836,000						
Market & Johnson	Labor Bid LP-1	$ 6,011,924	$ (39,000)	$ (37,000)	$ (1,000)	$ (138,000)	$ (5,000)	$ (500)
	Material Bid MP-1	$ 4,016,493	$ -	$ -	$ (1,000)	$ (19,000)	$ (7,000)	$ -
	Total Combined Bid	$ 10,028,417						
Industrial Main Sol	Labor Bid LP-1	$ 5,433,780	$ (31,833)	$ (6,564)	$ (345)	$ (18,080)	$ (4,300)	$ (300)
	Material Bid MP-1	$ 4,441,421	$ (29,190)	$ (4,695)	$ 1,363	$ (3,000)	$ (20,000)	$ (10,600)
	Total Combined Bid	$ 9,875,201						
Met-Con Construction	Labor Bid LP-1	$ 5,719,647	$ (47,180)	$ (14,830)	$ (460)	$ (149,270)	$ (5,600)	$ (500)
	Material Bid MP-1	$ 3,901,351	$ (13,000)	$ (4,050)	$ (2,020)	$ (27,420)	$ (9,900)	$ (240)
	Total Combined Bid	$ 9,620,998						

Attachment: Proposal Tab 2017-11-02 (8113 : Customer Service Center Building Expansion Project - Bid

PURCHASING AGENT AGREEMENT

THIS AGREEMENT is made by and between City of Rochester, a Minnesota municipal corporation ("Owner"), and xxxxxxxxx., a xxxxxx (type of) company ("Agent").

WHEREAS, Owner is undertaking the construction of Customer Service Center Expansion and Renovation on the property of the Owner (the "Project"); and

WHEREAS, the Owner is a Minnesota municipal corporation, exempt from the payment of Minnesota sales and use taxes.

WHEREAS, Owner wishes to purchase on its own account materials, supplies and equipment for the Project (collectively "Materials") as described in solicitation #2017-27, incorporated by reference; and

WHEREAS, the Owner has solicited separate bids for the Materials, the award of which was not contingent upon the successful award of any other part of the Project; and

WHEREAS, Agent is the successful bidder for the Materials.

NOW, IT IS **THEREFORE AGREED** between the parties hereto that:

1. This Agreement is made with reference to, and where applicable, shall be governed by the specifications and provisions set forth in the Contract Documents as such are defined in the Owner/Contractor Agreement for the Project.

2. The Owner appoints Agent to act as its purchasing agent for purchasing the Materials, and further authorizes Agent to appoint such sub-agents as Agent deems appropriate for carrying out the purposes of this Agreement, which sub-agents shall have similar powers of appointment.

3. The Agent shall notify all vendors and suppliers with which it deals in relation to purchasing Materials of its agency relationship with the Owner. The Agent shall make it clear to such vendors and suppliers that the obligation for payment for any and all Materials is that of the Owner and not the Agent. Agent shall include the following Notice to Vendors/Suppliers in all purchase orders and other documents furnished to a vendor or supplier in connection with the purchase of any Materials:

NOTICE TO VENDORS/SUPPLIERS

The materials to which this document relates are being purchased by xxxxxxxx, as the purchasing agent of City of Rochester ("the Owner"). It is the Owner's obligation, not the purchasing agent's, to pay for the materials. Because the Owner is a city of Minnesota, this purchase is exempt from sales tax under Minn. Stat.§ 297A.70.

4. It is understood and agreed that title to the Materials purchased pursuant to this Agreement shall immediately vest in the Owner at the point of delivery, even if

DRAFT

such delivery is made to Agent on Owner's behalf. The Owner assumes risk of loss at the time of delivery; however, Agent shall take all reasonable precautions for the safekeeping against loss of such Materials prior to their installation. Nothing contained in this Agreement shall be deemed to preclude Owner from proceeding against Agent in the event that such loss occurs as a consequence of Agent's fault or negligence or that of Agent's employees.

5. Prior to acceptance and payment, Agent shall endeavor to determine on Owner's behalf that all such Materials conform to the plans and specifications of the Contract Documents and are free from obvious or apparent defects.

6. Owner shall pay Agent for all Materials purchased by Agent under this Agreement. Invoices from vendors/and suppliers must be addressed to City of Rochester and sent to xxxxxxxxxx. Agent will obtain from vendors and suppliers for Owner any mechanics' lien waivers required by the Contract Documents. Invoices for payment must be submitted to Owner by Agent pursuant to, and will be paid according to, the provisions of the Contract Documents.

7. Agent shall promptly notify Owner of any sales and use tax audit by the Minnesota Commissioner of Revenue or of the threatened imposition or assessment of any sales or use taxes. Owner may, at its sole option and cost, dispute, contest or otherwise resist the imposition or assessment of any such taxes. Upon reasonable notice to Owner, Agent may (but is not obligated to) take such actions as it deems reasonable in response to the threatened imposition or assessment of taxes, which actions shall be deemed to have been taken on Owner's behalf. If any Minnesota sales or use taxes are imposed or assessed with respect to any Materials purchased pursuant to this Agreement, Owner shall be solely responsible for the payment of such taxes, including any related penalties and interest, and shall hold Agent harmless and indemnify Agent from any such cost or expense related thereto, including any legal fees and costs incurred by Agent in connection therewith.

8. The agency relationship created by this Agreement is intended to be in compliance with Minnesota Rule 8130.1200 and its current interpretation by the Minnesota Department of Revenue.

9. Owner may terminate this Agreement if Agent is in default hereunder or if Owner has abandoned the Project.

10. Neither this Agreement or any interest herein shall be assignable by either party without the prior written consent of the other party, except that no consent is required for the appointment of sub-agents as contemplated herein. The provisions of this Agreement shall be binding upon and inure to the benefit of the parties and their respective heirs, legal representatives, assigns, and any sub-agents appointed pursuant to this Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Purchasing Agent Agreement this xx day of xxxxx, 2017.

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XXXXXXXXXXXXXXXX	**CITY OF ROCHESTER**
By ___________________________________	By ____________________________
xxxxxxxxxx	Ardell Brede, Mayor
Its _____________________________	Attest
	___________________________________
	Anissa Hollingshead, City Clerk
	Approved as to Form
	___________________________________
	Terry Adkins, City Attorney
	ROCHESTER PUBLIC UTILITIES
	___________________________________
	Mark Kotschevar, General Manager

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Attachment: Purchase Agent Agreement Draft (8113 : Customer Service Center Building Expansion Project - Bid Award)

AIA® Document A101™ – 2007

Standard Form of Agreement Between Owner and Contractor where the basis of payment is a Stipulated Sum

AGREEMENT made as of the day of in the year
(In words, indicate day, month and year.)

BETWEEN the Owner:
(Name, legal status, address and other information)

City of Rochester
Rochester Public Utilities
4000 East River Road NE
Rochester, MN. 55906

and the Contractor:
(Name, legal status, address and other information)

for the following Project:
(Name, location and detailed description)

Rochester Public Utilities
Customer Service Center Addition and Renovation
400 East River Road NE
Rochester, MN 55906

The Architect:
(Name, legal status, address and other information)

RSP Architects, Ltd.
320 South Broadway, Suite B
Rochester, MN. 55904-6505

The Owner and Contractor agree as follows.

ADDITIONS AND DELETIONS:
The author of this document has added information needed for its completion. The author may also have revised the text of the original AIA standard form. An *Additions and Deletions Report* that notes added information as well as revisions to the standard form text is available from the author and should be reviewed. A vertical line in the left margin of this document indicates where the author has added necessary information and where the author has added to or deleted from the original AIA text.

This document has important legal consequences. Consultation with an attorney is encouraged with respect to its completion or modification.

AIA Document A201™–2007, General Conditions of the Contract for Construction, is adopted in this document by reference. Do not use with other general conditions unless this document is modified.

Attachment: AIA Contract (8113 : Customer Service Center Building Expansion Project - Bid Award)

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TABLE OF ARTICLES

ARTICLE 1 THE CONTRACT DOCUMENTS

The Contract Documents consist of this Agreement, Conditions of the Contract (General, Supplementary and other Conditions), Drawings, Specifications, Addenda issued prior to execution of this Agreement, other documents listed in this Agreement and Modifications issued after execution of this Agreement, all of which form the Contract, and are as fully a part of the Contract as if attached to this Agreement or repeated herein. The Contract represents the entire and integrated agreement between the parties hereto and supersedes prior negotiations, representations or agreements, either written or oral. An enumeration of the Contract Documents, other than a Modification, appears in Article 9.

ARTICLE 2 THE WORK OF THIS CONTRACT

The Contractor shall fully execute the Work described in the Contract Documents, except as specifically indicated in the Contract Documents to be the responsibility of others.

ARTICLE 3 DATE OF COMMENCEMENT AND SUBSTANTIAL COMPLETION

§ 3.1 The date of commencement of the Work shall be the date of this Agreement unless a different date is stated below or provision is made for the date to be fixed in a notice to proceed issued by the Owner.

(Insert the date of commencement if it differs from the date of this Agreement or, if applicable, state that the date will be fixed in a notice to proceed.)

If, prior to the commencement of the Work, the Owner requires time to file mortgages and other security interests, the Owner's time requirement shall be as follows:

§ 3.2 The Contract Time shall be measured from the date of commencement.

§ 3.3 The Contractor shall achieve Substantial Completion of the entire Work not later than ( ) days from the date of commencement, or as follows:

(Insert number of calendar days. Alternatively, a calendar date may be used when coordinated with the date of commencement. If appropriate, insert requirements for earlier Substantial Completion of certain portions of the Work.)

Attachment: AIA Contract (8113 : Customer Service Center Building Expansion Project - Bid Award)

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Portion of Work	Substantial Completion Date

, subject to adjustments of this Contract Time as provided in the Contract Documents.
(Insert provisions, if any, for liquidated damages relating to failure to achieve Substantial Completion on time or for bonus payments for early completion of the Work.)

ARTICLE 4 CONTRACT SUM

§ 4.1 The Owner shall pay the Contractor the Contract Sum in current funds for the Contractor's performance of the Contract. The Contract Sum shall be ($), subject to additions and deductions as provided in the Contract Documents.

§ 4.2 The Contract Sum is based upon the following alternates, if any, which are described in the Contract Documents and are hereby accepted by the Owner:
(State the numbers or other identification of accepted alternates. If the bidding or proposal documents permit the Owner to accept other alternates subsequent to the execution of this Agreement, attach a schedule of such other alternates showing the amount for each and the date when that amount expires.)

§ 4.3 Unit prices, if any:
(Identify and state the unit price; state quantity limitations, if any, to which the unit price will be applicable.)

Item	Units and Limitations	Price Per Unit ($0.00)

§ 4.4 Allowances included in the Contract Sum, if any:
(Identify allowance and state exclusions, if any, from the allowance price.)

Item	Price

ARTICLE 5 PAYMENTS

§ 5.1 PROGRESS PAYMENTS

§ 5.1.1 Based upon Applications for Payment submitted to the Architect by the Contractor and Certificates for Payment issued by the Architect, the Owner shall make progress payments on account of the Contract Sum to the Contractor as provided below and elsewhere in the Contract Documents.

§ 5.1.2 The period covered by each Application for Payment shall be one calendar month ending on the last day of the month, or as follows:

§ 5.1.3 Provided that an Application for Payment is received by the Architect not later than the day of a month, the Owner shall make payment of the certified amount to the Contractor not later than the day of the month. If an Application for Payment is received by the Architect after the application date fixed above, payment shall be made by the Owner not later than ( ) days after the Architect receives the Application for Payment.
(Federal, state or local laws may require payment within a certain period of time.)

§ 5.1.4 Each Application for Payment shall be based on the most recent schedule of values submitted by the Contractor in accordance with the Contract Documents. The schedule of values shall allocate the entire Contract Sum among the various portions of the Work. The schedule of values shall be prepared in such form and supported

Attachment: AIA Contract (8113 : Customer Service Center Building Expansion Project - Bid Award)

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by such data to substantiate its accuracy as the Architect may require. This schedule, unless objected to by the Architect, shall be used as a basis for reviewing the Contractor's Applications for Payment.

§ 5.1.5 Applications for Payment shall show the percentage of completion of each portion of the Work as of the end of the period covered by the Application for Payment.

§ 5.1.6 Subject to other provisions of the Contract Documents, the amount of each progress payment shall be computed as follows:

- **.1** Take that portion of the Contract Sum properly allocable to completed Work as determined by multiplying the percentage completion of each portion of the Work by the share of the Contract Sum allocated to that portion of the Work in the schedule of values, less retainage of percent (%). Pending final determination of cost to the Owner of changes in the Work, amounts not in dispute shall be included as provided in Section 7.3.9 of AIA Document A201™–2007, General Conditions of the Contract for Construction;
- **.2** Add that portion of the Contract Sum properly allocable to materials and equipment delivered and suitably stored at the site for subsequent incorporation in the completed construction (or, if approved in advance by the Owner, suitably stored off the site at a location agreed upon in writing), less retainage of percent (%);
- **.3** Subtract the aggregate of previous payments made by the Owner; and
- **.4** Subtract amounts, if any, for which the Architect has withheld or nullified a Certificate for Payment as provided in Section 9.5 of AIA Document A201–2007.

§ 5.1.7 The progress payment amount determined in accordance with Section 5.1.6 shall be further modified under the following circumstances:

- **.1** Add, upon Substantial Completion of the Work, a sum sufficient to increase the total payments to the full amount of the Contract Sum, less such amounts as the Architect shall determine for incomplete Work, retainage applicable to such work and unsettled claims; and
  (Section 9.8.5 of AIA Document A201–2007 requires release of applicable retainage upon Substantial Completion of Work with consent of surety, if any.)
- **.2** Add, if final completion of the Work is thereafter materially delayed through no fault of the Contractor, any additional amounts payable in accordance with Section 9.10.3 of AIA Document A201–2007.

§ 5.1.8 Reduction or limitation of retainage, if any, shall be as follows:
(If it is intended, prior to Substantial Completion of the entire Work, to reduce or limit the retainage resulting from the percentages inserted in Sections 5.1.6.1 and 5.1.6.2 above, and this is not explained elsewhere in the Contract Documents, insert here provisions for such reduction or limitation.)

§ 5.1.9 Except with the Owner's prior approval, the Contractor shall not make advance payments to suppliers for materials or equipment which have not been delivered and stored at the site.

§ 5.2 FINAL PAYMENT

§ 5.2.1 Final payment, constituting the entire unpaid balance of the Contract Sum, shall be made by the Owner to the Contractor when

- **.1** the Contractor has fully performed the Contract except for the Contractor's responsibility to correct Work as provided in Section 12.2.2 of AIA Document A201–2007, and to satisfy other requirements, if any, which extend beyond final payment; and
- **.2** a final Certificate for Payment has been issued by the Architect.

§ 5.2.2 The Owner's final payment to the Contractor shall be made no later than 30 days after the issuance of the Architect's final Certificate for Payment, or as follows:

Init.

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ARTICLE 6 DISPUTE RESOLUTION
§ 6.1 INITIAL DECISION MAKER
The Architect will serve as Initial Decision Maker pursuant to Section 15.2 of AIA Document A201–2007, unless the parties appoint below another individual, not a party to this Agreement, to serve as Initial Decision Maker.
(If the parties mutually agree, insert the name, address and other contact information of the Initial Decision Maker, if other than the Architect.)

§ 6.2 BINDING DISPUTE RESOLUTION
For any Claim subject to, but not resolved by, mediation pursuant to Section 15.3 of AIA Document A201–2007, the method of binding dispute resolution shall be as follows:
(Check the appropriate box. If the Owner and Contractor do not select a method of binding dispute resolution below, or do not subsequently agree in writing to a binding dispute resolution method other than litigation, Claims will be resolved by litigation in a court of competent jurisdiction.)

[ ] Arbitration pursuant to Section 15.4 of AIA Document A201–2007

[ ] Litigation in a court of competent jurisdiction

[ ] Other *(Specify)*

ARTICLE 7 TERMINATION OR SUSPENSION
§ 7.1 The Contract may be terminated by the Owner or the Contractor as provided in Article 14 of AIA Document A201–2007.

§ 7.2 The Work may be suspended by the Owner as provided in Article 14 of AIA Document A201–2007.

ARTICLE 8 MISCELLANEOUS PROVISIONS
§ 8.1 Where reference is made in this Agreement to a provision of AIA Document A201–2007 or another Contract Document, the reference refers to that provision as amended or supplemented by other provisions of the Contract Documents.

§ 8.2 Payments due and unpaid under the Contract shall bear interest from the date payment is due at the rate stated below, or in the absence thereof, at the legal rate prevailing from time to time at the place where the Project is located.
(Insert rate of interest agreed upon, if any.)

%

§ 8.3 The Owner's representative:
(Name, address and other information)

§ 8.4 The Contractor's representative:
(Name, address and other information)

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§ **8.5** Neither the Owner's nor the Contractor's representative shall be changed without ten days written notice to the other party.

§ **8.6** Other provisions:

ARTICLE 9 ENUMERATION OF CONTRACT DOCUMENTS

§ **9.1** The Contract Documents, except for Modifications issued after execution of this Agreement, are enumerated in the sections below.

§ **9.1.1** The Agreement is this executed AIA Document A101–2007, Standard Form of Agreement Between Owner and Contractor.

§ **9.1.2** The General Conditions are AIA Document A201–2007, General Conditions of the Contract for Construction.

§ **9.1.3** The Supplementary and other Conditions of the Contract:

Document	Title	Date	Pages

§ **9.1.4** The Specifications:
(Either list the Specifications here or refer to an exhibit attached to this Agreement.)

Section	Title	Date	Pages

§ **9.1.5** The Drawings:
(Either list the Drawings here or refer to an exhibit attached to this Agreement.)

Number	Title	Date

§ **9.1.6** The Addenda, if any:

Number	Date	Pages

Portions of Addenda relating to bidding requirements are not part of the Contract Documents unless the bidding requirements are also enumerated in this Article 9.

§ **9.1.7** Additional documents, if any, forming part of the Contract Documents:

.1 AIA Document E201™–2007, Digital Data Protocol Exhibit, if completed by the parties, or the following:

Init.

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.2 Other documents, if any, listed below:
(List here any additional documents that are intended to form part of the Contract Documents. AIA Document A201–2007 provides that bidding requirements such as advertisement or invitation to bid, Instructions to Bidders, sample forms and the Contractor's bid are not part of the Contract Documents unless enumerated in this Agreement. They should be listed here only if intended to be part of the Contract Documents.)

ARTICLE 10 INSURANCE AND BONDS

The Contractor shall purchase and maintain insurance and provide bonds as set forth in Article 11 of AIA Document A201–2007.
(State bonding requirements, if any, and limits of liability for insurance required in Article 11 of AIA Document A201–2007.)

Type of insurance or bond	Limit of liability or bond amount ($0.00)

This Agreement entered into as of the day and year first written above.

OWNER *(Signature)*	**CONTRACTOR** *(Signature)*
(Printed name and title)	*(Printed name and title)*

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we pledge, we deliver®

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve two agreements with Knutson Construction Services Rochester, Inc, following final review by the General Manager and City Attorney, and authorize the Mayor and the City Clerk to execute the agreements, following final review as follows:

Owner-Contractor Agreement (labor) $5,009,000

Purchasing Agent Agreement (materials) $3,827,000

In addition approve a contingency fund in the amount of $963,000 including granting authorization for the RPU Project Manager to perform the acts to execute the project.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 14th day of November, 2017.

____

President

____

Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 8110)** **Meeting Date: 11/14/2017**

SUBJECT: 2018 Water Utility Budget Approval

PREPARED BY: Peter Hogan

ITEM DESCRIPTION:

The preliminary budget for the water utility was presented to the finance and audit committees on October 17, 2017, and to the full Board on October 24, 2017, and incorporates a 6% rate increase which was approved in 2015 as part of a three-year rate track. The rate track approved in 2015 includes a 6% rate increase for each year 2016, 2017 and 2018, based on the cost of service study conducted in 2015.

The significant drivers for the 2018 Water Utility budget are:

- Adoption of the utility method (Industry Standard) of rate setting
  - Sustainability: Based on cost of service and alignment of variable and fixed costs with corresponding variable and fixed revenues
  - Establishing targeted change in net assets to fund operations and future capital replacements - $3,192K; current budget $ 1,112K
  - Establish targeted minimum cash reserves; per policy $6,063K; current budget $4,921K
- Addition of one FTE; overall 3.2% salary expense change and additional PERA accrual ($143K)
- Increase in water main replacements in conjunction with street reconstructions ($1,181K)
- New well and well house replacement

The budget supports the need for continued investment in infrastructure, maintenance and replacement reserves to avoid large unfunded outlays of capital in future years.

Summary financial sheets are attached reflecting the recommended budget. Staff will be available to answer questions.

UTILITY BOARD ACTION REQUESTED:

Management recommends that the Board approve and request Common Council approval of the 2018 RPU Water Utility operating and capital budget.

ROCHESTER PUBLIC UTILITIES
WATER UTILITY
2018 OPERATING BUDGET

BASIC ASSUMPTIONS

• Interest Earnings Rate:	0.25%
• Average Salary Expense Change:	3.2% (consists of COLA, merit and promotion increases)
• Change in Full-time Equivalents:	1
• Minimum Cash Reserve Requirement:	Policy Amount $6,063,120

RETAIL REVENUES / SALES

• Revenue Adjustment:	6.0%
• Water CCF Sales Forecast:	5.59% Increase from 2017 Projected Sales
• Total Water Utility Customers:	1.0% Increase over Y/E 2017 Projected Customers
• Forecast Assumes Normal Weather :	523 Cooling Degree Days, 23.9 Inches Summer Rainfall

OTHER ITEMS

- In Lieu of Tax forecast increasing $19,700 to a total of $390,290.
- RPU water projects are greatly dependent on the plans of the City Public Works Department and developers.
- Developer-installed subdivision water infrastructure assets are contributed to RPU at no cost. RPU records depreciation expense on these assets and is responsible for ongoing maintenance and replacement costs.

Attachment: Wtr-2018 Assumptions (8110 : 2018 Water Utility Budget Approval)

No.		2015	2016	2017 F2	2018	2019	2020	2021	2022
1	**ROCHESTER PUBLIC UTILITIES**								
2	**WATER UTILITY**								
3	**Management Reporting P&L**								
4		Historical Data							
5	in 000's	2015	2016	2017 F2	2018	2019	2020	2021	2022
6	RPU Rate Increase	3.5%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
7	**Revenue**								
8	Retail Water	$7,788	$8,519	$8,674	$9,818	$10,477	$11,184	$11,930	$12,728
9	Other Services & Fees	$873	$942	$947	$1,071	$1,090	$1,110	$1,130	$1,150
10	**Total Revenue**	**$8,661**	**$9,461**	**$9,621**	**$10,889**	**$11,567**	**$12,294**	**$13,060**	**$13,878**
11	**Cost of Revenue**								
12	Water Supply	$1,830	$1,970	$1,940	$1,774	$1,778	$1,764	$1,750	$1,734
13	**Total Cost of Revenue**	**$1,830**	**$1,970**	**$1,940**	**$1,774**	**$1,778**	**$1,764**	**$1,750**	**$1,734**
14	**Gross Margin**								
15	Retail Water	$5,958	$6,549	$6,734	$8,044	$8,699	$9,420	$10,181	$10,994
16	Other Services & Fees	$873	$942	$947	$1,071	$1,090	$1,110	$1,130	$1,150
17	**TOTAL GROSS MARGIN**	**$6,831**	**$7,491**	**$7,681**	**$9,115**	**$9,789**	**$10,529**	**$11,310**	**$12,144**
18	**Controllable Costs**								
19	Salaries & Benefits	$2,194	$2,368	$2,633	$2,989	$3,225	$3,358	$3,492	$3,638
20	Other Operating Expenses	$900	$1,016	$1,174	$1,403	$1,310	$1,304	$1,332	$1,366
21	Major Maintenance	$375	$226	$564	$507	$497	$549	$441	$333
22	Non-Bonded Capital Projects	$2,676	$1,957	$2,110	$3,146	$3,469	$2,677	$4,672	$3,557
23	**TOTAL CONTROLLABLE COSTS**	**$6,145**	**$5,567**	**$6,480**	**$8,045**	**$8,501**	**$7,888**	**$9,937**	**$8,893**
24	Depreciation & Amortization	$2,417	$2,525	$2,643	$2,682	$2,725	$2,772	$2,822	$2,878
25	Less Non Bonded Projects (capitalized)	($2,676)	($1,957)	($2,110)	($3,146)	($3,469)	($2,677)	($4,672)	($3,557)
26	Less Total Internal Costs (capitalized)	($399)	($282)	($313)	($305)	($254)	($256)	($245)	($258)
27	Interutility Allocation	$1,211	$1,230	$1,229	$1,449	$1,478	$1,508	$1,538	$1,569
28	**Total Operating Expenses**	**$6,697**	**$7,083**	**$7,930**	**$8,725**	**$8,980**	**$9,235**	**$9,380**	**$9,525**
29	**Net Operating Income (Loss)**	**$134**	**$408**	**($249)**	**$390**	**$809**	**$1,294**	**$1,930**	**$2,619**
30	**Financing & Other Non-Operating Items:**								
31	Bond & Interest Related Expenses	$0	$0	($0)	$0	$0	$0	$0	$0
32	Interest Income	$53	$63	$85	$13	$12	$12	$14	$17
33	Misc Non-Operating Income (Expense)	($67)	($17)	$0	$0	$0	$0	$0	$0
34	**Total Financing & Non-Operating Items**	**($13)**	**$45**	**$85**	**$13**	**$12**	**$12**	**$14**	**$17**
35	**Income Before Transfers or Capital Contributions**	**$120**	**$453**	**($165)**	**$403**	**$820**	**$1,306**	**$1,944**	**$2,635**
36	Transfers (In Lieu of Taxes)	($344)	($363)	($371)	($390)	($402)	($414)	($426)	($438)
37	Capital Contributions	$2,077	$2,242	$1,100	$1,100	$1,100	$1,100	$2,400	$1,100
38	Cash Transfers from City	$742	$513	$0	$0	$0	$0	$0	$0
39	**NET INCOME**	**$2,595**	**$2,845**	**$565**	**$1,112**	**$1,518**	**$1,992**	**$3,918**	**$3,297**
40	**TARGET NET INCOME**				**$ 3,192**	**$ 3,148**	**$ 3,097**	**$ 3,061**	**$ 3,017**
41	**Excess (Deficit) from Target**				**$(2,080)**	**$(1,630)**	**$(1,105)**	**$ 857**	**$ 280**
42	**1/01 Cash Balance**		**$ 4,918**	**$ 5,705**	**$ 5,534**	**$ 4,921**	**$ 4,539**	**$ 5,346**	**$ 6,069**
43	Change in Net Assets		2,845	565	1,112	1,518	1,992	3,918	3,297
44	Depreciation & Amortization		2,525	2,643	2,682	2,725	2,772	2,822	2,878
45	Capital Additions		(2,238)	(2,423)	(3,451)	(3,723)	(2,933)	(4,917)	(3,815)
46	Non-Cash Contributions		(2,242)	(1,100)	(1,100)	(1,100)	(1,100)	(2,400)	(1,100)
47	Debt Principal Payments		-	-	-	-	-	-	-
48	Debt Proceeds		-	-	-	-	-	-	-
49	Net Change in Other Assets/Liabilities		(103)	144	144	198	76	1,300	-
50	Net Changes in Cash		787	(171)	(613)	(382)	807	723	1,261
51	**12/31 Cash Balance**		**$ 5,705**	**$ 5,534**	**$ 4,921**	**$ 4,539**	**$ 5,346**	**$ 6,069**	**$ 7,330**
52	**Reserve Policy**		**$ 5,577**	**$ 5,852**	**$ 6,063**	**$ 6,187**	**$ 6,481**	**$ 6,406**	**$ 6,565**
53	**Excess (Deficit) from Policy**		**$ 129**	**$ (318)**	**$(1,142)**	**$(1,648)**	**$(1,136)**	**$ (337)**	**$ 764**
54	**Cash Balance as % of Reserve Policy**			**94.6%**	**81.2%**	**73.4%**	**82.5%**	**94.7%**	**111.6%**

Attachment: 2018 - 2022 Water Utility ProForma (8110 : 2018 Water Utility Budget Approval)

1 **ROCHESTER PUBLIC UTILITIES**
2 **CAPITAL AND MAJOR MAINTENANCE PLAN**
3 **MATERIALS, SUPPLIES & SERVICES**
4 **PROJECT BREAKDOWN ON 5 YEAR SUMMARY**

5 **WATER UTILITY**
6 **CAPITAL**
7 **($000's)**

#		2018	2019	2020	2021	2022	5-Yr Tot
8							
9	**Core Services**						
10	Well & Booster Station Metering	27	14	8	8	9	
11	Bulk Water Dispensing Station	38	-	39	-	40	1
12	Well House Manual Switchgear	15	15	16	17	18	
13	Portable Backup Power Generator	-	117	-	-	-	1
14	Water Meter Test Bench	53	-	-	-	-	
15	Portable Sand Blaster	18	-	-	-	-	
16	Water Leak Correlator	-	-	25	-	-	
17	Allocation - Water Distribution System Replacement	**143**	137	124	142	141	6
18	Replacement of Pumping Units	*73*	-	-	-	-	
19	Well Motor Replacements	*18*	-	-	-	-	
20	Installation of Variable Frequency Drive Units	*25*	-	-	-	-	
21	Replacement of Booster Pumps	*28*	-	-	-	-	
22	Allocation - Water Metering/AMR	293	298	304	310	316	1,5
23	New Wells	422	500	125	500	525	2,0
24	Water Utility Contingency Fund	150	150	200	200	250	9
25	New Marion L 1.0MG Reservoir	-	-	25	1,300	-	1,3
26	DMC Discovery Square Projects	-	256	296	207	233	9
27	DMC - 12th Ave SW from Center St W to 2nd St SW	-	135	-	-	-	1
28	DMC - 5th St SW from 2nd Ave SW to 9th Ave SW	-	273	-	-	-	2
29	Building Replacement - Well #26	325	75	50	-	-	4
30	DMC - 4th St SW from 1st Ave SW to 6th Ave SW	140	-	-	-	-	1
31	Allocation - Water Distribution System Expansion	**1,181**	1,440	1,248	1,731	1,817	7,4
32	T&D City Projects	*696*	-	-	-	-	
33	T&D Developer Projects	*249*	-	-	-	-	
34	T&D RPU Projects	*236*	-	-	-	-	
35	**Total Core Services**	2,804	3,410	2,460	4,415	3,349	16,4
36	**Power Resources**						
37	Allocation - RPU Water Facilities	40	42	44	46	48	2
38	Upgraded Hydro Vac Unit	222	-	-	-	-	2
39	Allocation - Fleet	80	17	173	211	160	6
40	**Total Field Services**	342	59	217	257	208	1,0
41	**Total Outside Expenditures**	3,146	3,469	2,677	4,672	3,557	17,5
42	**Total Internal Expenditures**	305	254	256	245	258	1,3
43	**Total Contributed Assets**	1,100	1,100	1,100	1,100	1,100	5,5
44	**Total Capital Plan**	4,551	4,823	4,033	6,017	4,915	24,3
45	**Total Capital & Major Maintenance Plan**	5,092	5,344	4,600	6,482	5,267	26,7

Attachment: Wtr-2018 Cpt Prjcts (8110 : 2018 Water Utility Budget Approval)

1 ROCHESTER PUBLIC UTILITIES
2 CAPITAL AND MAJOR MAINTENANCE PLAN
3 MATERIALS, SUPPLIES & SERVICES
4 PROJECT BREAKDOWN ON 5 YEAR SUMMARY

5 WATER UTILITY
6 MAJOR MAINTENANCE
7 ($000's)

		2018	2019	2020	2021	2022	5-Yr Tota
8							
9	**Core Services**						
10	Municipal Well Abandonment	37	45	-	-	-	
11	Allocation - Water Distribution System Maintenance	235	250	400	250	175	1,3
12	Water Cost-of-Service/Rate Design Study	35	-	-	40	-	
13	Operating Contingency Fund	70	70	75	75	80	3
14	**Total Core Services**	377	365	475	365	255	1,8
15	**Compliance and Public Affairs**						
16	Old Municipal Wells Sealing Project	60	60	-	-	-	1
17	**Total Compliance and Public Affairs**	60	60	-	-	-	1
18	**Power Resources**						
19	Allocation - RPU Water Facilities	70	72	74	76	78	3
20	**Total Power Resources**	70	72	74	76	78	3
21	**Total Outside Expenditures**	507	497	549	441	333	2,3
22	**Total Internal Expenditures**	34	23	18	24	19	1
23	**Total Major Maintenance Plan**	541	520	567	465	352	2,4

Attachment: Wtr-2018 Mjr Mntc Prjcts (8110 : 2018 Water Utility Budget Approval)

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, that the Common Council of the said City is requested to approve the

2018 Water Utility Capital and Operating Budgets

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 14th day of November, 2017.

____

President

____

Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 8100)** **Meeting Date: 11/14/2017**

SUBJECT: 2018 Electric Utility Rate Adjustment

PREPARED BY: Peter Hogan

ITEM DESCRIPTION:

Rochester Home Rule Charter Chapter 15.05, Subd. 3 states, *"The public utility board may adopt, amend, and rescind such rules and regulations as it may deem necessary for the control, management, and operation of the public utilities under its jurisdiction. The board shall, with the concurrence of the common council, fix the rates to be charged for the availability and use of the public utility commodities and services under its jurisdiction. Rates shall be* ***reasonable and compensatory*** *so as to cover all of the costs of the respective public utility and shall be* ***uniform for all consumers within the same class****, but different rates may be established for different classifications by the board. Rates within the city corporate limits may be less but shall be no greater than rates for the same classification outside the city limits."*

Based on the Charter, the RPU Board has further developed a policy for determining rates. The main objective of the policy is, *"to recover, through the application of rates and charges for utility services, revenues which are sufficient to meet the financial obligations of each independent utility enterprise. Further, the Board intends to apply rates and charges which are equitable among customer or classes of customers based on the Utility Basis of (generally accepted industry) rate-making principles."*

With this guidance, staff conducted a Cost of Service Study for the electric utility during 2017. The study results were presented to the Board on July 25, 2017. On August 29, 2017, the Board was presented with and gave preliminary consensus to a two-year rate track, which included an overall general rate increase for 2018 of 1.5%, and 1.9% for 2019.

A notice of the proposed revenue adjustment was provided to the public via the newspaper of record on Friday, September 8, 2017, and on the RPU web site. This topic was an agenda item for all remaining Board meetings up to and including this meeting.

During the October 17, 2017 budget review by the Finance Committee, and October 24, 2017 full Board review of the 2018 budget for the electric utility, management recommended that the Board approve a 1.5% overall general rate increase for 2018.

Management recommends that the Board approve, and recommend to the City Council, an increase in the electric retail revenue rates of 1.5% overall for 2018. This would increase the typical monthly residential bill by:

FOR BOARD ACTION

Agenda Item # **(ID # 8100)** **Meeting Date: 11/14/2017**

Residential Average Monthly Usage	Change in Monthly Bill
300 kWh	$1.13
600 kWh	$1.51
900 kWh	$1.90

UTILITY BOARD ACTION REQUESTED:

1. Approve and recommend to the Common Council an overall 1.5% electric revenue increase for 2018, with changes to all customer classes effective on or about January 1, 2018;

2. Approve a resolution for the following existing and modified rate schedules to be effective on or about January 1, 2018:

Residential Service (RES)

Residential Service-Dual Fuel (RES-DF)

Residential-High Efficiency HVAC (RESELGEO)

General Service (GS)

General Service-High Efficiency (GS-HEF)

General Service Time-Of-Use (GS-TOU)

Medium General Service (MGS)

Medium General Service-High Efficiency (MGS-HEF)

Medium General Service Time-Of-Use (MGS-TOU)

Unmetered Device (UMDR)

Public Car Charging(PCCR)

Large General Service (LGS)

Large Industrial Service (LIS)

Interruptible Service (INTR)

FOR BOARD ACTION

Agenda Item # **(ID # 8100)** **Meeting Date: 11/14/2017**

Load Management Credits (LMC)

City Street Lighting (CSL)

Traffic Signals (TS)

Highway Lighting (HL)

Security Lighting (SL)

Civil Defense Sirens (CDS)

Clean Air Rider (CAR)

Power Cost Adjustment (PCA)

we pledge, we deliver

2018 Rate Schedules

ROCHESTER PUBLIC UTILITIES
(RPU)

RATE SCHEDULE RES
SHEET 1 OF 1

RESIDENTIAL SERVICE

AVAILABILITY:

At all locations where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. Where service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished.

APPLICATION:

To electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. Existing single metered, multi-unit dwellings having not in excess of three separate dwelling units in the same structure may be served under this rate.

CHARACTER OF SERVICE:

Single phase, 60 Hertz, 120/240 volts alternating current.

RATE:	2017	2018
Customer Charge:	~~$18.76~~	$19.50
Non Summer Energy/kWh:	~~10.064¢~~	10.193¢
Summer Energy/ kWh :	~~12.083¢~~	12.212¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

	2017	2018
MINIMUM BILL per month:	~~$18.76~~	$19.50

PAYMENT: Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
2. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
3. Energy furnished under this rate shall not be resold.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE RES-DF SHEET 1 OF 2

RESIDENTIAL SERVICE - DUAL FUEL

AVAILABILITY:

Available only to existing dual fuel customers transferred from People's Cooperative Power Association's (PCPA) electrical system to RPU's system as part of RPU's electric service territory acquisitions.

APPLICATION:

To electric heating service required for residential purposes in individual private buildings. Such electric heating load shall be metered separately from the rest of the service.

CHARACTER OF SERVICE:

Single phase, 60 Hertz, 120/240 volts alternating current.

RATE:	2017	2018
Energy Charge/kWh:	~~7.240¢~~	7.513¢

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

MINIMUM BILL:

Energy usage.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service under this rate is only for electric heating. All other electrical loads shall be metered under the RES residential service rate.

2. Customer must keep his or her alternate fuel source heating system in satisfactory operating condition.

3. RPU reserves the right to transfer RES-DF customers from the primary electric heat source to the alternate fuel source at any such time that the electric heating load would add to RPU's monthly electric peak.

4. Customers that remove existing dual fuel heating systems shall not be eligible for the RES-DF rate with replacement heating systems.

5. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

RESIDENTIAL SERVICE - DUAL FUEL (Cont.)

CONDITIONS OF DELIVERY: (cont.)

6. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

7. Energy furnished under this rate shall not be resold.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board:	TBD
Effective Date:	January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE RESELGEO
SHEET 1 OF 2

RESIDENTIAL SERVICE – HIGH EFFICIENCY HVAC

AVAILABILITY:

To RPU residential customers that:

1. Use either an air source or ground source heat pump system as the only source of heating and cooling in their home.
2. Use an electric water heater (usually connected to a desuperheater on the heat pump) as their only source of domestic water heating.
3. Receive prior approval of the equipment from RPU. Note that equipment must be rated by the Air-Conditioning, Heating, and Refrigeration Institute (AHRI)*, and at the time of installation, meet the minimum efficiency requirements found on the Residential Electric Efficiency Rebate Application in effect at the time. The current application is available at www.rpu.org.

*For air source and ground source heat pumps the efficiency ratings are determined using the Air-Conditioning, Heating, and Refrigeration Institute's (AHRI) directory, which may be found at www.ahridirectory.org.

APPLICATION: Electric service required for residential purposes in individual private dwellings where service is supplied at one point of delivery and measured through one meter.

CHARACTER OF SERVICE:

Single phase, 60 hertz, 120/240 volts alternating current.

RATE:	2017	2018
Customer Charge	~~$18.76~~	$19.50
Energy Charge		
Winter first 600kwh	~~11.420¢~~	10.193¢
Winter over 600kwh	~~7.892¢~~	8.708¢
Summer kwh	~~13.562¢~~	12.212¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

RESIDENTIAL SERVICE – HIGH EFFICIENCY HVAC (Cont.)

POWER COST ADJUSTMENT:
Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

MINIMUM BILL:

	2017	2018
MINIMUM BILL per month:	~~$18.76~~	$19.50

PAYMENT:
Payments are due on or before the due date.

CONDITIONS OF DELIVERY:
1. Service under this rate is only for air-source or ground-source heat pump systems that meet the stated efficiency requirements as explained in the Availability subhead of this rate schedule.
2. Service provided under this rate is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
3. Energy provided under this rate shall not be resold.
4. RPU shall not be liable for any damage or loss sustained by the customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE GS SHEET 1 OF 2

GENERAL SERVICE

AVAILABILITY:

At all locations for loads of less than 75 kW where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished.

APPLICATION:

To commercial, industrial, governmental, and other types of general service customers with all service taken at one point and measured through one meter. Also applicable to temporary service in accordance with RPU's published Electric Service Rules and Regulations. Not applicable to standby service.

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:	2017	2018
Customer Charge:	~~$38.75~~	$40.00
Energy Charge:		
Non-Summer Kwh	~~10.299¢~~	10.329¢
Summer Kwh	~~12.328¢~~	12.714¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

	2017	2018
MINIMUM BILL per month:	~~$38.75~~	$40.00

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE GS SHEET 2 OF 2

GENERAL SERVICE (Cont.)

CONDITIONS OF DELIVERY (cont.):

2. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected, or operated in parallel, with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.
3. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
4. Energy furnished under this rate shall not be resold.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE GS-HEF SHEET 1 OF 2

GENERAL SERVICE - HIGH EFFICIENCY HVAC

AVAILABILITY:

At all locations for loads of less than 75 kW where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served and to customers who:

1. Use either an air source or ground source heat pump system as the only source of heating and cooling in their facility.
2. Use an electric water heater (usually connected to a desuperheater on the heat pump) as the only source of water heating.
3. Receive prior approval of the equipment from RPU. Note that equipment must be rated by the Air-Conditioning, Heating, and Refrigeration Institute (AHRI)* and at the time of installation, meet the minimum efficiency requirements found on the Commercial Heat Pumps Rebate Application in effect at the time. The current application is available at www.rpu.org.
4. Service under this rate must be separately metered from other facility loads.

*For air source and ground source heat pumps the efficiency ratings are determined using the Air-Conditioning, Heating and Refrigeration Institute's (AHRI) directory, which may be found at www.ahridirectory.org Note: Other all-electric HVAC systems may be considered for this rate if they meet the stated efficiency standards. To have a system considered, customers must submit an engineering analysis documenting the efficiency of the system.

APPLICATION:

To commercial, industrial, governmental, and other types of General Service customers reconfiguring their current electric service, or adding a new service, to separately meter their high efficiency HVAC equipment. Not applicable to standby service.

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE GS-HEF
SHEET 2 OF 2

GENERAL SERVICE - HIGH EFFICIENCY HVAC (Cont.)

RATE:

	2017	2018
Customer Charge:	~~$38.75~~	$40.00
Energy Charge:		
Non Summer / kwh	~~9.279¢~~	8.955¢
Summer / kwh	~~12.328¢~~	12.714¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

POWER COST ADJUSTMENT:
Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

	2017	2018
MINIMUM BILL per month**:**	~~$38.75~~	$40.00

PAYMENT:
Payments are due on or before the due date.

CONDITIONS OF DELIVERY:
1. Service under this rate is only for air source or ground source heat pumps and any other all-electric systems that meet the stated efficiency requirements as explained in the Availability subhead of this rate schedule.
2. Service under this rate must be separately metered from other facility loads.
3. Since the HVAC system must be separately metered for this rate, the customer is responsible for any rewiring and its associated costs.
4. Service provided under this rate is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
5. Energy provided under this rate shall not be resold.
6. RPU shall not be liable for any damage or loss sustained by the customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
7. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected, or operated in parallel, with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE GS-TOU SHEET 1 OF 2

GENERAL SERVICE - TIME-OF-USE

AVAILABILITY:

At all locations for loads of less than 75 kW where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished. RPU reserves the right to limit both the number of customers and the amount of load taken under this rate schedule.

APPLICATION:

To commercial, industrial, governmental, and other types of general service customers with all service taken at one point and measured through one meter. All electrical requirements at one location shall be taken under this rate schedule. Not applicable to temporary or standby service.

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:	2017	2018
Customer Charge:	~~$38.75~~	$40.00
Energy Charge:		
Non-Summer Energy		
On-peak Energy / Kwh:	~~17.595¢~~	17.732¢
Off-peak Energy /Kwh	~~5.822¢~~	5.964¢
Summer Energy:		
On-peak Energy / Kwh:	~~22.036¢~~	22.178¢
Off-peak Energy /Kwh:	~~6.190¢~~	6.332¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

Definition of On-Peak Energy: All energy used by the customer between the hours of 10:00 a.m. and 10:00 p.m. Monday through Friday.

Definition of Off-Peak Energy: All energy used by the customer that is not on-peak energy.

*Customer Charge: Customer charge per month plus any additional meter charge for costs above RPU's standard GS meter costs.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

GENERAL SERVICE - TIME-OF-USE (Cont.)

MINIMUM BILL:
Customer charge per month.

PAYMENT:
Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service under this rate will be made available at the option of the general service customer, subject to the availability of the necessary TOU metering equipment.

2. Customers converting to the GS-TOU rate from the GS rate shall make a one-time payment to RPU for any conversion cost above the normal cost to install GS-TOU metering.

3. A customer may switch back to the GS rate providing the customer gives RPU at least 60 days notice and agrees to pay any metering conversion costs.

4. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.

5. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected, or operated in parallel, with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.

6. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

7. Energy furnished under this rate shall not be resold.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE MGS SHEET 1 OF 2

MEDIUM GENERAL SERVICE

AVAILABILITY:

At all locations for loads where the demand is at least 75 kW or more for three or more billing periods in a given calendar year, but less than 1,000 kW, and where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished. Customers with minimum loads of at least 50kW for three or more billing periods in a given calendar year but less than 75 kW can choose to be classified as Medium General Service (MGS) and be billed under the MGS rate schedule below. The choice, once elected, is irrevocable for 12 billing periods, and remain in force unless revoked in writing by the customer.

APPLICATION:

To commercial, industrial, and governmental customers with all service taken at one point and measured through one meter. Also applicable to temporary service in accordance with RPU's published Electric Service Rules and Regulations. Not applicable to standby service.

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:	2017	2018
Demand Charge:		
Non-Summer /KW	~~$15.830~~	$16.830
Summer /KW	~~$20.060~~	$22.060
Energy Charge:		
Non-Summer Kwh	~~6.098¢~~	5.870¢
Summer Kwh	~~6.098¢~~	5.870¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

POWER FACTOR ADJUSTMENT:

The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

PRIMARY METER DISCOUNT:

Customers approved for metering at 13.8 kV will receive a discount of 1.25% on base rate charges for measured demand and energy.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

MEDIUM GENERAL SERVICE (Cont.)

TRANSFORMER OWNERSHIP CREDIT:

Customers owning transformers will receive a credit on each month's measured demand.

	2017	2018
Credit per KW	~~$0.35~~	$0.35

DETERMINATION OF DEMAND:

Measured demand is defined as the maximum rate at which energy is used for any period of fifteen consecutive minutes during the billing period. The billing demand shall be the greater of the measured demand for the billing period adjusted for power factor, or 50% of the maximum measured demand for the most current June-September billing periods adjusted for power factor. Billing periods may not coincide with calendar months.

MINIMUM BILL:

The minimum bill shall not be less than the billing demand, as provided above, whether or not energy is used.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
2. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected or operated in parallel with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.
3. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
4. Energy furnished under this rate shall not be resold.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE MGS-HEF
SHEET 1 OF 3

MEDIUM GENERAL SERVICE - HIGH EFFICIENCY HVAC

AVAILABILITY:

At all locations for loads where the demand is at least 75 kW or more for three or more billing periods in a given calendar year, but less than 1,000 kW, and where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served, and to customers who:

1. Use either an air source or ground source heat pump as the only source of heating and cooling in their facility.
2. Use an electric water heater (usually connected to a desuperheater on the heat pump) as the only source of water heating.
3. Receive prior approval of the equipment from RPU. Note that equipment must be rated by the Air-Conditioning, Heating, and Refrigeration Institute (AHRI)* and at the time of installation, meet the minimum efficiency requirements found on the Commercial Heat Pumps Rebate Application in effect at the time. The current application is available at www.rpu.org.
4. Service under this rate must be separately metered from other facility loads.

*For air source and ground source heat pumps the efficiency ratings are determined using the Air-Conditioning, Heating and Refrigeration Institute's (AHRI) directory, which may be found at www.ahridirectory.org.

Note: Other all-electric HVAC systems may be considered for this rate if they meet the stated efficiency standards. To have a system considered, customers must submit an engineering analysis documenting the efficiency of the system.

APPLICATION:

To commercial, industrial, governmental, and other types of Medium General Service customers reconfiguring their current electric service, or adding a new service, to separately meter their high efficiency HVAC equipment. Not applicable to standby service.

CHARACTER OF SERVICE:

Single or three phase 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

MEDIUM GENERAL SERVICE - HIGH EFFICIENCY HVAC (Cont.)

RATE:	2017	2018
Demand Charge per KW:		
Non-Summer	~~$13.610~~	$15.000
Summer	~~$20.640~~	$20.640
Energy Charge per Kwh:		
Non-Summer	~~5.098¢~~	4.888¢
Summer	~~6.006¢~~	5.985¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

POWER FACTOR ADJUSTMENT:

The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

PRIMARY METER DISCOUNT:

Customers approved for metering at 13.8 kV will receive a discount of 1.25% on base rate charges for measured demand and energy.

TRANSFORMER OWNERSHIP CREDIT:

Customers owning transformers will receive a credit on each month's measured demand.

	2017	2018
Credit per KW	~~$0.35~~	$0.35

DETERMINATION OF DEMAND:

Measured demand is defined as the maximum rate at which energy is used for any period of fifteen consecutive minutes during the billing period. The billing demand shall be the greater of the measured demand for the billing period adjusted for power factor, or 50% of the maximum measured demand for the most current June-September billing periods adjusted for power factor (referred to as ratchet). Billing periods may not coincide with calendar months.

For an existing facility reconfiguring its current electric service to come under this rate by separately metering its high efficiency HVAC equipment, the ratchet will be removed from the current electric service. The ratchet will be effective beginning in October following the first separately metered high efficiency HVAC service during one of the summer billing periods, June-September.

At that time the ratchet will be reapplied to the current electric service and will be applied for the first time to the high-efficiency HVAC service.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE MGS-HEF
SHEET 3 OF 3

MEDIUM GENERAL SERVICE - HIGH EFFICIENCY HVAC (Cont.)

MINIMUM BILL:

The minimum bill shall not be less than the billing demand, as provided above, whether or not energy is used.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service under this rate is only for air source or ground source heat pumps and any other all-electric HVAC systems that meet the stated efficiency requirements as explained in the Availability subhead of this rate schedule.
2. Service under this rate must be separately metered from other facility loads.
3. Since the HVAC system must be separately metered for this rate, the customer is responsible for any rewiring and its associated costs.
4. Service provided under this rate is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
5. Energy provided under this rate shall not be resold.
6. RPU shall not be liable for any damage or loss sustained by the customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
7. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected, or operated in parallel, with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE MGS-TOU SHEET 1 OF 3

MEDIUM GENERAL SERVICE - TIME-OF-USE

AVAILABILITY:

At all locations for loads where the demand is at least 75 kW or more for three or more billing periods in a given calendar year, but less than 1,000 kW, and where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished. RPU reserves the right to limit both the number of customers and the amount of load taken under this rate schedule.

APPLICATION:

To commercial, industrial, and governmental customers with all service taken at one point and measured through one meter. All electrical requirements at one location shall be taken under this rate schedule. Not applicable to temporary or standby service.

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:

Meter Charge: Any additional meter charge for costs above RPU's standard MGS meter costs.

	2017	2018
Non-Summer		
On-peak Demand / KW:	~~$15.830~~	$16.830
Off-peak Demand/ KW:	~~$1.933~~	$1.933
Energy Charge / Kwh:	~~6.098¢~~	5.870¢
Summer		
On-peak Demand / KW:	~~$20.060~~	$22.060
Off-peak Demand / KW:	~~$1.933~~	$1.933
Energy Charge / Kwh:	~~6.098¢~~	5.870¢

Definition of Season: Summer months are June through September. Non-summer months are January through May and October through December.

Definition of On-Peak Demand: The maximum kW used by the customer in any fifteen-minute period between the hours of 10:00 a.m. and 10:00 p.m. Monday through Friday.

Definition of Off-Peak Demand: The maximum kW used by the customer in any fifteen-minute period during the off-peak period.

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

MEDIUM GENERAL SERVICE - TIME-OF-USE (Cont.)

POWER FACTOR ADJUSTMENT:
The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

PRIMARY METER DISCOUNT:
Customers approved for metering at 13.8 kV will receive a discount of 1.25% on base rate charges for measured demand and energy.

TRANSFORMER OWNERSHIP CREDIT:
Customers owning transformers will receive a credit on each month's measured demand.

	2017	2018
Credit per KW	~~$0.35~~	$0.35

DETERMINATION OF DEMAND:
Measured demand is defined as the maximum rate at which energy is used for any period of fifteen consecutive minutes during the billing period.

BILLING DEMAND:
The on-peak billing demand shall be the greater of the measured on-peak demand for the billing period adjusted for power factor, or 50% of the maximum measured on-peak demand for the most current June-September billing periods adjusted for power factor. Billing periods may not coincide with calendar months.

The off-peak billing demand shall be the measured off-peak demand for the billing period adjusted for power factor less the on-peak billing demand for the billing period.

The total billing demand shall be the sum of the on-peak billing demand and the off-peak billing demand.

MINIMUM BILL:
The minimum bill shall not be less than the billing demand, as provided above, whether or not energy is used plus any meter charge.

PAYMENT:
Payments are due on or before the due date.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

MEDIUM GENERAL SERVICE - TIME-OF-USE (Cont.)

CONDITIONS OF DELIVERY:

1. Service under this rate will be made available at the option of the medium general service customer, subject to the availability of the necessary TOU metering equipment.
2. Customers converting to the MGS-TOU rate from the MGS rate shall make a one-time payment to RPU for any conversion cost above the normal cost to install MGS-TOU metering.
3. A customer may switch back to the MGS rate providing the customer gives RPU at least 60 days notice and agrees to pay any metering conversion costs.
4. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
5. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected or operated in parallel with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.
6. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
7. Energy furnished under this rate shall not be resold.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE LGS SHEET 1 OF 2

LARGE GENERAL SERVICE

AVAILABILITY:

At all locations for loads where the measured demand is at least 1,000 kW or more for three or more billing periods in a given calendar year, but less than 10,000 kW, and where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, additional contract arrangements may be required prior to service being furnished.

APPLICATION:

To commercial, industrial, and governmental customers with all service taken at one point and measured through one meter. Also applicable to temporary service in accordance with RPU's published Electric Service Rules and Regulations. Not applicable to standby service.

CHARACTER OF SERVICE:

Three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:

	2017	2018
Demand Charge / KW:	~~$18.100~~	$19.000
Energy Charge / KW :	~~6.057¢~~	5.959¢

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

POWER FACTOR ADJUSTMENT:

The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

PRIMARY METER DISCOUNT:

Customers approved for metering at 13.8 kV will receive a discount of 1.25% on base rate charges for measured demand and energy.

TRANSFORMER OWNERSHIP CREDIT:

Customers owning transformers will receive a credit on each month's measured demand.

	2017	2018
Credit per KW	~~$0.35~~	$0.35

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

LARGE GENERAL SERVICE (Cont.)

DETERMINATION OF DEMAND:
Measured demand is defined as the maximum rate at which energy is used for any period of fifteen consecutive minutes during the billing period. The billing demand shall be the greater of the measured demand for the billing period adjusted for power factor, or 50% of the maximum measured demand for the most current June-September billing periods adjusted for power factor. Billing periods may not coincide with calendar months.

MINIMUM BILL:
The minimum bill shall not be less than the billing demand, as provided above, whether or not energy is used.

PAYMENT:
Payments are due on or before the due date.

CONDITIONS OF DELIVERY:
1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
2. Unless authorized by separate written agreement, standby electric generating equipment installed by the customer shall not be interconnected or operated in parallel with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.
3. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
4. Energy furnished under this rate shall not be resold.
5. A separate electric service agreement may be required for service under this rate schedule.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE LIS SHEET 1 OF 2

LARGE INDUSTRIAL SERVICE

AVAILABILITY:

At all locations for loads with measured demands in excess of 10,000 kW for three or more billing periods in a given calendar year, and where facilities of adequate capacity and voltage are adjacent to the premises to be served. For loads where the service desired by the customer is not adjacent to the premises to be served, contract arrangements may be required prior to service being furnished.

APPLICATION:

To industrial customers with all service taken at one point and measured through one meter or meter totalizer. Not applicable to stand-by service.

CHARACTER OF SERVICE:

Three phase, 60 Hertz alternating current at 13,800 GRDY/7970 volts.

RATE:

	2017	2018
Demand Charge / KW:	~~$18.860~~	$19.500
Energy Charge / KW :	~~5.618¢~~	5.216¢

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

POWER FACTOR ADJUSTMENT:

The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

DETERMINATION OF DEMAND:

Measured demand is defined as the maximum rate at which energy is used for any period of fifteen consecutive minutes during the billing period. The billing demand shall be the greater of the measured demand for the billing period adjusted for power factor, or 50% of the maximum measured demand for the most current June-September billing periods adjusted for power factor. Billing periods may not coincide with calendar months.

MINIMUM BILL:

The minimum bill shall not be less than the billing demand, as provided above, whether or not energy is used.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

LARGE INDUSTRIAL SERVICE (Cont.)

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
2. Unless authorized by separate written agreement, stand-by electric generating equipment installed by the customer shall not be interconnected or operated in parallel with the RPU system: Customer shall own, install, operate, and maintain electrical interlocking equipment which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation.
3. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies or imperfections of service provided under this rate.
4. Energy furnished under this rate shall not be resold.
5. Customer agrees to manage its utilization equipment so as not to unbalance the current per phase by more than 10%.
6. RPU may require a separate electric service agreement for service under this rate schedule.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

INTERRUPTIBLE SERVICE

AVAILABILITY:

At all locations for customers who qualify and where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. Additional contractual arrangements may be required prior to service being furnished. RPU reserves the right to limit the amount of interruptible load taken by a customer and the total amount of interruptible load on the RPU system.

APPLICATION:

To commercial, industrial, and governmental customers contracting for electrical service for a period of one (1) year or more and having an interruptible load with a measured demand of 100 kW or more.

The INTR interruptible rate schedule is used in conjunction with the MGS, LGS, and LIS firm power rate schedules. To qualify for the INTR rate schedule, customers must have a minimum of 100 kW of interruptible demand. RPU reserves the right to limit the amount of interruptible load, which may be nominated.

Customers who qualify for the INTR rate shall either nominate an interruptible demand amount or a firm demand amount. Customers nominating an interruptible demand amount shall be required to interrupt at least the amount nominated, or their total load if their total load is less than the amount nominated. Customers nominating a firm demand amount shall be required to interrupt an amount sufficient to bring their load to or below the firm demand nominated. In no case shall the INTR rate be made available to customers with less than 100 kW of interruptible load.

All interruptible loads recognized under the INTR rate schedule shall be electrical loads that are coincident with RPU's system peak. Customers' electrical loads occurring outside this peak period shall not qualify for the INTR rate schedule. Any generation equipment used by the customer to qualify for the INTR rate shall be located at the site of the interruptible load such that RPU does not have to use its electrical facilities to transmit power for the customer.

CHARACTER OF SERVICE:

Three phase, 60 Hertz, alternating current at one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations. Service is subject to interruption at the sole discretion of RPU at any time during the year. There will be no more than 175 hours or 35 interruptions per year.

RATE:

MGS, LGS, and LIS customers are billed for interruptible power at the following rates:

Demand Charge per kW:

	2017	2018
MGS	~~$8.95~~	$10.95
LGS	~~$9.74~~	$10.64
LIS	~~$10.08~~	$10.72

The Energy Charge per kWh shall be equal to the appropriate customer class energy rate defined in the rate tariffs for the MGS, LGS, and LIS customer classes.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

INTERRUPTIBLE SERVICE (Cont.)

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

POWER FACTOR ADJUSTMENT:

The customer agrees to maintain an average power factor of 0.95 or greater for the billing period and to prevent a leading power factor. If the customer's average power factor is less than 0.95 for the billing period, the billing demand will be determined by multiplying the measured demand by 0.95 and dividing the results by the customer's average power factor. The average power factor is defined to be the quotient obtained by dividing the kWh used during the month by the square root of the sum of the squares of the kWh used and the lagging reactive kilovoltampere-hours supplied during the same period. The customer's average power factor will be determined by means of permanently installed meters.

PRIMARY METER DISCOUNT:

Customers approved for metering at 13.8 kV will receive a discount of 1.25% on base rate charges for measured demand and energy.

TRANSFORMER OWNERSHIP CREDIT:

Customers owning transformers will receive a credit on each month's measured demand.

	2017	2018
Credit per KW	~~$0.35~~	$0.35

SURCHARGE:

Customers whose service is taken outside the Rochester City limits are subject to a 10% surcharge on their bills (excluding charges computed under the Power Cost Adjustment).

PENALTY:

Unauthorized use of electricity during a peak period of service interruption ordered by RPU will require the customer to pay a penalty (in addition to standard charges) which is reflective of the uninterrupted load's cost impact on RPU's wholesale power cost from SMMPA over the ensuing 12 months:

A. No impact - No penalty
B. Occurs on monthly peak - Uninterrupted kW contribution to RPU's peak is billed at SMMPA rate.
C. Occurs on annual peak (as determined by analysis from October 1 analysis of summer demands) - Uninterrupted kW contribution to RPU's annual peak is additionally penalized at two times SMMPA rate and added to participants October billing.

Exception for first-time participants in an RPU peak reduction rate who have interruptible nominations of less than 500KW: The penalty for failure to interrupt will be waived during the initial 24 months.

DETERMINATION OF DEMAND:

Measured demand is defined as the maximum rate at which energy is used for any period of fifteen (15) consecutive minutes during the billing period.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

INTERRUPTIBLE SERVICE (Cont.)

BILLING DEMAND:

Customers nominating an amount of interruptible demand are required to interrupt at least their nominated interruptible demand. Customers may interrupt demand greater than their nominated interruptible demand. The billed interruptible demand for the month shall be the hourly integrated demand interrupted during the peak period of a service interruption requested by RPU. This interruptible demand will be billed at the appropriate interruptible rate for that month. Where no RPU requested interruption occurs during the month, all demand above the nominated interruptible demand shall be billed at the firm demand rate under the appropriate MGS, LGS, or LIS firm rate schedule.

Customers nominating an amount of firm demand are required to interrupt all demand over their firm service level.

Customers may interrupt demand below the firm service level. When peak metered demand for the billing period is equal to or greater than the firm service level, the Firm Billing Demand shall be equal to the actual metered demand during the RPU-requested service interruption concurrent with the system peak for the billing period When peak metered demand for the billing period is less than the firm service level, the Firm Billing Demand will be the greater of either the peak metered demand for the billing period minus the actual demand reduction during the RPU-requested service interruption concurrent with the RPU system peak for the billing period, or 50% of the Firm Demand Nomination for the most current June-September months minus the actual demand reduction during the RPU-requested service interruption concurrent with the RPU system peak for the billing period. All demand above the firm service level for the month shall be billed at the appropriate interruptible rate. Where no RPU requested interruption occurs during the month, all demand up to the firm demand nomination shall be billed at the appropriate firm demand rate.

Both firm and interruptible billing demands shall be adjusted for power factor.

There is no ratchet provision for interruptible demand.

MINIMUM BILL:

The minimum bill shall not be less than the adjusted billing demand, as provided above, whether or not energy is used.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
2. The Customer shall install, own, operate, and maintain the equipment necessary to interrupt its load.
3. In certain cases, the interruptible portion of the customer's load may have to be metered separately.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

INTERRUPTIBLE SERVICE (Cont.)

4. The Customer shall pay in advance of construction, all costs estimated by RPU for facilities located on Customer's premises which are necessary to serve the interruptible portion of the Customer's load and which duplicate other RPU facilities which are utilized to deliver electric service under other schedules. This includes any special metering needed for RPU to administer the INTR rate. Upon completion of the installation of such facilities by RPU, the actual cost of such facilities shall be charged to the Customer with the Customer's advance payment being applied as credit to such actual costs. The cost of major renewal and replacement of RPU-owned electric facilities located on the Customer's premises which are utilized for interruptible service and which duplicate other RPU facilities, shall be borne by the Customer.
5. When notified by RPU, the Customer shall remove the interruptible portion of its load from RPU's system in two (2) hours or less.
6. Upon one year's notice to the Customer, RPU may modify the hours and frequency of interruption specified herein to reflect changes in RPU's electric system load characteristics.
7. Interruptions of service caused by fire, accident, explosion, flood, strike, acts of God, or causes other than intentional interruptions ordered by RPU shall not be considered in determining the hours or frequency of interruption specified herein.
8. RPU, at its sole discretion, may immediately terminate service under this rate schedule upon the repeated unauthorized use of electricity by the customer during periods of interruption ordered by RPU.
9. Interruptible service shall not be used as standby for any other forms of energy or fuel.
10. Unless authorized by separate written agreement, standby electric generating equipment installed by the Customer shall not be interconnected or operated in parallel with the RPU system. Customer shall own, install, operate, and maintain electrical interlocking equipment, which will prevent parallel operation, and such equipment shall be approved by RPU prior to installation. RPU shall have the right to inspect the Customer's interrupting facilities as often as deemed prudent by RPU to verify their operating condition and proper interconnection.
11. RPU shall not be liable for any damage or loss sustained by Customer resulting from interruptions, deficiencies or imperfections of service provided under this rate.
12. Energy furnished under this rate shall not be resold.
13. Customers shall provide RPU with sufficient advance notice of their intention to use the INTR rate to allow RPU time to provide any necessary supplemental equipment and metering.
14. Customers using the INTR rate shall notify RPU in writing of their intention to use either the interruptible demand nomination or the firm demand nomination and the amount of their interruptible or firm loads.
15. Customers may change their method of nomination or level of nomination or both no more frequently than once per year with 60 days written notice and approval from RPU.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES
(RPU)

PCA
SHEET 1 OF 1

POWER COST ADJUSTMENT

APPLICATION:

Applicable to all rate schedules where there is a kWh charge.

1. The Power Cost Adjustment will be determined monthly, on a 12 month rolling average basis with application to the first revenue cycle each month.

2. The Power Cost Adjustment is determined by calculating the average actual cost per kWh of retail power supply from all sources during the previous 12 months, and subtracting the Established Power Supply Cost. All calculations will be carried out to $.00001 per kWh. Power supply costs include the cost of purchased power including charges for energy, demand, transmission, cost adjustments, and fees for regional power grid services.

3. The Established Power Supply Cost Base of $0.07285 was determined by the 2014 cost of service study. The base will remain at this level until subsequent review identifies a permanent and substantial change in the cost of power.

5. The Power Cost Adjustment will be the difference between the actual amount per kWh calculated in #2 above and the Established Power Supply Cost Base/ kWh.. This dollar amount per kWh will be added (subtracted) to each kWh of sales.

Approved by Rochester Public Utility Board: August 26, 2014
Effective Date: January 1, 2015

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE LMC
SHEET 1 OF 1

LOAD MANAGEMENT CREDITS

AVAILABILITY:
To customers participating in RPU's direct control load management program.

APPLICATION:
This rate schedule rider is to be applied in conjunction with all applicable rate schedules:

CREDITS:

	Monthly Credit	# Months Applied
Qualifying Central Air Conditioner	$ 3.00 each	5 months (May through September)
Qualifying Electric Water Heater	$ 3.00 each	12 months

TERMS AND CONDITIONS:
1. Participation in the direct control load management program is voluntary.
2. Customer agrees to participate in the program for one year or longer.
3. Qualifying appliances are central air conditioners up to 8 kW and electric water heaters with a minimum capacity of 40 gallons. Central air-conditioners above 8 kW, electric water heaters above 85 gallons, and other appliances or electrical loads applicable to direct control load management by RPU may be accepted by RPU in this program. In these cases, applicable credits will be calculated on a case by case basis.
4. Customer agrees to not utilize any other load management system in conjunction with equipment directly controlled by RPU.
5. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: TBD
Effective Date: Contingent upon implementation of RPU's new customer billing system.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE CSL
SHEET 1 OF 1

CITY STREET LIGHTING

AVAILABILITY:

To the City of Rochester for the illumination of public thoroughfares by means of RPU owned overhead street lighting facilities.

RATE:

Per kWh for all kWh Billed	2017	2018
Mercury Vapor (all Sizes)	~~21.620¢~~	22.377¢
Metal Halide (All Sizes)	~~22.929¢~~	23.732¢
LED (All Sizes)	~~37.143¢~~	38.443¢
High Pressure Sodium (All Sizes)	~~21.620¢~~	22.377¢

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

CONDITIONS OF DELIVERY:

1. This rate is based on lamps being lighted every night from approximately 30 minutes after sunset to 30 minutes before sunrise, providing dusk to dawn operation.
2. RPU will replace inoperative lamps and otherwise maintain luminaires during regular daytime hours. No credit will be allowed for periods during which the lamps are out of service. Routine lamp replacement will be made on a group replacement schedule.
3. RPU will determine the amount of energy used during any month by multiplying the rated kilowatt capacity of all lamps and accessory equipment by 350 hours for the month.
4. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE TS SHEET 1 OF 1

TRAFFIC SIGNALS

AVAILABILITY:

To governmental units for electric service to customer-owned traffic signal systems on public streets.

RATE:

Monthly Fixed charge: per traffic signal control cabinet served:

	2017	2018
Fixed Charge:	~~$32.07~~	$33.00
Energy Charge / Kwh:	~~10.543¢~~	10.528¢

MINIMUM BILL:

The minimum bill is per traffic signal control cabinet served for any month or portion of a month.

2017	2018
~~$32.07~~	$33.00

POWER COST ADJUSTMENT:

Bills computed under this rate schedule are subject to adjustment in accordance with the Power Cost Adjustment (PCA).

CONDITIONS OF DELIVERY:

1. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE CDS SHEET 1 OF 1

CIVIL DEFENSE SIRENS

AVAILABILITY:

At all locations where facilities of adequate capacity and suitable voltage are adjacent to the location of the siren to be served.

APPLICATION:

To Olmsted County Civil Defense for the periodic operation of civil defense sirens.

CHARACTER OF SERVICE:

Single of three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:

	2017	2018
Per Siren per month	~~$16.29~~	$16.29

MINIMUM BILL:

The minimum bill is per siren for any month or portion of a month.

	2017	2018
Minimum Bill	~~$16.29~~	$16.29

PAYMENT:

Bills will be rendered monthly; payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. The customer shall furnish, install, own, operate, and maintain all sirens. The customer shall also furnish, install, own, and maintain any structures required for the mounting and support of sirens; except where the customer specifically requests and RPU agrees to use RPU owned poles for this purpose. In such cases, RPU will assist in the installation and removal of sirens and the customer shall pay RPU for the actual costs thereof.
2. When RPU does not have secondary service available at the siren location and it is necessary to install a transformer or to extend secondary lines a distance greater than 150 feet, the customer shall pay RPU the actual costs for installing the transformer and/or making such line extensions.
3. RPU will make the connection and disconnection with its distribution lines.
4. Loads other than sirens shall not be connected to the siren's circuit.
5. The customer shall furnish RPU with a map indicating the location of sirens to be operated and shall notify RPU at least 30 days in advance of the planned addition, removal, or relocation of any siren.
6. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: November 15, 2016
Effective Date: January 1, 2017

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE SL SHEET 1 OF 2

SECURITY LIGHTING

AVAILABILITY:

At all locations whenever the service can be provided with overhead wiring on an existing RPU owned pole.

APPLICATION:

To all classes of customers contracting for security lighting.

RATE:

Mercury Vapor Lights (Closed)

Monthly Charge

Size	2017	2018
175 Watt Mercury Vapor	~~$ 10.71~~	$10.66
250 Watt Mercury Vapor	~~$13.10~~	$13.03
400 Watt Mercury Vapor	~~$18.61~~	$18.52

High Pressure Sodium Vapor Lights

Size	2017	2018
70 Watt (Closed)	~~$ 9.33~~	$ 9.28
100 Watt	~~$11.11~~	$11.05
150 Watt (Roadway)	~~$12.49~~	$12.43
250 Watt	~~$15.55~~	$15.47
400 Watt (Closed)	~~$20.39~~	$20.29

Light Emitting Diode (LED) Lights

Size	2017	2018
LED Area Light	~~$11.11~~	$11.05
LED Roadway Light	~~$15.55~~	$15.47

PAYMENT:

Bills will be rendered monthly; payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. RPU will furnish, install, own, and maintain a standard lighting unit consisting of a luminaire, complete with lamp and control device wired for operation, supported by a bracket mounted on an RPU owned pole, and will supply all electrical energy necessary for the operation of the unit.
2. When RPU does not have a suitable pole or secondary service available at the desired location and it is necessary to install a transformer or a pole or to extend secondary lines a distance greater than 150 feet, the customer shall pay RPU the actual costs for installing the transformer or pole and/or making such line extensions.
3. Service under this rate is not available underground or in underground areas unless the customer pays RPU the complete cost of the necessary underground facilities.
4. Lamps will automatically be switched on approximately 30 minutes after sunset and off 30 minutes before sunrise, providing dusk to dawn operation of approximately 4,200 hours per year.
5. RPU will make every attempt to replace inoperative lamps and maintain luminaries during regular daytime work hours within 3 working days after notification by the customer. No credit will be allowed for periods during which the lamp was out of service.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

SECURITY LIGHTING (Cont.)

CONDITIONS OF DELIVERY:

6. RPU will, at the customer's expense, relocate or change the position of any lamp or pole as requested in writing by the customer.
7. Service furnished under this rate is subject to applicable provisions of RPU's published Electric Service Rules and Regulations.
8. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE UMDR SHEET 1 OF 1

UNMETERED DEVICE RATE

AVAILABILITY:

At all locations where facilities of adequate capacity and suitable voltage are adjacent to the location of the device to be served.

APPLICATION:

To commercial customers where the estimated monthly kwh required does not exceed 300 kwh and is determined by RPU to not warrant a meter.

CHARACTER OF SERVICE:

Single of three phase, 60 Hertz, alternating current at any one of the standard secondary service voltages as described in RPU's published Electric Service Rules and Regulations.

RATE:

	2017	2018
Fixed Charge per device per month	N/A	$11.18
Energy Charge (Kwh)	N/A	11.217¢

MINIMUM BILL:

The minimum bill is per device for any month or portion of a month.

	2017	2018
Minimum Bill	N/A	$11.18

PAYMENT:

Bills will be rendered monthly; payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. The customer shall furnish, install, own, operate, and maintain all devices. The customer shall also furnish, install, own, and maintain any structures required for the mounting and support of devices; except where the customer specifically requests and RPU agrees to use RPU owned poles for this purpose. In such cases, RPU will assist in the installation and removal of devices and the customer shall pay RPU for the actual costs thereof.
2. When RPU does not have secondary service available at the device location and it is necessary to install a transformer or to extend secondary lines a distance greater than 150 feet, the customer shall pay RPU the actual costs for installing the transformer and/or making such line extensions.
3. RPU will make the connection and disconnection with its distribution lines.
4. Loads other than the device shall not be connected to the device's circuit.
5. The customer shall furnish RPU with a map indicating the location of sirens to be operated and shall notify RPU at least 30 days in advance of the planned addition, removal, or relocation of any siren.
6. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

Approved by Rochester Public Utility Board: TBD

Effective Date: Contingent upon the implementation of RPU's new customer billing system.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE CAR SHEET 1 OF 1

CLEAN AIR RIDER

APPLICATION:

The Clean Air Rider (CAR) will be used to recover costs related to renewable and environmental improvement programs and projects approved by the Utility Board. Applicable to all rate classes billed in kWh.

CONDITIONS OF DELIVERY:

1. Emission Reduction Project at Silver Lake Plant:
   a. The CAR for the Emission Reduction Project (ERP) at the Silver Lake Plant is to recover the annual debt service of the project.
   b. The CAR for the ERP will be calculated by dividing the ERP debt service requirements by the KWH forecast for all rate classes. This monthly charge under the CAR Schedule for 2018 is $0.00180/kwh.
   c. The CAR will terminate for the ERP with payment of all debt service requirements.
   d. An annual true-up will be done comparing the actual amount collected to the actual debt service requirement. The amount over or under collected will adjust future years debt service requirements used in the calculation.

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE WTR-C SHEET 1 OF 1

WATER SERVICE

AVAILABILITY:

At all locations within the Rochester City limits and at locations external to the City limits, that have been authorized by the Rochester Common Council.

MONTHLY RATE:

Customer Charge:	Size of Meter	2016	2017	2018
	5/8"	$ 6.26	$ 6.84	$ 7.50
	3/4"	$ 8.89	$ 9.72	$ 10.66
	1"	$ 14.29	$ 15.62	$ 17.14
	1-1/2"	$ 27.58	$ 30.14	$ 33.07
	2"	$ 43.54	$ 47.59	$ 52.21
	3"	$ 81.00	$ 88.53	$ 97.13
	4"	$ 134.39	$ 146.88	$ 161.15
	6"	$ 267.86	$ 292.76	$ 321.20
	8"	$ 479.03	$ 523.56	$ 574.42

Commodity Charge Rate/CCF:		2016	2017	2018
Residential	0 - 7 CCF	75.5¢	78.5¢	81.3¢
	7.01 - 12 CCF	82.7¢	85.7¢	88.5¢
	12.01 and over CCF	94.7¢	97.7¢	100.5¢
Commercial:		75.5¢	78.5¢	81.3¢
Industrial:		75.5¢	78.5¢	81.3¢
Interdepartmental:		75.5¢	78.5¢	81.3¢
Irrigation Meter (All Classes):		94.7¢	97.7¢	100.5¢

NOTE: Customers whose service is taken outside the Rochester city limits with individual water systems not connected to the City water system shall have a rate of 2.0 times the customer and commodity charges.

MINIMUM BILL:

Applicable monthly customer charge according to size of meter provided.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. Service furnished under this rate schedule is subject to connection policies of the Rochester City Council.
2. Service furnished under this rate schedule is subject to provisions of RPU's Water Service Rules and Regulations.
3. RPU shall not be liable for damage or loss sustained by customer in conjunction with taking service under this rate.
4. Water furnished under this rate shall not be resold.

Approved by Rochester Public Utility Board: November 10, 2015
Effective Date: January 1, 2016

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE FHFC SHEET 1 OF 1

FIRE HYDRANT FACILITIES CHARGE

APPLICABILITY:

To all residential and commercial and industrial water utility customers.

MONTHLY RATE:

Customer Class	2016	2017	2018
Residential	$ .90	$ .90	$ .90
Commercial/Industrial	$3.50	$3.70	$3.70

BILLINGS:

Billings will be on a monthly basis.

PAYMENT:

Payments are due on or before the due date.

CONDITIONS OF DELIVERY:

1. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.
2. The rate will not be applied to water service meters that are used exclusively for irrigation purposes.
3. The rate will not be applied to water service meters that are not connected to the City's central water system.
4. The rate will be applied regardless of the property's water service status (active or non-active).

Approved by Rochester Public Utility Board: November 10, 2015
Effective Date: January 1, 2016

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

SCHEDULE I

ROCHESTER PUBLIC UTILITIES
COGENERATION AND SMALL POWER PRODUCTION TARIFF

AVAILABILITY:

By separate written agreement only.

APPLICATION:

To residential and general service customers contracting for electric service for one year or more, with all service taken at one point and where part or all of the electrical requirements of the customer can be supplied by customer-owned electrical generating equipment which is connected for operation in parallel with RPU's system.

This rate schedule rider is to be applied in conjunction with the following schedules:

Residential Service	(RES)
General Service	(GS)
Medium General Service	(MGS)
Large General Service	(LGS)
Large Industrial Service	(LIS)
Power Cost Adjustment	(PCA)

CHARACTER OF SERVICE:

Single or three phase, 60 Hertz alternating current at any one of the standard secondary service voltages as described in RPU's published electric Service Rules and Regulations.

RATE:

Demand Charge:

The demand charge shall be determined in accordance with the applicable rate schedule (MGS, LGS and LIS customers only) and shall be applied in accordance with the provisions of Section VII (C) of RPU's Rules Covering Cogeneration and Small Power Production Facilities.

Energy Charge:

The energy charge shall be determined in accordance with the applicable rate schedule (RES, GS MGS, LGS or LIS customers) and shall be applied in accordance with the provisions of Section VII (B or C as applicable) of RPU's Rules Covering Cogeneration and Small Power Production Facilities.

Minimum Charge: The minimum charge shall be determined in accordance with the applicable rate schedule (RES, GS, MGS, LGS, or LIS customers).

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Energy and Capacity Credits: The energy and capacity credits shall be applied in accordance with the provisions of Section VII (B or C as applicable) of RPU's Rules Covering Cogeneration and Small Power Production Facilities.

POWER COST ADJUSTMENT:

The energy credit computed under this rate schedule rider is subject to a Power Cost Adjustment.

PAYMENT:

Payments are due on or before the due date.

1. **CONDITIONS OF DELIVERY:** Service furnished under this rate schedule rider is subject to applicable provisions of RPU's published Electric Service Rules and Regulations and Rules Covering Cogeneration and Small Power Production.
2. Service under this rate schedule rider will be furnished only to customers whose maximum electrical generating capacity is 40 kW or less; such service may be limited at the sole discretion of RPU, to those customers who obtain "qualifying" status under FERC Regulations (18CFR Part 292) implementing section 201 of the Public Utility Regulatory Policies Act of 1978.
3. Service under this rate schedule rider will be furnished only after the customer and RPU have entered into a separate written agreement which specifies the type of metering and interconnection facilities to be employed, the responsibilities for installation, ownership, and maintenance of these facilities, and the procedures required for safe and technically acceptable operation of parallel electrical generating equipment.
4. RPU shall not be liable for any damage or loss sustained by the customer resulting from the parallel operation of the customer's electrical generating equipment, or resulting from interruptions, deficiencies, or imperfections of service provided under this rate schedule rider.
5. Energy furnished under this rate schedule rider shall not be resold.

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: March 28, 2006
Effective Date: April 4, 2006

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE PEVC SHEET 1 OF 1

RPU Public Electric Vehicle Charging Rate

AVAILABILITY:

To Electric and Plug-in Hybrid vehicles with level 1 or level 2 charging capability, at RPU managed car charging stations.

RATE:

Per hour of plugged in time	2017	2018
The hours of 4 pm – 7 pm	N/A	$ 2.00 per hour
All other hours	N/A	75¢ per hour

CONDITIONS OF DELIVERY:

1. Customers must be registered with ChargePoint and have a ChargePoint RFID card, or have the ChargePoint app installed on a smartphone. Instructions are available at ChargePoint.com. *
2. Station payment is managed by a third party, ChargePoint.com, and requires prepayment by credit card. RPU is unable to take payment to recharge your ChargePoint card. *
3. It is recommended to have a smartphone enabled device with the Chargepoint App installed.
4. Rates are applied during the time period the car is plugged in. Not when the car starts or finishes charging.
5. RPU shall not be liable for any damage or loss sustained by customer resulting from interruptions, deficiencies, or imperfections of service provided under this rate.

**For instructions on how to register for a ChargePoint RFID card, please visit ChargePoint.com or contact RPU Customer Service*

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

ROCHESTER PUBLIC UTILITIES (RPU)

RATE SCHEDULE LINEEXT SHEET 1 OF 1

LINE EXTENSIONS

AVAILABILITY:

Available to all customers and developers in RPU's Service Territory.

APPLICATION:

The Rules for Line Extensions in this schedule apply to all existing and prospective customers requesting a new line extension or change of existing service.

RATE:	2018
Residential	$900 / Standard Service***
Commercial, Industrial and Multi-Family Housing	
Installed transformer Capacity	Rate
Up to 25 kVA	$1,100 / Standard Service*
25 kVA up to 50 kVA	$2,500 / Standard Service*
50 kVA up to 75 kVA	$4,500 / Standard Service*
75 kVA up to 10,000 kVA	Total cost of Standard Service less a credit of $63/kVA of installed transformer Capacity**
Above 10,000 kVA and/or Non-standard Service	Negotiated

*Single Phase Service is assumed. If three phase service is requested, the customer must also pay the difference between three phase and single phase service.

**In cases where the installed transformer credit offsets the total cost of the Standard Service, no additional amount will be charged.

***For the purposes of this rate schedule, Standard Residential Service is considered to be a single lot or single structure with three or fewer dwelling units.

PAYMENT:

Payments must be received before work on the line extension or enhancement will begin.

Approved by Rochester Public Utility Board: April 25, 2017
Effective Date: January 1, 2018

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

MISCELLANEOUS FEES SHEET 1 of 2

MISCELLANEOUS FEES - ELECTRIC UTILITY

	2018 Rate	
NSF Check	$30.00	
Meter Test-Residential (2nd request within the past 12 months)	$100.00	
Meter Test-Commercial (2nd request within the past 12 months)	$210.00	
Outage Call (The problem is with the customer's equipment, and this is the second request within the past twelve months)	$100.00	
Copies per page, black & white	$0.25	
Copies, black & white, duplex	$0.50	
Copies per page, color (from color printer, not copier)	$0.35	
Reconnection After Disconnection (Workdays, 8:00 AM - 5:00 PM)	$70.00	
Meter Connections After Hours		
Workdays, 5:00 PM - 9:00 PM	$145.00	
Workdays, 9:00 PM - 8:00 AM	$230.00	
Non-Workdays	$230.00	
Holidays	$230.00	
House Move Investigation	$350.00	
Temporary Meter Installation Fee	$100.00	
Temporary Commercial Meter Installation Fee	$760.00	
Pole Reconnection (Commercial)	$295.00	
Meter Tampering	$240.00	
Meter Service Call	$70.00	
Infraview services - per hour	$115.00	per hr

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

ROCHESTER PUBLIC UTILITIES (RPU)

MISCELLANEOUS FEES SHEET 2 of 2

MISCELLANEOUS FEES - WATER UTILITY

Water Main Tapping Fee 3/4 "	$225.00
Water Main Tapping Fee 1 "	$225.00
Water Main Tapping Fee 4"	$760.00
Water Main Tapping Fee 6"	$760.00
Water Main Tapping Fee 8"	$760.00
Water Main Tapping Fee 10"	$760.00
Water Main Tapping Fee 12"	$760.00
Frozen Meter Repair	$90.00
Hydrant Meter Rental	
Flat fee for installtion and retrieval (plus tax)	$120.00
Addition for 1" Meter	$40.00
Addition for 2-3" Meter	$80.00
Unauthorized Use - Valve or Hyrdrant (Per Occurance)	$500.00
Water Leak Detection	
1 person	$170.00
2 people	$320.00
Curb Box Operation	$50.00
Meter Removal Fee	$50.00
Meter Installation Fee	$50.00
Frozen Pipes - Per Man Hour	$85.00
After Hours Tower Access	$130.00

Attachment: 2018 Rates 01-01-2018 (8100 : 2018 Electric Utility Rate Adjustment)

Approved by Rochester Public Utility Board: TBD
Effective Date: January 1, 2018

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the following rate schedules and attached tariff effective on or about January 1, 2018.

Residential Service (RES)

Residential Service-Dual Fuel (RES-DF)

Residential-High Efficiency HVAC (RESELGEO)

General Service (GS)

General Service-High Efficiency (GS-HEF)

General Service Time-Of-Use (GS-TOU)

Medium General Service (MGS)

Medium General Service-High Efficiency (MGS-HEF)

Medium General Service Time-Of-Use (MGS-TOU)

Unmetered Device(UMDR)

Public Car Charging (PCCR)

Large General Service (LGS)

Large Industrial Service (LIS)

Interruptible Service (INTR)

City Street Lighting (CSL)

Traffic Signals (TS)

Highway Lighting (HL)

Security Lighting (SL)

Civil Defense Sirens (CDS)

Clean Air Rider (CAR)

Power Cost Adjustment (PCA)

Load Management Credits (LMC)

BE IT FURTHER RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, that the Common Council of the said City is requested to approve an overall 1.5% electric revenue increase with changes to all customer classes and an annual update to the Clean Air Rider Rate effective on or about January 1, 2018.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 14th day of November, 2017.

President

Secretary

FOR BOARD ACTION

Agenda Item # (ID # 8108) Meeting Date: 11/14/2017

SUBJECT: 2018 Electric Utility Budget Approval

PREPARED BY: Peter Hogan

ITEM DESCRIPTION:

The preliminary 2018 electric utility budget was reviewed with the finance and audit committee on October 17, 2017, and with the full Board on October 24, 2017. The budget as presented reflects a reduction of approximately $4.1 million in operating and capital expenses from staff's original submissions in order to meet the 2017 cost of service study recommendations.

The significant drivers for the 2018 budget are:

- Proposed electric rate increases for 2018 @ 1.5%
- Our SMMPA wholesale rate for 2018 will be unchanged
- Continuation of prudent investments into our system to improve reliability, service, safety, sustainability and to serve new growth
- Investment in the West Side Energy Station with a commercial production date of 2018.
- Investments in IT systems and distribution systems
- Additional principal and interest payment ($5.7M) due to the 2017 bond issuance of $108M debt for the completion of CAPX 2020 project, funding of the West Side Energy Station, Service Center expansion and refunding of 2007 Bond Issuance
- Continued funding for our energy conservation programs
- Movement towards the financial targets set based on the adoption of the utility method of rate setting:
    - Alignment of variable and fixed costs with corresponding variable and fixed revenues reduces cross subsidies and improves financial sustainability
    - Change in Net Assets goal for 2018: $14,370,000; Budget $13,680,000
    - Debt Service Coverage Ratio, excluding payment in lieu of taxes (PILOT), of 3.0 times or greater; Budget projects 2.8 times in 2018
    - Minimum cash reserves goal for 2018: $53,954,000; Budget

FOR BOARD ACTION

Agenda Item # **(ID # 8108)** **Meeting Date: 11/14/2017**

$54,079,000

Summary financial sheets are attached reflecting the recommended budget. Staff will be available to answer questions.

UTILITY BOARD ACTION REQUESTED:

Management recommends that the Board approve and request Common Council approval of the 2018 RPU electric utility operating and capital budget.

ROCHESTER PUBLIC UTILITIES
ELECTRIC UTILITY
2018 OPERATING BUDGET

BASIC ASSUMPTIONS

- Cost center budgets and non-bonded projects set at level used in cost-of-service study
- Other than specifically identified projects, no assumptions have been made with regards to DMC
- Interest Earnings Rate: 0.25%
- Average Salary Expense Change: 3.5% (consists of COLA, merit and promotion increases)
- Anticipated Bonding: none
- Change in Full-time Equivalents: 2
- SMMPA Wholesale Power Cost: 0.0% increase
- SMMPA CROD Level: 216 MW
- Minimum Cash Reserve Requirement: Current policy amount $53,954,000

RETAIL REVENUES / SALES

- Revenue Adjustment: 1.50%
- Electric KWH Sales Forecast: 0.8 % Increase from 2017 F2 Year End Projected Sales
- Total Electric Utility Customers: 2.0% Increase over Year End 2017 F2 Projected Customers
- Forecast Assumes Normal Weather : 523 Cooling Degree Days

WHOLESALE REVENUES / SALES & EXPENSES

- Estimated Cost of Fuel 2018: $3.705 / mmBtu
- Budgeted Cost of Fuel 2017 F2: $3.650 / mmBtu

OTHER ITEMS

- In Lieu of Tax forecast increasing $243,800 to a total of $8,655,429.

ROCHESTER PUBLIC UTILITIES
ELECTRIC UTILITY
Management Reporting P&L

#		Historical Data 2015	2016	2017 F2	2018	2019	2020	2021	2022
5	in 000's	2015	2016	2017 F2	2018	2019	2020	2021	2022
6	RPU Rate Increase	3.5%	1.7%	3.7%	1.5%	1.9%	2.5%	2.5%	2.5%
7	**Revenue**								
8	Retail Electric	$133,560	$142,011	$150,769	$153,878	$156,695	$160,352	$164,057	$167,481
9	Wholesale Electric	$2,579	$2,311	$1,666	$2,759	$3,073	$3,133	$3,197	$3,268
10	Wholesale Steam	$5,412	$4,039	$4,259	$4,349	$4,456	$4,565	$4,675	$4,768
11	Transmission	$1,387	$4,917	$4,526	$5,000	$5,000	$5,000	$5,000	$5,000
12	Other Services & Fees	$2,917	$3,157	$3,125	$3,624	$3,712	$3,942	$3,904	$3,946
13	**Total Revenue**	**$145,856**	**$156,435**	**$164,344**	**$169,610**	**$172,936**	**$176,991**	**$180,832**	**$184,463**
14	**Cost of Revenue** — SMMPA Rate Increase	0.0%	6.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Power Supply	$86,639	$92,700	$92,959	$94,661	$95,064	$95,352	$95,540	$95,571
16	Generation Fuel	$3,871	$3,563	$3,304	$4,099	$4,341	$4,416	$4,493	$4,569
17	**Total Cost of Revenue**	**$90,510**	**$96,262**	**$96,263**	**$98,760**	**$99,405**	**$99,767**	**$100,033**	**$100,139**
18	**Gross Margin**								
19	Retail Electric	$46,921	$49,311	$57,810	$59,217	$61,631	$65,000	$68,517	$71,910
20	Wholesale	$4,120	$2,787	$2,620	$3,009	$3,188	$3,282	$3,379	$3,467
21	Transmission	$1,387	$4,917	$4,526	$5,000	$5,000	$5,000	$5,000	$5,000
22	Other Services & Fees	$2,917	$3,157	$3,125	$3,624	$3,712	$3,942	$3,904	$3,946
23	**TOTAL GROSS MARGIN**	**$55,346**	**$60,172**	**$68,081**	**$70,850**	**$73,532**	**$77,224**	**$80,800**	**$84,324**
24	**Controllable Costs**								
25	Salaries & Benefits	$18,819	$20,303	$22,056	$23,998	$25,565	$26,952	$27,910	$29,313
26	Other Operating Expenses	$8,408	$8,655	$9,163	$9,602	$10,335	$10,349	$10,548	$10,755
27	Major Maintenance	$3,890	$1,690	$3,133	$3,257	$3,850	$2,351	$2,630	$2,407
28	Non-Bonded Capital Projects	$5,908	$9,888	$13,995	$9,365	$13,900	$14,459	$11,958	$15,871
29	**TOTAL CONTROLLABLE COSTS**	**$37,026**	**$40,536**	**$48,347**	**$46,221**	**$53,650**	**$54,111**	**$53,046**	**$58,346**
30	Depreciation & Amortization	$10,589	$9,804	$11,322	$12,948	$14,494	$15,224	$15,383	$15,756
31	Less Non Bonded Projects (capitalized)	($5,908)	($9,888)	($13,995)	($9,365)	($13,900)	($14,459)	($11,958)	($15,871)
32	Less Total Internal Costs (capitalized)	($3,439)	($3,292)	($5,406)	($3,811)	($4,166)	($5,167)	($5,753)	($5,121)
33	Interutility Allocation	($1,211)	($1,230)	($1,229)	($1,449)	($1,478)	($1,508)	($1,538)	($1,569)
34	**Total Operating Expenses**	**$37,058**	**$35,931**	**$39,038**	**$44,545**	**$48,600**	**$48,201**	**$49,180**	**$51,541**
35	**Net Operating Income (Loss)**	**$18,288**	**$24,242**	**$29,042**	**$26,305**	**$24,931**	**$29,023**	**$31,619**	**$32,783**
36	**Financing & Other Non-Operating Items:**								
37	Bond & Interest Related Expenses	($3,495)	($3,507)	($5,011)	($4,854)	($6,271)	($7,307)	($7,136)	($6,949)
38	Interest Income	$240	$256	$1,066	$536	$373	$414	$413	$412
39	Misc Non-Operating Income (Expense)	($610)	($367)	($31)	($53)	($54)	($56)	($57)	($58)
40	**Total Financing & Non-Operating Items**	**($3,865)**	**($3,617)**	**($3,977)**	**($4,371)**	**($5,953)**	**($6,948)**	**($6,780)**	**($6,594)**
41	**Income Before Transfers or Capital Contributions**	**$14,423**	**$20,625**	**$25,065**	**$21,934**	**$18,979**	**$22,074**	**$24,839**	**$26,189**
42	Transfers (In Lieu of Taxes)	($8,384)	($8,470)	($8,412)	($8,655)	($8,801)	($8,948)	($9,096)	($9,242)
43	Capital Contributions	$0	$0	$0	$0	$0	$0	$0	$0
44	Other Revenues	$0	$3,062	$2,809	$401	$171	$40	$40	$40
45	Special Items	$0	$0	$0	$0	$0	$0	$0	($0)
46	**NET INCOME**	**$6,040**	**$15,217**	**$19,463**	**$13,680**	**$10,349**	**$13,166**	**$15,783**	**$16,987**
47	**TARGET NET INCOME**				**$ 14,370**	**$ 14,880**	**$ 15,550**	**$ 16,300**	**$ 17,010**
48	**Excess (Deficit) from Target**				**$ (690)**	**$ (4,531)**	**$ (2,384)**	**$ (517)**	**$ (23)**
49	**1/01 Cash Balance**		**$ 41,698**	**$ 40,753**	**$ 47,578**	**$ 54,079**	**$ 52,408**	**$ 55,137**	**$ 59,687**
50	Change in Net Assets		15,217	19,463	13,680	10,349	13,166	15,783	16,987
51	Depreciation & Amortization		9,804	11,322	12,948	14,494	15,224	15,383	15,756
52	Capital Additions/Service Territory Comp		(39,037)	(69,704)	(34,465)	(20,973)	(29,626)	(26,711)	(21,042)
53	Bond Principal Payments		(3,895)	(3,685)	(5,460)	(5,725)	(6,422)	(6,738)	(7,065)
54	Bond Proceeds		13,350	125,227	-	(0)	22,800	-	-
55	Net Change in Other Assets/Liabilities		3,616	(75,798)	19,799	183	(12,413)	6,832	(1,625)
56	Net Changes in Cash		(945)	6,825	6,501	(1,672)	2,730	4,550	3,011
57	**12/31 Cash Balance**		**$ 40,753**	**$ 47,578**	**$ 54,079**	**$ 52,408**	**$ 55,137**	**$ 59,687**	**$ 62,698**
58	**Reserve Target**		**$ 50,419**	**$ 52,561**	**$ 53,954**	**$ 54,627**	**$ 54,418**	**$ 54,426**	**$ 54,877**
59	**Excess (Deficit) from Target**		**$ (9,666)**	**$ (4,983)**	**$ 125**	**$ (2,219)**	**$ 719**	**$ 5,261**	**$ 7,821**
60	**Cash Balance as % of Reserve Target**			**90.5%**	**100.2%**	**95.9%**	**101.3%**	**109.7%**	**114.3%**
61	**Debt Service Coverage Ratio**				**2.8**	**2.8**	**2.9**	**3.1**	**3.2**

Attachment: 2018 Electric Utility Proforma (8108 : 2018 Electric Utility Budget Approval)

1 **ROCHESTER PUBLIC UTILITIES**
2 **CAPITAL AND MAJOR MAINTENANCE PLAN**
3 **MATERIALS, SUPPLIES & SERVICE**
4 **PROJECT BREAKDOWN ON 5 YEAR SUMMARY**

5 **ELECTRIC UTILITY**
6 **CAPITAL**
7 **($000's)**

8		2018	2019	2020	2021	2022	5-Yr Total
9	**Core Services**						
10	Allocation - New Services	**1,343**	1,371	1,398	1,426	1,454	6,991
11	New Service Installations	*483*	-	-	-	-	-
12	Overhead Replacements	*40*	-	-	-	-	-
13	Pole Replacement	*30*	-	-	-	-	-
14	Annual Underground Cable Replacements (URD)	*600*	-	-	-	-	-
15	Other Projects	*80*	-	-	-	-	-
16	Property Damage - Repair/Replace	*80*	-	-	-	-	-
17	Other Equipment Failures	*30*	-	-	-	-	-
18	Load Management Installations	1	15	15	15	15	61
19	Mobile Meter Reader	30	-	32	-	34	96
20	Metering/Shop Test Equipment Upgrade/Repl	15	15	15	15	15	75
21	Substation/Shop Test Equipment Upgrade/Repl	25	15	15	15	15	85
22	SF-6 Gas Cart	65	-	-	-	-	65
23	Substation Spares and Replacements	70	-	-	-	-	70
24	Allocation - Metering/AMR	651	650	650	650	650	3,251
25	345kV Transmission Project HC/Roch/LaCrosse	(239)	-	-	-	-	(239)
26	Hydro Line Rebuild	45	-	-	-	50	95
27	Northern Hills 65th St Feeder	-	-	250	-	-	250
28	Feeder 306 Install	-	-	-	-	300	300
29	Feeder 615 Install	-	-	350	-	-	350
30	Feeder 715 Install	-	200	200	-	-	400
31	Feeder 913 Install	-	-	300	-	-	300
32	Feeder 914 Install	-	-	-	300	-	300
33	Feeder 1315 Install	-	-	250	-	-	250
34	Feeder 1602 Install	-	-	-	-	300	300
35	Feeder 1732 Install	-	70	-	-	-	70
36	Feeder 1733 Install	-	-	200	-	-	200
37	Feeder 1734 Install	-	-	-	-	300	300
38	1st Ave SE Duct Relocation	228	-	-	-	-	228
39	Miracle Mile Feeder Relocation	65	-	-	-	-	65
40	Downtown New Duct Systems	-	300	2,000	200	1,000	3,500
41	Downtown New Feeder Extensions	-	-	-	500	500	1,000
42	65th St - 50th to 60th Ave	-	-	-	-	250	250
43	48th St NE	-	-	100	125	-	225
44	60th Ave Duct Banks	-	-	-	-	300	300
45	55th St NW - 60th Ave to CR #3	-	-	-	-	200	200
46	75th St NW	-	-	-	150	200	350
47	FDR 712 - Tie to 711/19th St	-	150	-	-	-	150
48	40th St SW	-	-	-	100	-	100
49	FDR Tie - 713/401	-	85	-	-	-	85
50	Hwy 14 E	-	-	-	-	85	85
51	FDR 302 to 406 Load Transfer	-	-	-	150	-	150
52	1305 Feed into N Walmart Loop	75	-	-	-	-	75
53	FDR 811 Extension to 55th St	-	-	-	-	100	100
54	FDR 301 Load Relief	-	-	-	-	200	200
55	Feeder 401 - Reconfigure	110	125	-	-	-	235
56	Q2 Rebuild from Bear Creek - RCTC	-	-	-	250	-	250
57	Q4 Rebuild from BV Sub to Salem Rd	150	670	-	-	-	820
58	Q7 Rebuild to Grade B	-	-	-	450	500	950
59	Q11 W.C. to new St. Bridget Sub - ROW	-	350	-	-	-	350
60	Q11 W.C. to new St. Bridget Sub - Constr	-	-	-	200	750	950
61	Transmission Extension to New Downtown Sub	20	650	5,000	4,000	50	9,720
62	Willow Creek Expansion for Q11	-	-	-	750	1,000	1,750
63	St. Bridget Sub	-	-	-	-	1,000	1,000
64	Downtown Capacity Addition	150	1,250	5,000	5,000	-	11,400
65	Crosstown - Install Capacitor Bank	-	-	-	-	90	90
66	Fiber Willow Creek to Bamber Valley	45	-	-	-	-	45
67	Fiber Cascade Creek to Westside	-	195	-	-	-	195
68	Fiber Cascade Creek to Crosstown	75	-	-	-	-	75
69	Fiber OWEF Splice to Chester	-	-	-	165	-	165
70	Verizon Small Cell	50	50	-	-	-	100

Attachment: Elc-2018 Cpt Prjcts (8108 : 2018 Electric Utility Budget Approval)

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3 MATERIALS, SUPPLIES & SERVICE
4 PROJECT BREAKDOWN ON 5 YEAR SUMMARY

5 ELECTRIC UTILITY
6 CAPITAL
7 ($000's)

		2018	2019	2020	2021	2022	5-Yr Total
8		**2018**	**2019**	**2020**	**2021**	**2022**	**5-Yr Total**
71	Allocation - Distribution Expansion	**2,030**	2,955	2,580	2,825	3,160	13,550
72	Feeder Extensions	*95*	-	-	-	-	-
73	Feeder Rebuilds	*55*	-	-	-	-	-
74	Minor Transmission Projects	*30*	-	-	-	-	-
75	Substation Projects	*385*	-	-	-	-	-
76	Road Projects	*175*	-	-	-	-	-
77	Capacitor Bank Installations	*165*	-	-	-	-	-
78	Fiber Optic Projects	*100*	-	-	-	-	-
79	Distribution Transformers	*600*	-	-	-	-	-
80	Overhead to Underground Conversion	*50*	-	-	-	-	-
81	Manhole Switch Replacements	*75*	-	-	-	-	-
82	Mainline Cable Replacement	*300*	-	-	-	-	-
83	Survey GPS Replacement	33	-	-	-	-	33
84	GIS Integration with Cayenta	-	80	85	90	95	350
85	Communication Platform	150	-	-	-	-	150
86	Service Territory Payments	308	308	310	315	320	1,561
87	**Total Core Services**	5,495	9,504	18,750	17,691	12,933	64,372
88	**Customer Relations**						
89	CRM	725	-	-	-	-	725
90	**Total Customer Relations**	725	-	-	-	-	725
91	**Corporate Services**						
92	Racking for Storage Yard Expansion	25	-	-	-	-	25
93	ERP/Work Mgmt Implementation	-	1,741	1,483	124	-	3,348
94	Substation Communications	-	1,000	725	40	40	1,805
95	Operation Technology	150	150	130	110	110	650
96	Enterprise Systems and Applications	-	300	300	300	300	1,200
97	Allocation - Technology	**650**	768	806	846	889	3,958
98	Network Management	*237*	-	-	-	-	-
99	Output Management	*12*	-	-	-	-	-
100	Server Management	*50*	-	-	-	-	-
101	Workstation Management	*88*	-	-	-	-	-
102	Backup/DR	*33*	-	-	-	-	-
103	Information Risk and Security	*80*	-	-	-	-	-
104	Storage Management	*40*	-	-	-	-	-
105	Business Systems/Applications	*60*	-	-	-	-	-
106	City Shared Infrastructure	*50*	-	-	-	-	-
107	**Total Corporate Services**	825	3,958	3,444	1,420	1,339	10,986
108	**Compliance and Public Affairs**						
108	Electric Safety Exhibit	65	-	-	-	-	65
109	**Total Compliance and Public Affairs**	65	-	-	-	-	65
110	**Power Resources**						
111	West Side Energy Station	6,845	-	-	-	-	6,845
112	Allocation - Power Resources	200	250	510	325	120	1,405
113	Building Expansion	12,887	1,117	-	-	-	14,005
114	Substation Physical Security	-	95	95	95	95	380
115	Customer Service Desk Modifications	90	-	-	-	-	90
116	Fleet Hoist Replacement	158	-	-	-	-	158
117	Design Study to Replace AHU 1-4	25	250	200	-	-	475
118	SC Canopy Roof Replacement	135	-	-	-	-	135
119	Allocation - Facilities	76	78	80	82	84	400
120	Allocation - Fleet	633	582	680	645	651	3,191
121	**Total Power Resources**	21,048	2,372	1,565	1,147	950	27,083
122	**General Management**						
123	Project Contingency Fund	700	700	700	700	700	3,500
124	**Total General Management**	700	700	700	700	700	3,500
125	**Total Outside Expenditures**	28,858	16,535	24,459	20,958	15,921	106,730
126	**Capitalized Interest**	1,796	272	-	-	-	2,069
127	**Total Internal Expenditures**	3,811	4,166	5,167	5,753	5,121	24,018
128	**Less Bonding**	(21,289)	(2,907)	(10,000)	(9,000)	(50)	(43,246)
129	**Net Capital Plan**	13,176	18,066	19,626	17,711	20,992	89,571
130	**Net Capital and Major Maintenance Plan**	16,765	22,090	22,103	20,485	23,532	104,975

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4 **PROJECT BREAKDOWN ON 5 YEAR SUMMARY**

5 **ELECTRIC UTILITY**
MAJOR MAINTENANCE
6 **($000's)**

#		2018	2019	2020	2021	2022	5-Yr Total
7		**2018**	**2019**	**2020**	**2021**	**2022**	**5-Yr Total**
8	**Core Services**						
9	Tree Trimming	1,001	800	800	800	800	4,201
10	Downtown Resource Planning Study	110	-	-	-	-	110
11	Distribution System Planning Study	-	70	-	70	-	140
12	Substation Switchgear Analysis Report	55	-	-	-	-	55
13	Transmission Coordination Study	25	-	-	-	-	25
14	Allocation - Distribution System Maintenance	200	240	180	195	210	1,025
15	**Total Core Services**	1,391	1,110	980	1,065	1,010	5,556
16	**Corporate Services**						
17	Document Management Solution	50	25	25	25	25	150
18	Elec Cost-of-Srvc/Rate Design Study	-	-	65	-	-	65
19	CIAC/AFUDC Asset Accounting Conversion	80	-	-	-	-	80
20	KPIT Support Contract	284	284	284	142	142	1,136
21	**Total Corporate Services**	414	309	374	167	167	1,431
22	**Compliance and Public Affairs**						
23	Zumbro River Dredging	120	700	81	-	-	901
24	**Total Compliance and Public Affairs**	120	700	81	-	-	901
25	**Power Resources**						
26	SLP Decommissioning	25	630	200	450	250	1,555
27	Allocation - Power Resources	665	657	270	500	530	2,622
28	Allocation - Facilities	142	144	146	148	150	730
29	**Total Power Resources**	832	1,431	616	1,098	930	4,907
30	**General Management**						
31	Operating Contingency Fund	500	300	300	300	300	1,700
32	**Total General Management**	500	300	300	300	300	1,700
33	**Total Outside Expenditures**	3,257	3,850	2,351	2,630	2,407	14,495
34	**Total Internal Expenditures**	332	174	125	144	133	909
35	**Total Major Maintenance Plan**	3,589	4,024	2,476	2,774	2,540	15,404

Attachment: Elc-2018 Mjr Mntc Prjcts (8108 : 2018 Electric Utility Budget Approval)

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, that the Common Council of the said City is requested to approve the

2018 Electric Utility Capital and Operating Budgets

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 14th day of November, 2017.

President

Secretary