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June 20, 2018

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Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota
Docket No. E017/GR-15-1033
Supplemental Compliance Filing

Dear Mr. Wolf:

Otter Tail Power Company (Otter Tail) respectfully submits this Supplemental Compliance Filing to the Minnesota Public Utilities Commission (Commission) as required by the Commission in the May 1, 2017 Findings of Fact, Conclusions, and Order in the above referenced Docket.

This filing is being made in response to observations noted by the Department of Commerce upon review of the March 30, 2018 filing of the original report. During the review it was noted that comparisons of Test Year base line revenues against actual operating results differed from the order point.

Specifically, the first 3 ½ months of the 2016 Test Year base line results initially included revenues based on 2009 rates. The 2016 Test Year has subsequently been updated to reflect the revenues that were projected to be collected based upon approved final rates.

Second, the updated 2016 Test Year was compared against both 2016 and 2017 actual results, and the 2009 Test Year comparison was modified to be compared to 2014 and 2015 actual results.

The overall conclusions reached in the original report have not changed as a result of the update.

Otter Tail has updated the original report to provide information consistent with the time frame comparisons noted in the order point.

If there are any questions concerning this filing, please direct them to me at 218-739-8657 or at molsen@otpco.com.

Sincerely,

/S/ MATTHEW J. OLSEN
Matthew J. Olsen
Manager Regulatory Proceedings and Compliance

jch
Enclosures
c: Service List
By electronic filing

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E017/GR-15-1033

Supplemental Decoupling Analysis and Response

June 20, 2018
Originally filed March 30, 2018

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ATTACHMENTS

I. INTRODUCTION

A. Restate the order point from Docket No. E017/GR-10-239

Ordering Point 26 Regarding Decoupling, part B in the above referenced Docket states the following:

> B. Otter Tail must prepare a report analyzing the potential customer impacts of Fresh Energy's proposed revenue-decoupling mechanism for the Residential, Farm, and Small General Service rate classes.
>
> 1) The report will be filed on or before April 1, 2018 and will include the following:
>   - Comparison of actual 2016 and 2017 revenues to 2016 Test Year baseline revenues (with baseline revenue per customer calculated using the final rates, sales and customer counts of this rate case) for the classes recommended by Fresh Energy (Residential, Farm, and Small General Service rate classes); and
>   - Comparison of actual 2014 and 2015 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales and customer counts from OTP's 2010 Rate Case (Docket No. E017/GR-10-239)) for the classes recommended by Fresh Energy.
>
> 2) Otter Tail shall file the report by April 1, 2018.
>
> 3) Interested parties will be invited to file comments on the report addressing identified customer impacts, potential strategies for implementing a decoupling mechanism for Otter Tail, and other matters.

B. Recap the testimony of Dr. Mark Lowry

Dr. Mark Lowry of Pacific Economics Group Research LLC, was engaged by Fresh Energy to evaluate Otter Tail Power incentives for small volume customers to adopt distributed energy resources (DERs) as well as demand side management (DSM) and distributed generation and storage (DGS). In his direct testimony, Dr. Lowry offered his views on what he considered poor incentives for utilities to embrace DER's using traditional regulation and then conducted an analysis of Otter Tail Power data to make the case for adopting an alternative regulatory system that was judged by Fresh Energy and Pacific Economics Group to be better suited for the promotion of DER's by Otter Tail Power to its customers. In making that case, Dr. Lowry described traditional utility regulation, introduced alternative regulation strategies ("alt reg") and elaborated on the following types of alternative regulation:

1. Revenue Decoupling
2. Tracking of DSM expenses
3. DSM performance incentives
4. Multiyear rate plans
5. Fixed/variable rate designs

Upon concluding the analysis, Dr. Lowry recommended that Otter Tail Power implement a revenue decoupling system that was broadly like one approved by the Minnesota Public Utilities Commission for Xcel Energy. In support of that recommendation, Dr. Lowry provided a financial model and illustrative tariff sheet.

C. Report summary

This report contains the examination of two different test years against actual results of company operations for select years outlined in the rate case order. In addition to the defined scope of the report per the rate case order, Otter Tail elected to analyze all the years between 2009 and 2017 in order gain a better understanding of how the decoupling mechanism would have worked during that time frame. Along with that analysis Otter Tail also performed an investigation into national decoupling examples from companies that possess certain similarities to Otter Tail Power. After examination of the decoupling analysis and taking the lessons learned from other decoupling implementations, Otter Tail evaluated the proposed decoupling model against criteria defined by the Commission. The evaluation provides a guide to what factors are necessary for successful adoption of a decoupling mechanism.

II. EXAMINATION OF NATIONAL DECOUPLING EXAMPLES

Dr. Lowry introduces revenue decoupling in section 3 of Attachment 3 to his direct testimony in Docket No. E017/GR-15-1033. Section 3.1 introduces the concepts of the revenue decoupling mechanism (RDM) and revenue adjustment mechanism (RAM). Section 3.2 provides national context for the decoupling story, while table 3 contains a listing of states which had decoupling programs for both natural gas and electric utilities and the companies that were participating in them.

When considering the national context of decoupling, Otter Tail Power is specifically interested in learning more about electric utilities from the United States which have decoupling programs. Finding comparable companies is important to Otter Tail to be informed of any lessons learned in addition to studying the process the companies and state commissions went through to arrive at the decoupling implementation. Canadian companies and non-Minnesota natural gas utilities were not considered further, as there would be limited comparability to Otter Tail Power. Attachment 3 shows 26 companies from the United States that have electric only operations and two that have combined gas and electric operations. These 28 utilities will form the proxy group from which Otter Tail Power will draw upon the experience of companies with similar size and operating environments.

Inspection of the list reveals that 12 states are home to the 28 companies that have decoupled some form of their electric operations. As called out in section 3.2 of Dr. Lowry's direct testimony, California, Rhode Island, Massachusetts and New York have mandated revenue decoupling. California has five utilities in the Attachment 3 list and as described by Dr. Lowry, the state had several motivations for pursing decoupling, among them the bulk power market crisis of 2000 – 2001 and the desire to promote conservation.

Hawaii has three electric utilities listed in Attachment 3, with each of them being part of a joint docket, No. 2008 – 0274, opened in 2008. The Public Utilities Commission of the state of Hawaii initiated an investigation to examine decoupling for the three state utilities. The effort started in 2008 with a joint agreement between the Governor, the State of Hawaii Department of

Business, Economic Development and Tourism, the State of Hawaii Division of Consumer Advocacy of the Department of Commerce and the Hawaii Electric Companies (HECO) that was designed to move the state away from its dependence on imported fossil fuels for electricity and ground transportation. According to the initial filing in this docket, the stakeholders wanted to migrate to "indigenously produced renewable energy and an ethic of energy efficiency". This agreement is a product of the Hawaii Clean Energy Initiative with the following goals:

- Accelerating development of clean resource generation on all islands.
- Transition HECO away from a business model that encourages increased electricity use.
- Provide measures for customers to reduce their energy bills.

The Hawaii Clean Energy Initiative was created from a Memorandum of Understanding between the state of Hawaii and the U.S. Department of Energy which established a partnership with the goal of having 70 percent of the state electricity needs generated by renewable energy by 2030, while simultaneously protecting the sponsoring utilities financial health from erosion. The first implementation was scheduled to occur in Commission mandated rate cases by the HECO companies that were set to begin in 2009.

Massachusetts has three utilities listed in Attachment 3. The state electric utilities adopted decoupling because they were compelled to as elaborated on in docket D.P.U. 07-50-A. Massachusetts passed a state law called "An Act Relative to Green Communities", Chapter 169 of the Acts of 2008 which promoted energy efficiency. (aka Green Communities Act). That act along with the actions of the Department of Public Utilities led to the decoupling adoption.

New York and Maryland, respectively, have five and three utilities listed in Attachment 3, effectively making all investor owned utilities in those states subject to revenue decoupling. When combined with Rhode Island, as mentioned previously, six states (California, Hawaii, Massachusetts, New York and Rhode Island) combine to host 20 of the 28 electric utilities that have adopted some form of decoupling. This heavy concentration of decoupling adopters in such a small number of states does not present a large proxy group of utilities for Otter Tail to study. Otter Tail hoped to find similarly sized, vertically integrated, electric utilities (VIEU's) located in states where adoption is given due consideration, rather than being compulsory.

Given those circumstances, Otter Tail selected the following companies to study as they most closely resembled Otter Tail Power in either business operations or the state where business is conducted.

- Idaho Power Company
- Portland General Electric
- Northern States Power Company – Minnesota
- CenterPoint Energy
- Minnesota Energy Resources Corporation

Brief summaries of the companies decoupling adoption is presented to illustrate their respective road to decoupling.

Idaho Power Company

Case: IPC – E – 11 – 19

Why did they decouple?

The evaluation started with Docket IPC – E – 04 -15 which the Commission opened to investigate decoupling. The order from that docket was issued on March 12, 2007 and created a pilot project for "fixed cost adjustments" or FCA. The pilot project applied to residential and small general service customers. On October 1, 2009 the company applied to make the pilot program permanent, see Case IPC-E-09-28. The request to make the program permanent was denied at that time by the Commission. Instead, the Commission extended the pilot another two years. The request to make the decoupling permanent was made again in Docket IPC E-11-19 and was approved in that filing.

What kind of decoupling is this?

The company sets a fixed cost per customer which is then compared to the amount collected. The over/under collection is then subject to true up. One interesting thing to note is the Commission acknowledged the imperfections of identifying the source of the load reduction as being attributed to DSM programs or other outside forces. The Commission remedied this by allocating any incentives earned from identified savings as being split equally between the company and customer.

What lessons can Otter Tail learn from this?

Idaho Power (IP) had a very specific reason for wanting to decouple and that reason involved the recovery of fixed costs. The rate design for the company prior to decoupling was shifting the recovery of fixed costs into volume-based rates and subsequently it became very difficult to recover costs from the irrigation class for instance. According to the 2016 IdaCorp annual report, (the parent company of Idaho Power) approximately 13 percent of IP's revenue and 13 percent of the sales volume came from the irrigation class. At the same time that class only had three percent of the customers. When subsequently designing the mechanism, Idaho Power worked with the various stakeholders to implement the fixed cost adjustment (FCA) decoupling method and proved through the pilot period that it was a viable rate setting tool for Idaho Power and their customers.

Portland General Electric Docket:

Most recent approval was in Order 13-459 (Docket UE 262), while a request to resume was in Order 09-176 (Docket UE 197).

Why did they decouple?

Oregon has had a very interesting relationship with the concept of decoupling. Starting in 1992 with Order number 92-1673, the Oregon Public Utilities Commission directed Portland General Electric (PGE) to develop a decoupling mechanism suitable to its circumstances. In 1995 in Order 95-322, decoupling was approved for PGE. In 2002, in Order 02-633, the Oregon Public Utilities Commission rejected a request from PGE to continue to decouple, citing "harm to the customer." PGE initiated another request in 2008 and while that request was granted in Order 09-020, Oregon PUC staff argued against allowing decoupling on the grounds that over collection of fixed costs would occur, limited energy conservation would be achieved as a third party, the Energy Trust of Oregon, was responsible for administering those programs and there was an inordinate shifting of risk from shareholders to ratepayers.

What kind of decoupling is this?

PGE is using a system they call Sales Normalization Adjustment (SNA). This system is applied to residential and small non-residential customers. Large non-residential customers with loads of less than one average megawatt (MW) participate in a Lost Revenue Recovery (LRR) mechanism. Very large non-residential loads are not part of the decoupling plan.

The sales normalization adjustment compares weather adjusted distribution, transmission and fixed generation revenues that are collected on a per – kWh basis with those that would be collected using a fixed per-customer charge. The difference is accumulated in a balancing account and refunded/collected over a future period. The result is PGE receives revenues as if it had a flat distribution charge while customers continue to be billed on a per kWh basis.

What lessons can Otter Tail learn from this?

The PGE proceedings illustrate the importance of having all stakeholders in agreement on the purpose, process and implementation of the chosen decoupling mechanism. Over the twenty plus years that the proceedings occurred, the Oregon PUC first embraced, then rejected, and then approved a decoupling mechanism. The primary concerns when decoupling was rejected included; shifting business risk from the utility to the consumer, the lag in correcting over or under collected revenues would result in monthly bill volatility and associated intergenerational inequity, and reduced quality of customer service. Without uniform agreement and participation between the company and stakeholders, successful decoupling implementation is made much harder.

Northern States Power Company - Minnesota (Xcel Energy)

Docket No. : E002/GR-13-868

Why did they decouple?

Xcel witness Daniel Hansen (Ph.D.) listed three reasons to pursue decoupling. First, declining natural gas prices have reduced the benefits associated with pursuing conservation of electricity, while at the same time the conservation program costs are rising. Second, higher lighting efficiency because of the Energy Independence and Security Act (EISA) has made reaching conservation program goals more difficult. Finally, Xcel has been experiencing reductions in usage per customer in the residential and small commercial categories over the years preceding the filing. That trend was expected to continue and in the absence of decoupling would lead to downward pressure on utility revenues.

What kind of decoupling is this?

Xcel proposed to use a revenue-per-customer (RPC) mechanism that removes the effect of weather from the decoupling deferrals.

What lessons can Otter Tail learn from this?

The first item is gaining familiarity with how the revenue per customer model works, as the one suggested by Dr. Lowry is essentially what is being used by Xcel. Otter Tail notes that the accuracy of Xcel's test year billing determinants allow the company to stay within the permitted recovery bandwidth. In the 2017 Decoupling Annual Report, Docket Nos. E002/GR-13-868 and E002/GR-15-826, Xcel reported that only a single class, residential space heating, exceeded the three percent collection recovery band width.

CenterPoint Energy

Docket: G-008/GR-13-316

Why did they decouple?

CenterPoint was facing challenges in the following areas; weather variability and warmer temperatures, declining use per customer as well as the ongoing energy efficiency and conservation efforts of their customers. CenterPoint realized that those factors along with rising fixed cost charges necessary to support infrastructure maintenance and upgrades was making appropriate rate setting increasingly difficult. At that point, CenterPoint didn't feel rates could be set appropriately under the existing construct and they asked to be decoupled so they didn't have weather variability harming sales and related cash collection. In 2009 CenterPoint was partially decoupled on a pilot basis. The partial decoupling did not sever the link between sales and weather. In July 2012 the Minnesota Public Utilities Commission approved a "full" revenue decoupling mechanism for Minnesota Energy Resources Corporation (MERC). MERC's full decoupling was described as "symmetrical" because it adjusts a utility's rates for the effects of both energy efficiency and weather that varies from the normal weather assumed for regular rate making purposes. "Partial" decoupling on the other hand is asymmetrical because it computes rate adjustments only for energy efficiency and conservation related usage changes and does not adjust for weather variations. CenterPoint's partial decoupling rider ended June 30, 2013 after a thirty-six-month pilot program. CenterPoint elected not to renew the pilot and instead filed a rate case to request moving to full decoupling. During the case the company could not come to agreement with the intervenors and during the evidentiary hearing, the Department withdrew support for the company decoupling proposal. After learning about the withdrawal during the evidentiary hearings, the Company stated that it would no longer seek approval of a decoupling mechanism in this case. In CenterPoint's opinion, no decoupling was better than bad (partial) decoupling. In oral arguments to the Commission however, the company stated that it still supported full decoupling and stood by its decoupling related testimony. The Commission decided to allow CenterPoint full decoupling as a pilot project.

What kind of decoupling is this?

CenterPoint implemented "full" decoupling that incorporated weather normalization.

What lessons can Otter Tail learn from this?

The form of decoupling that is chosen and implemented can be crucial to the success of the program in allowing the utility to achieve the targeted revenue recovery while at the same time supporting promotion of energy efficiency measures. The form of the decoupling mechanism must match company and customer parameters to provide the maximum benefits.

Minnesota Energy Resources Corporation (MERC)

Docket: G-007, 011/GR-10-977

Why did they decouple?

In 2007, a Minnesota state statute was passed that directed the PUC to set up pilot programs to decouple. MERC decided to file a proposed decoupling plan without elaborating on the reasons for doing so other than to refer to the state statute.

What kind of decoupling is this?

MERC was authorized to implement a pilot program using “full” decoupling that incorporated weather normalization.

What lessons can Otter Tail learn from this?

Otter Tail drew no conclusions about the efficacy of MERC’s decoupling mechanism other than it must have been well thought out and capably implemented because there did not appear to be objections or protests being registered. Perhaps this is the finest compliment that can be paid to a decoupling initiative.

Summary of Lessons Learned

First, determine the reason for implementing decoupling. Idaho Power demonstrated with the right reasons and cause for action, decoupling can be successfully implemented. Second, make sure all stake holders want decoupling and understand want the impact will be. The case of the Oregon Public Utilities commission and Portland General Electric illustrated what happens if all parties are not in agreement on how decoupling can be successful. Third, have the proper starting point as it relates to sales and associated revenues. From Xcel Energy, Otter Tail observed how representative test year determinants can facilitate the proper level of revenue recovery. Fourth, the company needs to have the right mechanism for both the customer and the company. CenterPoint’s case illustrates how important the form can be in facilitating proper function. Finally, Otter Tail noted that if all these components are present and properly implemented, decoupling should present a relatively innocuous and benign change to customers and the company.

III. EVALUATING THE FRESH ENERGY PROPOSAL ACCORDING TO MINNESOTA PUBLIC UTILITY COMMISSION ORDER IN DOCKET NO. E,G999/CI-08-132

Otter Tail Power agreed to look at the revenue per customer model that Dr. Mark Lowry of the Pacific Economics Research submitted and provide two different comparisons. First, a comparison of actual 2016 and 2017 revenues to 2016 baseline revenues (with baseline revenue per customer calculated using the final rates, sales and customer counts of this rate case) for the classes recommended by Fresh Energy (Residential, Farm, and Small General Service rate classes). Second, a comparison of actual 2014 and 2015 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales and customer counts from OTP's 2010 Rate Case (Docket No. E017-GR-10-239)) for the classes recommended by Fresh Energy.

That analysis has been completed and as shown in Attachment 1, Otter Tail evaluates the results of this analysis per the criteria laid out in the order for Docket No. E,G – 999/CI-08-132, "Order Establishing criteria and standards to be utilized in pilot proposals for revenue decoupling", dated June 19, 2009 beginning at page 7.

1. Purpose
2. Form
3. Cost of Capital
4. Classes Included
5. Mechanics
6. Service Quality
7. Review
8. Pilot Implementation

A. Criteria 1

<u>Purpose</u>: All utilities shall state how their proposed decoupling mechanism adheres to the guiding statute. Each utility shall explain the purpose of the mechanism in the context of the Next Generation Energy Act of 2007's energy savings goals and how their mechanism will further the state policy of increased conservation investment.

The decoupling mechanism proposed by Fresh Energy is modeled after one implemented by Xcel Energy which is a pilot program that has been approved by the Minnesota Public Utilities Commission in Docket No. E002/GR-13-868, 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, page 71 (May 8, 2015). The purpose of the mechanism is to remove the Company's disincentive to promote conservation and energy efficiency for residential, farm, small general service and general service customers.

B. Criteria 2

Form: All utilities shall state the form of decoupling proposed and the purpose behind such choice. This should provide a detailed definition of what types of sales changes are included in the mechanism, i.e. weather-related sales changes, declining use per customer, etc., and the reason for such inclusion.

The form of revenue decoupling proposed is the revenue-per-customer model that has been approved in Xcel Energy's pilot program. This model effects "full decoupling" and will be applicable for the two service baskets defined by Dr. Lowry: Residential and Farm as well as General Service. According to the model defined for Otter Tail to evaluate, no customer charges will be included in the revenue collection and base rate collection of fuel and Conservation Improvement Program (CIP) charges will be removed. The full decoupling adoption also removes the impact of weather on sales and declining use per customer.

C. Criteria 3

Cost of Capital: Otter Tail reviewed several published reports that discuss the impact of decoupling on the cost of capital. First, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations" that was authored by Pamela Morgan and initially published in December 2012 and later updated in February 2013. Ms. Morgan concludes in her report that adopting a decoupling mechanism does not reduce the risk to a utility and subsequently warrant a reduction in the return on equity[1]. The second report is from the Brattle Group titled "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation" and was released in March 2014. The conclusion of the authors was that adopting decoupling did

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[1] A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations. Morgan, Pamela, page 17.

not reduce utility risk and warrant a reduction in the return on equity[2]. Finally, Otter Tail references the testimony of Dr. Robert Hevert for Xcel Energy in docket No. E002/GR-13-868, Hevert Direct. On page 51, Dr. Hevert states that the adoption of decoupling by Xcel would not substantially lower the risk profile and lead to a lower return on equity. There is a mature, multi-decade record of testimony related to the cost of capital for decoupled utilities and Otter Tail cannot substantially add to that body of knowledge and advocates for a negligible impact to the cost of capital.

D. Criteria 4

Classes Included:

Per the model supplied by Fresh Energy, Otter Tail looked at the Residential and Farm as well as General Service classes within the following parameters:

- Decoupling would apply to residential, farm, and general services (excluding large general services).
- Separate service baskets would apply to residential and farm services and to general services. The use of multiple baskets protects customers in each basket from rate adjustments resulting from the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equi-proportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.
- The RDM would affect *full* decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually.
- Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.

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[2] The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation. Vilbert, M., Wharton, J., Gibbons, C., Rosenberg, M., Neo, Y, page 21.

- Decoupling adjustments would be applied in each month of the following April-March period.

E. Criteria 5

Mechanics: All utilities must provide precise detail on how the decoupling mechanism will operate, with the understanding that any decoupling pilot program be transparent and easy to follow from a customer perspective. Details to be provided are as follows:

a) How the rate adjustment will be calculated.

Otter Tail makes class modifications to the Xcel approach because Otter Tail does not have a residential space heating class and labels as General Service and Small General Service what Xcel calls small Commercial and Industrial non-demand customers. Another difference is that Otter Tail will include the residential demand control service rate, which has a demand component, as agreed to with Fresh Energy. Finally, as noted by Dr. Lowry on page 73, footnote 57, the Otter Tail method includes calculating the revenue per customer, not revenue per kWh. Fresh Energy was concerned that would incent Otter Tail to shift sales from low rates to higher rates. Otherwise, like Xcel Energy, Otter Tail would follow the method described by Daniel Hansen, Ph.D., who described the Xcel method in docket number E002/GR-13-868[3].

> "The Company does not propose to apply a carrying charge on deferrals. At the end of a 12-month period, the total deferral for each customer group will be divided by the forecast of sales to that group for the coming year. The resulting charge will be added to or subtracted from the customer group's volumetric rate for the following 12 months."

b) When the rate adjustments will be made.

Per the Lowry direct testimony, page 71, decoupling adjustments would be applied in each month of the following April- March period.

[3] Docket No. E002/GR-13-868, Hansen Direct, page 16.

c) Will a rate cap be present to mitigate the risk of rate shock?

Yes, per the Lowry direct testimony, page 71, "the RDM would effect full decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year".

d) What portion of the customer's bill will be impacted by the true-up?

Otter Tail would adjust the volumetric rate.

e) How will the adjustment be displayed on the customer's bill?

Otter Tail cannot answer that question at this point but does take into consideration the suggestion made by Fresh Energy and Dr. Lowry regarding the proposed tariff sheet.

f) Length of the pilot

Any implementation would follow the mandatory thirty-six-month pilot program length.

g) How will the decoupling rider work in concert with other automatic recovery mechanisms or financial incentives?

Otter Tail anticipates no interference between a decoupling rider and other riders that are present currently.

F. Criteria 6

Service Quality:

Otter Tail expects no adverse impact on the quality of service it provides to its customers.

G. Criteria 7

Review: Otter Tail offers the following commentary and response to the model provided by Fresh Energy. First, a comparison of 2016 and 2017 actual results to the 2016 test year was made. Second, an evaluation of the 2014 and 2015 results to the 2009 baseline revenues is provided with commentary.

H. Criteria 8

<u>Pilot Implementation:</u> This not applicable as Otter Tail has not taken the step to agree to or institute a pilot program.

Prior to evaluating the results, several key points must be established. First, Otter Tail will begin by evaluating the 2009 test year against 2009 actual results and notes that the 2009 test year was an historic test year that was filed in March of 2010. Knowing this, one must remember that the actual rates in place during 2009 were approved from the rate case that was filed in 2007. When performing the analysis of 2009 actual results against 2009 test year, this must be kept in mind because of the impact it has on the actual revenue.

Second, Otter Tail chose to extend the analysis from 2009 through 2017. The extra detail is intended to bring additional depth to the research.

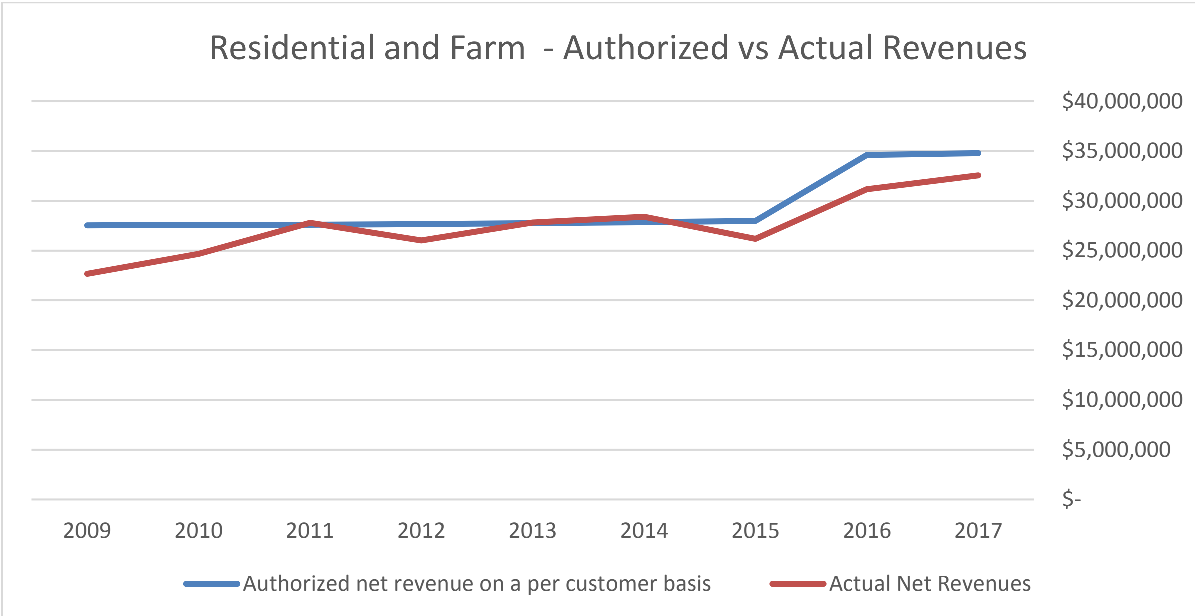
Third, during the 2009 through 2017 timeframe there was a mixture of final rates from the 2007 rate case, interim rates from the 2010 case beginning in 2010 and extending into September of 2011 and lastly, interim and final rates from the 2016 rate case. In order to standardize evaluation of the model, Otter Tail elected to insert final rates into the period in which interim rates were collected. This facilitated a consistent revenue stream and clarity in evaluating the results. That decision negated having to calculate an interim rate collection and subsequent one-month lump sum refund that would skew the results of the model.

Finally, the impact of overall revenue adjustments from the residential demand control service rate is addressed through adjusting the rate per kilo-watt hour. The revenues derived from demand sales on a kW basis do not significantly sway any conclusion reached in this evaluation.

Evaluation of the results for the Residential and Farm Classes

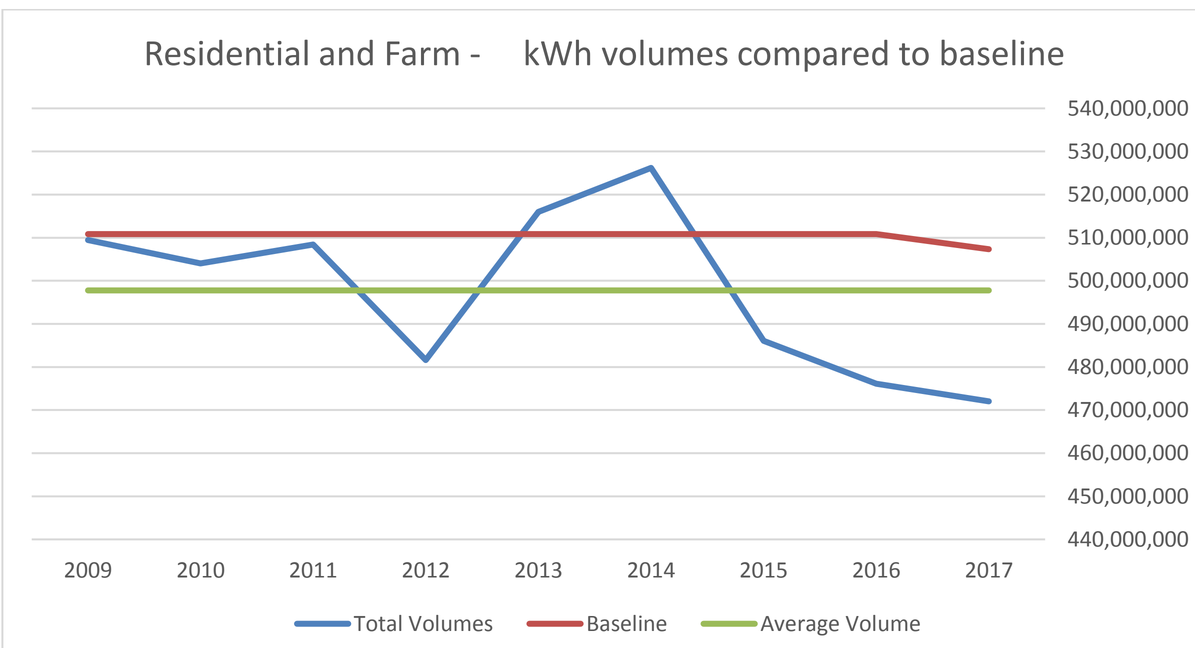
Looking at the results from 2009 through 2017, actual revenues rarely exceeded the allowed revenue per customer during that time frame. The graph below shows the comparison for that time period:

Graph 1: Residential and Farm revenues 2009 through 2017



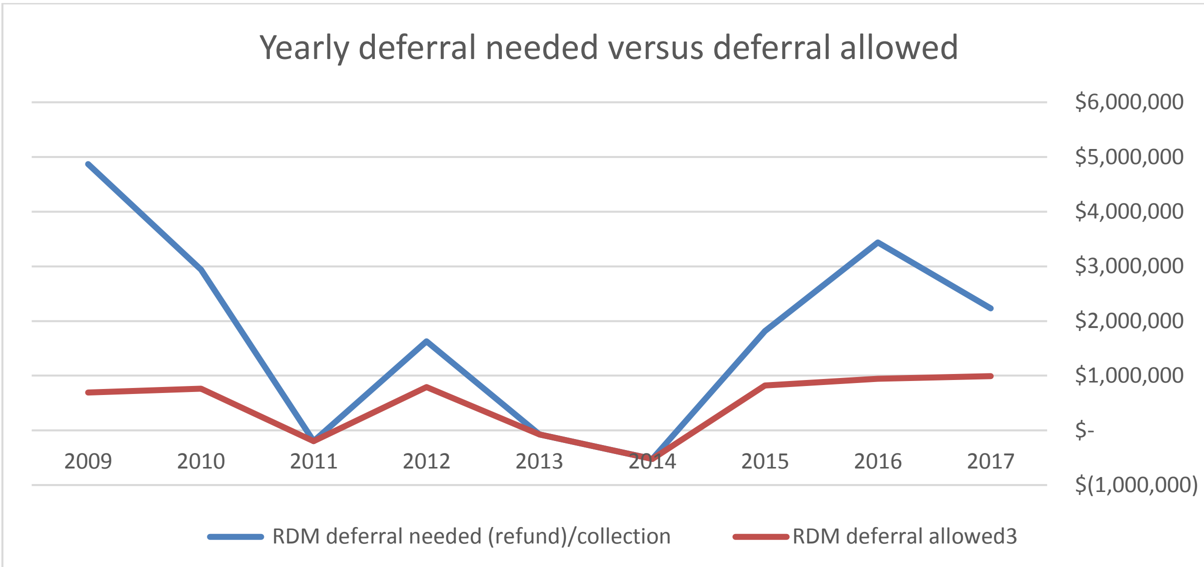
At the same time, inspection of the sale volumes in graph 2 shows that only during the polar vortex winter of 2013 through 2014 did actual volumes exceed the level agreed to in the test year.

Graph 2: Residential and Farm sales volumes 2009 through 2017



With that background in mind, we can anticipate there will be a difference in the revenue recovery which needs to be collected in future periods versus what will be allowed per the 3% revenue cap. That difference is shown in graph 3.

Graph 3: Residential and Farm RDM deferral balance



The evaluation will continue by looking at the 2009 test year and how that compares to 2009 actual results, which is shown in Table 1. Comparison of 2009 actual results against 2009 test year billing determinants shows that an under collection of $4,869,795 occurred. The deficiency was primarily related to the rates being too low because 2009 rates were still being impacted by the sales level set in the 2007 rate case. Interim rates from the 2007 case were still in effect in January 2009 with final rates from that case commencing in February 2009.

The decoupling impact to the company for the residential and farm classes for 2009 is substantial. The three percent customer impact is capped at a revenue adjustment of $694,933 while the sales shortfall was $4,869,795, leaving the company deficient $4,174,862. The final comparison for 2009 is seen in Table 1. The customer impact would have been capped at a rate increase of $1.18 per customer. The company, however, needed a rate increase of $8.24 per customer to achieve the revenue requirement for that class.

Table 1

Residential and Farm Classes - Comparison of 2009 Test Year to 2009 Actual Results

RDM Adjustments	Source	Unit	Step	2009
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM	$	A	4,869,795
RDM deferral allowed	Tab 5 - res & farm RDM	$	B	694,933
Deferral difference	Calculated		C (A - B)	4,174,862
Cumulative Deferral	Calculated		Prior balance + Current	4,174,862
Cap on Customer RDM Surcharges	Tab 5 - res & farm RDM	$	D	694,933
Forecasted Volume: April - March	Tab 5 - res & farm RDM	kWh	E	508,085,032
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001368
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.009585
Total Volumes	Tab 5 - res & farm RDM	kWh	H	509,435,858
Total Customer Served - month	Tab 5 - res & farm RDM		I	592,395
Volume per customer		kWh	J(H/I)	860
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 1.18**
Per customer at needed rate	Calculated	$	L(G*J)	**$ 8.24**

Table 2 provides a comparison of the 2009 test year rates with the actual 2009 volumes. Here we can see a much more reasonable result, however, the company is still not falling within the revenue adjustment band width as $203,682 would be deferred until the next collection period.

Before moving on, reflection upon these results confirms that the company was revenue deficient in 2009 and needed to return for a rate case in Minnesota in 2010.

Table 2

Residential and Farm Classes - 2009 Test Year Rates Using 2009 Actual Volumes

RDM Adjustments	Source	Unit	Step	2009
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM	$	A	986,000
RDM deferral allowed	Tab 5 - res & farm RDM	$	B	782,319
Deferral difference	Calculated		C (A - B)	203,682
Cumulative Deferral	Calculated		Prior balance + Current	203,682
Cap on Customer RDM Surcharges	Tab 5 - res & farm RDM	$	D	782,319
Forecasted Volume: April -March	Tab 5 - res & farm RDM	kWh	E	508,085,032
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001540
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.001941
Total Volumes	Tab 5 - res & farm RDM	kWh	H	509,435,858
Total Customer Served - month	Tab 5 - res & farm RDM		I	592,395
Volume per customer		kWh	J(H/I)	860
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 1.32**
Per customer at needed rate	Calculated	$	L(G*J)	**$ 1.67**

Upon implementation of interim rates in 2010, revenue did increase, however, revenues did not exceed the test year level as the volumes continued to decline from the test year. As noted earlier, to mitigate the impacts of interim rates and subsequent refund, Otter Tail used final rates for the period in which interim rates were in effect. By using final rates, Otter Tail was able to smooth the revenue stream by removing interim rate impacts. The result provides a clearer picture of what is happening within the decoupling model.

Falling sales volumes continued to play a role by impacting recovery bandwidth. From 2009 through 2015, only three of the years had an over- collection, 2011, 2013 and 2014. 2011 and 2013 had minor over-collections, while 2014 had a more substantial over-collection. The winter of 2013 – 2014 was abnormally cold and higher volumes drove the over collection. The remaining four years from 2009 through 2015 had a under collection. If each year within that period was considered in isolation, the non-compounded, cumulative deferral is $8,179,388.

When considering the impact of sales on decoupling, one point that stands out is the importance of setting the test year sales level correctly. Having sales volumes that are too high corresponds with setting rates too low. The low rates will not allow the utility the opportunity to stay within the bandwidth because there is not enough volume to achieve the revenue requirement target leaving the utility in the position of continually requesting permission to recover the deferred amounts. Even if the 2009 actual volumes were used in conjunction with 2009 test year rates as a starting point to evaluate 2009 through 2017, the cumulative deferral would still have been $7,938,749.

After establishing the background for the 2009 test year and 2009 actual results, the order required an evaluation of that test year against 2014 and 2015 actual results, which is shown in Table 3. 2015 needed an additional $1,813,604 in revenue, of which $991,001 needed to be carried forward to a future period. 2014 showed a refund to customers of $522,698, which was due to the sales increase caused by the colder weather of the 2013-2014 winter.

Table 3

Residential and Farm Classes - 2014 And 2015 Actual Results Compared to 2009 Test Year

RDM Adjustments	Source	Unit	Step	2015	2014
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM	$	A	1,813,604	-522,698
RDM deferral allowed	Tab 5 - res & farm RDM	$	B	822,603	-522,698
Deferral difference	Calculated		C (A - B)	991,001	0
Cumulative Deferral	Calculated		Prior balance + Current	8,179,388	7,188,387
Cap on Customer RDM Surcharges	Tab 5 - res & farm RDM	$	D	822,603	834,944
Forecasted Volume: April - March	Tab 5 - res & farm RDM	kWh	E	483,573,678	516,158,605
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001701	-0.001013
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.003750	-0.001013
Total Volumes	Tab 5 - res & farm RDM	kWh	H	486,058,050	526,192,123
Total Customer Served - month	Tab 5 - res & farm RDM		I	602,129	599,356
Volume per customer		kWh	J(H/I)	807	878
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 1.37**	$ (0.89)
Per customer at needed rate	Calculated	$	L(G*J)	**$3.03**	$ (0.89)

Now the evaluation will turn to examining the impact of 2016 and 2017 actual revenues to the 2016 test year, which is referred to as “2017 baseline revenue”. Starting in 2017 with the Residential and Farm classes, inspection of the models results in Table 4 show a $2,233,163 deferral necessary for full revenue recovery, but the deferral cap is $991,583 resulting in a roll forward amount of $1,241,581. Again, inspection of the model shows that, with one exception, actual sales volumes never rise to level set in the test year. The lone exception is the farm service rate, but that single class makes up less than 10% of the total volume. Residential sales are much of this category and they fall short of the baseline target, which subsequently depresses the entire class. In terms of the rate impact to the customer, the allowed rate is $1.54 per customer, while the required rate is $3.47 per customer.

Regarding 2016, the rates from the 2010 rate case were in effect from January through April 15th, so when actual revenues are compared to the test year for that time period, one must remember that the three-and-a-half-month rate differential contributes to the rather significant RDM deferral of $3,434,054. Like 2017, the sales volumes were lower than the test year, which combined with the lower revenue collections in the first three and half months of the year, contributed to the differential.

Table 4

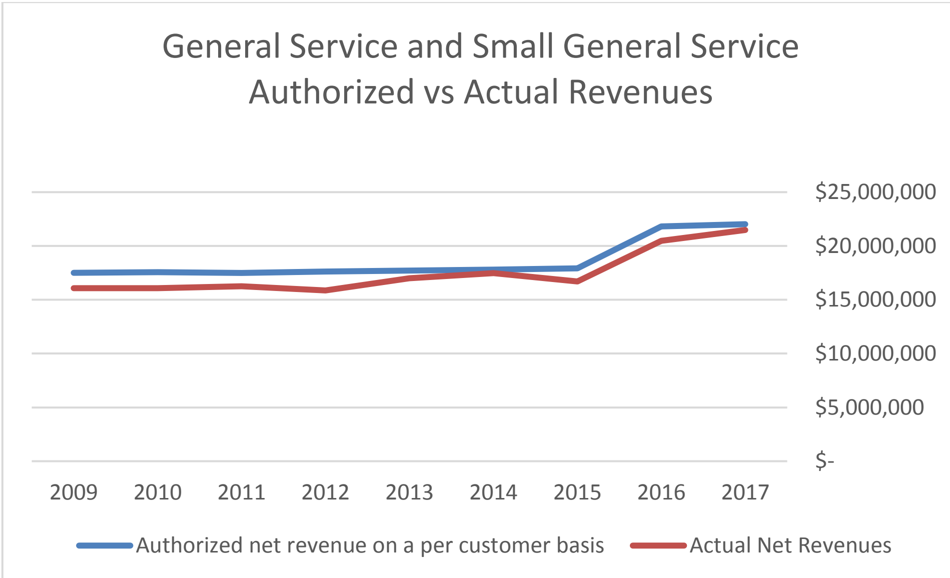
Residential and Farm Classes – 2016 and 2017 Actual Results Compared to 2016 Test Year

RDM Adjustments	Source	Unit	Step	2017	2016
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM	$	A	2,233,163	3,434,054
RDM deferral allowed	Tab 5 - res & farm RDM	$	B	991,583	945,093
Deferral difference	Calculated		C (A - B)	1,241,581	2,488,961
Cap on Customer RDM Surcharges	Tab 5 - res & farm RDM	$	D	991,583	945,093
Forecasted Volumes: April - March	Tab 5 - res & farm RDM	kWh	E	498,503,774	475,098,024
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001989	0.001989
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.004480	0.007228
Total Volumes	Tab 5 - res & farm RDM	kWh	H	472,030,410	476,120,562
Total Customer Served – month	Tab 5 - res & farm RDM		I	608,741	605,207
Volume per customer		kWh	J(H/I)	775	787
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 1.54**	**$ 1.56**
Per customer at needed rate	Calculated	$	L(G*J)	**$ 3.47**	**$ 5.69**

Evaluation of the results for the General Service and Small General Service Classes

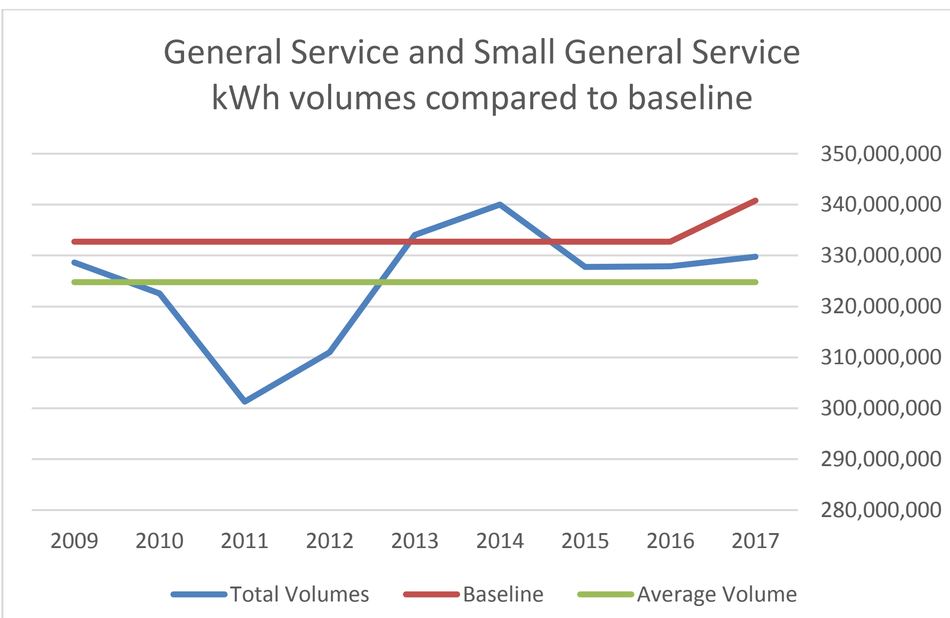
The next step in the evaluation is to look at the decoupling impact on the General Service and Small General Service classes. Looking at the results from 2009 through 2017, it can be observed that actual revenues never exceeded the allowed revenue per customer during that time frame. The graph below shows the comparison for that time:

Graph 4: General Service and Small General Service Revenues 2009 through 2017



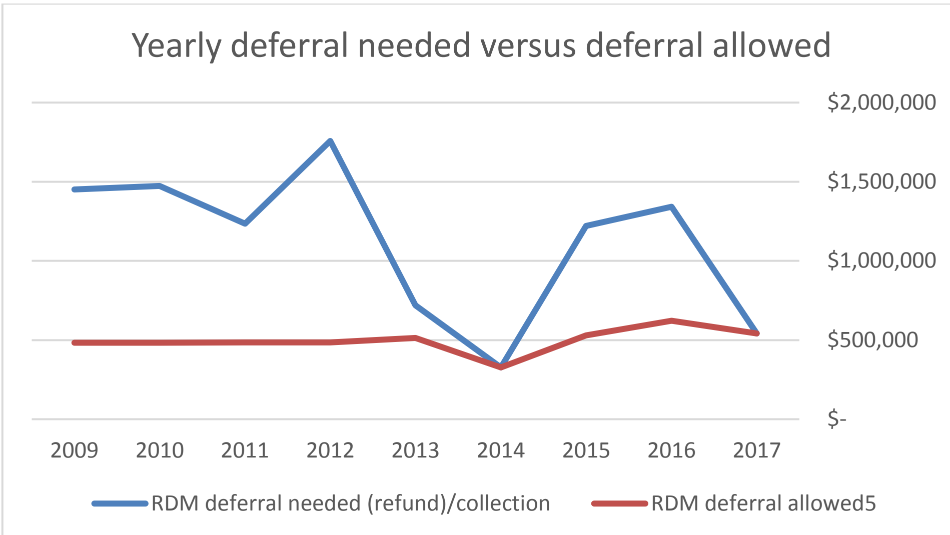
At the same time, inspection of the sale volumes in graph 5 shows that only during the polar vortex winter of 2013 through 2014 did actual volumes exceed the level agreed to in the test year.

Graph 5: General Service and Small General Service Volumes 2009 through 2017



Like the Residential and Farm classes, we can anticipate there will be a difference in the revenue recovery which needs to be collected in future periods versus what will be allowed per the three percent revenue cap. That difference is shown in graph 6.

Graph 6: General Service and Small General Service RDM deferral balance



The evaluation will continue by looking at the 2009 test year and how that compares to 2009 actual results, which is shown in Table 5. Comparison of 2009 actual results against test year billing determinants shows that an under collection of $1,450,465 occurred. The deficiency was primarily related to the rates being too low because 2009 rates were still being impacted by the 2007 rate case. Interim rates from that case were still in effect in January 2009 with final rates from that case commencing in February 2009.

The decoupling impact to the company for the General Service and Small General Service classes in 2009 is material. The customer impact is capped at a revenue adjustment of $482,176 while the sales shortfall and associated revenue was three times greater at $1,450,465, leaving the company deficient $968,289. The final comparison for 2009 is seen in the table below. The customer impact would have been capped at a rate increase of $3.89 per customer. The company, however, needed a rate increase of $11.69 per customer to achieve the revenue requirement for that class.

Table 5

General and Small General Service - Comparison of 2009 Test Year to 2009 Actual Results

RDM Adjustments	**Source**	**Unit**	**Step**	**2009**	**2009 Baseline**
RDM deferral needed (refund)/collection	6 -gen service RDM	$	A	1,450,465	0
RDM deferral allowed	6 -gen service RDM	$	B	482,176	0
Deferral difference	Calculated		C (A - B)	968,289	0
Cumulative Deferral	Calculated		Prior balance + Current	968,289	
Cap on Customer RDM Surcharges	6 -gen service RDM	$	D	482,176	515,453
Forecasted Volumes: April -March	6 -gen service RDM	kWh	E	327,075,814	257,853,263
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001474	0
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.004435	0
Total Volumes	6 -gen service RDM	kWh	H	328,661,035	332,724,039
Total Customer Served - month	6 -gen service RDM		I	124,646	10,407
Volume per customer		kWh	J(H/I)	2,637	2,664
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 3.89**	$ -
Per customer at needed rate	Calculated	$	L(G*J)	**$ 11.69**	$ -

Moving to Table 6, a comparison will be made of the 2009 test year rates with the actual 2009 volumes. Here we can see a marginally better result, however, the company is still not falling within the revenue adjustment band width as $333,142 would be deferred until the next collection period. The necessary RDM collection of $829, 295 is one and two-thirds times larger than the allowed revenue cap. Again, before moving on, reflection upon these results confirms that the company was revenue deficient in 2009 and needed to return for a rate case in Minnesota in 2010.

Table 6

General and Small General Service - 2009 Test Year Rates Using Actual Volumes

RDM Adjustments	Source	Unit	Step	2009	2009 Baseline
RDM deferral needed (refund)/collection	6 -gen service RDM	$	A	829,295	0
RDM deferral allowed	6 -gen service RDM	$	B	496,152	0
Deferral difference	Calculated		C (A - B)	333,142	0
Cumulative Deferral	Calculated		Prior balance + Current	333,142	
Cap on Customer RDM Surcharges	6 -gen service RDM	$	D	496,152	520,112
Forecasted Volumes: April -March	6 -gen service RDM	kWh	E	327,075,814	257,853,263
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001517	0
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.002535	0
Total Volumes	6 -gen service RDM	kWh	H	328,661,035	332,724,039
Total Customer Served - month	6 -gen service RDM		I	124,646	10,407
Volume per customer		kWh	J(H/I)	2,637	2,664
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 4.00**	$ -
Per customer at needed rate	Calculated	$	L(G*J)	**$ 6.68**	$ -

Upon implementation of interim rates in 2010 revenue did increase, however, revenues did not exceed the allowed test year amount as the volumes continued to decline from the test year. Again, please bear in mind the interim assumption that Otter Tail used in populating the model. In order to mitigate the impacts of interim rates and subsequent refund, Otter Tail used final rates for the period in which interim rates were in effect. That permits smoothing the revenue stream by removing interim rate impacts. The result is intended to provide a clearer picture of what is happening within the decoupling model.

Falling sales volumes continued to play a role by impacting recovery bandwidth. Looking beyond 2009 through 2015, it is observed that none of the years had an over collection. Even the polar vortex winter of 2013 – 2014 was not enough to drive sales into an over collection. If each year within that period was considered in isolation, the non-compounded, cumulative deferral is $4,878,055.

As described during the evaluation of the residential and farm classes, one point that stands out is the importance of setting the test year sales level correctly. Having sales volumes that are too high corresponds with setting rates too low. The low rates will not allow the utility the opportunity to stay within the bandwidth because there is not enough volume to achieve the revenue requirement target leaving the utility in the position of continually requesting permission to recover the deferred amounts. Even if the 2009 actual volumes were used in conjunction with 2009 test year rates as a starting point to evaluate 2009 through 2017, the cumulative deferral would still have been $4,962,068, which is not a material reduction in the cumulative balance.

This impact can be demonstrated by looking at the comparison of 2014 and 2015 operating results compared against the 2009 test year in Table 7.

Table 7

General and Small General Service – 2014 And 2015 Actual Results Compared to 2009 Test Year.

RDM Adjustments	Source	Unit	Step	2015	2014
RDM deferral needed (refund)/collection	6 -gen service RDM	$	A	1,221,199	327,161
RDM deferral allowed	6 -gen service RDM	$	B	529,277	327,161
Deferral difference	Calculated		C (A - B)	691,922	0
Cap on Customer RDM Surcharges	6 -gen service RDM	$	D	529,277	518,354
Forecasted Volumes: April -March	6 -gen service RDM	kWh	E	327,784,760	336,945,765
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	.001615	.000971
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	.003726	.000971
Total Volumes	6 -gen service RDM	kWh	H	327,742,353	340,013,569
Total Customer Served - month	6 -gen service RDM		I	127,476	126,647
Volume per customer		kWh	J(H/I)	2,571	2,685
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 4.15**	**2.61**
Per customer at needed rate	Calculated	$	L(G*J)	**$ 9.58**	**2.61**

Table 7 shows that 2015 had a required deferral of $1,221,199 while the deferral cap was $529,277 resulting in a carry forward of $691,922. Looking at 2014 we see that there was an under collection of $327,161, but this was within the allowed recovery bandwidth. Again, the increased sales due to the cold winter of 2013-2014 allowed recovery to fall within the recovery bandwidth.

Next, we will look at the results for the comparison of 2017 actual results against the 2016 test year. The sales volumes and corresponding rates were sufficient to fall within the recovery bandwidth. The calculated deferral was $541,557 while the deferral cap was $645,001. The impact to the customer is $4.21 per customer and the results are shown in the table below. Inspection of the 2016 results compared to the test year show that an under collection occurred, with the company requiring $1,342,182, while the cap was at $622,022 leaving $719,160 exceeding the cap.

Table 8

General and Small General Service Classes – 2016 and 2017 Actual Results Compared to 2016 Test Year

RDM Adjustments	Source	Unit	Step	2017	2016
RDM deferral needed (refund)/collection	6 -gen service RDM	$	A	541,557	1,341,182
RDM deferral allowed	6 -gen service RDM	$	B	541,557	622,022
Deferral difference	Calculated		C (A - B)	0	719,160
Cap on Customer RDM Surcharges	6 -gen service RDM	$	D	645,001	622,022
Forecasted Volumes: April -March	6 -gen service RDM	kWh	E	326,801,503	328,370,986
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001657	.001894
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.001657	.004084
Total Volumes	6 -gen service RDM	kWh	H	329,747,999	327,911,981
Total Customer Served - month	6 -gen service RDM		I	129,759	128,580
Volume per customer		kWh	J(H/I)	2,541	2,550
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 4.21**	**$ 4.83**
Per customer at needed rate	Calculated	$	L(G*J)	**$ 4.21**	**$ 10.42**

IV. LESSONS LEARNED

Now that the results of the model have been calculated, the lessons learned will be applied as a framework to evaluate how effective decoupling can be for Otter Tail Power.

1. Find your reason for adopting decoupling.

At this point Otter Tail is still evaluating potential reasons to implement decoupling. Fresh Energy is the first group to propose this to Otter Tail and the goal of the initiative is to promote distributed energy resources. Stepping back from the issue, perhaps there are other avenues outside of revamping the pricing mechanism that would accomplish the change that Fresh Energy is seeking.

2. Do all the stakeholders want decoupling and understand the impact?

Otter Tail's observance of other Minnesota utilities shows that several consumer advocate groups have opposed decoupling on various grounds, so reaching unanimous support may not be possible. Also, Otter Tail's customers haven't raised the topic either, whether for or against the concept. On the other hand, seeing the magnitude of deferral surcharges that would be applied to customer bills may prove startling for the impacted classes. At this point Otter Tail is not seeing stakeholder consensus on supporting decoupling.

3. Successful decoupling requires the proper starting point in the test year billing determinates.

This point was most illuminating for Otter Tail. Otter Tail looked to the Xcel Energy pilot program for guidance. One must step back and consider the comparative size of the two companies to appreciate the magnitude of what has happened in the growth of the surcharge accounts in both cases using the revenue per customer decoupling model. For comparison, referencing the 2016 form EIA 861 one can see the following:

Table 9

Otter Tail Power Residential Sales Compared to Xcel Energy - Minnesota

Utility Characteristics			RESIDENTIAL		
			Revenues	Sales	Customers
Data Year	Utility Name	State	Thousand Dollars	Megawatt hours	Count
2016	Northern States Power Co - Minnesota	MN	1,136,510.7	8,621,046	1,131,107
2016	Otter Tail Power Co	MN	53,510.7	528,189	48,186
		Percent	4.71%	6.13%	4.26%

Table 10

Otter Tail Power Commercial Sales Compared to Xcel Energy - Minnesota

Utility Characteristics			COMMERCIAL		
			Revenues	Sales	Customers
Data Year	Utility Name	State	Thousand Dollars	Megawatt hours	Count
2016	Northern States Power Co - Minnesota	MN	1,338,791.8	13,491,895	137,797
2016	Otter Tail Power Co	MN	90,554.2	1,071,890	13,286
		Percent	6.76%	7.94%	9.64%

For both residential and commercial classes, the Northern States Power – Minnesota part of Xcel is roughly 20 times larger than Otter Tail Power. With that in mind, attention can be focused on the 2017 decoupling report that Xcel filed with the Minnesota Public Utilities Commission in Docket Nos. E002/GR-13-868 and E002/GR-15-826.

Table 1: Total Over- or Under-Collection of Allowed Revenues by Customer Class

2017 Actual Sales and Actual Customer Counts

	($ Millions)			Avg Monthly Customer Surcharge/ (Refund)	RDM Rate ($/kWh) Apr 18 – Mar 19
	Total RDM Surcharge/ (Refund)	Estimated Surcharge Cap	2017 Class Impact		
Residential	$25.0	$26.2	$25.0	$1.87[12]	$0.003064
Residential with Space Heating	$1.3	$0.9	$0.9	$2.19[13]	$0.002361
Small Commercial Non-Demand	$1.1	$2.5	$1.1	$1.06[14]	$0.001245
Total	$27.5		$27.1		

Now let us turn our attention to Otter Tail's 2017 comparison as shown earlier.

Table 11

RDM Adjustments	Source	Unit	Step	2017
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM	$	A	2,233,163
RDM deferral allowed	Tab 5 - res & farm RDM	$	B	991,583
Deferral difference	Calculated		C (A - B)	1,241,581

Otter Tail Power at approximately 1/20th the size of XCEL – Minnesota exceeded the residential surcharge cap by $1,241,581 while XCEL – Minnesota remained with in the residential surcharge cap and only exceeded the Residential with Space Heating category cap by $400,000.

Continuing the comparison, inspection will be made of the General Service/Commercial classes:

Table 12

RDM Adjustments	Source	Unit	Step	2017
RDM deferral needed (refund)/collection	6 -gen service RDM	$	A	541,557
RDM deferral allowed	6 -gen service RDM	$	B	541,557
Deferral difference	Calculated		C (A - B)	0

For the nine years of General Service activity reviewed by Otter Tail, only 2017 and 2014 fell within the recovery bandwidth. 2017 of course had the rates set from the 2016 rate case while 2014 had effects of the polar vortex winter.

This comparison illustrated to Otter Tail the importance of setting the initial test year billing determinants for the base line of revenue per customer decoupling.

4. The importance of choosing the correct decoupling mechanism.

Otter Tail does not object to the revenue per customer model that Xcel is using, if the starting test year billing determinants are sufficient to stay within the recovery bandwidth. However, perhaps more thought should be given to the other alternative regulation options shared by Dr. Lowry. After presenting the options, Dr. Lowry prescribed what was in his opinion the best choice for Otter Tail Power, which was the revenue per customer model.

5. After selecting the right model with the proper components, execute implementation.

Otter Tail appreciates the chance to evaluate decoupling examples from both a regional and national perspective. The examination has proved illuminating on the importance of aligning stakeholder interests with the proper measures to achieve those goals.

V. CONCLUSION

Upon examining the results of the study, Otter Tail notes the impact of several items. First, for the Residential and Farm classes, from 2009 through 2017, Otter Tail would have been applying the maximum surcharge in all years except for 2011, 2013 and 2014. In the General Service and Small General Service classes, the maximum surcharge would have been applied in all years except for 2014 and 2017. From the company perspective, questions remain about what would have happened to any unrecovered balance that carried forward in excess of applying the maximum three percent surcharge.

Those observations lead to the impact for the second item, which is setting the appropriate approved test year billing determinants. The approved volumes from the 2009 test year appear to have been reachable only through the extra-ordinary circumstances of the polar vortex winter[4].

Finally, Otter Tail appreciates having the opportunity to examine decoupling and observe how it applies to company operations. This evaluation has proved valuable in examining decoupling from both national and local perspectives as well as taking lessons learned from other companies that have implemented decoupling mechanisms.

[4] "A polar vortex is a low-pressure system of cold polar air—a normal weather phenomenon. But during the 2013-2014 winter, a high-pressure system in the Pacific pushed the northern polar vortex southward, contributing to North America's cold, snowy and icy winter."
Kazmierczak, Jeanette. "The 2013-2014 polar vortex adds data points to the books."
https://climate.nasa.gov/news/2262/the-2013-2014-polar-vortex-adds-data-points-to-the-books/ NASA, April 1, 2015; March 26, 2018.

Approved Test Year 2009 Operating Revenue Summary Comparison - By Rate Schedule

Line No.	Rate Schedule	Operating Revenues 2014	2015	2009 TY	Difference 2009 to 2015	Percent Change 2009 to 2015	Difference 2009 to 2014	Percent Change 2009 to 2014
1	9.01 Residential Service (Rate 101)	$ 24,037,935	$ 22,472,249	$ 23,472,422	$ (1,000,173)	-4.26%	$ 565,512	2.41%
2	9.02 Residential Demand Control (Rate 241)	$ 2,328,646	$ 1,902,251	$ 2,197,096	$ (294,845)	-13.42%	$ 131,550	5.99%
3	Total Residential:	$ 26,366,581	$ 24,374,499	$ 25,669,518	$ (1,295,018)	-5.04%	$ 697,061	2.72%
4								
5	9.03 Farm Service (Rate 361)	$ 2,016,731	$ 1,801,410	$ 1,869,888	$ (68,478)	-3.66%	$ 146,843	7.85%
6	Total Farm:	$ 2,016,731	$ 1,801,410	$ 1,869,888	$ (68,478)	-3.40%	$ 146,843	7.85%
7								
8	**Total Residential and Farm:**	**$ 28,383,312**	**$ 26,175,909**	**$ 27,539,406**	**$ (1,363,496)**	**-4.95%**	**$ 843,904**	**3.06%**
9								
10	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 4,828,371	$ 4,760,840	$ 4,546,876	$ 213,963	4.71%	$ 281,495	6.19%
11	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 2,925	$ 3,829	$ 2,308	$ 1,522	65.94%	$ 617	26.75%
12	10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)	$ 31,974	$ 29,104	$ 28,675	$ (839)	-2.93%	$ (938)	-3.27%
13	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 11,210,007	$ 10,809,666	$ 12,145,208	$ (1,335,543)	-11.00%	$ (935,201)	-7.70%
14	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 206,851	$ 187,951	$ 267,344	$ (79,394)	-29.70%	$ (60,493)	-22.63%
15	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)	$ 1,192,723	$ 903,939	$ 562,518	$ 341,420	60.69%	$ 630,205	112.03%
	Total General Service:	**$ 17,472,852**	**$ 16,695,328**	**$ 17,552,930**	**$ (858,870)**	**-4.89%**	**$ (84,315)**	**-0.48%**

Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Approved Rate Summer	Approved Rate Winter	2014 Operating Revenues Annual	2015 Operating Revenues Annual	2009 TY Operating Revenues Annual	2009 to 2015 Increase/(Decrease) Annual	2009 to 2015 Pct Inc/(Dec) Annual	2009 to 2014 Increase/(Decrease) Annual	2009 to 2014 Pct Inc/(Dec) Annual
1	**9.01 Residential Service (Rate 101)**															
4	Energy	kWh	116,187,468	299,758,580	415,946,048	$0.00000	$0.00000	$0.07976	$0.08192	$ 34,743,904	$ 32,469,088	$ 33,822,408	$ (1,353,320)	-4.0%	$ 921,496	2.7%
9	**Total Base Revenue:**									$ 34,743,904	$ 32,469,088	$ 33,822,408	$ (1,353,320)	-4.0%	$ 921,496	2.7%
10	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
11	Conservation Program Adjustment									$ (740,034)	$ (691,016)	$ (715,427)	$ 24,411	-3.4%	$ (24,607)	3.4%
12	Environmental Cost Recovery Rider Adjustment															
13	Fuel Adjustment									$ (9,965,935)	$ (9,305,822)	$ (9,634,558)	$ 328,736	-3.4%	$ (331,377)	3.4%
14	Transmission Rider Adjustment															
15	**Total Adjustments:**									$ (10,705,969)	$ (9,996,839)	$ (10,349,986)	$ 353,147	-3.4%	$ (355,983)	3.4%
16																
17																
18	**9.02 Residential Demand Control (Rate 241)**															
19	Customer Charge															
20	Facilities Charge															
21	Energy - All kWh	kWh	10,475,398	49,342,908	59,818,306			$0.04671	$0.05058	$ 2,970,049	$ 2,551,720	$ 2,985,135	$ (433,415)	-14.5%	$ (15,086)	-0.5%
22	All kW	kW	41,951	87,155	129,106			$6.08	$5.11	$ 756,506	$ 568,811	$ 700,420	$ (131,609)	-18.8%	$ 56,086	8.0%
23	**Total Base Revenue:**									$ 3,726,555	$ 3,120,532	$ 3,685,555	$ (565,023)	-15.3%	$ 41,000	1.1%
24	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
25	Conservation Program Adjustment						$0.00000			$ (96,628)	$ (84,212)	$ (102,887)	$ 18,676	-18.2%	$ 6,259	-6.1%
26	Environmental Cost Recovery Rider Adjustment						0.00%									
27	Fuel Adjustment						$0.00000			$ (1,301,281)	$ (1,134,069)	$ (1,385,571)	$ 251,503	-18.2%	$ 84,291	-6.1%
28	Transmission Rider Adjustment						$0.00000									
29	**Total Adjustments:**									$ (1,397,909)	$ (1,218,281)	$ (1,488,459)	$ 270,178	-18.2%	$ 90,550	-6.1%
30																
31	**Total Base Revenue for the COSS Class:**									**$ 38,470,459**	**$ 35,589,620**	**$ 37,507,963**	$ (1,918,343)	-5.1%	$ 962,496	2.6%
32	**Total Adjustments for the COSS Class:**									**$ (12,103,878)**	**$ (11,215,120)**	**$ (11,838,444)**	$ 623,325	-5.3%	$ (265,434)	2.2%
33	**Total for the COSS Class:**									**$ 26,366,581**	**$ 24,374,500**	**$ 25,669,519**	$ (1,295,019)	-5.0%	$ 697,062	2.7%
34																
35	**9.03 Farm Service (Rate 361)**															
37	Energy - All kWh	kWh	9,010,104	26,061,626	35,071,730			$0.07666	$0.07873	$ 3,006,091	$ 2,680,872	$ 2,742,578	$ (61,706)	-2.2%	$ 263,513	9.6%
43	**Total Base Revenue:**									$ 3,006,091	$ 2,680,872	$ 2,742,578	$ (61,706)	-2.2%	$ 263,513	9.6%
44	***Adjustments for Fuel and CIP included in Base Rates***					**COSS - RevAlloc Factors**										
45	Conservation Program Adjustment						$0.00000			$ (68,388)	$ (60,792)	$ (60,323)	$ (468)	0.8%	$ (8,065)	13.4%
46	Environmental Cost Recovery Rider Adjustment															
47	Fuel Adjustment						$0.00000			$ (920,973)	$ (818,671)	$ (812,366)	$ (6,305)	0.8%	$ (108,606)	13.4%
48	Transmission Rider Adjustment															
49	**Total Adjustments:**									$ (989,360)	$ (879,462)	$ (872,690)	$ (6,772)	0.8%	$ (116,670)	13.4%
50																
51	**Total Base Revenue for the COSS Class:**									**$ 41,476,549**	**$ 38,270,492**	**$ 40,250,541**	$ (1,980,049)	-4.9%	$ 1,226,008	3.0%
52	**Total Adjustments for the COSS Class:**									**$ (13,093,238)**	**$ (12,094,581)**	**$ (12,711,134)**	$ 616,553	-4.9%	$ (382,104)	3.0%
53	**Total for the COSS Class:**									**$ 28,383,311**	**$ 26,175,911**	**$ 27,539,407**	$ (1,363,496)	-5.0%	$ 843,904	3.1%
54																
55																

Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Approved Rate Summer	Approved Rate Winter	2014 Operating Revenues Annual	2015 Operating Revenues Annual	2009 TY Operating Revenues Annual	2009 to 2015 Increase/(Decrease) Annual	2009 to 2015 Pct Inc/(Dec) Annual	2009 to 2014 Increase/(Decrease) Annual	2009 to 2014 Pct Inc/(Dec) Annual
56	**10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)**															
59	Energy	kWh	25,759,423	61,896,887	87,656,310			$0.07579	$0.07784	$ 7,226,551	$ 7,057,235	$ 6,770,227	$ 287,008	4.2%	$ 456,324	6.7%
64	**Total Base Revenue:**									$ 7,226,551	$ 7,057,235	$ 6,770,227	$ 287,008	4.2%	$ 456,324	6.7%
65	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
66	Conservation Program Adjustment						$0.00000			$ (165,771)	$ (158,735)	$ (153,686)	$ (5,049)	3.3%	$ (12,085)	7.9%
67	Environmental Cost Recovery Rider Adjustment						0.00%			$ -	$ -	$ -				
68	Fuel Adjustment						$0.00000			$ (2,232,409)	$ (2,137,661)	$ (2,069,665)	$ (67,996)	3.3%	$ (162,744)	7.9%
69	Transmission Rider Adjustment						$0.00000			$ -	$ -	$ -				
70	**Total Adjustments:**									$ (2,398,180)	$ (2,296,396)	$ (2,223,351)	$ (73,045)	3.3%	$ (174,829)	7.9%
71																
72	**10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)**															
75	Energy	kWh	23,421	23,491	46,912			$0.07331	$0.07484	$ 4,417	$ 5,766	$ 3,475	$ 2,291	65.9%	$ 942	27.1%
76	**Total Base Revenue:**									$ 4,417	$ 5,766	$ 3,475	$ 2,291	65.9%	$ 942	27.1%
77	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
78	Conservation Program Adjustment									$ (103)	$ (134)	$ (81)	$ (53)	65.9%	$ (22)	27.8%
79	Environmental Cost Recovery Rider Adjustment									$ -	$ -	$ -				
80	Fuel Adjustment									$ (1,389)	$ (1,803)	$ (1,087)	$ (716)	65.9%	$ (302)	27.8%
81	Transmission Rider Adjustment									$ -	$ -	$ -				
82	**Total Adjustments:**									$ (1,492)	$ (1,937)	$ (1,167)	$ (769)	65.9%	$ (324)	27.8%
83																
84	**10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)**															
87	Energy	kWh	274,292	274,292	548,583			$0.07715	$0.07715	$ 47,196	$ 42,959	$ 42,325	$ 634	1.5%	$ 4,871	11.5%
88	**Total Base Revenue:**									$ 47,196	$ 42,959	$ 42,325	$ (634)		$ 634	
89	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
90	Conservation Program Adjustment				-		$0.00000	$ -	$ -	$ (1,052)	$ (958)	$ (944)	$ (14)	1.5%	$ (109)	11.5%
91	Environmental Cost Recovery Rider Adjustment															
92	Fuel Adjustment				-		$0.00000	$ -	$ -	$ (14,170)	$ (12,898)	$ (12,707)	$ (191)	1.5%	$ (1,463)	11.5%
93	Transmission Rider Adjustment															
94	**Total Adjustments:**									$ (15,222)	$ (13,855)	$ (13,650)	$ (205)	1.5%	$ (1,572)	11.5%

Approved Test Year 2009 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Approved Rate Summer	Approved Rate Winter	2014 Operating Revenues Annual	2015 Operating Revenues Annual	2009 TY Operating Revenues Annual	2009 to 2015 Increase/(Decrease) Annual	2009 to 2015 Pct Inc/(Dec) Annual	2009 to 2014 Increase/(Decrease) Annual	2009 to 2014 Pct Inc/(Dec) Annual
95																
96	**10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)**															
98	Energy	kWh	68,769,863	150,901,063	219,670,926			$0.06791	$0.07353	$ 14,249,762	$ 13,694,300	$ 15,766,400	$ (2,072,100)	-13.1%	$ (1,516,638)	-9.6%
99	Demand per kW	kW	342,444	613,736	956,180			$1.22	$1.02	$ 1,107,716	$ 1,087,344	$ 1,043,401	$ 43,943	4.2%	$ 64,315	6.2%
100	Facilities Charge				1,335,798		$0.00	$0.60	$0.60	$ 853,406	$ 837,399	$ 801,479	$ 35,920	4.5%	$ 51,927	6.5%
104	**Total Base Revenue:**									$ 16,210,883	$ 15,619,041	$ 17,611,280	$ (1,992,239)	-11.3%	$ (1,400,397)	-8.0%
105	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
106	Conservation Program Adjustment									$ (345,678)	$ (332,441)	$ (377,834)	$ 45,393	-12.0%	$ 32,156	-8.5%
107	Environmental Cost Recovery Rider Adjustment									$ -	$ -	$ -				
108	Fuel Adjustment									$ (4,655,198)	$ (4,476,934)	$ (5,088,238)	$ 611,303	-12.0%	$ 433,040	-8.5%
109	Transmission Rider Adjustment									$ -	$ -	$ -				
110	**Total Adjustments:**									$ (5,000,876)	$ (4,809,375)	$ (5,466,072)	$ 656,696	-12.0%	$ 465,196	-8.5%
111																
112	**10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)**															
114	Energy	kWh	776,870	2,898,262	3,675,132			$0.06583	$0.07090	$ 202,105	$ 186,549	$ 256,623	$ (70,074)	-27.3%	$ (54,518)	-21.2%
115	Demand per kW	kW	6,276	10,033	16,309			$1.17	$0.97	$ 18,271	$ 14,801	$ 17,067	$ (2,266)	-13.3%	$ 1,204	7.1%
116	Facilities Charge								$0.00	$ 11,861	$ 11,527	$ 17,447	$ (5,920)	-33.9%	$ (5,586)	-32.0%
117	**Total Base Revenue:**									$ 232,237	$ 212,877	$ 291,137	$ (78,260)	-26.9%	$ (58,900)	-20.2%
118	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
119	Conservation Program Adjustment						$0.00000	$ -	$ -	$ (1,755)	$ (1,723)	$ (1,645)	$ (78)	4.8%	$ (110)	6.7%
120	Environmental Cost Recovery Rider Adjustment						0.00%	$ -	$ -	$ -	$ -	$ -				
121	Fuel Adjustment				-		$0.00000	$ -	$ -	$ (23,631)	$ (23,203)	$ (22,148)	$ (1,055)	4.8%	$ (1,483)	6.7%
122	Transmission Rider Adjustment				-		$0.00000	$ -	$ -	$ -	$ -	$ -				
123	**Total Adjustments:**									$ (25,386)	$ (24,926)	$ (23,793)	$ (1,134)	4.8%	$ (1,594)	6.7%
124																
125	**10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)**															
127	Energy - Declared-Peak	kWh	745	311,985	312,730			$0.20332	$0.21624	$ 395,406	$ 26,435	$ 67,613	$ (41,178)	-60.9%	$ 327,793	484.8%
128	Energy - Intermediate	kWh	4,117,970	9,134,218	13,252,188			$0.05162	$0.04703	$ 1,014,201	$ 1,195,031	$ 642,161	$ 552,870	86.1%	$ 372,040	57.9%
129	Energy - Off-Peak	kWh	2,203,950	5,357,308	7,561,258			$0.02331	$0.03505	$ 171,906	$ 177,912	$ 103,267	$ 74,645	72.3%	$ 68,639	66.5%
130	Demand per kW - Declared-Peak	kW			-		$ -	N/A	N/A							
131	Demand per kW - Intermediate	kW	24,228	28,803	53,031			$2.64	$1.36	$ 551,732	$ 436,127	$ 239,159	$ 196,968	82.4%	$ 312,573	130.7%
132	Demand per kW - Off-Peak	kW	-	-	-											
133	Facilities Charge	kW			102,431		$0.00	$0.60	$0.60	$ 78,880	$ 77,158	$ 61,458	$ 15,700	25.5%	$ 17,422	28.3%
134	Forecasted WAPA Credits															
135	**Total Base Revenue:**									$ 2,212,125	$ 1,912,662	$ 1,113,658	$ 799,004	71.7%	$ 1,098,467	98.6%
136	***Adjustments for Riders included in Base Rates***					**COSS - RevAlloc Factors**										
137	Conservation Program Adjustment						$0.00000			$ (70,465)	$ (69,726)	$ (38,097)	$ (31,630)	83.0%	$ (32,368)	85.0%
138	Environmental Cost Recovery Rider Adjustment						0.00%									
139	Fuel Adjustment						$0.00000			$ (948,937)	$ (938,997)	$ (513,043)	$ (425,954)	83.0%	$ (435,894)	85.0%
140	Transmission Rider Adjustment						$0.00000			$ -	$ -	$ -				
141	**Total Adjustments:**									$ (1,019,402)	$ (1,008,724)	$ (551,140)	$ (457,584)	83.0%	$ (468,262)	85.0%
142																
143	**Total Base Revenue for the COSS Class:**									**$ 25,933,409**	**$ 24,850,540**	**$ 25,832,102**	**$ (981,562)**	**-3.8%**	**$ 101,307**	**0.4%**
144	**Total Adjustments for the COSS Class:**									**$ (8,460,558)**	**$ (8,155,213)**	**$ (8,279,172)**	**$ 123,959**	**-1.5%**	**$ (181,386)**	**2.2%**
145	**Total for the COSS Class:**									**$ 17,472,851**	**$ 16,695,327**	**$ 17,552,930**	**$ (857,603)**	**-4.9%**	**$ (80,079)**	**-0.5%**
146																
147																

Approved Test Year 2016 Operating Revenue Summary Comparison - By Rate Schedule

Line No.	Rate Schedule	2016	2017	2016 TY	Difference 2016 to 2017	Percent Change 2016 to 2017	Difference 2016 to 2016	Percent Change 2016 to 2016
1	9.01 Residential Service (Rate 101)	$ 26,577,802	$ 28,928,125	$ 29,168,294	$ (240,169)	-0.82%	$ (2,590,492)	-8.88%
2	9.02 Residential Demand Control (Rate 241)	$ 2,293,057	$ 1,684,750	$ 3,159,573	$ (1,474,823)	-46.68%	$ (866,516)	-27.43%
3	Total Residential:	$ 28,870,858	$ 30,612,874	$ 32,327,866	$ (1,714,992)	-5.30%	$ (3,457,008)	-10.69%
4								
5	9.03 Farm Service (Rate 361)	$ 2,281,810	$ 1,941,548	$ 2,219,868	$ (278,320)	-12.54%	$ 61,941	2.79%
6	Total Farm:	$ 2,281,810	$ 1,941,548	$ 2,219,868	$ (278,320)	-12.54%	$ 61,941	2.79%
7								
8	**Total Residential and Farm:**	**$ 31,152,668**	**$ 32,554,422**	**$ 34,547,734**	**$ (1,993,312)**	-5.77%	**$ (3,395,067)**	-9.83%
9								
10	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 5,608,261	$ 5,753,087	$ 5,830,434	$ (77,346)	-1.33%	$ (222,172)	-3.81%
11	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 4,386	$ 5,055	$ 3,110	$ 1,946	62.58%	$ 1,277	41.05%
12	10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)	$ 31,547	$ 32,416	$ 37,908	$ 11,949	31.52%	$ (6,361)	-16.78%
13	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 12,962,709	$ 13,684,631	$ 13,934,019	$ (249,388)	-1.79%	$ (971,310)	-6.97%
14	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 188,903	$ 217,186	$ 272,679	$ (55,492)	-20.35%	$ (83,775)	-30.72%
15	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)	$ 1,688,514	$ 1,790,956	$ 1,650,037	$ 140,918	8.54%	$ 38,477	2.33%
	Total General Service:	**$ 20,484,321**	**$ 21,483,332**	**$ 21,728,186**	**$ (227,414)**	-1.05%	**$ (1,243,865)**	-5.72%

Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Approved Rate Summer	Approved Rate Winter	2016 Actual Operating Revenues Annual	2017 Actual Operating Revenues Annual	2016 Approved Operating Revenues Annual	2017 Actual to 2016 Approved Increase/(Decrease) Annual	2017 Actual to 2016 Approved Pct Inc/(Dec) Annual	2016 to 2016 Increase/(Decrease) Annual	2016 to 2016 Pct Inc/(Dec) Annual
1	**9.01 Residential Service (Rate 101)**													
2	Customer Charge	Bills												
3	Seasonal Fixed Charge	Bills												
4	Energy	kWh	129,790,104	289,433,002	419,223,106	$0.10964	$0.09064	$ 36,734,495	$ 37,348,886	$ 40,464,394	$ (3,115,509)	-7.7%	$ (3,729,900)	-9.2%
5	Water Heating Control Credit 14.01 (Rate 192)	Bills												
6	Air Conditioning Control Rider 14.08 (Rate 760)	Bills												
7	TailWinds Program 14.09	kWh												
8														
9	**Total Base Revenue:**							$ 36,734,495	$ 37,348,886	$ 40,464,394	$ (3,115,508)	-7.7%	$ (3,729,899)	-9.2%
10	***Adjustments for Riders included in Base Rates***													
11	Conservation Program Adjustment	kWh						$ (674,414)	$ (559,191)	$ (937,070)	$ 377,879	-40.3%	$ 262,656	-28.0%
12	Environmental Cost Recovery Rider Adjustment	$												
13	Fuel Adjustment	kWh						$ (9,482,279)	$ (7,861,570)	$ (10,359,031)	$ 2,497,461	-24.1%	$ 876,752	-8.5%
14	Transmission Rider Adjustment	kWh												
15	**Total Adjustments:**							$ (10,156,693)	$ (8,420,761)	$ (11,296,100)	$ 2,875,339	-25.5%	$ 1,139,407	-10.1%
16														
17														
18	**9.02 Residential Demand Control (Rate 241)**													
19	Customer Charge	Bills												
20	Facilities Charge	Bills												
21	Energy - All kWh	kWh	10,551,958	42,856,627	53,408,585	$0.06425	$0.06738	$ 2,855,614	$ 3,265,497	$ 3,565,643	$ (300,146)	-8.4%	$ (710,029)	-19.9%
22	All kW	kW	42,281	83,281	125,562	$8.00	$8.00	$ 648,414	$ 854,294	$ 1,004,496	$ (150,202)	-15.0%	$ (356,082)	-35.4%
23	**Total Base Revenue:**							$ 3,504,028	$ 4,119,791	$ 4,570,138	$ (450,347)	-9.9%	$ (1,066,110)	-23.3%
24	***Adjustments for Riders included in Base Rates***													
25	Conservation Program Adjustment	kWh						$ (80,410)	$ (161,702)	$ (117,014)	$ (44,688)	38.2%	$ 36,604	-31.3%
26	Environmental Cost Recovery Rider Adjustment	$												
27	Fuel Adjustment	kWh						$ (1,130,562)	$ (2,273,340)	$ (1,293,552)	$ (979,788)	75.7%	$ 162,990	-12.6%
28	Transmission Rider Adjustment	kWh												
29	**Total Adjustments:**							$ (1,210,972)	$ (2,435,042)	$ (1,410,565)	$ (1,024,476)	72.6%	$ 199,594	-14.1%
30														
31	**Total Base Revenue for the COSS Class:**							**$ 40,238,523**	**$ 41,468,677**	**$ 45,034,532**	$ (3,565,855)	-7.9%	$ (4,796,009)	-10.6%
32	**Total Adjustments for the COSS Class:**							**$ (11,367,665)**	**$ (10,855,803)**	**$ (12,706,666)**	$ 1,850,863	-14.6%	$ 1,339,001	-10.5%
33	**Total for the COSS Class:**							**$ 28,870,858**	**$ 30,612,874**	**$ 32,327,866**	$ (1,714,992)	-5.3%	$ (3,457,008)	-10.7%
34														
35	**9.03 Farm Service (Rate 361)**													
36	Customer Charge	Bills												
37	Energy - All kWh	kWh	9,992,135	24,704,403	34,696,538	$0.10435	$0.08535	$ 3,247,218	$ 3,311,895	$ 3,151,200	$ 160,695	5.1%	$ 96,018	3.0%
38	All Three Phase Facilities	Bills												
39	Water Heating Control Credit 14.01	Bills												
40	Air Conditioning Control Rider 14.08	Bills												
41	TailWinds Program 14.09	kWh												
42														
43	**Total Base Revenue:**							$ 3,247,218	$ 3,311,895	$ 3,151,200	$ 160,695	5.1%	$ 96,018	3.0%
44	***Adjustments for Fuel and CIP included in Base Rates***													
45	Conservation Program Adjustment	kWh						$ (64,104)	$ (91,000)	$ (77,259)	$ (13,741)	17.8%	$ 13,155	-17.0%
46	Environmental Cost Recovery Rider Adjustment	%												
47	Fuel Adjustment	kWh						$ (901,305)	$ (1,279,348)	$ (854,073)	$ (425,275)	49.8%	$ (47,231)	5.5%
48	Transmission Rider Adjustment	kWh												
49	**Total Adjustments:**							$ (965,408)	$ (1,370,347)	$ (931,332)	$ (439,015)	47.1%	$ (34,076)	3.7%
50														
51	**Total Base Revenue for the COSS Class:**							**$ 43,485,740**	**$ 44,780,572**	**$ 48,185,732**	$ (3,405,160)	-7.1%	$ (4,699,992)	-9.8%
52	**Total Adjustments for the COSS Class:**							**$ (12,333,072)**	**$ (12,226,149)**	**$ (13,637,997)**	$ 1,411,848	-10.4%	$ 1,304,925	-9.6%
53	**Total for the COSS Class:**							**$ 31,152,668**	**$ 32,554,423**	**$ 34,547,735**	$ (1,993,312)	-5.8%	$ (3,395,067)	-9.8%
54														
55														

Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

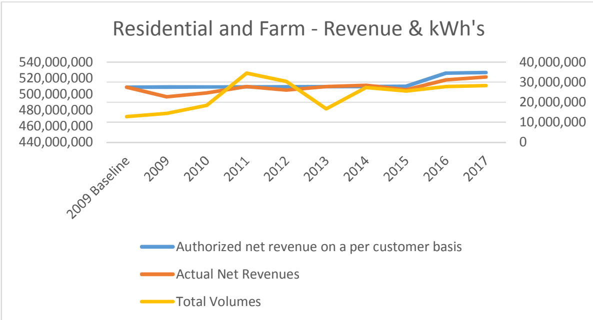
Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Approved Rate Summer	Approved Rate Winter	2016 Actual Operating Revenues Annual	2017 Actual Operating Revenues Annual	2016 Approved Operating Revenues Annual	2017 Actual to 2016 Approved Increase/(Decrease) Annual	2017 Actual to 2016 Approved Pct Inc/(Dec) Annual	2016 to 2016 Increase/(Decrease) Annual	2016 to 2016 Pct Inc/(Dec) Annual
56	**10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)**													
57	Customer Charge	Bills												
58	Seasonal Fixed Charge	Bills												
59	Energy	kWh	30,487,603	64,904,965	95,392,568	$0.10126	$0.08226	$ 8,005,529	$ 8,174,445	$ 8,426,257	$ (251,812)	-3.0%	$ (420,729)	-5.0%
60	Water Heating Control Credit 14.01	Bills												
61	Air Conditioning Control Rider 14.08	Bills						$ -	$ -					
62	TailWinds Program 14.09	kWh												
63														
64	**Total Base Revenue:**							$ 8,005,529	$ 8,174,445	$ 8,426,257	$ (251,812)	-3.0%	$ (420,728)	-5.0%
65	***Adjustments for Riders included in Base Rates***													
66	Conservation Program Adjustment	kWh						$ (158,797)	$ (160,438)	$ (215,337)	$ 54,899	-25.5%	$ 56,540	-26.3%
67	Environmental Cost Recovery Rider Adjustment	%						$ -	$ -	$ -				
68	Fuel Adjustment	kWh						$ (2,238,470)	$ (2,260,919)	$ (2,380,486)	$ 119,567	-5.0%	$ 142,016	-6.0%
69	Transmission Rider Adjustment	kWh						$ -	$ -	$ -				
70	**Total Adjustments:**							$ (2,397,267)	$ (2,421,358)	$ (2,595,823)	$ 174,466	-6.7%	$ 198,556	-7.6%
71														
72	**10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)**													
73	Customer Charge	Bills												
74	Seasonal Fixed Charge	Bills												
75	Energy	kWh	33,541	14,253	47,794	$0.09761	$0.07861	$ 6,226	$ 7,145	$ 4,394	$ 2,750	62.6%	$ 1,832	41.7%
76	**Total Base Revenue:**							$ 6,226	$ 7,145	$ 4,394	$ 2,750	62.6%	$ 1,832	41.7%
77	***Adjustments for Riders included in Base Rates***													
78	Conservation Program Adjustment	kWh						$ (122)	$ (138)	$ (107)	$ (32)	29.9%	$ (15)	14.4%
79	Environmental Cost Recovery Rider Adjustment	%						$ -	$ -	$ -				
80	Fuel Adjustment	kWh						$ (1,718)	$ (1,951)	$ (1,178)	$ (773)	65.6%	$ (540)	45.8%
81	Transmission Rider Adjustment	kWh						$ -	$ -	$ -				
82	**Total Adjustments:**							$ (1,840)	$ (2,089)	$ (1,285)	$ (804)	62.6%	$ (555)	43.2%
83														
84	**10.01 Small General Service - Under 20 kW - Non-metered Service - 1,000 Watts and Under (Rate 408)**													
85	Customer Charge	Bills					$0.00							
86	Seasonal Fixed Charge	Bills			-		$0.00							
87	Energy	kWh	321,205	321,205	642,410	$0.08589	$0.08589	$ 45,831	$ 46,457	$ 55,177	$ (8,720)	-15.8%	$ (9,346)	-16.9%
88	**Total Base Revenue:**							$ 45,831	$ 46,457	$ 55,177	$ 8,720		$ (9,346)	-16.9%
89	***Adjustments for Riders included in Base Rates***													
90	Conservation Program Adjustment	kWh			-	$ -	$ -	$ (946)	$ (930)	$ (1,433)	$ 502	-35.1%	$ 486	-33.9%
91	Environmental Cost Recovery Rider Adjustment	%												
92	Fuel Adjustment	kWh			-	$ -	$ -	$ (13,338)	$ (13,110)	$ (15,837)	$ 2,726	-17.2%	$ 2,498	-15.8%
93	Transmission Rider Adjustment	kWh												
94	**Total Adjustments:**							$ (14,285)	$ (14,041)	$ (17,269)	$ 3,229	-18.7%	$ 2,985	-17.3%
95														
96	**10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)**													
97	Customer Charge	Bills												
98	Energy	kWh	65,453,843	136,945,561	202,399,404	$0.07495	$0.07860	$ 14,809,389	$ 15,288,883	$ 15,669,687	$ (380,803)	-2.4%	$ (860,298)	-5.5%
99	Demand per kW	kW	354,779	719,710	1,074,489	$3.63	$1.39	$ 2,020,957	$ 2,160,415	$ 2,288,245	$ (127,830)	-5.6%	$ (267,287)	-11.7%
100	Facilities Charge	kW			1,460,814	$0.97	$0.97	$ 1,199,343	$ 1,360,250	$ 1,416,990	$ (56,740)	-4.0%	$ (217,646)	-15.4%
101	TailWinds Program 14.09	kWh												
102	Water Heating Control Credit 14.01	Bills						$ -	$ -					
103	Air Conditioning Control Rider 14.08	Bills						$ -	$ -					
104	**Total Base Revenue:**							$ 18,029,689	$ 18,809,547	$ 19,374,920	$ (565,373)	-2.9%	$ (1,345,231)	-6.9%
105	***Adjustments for Riders included in Base Rates***													
106	Conservation Program Adjustment	kWh						$ (335,641)	$ (339,575)	$ (451,351)	$ 111,776	-24.8%	$ 115,709	-25.6%
107	Environmental Cost Recovery Rider Adjustment	%						$ -	$ -	$ -				
108	Fuel Adjustment	kWh						$ (4,731,339)	$ (4,785,341)	$ (4,989,550)	$ 204,209	-4.1%	$ 258,212	-5.2%
109	Transmission Rider Adjustment	kWh						$ -	$ -	$ -				
110	**Total Adjustments:**							$ (5,066,980)	$ (5,124,916)	$ (5,440,901)	$ 315,985	-5.8%	$ 373,921	-6.9%
111														
112	**10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)**													
113	Customer Charge	Bills												
114	Energy	kWh	1,467,410	1,669,419	3,136,829	$0.07244	$0.07535	$ 157,649	$ 183,385	$ 232,090	$ (48,705)	-21.0%	$ (74,441)	-32.1%
115	Demand per kW	kW	7,796	9,686	17,482	$4.02	$1.89	$ 40,954	$ 42,051	$ 49,646	$ (7,596)	-15.3%	$ (8,693)	-17.5%

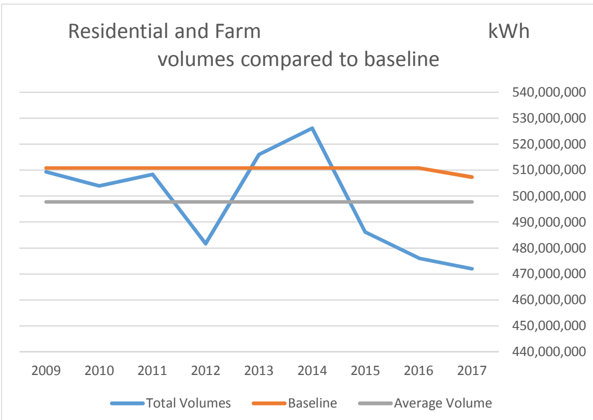
Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

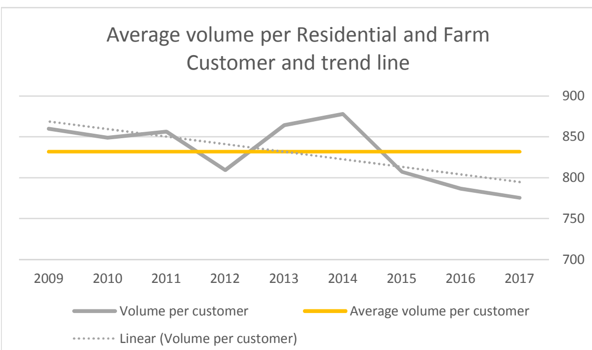
Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Approved Rate Summer	Approved Rate Winter	2016 Actual Operating Revenues Annual	2017 Actual Operating Revenues Annual	2016 Approved Operating Revenues Annual	2017 Actual to 2016 Approved Increase/(Decrease) Annual	2017 Actual to 2016 Approved Pct Inc/(Dec) Annual	2016 to 2016 Increase/(Decrease) Annual	2016 to 2016 Pct Inc/(Dec) Annual
116	Facilities Charge	kW					$0.00	$ 16,307	$ 18,241	$ 19,827	$ (1,586)	-8.0%	$ (3,520)	-17.8%
117	**Total Base Revenue:**							$ 214,910	$ 243,677	$ 301,563	$ (57,886)	-19.2%	$ (86,653)	-28.7%
118	***Adjustments for Riders included in Base Rates***													
119	Conservation Program Adjustment	kWh				$ -	$ -	$ (1,723)	$ (1,755)	$ (2,396)	$ 641	-26.7%	$ 673	-28.1%
120	Environmental Cost Recovery Rider Adjustment	%				$ -	$ -	$ -	$ -	$ -				
121	Fuel Adjustment	kWh			-	$ -	$ -	$ (24,284)	$ (24,735)	$ (26,488)	$ 1,753	-6.6%	$ 2,205	-8.3%
122	Transmission Rider Adjustment	kWh			-	$ -	$ -	$ -	$ -	$ -				
123	**Total Adjustments:**							$ (26,006)	$ (26,491)	$ (28,884)	$ 2,394	-8.3%	$ 2,878	-10.0%
124														

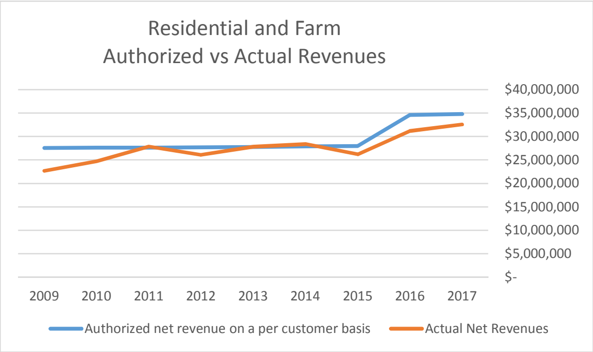
Approved Test Year 2016 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

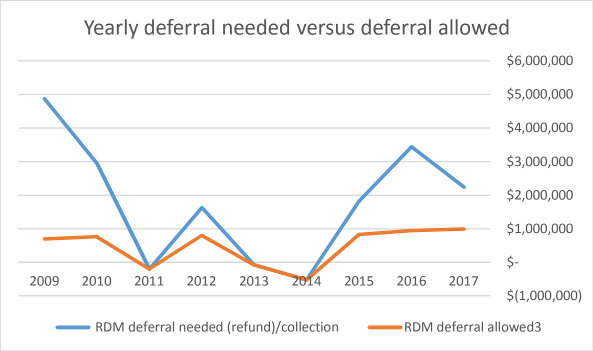
Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Approved Rate Summer	Approved Rate Winter	2016 Actual Operating Revenues Annual	2017 Actual Operating Revenues Annual	2016 Approved Operating Revenues Annual	2017 Actual to 2016 Approved Increase/(Decrease) Annual	2017 Actual to 2016 Approved Pct Inc/(Dec) Annual	2016 to 2016 Increase/(Decrease) Annual	2016 to 2016 Pct Inc/(Dec) Annual
125	**10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)**													
126	Customer Charge	Bills												
127	Energy - Declared-Peak	kWh	85,911	483,618	569,529	$0.53978	$0.28109	$ 337,954	$ 249,576	$ 182,313	$ 67,263	36.9%	$ 155,641	85.4%
128	Energy - Intermediate	kWh	6,954,029	14,005,566	20,959,595	$0.06938	$0.06997	$ 1,447,981	$ 1,532,667	$ 1,462,440	$ 70,227	4.8%	$ (14,459)	-1.0%
129	Energy - Off-Peak	kWh	6,195,725	11,452,196	17,647,921	$0.03910	$0.04676							
130	Demand per kW - Declared-Peak	kW			-	N/A	N/A	$ 215,389	$ 245,024	$ 292,039			$ (76,651)	-26.2%
131	Demand per kW - Intermediate	kW	37,413	71,430	108,843	$2.67	$2.69	$ 587,115	$ 619,314	$ 777,758	$ (158,444)	-20.4%	$ (190,642)	-24.5%
132	Demand per kW - Off-Peak	kW	-	-	-									
133	Facilities Charge	kW			12,994	$0.97	$0.97	$ 108,207	$ 115,241	$ 12,604	$ 102,637	814.3%	$ 95,603	758.5%
134	Forecasted WAPA Credits													
135	**Total Base Revenue:**							$ 2,696,645	$ 2,761,822	$ 2,727,154	$ 34,668	1.3%	$ (30,509)	-1.1%
136	***Adjustments for Riders included in Base Rates***													
137	Conservation Program Adjustment	kWh						$ (66,779)	$ (64,329)	$ (89,352)	$ 25,023	-28.0%	$ 22,573	-25.3%
138	Environmental Cost Recovery Rider Adjustment	%												
139	Fuel Adjustment	kWh						$ (941,351)	$ (906,537)	$ (987,764)	$ 81,228	-8.2%	$ 46,413	-4.7%
140	Transmission Rider Adjustment	kWh						$ -	$ -	$ -				
141	**Total Adjustments:**							$ (1,008,131)	$ (970,866)	$ (1,077,117)	$ 106,251	-9.9%	$ 68,986	-6.4%
142														
143	**Total Base Revenue for the COSS Class:**							**$ 28,998,829**	**$ 30,043,092**	**$ 30,889,465**	**$ (846,373)**	**-2.7%**	$ (1,890,636)	-6.1%
144	**Total Adjustments for the COSS Class:**							**$ (8,514,509)**	**$ (8,559,760)**	**$ (9,161,279)**	**$ 601,519**	**-6.6%**	$ 646,770	-7.1%
145	**Total for the COSS Class:**							**$ 20,484,320**	**$ 21,483,332**	**$ 21,728,186**	**$ (244,854)**	**-1.1%**	$ (1,243,866)	-5.7%
146														
147														

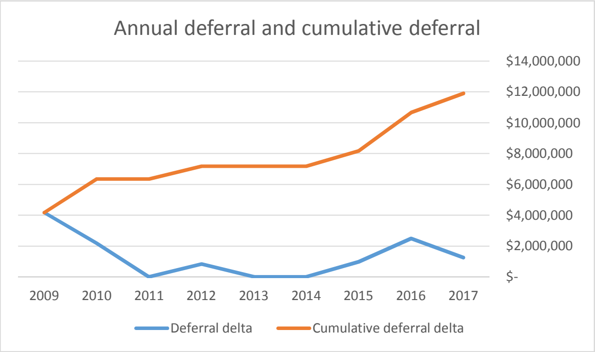

Residential and Farm - Revenue & kWh's
540,000,000
520,000,000
500,000,000
480,000,000
460,000,000
440,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
2009 Baseline
2009
2010
2011
2012
2013
2014
2015
2016
2017
Authorized net revenue on a per customer basis
Actual Net Revenues
Total Volumes

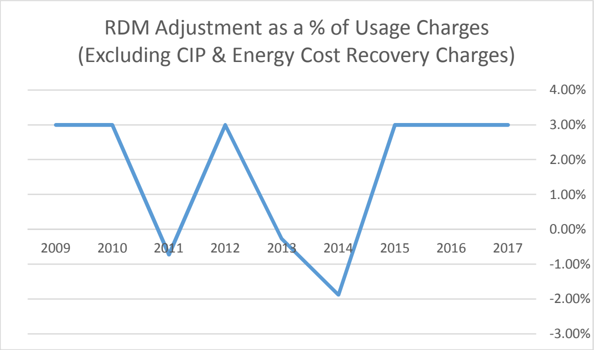

Residential and Farm
volumes compared to baseline
kWh
540,000,000
530,000,000
520,000,000
510,000,000
500,000,000
490,000,000
480,000,000
470,000,000
460,000,000
450,000,000
440,000,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
Total Volumes
Baseline
Average Volume

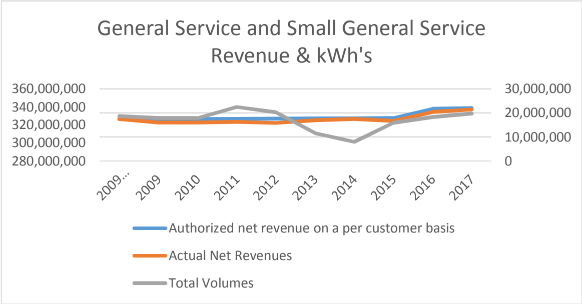

Average volume per Residential and Farm
Customer and trend line
900
850
800
750
700
2009
2010
2011
2012
2013
2014
2015
2016
2017
Volume per customer
Average volume per customer
Linear (Volume per customer)

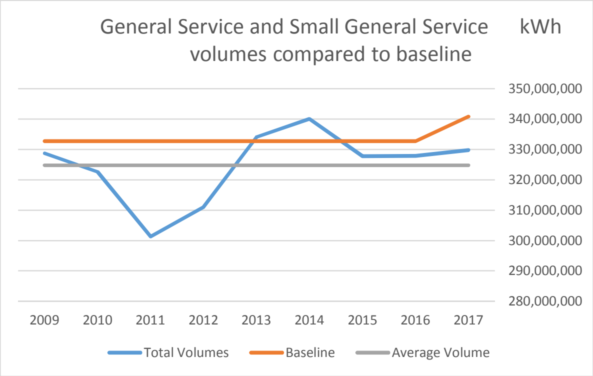

Residential and Farm
Authorized vs Actual Revenues
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
Authorized net revenue on a per customer basis
Actual Net Revenues

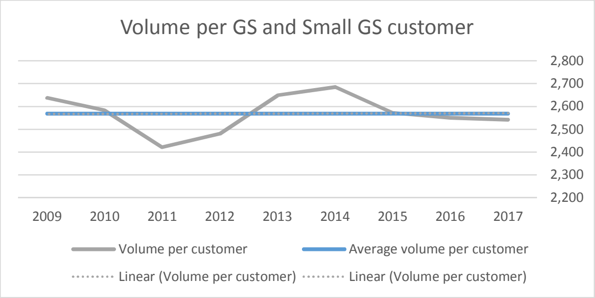

Yearly deferral needed versus deferral allowed
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
$(1,000,000)
2009 2010 2011 2012 2013 2014 2015 2016 2017
RDM deferral needed (refund)/collection
RDM deferral allowed3

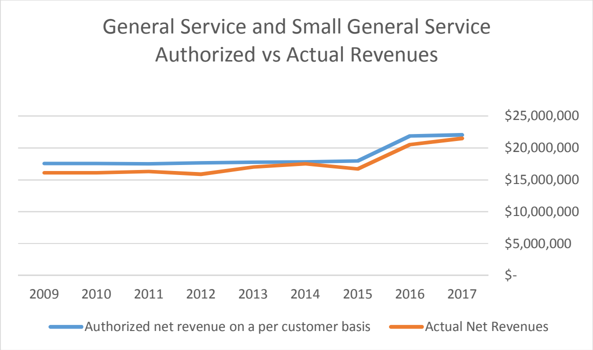

Annual deferral and cumulative deferral
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
Deferral delta
Cumulative deferral delta

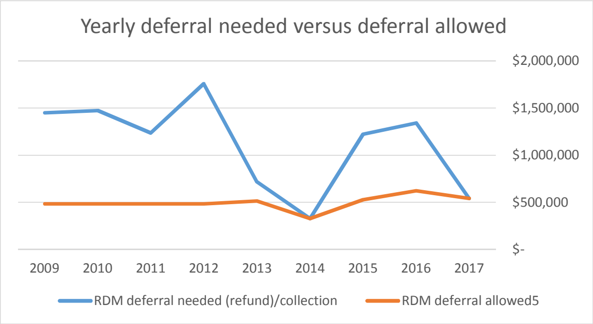

RDM Adjustment as a % of Usage Charges
(Excluding CIP & Energy Cost Recovery Charges)
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
-3.00%
2009
2010
2011
2012
2013
2014
2015
2016
2017

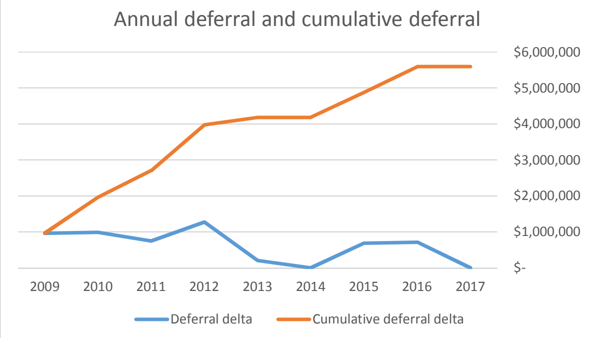

General Service and Small General Service
Revenue & kWh's
360,000,000
340,000,000
320,000,000
300,000,000
280,000,000
30,000,000
20,000,000
10,000,000
0
2009...
2009
2010
2011
2012
2013
2014
2015
2016
2017
Authorized net revenue on a per customer basis
Actual Net Revenues
Total Volumes

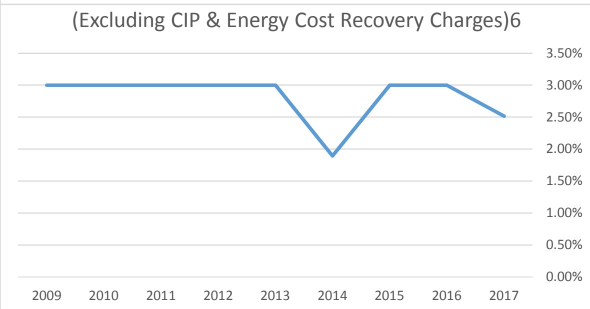

General Service and Small General Service
volumes compared to baseline
kWh
350,000,000
340,000,000
330,000,000
320,000,000
310,000,000
300,000,000
290,000,000
280,000,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
Total Volumes
Baseline
Average Volume


Volume per GS and Small GS customer
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2009 2010 2011 2012 2013 2014 2015 2016 2017
Volume per customer
Average volume per customer
Linear (Volume per customer)
Linear (Volume per customer)


General Service and Small General Service
Authorized vs Actual Revenues
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
Authorized net revenue on a per customer basis
Actual Net Revenues


Yearly deferral needed versus deferral allowed
$2,000,000
$1,500,000
$1,000,000
$500,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
RDM deferral needed (refund)/collection
RDM deferral allowed5


Annual deferral and cumulative deferral
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
2009 2010 2011 2012 2013 2014 2015 2016 2017
Deferral delta
Cumulative deferral delta


(Excluding CIP & Energy Cost Recovery Charges)6
3.50%
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
2009 2010 2011 2012 2013 2014 2015 2016 2017

RDM Adjustments	Source	Unit	Step	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
RDM deferral needed (refund)/collection	Tab 5 - res & farm RDM - not public	$	A	2,233,163	3,434,054	1,813,604	-522,698	-76,502	1,631,038	-199,068	2,940,028	4,869,795	0
RDM deferral allowed	Tab 5 - res & farm RDM - not public	$	B	991,583	945,093	822,603	-522,698	-76,502	794,303	-199,068	763,237	694,933	0
Deferral difference	Calculated		C (A - B)	1,241,581	2,488,961	991,001	0	0	836,735	0	2,176,790	4,174,862	
Cumulative Deferral	Calculated		Prior balance + Current	11,909,930	10,668,349	8,179,388	7,188,387	7,188,387	7,188,387	6,351,652	6,351,652	4,174,862	
Cap on Customer RDM Surcharges	Tab 5 - res & farm RDM - not public	$	D	991,583	945,093	822,603	834,944	839,084	794,303	820,617	763,237	694,933	789,641
Forecasted Volumes : April - March	Tab 5 - res & farm RDM - not public	kWh	E	498,503,774	475,098,024	483,573,678	516,158,605	518,548,825	490,229,686	501,732,170	505,131,870	508,085,032	0
Allowed Surcharge (Rate)	Calculated	$/kWh	F (B/E)	0.001989	0.001989	0.001701	-0.001013	-0.000148	0.001620	-0.000397	0.001511	0.001368	
Required Surcharge (Rate)	Calculated	$/kWh	G (A/E)	0.004480	0.007228	0.003750	-0.001013	-0.000148	0.003327	-0.000397	0.005820	0.009585	
Total Volumes	Tab 5 - res & farm RDM - not public	kWh	H	472,030,410	476,120,562	486,058,050	526,192,123	516,001,059	481,639,228	508,429,817	504,032,554	509,435,858	510,836,084
Total Customer Served - month	Tab 5 - res & farm RDM - not public		I	608,741	605,207	602,129	599,356	597,084	594,959	593,701	593,665	592,395	49,371
Volume per customer		kWh	J(H/I)	775	787	807	878	864	810	856	849	860	862
Per customer at allowed rate	Calculated	$	K(F*J)	**$ 1.54**	**$ 1.56**	**$ 1.37**	**$ (0.89)**	**$ (0.13)**	**$ 1.31**	**$ (0.34)**	**$ 1.28**	**$ 1.18**	
Per customer at needed rate	Calculated	$	L(G*J)	**$ 3.47**	**$ 5.69**	**$ 3.03**	**$ (0.89)**	**$ (0.13)**	**$ 2.69**	**$ (0.34)**	**$ 4.94**	**$ 8.24**	

Residential & Farm: RDM Calculation

Usage & Customers	Row Identifier	Unit	2016 - Rate Case Test Year 2016 Test Year	2017 Actual 2017	2016 Actual 2016	2015 Actual 2015	2014 Actual 2014	2013 Actual 2013	2012 Actual 2012	2011 Actual 2011	2010 Actual 2010	2009 Actual 2009	2009 - Rate Case Test Year 2009 Baseline
9.01. Residential Service [Rate 101]	[A]	kWh	**419,223,106**	386,580,240	391,295,747	400,388,013	428,076,848	422,494,945	399,985,327	419,068,791	413,563,173	414,119,324	**415,946,048**
9.02. Residential Demand Control Service [Rate 241]	[B]	kWh	**53,408,585**	48,918,241	48,326,161	51,220,923	59,506,888	57,576,067	50,635,839	57,009,506	55,579,326	59,565,714	**59,818,306**
9.02. Residential Demand Control Service [Rate 241]	[C]	kW	**125,562**	106,787	90,566	102,208	135,148	129,020	117,461	126,473	134,284	126,257	**129,106**
9.03. Farm Service [Rate 361]	[D]	kWh	**34,696,538**	36,531,929	36,498,654	34,449,114	38,608,387	35,930,047	31,018,062	32,351,520	34,890,055	35,750,820	**35,071,730**
Total Volumes	[E = A+B+D]	kWh	**507,328,229**	472,030,410	476,120,562	486,058,050	526,192,123	516,001,059	481,639,228	508,429,817	504,032,554	509,435,858	510,836,084
Total Demand	[C]	kW	**125,562**	106,787	90,566	102,208	135,148	129,020	117,461	126,473	134,284	126,257	**129,106**
Total Customer Served - month	[F]	Customers	**604,829**	608,741	605,207	602,129	599,356	597,084	594,959	593,701	593,665	592,395	**49,371**

Rates		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
9.01. Residential Service: Volumetric	[H]	$/kWh	0.09064	0.09064	0.09064	0.08192	0.08192	0.08192	0.08192	0.08192	0.08192	0.07162	Varies by season
9.02. Residential Demand Control Service: Volumetric	[I]	$/kWh	0.06738	0.06738	0.06738	0.05058	0.05058	0.05058	0.05058	0.05058	0.05058	0.04263	Varies by season
9.02. Residential Demand Control Service: Demand	[J]	$/kW	8.00000	8.00000	8.00000	5.11000	5.11000	5.11000	5.11000	5.11000	5.11000	3.81000	Varies by season
9.03. Farm Service: Volumetric	[K]	$/kWh	0.08535	0.08535	0.08535	0.07873	0.07873	0.07873	0.07873	0.07873	0.07873	0.06832	Varies by season

Net Revenues Per Actual Billing Determinants		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
9.01. Residential Service: Volumetric	[L = A*H]	$	**40,464,394**	37,348,886	36,734,495	32,469,088	34,743,904	34,278,823	32,422,844	34,044,731	31,616,908	30,514,272	**33,822,408**
9.02. Residential Demand Control Service: Volumetric	[M = B*I]	$	**3,565,643**	3,265,497	2,855,614	2,551,720	2,970,049	2,871,368	2,519,865	2,840,568	2,511,719	2,574,649	**2,985,135**
9.02. Residential Demand Control Service: Demand	[N = C*J]	$	**1,004,496**	854,294	648,414	568,811	756,506	722,020	656,209	687,275	665,795	585,915	**700,420**
9.03. Farm Service: Volumetric	[O = D*K]	$	**3,151,200**	3,311,895	3,247,218	2,680,872	3,006,091	2,798,946	2,410,895	2,527,608	2,556,067	2,513,303	**2,742,578**
Calculated Gross Revenues	[P = L+M+N+O]	$	48,185,733	44,780,572	43,485,741	38,270,492	41,476,549	40,671,157	38,009,813	40,100,182	37,350,488	36,188,139	**40,250,541**
Adjustment for Conservation Improvement Program (CIP)	[Q = E*(-CIP Rate)]	$	-1,131,342	-811,892	-818,927	-836,020	-905,050	-887,522	-828,419	-526,610	-423,387	-422,793	**-878,638**
Adjustment for Energy Cost Recovery	[R = E*(-ECR Rate)]	$	-12,506,656	-11,414,258	-11,514,146	-11,258,563	-12,188,188	-11,952,133	-11,156,209	-11,776,760	-12,271,057	-13,098,105	**-11,832,496**
Actual Net Revenues	[S = P+Q+R]	$	34,547,736	32,554,422	31,152,668	26,175,910	28,383,311	27,831,503	26,025,184	27,796,812	24,656,043	22,667,241	**27,539,407**
		CIP rate:	0.00172	0.00172	0.00172	0.00172	0.00172	0.00172	0.00172	0.00172	0.00084	0.00084	0.00084
		ECR rate:	0.02464	0.02464	0.02464	0.02316	0.02316	0.02316	0.02316	0.02316	0.02316	0.02571	0.02571

Net Revenues Authorized Per Test Year Determinants		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
Test Year Revenue (per table inputs)	[S]	$	34,547,736	34,547,736	34,547,736	27,539,407	27,539,407	27,539,407	27,539,407	27,539,407	27,539,407	27,539,407	27,539,407
Test Year Customers	[T]	Customers	604,829	604,829	604,829	592,446	592,446	592,446	592,446	592,446	592,446	592,446	49,371
Test Year Revenue per Customer	[U = S/T]	$/Customer	685	685	685	558	558	558	558	558	558	558	558
Actual Customers	[V]		604,829	608,741	605,207	602,129	599,356	597,084	594,959	593,701	593,665	592,395	49,371
Authorized net revenue on a per customer basis	[W = U*V]	$	34,547,736	34,787,586	34,586,721	27,989,514	27,860,613	27,755,001	27,656,222	27,597,744	27,596,071	27,537,036	27,539,407

Actual Net Revenues & RDM Deferral		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
Actual Net Revenues	[S]	$	34,547,736	32,554,422	31,152,668	26,175,910	28,383,311	27,831,503	26,025,184	27,796,812	24,656,043	22,667,241	27,539,407
RDM Deferral [(-) is a refund, (+) is a collection from customer]	[X = W-S]	$	0	2,233,163	3,434,054	1,813,604	-522,698	-76,502	1,631,038	-199,068	2,940,028	4,869,795	0

RDM Adjustments		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
RDM deferral needed (refund)/collection	Y = X	$	0	2,233,163	3,434,054	1,813,604	-522,698	-76,502	1,631,038	-199,068	2,940,028	4,869,795	0
Projected Volumes:[1]	Z = e	kWh	0	498,503,774	475,098,024	483,573,678	516,158,605	518,548,825	490,229,686	501,732,170	505,131,870	508,085,032	0
Forecasted Net Revenues:[2]	BA = n	$	0	33,052,751	31,503,106	27,420,099	27,831,460	27,969,455	26,476,764	27,353,905	25,441,236	23,164,442	26,321,365
Cap on Customer RDM Surcharges	[BB = BA*(0.03)]	$	0	991,583	945,093	822,603	834,944	839,084	794,303	820,617	763,237	694,933	789,641
RDM deferral allowed[3]	[BC = min(Y,BB)]	$	0	991,583	945,093	822,603	-522,698	-76,502	794,303	-199,068	763,237	694,933	0
RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[4]	[BD = BA/BC]	%	#DIV/0!	3.00%	3.00%	3.00%	-1.88%	-0.27%	3.00%	-0.73%	3.00%	3.00%	0.00%
RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[4]	[BE = BC/(BA+Z*(CIP+ECR))]	%	#DIV/0!	2.15%	2.15%	2.09%	-1.29%	-0.19%	2.05%	-0.50%	2.03%	1.90%	0.00%

[1] Projected volumes during the RDM adjustment period [Z] is calculated as a weighted average of 9 months of the current year and 3 months of the subsequent year.

[2] Projected net revenues during the RDM adjustment period [BA] are calculated as a weighted average of 9 months in the current year and 3 months in the subsequent year.

[3] A positive RDM adjustment [BC] is a customer surcharge, a negative adjustment a customer refund.

[4] The RDM adjustment is computed as a percentage of volumetric and demand rates, and applied uniformly to all rates in the service basket.

General Service: RDM Calculation

Usage & Customers		Unit	2016 - Rate Case Test Year 2016 Test Year	2017 Actual 2017	2016 Actual 2016	2015 Actual 2015	2014 Actual 2014	2013 Actual 2013	2012 Actual 2012	2011 Actual 2011	2010 Actual 2010	2009 Actual 2009	2009 - Rate Case Test Year 2009 Baseline
10.01. Small General Service (Metered Secondary) [Rate 404]	[A]	kWh	**95,392,568**	92,526,330	91,872,171	91,795,074	93,937,626	94,274,382	87,563,421	81,149,380	84,184,168	75,886,177	**87,656,310**
10.01. Small General Service (Metered Primary) [Rate 405]	[B]	kWh	**47,794**	80,482	70,870	77,835	59,947	35,435	40,195	18,235	20,976	41,267	**46,912**
10.01. Small General Service (Non-Metered) [Rate 408]	[C]	kWh	**642,410**	540,888	550,128	556,824	611,747	620,100	619,536	612,486	615,457	0	**548,583**
10.02. General Service (Secondary) [Rate 401]	[D]	kWh	**202,399,404**	197,427,354	195,140,249	193,279,559	200,975,607	195,477,673	184,585,001	194,011,146	214,251,471	227,216,312	**219,670,926**
10.02. General Service (Secondary) [Rate 401]	[E]	kW	**1,074,489**	1,020,498	1,001,556	1,001,739	1,020,223	981,202	976,017	1,056,676	1,109,878	1,144,965	**956,180**
10.02. General Service (Secondary) [Facilities] 401 Facilities Charge	[F]	Annual kW	**1,460,814**	1,402,319	1,391,477	1,395,664	1,422,343	1,352,522	1,337,369	1,416,475	1,460,936	1,342,000	**1,335,798**
10.02. General Service (Primary) [Rate 403]	[G]	kWh	**3,136,829**	2,483,823	2,148,366	2,759,780	2,979,180	2,848,066	3,124,813	2,856,298	2,869,465	4,519,736	**3,675,132**
10.02. General Service (Primary) [Rate 403]	[H]	kW	**17,482**	14,109	15,175	13,929	17,257	16,722	15,049	14,609	18,152	17,045	**16,309**
10.02. General Service (Primary) [Facilities] 403 Facilities Charge	[I]	Annual kW	**30,503**	28,063	28,299	28,816	29,653	30,786	26,041	27,888	30,915	51,611	**43,618**
10.03. General Service-Time of Use (Declared Peak) [Rate 708]	[J]	kWh	**569,529**	690,729	696,394	130,283	1,904,004	1,104,027	455,330	102,779	249,056	310,825	**312,730**
10.03. General Service-Time of Use (Intermediate) [Rate 709]	[K]	kWh	**20,959,595**	21,971,247	22,999,134	24,195,612	20,566,766	21,628,175	18,782,762	14,134,750	13,146,212	13,171,499	**13,252,188**
10.03. General Service-Time of Use (Intermediate) [Rate 709]	[L]	kW	**108,843**	91,323	93,128	98,592	96,754	96,317	88,522	70,147	72,906	55,722	**53,031**
10.03. General Service-Time of Use (Off Peak) [Rate 710]	[M]	kWh	**17,647,921**	14,027,146	14,434,669	14,947,386	18,978,692	18,047,283	15,819,658	8,411,415	7,230,370	7,515,219	**7,561,258**
10.03. General Service-Time of Use [Facilities]	[N]	Annual kW	**12,994**	118,805	125,685	128,597	131,467	126,644	119,841	26,709	0	0	**102,431**
Total Volumes	[O = A+B+C+D+G+J+K+M]	kWh	340,796,050	329,747,999	327,911,981	327,742,353	340,013,569	334,035,141	310,990,716	301,296,489	322,567,175	328,661,035	332,724,039
Total Demand[1]	[P = E+H+L]	kW	1,200,814	1,125,931	1,109,858	1,114,259	1,134,234	1,094,241	1,079,588	1,141,432	1,200,937	1,217,731	1,025,520
Total Facilities Demand[2]	[Q = F+I+N]	Annual kW	1,504,311	1,549,187	1,545,460	1,553,077	1,583,463	1,509,952	1,483,251	1,471,071	1,491,851	1,393,611	1,481,847
Total Customers	[R]	Customers	128,057	129,759	128,580	127,476	126,647	126,117	125,402	124,459	124,931	124,646	10,407

Rates		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
10.01. Small General Service (Metered Secondary) [Rate 404]	[S]	$/kWh	0.08226	0.08226	0.08226	0.07784	0.07784	0.07784	0.07784	0.07784	0.07784	0.07413	Varies by season
10.01. Small General Service (Metered Primary) [Rate 405]	[T]	$/kWh	0.07861	0.07861	0.07861	0.07484	0.07484	0.07484	0.07484	0.07484	0.07484	0.07381	Varies by season
10.01. Small General Service (Non-Metered) [Rate 408]	[U]	$/kWh	0.08589	0.08589	0.08589	0.07715	0.07715	0.07715	0.07715	0.07715	0.07715	0.07490	Varies by season
10.02. General Service (Secondary) [Rate 401]	[V]	$/kWh	0.07860	0.07860	0.07860	0.07353	0.07353	0.07353	0.07353	0.07353	0.07353	0.07107	Varies by season
10.02. General Service (Secondary) [Rate 401]	[W]	$/kW	1.39000	1.39000	1.39000	1.02000	1.02000	1.02000	1.02000	1.02000	1.02000	0.00000	Varies by season
10.02. General Service (Secondary) [Facilities] 401 Facilities Charge	[X]	$/Annual kW	0.97000	0.97000	0.97000	0.60000	0.60000	0.60000	0.60000	0.60000	0.60000	0.45766	Varies by season
10.02. General Service (Primary) [Rate 403]	[Y]	$/kWh	0.07535	0.07535	0.07535	0.07090	0.07090	0.07090	0.07090	0.06820	0.07090	0.07075	Varies by season
10.02. General Service (Primary) [Rate 403]	[Z]	$/kW	1.89000	1.89000	1.89000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.00000	Varies by season
10.02. General Service (Primary) [Facilities] 403 Facilities Charge	[AA]	$/Annual kW	0.65000	0.65000	0.65000	0.40000	0.40000	0.40000	0.40000	0.40000	0.40000	0.30511	Varies by season
10.03. General Service-Time of Use (Declared Peak) [Rate 708]	[AB]	$/kWh	0.28109	0.28109	0.28109	0.21624	0.21624	0.21624	0.21624	0.16779	0.21624	0.17034	Varies by season
10.03. General Service-Time of Use (Intermediate) [Rate 709]	[AC]	$/kWh	0.06997	0.06997	0.06997	0.04703	0.04703	0.04703	0.04703	0.04352	0.04703	0.04607	Varies by season
10.03. General Service-Time of Use (Intermediate) [Rate 709]	[AD]	$/kW	2.67000	2.69000	2.69000	1.36000	1.36000	1.36000	1.36000	1.36000	1.36000	2.74222	Varies by season
10.03. General Service-Time of Use (Off Peak) [Rate 710]	[AE]	$/kWh	0.04676	0.04676	0.04676	0.03505	0.03505	0.03505	0.03505	0.01036	0.03505	0.01291	Varies by season
10.03. General Service-Time of Use [Facilities]	[AF]	$/Annual kW	0.97000	0.97000	0.97000	0.60000	0.60000	0.60000	0.60000	0.60000	0.00000	0.00000	Varies by season

Net Revenues Per Actual Billing Determinants		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
10.01. Small General Service (Metered Secondary): Volumetric [404]	[AG = A*S]	$	**8,426,257**	8,174,445	8,005,529	7,057,235	7,226,551	7,249,924	6,730,460	6,264,245	6,344,103	5,943,981	**6,770,227**
10.01. Small General Service (Metered Primary): Volumetric [405]	[AH = B*T}	$	**4,394**	7,145	6,226	5,766	4,417	2,603	2,952	1,345	1,543	3,264	**3,475**
10.01. Small General Service (Non-Metered): Volumetric [408]	[AI = C*U]	$	**55,177**	46,457	45,831	42,959	47,196	47,841	47,797	47,253	46,906	0	**42,325**
10.02. General Service (Secondary): Volumetric [401]	[AJ = D*V]	$	**15,669,687**	15,288,883	14,809,389	13,694,300	14,249,762	13,862,496	13,053,357	13,909,813	15,038,279	16,962,091	**15,766,400**
10.02. General Service (Secondary): Demand [401]	[AK = E*W]	$	**2,288,245**	2,160,415	2,020,957	1,087,344	1,107,716	1,065,191	1,061,498	1,148,735	738,967	0	**1,043,401**
10.02. General Service (Secondary): Facilities Demand [401 FC]	[AL = F*X]	$	**1,416,990**	1,360,250	1,199,343	837,399	853,406	811,513	802,421	849,885	790,268	614,184	**801,479**
10.02. General Service (Primary): Volumetric [403]	[AM = G*Y]	$	**232,090**	183,385	157,649	186,549	202,105	193,198	210,875	196,911	196,359	328,692	**256,623**
10.02. General Service (Primary): Demand [403]	[AN = H*Z]	$	**49,646**	42,051	40,954	14,801	18,271	17,743	15,958	15,381	12,849	0	**17,067**
10.02. General Service (Primary): Facilities Demand [403 FC]	[AO = I*AA]	$	**19,827**	18,241	16,307	11,527	11,861	12,314	10,416	11,155	11,223	15,747	**17,447**
10.03. General Service-Time of Use (Declared Peak): Volumetric [708]	[AP = J*AB]	$	**182,313**	249,576	337,954	26,435	395,406	213,877	51,987	21,469	43,675	52,960	**67,613**
10.03. General Service-Time of Use (Intermediate): Volumetric [709]	[AQ = K*AC]	$	**1,462,440**	1,532,667	1,447,981	1,195,031	1,014,201	1,067,776	925,945	683,409	632,338	620,919	**642,161**
10.03. General Service-Time of Use (Intermediate): Demand [709]	[AR = L*AD]	$	**292,039**	245,024	215,389	177,912	171,906	173,217	158,831	122,069	172,112	158,253	**103,267**
10.03. General Service-Time of Use (Off Peak): Volumetric [710]	[AS = M*AE]	$	**777,758**	619,314	587,115	436,127	551,732	524,598	461,416	268,468	157,738	91,840	**239,159**
10.03. General Service-Time of Use: Facilities Demand	[AT = N*AF]	$	**12,604**	115,241	108,207	77,158	78,880	75,986	71,904	16,025	0	0	**61,458**
Calculated Gross Revenues	[AU = sum(AG:AT)]	$	30,889,466	30,043,093	28,998,830	24,850,542	25,933,410	25,318,276	23,605,820	23,556,163	24,186,358	24,791,932	25,832,102
Adjustment for Conservation Improvement Program (CIP)	[AV = O*(-CIP Rate)]	$	-759,975	-567,167	-564,009	-563,717	-584,823	-574,540	-534,904	-319,225	-270,956	-273,416	-572,285
Adjustment for Energy Cost Recovery	[AW = O*(-ECR rate)]	$	-8,401,304	-7,992,594	-7,950,500	-7,591,496	-7,875,734	-7,737,256	-7,203,478	-6,978,931	-7,830,211	-8,450,204	-7,706,887
Calculated (Actual) Net Revenues	[AX = AU+AV+AW]	$	21,728,187	21,483,333	20,484,321	16,695,329	17,472,852	17,006,480	15,867,438	16,258,008	16,085,190	16,068,312	17,552,930
		CIP rate:	**0.00172**	**0.00172**	**0.00172**	**0.00172**	**0.00172**	**0.00172**	**0.00172**	**0.00172**	**0.00084**	**0.00084**	
		ECR rate:	**0.02464**	**0.02464**	**0.02464**	**0.023163**	**0.023163**	**0.023163**	**0.023163**	**0.023163**	**0.023163**	**0.025711**	

Net Revenues Authorized Per Test Year Determinants		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
Test Year Revenue	[AX]	$	21,728,187	21,728,187	21,728,187	17,552,930	17,552,930	17,552,930	17,552,930	17,552,930	17,552,930	17,552,930	17,552,930
Test Year Customers	[R]	Customers	128,057	128,057	128,057	124,889	124,889	124,889	124,889	124,889	124,889	124,889	10,407
Test Year Revenues per Customer	[AY = AX/R]	$/Customer	170	2,036	2,036	1,687	1,687	1,687	1,687	1,687	1,686.58	140.55	1,687
Actual Customers	[AZ]		128,057	129,759	128,580	127,476	126,647	126,117	125,402	124,459	124,931.00	124,646	10,407
Authorized net revenue on a per customer basis	[BA = AY*AZ]	$	21,728,187	22,024,890	21,825,504	17,916,528	17,800,014	17,725,523	17,625,031	17,492,494	17,558,833	17,518,777	17,552,930

Actual Net Revenues & RDM Deferral		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
Actual Net Revenues	[AX]	$	21,728,187	21,483,333	20,484,321	16,695,329	17,472,852	17,006,480	15,867,438	16,258,008	16,085,190	16,068,312	17,552,930
RDM Deferral [(-) is a refund, (+) is a collection from customer]	[BB = BA-AX]	$	0	541,557	1,341,182	1,221,199	327,161	719,043	1,757,593	1,234,486	1,473,642	1,450,465	0

RDM Adjustments		Unit	2016 Test Year	2017	2016	2015	2014	2013	2012	2011	2010	2009	2009 Baseline
RDM deferral needed (refund)/collection	[BC]	$	0	541,557	1,341,182	1,221,199	327,161	719,043	1,757,593	1,234,486	1,473,642	1,450,465	0
Projected Volumes [3]	[BD]	kWh	0	326,801,503	328,370,986	327,784,760	336,945,765	335,529,748	316,751,822	303,720,046	317,249,504	327,137,570	257,853,263
Forecasted Net Revenues[4]	[BE]	$	0	21,500,049	20,734,074	17,642,577	17,278,472	17,123,073	16,152,198	16,160,365	16,128,395	16,072,531	17,181,775
Cap on Customer RDM Surcharges	[BF = BE*(0.03)]	$	0	645,001	622,022	529,277	518,354	513,692	484,566	484,811	483,852	482,176	515,453
RDM deferral allowed[5]	[BG = min(BC,BF)]	$	0	541,557	622,022	529,277	327,161	513,692	484,566	484,811	483,852	482,176	0
RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[6]	[BH = BE/BG]	%	0.00%	2.52%	3.00%	3.00%	1.89%	3.00%	3.00%	3.00%	3.00%	3.00%	0.00%
RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[6]	[BI = BG/(BE+BD*(CIP+ECR))]	%	0.00%	1.80%	2.12%	2.05%	1.27%	2.02%	2.02%	2.04%	2.04%	1.95%	0.00%

[1] Billing demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use).

[2] Facilities charge demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use).

[3] Projected volumes during the RDM adjustment period [BW] are calculated as a weighted average of the current year and subsequent year.

[4] Projected net revenues during the RDM adjustment period [BX] are calculated as a weighted average of the current year and subsequent year.

[5] A positive positive RDM adjustment [BZ] is a customer surcharge, a negative adjustment a customer refund.

[6] The RDM adjustment is computed as a percentage of volumetric, demand and facilities demand rates, and applied uniformly to all rates

Direct Testimony and Schedules
Daniel G. Hansen

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-13-868
Exhibit___(DGH-1)

Decoupling

November 4, 2013

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE AS IT RELATES TO DECOUPLING.

A. I have a Ph.D. in Economics from Michigan State University and I have worked as a consultant in the energy industry since 1997. I have conducted independent evaluations of revenue decoupling mechanisms that were implemented at Portland General Electric, New Jersey Natural Gas, South Jersey Gas, and Northwest Natural Gas. I have testified on issues related to revenue decoupling in Arizona, Connecticut, Nevada, Oregon, and Utah. I participated in a panel discussion on revenue decoupling before the Massachusetts Department of Public Utilities. In my work on revenue decoupling, my clients have included a regulator, an environmental organization, a non-profit organization of utility investors, and an investor-owned utility. A summary of my qualifications is provided as Exhibit__(DGH-1) Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony describes and supports the Company's proposed revenue decoupling mechanism. Section II describes the relevance of revenue decoupling for the Company as it pursues its conservation goals. Section III describes the revenue decoupling mechanism and addresses each of the revenue decoupling criteria and standards established in Docket No. E,G-999/CI-08-132. Section IV provides concluding remarks.

II. THE PURPOSE AND BENEFIT OF REVENUE DECOUPLING

Q. IS THE COMPANY PROPOSING TO IMPLEMENT A MECHANISM THAT CHANGES THE WAY IN WHICH IT RECOVERS REVENUE TOWARD FIXED COSTS?

A. Yes. The Company is proposing to implement a partial revenue decoupling mechanism ("RDM") for its residential customers and a subset of its small commercial and industrial ("C&I") customers (*i.e.*, those that do not pay a demand charge). I refer to the proposal as a partial RDM because it excludes weather effects. The details of the proposed RDM are presented in Section III.

Q. WHAT IS THE PURPOSE OF THE PROPOSED RDM?

A. Because the Company recovers most of its fixed costs through volumetric rates (*i.e.*, energy charges), the Company has a financial incentive to maintain or increase its sales to recover those costs. The proposed RDM is intended to remove the Company's financial disincentive to promote conservation and energy efficiency that exists because of this. By eliminating the link between sales and revenues, the Company's proposed RDM will better align the

Company's shareholder interests with the public policy goals of conservation and energy efficiency.

Q. HOW DO YOU DEFINE "FIXED COSTS" FOR PURPOSES OF THIS DISCUSSION?

A. Fixed costs are those that do not change with the level of customer usage, at least in the short run. For example, the costs associated with a utility's distribution system are fixed because they do not change when customers conserve energy by installing more efficient lighting or purchasing more efficient appliances.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW THE CURRENT RATE STRUCTURES GIVE THE COMPANY A DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY.

A. The recovery of fixed costs through energy charges creates a link between the Company's net revenues and customer sales. When a utility's customers use more energy (*i.e.*, when sales increase), revenues increase. Conversely, when a utility's customers use less energy, there is a decrease in utility revenue toward fixed costs without a corresponding decrease in utility costs. Therefore, a traditional utility ratemaking structure inherently motivates a utility to increase its sales to ensure recovery of its fixed costs and maximize revenues. As such, the traditional ratemaking model creates a disincentive for utilities to fully promote conservation or energy efficiency. The proposed RDM will eliminate this disincentive with respect to the customer classes to which it applies.

Q. HOW DOES THE PROPOSED RDM ADDRESS THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?

A. With the RDM in place, the lost revenue associated with customer usage reductions are placed in a deferral account for recovery in the following year through an increase in the energy rate. Because the utility is "made whole" for the decreased revenues due to conservation, it is indifferent toward customer conservation, absent a consideration of the time cost of money or regulatory uncertainty associated with the utility's ability to recover deferrals.

Q. DOES THE RDM AFFECT THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. No. With the RDM in place, a customer who is evaluating whether to engage in a conservation activity can expect an immediate benefit that is the same as it would have obtained under standard rates. That is, the customer can expect a bill reduction in the amount of the full volumetric rate, including all riders and fees, multiplied by the amount of saved energy (*i.e.*, kWh). The portion of this bill reduction that is associated with fixed-cost recovery is then placed in the RDM deferral account for the utility to recover in the following year. Because each residential or small C&I customer uses a very small percentage of the total group-level usage, a conserving customer pays back essentially none of its own lost revenues. Therefore, a customer's decision to conserve should not be affected by the presence of the RDM because the customer cannot conserve enough energy to affect the rate it pays in the following year.

Q. HAVE OTHER REGULATORS ACKNOWLEDGED THAT RDMS DO NOT AFFECT THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE?

A. Yes. The Oregon Public Utility Commission concluded the following in Order No. 09-020 for Docket UE-197, which approved an RDM referred to as the Sales Normalization Adjustment, or SNA, for Portland General Electric.

> Staff also argues that the SNA would create a disincentive for customers to improve their energy efficiency because the SNA would increase rates and reduce the bill savings. We believe that the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling 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. (page 28)

Q. IS THERE A TREND TOWARDS DECOUPLING IN THE GAS AND ELECTRIC UTILITY INDUSTRIES?

A. Yes. Decoupling has become more prevalent in recent years for both gas and electric utilities. One study reports that between May 2009 and May 2013, decoupling increased from 28 to 50 local natural gas distribution utilities and from 12 to 27 electric utilities.[1]

Q. HAVE YOU EXAMINED DECOUPLING MECHANISMS OF OTHER ELECTRIC UTILITIES?

A. Yes. I have found twenty-five electric utilities that currently have an RDM in place, located in twelve states and the District of Columbia. They are listed in Exhibit__(DGH-1), Schedule 2, along with some information about the design of the mechanism.[2] The "RPCD" column indicates whether the RDM uses a revenue per-customer design to determine allowed revenues. Where "no" is indicated, the utility trues up revenues to a pre-specified total revenue amount. For all but one utility, United Illuminating, the revenue amount

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[1] *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations,* Pamela Morgan, Graceful Systems LLC (Dec. 2012) at pp. 2-3.
[2] The list of decoupled utilities was developed using the previously cited Morgan study and the following study: *State Electric Efficiency Regulatory Frameworks*, Institute for Electric Efficiency, July 2013.

changes over time according to a schedule determined at the time the RDM was approved.

The "Include Weather Effects" column indicates whether the effects of changing weather conditions on customer sales, and therefore utility revenue, are included in the RDM deferrals. The "EE Performance Incentives" column indicates whether the utility has a separate energy efficiency incentive program in place in addition to its RDM. The "Cap on Deferral" column indicates whether the RDM rate adjustments are capped at a certain percentage or level. The "Cap Level" column contains the amount of the cap, if applicable. The "Soft or Hard Cap" column indicates whether deferrals in excess of the cap amount are carried over into subsequent periods, a "soft" cap; or lost forever, a "hard" cap.

Q. IN RECENT YEARS, THE COMPANY HAS PERFORMED WELL RELATIVE TO ITS ENERGY EFFICIENCY TARGETS. GIVEN THAT PERFORMANCE, WHAT IS THE VALUE OF THE PROPOSED RDM?

A. Though the Company has been effective in successfully implementing its DSM programs without a RDM, changing circumstances will make it more important that all regulatory barriers to the utility's promotion of conservation and energy efficiency are removed.

Q. WHAT ARE SOME OF THESE CHANGING CIRCUMSTANCES THAT DRIVE THE NEED FOR A RDM?

A. As the Company indicates in its 2013-2015 Triennial Plan for its Minnesota Electric and Natural Gas Conservation Improvement Program[3] (the

3 Filed June 1, 2012 under Docket No. E,G002 / CIP-12-447

"Triennial Plan"), several challenges have arisen that affect the Company's ability to meet its conservation goals. First, the decline in natural gas prices has reduced the economic benefits associated with pursuing electric conservation, yet the costs to administer these programs have typically increased as the Company has pursued harder-to-reach customers and savings opportunities. The savings opportunities the Company is adding to its portfolio to reach goals can have longer payback periods for customers, making these programs less attractive, which affects participation and overall achievement. In addition, the reduction in avoided costs reduces the cost effectiveness of some programs, putting into question the inclusion of certain measures and programs over the long-term. (Triennial Plan, pps 1-2.)

Second, higher lighting efficiency baselines will make it difficult for the Company to deliver significant and cost-effective energy savings through efficient lighting programs. (Triennial Plan, pg 2.) The 2007 Energy Independence and Security Act increased the minimum efficiency for 45W-100W incandescent light bulbs by 30 percent phased in starting in 2012. As a result, the residential lighting program will no longer deliver the same significant incremental energy savings due to the new baseline/energy standard. In addition, utilities will be further challenged due to the increase in commercial lighting efficiency standards. In a 2009 rulemaking, the Department of Energy increased commercial lighting standards from T12 fluorescent lamps as the baseline to the more efficient T8 lamps. This took effect in 2012.

Third, the Company has been experiencing reductions in residential and small commercial use per customer in recent years, a trend that is expected to continue according to the Company's forecast. In the absence of a decoupling mechanism, this places downward pressure on utility revenues over time. This, coupled with the reality that opportunities for further cost-effective energy efficiency decrease as customers become more efficient, will drive a need for more of the Company's focus on conservation and energy efficiency to stay effective in the market.

While the Company has thus far been willing to promote its DSM programs as effectively as it can in order to meet energy efficiency goals, the financial pressures associated with a less favorable market for energy efficiency due to lower avoided costs, more strict energy efficiency standards, and declining use per customer increase the importance of removing the Company's financial disincentives to promoting conservation and energy efficiency.

Q. WHAT CONSERVATION AND ENERGY EFFICIENCY BENEFITS MAY OCCUR BECAUSE OF THE IMPLEMENTATION OF THE RDM?

A. Most importantly, I expect that the RDM will allow the Company to continue supporting an aggressive energy efficiency portfolio after incorporating consideration for the changing circumstances in the market. As I described earlier, continuing to achieve energy efficiency at the Company's current level will become increasingly challenging in the coming years.

III. ADDRESSING THE REVENUE DECOUPLING CRITERIA AND STANDARDS

Q. IS THE COMPANY'S DECOUPLING PROPOSAL CONSISTENT WITH THE REVENUE DECOUPLING CRITERIA AND STANDARDS THAT THE MINNESOTA PUBLIC UTILITIES COMMISSION ESTABLISHED FOR PILOT PROGRAMS IN DOCKET NO. E,G-999/CI-08-132?

A. Yes. I will address each of the eight criteria contained in the Standards, which are attached as Exhibit__(DGH-1), Schedule 3.

1. Criterion 1

Q. WHAT IS THE PURPOSE OF THE COMPANY'S RDM AND HOW WILL IT FURTHER THE STATE POLICY OF INCREASED CONSERVATION INVESTMENT?

A. The goal of the RDM is to remove the Company's disincentive to promote conservation and energy efficiency for its residential and non-demand small C&I customers. I discussed the relevance of RDM to the Company's pursuit of its conservation goals in detail in Section II.

2. Criterion 2

Q. PLEASE DESCRIBE THE FORM OF THE PROPOSED REVENUE DECOUPLING MECHANISM, INCLUDING THE TYPES OF SALES CHANGES THAT ARE INCLUDED IN THE MECHANISM.

A. The Company proposes to implement a revenue-per-customer decoupling ("RPCD") mechanism that removes the effect of weather from the decoupling deferrals. The Company's RDM model and proposed tariff are attached as Exhibit__(DGH-1), Schedule 4 and Exhibit__(DGH-1), Schedule 5 respectively. In his direct testimony, Company witness Steven V. Huso provides the class-by-class shares of the overall test year revenue requirement. As explained by Mr. Huso, a portion of the non-fuel revenue requirement is recovered through a fixed "customer charge" while the remaining revenue requirement is recovered through the volumetric energy charge for the residential and small C&I classes. The revenue requirement recovered through the non-fuel energy charge, on a per-customer basis, is the revenue baseline for calculating the decoupling deferrals as described in the formula below. Each month, the RDM deferral will be calculated as the difference between the monthly baseline revenue and the weather-normalized revenue collected under the volumetric rates from those customers.

Specifically, the RPCD mechanism will calculate monthly deferrals as follows:

Equation 1: $Deferral_{c,t} = (FRC_c \text{ x } C_{c,t}) - (FEC_c \text{ x } kWh_{c,t}^{Billed,WN})$

where

$Deferral_{c,t}$ is the RDM deferral for customer group *c* in month *t*;

FRC_c is the fixed revenue per customer for customer group *c*;

$C_{c,t}$ is the number of customers in customer group *c* during month *t*;

FEC_c is the non-fuel energy rate for customer group *c*, expressed in $/kWh; and

$kWh_{c,t}^{Billed,WN}$ is the weather-normalized billed sales to customer group *c* in month *t*.

The RDM will apply to three customer groups: residential non-space heating,[4] residential space heating,[5] and small C&I customers that do not pay a demand charge.[6] Every twelve months, the cumulative deferral for each customer group will be incorporated into customer rates for the following year by

[4] This includes customers served on rate codes A01, A02, A03, A04, A05, and A06.
[5] This includes customers served on rate codes A00, A01, A02, A03, A04, A05, and A06.
[6] This includes customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22.

dividing the deferral amount by the forecast of sales to the customer group. A positive cumulative deferral will result in a rate increase. A negative cumulative deferral will result in a rate decrease. Sales changes from all sources except weather will be included in the RDM deferrals.

Q. HAS THIS RDM DESIGN BEEN USED BY OTHER ELECTRIC UTILITIES?

A. Yes. The design matches the RDM used by Idaho Power and Portland General Electric. Similar RPCD mechanisms have been implemented in Maryland, Ohio, Washington, Wisconsin, and the District of Columbia.

Q. HOW WILL THE PARAMETERS IN THE RDM BE CALCULATED?

A. $kWh_{c,t}^{Billed,WN}$ will be calculated as billed sales to customer group c in month t, adjusted to account for deviations from normal weather conditions. Sales will be weather normalized using the same methods used to develop test year sales, as described in Section VI and Section X of the testimony of Company witness Jannell E. Marks and in Information Request No. 18 in the October 3, 2013 pre-filing of sales forecast information. $C_{c,t}$ is the number of customers billed in customer group c during month t.

FRC_c and FEC_c are calculated for each month of the test year, using test year revenues, numbers of customers, and sales. FRC_c is calculated as the fixed-cost revenue requirement (described below) divided by the number of customers forecast for each month in the 2015 test year[7]. FEC_c is calculated as the fixed-cost revenue requirement (described below) divided by the sales forecast for each month of the 2015 test year. The use of month-specific

7 As described in more detail by Ms. Heuer, the 2015 revenue requirement is calculated using 2014 sales. Present and proposed 2015 revenues are therefore based on the application of present rates and proposed 2015 rates to the 2014 test year budgeted sales and customers supported by Ms. Marks.

values, rather than a single value that is constant across months, for these parameters helps minimize month-to-month deferrals.

Q. DOES THE EXCLUSION OF WEATHER EFFECTS FROM THE RDM RATE ADJUSTMENTS AFFECT THE ABILITY OF THE MECHANISM TO REMOVE THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?

A. No. Because weather conditions are outside of the Company's control, retaining the variability in revenues toward fixed costs that is caused by deviations from normal weather conditions does not change the Company's incentive to promote conservation and energy efficiency. If the Company engages in activities that reduce applicable customer usage levels, the proposed RDM will make the Company whole for the lost revenues associated with the recovery of fixed costs through volumetric rates.

Q. HOW IS THE TOTAL FIXED-REVENUE AMOUNT CALCULATED?

A. It is calculated using the test year energy charges, less the CIP component, multiplied by test year sales for the corresponding customers. Separate values are calculated for each month of the test year. The calculations are conducted at the rate code level, with revenues aggregated up to the customer group level for purposes of the FRC_c and FEC_c calculations. Customer charge revenue is excluded from the RDM because it is already decoupled from customer sales. Schedule 4 contains the calculations of FRC_c and FEC_c using the 2015 test year, as well as a forecast of RDM deferrals for 2015 and 2016.

Q. HAS THE COMPANY PERFORMED ANY SENSITIVITY ANALYSES ON THE RDM CALCULATIONS?

A. Yes, the Company analyzed the impact of changing sales and customer counts on the RDM rates. Exhibit__(DGH-1), Schedule 6 contains the Company's sensitivity analysis using two scenarios: (1) a three percent decrease in sales holding the number of customers constant; and (2) a two percent decrease in the number of customers holding use per customer constant. Note that no RDM deferral is produced in the latter scenario because use per customer has not changed.

3. Criterion 3

Q. HOW, IF AT ALL, WILL THE PROPOSED DECOUPLING MECHANISM AFFECT THE COMPANY'S COST OF CAPITAL?

A. Company witness Robert B. Hevert addresses this issue in his direct testimony.

4. Criterion 4

Q. WHICH CUSTOMER CLASSES WILL BE INCLUDED IN THE DECOUPLING MECHANISM AND WHY?

A. As described earlier, the RDM will apply to all residential customers and small C&I customers that do not pay a demand charge. The RDM focuses on the customers with the largest share of fixed costs recovered through volumetric rates. Exhibit__(DGH-1), Schedule 7, which contains information provided in the Company's September 19, 2013 compliance filing for Docket No. E002/GR-12-961, shows that for residential and C&I non-demand customers, 85 percent of base revenue is recovered through the energy charge. For the customers not eligible for the RDM, which consist largely of C&I customers who pay demand charges, 52 percent of base revenue is recovered through the energy charge. Note that, for these customers, we have included revenue from demand charges as non-volumetric revenue.

The Company has excluded larger C&I customers from the RDM because the sales of this customer group tend to be more volatile and the class revenue per customer is more sensitive to a single large customer leaving the system. Also, revenue decoupling will be a new regulatory structure for the Company and limiting its application is a more conservative approach of implementing the mechanism.

5. Criterion 5A

Q. HOW WILL DECOUPLING ADJUSTMENTS BE CALCULATED?

A. Separate adjustments will be calculated for the residential non-space heating, residential space heating, and small C&I non-demand customer groups. For each group, the monthly deferral amounts will be calculated according to Equation 1 above. The Company does not propose to apply a carrying charge on deferrals. At the end of a 12-month period, the total deferral for each customer group will be divided by the forecast of sales to that group for the coming year. The resulting charge will be added to or subtracted from the customer group's volumetric rate for the following 12 months. The forecast of sales will be developed using the methods described in the testimony of Ms. Marks.

6. Criterion 5B

Q. WHEN WILL DECOUPLING-INDUCED RATE ADJUSTMENTS BE MADE?

A. RDM rate adjustments will be made once per year and remain in effect for 12 months. The Company proposes to begin calculating deferrals in the month after the Commission's final Order in this proceeding. The RDM deferrals will be calculated each month through December, after which the RDM rate adjustment will be calculated and put into effect on April 1 for the following 12 months. The RDM rate adjustment will include deferrals for January through December. However, the first year of the RDM adjustment may include less than 12 monthly deferrals due to implementation timing.

7. Criterion 5C

Q. WILL THE DECOUPLING-INDUCED RATE ADJUSTMENTS BE SUBJECT TO A CAP OR COLLAR ?

A. If the rate adjustment produces a rate increase that is more than five percent of total customer group revenue, including fuel and all applicable riders, the excess deferral amount above the five percent will be carried over to the RDM deferral account in the following year. There will be no limit on the rate reduction that the RDM rate adjustment produces.

Q. IS IT COMMON FOR DEFERRALS IN EXCESS OF THE CAP TO BE CARRIED OVER INTO SUBSEQUENT YEARS?

A. Yes. As my survey of electric RDMs shows in Exhibit__(DGH-1), Schedule 2, 10 out of the 12 utilities with caps on deferrals allow the excess to be carried over into the subsequent year. The RDMs in place at the remaining 13 utilities do not place a cap on the RDM rate adjustment.

8. Criterion 5D

Q. WHICH PORTION OF THE CUSTOMER'S BILL WILL BE AFFECTED BY THE DECOUPLING-INDUCED RATE ADJUSTMENTS?

A. The decoupling deferrals will affect the energy charge in the following year. The deferral could cause the energy charge to increase or decrease.

9. Criterion 5E

Q. HOW WILL THE DECOUPLING-INDUCED RATE ADJUSTMENT BE DISPLAYED ON THE CUSTOMER'S BILL?

A. The RDM rate adjustment will be listed as a separate line item on the customer's bill.

10. Criterion 5F

Q. HOW LONG WILL THE DECOUPLING MECHANISM BE IN PLACE?

A. The Company is proposing to implement the decoupling mechanism as an ongoing program. According to the Order, the mechanism is not eligible for pilot program status, as all pilot proposals needed to be filed by December 30, 2011.

11. Criterion 5G

Q. HOW WILL THE DECOUPLING MECHANISM WORK IN CONCERT WITH THE COMPANY'S AUTOMATIC RECOVERY MECHANISMS AND FINANCIAL INCENTIVES?

A. The Company's proposed RDM is compatible with all of its automatic recovery mechanisms and financial incentives. The RDM only includes revenue from base energy charges, excluding the Conservation Cost Recovery Charge (CCRC) component. Therefore, the RDM does not affect the way in which the Company's current riders function. In addition, the RDM is compatible with the Company's existing shared savings demand-side management ("DSM") financial incentive model. That is, the RDM has the effect of minimizing any disincentive to promote conservation and energy efficiency that is caused by the recovery of fixed costs through volumetric rates. Notably, the RDM does not provide the utility with an *incentive* to promote conservation or energy efficiency. Rather, the RDM renders the utility indifferent to the usage levels of the applicable customers. It is therefore appropriate and compatible to provide the utility with a separate incentive to promote conservation and energy efficiency through mechanisms such as the DSM financial incentive model.

Q. ARE THERE ANY OTHER ELECTRIC UTILITIES THAT HAVE BOTH A RDM AND AN ENERGY EFFICIENCY INCENTIVE MECHANISM?

A. Yes. As shown in Exhibit__(DGH-1), Schedule 2, many decoupled electric utilities also have incentives associated with meeting or exceeding energy efficiency goals, including utilities in California, Connecticut, Massachusetts, New York, Ohio, and Rhode Island.

12. Criterion 6

Q. DOES THE COMPANY'S DECOUPLING PROPOSAL RAISE ANY CONCERNS REGARDING SERVICE QUALITY?

A. No. The Company is already subject to under-performance penalties across a range of service quality measures, including customer complaints, telephone response time, System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and invoicing accuracy. The service quality performance goals and penalties are described in

Section 1.9 of the General Rules and Regulations within Xcel Energy's Minnesota Electric Rate Book.

Even in the absence of the existing penalties, the proposed RDM would not introduce a disincentive for the Company to continue providing high quality customer service. A RDM would only serve as a disincentive if customers were likely to use less electricity in response to receiving poor customer service from the utility, for which the utility would subsequently be "made whole" through the RDM. It is unlikely that customers would respond in that manner to service quality problems.

With respect to service outages, the RDM has only a minor effect on utility revenue. Specifically, the lost sales caused by the service outage reduce utility revenues, but under the RDM those lost revenues, which are limited to the fixed-cost recovery component, would be recovered for the utility through the RDM rate adjustment. However, the effect on the RDM deferral from delaying a response to service outages would be trivial compared to the existing SAIDI- and SAIFI-based penalties and the liability to which utility may be exposed.

13. Criterion 7

Q. HOW DOES THE COMPANY PROPOSE TO EVALUATE THE DECOUPLING MECHANISM OVER TIME?

A. The Company will provide an annual report based on the items that were required for pilot programs related to the performance of the RDM. The Company proposes to include the following items in an annual report: (1) total over or under collection of allowed revenues by class; (2) total collection of prior deferred revenue; (3) calculations of the RDM deferral amounts; (4) the number of customer complaints; (5) the amount of revenues stabilized and how the stabilization impacted the Company's overall risk profile; and (6) a comparison of how revenues under traditional regulation would have differed from those collected under the decoupling proposal. The Company proposes to continue reporting the details of our conservation program results, including how the RDM influenced the achievement of those goals, in our annual status reports in Docket No. E,G002/CIP-09-198.

14. Criterion 8

Q. THE FINAL CRITERION INCLUDED IN THE ORDER RELATES TO PILOT PROGRAM IMPLEMENTATION. EVEN THOUGH THE COMPANY IS PROPOSING AN ONGOING PROGRAM AND NOT A PILOT PROGRAM, ARE THERE ANY RELEVANT ISSUES TO CONSIDER?

A. Yes. As prescribed, the decoupling mechanism is being implemented as part of a rate case. In addition, more than one customer class is included in the decoupling proposal.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission adopt the Company's proposal to implement a revenue decoupling mechanism for its residential and small C&I customers that do not pay a demand charge. The mechanism will help ensure that the Company continues to perform well in its promotion of energy efficiency. The design of the mechanism has been implemented, and subsequently renewed, in other electric jurisdictions and the proposal meets all of the requirements contained in the Revenue Decoupling Criteria and Standards the Commission established in Docket No. E,G-999/CI-08-132.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Daniel G. Hansen

RESUME

September 2013

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Academic Background:

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding a the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

Utility	State	RPCD?	Include Weather Effects?	EE Performance Incentives?	Cap on Deferral	Cap Level	Soft or Hard Cap?
PG&E	California	No	Yes	Yes	No	n/a	n/a
SCE	California	No	Yes	Yes	No	n/a	n/a
SDG&E	California	No	Yes	Yes	No	n/a	n/a
United Illuminating	Connecticut	No	Yes	Yes	No	n/a	n/a
PEPCO	District of Columbia	Yes	Yes	No	Yes	10% of base rate	Soft
Hawaii Electric	Hawaii	No	Yes	Yes	No	n/a	n/a
Idaho Power	Idaho	Yes	No	No	No	n/a	n/a
Delmarva	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
PEPCO	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
Baltimore Gas & Electric	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
Fitchburg Gas & Electric	Massachusetts	No	Yes	Yes	Yes	1% of total rev.	Soft
Western Mass. Elec.	Massachusetts	No	Yes	Yes	Yes	1% of total rev.	Soft
Mass. Elec. and Nantucket	Massachusetts	No	Yes	Yes	Yes	3% of total rev.	Soft
Central Hudson	New York	No	Yes	Yes	No	n/a	n/a
Consolidated Edison	New York	No	Yes	Yes	No	n/a	n/a
NYSEG	New York	No	Yes	Yes	No	n/a	n/a
Niagara Mohawk	New York	No	Yes	Yes	No	n/a	n/a
Orange & Rockland	New York	No	Yes	Yes	No	n/a	n/a
Rochester Gas & Elec.	New York	No	Yes	Yes	No	n/a	n/a
American Electric Power	Ohio	Yes	Yes	Yes	Yes	3% of dist. rev.	Soft
Duke Energy Ohio	Ohio	Yes	No	Yes	Yes	3% of dist. rev.	Soft
Portland General Electric	Oregon	Yes	No	No	Yes	2% of total bill	Hard
Narragansett Electric	Rhode Island	No	Yes	Yes	No	n/a	n/a
Puget Sound Energy	Washington	Yes	Yes	No	Yes	3% of rates	Soft
Wisconsin Public Service	Wisconsin	Yes	Yes	No	Yes	$14 mill.	Hard
	# Yes	10	22	17	12		

Revenue Decoupling Criteria and Standards adopted by the Minnesota Public Utilities Commission in Docket No. E, G-999/CI-08-132

Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling, dated June 19, 2009 beginning at page 7.

All utility decoupling pilot proposals under Minn. Stat. 216B.2412 shall provide the following information in the initial filing:

1. Purpose: All utilities shall state how their proposed decoupling mechanism adheres to the guiding statute. Each utility shall explain the purpose of their mechanism in the context of the Next Generation Energy Act of 2007's energy savings goals and how their mechanism will further the state policy of increased conservation investment.
2. Form: All utilities shall state the form of decoupling proposed and the purpose behind such choice. This should provide a detailed definition of what types of sales changes are included in the mechanism, i.e. weather-related sales changes, declining use per customer, etc., and the reason for such inclusion.
3. Cost of Capital: All utilities shall detail how their proposed mechanism will/will not impact the company's cost of capital.
4. Classes Included: All utilities must identify the rate classes involved in the pilot, as well as provide rationale for the inclusion of participating classes and the exclusion, if any, of other classes.
5. Mechanics: All utilities must provide precise detail on how the decoupling mechanism will operate, with the understanding that any decoupling pilot program be transparent and easy to follow from a customer perspective. Details to be provided are as follows:
    - A. how rate adjustments will be calculated;
    - B. when rate adjustments will be made;
    - C. whether a rate cap or collar is provided to mitigate the risk of rate shock and justification for not so providing if a proposal lacks such safeguards;
    - D. what portion of the customer's bill will be impacted by the true-up (volumetric vs. customer charge);
    - E. how will the rate adjustment be displayed on the customer's bill;

    F. length of pilot (with the understanding that no pilot may extend longer than 36 months except through implementation in a rate case);
    G. how the decoupling mechanism will work in concert with any automatic recovery mechanism or financial incentive; this evaluation requires that all utilities provide a list of all automatic recovery mechanisms and incentives as well as justification for any such mechanism/incentive that the utility plans to continue throughout the course of the pilot including an explanation as to how the decoupling pilot mechanism, coupled with any other automatic adjustments and incentives, will not result in double recovery.
6. Service Quality: All utilities must provide detail, consistent with other service quality documentation, on how the utility plans to measure and maintain service quality under the pilot program. Phone answer time, gas emergency response time, missed appointments for service installations, time to reconnect service, and number of customers disconnected for non-payment should all be addressed in a pilot service quality evaluation.
7. Review: All utility pilot proposals shall be reviewed yearly. If the Commission determines that the pilot is harming ratepayers and/or failing to meet objectives, the Commission may suspend the pilot at any time or recommend modifications. As part of this annual review, all utilities shall provide information that shall be specified in an evaluation plan established as part of the pilot plan that shall include, but not be limited to the following information:
    A. total adjustments by class
    B. total adjustment charges collected
    C. number of customer complaints
    D. has the pilot stabilized revenues for the class(es) under the pilot and how has such stabilization impacted the utility's overall risk profile
    E. comparison of how revenues under traditional regulation would have differed from those collected under the decoupling pilot
    F. is the utility meeting energy efficiency savings goals? has the decoupling pilot influenced the achievement or likelihood of achievement of those goals?
    G. problems encountered and improvements/suggestions for the future.
8. Pilot Implementation:

A. Pilot proposals should be filed and implemented within a rate case; or
B. Pilot proposals may be filed outside of a rate case if the following conditions are met:
    (1) updated sales forecasts are provided with the pilot proposal;
    (2) detailed evaluation of how any decrease in risk as a result of the pilot proposal will impact the cost of capital; and
    (3) proposals are filed within one year of the final Commission order in a rate case.
C. Class Exclusion. The Commission requires that all decoupling pilot programs be implemented in more than one customer class.
D. Deadline for filing Pilot Programs
    (1) All utilities shall file a non-binding notice of intent as to their plans for filing a decoupling pilot by June 1, 2010.
    (2) All pilot proposals shall be filed by December 30, 2011.

Revenue Decoupling Model

Residential RDM Rate Calculation

Residential TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	427,855,354	373,745,099	369,256,223	305,419,219	330,726,778	416,384,868	511,094,084	469,753,320	352,528,244	348,627,215	356,142,553	410,536,346	4,672,069,303
RES_A02	54,935	49,639	49,204	37,058	38,744	47,205	55,913	52,687	39,992	40,395	46,458	56,752	568,982
RES_A02_Off	142,849	123,178	117,156	87,069	85,907	93,937	99,333	85,993	73,237	79,704	96,656	132,758	1,217,777
RES_A03	313,470,522	265,967,885	260,351,662	220,960,789	243,746,026	318,536,428	381,249,446	339,564,247	271,858,913	253,863,645	264,736,791	307,297,540	3,441,603,896
RES_A04	51,059	46,051	39,750	32,679	32,358	39,176	46,785	42,297	33,717	32,264	38,235	49,887	484,260
RES_A04_Off	124,608	102,082	90,967	73,742	71,758	77,704	80,357	65,559	58,766	63,454	79,515	112,055	1,000,567
RES_A05	1,245,153	1,137,726	996,815	516,147	412,724	301,453	338,850	284,304	220,694	281,160	559,923	966,179	7,261,129
RES_A05 - Optional	17,680	16,154	14,154	7,329	5,860	6,466	7,268	6,098	4,734	3,992	7,950	13,719	111,405
RES_A06	11,928	14,181	11,469	9,981	6,387	4,116	5,133	4,466	3,623	5,261	7,526	15,825	99,897
RES_A06_Off	493,618	448,726	425,454	216,578	132,398	67,368	44,661	38,471	39,849	95,598	222,226	397,237	2,622,185
Residential TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297	8,127,039,398

Residential TY 2015 Energy Charge	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
RES_A01, A03	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810
RES_A02, A04	0.178480	0.178480	0.178480	0.178480	0.178480	0.216620	0.216620	0.216620	0.216620	0.178480	0.178480	0.178480
RES_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
RES_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
RES_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970
RES_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
RES_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260

Residential TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	37,142,123	32,444,812	32,055,133	26,513,442	28,710,392	42,084,019	51,656,279	47,477,968	35,630,030	30,264,329	30,916,735	35,638,660	430,533,921
RES_A02	9,805	8,859	8,782	6,614	6,915	10,226	12,112	11,413	8,663	7,210	8,292	10,129	109,020
RES_A02_Off	4,580	3,949	3,756	2,791	2,754	3,012	3,185	2,757	2,348	2,555	3,099	4,256	39,042
RES_A03	27,212,376	23,088,672	22,601,128	19,181,606	21,159,593	32,194,477	38,532,882	34,319,758	27,476,780	22,037,903	22,981,801	26,676,499	317,463,475
RES_A04	9,113	8,219	7,095	5,832	5,775	8,486	10,135	9,162	7,304	5,759	6,824	8,904	92,608
RES_A04_Off	3,995	3,273	2,916	2,364	2,301	2,491	2,576	2,102	1,884	2,034	2,549	3,592	32,078
RES_A05	58,485	53,439	46,820	24,243	19,386	14,159	15,916	13,354	10,366	13,206	26,300	45,381	341,055
RES_A05 Optional	830	759	665	344	275	654	735	616	478	188	373	644	6,562
RES_A06	3,817	4,538	3,670	3,194	2,044	1,317	1,643	1,429	1,159	1,684	2,408	5,064	31,967
RES_A06_Off	13,950	12,681	12,023	6,120	3,742	1,904	1,262	1,087	1,126	2,702	6,280	11,226	74,103
Residential TY 2015 Energy Chg Rev	64,459,074	55,629,202	54,741,988	45,746,553	49,913,176	74,320,744	90,236,723	81,839,647	63,140,139	52,337,568	53,954,661	62,404,357	748,723,831

Residential TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	2,371,662	2,046,866	2,014,016	1,682,280	1,835,076	2,346,432	2,848,740	2,583,573	1,993,309	1,923,866	1,983,982	2,295,455	25,925,256
Res Energy Chg Rev w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902	722,798,575

FRC = TY 2015 Fixed Rev per Cust	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 Customer Count	1,075,105	1,076,198	1,076,713	1,076,258	1,075,853	1,074,944	1,074,792	1,076,013	1,076,239	1,077,942	1,077,850	1,078,421
FRC	**58**	**50**	**49**	**41**	**45**	**67**	**81**	**74**	**57**	**47**	**48**	**56**

FEC = TY 2015 Fixed Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297
FEC	**0.0835106**	**0.0835070**	**0.0835159**	**0.0835562**	**0.0835764**	**0.0978499**	**0.0978565**	**0.0978594**	**0.0978566**	**0.0835920**	**0.0835625**	**0.0835335**

Revenue Decoupling Model

YEAR 1 Residential

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	58	50	49	41	45	67	81	74	57	47	48	56	
C = 2015 Actual Customer Count	1,079,601	1,080,824	1,081,274	1,080,741	1,080,246	1,079,344	1,079,189	1,080,399	1,080,639	1,082,349	1,082,257	1,082,814	
2015 Allowed Revenue	62,347,056	53,812,658	52,951,330	44,247,816	48,274,415	72,268,920	87,745,490	79,579,135	61,396,817	50,619,811	52,183,172	60,353,759	725,780,378

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0835106	0.0835070	0.0835159	0.0835562	0.0835764	0.0978499	0.0978565	0.0978594	0.0978566	0.0835920	0.0835625	0.0835335	
WN kWh = 2015 Actual WN Sales	733,349,155	631,682,467	621,940,750	518,609,873	566,460,518	727,794,279	886,490,381	803,131,840	619,170,860	597,457,368	616,930,239	715,036,893	
2015 Actual Revenue	61,242,406	52,749,917	51,941,913	43,333,095	47,342,759	71,214,562	86,748,839	78,593,997	60,589,937	49,942,635	51,552,233	59,729,543	714,981,833

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	62,347,056	53,812,658	52,951,330	44,247,816	48,274,415	72,268,920	87,745,490	79,579,135	61,396,817	50,619,811	52,183,172	60,353,759	
Actual Revenue	61,242,406	52,749,917	51,941,913	43,333,095	47,342,759	71,214,562	86,748,839	78,593,997	60,589,937	49,942,635	51,552,233	59,729,543	
Under / (Over) Collection	1,104,650	1,062,741	1,009,418	914,721	931,657	1,054,357	996,651	985,138	806,880	677,176	630,939	624,216	10,798,545

TY 2015 Total Revenue	1,085,638,488
5% of Total Revenue	54,281,924
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate Cap	0.006731

Under / (Over) $	10,798,545
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.001339**

YEAR 2 Residential

2016 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	58	50	49	41	45	67	81	74	57	47	48	56	
C = 2016 Actual Customer Count	1,083,975	1,085,173	1,085,619	1,085,078	1,084,571	1,083,705	1,083,584	1,084,825	1,085,098	1,086,839	1,086,775	1,087,377	
2016 Allowed Revenue	62,599,655	54,029,188	53,164,111	44,425,382	48,467,693	72,560,916	88,102,833	79,905,142	61,650,156	50,829,802	52,401,016	60,608,091	728,743,984

2016 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0835106	0.0835070	0.0835159	0.0835562	0.0835764	0.0978499	0.0978565	0.0978594	0.0978566	0.0835920	0.0835625	0.0835335	
WN kWh = 2016 Actual WN Sales	742,267,059	638,029,810	622,540,572	521,070,723	563,384,705	729,361,181	893,971,072	810,430,852	629,091,340	586,653,667	615,309,980	717,614,302	
2016 Actual Revenue	61,987,145	53,279,964	51,992,007	43,538,715	47,085,693	71,367,883	87,480,873	79,308,274	61,560,721	49,039,532	51,416,840	59,944,843	718,002,489

Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	62,599,655	54,029,188	53,164,111	44,425,382	48,467,693	72,560,916	88,102,833	79,905,142	61,650,156	50,829,802	52,401,016	60,608,091	
Actual Revenue	61,987,145	53,279,964	51,992,007	43,538,715	47,085,693	71,367,883	87,480,873	79,308,274	61,560,721	49,039,532	51,416,840	59,944,843	
Under / (Over) Collection	612,510	749,224	1,172,103	886,667	1,382,000	1,193,033	621,961	596,868	89,435	1,790,269	984,176	663,248	10,741,494

2016 Total Revenue[1]	1,085,638,488
5% of Total Revenue	54,281,924
Apr 2017 - Mar 2018 Sales (kWh)	8,073,573,861
RDM Rider Rate Cap	0.006723

Under / (Over) $	10,741,494
Apr 2017 - Mar 2018 Sales (kWh)	8,073,573,861
RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018	**0.001330**

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model

Residential with Space Heating RDM Rate Calculation

Res Space Htg TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	19,250	18,947	16,630	12,336	16,771	15,213	17,621	17,314	15,597	17,730	20,088	18,259	205,756
RSH_A01	31,717,218	29,106,460	22,798,004	14,187,703	14,346,535	11,395,087	13,553,422	12,698,695	11,526,266	14,176,630	22,268,712	28,723,102	226,497,833
RSH_A02	23,777	22,491	19,096	10,450	9,587	8,567	9,655	11,912	9,052	11,228	17,740	19,556	173,110
RSH_A02_Off	51,971	45,574	40,446	21,374	20,086	16,480	17,401	19,406	15,940	20,489	33,862	39,612	342,640
RSH_A03	16,777,939	15,335,255	12,081,840	8,087,127	8,193,100	7,283,073	8,463,174	7,870,653	7,277,175	8,312,687	12,214,042	15,587,459	127,483,523
RSH_A04	23,720	22,550	16,897	11,474	11,801	11,598	14,060	14,206	12,553	13,031	18,135	22,966	192,992
RSH_A04_Off	56,079	48,071	38,301	24,866	25,218	21,933	23,881	26,319	21,470	25,316	35,500	48,767	395,722
RSH_A05	3,750,698	3,437,075	2,674,676	1,365,668	1,155,670	762,626	970,793	867,527	758,565	970,429	2,255,089	3,598,574	22,567,391
RSH_A05 Optional	482,595	442,242	344,146	175,718	148,698	100,073	127,389	113,838	99,540	124,863	290,158	463,022	2,912,284
RSH_A06	78	197	125	158	169	128	98	89	117	140	177	175	1,651
RSH_A06_Off	8,240	12,248	7,463	4,197	10,407	1,010	365	195	247	952	4,357	11,110	60,792
Res Space Htg TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601	380,833,693

Res Space Htg TY 2015 Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
RSH_A00	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810
RSH_A01, A03	0.062470	0.062470	0.062470	0.062470	0.062470	0.101070	0.101070	0.101070	0.101070	0.062470	0.062470	0.062470
RSH_A02, A04	0.117710	0.117710	0.117710	0.117710	0.117710	0.216620	0.216620	0.216620	0.216620	0.117710	0.117710	0.117710
RSH_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
RSH_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
RSH_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970
RSH_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
RSH_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260

Res SH TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	1,671	1,645	1,444	1,071	1,456	1,538	1,781	1,750	1,576	1,539	1,744	1,585	18,799
RSH_A01	1,981,375	1,818,281	1,424,191	886,306	896,228	1,151,701	1,369,844	1,283,457	1,164,960	885,614	1,391,126	1,794,332	16,047,416
RSH_A02	2,799	2,647	2,248	1,230	1,128	1,856	2,091	2,580	1,961	1,322	2,088	2,302	24,253
RSH_A02_Off	1,666	1,461	1,297	685	644	528	558	622	511	657	1,086	1,270	10,985
RSH_A03	1,048,118	957,993	754,753	505,203	511,823	736,100	855,373	795,487	735,504	519,294	763,011	973,749	9,156,407
RSH_A04	2,792	2,654	1,989	1,351	1,389	2,512	3,046	3,077	2,719	1,534	2,135	2,703	27,902
RSH_A04_Off	1,798	1,541	1,228	797	808	703	766	844	688	812	1,138	1,563	12,687
RSH_A05	176,170	161,439	125,630	64,145	54,282	35,821	45,598	40,748	35,630	45,581	105,922	169,025	1,059,990
RSH_A05 Optional	22,668	20,772	16,165	8,253	6,984	10,114	12,875	11,506	10,061	5,865	13,629	21,748	160,639
RSH_A06	25	63	40	51	54	41	31	29	37	45	57	56	528
RSH_A06_Off	233	346	211	119	294	29	10	6	7	27	123	314	1,718
Res SH TY 2015 Energy Chg Rev	3,239,314	2,968,843	2,329,194	1,469,211	1,475,091	1,940,943	2,291,974	2,140,105	1,953,654	1,462,288	2,282,058	2,968,648	26,521,324

Res Space Htg TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	168,788	154,687	121,340	76,244	76,362	62,574	74,001	69,032	62,960	75,518	118,534	154,819	1,214,859
Res Energy Chg Rev w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	25,306,464

FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829
TY 2015 Customer Count	31,833	31,869	31,930	31,959	31,956	31,950	31,965	31,980	31,995	32,011	32,027	32,044
FRC	**96**	**88**	**69**	**44**	**44**	**59**	**69**	**65**	**59**	**43**	**68**	**88**

FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829
TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601
FEC	**0.0580313**	**0.0580345**	**0.0580439**	**0.0582805**	**0.0584312**	**0.0957580**	**0.0956111**	**0.0957051**	**0.0957968**	**0.0585790**	**0.0582252**	**0.0579781**

Revenue Decoupling Model

YEAR 1 - Residential with Space Heating

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	96	88	69	44	44	59	69	65	59	43	68	88	
C = 2015 Actual Customer Count	32,061	32,078	32,092	32,107	32,122	32,138	32,155	32,171	32,188	32,206	32,223	32,241	
2015 Allowed Revenue	3,092,519	2,832,612	2,219,056	1,399,417	1,405,995	1,889,421	2,231,157	2,083,442	1,902,100	1,395,218	2,176,765	2,831,127	25,458,828

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0580313	0.0580345	0.0580439	0.0582805	0.0584312	0.0957580	0.0956111	0.0957051	0.0957968	0.0585790	0.0582252	0.0579781	
WN kWh = 2015 Actual WN Sales	52,782,650	47,929,698	37,955,682	23,955,046	24,021,489	19,366,489	23,159,870	21,617,034	19,782,416	23,792,347	36,719,918	48,493,043	
2015 Actual Revenue	3,063,045	2,781,576	2,203,098	1,396,112	1,403,605	1,854,496	2,214,341	2,068,860	1,895,091	1,393,732	2,138,025	2,811,535	25,223,516

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	3,092,519	2,832,612	2,219,056	1,399,417	1,405,995	1,889,421	2,231,157	2,083,442	1,902,100	1,395,218	2,176,765	2,831,127	
Actual Revenue	3,063,045	2,781,576	2,203,098	1,396,112	1,403,605	1,854,496	2,214,341	2,068,860	1,895,091	1,393,732	2,138,025	2,811,535	
Under / (Over) Collection	29,473	51,037	15,958	3,305	2,390	34,925	16,816	14,582	7,009	1,486	38,740	19,592	235,312

TY 2015 Total Revenue	41,414,614
5% of Total Revenue	2,070,731
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate Cap	0.005358

Under / (Over) $	235,312
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.000609**

YEAR 2 - Residential with Space Heating

2016 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	96	88	69	44	44	59	69	65	59	43	68	88	
C = 2016 Actual Customer Count	32,258	32,276	32,297	32,319	32,340	32,362	32,383	32,405	32,427	32,449	32,472	32,493	
2016 Allowed Revenue	3,111,521	2,850,096	2,233,231	1,408,657	1,415,537	1,902,591	2,246,977	2,098,597	1,916,223	1,405,745	2,193,586	2,853,256	25,636,015

2016 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0580313	0.0580345	0.0580439	0.0582805	0.0584312	0.0957580	0.0956111	0.0957051	0.0957968	0.0585790	0.0582252	0.0579781	
WN kWh = 2016 Actual WN Sales	54,187,295	46,414,620	42,495,747	26,192,285	19,878,443	20,240,582	24,518,780	22,354,777	19,011,353	25,728,220	35,334,893	50,854,423	
2016 Actual Revenue	3,144,559	2,693,649	2,466,621	1,526,499	1,161,522	1,938,198	2,344,268	2,139,466	1,821,226	1,507,134	2,057,382	2,948,443	25,748,965

Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	3,111,521	2,850,096	2,233,231	1,408,657	1,415,537	1,902,591	2,246,977	2,098,597	1,916,223	1,405,745	2,193,586	2,853,256	
Actual Revenue	3,144,559	2,693,649	2,466,621	1,526,499	1,161,522	1,938,198	2,344,268	2,139,466	1,821,226	1,507,134	2,057,382	2,948,443	
Under / (Over) Collection	-33,038	156,448	-233,390	-117,842	254,015	-35,607	-97,291	-40,869	94,997	-101,389	136,204	-95,188	-112,950

2016 Total Revenue[1]	41,414,614
5% of Total Revenue	2,070,731
Apr 2017 - Mar 2018 Sales (kWh)	386,474,996
RDM Rider Rate Cap	0.005358

Under / (Over) $	-112,950
Apr 2017 - Mar 2018 Sales (kWh)	386,474,996
RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018	**-0.000292**

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Small Commercial non-demand RDM Rate Calculation

SCI non-demand TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	254,024	248,335	258,861	184,544	96,631	61,149	54,499	58,258	45,602	42,237	77,541	153,701	1,535,382
SCI_A05 Optional	12,808	12,521	13,052	9,305	4,872	0	0	0	0	2,130	3,910	7,750	66,347
SCI_A06	18,109	14,653	13,171	26,076	19,249	22,063	22,317	22,466	25,876	28,575	16,215	11,771	240,541
SCI_A06 1S	143,656	142,144	149,065	107,828	74,988	19,189	17,354	15,515	12,552	37,764	47,900	79,647	847,601
SCI_A06 3S	186,252	184,291	193,264	139,801	97,223	97,192	87,900	78,586	63,579	48,962	62,103	103,263	1,342,416
SCI_A06 P	7,794	7,712	8,087	5,850	4,068	0	0	0	0	2,049	2,599	4,321	42,480
SCI_A09	2,501	2,390	2,509	2,462	2,541	2,521	2,634	2,348	2,128	2,288	2,388	2,398	29,110
SCI_A10	77,354,696	71,350,465	73,381,813	68,000,687	67,494,140	68,321,702	76,540,496	76,406,372	66,396,951	63,523,823	61,325,645	66,657,846	836,754,635
SCI_A11	25,096	23,167	25,033	24,444	25,230	25,595	25,032	22,287	19,556	20,140	19,831	20,448	275,860
SCI_A12	1,490,935	1,393,115	1,464,663	1,346,903	1,303,930	1,227,053	1,220,513	1,167,015	1,056,260	1,105,063	1,212,910	1,383,594	15,371,954
SCI_A12_Off	3,175,501	2,894,501	2,908,517	2,748,343	2,765,887	2,602,107	2,555,705	2,381,962	2,159,749	2,292,678	2,452,748	2,817,753	31,755,453
SCI_A16	1,219,663	1,093,152	1,124,759	1,105,674	1,149,599	1,109,476	1,131,775	1,056,621	946,917	1,041,807	1,073,011	1,137,832	13,190,288
SCI_A18	2,394,670	2,174,187	2,136,171	2,090,325	2,561,330	2,611,614	2,421,494	2,182,897	1,954,500	2,165,333	2,307,911	2,354,167	27,354,598
SCI_A22	195,473	180,251	194,807	195,563	210,719	205,888	208,768	188,787	172,708	185,759	193,405	200,556	2,332,684
SCI non-demand TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048	931,139,348

SCI non-demand TY 2015 Energy Charg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
SCI_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
SCI_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.094230	0.094230	0.094230	0.094230	0.046970	0.046970	0.046970
SCI_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
SCI_A06 1S, A06_3S	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260
SCI_A06 P	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302
SCI_A09, A10, A11	0.079970	0.079970	0.079970	0.079970	0.079970	0.094230	0.094230	0.094230	0.094230	0.079970	0.079970	0.079970
SCI_A12	0.132560	0.132560	0.132560	0.132560	0.132560	0.162470	0.162470	0.162470	0.162470	0.132560	0.132560	0.132560
SCI_A12_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
SCI_A16, A18, A22	0.067240	0.067240	0.067240	0.067240	0.067240	0.077700	0.077700	0.077700	0.077700	0.067240	0.067240	0.067240

SCI non-dem TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	11,931	11,664	12,159	8,668	4,539	2,872	2,560	2,736	2,142	1,984	3,642	7,219	72,117
SCI_A05 Optional	602	588	613	437	229	0	0	0	0	100	184	364	3,116
SCI_A06	5,795	4,689	4,215	8,344	6,160	7,060	7,142	7,189	8,280	9,144	5,189	3,767	76,973
SCI_A06 1S	4,060	4,017	4,213	3,047	2,119	542	490	438	355	1,067	1,354	2,251	23,953
SCI_A06 3S	5,263	5,208	5,462	3,951	2,748	2,747	2,484	2,221	1,797	1,384	1,755	2,918	37,937
SCI_A06 P	213	211	221	160	111	0	0	0	0	56	71	118	1,160
SCI_A09	200	191	201	197	203	238	248	221	201	183	191	192	2,465
SCI_A10	6,186,055	5,705,897	5,868,344	5,438,015	5,397,506	6,437,954	7,212,411	7,199,772	6,256,585	5,080,000	4,904,212	5,330,628	71,017,378
SCI_A11	2,007	1,853	2,002	1,955	2,018	2,412	2,359	2,100	1,843	1,611	1,586	1,635	23,379
SCI_A12	197,638	184,671	194,156	178,545	172,849	199,359	198,297	189,605	171,611	146,487	160,783	183,409	2,177,411
SCI_A12_Off	101,807	92,798	93,247	88,112	88,674	83,424	81,936	76,366	69,242	73,503	78,635	90,337	1,018,080
SCI_A16	82,010	73,504	75,629	74,346	77,299	86,206	87,939	82,099	73,575	70,051	72,149	76,508	931,315
SCI_A18	161,018	146,192	143,636	140,553	172,224	202,922	188,150	169,611	151,865	145,597	155,184	158,294	1,935,247
SCI_A22	13,144	12,120	13,099	13,150	14,169	15,998	16,221	14,669	13,419	12,490	13,005	13,485	164,968
SCI non-dem TY 2015 Energy Chg Rev	6,771,742	6,243,602	6,417,194	5,959,480	5,940,847	7,041,734	7,800,237	7,747,029	6,750,913	5,543,657	5,397,939	5,871,126	77,485,500

SCI non-demand TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	275,875	254,310	261,177	242,401	241,835	243,415	268,880	266,630	232,412	224,891	219,466	239,043	2,970,335
Res Energy Chg Rev w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083	74,515,166

FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 Customer Count	85,498	85,584	85,628	85,593	85,559	85,486	85,474	85,569	85,587	85,720	85,712	85,757
FRC	**76**	**70**	**72**	**67**	**67**	**80**	**88**	**87**	**76**	**62**	**60**	**66**

FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048
FEC	**0.0751131**	**0.0751283**	**0.0751891**	**0.0752368**	**0.0751745**	**0.0890934**	**0.0893521**	**0.0894965**	**0.0894706**	**0.0754450**	**0.0752706**	**0.0751595**

Revenue Decoupling Model

YEAR 1 - Small Commercial non-demand

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	76	70	72	67	67	80	88	87	76	62	60	66	
C = 2015 Actual Customer Count	85,850	85,946	85,981	85,938	85,899	85,829	85,817	85,911	85,930	86,064	86,057	86,101	
2015 Allowed Revenue	6,522,609	6,014,571	6,181,369	5,740,147	5,721,665	6,825,575	7,561,555	7,510,302	6,544,655	5,340,156	5,199,299	5,654,679	74,816,583

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0751131	0.0751283	0.0751891	0.0752368	0.0751745	0.0890934	0.0893521	0.0894965	0.0894706	0.0754450	0.0752706	0.0751595	
WN kWh = 2015 Actual WN Sales	86,324,781	79,344,007	83,105,236	75,167,453	76,102,826	75,197,305	83,764,014	83,476,688	72,757,213	70,392,492	68,705,811	74,828,273	
2015 Actual Revenue	6,484,120	5,960,979	6,248,609	5,655,358	5,720,994	6,699,582	7,484,493	7,470,874	6,509,629	5,310,761	5,171,525	5,624,058	74,340,982

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	6,522,609	6,014,571	6,181,369	5,740,147	5,721,665	6,825,575	7,561,555	7,510,302	6,544,655	5,340,156	5,199,299	5,654,679	
Actual Revenue	6,484,120	5,960,979	6,248,609	5,655,358	5,720,994	6,699,582	7,484,493	7,470,874	6,509,629	5,310,761	5,171,525	5,624,058	
Under / (Over) Collection	38,489	53,593	-67,241	84,789	671	125,993	77,062	39,428	35,026	29,395	27,774	30,621	475,600

TY 2015 Total Revenue	116,126,344
5% of Total Revenue	5,806,317
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate Cap	0.006259

Under / (Over) $	475,600
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.000513**

YEAR 2 - Small Commercial non-demand

2016 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	76	70	72	67	67	80	88	87	76	62	60	66	
C = 2016 Actual Customer Count	86,193	86,286	86,322	86,280	86,241	86,174	86,165	86,263	86,285	86,422	86,418	86,465	
2016 Allowed Revenue	6,548,649	6,038,417	6,205,914	5,762,996	5,744,406	6,853,041	7,592,220	7,541,014	6,571,663	5,362,323	5,221,083	5,678,575	75,120,301

2016 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0751131	0.0751283	0.0751891	0.0752368	0.0751745	0.0890934	0.0893521	0.0894965	0.0894706	0.0754450	0.0752706	0.0751595	
WN kWh = 2016 Actual WN Sales	86,694,419	81,837,592	81,920,228	73,892,722	74,855,819	77,303,556	84,023,598	83,902,244	71,911,877	69,574,360	68,522,745	75,314,285	
2016 Actual Revenue	6,511,884	6,148,317	6,159,510	5,559,451	5,627,251	6,887,235	7,507,688	7,508,959	6,433,996	5,249,037	5,157,746	5,660,586	74,411,662

Year 2 (2016) - Under / (Over) Collection Calculation: 2016 Allowed Revenue - 2016 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	6,548,649	6,038,417	6,205,914	5,762,996	5,744,406	6,853,041	7,592,220	7,541,014	6,571,663	5,362,323	5,221,083	5,678,575	
Actual Revenue	6,511,884	6,148,317	6,159,510	5,559,451	5,627,251	6,887,235	7,507,688	7,508,959	6,433,996	5,249,037	5,157,746	5,660,586	
Under / (Over) Collection	36,764	-109,900	46,404	203,544	117,155	-34,194	84,532	32,055	137,667	113,286	63,338	17,989	708,639

2016 Total Revenue[1]	116,126,344
5% of Total Revenue	5,806,317
Apr 2017 - Mar 2018 Sales (kWh)	928,519,492
RDM Rider Rate Cap	0.006253

Under / (Over) $	708,639
Apr 2017 - Mar 2018 Sales (kWh)	928,519,492
RDM Rider Rate ($/kWh) - Apr 2017 - Mar 2018	**0.000763**

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Northern States Power Company, a Minnesota corporation
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PROPOSED

REVENUE DECOUPLING MECHANISM RIDER

Section No. 5
Original Sheet No. XX

APPLICABILITY
Applicable to bills for electric service provided under the Company's Residential and non-demand-metered Small General Service schedules, excluding lighting services.

RIDER
There shall be included on each customer's monthly bill a Revenue Decoupling Mechanism Rider (RDM Rider) which shall be the applicable Revenue Decoupling Mechanism Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RDMR FACTORS
Annual RDM Rider Factor
Each year during the term of this rider the Company will calculate an RDM Rider factor. This factor will be based on revenues billed through December 31 and applied to bills from April 1 through the March 31 of the following year. The RDM Rider factors are:

Residential Standard	$0.001143 per kWh
Residential with Space Heating	$0.000461 per kWh
Small General Service (non-demand)	$0.000436 per kWh

The calculation for the RDM Rider factor is:

Annual RDM Rider factor = RDM Rider Deferral / Forecasted Sales

For purposes of this section the following definitions apply:

RDM Rider Deferral — Annual RDM Rider Deferral = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery from previous Periods being deferred in the RDM Rider Deferral Account (see description below for Account details). In the first year of this rider there may be less than 12 monthly deferrals included.

Forecasted Sales — Forecasted Usage for Year = forecasted use in kWh from April 1 of the year in which the Annual RDM Rider factor is calculated through March 31 of the following year.

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +5% of the total customer group revenue for each of the rate classes. The under-recovered revenues in excess of the +5% cap will be carried over to the RDM deferral account in the following year. The RDM Rider factor to return over-recovered revenues shall not be capped.

(Continued on Sheet No. 5-XX)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PROPOSED

REVENUE DECOUPLING MECHANISM RIDER

Section No. 5
Original Sheet No. XX

RDM Rider Deferral Account

1. Each month the Company will calculate the Monthly RDM Rider Deferral, which will be entered in the RDM Rider Deferral Account. Separate deferrals will be calculated for Residential Standard, Residential with Electric Space Heating, and non-demand-metered Small General services.

   Monthly RDM Rider Deferral = (FRC x C) – (FEC x WN kWh)

   For purposes of this section, the following definitions apply:

   FRC — Fixed Revenue per Customer = Energy charge revenues divided by customer count, calculated monthly from test year data. Expressed in dollars per customer

   C — Customer Count = Actual customer count for deferral month.

   FEC — Fixed Energy Charge = Average energy charge for each month of test year. Expressed in dollars per kWh

   WN kWh — Weather-normalized Sales = Weather-normalized billed sales for deferral month. Expressed in kWh. Weather-normalized sales will be calculated using the same approach to weather normalization adopted in the Company's last electric general rate case (Docket No. E002/GR-13-868)

2. The Company will defer and amortize the Monthly RDM Deferrals in sub-account of Account 186.

3. Any under- or over-recovery of the Annual RDM RIder Deferral will be included as a deferral in the RDM Rider Deferral Account and reflected in the calculation of the following year's Annual RDM Rider factor.

TERM

The Company will begin collecting data for the initial deferral period on the first full month after receiving a Final Order from the Minnesota Public Utilities Commission ("Commission").

The Company will file its proposed Annual RDM Rider factor surcharge or credit with the Commission annually on April 1, beginning on April 1 following the Final Order from the Commission. The proposed rate will become effective on the filing date and remain in effect for the next 12 months, or until April 1 of the following year.

(Continued on Sheet No. 5-XX)

Revenue Decoupling Model - Sensitivity Analysis

Residential RDM Rate Calculation | Sales Sensitivity | Sales changes from Test Year: -3.0%

Residential TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	427,855,354	373,745,099	369,256,223	305,419,219	330,726,778	416,384,868	511,094,084	469,753,320	352,528,244	348,627,215	356,142,553	410,536,346	4,672,069,303
RES_A02	54,935	49,639	49,204	37,058	38,744	47,205	55,913	52,687	39,992	40,395	46,458	56,752	568,982
RES_A02_Off	142,849	123,178	117,156	87,069	85,907	93,937	99,333	85,993	73,237	79,704	96,656	132,758	1,217,777
RES_A03	313,470,522	265,967,885	260,351,662	220,960,789	243,746,026	318,536,428	381,249,446	339,564,247	271,858,913	253,863,645	264,736,791	307,297,540	3,441,603,896
RES_A04	51,059	46,051	39,750	32,679	32,358	39,176	46,785	42,297	33,717	32,264	38,235	49,887	484,260
RES_A04_Off	124,608	102,082	90,967	73,742	71,758	77,704	80,357	65,559	58,766	63,454	79,515	112,055	1,000,567
RES_A05	1,245,153	1,137,726	996,815	516,147	412,724	301,453	338,850	284,304	220,694	281,160	559,923	966,179	7,261,129
RES_A05 - Optional	17,680	16,154	14,154	7,329	5,860	6,466	7,268	6,098	4,734	3,992	7,950	13,719	111,405
RES_A06	11,928	14,181	11,469	9,981	6,387	4,116	5,133	4,466	3,623	5,261	7,526	15,825	99,897
RES_A06_Off	493,618	448,726	425,454	216,578	132,398	67,368	44,661	38,471	39,849	95,598	222,226	397,237	2,622,185
Residential TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297	8,127,039,398

Residential TY 2015 Energy Charge	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
RES_A01, A03	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810
RES_A02, A04	0.178480	0.178480	0.178480	0.178480	0.178480	0.216620	0.216620	0.216620	0.216620	0.178480	0.178480	0.178480
RES_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
RES_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
RES_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970
RES_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
RES_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260

Residential TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	37,142,123	32,444,812	32,055,133	26,513,442	28,710,392	42,084,019	51,656,279	47,477,968	35,630,030	30,264,329	30,916,735	35,638,660	430,533,921
RES_A02	9,805	8,859	8,782	6,614	6,915	10,226	12,112	11,413	8,663	7,210	8,292	10,129	109,020
RES_A02_Off	4,580	3,949	3,756	2,791	2,754	3,012	3,185	2,757	2,348	2,555	3,099	4,256	39,042
RES_A03	27,212,376	23,088,672	22,601,128	19,181,606	21,159,593	32,194,477	38,532,882	34,319,758	27,476,780	22,037,903	22,981,801	26,676,499	317,463,475
RES_A04	9,113	8,219	7,095	5,832	5,775	8,486	10,135	9,162	7,304	5,759	6,824	8,904	92,608
RES_A04_Off	3,995	3,273	2,916	2,364	2,301	2,491	2,576	2,102	1,884	2,034	2,549	3,592	32,078
RES_A05	58,485	53,439	46,820	24,243	19,386	14,159	15,916	13,354	10,366	13,206	26,300	45,381	341,055
RES_A05 Optional	830	759	665	344	275	654	735	616	478	188	373	644	6,562
RES_A06	3,817	4,538	3,670	3,194	2,044	1,317	1,643	1,429	1,159	1,684	2,408	5,064	31,967
RES_A06_Off	13,950	12,681	12,023	6,120	3,742	1,904	1,262	1,087	1,126	2,702	6,280	11,226	74,103
Residential TY 2015 Energy Chg Rev	64,459,074	55,629,202	54,741,988	45,746,553	49,913,176	74,320,744	90,236,723	81,839,647	63,140,139	52,337,568	53,954,661	62,404,357	748,723,831

Residential TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	2,371,662	2,046,866	2,014,016	1,682,280	1,835,076	2,346,432	2,848,740	2,583,573	1,993,309	1,923,866	1,983,982	2,295,455	25,925,256
Res Energy Chg Rev w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902	722,798,575

FRC = TY 2015 Fixed Rev per Cust	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 Customer Count	1,075,105	1,076,198	1,076,713	1,076,258	1,075,853	1,074,944	1,074,792	1,076,013	1,076,239	1,077,942	1,077,850	1,078,421
FRC	**58**	**50**	**49**	**41**	**45**	**67**	**81**	**74**	**57**	**47**	**48**	**56**

FEC = TY 2015 Fixed Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297
FEC	**0.0835106**	**0.0835070**	**0.0835159**	**0.0835562**	**0.0835764**	**0.0978499**	**0.0978565**	**0.0978594**	**0.0978566**	**0.0835920**	**0.0835625**	**0.0835335**

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 Residential | Sales Sensitivity | Sales changes from Test Year: -3.0%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	58	50	49	41	45	67	81	74	57	47	48	56	
C = 2015 Actual Customer Count	1,075,105	1,076,198	1,076,713	1,076,258	1,075,853	1,074,944	1,074,792	1,076,013	1,076,239	1,077,942	1,077,850	1,078,421	
2015 Allowed Revenue	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902	722,798,575

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0835106	0.0835070	0.0835159	0.0835562	0.0835764	0.0978499	0.0978565	0.0978594	0.0978566	0.0835920	0.0835625	0.0835335	
WN kWh = 2015 Actual WN Sales	721,163,675	622,401,200	612,412,269	511,539,773	558,001,173	713,491,961	866,231,176	785,600,520	606,115,916	584,999,909	603,279,697	697,990,948	
2015 Actual Revenue	60,224,789	51,974,866	51,146,133	42,742,344	46,635,757	69,815,082	84,766,344	76,878,392	59,312,425	48,901,291	50,411,559	58,305,635	701,114,618

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902	
Actual Revenue	60,224,789	51,974,866	51,146,133	42,742,344	46,635,757	69,815,082	84,766,344	76,878,392	59,312,425	48,901,291	50,411,559	58,305,635	
Under / (Over) Collection	1,862,622	1,607,470	1,581,839	1,321,928	1,442,343	2,159,229	2,621,640	2,377,682	1,834,405	1,512,411	1,559,120	1,803,267	21,683,957

TY 2015 Total Revenue	1,085,638,488
5% of Total Revenue	54,281,924
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate Cap	0.006731

Under / (Over) $	21,683,957
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.002689**

Revenue Decoupling Model - Sensitivity Analysis

Residential with Space Heating RDM Rate Calc	Sales Sensitivity	Sales changes from Test Year:	-3.0%

Res Space Htg TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	19,250	18,947	16,630	12,336	16,771	15,213	17,621	17,314	15,597	17,730	20,088	18,259	205,756
RSH_A01	31,717,218	29,106,460	22,798,004	14,187,703	14,346,535	11,395,087	13,553,422	12,698,695	11,526,266	14,176,630	22,268,712	28,723,102	226,497,833
RSH_A02	23,777	22,491	19,096	10,450	9,587	8,567	9,655	11,912	9,052	11,228	17,740	19,556	173,110
RSH_A02_Off	51,971	45,574	40,446	21,374	20,086	16,480	17,401	19,406	15,940	20,489	33,862	39,612	342,640
RSH_A03	16,777,939	15,335,255	12,081,840	8,087,127	8,193,100	7,283,073	8,463,174	7,870,653	7,277,175	8,312,687	12,214,042	15,587,459	127,483,523
RSH_A04	23,720	22,550	16,897	11,474	11,801	11,598	14,060	14,206	12,553	13,031	18,135	22,966	192,992
RSH_A04_Off	56,079	48,071	38,301	24,866	25,218	21,933	23,881	26,319	21,470	25,316	35,500	48,767	395,722
RSH_A05	3,750,698	3,437,075	2,674,676	1,365,668	1,155,670	762,626	970,793	867,527	758,565	970,429	2,255,089	3,598,574	22,567,391
RSH_A05 Optional	482,595	442,242	344,146	175,718	148,698	100,073	127,389	113,838	99,540	124,863	290,158	463,022	2,912,284
RSH_A06	78	197	125	158	169	128	98	89	117	140	177	175	1,651
RSH_A06_Off	8,240	12,248	7,463	4,197	10,407	1,010	365	195	247	952	4,357	11,110	60,792
Res Space Htg TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601	380,833,693

Res Space Htg TY 2015 Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
RSH_A00	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810
RSH_A01, A03	0.062470	0.062470	0.062470	0.062470	0.062470	0.101070	0.101070	0.101070	0.101070	0.062470	0.062470	0.062470
RSH_A02, A04	0.117710	0.117710	0.117710	0.117710	0.117710	0.216620	0.216620	0.216620	0.216620	0.117710	0.117710	0.117710
RSH_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
RSH_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
RSH_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970
RSH_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
RSH_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260

Res SH TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	1,671	1,645	1,444	1,071	1,456	1,538	1,781	1,750	1,576	1,539	1,744	1,585	18,799
RSH_A01	1,981,375	1,818,281	1,424,191	886,306	896,228	1,151,701	1,369,844	1,283,457	1,164,960	885,614	1,391,126	1,794,332	16,047,416
RSH_A02	2,799	2,647	2,248	1,230	1,128	1,856	2,091	2,580	1,961	1,322	2,088	2,302	24,253
RSH_A02_Off	1,666	1,461	1,297	685	644	528	558	622	511	657	1,086	1,270	10,985
RSH_A03	1,048,118	957,993	754,753	505,203	511,823	736,100	855,373	795,487	735,504	519,294	763,011	973,749	9,156,407
RSH_A04	2,792	2,654	1,989	1,351	1,389	2,512	3,046	3,077	2,719	1,534	2,135	2,703	27,902
RSH_A04_Off	1,798	1,541	1,228	797	808	703	766	844	688	812	1,138	1,563	12,687
RSH_A05	176,170	161,439	125,630	64,145	54,282	35,821	45,598	40,748	35,630	45,581	105,922	169,025	1,059,990
RSH_A05 Optional	22,668	20,772	16,165	8,253	6,984	10,114	12,875	11,506	10,061	5,865	13,629	21,748	160,639
RSH_A06	25	63	40	51	54	41	31	29	37	45	57	56	528
RSH_A06_Off	233	346	211	119	294	29	10	6	7	27	123	314	1,718
Res SH TY 2015 Energy Chg Rev	3,239,314	2,968,843	2,329,194	1,469,211	1,475,091	1,940,943	2,291,974	2,140,105	1,953,654	1,462,288	2,282,058	2,968,648	26,521,324

Res Space Htg TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	168,788	154,687	121,340	76,244	76,362	62,574	74,001	69,032	62,960	75,518	118,534	154,819	1,214,859
Res Energy Chg Rev w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	25,306,464

FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829
TY 2015 Customer Count	31,833	31,869	31,930	31,959	31,956	31,950	31,965	31,980	31,995	32,011	32,027	32,044
FRC	**96**	**88**	**69**	**44**	**44**	**59**	**69**	**65**	**59**	**43**	**68**	**88**

FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829
TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601
FEC	**0.0580313**	**0.0580345**	**0.0580439**	**0.0582805**	**0.0584312**	**0.0957580**	**0.0956111**	**0.0957051**	**0.0957968**	**0.0585790**	**0.0582252**	**0.0579781**

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 - Residential with Space Heating	Sales Sensitivity	Sales changes from Test Year:	-3.0%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	96	88	69	44	44	59	69	65	59	43	68	88	
C = 2015 Actual Customer Count	31,833	31,869	31,930	31,959	31,956	31,950	31,965	31,980	31,995	32,011	32,027	32,044	
2015 Allowed Revenue	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	25,306,464

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0580313	0.0580345	0.0580439	0.0582805	0.0584312	0.0957580	0.0956111	0.0957051	0.0957968	0.0585790	0.0582252	0.0579781	
WN kWh = 2015 Actual WN Sales	51,324,219	47,036,377	36,896,495	23,184,039	23,219,900	19,027,314	22,501,923	20,990,951	19,144,427	22,963,291	36,043,124	47,076,623	
2015 Actual Revenue	2,978,411	2,729,732	2,141,618	1,351,177	1,356,767	1,822,018	2,151,434	2,008,941	1,833,974	1,345,167	2,098,619	2,729,414	24,547,270

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	
Actual Revenue	2,978,411	2,729,732	2,141,618	1,351,177	1,356,767	1,822,018	2,151,434	2,008,941	1,833,974	1,345,167	2,098,619	2,729,414	
Under / (Over) Collection	92,116	84,425	66,236	41,789	41,962	56,351	66,539	62,132	56,721	41,603	64,906	84,415	759,194

TY 2015 Total Revenue	41,414,614
5% of Total Revenue	2,070,731
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate Cap	0.005358

Under / (Over) $	759,194
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.001964**

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model - Sensitivity Analysis

Small Commercial non-demand RDM Rate Calc	Sales Sensitivity	Sales changes from Test Year:	-3.0%

SCI non-demand TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	254,024	248,335	258,861	184,544	96,631	61,149	54,499	58,258	45,602	42,237	77,541	153,701	1,535,382
SCI_A05 Optional	12,808	12,521	13,052	9,305	4,872	0	0	0	0	2,130	3,910	7,750	66,347
SCI_A06	18,109	14,653	13,171	26,076	19,249	22,063	22,317	22,466	25,876	28,575	16,215	11,771	240,541
SCI_A06 1S	143,656	142,144	149,065	107,828	74,988	19,189	17,354	15,515	12,552	37,764	47,900	79,647	847,601
SCI_A06 3S	186,252	184,291	193,264	139,801	97,223	97,192	87,900	78,586	63,579	48,962	62,103	103,263	1,342,416
SCI_A06 P	7,794	7,712	8,087	5,850	4,068	0	0	0	0	2,049	2,599	4,321	42,480
SCI_A09	2,501	2,390	2,509	2,462	2,541	2,521	2,634	2,348	2,128	2,288	2,388	2,398	29,110
SCI_A10	77,354,696	71,350,465	73,381,813	68,000,687	67,494,140	68,321,702	76,540,496	76,406,372	66,396,951	63,523,823	61,325,645	66,657,846	836,754,635
SCI_A11	25,096	23,167	25,033	24,444	25,230	25,595	25,032	22,287	19,556	20,140	19,831	20,448	275,860
SCI_A12	1,490,935	1,393,115	1,464,663	1,346,903	1,303,930	1,227,053	1,220,513	1,167,015	1,056,260	1,105,063	1,212,910	1,383,594	15,371,954
SCI_A12_Off	3,175,501	2,894,501	2,908,517	2,748,343	2,765,887	2,602,107	2,555,705	2,381,962	2,159,749	2,292,678	2,452,748	2,817,753	31,755,453
SCI_A16	1,219,663	1,093,152	1,124,759	1,105,674	1,149,599	1,109,476	1,131,775	1,056,621	946,917	1,041,807	1,073,011	1,137,832	13,190,288
SCI_A18	2,394,670	2,174,187	2,136,171	2,090,325	2,561,330	2,611,614	2,421,494	2,182,897	1,954,500	2,165,333	2,307,911	2,354,167	27,354,598
SCI_A22	195,473	180,251	194,807	195,563	210,719	205,888	208,768	188,787	172,708	185,759	193,405	200,556	2,332,684
SCI non-demand TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048	931,139,348

SCI non-demand TY 2015 Energy Charg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
SCI_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
SCI_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.094230	0.094230	0.094230	0.094230	0.046970	0.046970	0.046970
SCI_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
SCI_A06 1S, A06_3S	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260
SCI_A06 P	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302
SCI_A09, A10, A11	0.079970	0.079970	0.079970	0.079970	0.079970	0.094230	0.094230	0.094230	0.094230	0.079970	0.079970	0.079970
SCI_A12	0.132560	0.132560	0.132560	0.132560	0.132560	0.162470	0.162470	0.162470	0.162470	0.132560	0.132560	0.132560
SCI_A12_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
SCI_A16, A18, A22	0.067240	0.067240	0.067240	0.067240	0.067240	0.077700	0.077700	0.077700	0.077700	0.067240	0.067240	0.067240

SCI non-dem TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	11,931	11,664	12,159	8,668	4,539	2,872	2,560	2,736	2,142	1,984	3,642	7,219	72,117
SCI_A05 Optional	602	588	613	437	229	0	0	0	0	100	184	364	3,116
SCI_A06	5,795	4,689	4,215	8,344	6,160	7,060	7,142	7,189	8,280	9,144	5,189	3,767	76,973
SCI_A06 1S	4,060	4,017	4,213	3,047	2,119	542	490	438	355	1,067	1,354	2,251	23,953
SCI_A06 3S	5,263	5,208	5,462	3,951	2,748	2,747	2,484	2,221	1,797	1,384	1,755	2,918	37,937
SCI_A06 P	213	211	221	160	111	0	0	0	0	56	71	118	1,160
SCI_A09	200	191	201	197	203	238	248	221	201	183	191	192	2,465
SCI_A10	6,186,055	5,705,897	5,868,344	5,438,015	5,397,506	6,437,954	7,212,411	7,199,772	6,256,585	5,080,000	4,904,212	5,330,628	71,017,378
SCI_A11	2,007	1,853	2,002	1,955	2,018	2,412	2,359	2,100	1,843	1,611	1,586	1,635	23,379
SCI_A12	197,638	184,671	194,156	178,545	172,849	199,359	198,297	189,605	171,611	146,487	160,783	183,409	2,177,411
SCI_A12_Off	101,807	92,798	93,247	88,112	88,674	83,424	81,936	76,366	69,242	73,503	78,635	90,337	1,018,080
SCI_A16	82,010	73,504	75,629	74,346	77,299	86,206	87,939	82,099	73,575	70,051	72,149	76,508	931,315
SCI_A18	161,018	146,192	143,636	140,553	172,224	202,922	188,150	169,611	151,865	145,597	155,184	158,294	1,935,247
SCI_A22	13,144	12,120	13,099	13,150	14,169	15,998	16,221	14,669	13,419	12,490	13,005	13,485	164,968
SCI non-dem TY 2015 Energy Chg Rev	6,771,742	6,243,602	6,417,194	5,959,480	5,940,847	7,041,734	7,800,237	7,747,029	6,750,913	5,543,657	5,397,939	5,871,126	77,485,500

SCI non-demand TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	275,875	254,310	261,177	242,401	241,835	243,415	268,880	266,630	232,412	224,891	219,466	239,043	2,970,335
Res Energy Chg Rev w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083	74,515,166

FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 Customer Count	85,498	85,584	85,628	85,593	85,559	85,486	85,474	85,569	85,587	85,720	85,712	85,757
FRC	**76**	**70**	**72**	**67**	**67**	**80**	**88**	**87**	**76**	**62**	**60**	**66**

FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048
FEC	**0.0751131**	**0.0751283**	**0.0751891**	**0.0752368**	**0.0751745**	**0.0890934**	**0.0893521**	**0.0894965**	**0.0894706**	**0.0754450**	**0.0752706**	**0.0751595**

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 - Small Commercial non-demand | Sales Sensitivity | Sales changes from Test Year: -3.0%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	76	70	72	67	67	80	88	87	76	62	60	66	
C = 2015 Actual Customer Count	85,498	85,584	85,628	85,593	85,559	85,486	85,474	85,569	85,587	85,720	85,712	85,757	
2015 Allowed Revenue	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083	74,515,166

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0751131	0.0751283	0.0751891	0.0752368	0.0751745	0.0890934	0.0893521	0.0894965	0.0894706	0.0754450	0.0752706	0.0751595	
WN kWh = 2015 Actual WN Sales	83,886,741	77,329,258	79,417,559	73,708,171	73,536,095	74,016,383	81,759,834	81,075,622	70,670,687	68,383,650	66,734,171	72,686,997	
2015 Actual Revenue	6,300,991	5,809,614	5,971,336	5,545,566	5,528,042	6,594,369	7,305,416	7,255,987	6,322,946	5,159,204	5,023,119	5,463,121	72,279,711

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083	
Actual Revenue	6,300,991	5,809,614	5,971,336	5,545,566	5,528,042	6,594,369	7,305,416	7,255,987	6,322,946	5,159,204	5,023,119	5,463,121	
Under / (Over) Collection	194,876	179,679	184,681	171,512	170,970	203,950	225,941	224,412	195,555	159,563	155,354	168,962	2,235,455

TY 2015 Total Revenue	116,126,344
5% of Total Revenue	5,806,317
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate Cap	0.006259

Under / (Over) $	2,235,455
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.002410**

Revenue Decoupling Model - Sensitivity Analysis

Residential RDM Rate Calculation | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

Residential TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	427,855,354	373,745,099	369,256,223	305,419,219	330,726,778	416,384,868	511,094,084	469,753,320	352,528,244	348,627,215	356,142,553	410,536,346	4,672,069,303
RES_A02	54,935	49,639	49,204	37,058	38,744	47,205	55,913	52,687	39,992	40,395	46,458	56,752	568,982
RES_A02_Off	142,849	123,178	117,156	87,069	85,907	93,937	99,333	85,993	73,237	79,704	96,656	132,758	1,217,777
RES_A03	313,470,522	265,967,885	260,351,662	220,960,789	243,746,026	318,536,428	381,249,446	339,564,247	271,858,913	253,863,645	264,736,791	307,297,540	3,441,603,896
RES_A04	51,059	46,051	39,750	32,679	32,358	39,176	46,785	42,297	33,717	32,264	38,235	49,887	484,260
RES_A04_Off	124,608	102,082	90,967	73,742	71,758	77,704	80,357	65,559	58,766	63,454	79,515	112,055	1,000,567
RES_A05	1,245,153	1,137,726	996,815	516,147	412,724	301,453	338,850	284,304	220,694	281,160	559,923	966,179	7,261,129
RES_A05 - Optional	17,680	16,154	14,154	7,329	5,860	6,466	7,268	6,098	4,734	3,992	7,950	13,719	111,405
RES_A06	11,928	14,181	11,469	9,981	6,387	4,116	5,133	4,466	3,623	5,261	7,526	15,825	99,897
RES_A06_Off	493,618	448,726	425,454	216,578	132,398	67,368	44,661	38,471	39,849	95,598	222,226	397,237	2,622,185
Residential TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297	8,127,039,398

Residential TY 2015 Energy Charge	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
RES_A01, A03	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810
RES_A02, A04	0.178480	0.178480	0.178480	0.178480	0.178480	0.216620	0.216620	0.216620	0.216620	0.178480	0.178480	0.178480
RES_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
RES_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
RES_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970
RES_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
RES_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260

Residential TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RES_A01	37,142,123	32,444,812	32,055,133	26,513,442	28,710,392	42,084,019	51,656,279	47,477,968	35,630,030	30,264,329	30,916,735	35,638,660	430,533,921
RES_A02	9,805	8,859	8,782	6,614	6,915	10,226	12,112	11,413	8,663	7,210	8,292	10,129	109,020
RES_A02_Off	4,580	3,949	3,756	2,791	2,754	3,012	3,185	2,757	2,348	2,555	3,099	4,256	39,042
RES_A03	27,212,376	23,088,672	22,601,128	19,181,606	21,159,593	32,194,477	38,532,882	34,319,758	27,476,780	22,037,903	22,981,801	26,676,499	317,463,475
RES_A04	9,113	8,219	7,095	5,832	5,775	8,486	10,135	9,162	7,304	5,759	6,824	8,904	92,608
RES_A04_Off	3,995	3,273	2,916	2,364	2,301	2,491	2,576	2,102	1,884	2,034	2,549	3,592	32,078
RES_A05	58,485	53,439	46,820	24,243	19,386	14,159	15,916	13,354	10,366	13,206	26,300	45,381	341,055
RES_A05 Optional	830	759	665	344	275	654	735	616	478	188	373	644	6,562
RES_A06	3,817	4,538	3,670	3,194	2,044	1,317	1,643	1,429	1,159	1,684	2,408	5,064	31,967
RES_A06_Off	13,950	12,681	12,023	6,120	3,742	1,904	1,262	1,087	1,126	2,702	6,280	11,226	74,103
Residential TY 2015 Energy Chg Rev	64,459,074	55,629,202	54,741,988	45,746,553	49,913,176	74,320,744	90,236,723	81,839,647	63,140,139	52,337,568	53,954,661	62,404,357	748,723,831

Residential TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	2,371,662	2,046,866	2,014,016	1,682,280	1,835,076	2,346,432	2,848,740	2,583,573	1,993,309	1,923,866	1,983,982	2,295,455	25,925,256
Res Energy Chg Rev w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902	722,798,575

FRC = TY 2015 Fixed Rev per Cust	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 Customer Count	1,075,105	1,076,198	1,076,713	1,076,258	1,075,853	1,074,944	1,074,792	1,076,013	1,076,239	1,077,942	1,077,850	1,078,421
FRC	**58**	**50**	**49**	**41**	**45**	**67**	**81**	**74**	**57**	**47**	**48**	**56**

FEC = TY 2015 Fixed Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
TY 2015 Energy Revenue w/o CCRC	62,087,412	53,582,336	52,727,973	44,064,272	48,078,100	71,974,312	87,387,983	79,256,075	61,146,830	50,413,703	51,970,680	60,108,902
TY 2015 kWh	743,467,706	641,650,722	631,352,855	527,360,590	575,258,941	735,558,722	893,021,830	809,897,444	624,861,769	603,092,689	621,937,832	719,578,297
FEC	**0.0835106**	**0.0835070**	**0.0835159**	**0.0835562**	**0.0835764**	**0.0978499**	**0.0978565**	**0.0978594**	**0.0978566**	**0.0835920**	**0.0835625**	**0.0835335**
TY 2015 UPC	691.53	596.22	586.37	489.99	534.70	684.28	830.88	752.68	580.60	559.49	577.02	667.25

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 Residential | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	58	50	49	41	45	67	81	74	57	47	48	56	
C = 2015 Actual Customer Count	1,053,603	1,054,674	1,055,179	1,054,733	1,054,336	1,053,445	1,053,296	1,054,493	1,054,714	1,056,383	1,056,293	1,056,853	
2015 Allowed Revenue	60,845,663	52,510,689	51,673,413	43,182,987	47,116,538	70,534,825	85,640,224	77,670,953	59,923,893	49,405,428	50,931,266	58,906,724	708,342,604

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0835106	0.0835070	0.0835159	0.0835562	0.0835764	0.0978499	0.0978565	0.0978594	0.0978566	0.0835920	0.0835625	0.0835335	
WN kWh = 2015 Actual WN Sales	728,598,352	628,817,707	618,725,798	516,813,378	563,753,763	720,847,548	875,161,394	793,699,495	612,364,534	591,030,836	609,499,075	705,186,731	
2015 Actual Revenue	60,845,663	52,510,689	51,673,413	43,182,987	47,116,538	70,534,825	85,640,224	77,670,953	59,923,893	49,405,428	50,931,266	58,906,724	708,342,604

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	60,845,663	52,510,689	51,673,413	43,182,987	47,116,538	70,534,825	85,640,224	77,670,953	59,923,893	49,405,428	50,931,266	58,906,724	
Actual Revenue	60,845,663	52,510,689	51,673,413	43,182,987	47,116,538	70,534,825	85,640,224	77,670,953	59,923,893	49,405,428	50,931,266	58,906,724	
Under / (Over) Collection	0	0	0	0	0	0	0	0	0	0	0	0	0

TY 2015 Total Revenue	1,085,638,488
5% of Total Revenue	54,281,924
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate Cap	0.006731

Under / (Over) $	0
Apr 2016 - Mar 2017 Sales (kWh)	8,064,433,023
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.000000**

Revenue Decoupling Model - Sensitivity Analysis

Residential with Space Heating RDM Rate Calc	Customer Count Sensitivity	Customer Count changes from Test Year:	-2%

Res Space Htg TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	19,250	18,947	16,630	12,336	16,771	15,213	17,621	17,314	15,597	17,730	20,088	18,259	205,756
RSH_A01	31,717,218	29,106,460	22,798,004	14,187,703	14,346,535	11,395,087	13,553,422	12,698,695	11,526,266	14,176,630	22,268,712	28,723,102	226,497,833
RSH_A02	23,777	22,491	19,096	10,450	9,587	8,567	9,655	11,912	9,052	11,228	17,740	19,556	173,110
RSH_A02_Off	51,971	45,574	40,446	21,374	20,086	16,480	17,401	19,406	15,940	20,489	33,862	39,612	342,640
RSH_A03	16,777,939	15,335,255	12,081,840	8,087,127	8,193,100	7,283,073	8,463,174	7,870,653	7,277,175	8,312,687	12,214,042	15,587,459	127,483,523
RSH_A04	23,720	22,550	16,897	11,474	11,801	11,598	14,060	14,206	12,553	13,031	18,135	22,966	192,992
RSH_A04_Off	56,079	48,071	38,301	24,866	25,218	21,933	23,881	26,319	21,470	25,316	35,500	48,767	395,722
RSH_A05	3,750,698	3,437,075	2,674,676	1,365,668	1,155,670	762,626	970,793	867,527	758,565	970,429	2,255,089	3,598,574	22,567,391
RSH_A05 Optional	482,595	442,242	344,146	175,718	148,698	100,073	127,389	113,838	99,540	124,863	290,158	463,022	2,912,284
RSH_A06	78	197	125	158	169	128	98	89	117	140	177	175	1,651
RSH_A06_Off	8,240	12,248	7,463	4,197	10,407	1,010	365	195	247	952	4,357	11,110	60,792
Res Space Htg TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601	380,833,693
Res Space Htg TY 2015 Energy Chg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	
RSH_A00	0.086810	0.086810	0.086810	0.086810	0.086810	0.101070	0.101070	0.101070	0.101070	0.086810	0.086810	0.086810	
RSH_A01, A03	0.062470	0.062470	0.062470	0.062470	0.062470	0.101070	0.101070	0.101070	0.101070	0.062470	0.062470	0.062470	
RSH_A02, A04	0.117710	0.117710	0.117710	0.117710	0.117710	0.216620	0.216620	0.216620	0.216620	0.117710	0.117710	0.117710	
RSH_A02_Off, A04_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	
RSH_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	
RSH_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.101070	0.101070	0.101070	0.101070	0.046970	0.046970	0.046970	
RSH_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	
RSH_A06_Off	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	
Res SH TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
RSH_A00	1,671	1,645	1,444	1,071	1,456	1,538	1,781	1,750	1,576	1,539	1,744	1,585	18,799
RSH_A01	1,981,375	1,818,281	1,424,191	886,306	896,228	1,151,701	1,369,844	1,283,457	1,164,960	885,614	1,391,126	1,794,332	16,047,416
RSH_A02	2,799	2,647	2,248	1,230	1,128	1,856	2,091	2,580	1,961	1,322	2,088	2,302	24,253
RSH_A02_Off	1,666	1,461	1,297	685	644	528	558	622	511	657	1,086	1,270	10,985
RSH_A03	1,048,118	957,993	754,753	505,203	511,823	736,100	855,373	795,487	735,504	519,294	763,011	973,749	9,156,407
RSH_A04	2,792	2,654	1,989	1,351	1,389	2,512	3,046	3,077	2,719	1,534	2,135	2,703	27,902
RSH_A04_Off	1,798	1,541	1,228	797	808	703	766	844	688	812	1,138	1,563	12,687
RSH_A05	176,170	161,439	125,630	64,145	54,282	35,821	45,598	40,748	35,630	45,581	105,922	169,025	1,059,990
RSH_A05 Optional	22,668	20,772	16,165	8,253	6,984	10,114	12,875	11,506	10,061	5,865	13,629	21,748	160,639
RSH_A06	25	63	40	51	54	41	31	29	37	45	57	56	528
RSH_A06_Off	233	346	211	119	294	29	10	6	7	27	123	314	1,718
Res SH TY 2015 Energy Chg Rev	3,239,314	2,968,843	2,329,194	1,469,211	1,475,091	1,940,943	2,291,974	2,140,105	1,953,654	1,462,288	2,282,058	2,968,648	26,521,324
Res Space Htg TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	168,788	154,687	121,340	76,244	76,362	62,574	74,001	69,032	62,960	75,518	118,534	154,819	1,214,859
Res Energy Chg Rev w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	25,306,464
FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	
TY 2015 Customer Count	31,833	31,869	31,930	31,959	31,956	31,950	31,965	31,980	31,995	32,011	32,027	32,044	
FRC	**96**	**88**	**69**	**44**	**44**	**59**	**69**	**65**	**59**	**43**	**68**	**88**	
FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
TY 2015 Energy Revenue w/o CCRC	3,070,526	2,814,157	2,207,854	1,392,966	1,398,729	1,878,369	2,217,973	2,071,073	1,890,695	1,386,770	2,163,525	2,813,829	
TY 2015 kWh	52,911,565	48,491,110	38,037,623	23,901,071	23,938,041	19,615,787	23,197,859	21,640,155	19,736,523	23,673,496	37,157,860	48,532,601	
FEC	**0.0580313**	**0.0580345**	**0.0580439**	**0.0582805**	**0.0584312**	**0.0957580**	**0.0956111**	**0.0957051**	**0.0957968**	**0.0585790**	**0.0582252**	**0.0579781**	
TY 2015 UPC	1,662.16	1,521.58	1,191.28	747.87	749.09	613.95	725.73	676.68	616.86	739.54	1,160.20	1,514.56	

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 - Residential with Space Heating | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	96	88	69	44	44	59	69	65	59	43	68	88	
C = 2015 Actual Customer Count	31,196	31,232	31,291	31,320	31,317	31,311	31,326	31,340	31,355	31,371	31,386	31,403	
2015 Allowed Revenue	3,009,116	2,757,874	2,163,697	1,365,107	1,370,754	1,840,801	2,173,613	2,029,651	1,852,881	1,359,035	2,120,254	2,757,552	24,800,335

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0580313	0.0580345	0.0580439	0.0582805	0.0584312	0.0957580	0.0956111	0.0957051	0.0957968	0.0585790	0.0582252	0.0579781	
WN kWh = 2015 Actual WN Sales	51,853,334	47,521,288	37,276,871	23,423,050	23,459,280	19,223,472	22,733,902	21,207,352	19,341,793	23,200,026	36,414,703	47,561,949	
2015 Actual Revenue	3,009,116	2,757,874	2,163,697	1,365,107	1,370,754	1,840,801	2,173,613	2,029,651	1,852,881	1,359,035	2,120,254	2,757,552	24,800,335

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	3,009,116	2,757,874	2,163,697	1,365,107	1,370,754	1,840,801	2,173,613	2,029,651	1,852,881	1,359,035	2,120,254	2,757,552	
Actual Revenue	3,009,116	2,757,874	2,163,697	1,365,107	1,370,754	1,840,801	2,173,613	2,029,651	1,852,881	1,359,035	2,120,254	2,757,552	
Under / (Over) Collection	0	0	0	0	0	0	0	0	0	0	0	0	0

TY 2015 Total Revenue	41,414,614
5% of Total Revenue	2,070,731
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate Cap	0.005358

Under / (Over) $	0
Apr 2016 - Mar 2017 Sales (kWh)	386,474,589
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.000000**

1 TY 2015 Total Revenue used as a proxy for 2016 Total Revenues.

Revenue Decoupling Model - Sensitivity Analysis

Small Commercial non-demand RDM Rate Calc | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

SCI non-demand TY 2015 kWh	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	254,024	248,335	258,861	184,544	96,631	61,149	54,499	58,258	45,602	42,237	77,541	153,701	1,535,382
SCI_A05 Optional	12,808	12,521	13,052	9,305	4,872	0	0	0	0	2,130	3,910	7,750	66,347
SCI_A06	18,109	14,653	13,171	26,076	19,249	22,063	22,317	22,466	25,876	28,575	16,215	11,771	240,541
SCI_A06 1S	143,656	142,144	149,065	107,828	74,988	19,189	17,354	15,515	12,552	37,764	47,900	79,647	847,601
SCI_A06 3S	186,252	184,291	193,264	139,801	97,223	97,192	87,900	78,586	63,579	48,962	62,103	103,263	1,342,416
SCI_A06 P	7,794	7,712	8,087	5,850	4,068	0	0	0	0	2,049	2,599	4,321	42,480
SCI_A09	2,501	2,390	2,509	2,462	2,541	2,521	2,634	2,348	2,128	2,288	2,388	2,398	29,110
SCI_A10	77,354,696	71,350,465	73,381,813	68,000,687	67,494,140	68,321,702	76,540,496	76,406,372	66,396,951	63,523,823	61,325,645	66,657,846	836,754,635
SCI_A11	25,096	23,167	25,033	24,444	25,230	25,595	25,032	22,287	19,556	20,140	19,831	20,448	275,860
SCI_A12	1,490,935	1,393,115	1,464,663	1,346,903	1,303,930	1,227,053	1,220,513	1,167,015	1,056,260	1,105,063	1,212,910	1,383,594	15,371,954
SCI_A12_Off	3,175,501	2,894,501	2,908,517	2,748,343	2,765,887	2,602,107	2,555,705	2,381,962	2,159,749	2,292,678	2,452,748	2,817,753	31,755,453
SCI_A16	1,219,663	1,093,152	1,124,759	1,105,674	1,149,599	1,109,476	1,131,775	1,056,621	946,917	1,041,807	1,073,011	1,137,832	13,190,288
SCI_A18	2,394,670	2,174,187	2,136,171	2,090,325	2,561,330	2,611,614	2,421,494	2,182,897	1,954,500	2,165,333	2,307,911	2,354,167	27,354,598
SCI_A22	195,473	180,251	194,807	195,563	210,719	205,888	208,768	188,787	172,708	185,759	193,405	200,556	2,332,684
SCI non-demand TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048	931,139,348

SCI non-demand TY 2015 Energy Charg	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
SCI_A05	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970	0.046970
SCI_A05 Optional	0.046970	0.046970	0.046970	0.046970	0.046970	0.094230	0.094230	0.094230	0.094230	0.046970	0.046970	0.046970
SCI_A06	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000	0.320000
SCI_A06 1S, A06_3S	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260	0.028260
SCI_A06 P	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302	0.027302
SCI_A09, A10, A11	0.079970	0.079970	0.079970	0.079970	0.079970	0.094230	0.094230	0.094230	0.094230	0.079970	0.079970	0.079970
SCI_A12	0.132560	0.132560	0.132560	0.132560	0.132560	0.162470	0.162470	0.162470	0.162470	0.132560	0.132560	0.132560
SCI_A12_Off	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060	0.032060
SCI_A16, A18, A22	0.067240	0.067240	0.067240	0.067240	0.067240	0.077700	0.077700	0.077700	0.077700	0.067240	0.067240	0.067240

SCI non-dem TY 2015 Energy Chg Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
SCI_A05	11,931	11,664	12,159	8,668	4,539	2,872	2,560	2,736	2,142	1,984	3,642	7,219	72,117
SCI_A05 Optional	602	588	613	437	229	0	0	0	0	100	184	364	3,116
SCI_A06	5,795	4,689	4,215	8,344	6,160	7,060	7,142	7,189	8,280	9,144	5,189	3,767	76,973
SCI_A06 1S	4,060	4,017	4,213	3,047	2,119	542	490	438	355	1,067	1,354	2,251	23,953
SCI_A06 3S	5,263	5,208	5,462	3,951	2,748	2,747	2,484	2,221	1,797	1,384	1,755	2,918	37,937
SCI_A06 P	213	211	221	160	111	0	0	0	0	56	71	118	1,160
SCI_A09	200	191	201	197	203	238	248	221	201	183	191	192	2,465
SCI_A10	6,186,055	5,705,897	5,868,344	5,438,015	5,397,506	6,437,954	7,212,411	7,199,772	6,256,585	5,080,000	4,904,212	5,330,628	71,017,378
SCI_A11	2,007	1,853	2,002	1,955	2,018	2,412	2,359	2,100	1,843	1,611	1,586	1,635	23,379
SCI_A12	197,638	184,671	194,156	178,545	172,849	199,359	198,297	189,605	171,611	146,487	160,783	183,409	2,177,411
SCI_A12_Off	101,807	92,798	93,247	88,112	88,674	83,424	81,936	76,366	69,242	73,503	78,635	90,337	1,018,080
SCI_A16	82,010	73,504	75,629	74,346	77,299	86,206	87,939	82,099	73,575	70,051	72,149	76,508	931,315
SCI_A18	161,018	146,192	143,636	140,553	172,224	202,922	188,150	169,611	151,865	145,597	155,184	158,294	1,935,247
SCI_A22	13,144	12,120	13,099	13,150	14,169	15,998	16,221	14,669	13,419	12,490	13,005	13,485	164,968
SCI non-dem TY 2015 Energy Chg Rev	6,771,742	6,243,602	6,417,194	5,959,480	5,940,847	7,041,734	7,800,237	7,747,029	6,750,913	5,543,657	5,397,939	5,871,126	77,485,500

SCI non-demand TY 2015 CCRC Rev	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual
CCRC = $0.00319 per kWh	275,875	254,310	261,177	242,401	241,835	243,415	268,880	266,630	232,412	224,891	219,466	239,043	2,970,335
Res Energy Chg Rev w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083	74,515,166

FRC = TY 2015 Fixed Rev per Cust	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 Customer Count	85,498	85,584	85,628	85,593	85,559	85,486	85,474	85,569	85,587	85,720	85,712	85,757
FRC	**76**	**70**	**72**	**67**	**67**	**80**	**88**	**87**	**76**	**62**	**60**	**66**

FEC = TY 2015 Fixed Energy Chg	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
TY 2015 Energy Revenue w/o CCRC	6,495,867	5,989,293	6,156,017	5,717,079	5,699,012	6,798,319	7,531,356	7,480,399	6,518,501	5,318,767	5,178,473	5,632,083
TY 2015 kWh	86,481,176	79,720,884	81,873,772	75,987,805	75,810,407	76,305,550	84,288,489	83,583,116	72,856,379	70,498,609	68,798,114	74,935,048
FEC	**0.0751131**	**0.0751283**	**0.0751891**	**0.0752368**	**0.0751745**	**0.0890934**	**0.0893521**	**0.0894965**	**0.0894706**	**0.0754450**	**0.0752706**	**0.0751595**

TY 2015 UPC	1,011.50	931.49	956.16	887.78	886.06	892.61	986.13	976.79	851.26	822.43	802.66	873.80

Revenue Decoupling Model - Sensitivity Analysis

YEAR 1 - Small Commercial non-demand | Customer Count Sensitivity | Customer Count changes from Test Year: -2%

2015 Allowed Rev = FRC * C	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FRC	76	70	72	67	67	80	88	87	76	62	60	66	
C = 2015 Actual Customer Count	83,788	83,873	83,915	83,881	83,848	83,776	83,765	83,858	83,875	84,005	83,998	84,042	
2015 Allowed Revenue	6,365,950	5,869,507	6,032,896	5,602,737	5,585,032	6,662,353	7,380,729	7,330,791	6,388,131	5,212,391	5,074,903	5,519,442	73,024,862

2015 Actual Rev = FEC * WN kWh	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
FEC	0.0751131	0.0751283	0.0751891	0.0752368	0.0751745	0.0890934	0.0893521	0.0894965	0.0894706	0.0754450	0.0752706	0.0751595	
WN kWh = 2015 Actual WN Sales	84,751,552	78,126,466	80,236,297	74,468,049	74,294,199	74,779,439	82,602,719	81,911,454	71,399,251	69,088,636	67,422,152	73,436,347	
2015 Actual Revenue	6,365,950	5,869,507	6,032,896	5,602,737	5,585,032	6,662,353	7,380,729	7,330,791	6,388,131	5,212,391	5,074,903	5,519,442	73,024,862

Year 1 (2015) - Under / (Over) Collection Calculation: 2015 Allowed Revenue - 2015 Actual Revenue = (FRC x C) - (FEC x WN kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Allowed Revenue	6,365,950	5,869,507	6,032,896	5,602,737	5,585,032	6,662,353	7,380,729	7,330,791	6,388,131	5,212,391	5,074,903	5,519,442	
Actual Revenue	6,365,950	5,869,507	6,032,896	5,602,737	5,585,032	6,662,353	7,380,729	7,330,791	6,388,131	5,212,391	5,074,903	5,519,442	
Under / (Over) Collection	0	0	0	0	0	0	0	0	0	0	0	0	0

TY 2015 Total Revenue	116,126,344
5% of Total Revenue	5,806,317
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate Cap	0.006259

Under / (Over) $	0
Apr 2016 - Mar 2017 Sales (kWh)	927,659,958
RDM Rider Rate ($/kWh) - Apr 2016 - Mar 2017	**0.000000**

2013 TY Revenues
from September 19, 2013 Compliance Filing in Docket No. E002/GR-12-961

	MWh	Base Fixed $1000s	Base Variable $1000s	Fuel $1000s	Riders $1000s	Total $1000s
Residential	8,692,532	115,301	655,409	235,613	4,097	1,010,421
Sm C&I Non-Demand	984,589	10,212	70,640	27,590	464	108,906
Total	9,677,121	125,513	726,049	263,203	4,561	1,119,328

Fixed	125,513	15%
Variable	726,049	85%
Total	851,563	

	MWh	Base Fixed $1000s	Base Variable $1000s	Fuel $1000s	Riders $1000s	Total $1000s
C&I Demand	20,920,504	511,350	564,527	556,610	9,861	1,642,348
Public Authorities	72,728	3,078	2,401	1,971	34	7,483
Lighting	174,426	20,698	1,779	3,463	82	26,022
Total	21,167,658	535,126	568,706	562,044	9,978	1,675,854

Fixed	535,126	48%
Variable	568,706	52%
Total	1,103,832	

	MWh	Base Fixed $1000s	Base Variable $1000s	Fuel $1000s	Riders $1000s	Total $1000s
Total	30,844,779	660,640	1,294,755	825,247	14,539	2,795,181

Fixed	660,640	34%
Variable	1,294,755	66%
Total	1,955,395	

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

In the Matter of the Application of Otter Tail Power Company For Authority to Increase Rates for Electric Utility Service in Minnesota	**PUC Docket No. E017/GR-15-1033** **OAH Docket No. 8-2500-33355**

DIRECT TESTIMONY OF

MARK LOWRY
President

KAJA REBANE
Economist II

Pacific Economics Research LLC

On Behalf of

Fresh Energy

I. INTRODUCTION

Q. Please state your names, occupations, and business addresses.

A. We are Mark Newton Lowry and Kaja Rebane of Pacific Economics Group ("PEG") Research LLC. Our business address is 44 East Mifflin St., Suite 601, Madison, WI 53703.

Q. On whose behalf are you testifying in this rate case proceeding?

A. Our testimony is sponsored by Fresh Energy.

Q. Dr. Lowry, what is your occupation and professional background?

A. I am the President of PEG Research, a company in the Pacific Economics Group consortium that is prominent in the field of alternative regulation. I have almost thirty years of experience as an industry economist. Revenue decoupling, performance-based regulation, cost trackers, and other alternatives to traditional rate regulation --- sometimes jointly called alternative regulation ("Altreg") --- have been my chief professional focus for twenty-five years. I have testified dozens of times on Altreg issues. Work for a mix of well-known utilities, trade associations, regulatory commissions, environmental organizations, and other clients has given my practice a reputation for objectivity and dedication to good regulation. Our practice is multinational and has included extensive work in Canada.

Before joining PEG, I was for several years an Assistant Professor of Mineral Economics at the University Park campus of the Pennsylvania State University. I have also worked as a Vice President at Christensen Associates and as a visiting professor at l'Ecole des

Hautes Etudes Commerciales in Montreal. My resume includes an extensive list of publications and public appearances. A native of Cleveland, I attended Princeton University and hold a Ph.D. in Applied Economics from the University of Wisconsin ("UW") Madison. My resume can be found in Attachment 1.

Q. Ms. Rebane, what is your occupation and professional background?

A. I am a Level II Economist at PEG Research and have four years of experience as a professional energy economist. I hold an undergraduate degree in Biology from Stanford University, as well as Master's degrees in Applied Economics and Land Resources and a certificate in Energy Analysis and Policy from UW Madison. A Las Vegas native, I am pursuing a Ph.D. in Environment and Resources at UW Madison. My resume can be found in Attachment 2.

Q. What issues does your testimony address?

A. Otter Tail Power ("OTP") is in this proceeding proposing a change in its rate designs for small volume customers that substantially increases its fixed charges relative to volumetric charges. This will substantially reduce the incentives of small volume customers to adopt DERs. Fresh Energy has asked us to appraise the incentives that Otter Tail's proposed regulatory system provides for the Company to embrace efficient demand side management ("DSM"), distributed generation and storage ("DGS"), and other kinds of distributed energy resources ("DERs").

Following a general discussion of the poor incentives for utilities to embrace DERs under traditional rate regulation, we detail several touted Altreg remedies for improving these incentives and consider their pros and cons. After reviewing the situation of OTP, we then provide an analysis of their incentives to embrace efficient DERs and prescribe an alternative regulatory system that would produce better results. A report on our work for Fresh Energy is found in Attachment 3.

Q. What do you conclude from your analysis of Otter Tail's situation and proposed regulatory system?

A. Our general analysis of utility performance incentives and our review of the Company's situation suggests that Otter Tail does not have appropriately strong incentives to embrace efficient DERs. We find that even with the proposed hikes in customer charges, most revenue addressing costs that are fixed in the short run with respect to system use would continue to be addressed by usage charges. There is thus potentially a strong throughput incentive and a concomitant disincentive to embrace DERs even when they are the low cost option for customers and society.

Another cause for concern is the Company's weak incentive to contain many load-related costs. While the expected rate case cycle would provide some incentive to contain some load-related costs, most of OTP's load-related costs are subject to cost trackers or formula rates. Otter Tail's finances are also insensitive to many kinds of environmental damage that its operations cause.

Q. Does the CIP Financial Incentive Mechanism help with this problem?

A. Yes it does, but only with respect to conservation programs that it covers. This mechanism doesn't encourage Otter Tail to embrace DGS or a wide range of initiatives the Company can take to promote conservation and peak demand management.

Perhaps reflecting this, the Company's conservation goals only slightly exceed the statutory minimum. Instead of moving in the direction of time-sensitive pricing that could encourage more efficient DERs, Otter Tail is proposing a reduction in volumetric charges relative to fixed charges that discourages all forms of DERs for small-volume customers.

Q. What do you recommend as an alternative to Otter Tail's proposal?

A. Based on our analysis, we believe that reforms to OTP's regulatory system are needed to encourage efficient DERs. Most importantly, revenue decoupling should be instituted. This can immediately and completely remove the throughput-related disincentive to embrace efficient DGS and peak load management and the full range of initiatives that encourage conservation. Debate over future billing determinants can be reduced in forward test year rate cases. The institution of decoupling can buy OTP time to reconsider its rate designs to ensure that they send the right price signals for DERs, as required by Minnesota law.

We also believe that the MNCIP Financial Incentive Mechanism and tracker treatment of DSM expenses should continue in order to provide some positive incentive to use DSM for cost management. Additional reforms are needed to improve DER incentives that may go beyond what can be addressed in this rate case. These include the development of positive financial incentives for OTP to encourage efficient DGS, peak load management, and a wider range of conservation initiatives. A multiyear rate plan can further strengthen incentives to contain load-related capex.

Q. Please provide some details of your proposed revenue decoupling system.

A. We propose a revenue decoupling system broadly similar to that which the Commission approved for Xcel Energy in its last rate case.[1]

- Decoupling would apply to residential, farm, and general service (excluding large general service) customers.
- Separate baskets would apply to residential and farm services and to the general services. The use of multiple baskets protects customers in each basket from rate adjustments due to the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equiproportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.
- The RDM would effect *full* decoupling subject to the constraint that rate increases due to the revenue decoupling mechanism would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.
- Decoupling adjustments would be applied in each month of the following April-March period.

[1] MNPUC Docket No. E-002/GR-13-868, May 2015.

- OTP would be required to file a plan proposing education and outreach program to customers explaining the goals and operations of its RDM program.

- The decoupling adjustment would appear as a separate rider on customers' bills to enhance transparency.

Illustrative revenue decoupling mechanisms and tariff sheets are found in the Appendix to our report.

Q. Does this conclude your Direct Testimony?

A. Yes it does.

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Education High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural & Resource Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 — **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 — **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 — **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
7. Gas Transmission Productivity Research for a U.S. Trade Association. 1990.
8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.
16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.
18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.

23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
25. White Paper on Price Cap Regulation for a U.S. Trade Association. 1994.
26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
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29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
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32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
55. White Paper and Public Appearances on PBR Options for Australian Power Distributors. 1997-98.
56. Gas and Power Distribution PBR Research and Testimony for a Western Energy Utility. 1997-98.
57. Research on the Cost Structure of Power Distribution for a U.S. Trade Association. 1998.
58. Research on Cross-Subsidization for a U.S. Trade Association. 1998.
59. Testimony on Brand Names for a U.S. Trade Association. 1998.
60. Research and Testimony on Economies of Scale in Power Supply for a Western Electric Utility. 1998.
61. PBR Plan Design and Testimony for a Western Electric Utility. 1998-99.
62. PBR and Bundled Power Service Testimony and Testimony for Two Southeast U.S. Electric Utilities. 1998-99.
63. Statistical Benchmarking for an Australian Power Distributor. 1998-9.
64. Testimony on Functional Separation of Power Generation and Delivery for a U.S. Trade Association. 1998.
65. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. 1998.
66. Consultation on PBR and Code of Conduct Issues for a Western Electric Utility. 1999.
67. PBR and Bundled Power Service Benchmarking Research and Testimony for a Southwest Electric Utility. 1999.

68. Power Transmission and Distribution Cost Benchmarking for a Western Electric Utility. 1999.
69. Cost Benchmarking for Three Australian Power Distributors. 1999.
70. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1999.
71. Benchmarking Research for an Australian Power Distributor. 2000.
72. Critique of a Commission-Sponsored Benchmarking Study for Three Australian Power Distributors. 2000.
73. Statistical Benchmarking for an Australian Power Transco. 2000.
74. PBR and Benchmarking Testimony for a Southwest Electric Utility. 2000.
75. PBR Workshop (for Regulators) for a Northeast Gas and Electric Utility. 2000.
76. Research on Economies of Scale and Scope for an Australian Electric Utility. 2000.
77. Research and Testimony on Economies of Scale in Power Delivery, Metering, and Billing for a Consortium of Northeast Electric Utilities. 2000.
78. Research and Testimony on Service Quality PBR for a Consortium of Northeast Energy Utilities. 2000.
79. Power and Natural Gas Procurement PBR for a Western Electric Utility. 2000.
80. PBR Plan Design for a Canadian Natural Gas Distributor. 2000.
81. TFP and Benchmarking Research for a Western Gas and Electric Utility. 2000.
82. E-Forum on PBR for Power Procurement for a U.S. Trade Association. 2001.
83. PBR Presentation to Florida's Energy 2000 Commission for a U.S. Trade Association. 2001.
84. Research on Power Market Competition for an Australian Electric Utility. 2001.
85. TFP and Other PBR Research and Testimony for a Northeast Power Distributor. 2000.
86. PBR and Productivity for a Canadian Electric Utility. 2002
87. Statistical Benchmarking for an Australian Power Transco. 2002.
88. PBR and Bundled Power Service Benchmarking Research and Testimony for a Midwest Energy Utility. 2002.
89. Consultation on the Future of Power Transmission and Distribution Regulation for a Western Electric Utility. 2002.
90. Benchmarking and Productivity Research and Testimony for Two Western U.S. Energy Distributors. 2002.
91. Workshop on PBR (for Regulators) for a Canadian Trade Association. 2003.
92. PBR, Productivity, and Benchmarking Research for a Mid-Atlantic Gas and Electric Utility. 2003.
93. Workshop on PBR (for Regulators) for a Southeast Electric Utility. 2003.
94. Strategic Advice for a Midwest Power Transmission Company. 2003.
95. PBR Research for a Canadian Gas Distributor. 2003.
96. Benchmarking Research and Testimony for a Canadian Gas Distributor. 2003-2004.
97. Consultation on Benchmarking and Productivity Issues for Two British Power Distributors. 2003.
98. Power Distribution Productivity and Benchmarking Research for a South American Regulator. 2003-2004.
99. Statistical Benchmarking of Power Transmission for a Japanese Research Institute. 2003-4.
100. Consultation on PBR for a Western Gas Distributor. 2003-4.
101. Research and Advice on PBR for Gas Distribution for a Western Gas Distributor. 2004.
102. PBR, Benchmarking and Productivity Research and Testimony for Two Western Energy Distributors. 2004.
103. Advice on Productivity for Two British Power Distributors. 2004.
104. Workshop on Service Quality Regulation for a Canadian Trade Association. 2004.
105. Strategic Advice for a Canadian Trade Association. 2004.
106. White Paper on Unbundled Storage and Local Gas Markets for a Midwestern Gas Distributor. 2004.
107. Statistical Benchmarking Research for a British Power Distributor. 2004.
108. Statistical Benchmarking Research for Three British Power Distributors. 2004.

109. Benchmarking Testimony for Three Ontario Power Distributors. 2004.
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117. White Paper on Utility Rate Trends for a U.S. Trade Association. 2005.
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119. Seminars on PBR and Statistical Benchmarking for a Northeast Electric Utility, 2005.
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121. Testimony Transmission PBR for a Canadian Electric Utility, 2005.
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125. White Paper on PBR for Major Plant Additions for a U.S. Trade Association. 2006.
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129. Revenue Decoupling Research and Presentation for a Northeast Power Distributor. 2007.
130. Gas Utility Productivity Research and PBR Plan Design for a Canadian Regulator. 2007.
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133. Research and Testimony in Support of a Revenue Adjustment Mechanism for a Northeastern Power Utility. 2008.
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141. Research and Testimony on Forward Test Years and the cost performance of a Vertically Integrated Western Electric Utility. 2009.
142. White Paper for a National Trade Association on the Importance of Forward Test Years for U.S. Electric Utilities. 2009-2010.
143. Research and Testimony on Altreg for Western Gas and Electric Utilities Operating under Decoupling. 2009-2010.
144. Research and Report on PBR Designed to Incent Long Term Performance Gains. 2009-2010.
145. Research and Report on Revenue Decoupling for Ontario Gas and Electric Utilities. 2009-2010.
146. Research and Testimony on the Performance of a Western Electric Utility. 2009-2010.
147. Research on Decoupling for a Western Gas Distributor. 2009-2010.
148. Research on Alternative Regulation Precedents for a Midwestern Electric Utility. 2010.
149. Research on Revenue Decoupling for a Northwestern Gas & Electric Utility. 2010.
150. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2010.

151. Research and Testimony on Forward Test Years and the cost performance of a large Western Gas Distributor. 2010-2011.
152. Research and Testimony in Support of Revenue Decoupling for a Midwestern Power Distributor. 2010-2011.
153. Benchmarking Research and Report on the Generation Maintenance Performance of a Midwestern Electric Utility. 2010-2011.
154. Research and Testimony on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor. 2010-2011.
155. White Paper for a National Trade Association on Remedies for Regulatory Lag. 2010-2011.
156. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2011.
157. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor. 2011.
158. Research and Testimony on Remedies for Regulatory Lag for Three Northeastern Power Distributors. 2011-2012.
159. Research and Testimony on the Design of Performance Based Ratemaking Mechanisms for a Canadian Consumer Group. 2011-2012.
160. Research and Testimony on Projected Attrition for a Northwest Electric Utility. 2011-2012.
161. Research and Testimony on the Design of a Performance Based Ratemaking Plan for a Canadian Gas Utility. 2012-2013.
162. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012.
163. Survey of Gas and Electric Altreg Precedents for a US Trade Association. 2012-2013.
164. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast Electric Utility. 2013.
165. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group. 2013.
166. Consultation on an Altreg Strategy for a Southeast Electric Utility. 2013.
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168. Research and Testimony on the Design of a PBR Plan for a Northeast Electric Utility. 2013.
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170. Consultation on Altreg Strategy for a California Electric Utility. 2013.
171. Research on Drivers of O&M expenses for a Canadian Gas Utility. 2013.
172. Research on the Design of an Attrition Relief Mechanism for a Midwest Electric & Gas Distributor. 2013.
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175. Research and Testimony on Productivity Trends of Gas and Electric Power Distributors for a Canadian Consumer Group, 2013-2014.
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191. Development of a Revenue Decoupling Mechanism and Supporting Testimony on behalf of a Midwest Environmental Advocate, 2016.
192. Research and Testimony on Total Factor Productivity of Hydroelectric Generators for a Canadian Regulator. 2016.
193. White Paper on Utility Experience and Lessons Learned from Performance-Based Regulation Plans, 2016-2017.

Publications

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2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November, 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
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12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
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46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf, Synapse Energy Economics), Lawrence Berkeley National Laboratory, January 2016.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans, LA, March 1986
2. International Association of Energy Economists, Calgary, AL, July 1987
3. American Agricultural Economics Association, Knoxville, TN, August 1988
4. Association d'Econometrie Appliqué, Washington, DC, October 1988
5. Electric Council of New England, Boston, MA, November 1989
6. Electric Power Research Institute, Milwaukee, WI, May 1990
7. New York State Energy Office, Saratoga Springs, NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus, OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg, VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell, MT, May 1994
12. Edison Electric Institute, Washington, DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando, FL, March 1995
14. Illinois Commerce Commission, St. Charles, IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco, CA, April 1996
18. AIC Conferences, Orlando, FL, April 1996
19. IBC Conferences, San Antonio, TX, June 1996
20. American Gas Association, Arlington, VA, July 1996
21. IBC Conferences, Washington, DC, October 1996
22. Center for Regulatory Studies, Springfield, IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg, VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton, AL, July 1997

26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving, TX, Sept. 1997
27. American Gas Association, Washington, DC [national telecast], September 1997
28. Infocast, Miami Beach, FL, Oct. 1997
29. Edison Electric Institute, Arlington, VA, March 1998
30. Electric Utility Consultants, Denver, CO, April 1998
31. University of Indiana, Indianapolis, IN, August 1998
32. Edison Electric Institute, Newport, RI, September 1998
33. University of Southern California, Los Angeles, CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio, TX, April 2000
38. Infocast, Chicago, IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster, MA, July 2000
41. Infocast, Washington, DC, October 2000
42. Wisconsin Public Utility Institute, Madison, WI, November 2000
43. Infocast, Boston, MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa, FL, August 2001
45. Infocast, Washington, DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto, ON, March 2002
47. Canadian Electricity Association, Whistler, BC, May 2002
48. Canadian Electricity Association, Montreal, PQ, September 2002
49. Ontario Energy Association, Toronto, ON, November 2002
50. Canadian Gas Association, Toronto, ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge, LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax, NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto, ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington, VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle, WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007
69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]

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75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago, IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas, NV, March 2013
85. Edison Electric Institute, Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago, IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas, NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
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96. Wisconsin Public Service Commission, Madison WI, March 2016
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98. Edison Electric Institute, Madison WI, August 2016

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
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Association Memberships (active)

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Relevant Work Experience:

August 2012-present: Economist II
Pacific Economics Group Research
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Conduct empirical research and policy analysis related to the regulation of electric and gas utilities. Focal areas include statistical and econometric evaluation of cost and reliability performance, revenue decoupling, performance incentive mechanisms, and regulatory reforms to encourage utility accommodation of distributed energy resources.

July 2009-June 2012: Project Assistant
Department of Agricultural & Applied Economics
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Evaluated outcomes of entrepreneurship-related programs on behalf of the Kauffman Foundation. Duties included the gathering of data, preparation of case studies, and collaboration with campus stakeholders.

February 2007-May 2009: Project Assistant
Nelson Institute for Environmental Studies
University of Wisconsin-Madison

Assisted in establishing a graduate certificate in Business, Environment and Social Responsibility, supported the foundation of the Wisconsin Initiative on Climate Change Impacts, helped develop an Engineering Professional Development online sustainability curriculum, assisted in construction of a campus sustainability web portal, and provided research and project support.

January 2008-May 2008: Teaching Assistant (People, Planet, Profit)
School of Business
University of Wisconsin-Madison

Co-delivered a new course on use of the triple bottom line concept in business. Duties included curriculum development, grading and student support.

September 2006-December 2006: Teaching Assistant (Ecology, Evolution and Genetics)
Biology Core Curriculum
University of Wisconsin-Madison

Provided teaching support for an introductory course in the biological sciences. Ran discussion sections, responded to student questions, and graded assignments and exams.

September 2005-December 2005: Teaching Assistant (Renewable Energy Technology)
Department of Biological Systems Engineering
University of Wisconsin-Madison

Developed and delivered lectures, recorded and edited lecture videos, graded assignments and exams, and provided general support for a new course on renewable energy systems.

Publications:

Rebane, K. L, & Goldrick-Rab, S. (2012). Collecting detailed expenditure information from undergraduates: Lessons learned and recommendations for future efforts. Working Paper, Wisconsin Scholars Longitudinal Study.

Rebane, K. L., & Barham, B. L. (2011). Knowledge and adoption of solar home systems in rural Nicaragua. *Energy Policy*, *39*(6), 3064-3075.

PEG Research Projects:

1. Revenue Decoupling of a Vertically Integrated US Utility (2016): Researched Minnesota's regulatory background and constructed a revenue decoupling mechanism simulation. Work performed on behalf of an environmental intervenor.

2. Performance-based regulation of power and gas distributors in Alberta (2016): Researched Alberta's regulatory background, gathered data for use in productivity analyses, and constructed customer growth forecasts. Work performed on behalf of a Canadian consumer group.

3. Multiyear rate plans for distribution and transmission utilities in Québec (2015-2016): Researched Québec's regulatory policy framework, gathered data related to transmission and distribution productivity, and simulated a revenue cap for a Canadian electric utility based on a Kahn X factor methodology. Work performed for a Canadian consumers' association.

4. Implications of alternative regulation for demand-side management in Pennsylvania (2016): Helped draft testimony on the implications of revenue decoupling, performance incentive mechanisms, multiyear rate plans, and other aspects of alternative regulation for demand-side management in Pennsylvania. Work conducted on behalf of an environmental intervenor.

5. Performance metrics for the utility of the future (2016): Helped draft white paper on performance metrics for the utility of the future. Researched the regulatory history of metrics used in incentive regulation, and evaluated the implications of different approaches for addressing emerging challenges. Work performed for a US trade association and a consortium of electric utilities.

6. Midwestern US electric company merger implications (2015): Researched potential implications of proposed merger for customer choice and market power. Work performed on behalf of a municipal electric utility.

7. Development of alternative US/Ontario benchmarking model (2014-2015): Replicated benchmarking results submitted by a distribution company, and developed an alternative transnational benchmarking model. Work conducted for a Canadian regulator.

8. Australian/US database construction and benchmarking (2014): Collaborated on constructing transnational database of electric distribution company data, and performed econometric benchmarking analyses for demonstration purposes. Work performed for an Australian regulator.

9. Productivity of vertically integrated US electric utilities (2013-2014): Assisted in a productivity analysis of a large sample of vertically integrated US electricity companies, and of a more limited peer group on behalf of an electric utility.

10. Evaluation of company-sponsored productivity evidence in British Columbia (2013): Analyzed productivity evidence supplied by companies on behalf of a Canadian consumers' association.

11. Reliability benchmarking of Ontario electric utilities (2013): Conducted econometric modeling of the reliability performance of Ontario electric utilities.

12. O&M productivity and return on investment of Alberta gas and electric distributors (2013): Assisted in O&M partial factor productivity analysis of Alberta gas and electric distributors, and implemented econometric models of the impact of regulatory systems on the return on investment for US electric utilities. Work done on behalf of a Canadian consumers' group.

13. Productivity of Northeast US power distributors (2013): Assisted in research measuring the productivity of power distributors on behalf of a northeast electric utility.

14. Power distribution productivity and cost benchmarking (2012-2013): Assisted in analyzing the productivity and cost of power distributors on behalf of a Canadian regulator.

Incentivizing Efficient DERs for Otter Tail Power

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1. Introduction

Distributed energy resources ("DERs") in the form of demand-side management ("DSM") and distributed generation and storage ("DGS") are transforming America's electric power industry.[1] DSM is the cheapest and cleanest way to meet America's energy needs. There is enormous potential to save money, create local jobs, and reduce environmental damage by making use of the grid less peaked and reducing the volumes of energy needed by buildings, processes, and energy-using equipment. DGS is an increasingly attractive alternative to grid-supplied power. Minnesota's energy utilities are strategically placed to facilitate DERs, but reforms in the existing regulatory system are needed for utilities to fully embrace their potential.

Otter Tail Power ("OTP" or "the Company") filed a general rate case with Minnesota's Public Utilities Commission ("MNPUC" or "the Commission") in February. The Company, near the midpoint of a period of high capital expenditures ("capex"), has asked for a sizable rate increase and a redesign of rates for small-volume customers that lowers their volumetric charges relative to their fixed charges. The revised rates are touted as helping customers make better DER choices.

Pacific Economics Group ("PEG") Research LLC is a leading provider of research and testimony on revenue decoupling, performance-based regulation, and other alternatives to traditional cost of service regulation, which are sometimes referred to jointly as "alternative regulation" ("Altreg"). Work for diverse clients that include utilities, regulators, and environmental groups in the United States, Canada, and countries overseas has given us a reputation for objectivity and dedication to good regulation. We have been retained by Fresh Energy to discuss revenue decoupling and other ways to strengthen Otter Tail's incentives to embrace efficient DERs.

To evaluate the likely impact of revenue decoupling on DER outcomes, an understanding of the implicit disincentives for utilities to embrace DERs which are created by

[1] DSM is here defined to include both conservation and demand response programs.

traditional regulation is needed. Revenue decoupling is an effective way to remove some of these disincentives, but by itself cannot address them all. It is thus desirable to consider revenue decoupling alongside other regulatory tools that can work together synergistically to achieve the desired effects. To assist the Commission in its deliberations, we therefore place revenue decoupling in a broader regulatory context.

The plan for the paper is as follows. In Section 2, we discuss ways in which traditional regulation discourages efficient DERs and consider how Altreg reforms can provide more encouragement. There follow in Sections 3-7 consideration of five Altreg tools that have been touted for their ability to encourage DERs.

- Revenue decoupling
- Tracking of DSM expenses
- DSM performance incentive mechanisms
- Multiyear rate plans
- Fixed/variable rate designs

We then discuss the situation of Otter Tail and prescribe an Altreg solution.

2. Traditional Regulation and the Need for Altreg

2.1. Traditional Regulation

The traditional US approach to regulating retail rates of energy utilities developed over many decades. In this system, called "cost-of-service" regulation ("COSR"), a utility's rates are designed to recover its cost of providing service. The chief means of resetting rates is the general rate case. In these litigated proceedings, a revenue requirement is established that reflects the normalized and prudent cost of service in a test year. The Federal Energy Regulatory Commission ("FERC") often uses a substantially different system to regulate interstate power transmission that involves formula rate plans (a kind of broad-based cost tracker).

The revenue requirement is allocated across the utility's services. Rates are then designed to recover the revenue requirement for each service given assumptions about billing determinants (e.g., energy consumption and peak demand). Most revenue is drawn from volumetric and other usage charges, so called because they vary with a customer's use of the system. The balance of revenue is typically drawn from fixed charges such as customer charges.

To address changes in some costs more promptly than is possible through rate cases, regulators often use cost trackers and associated rate riders. Large, volatile costs like those for fuel and purchased power are typically recovered using cost trackers. The components of rates that address costs of non-energy inputs such as capital, labor, and materials are sometimes called base rates.[2] Costs that cause overall cost to grow rapidly are increasingly subject to tracker treatment today and include costs of certain capital expenditures.

Utilities file rate cases when revenue is, in the absence of higher rates, expected to fall short of the cost of service, resulting in financial attrition. The timing of these cases is irregular and depends on business conditions. For example, rate cases tend to be more frequent when inflation is rapid or when high capex is needed which does not automatically trigger new revenue.

Trends in the demand for utility services are also important drivers of attrition and rate case filings. Under traditional rate designs, growth in base rate revenue is chiefly driven by growth in system use. Meanwhile, cost is largely fixed in the short run with respect to system use but grows with customer connections and other dimensions of system capacity. The difference between the growth of system use and capacity is thus an important determinant of rate case frequency. Since the capacity growth of utilities is highly correlated with growth in the number of customers they serve, this difference is often approximated by the trends in use per customer (aka “average use”).

Historical trends in the average use of electricity by residential and commercial (“R&C”) customers of US electric utilities are detailed in Table 1. It can be seen that the average use of these customers grew rapidly for decades until the 1970s. During this period, high usage charges benefitted electric utilities and helped revenue track cost growth so that frequent rate cases were unnecessary.

[2] Utilities vary in the precise rates that they label "base" rates.

Table 1

Trends in Average Deliveries of Electricity to

US Residential and Commercial Customers

	Residential		Commercial	
	Level	Growth Rate	Level	Growth Rate
Multiyear Averages				
1926-1930	464	7.06%	3,545	6.67%
1931-1940	723	5.45%	4,048	2.00%
1941-1950	1,304	6.48%	6,485	5.08%
1951-1960	2,836	7.53%	12,062	6.29%
1961-1970	5,235	6.13%	28,893	9.51%
1971-1980	8,205	2.45%	49,045	3.07%
1981-1990	9,062	0.63%	56,571	1.40%
1991-2000	10,061	1.15%	67,006	1.68%
2001-2007	10,941	0.73%	74,224	0.64%
2008-2014	11,059	-0.38%	75,311	-0.22%

Sources: US Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and form EIA-0035, "Monthly Energy Review."

Growth in average use declined in the 1970s and was sluggish in the 1980-2007 period. This increased the frequency of rate cases. Since 2007, R&C average use trends of many electric utilities have been close to zero or negative. The effect of this development on the frequency of rate cases has been mitigated by slow input price inflation, but this tempering influence is offset when utilities have high levels of non-revenue producing capex. Declines in average use were, incidentally, chronic in the gas distribution industry for many years. This makes gas industry regulatory precedents increasingly relevant for electric utilities today.

2.2. The Need for Altreg

Traditional regulation has certain shortcomings that Altreg can address. For example, the frequent rate cases triggered by unfavorable business conditions raise regulatory cost and weaken utility performance incentives.[3] While a number of tools can be used to reduce the cost of traditional regulation, these can have undesirable side effects. For example, regulation

[3] Rate cases nonetheless have benefits, which include the opportunity to review utility operations and provide feedback.

can be simplified by tracking more costs or by de-emphasizing prudence reviews. However, these measures weaken utility cost-containment incentives.[4] Thus, the generally less favorable business conditions of utilities since the 1960s have tended to weaken their performance incentives.

Traditional regulation is also well known to discourage utilities from embracing efficient DERs. Utilities are incentivized to bolster average use, a phenomenon called the "throughput incentive." DERs slow growth in average use, thereby eroding margins. Utilities are more reluctant to implement time-sensitive base rates and other rate designs that encourage efficient DERs because of increased exposure to demand volatility and the unpredictability of the response to new rates. For example, utilities are unsure how customers will respond to high peak period charges in an era when the cost of distributed power storage is rapidly falling.

Another problem is the weak incentives utilities can have under traditional regulation to use DSM to contain costs. For environmental groups such as Fresh Energy, a special concern is the insensitivity of utility finances to the environmental impact of their operations. Utilities may also lack sufficient incentives to use DERs to contain their own load-related costs. Their load-related costs include those for fuel and purchased power, generation and transmission facilities, and distribution substations and transformers.

The frequent rate cases that can occur under COSR reduce utility incentives to slow load-related capex with DERs. For example, there is less benefit from using DERs to postpone distribution system upgrades to serve load growth. Reductions in load-related capex also reduce utility investment opportunities. In addition, some load-related costs, (e.g., those for fuel, purchased power, and transmission) which could be reduced by DERs are recovered through trackers or formula rates which weaken utility incentives to embrace them.[5] For example, DSM programs provide an opportunity for a distributor to reduce the cost of purchased energy, but the utility has little incentive to reduce energy costs if they are passed promptly through to customers in a tracker.

[4] Trackers can be designed to strengthen cost containment incentives but typically are not.
[5] Many utilities have formula rates (a form of broad-based cost tracker) for their transmission costs. Additionally, many have cost trackers to recover charges they pay for transmission services from retail customers.

We conclude that utilities under traditional regulation often have a material disincentive to embrace DERs, even when DERs meet customer needs at lower cost than traditional grid service. Active opposition to certain DERs by utilities may occur. In addition, utilities do not benefit financially from many social benefits of DERs, such as a lighter environmental footprint. The DER incentive problem is increasingly important in an era when competition from alternatives to grid service is mounting and utilities are under pressure to reduce their environmental impact. In addition to incentive problems, DERs can place stress on a traditional regulatory system. For example, slower growth in average use due to DER adoption can increase the frequency of rate cases.

2.3. Mandates Versus Incentives

Key aspects of utility behavior can and should be mandated. For example, regulators should play an active role in the design of rates to ensure that they send appropriate price signals to customers. Even where mandates are feasible, however, there are often benefits to complementing them with incentives that help align utility interests with the public interest. This decreases utility resistance to complying with mandates, and results in increased enthusiasm, creativity, and industry on the part of utilities in pursuing regulatory goals. The burden of regulatory oversight can be reduced.

2.4. Criteria for Evaluating Altreg Remedies

In this testimony we consider five Altreg tools that have been touted for their ability to encourage efficient DERs. Sensible criteria are needed to compare these options. Relevant criteria include the success of the approach in fostering efficient DERs, addressing any attrition that can result, and making regulation more efficient. Special features of the options should also be considered.

3. Revenue Decoupling

3.1. The Basic Idea

Revenue decoupling adjusts a utility's rates periodically to enable *actual* revenue to track *allowed* revenue more closely. Most revenue decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue, and adjusts rates to draw down these variances. Meanwhile, the RAM escalates allowed revenue to provide relief for growing cost pressures. These mechanisms thus address different sources of financial attrition that utilities can experience between rate cases. The RDM addresses *revenue*-related attrition, leaving the RAM to address *cost*-related attrition.

Revenue Decoupling Mechanisms

An RDM makes regularly scheduled adjustments to rates via a true-up mechanism. Such mechanisms usually involve a balancing account in which past differences between actual and allowed revenue are entered. The accumulated net variance, together with any interest that may be paid, provides the basis for a periodic rate adjustment. This is usually undertaken with respect to usage charges, a practice that favors low-usage customers. Rates rise when volumes are low but also fall when volumes are high.

RDMs can make true-ups annually or more frequently. The size of the rate adjustment permitted in a given year may be capped; this guards against rate shocks that engender customer dissatisfaction and opposition to decoupling. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from R&C customers are decoupled. These customers together account for a high share of a utility's base rate revenue, and are often the primary focus of DSM programs.

RDMs also vary in terms of the services and corresponding tariffs over which revenues are pooled for true-up purposes. In some plans all services are placed in the same group for the calculation of revenue variances and trueups. Other plans have multiple groups of services, sometimes called service "baskets", so that customers of services in each basket are insulated from revenue variances in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true-ups are sometimes allowed only for the difference between allowed revenue and the *weather-normalized* actual revenue. An RDM that addresses demand variances from *all* sources is called a "full" decoupling mechanism. With full decoupling, the utility receives no more and no less than its commission-approved revenue requirement. The complication of weather-normalizing usage data is avoided.

Revenue Adjustment Mechanisms

If allowed revenue doesn't change over time under decoupling the utility will experience financial attrition, since cost tends to rise for various reasons that include input price inflation and demand growth. For this reason, most decoupling systems have a RAM. Utilities operating without RAMs in their decoupling systems often file frequent rate cases. When developing a decoupling system, the need for a RAM is thus less of an issue than its design.

Most RAMs escalate allowed revenue only for customer growth. This is sometimes accomplished by adjusting rates to hold revenue-per-customer constant. Customer growth is an important driver of cost in its own right, and it is highly correlated with other cost drivers such as peak demand. The number of retail customers has frequently been the most important scale variable in PEG's numerous econometric studies of electric utility cost.

Escalating revenue for customer growth reduces the need for rate cases but rarely eliminates it because cost has several other drivers. Some approved RAMs have been "broad based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can reduce the need for rate cases substantially and thereby provide the foundation for a multiyear rate plan.[6] Broad-based RAMs in the United States are most commonly designed using cost forecasts, but inflation and productivity indexing can also be used. The following simple revenue cap index formula is illustrative.

growth Revenue = growth Inflation – X + growth Customers.

Here X, called the "X factor," can reflect achievable productivity growth and any tendency of the chosen inflation measure not to reflect the input price inflation that utilities experience.

[6] These plans are discussed further below.

To illustrate, we have gathered data from the FERC and other publicly available sources on the trend in the cost of base-rate inputs of a sample of 42 vertically integrated electric utilities ("VIEUs") in the US. The sample period is 1997-2014. Costs considered in our study included most non-energy O&M expenses, amortization and depreciation expenses, taxes, and a pro-forma return on net plant value. The sample includes a mix of large and small utilities that together serve 34 states. Table 2 and Figure 1 provide results of this work.

The table and figure also show the trend in the gross domestic price index ("GDPPI") and in the number of retail customers served by the sampled utilities. The GDPPI is the federal government's featured index of inflation in the prices of final goods and services in the US economy. Final goods and services include consumer products, capital equipment, and exports. The GDPPI tends to grow more slowly than the economy's input prices due to the rapid productivity growth of the economy.

Inspecting the results of Table 2 it can be seen that, over the full sample period, the average annual growth rate of VIEU cost substantially exceeded the corresponding trends in the GDPPI and the number of customers served. In fact, the cost trend was nearly equal to the *sum* of the trends of the other two variables. Similar results obtain for energy distribution. When a RAM escalates allowed revenue only for customer growth, utilities therefore usually retain the freedom to file rate cases and occasionally do file. It follows that regulators can approve revenue-per-customer decoupling with little concern that it will produce overearning.

An illustrative revenue cap index is constructed in Table 2 using GDPPI as the inflation measure. X is set at the value needed for the formula to match the cost trend of the utilities in our sample.[7] This value is 0.14% for the full sample period. A RAM with a GDPPI – 0.14% + Customers formula would have exactly compensated utilities (on average) over the *full* sample period but would have materially undercompensated them (on average) over the more recent 2008-2014 period.

[7] This simple method for setting X factors is sometimes called the "Kahn method" since it was developed by noted regulatory economist Alfred Kahn.

Table 2

Trends in VIEU Cost, VIEU Customers and Inflation[8,9]

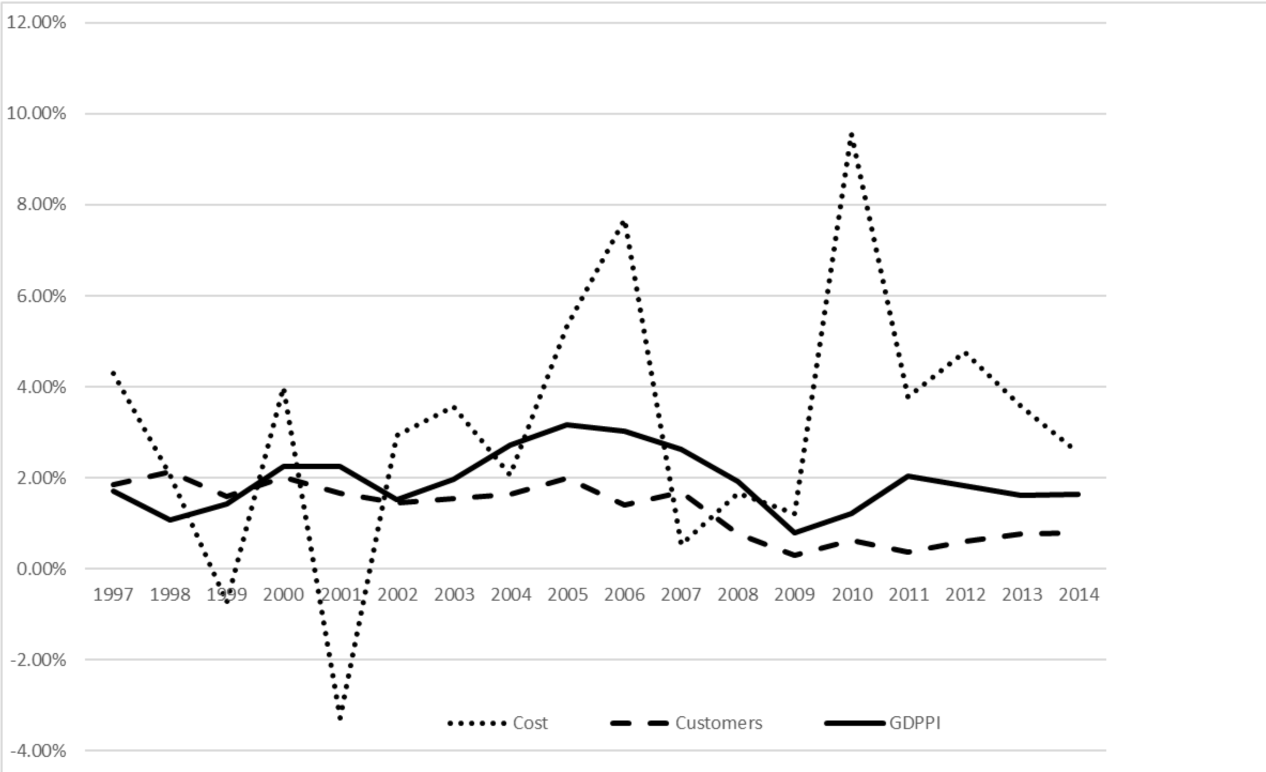
				Revenue Cap Index	
	Cost [%] [A]	Customers [%] [B]	GDPPI [%] [C]	Calculating an X Factor [D=(B+C)-A]	GDPPI-X + Customers [C-X+B]
					[X=0.14%]
1997	4.30%	1.86%	1.71%	-0.73%	3.43%
1998	2.07%	2.13%	1.08%	1.14%	3.07%
1999	-0.73%	1.58%	1.42%	3.73%	2.87%
2000	3.99%	2.02%	2.25%	0.29%	4.14%
2001	-3.28%	1.67%	2.25%	7.20%	3.78%
2002	2.93%	1.46%	1.52%	0.06%	2.85%
2003	3.57%	1.55%	1.97%	-0.05%	3.39%
2004	2.06%	1.63%	2.71%	2.28%	4.21%
2005	5.34%	1.99%	3.17%	-0.19%	5.02%
2006	7.69%	1.40%	3.03%	-3.25%	4.30%
2007	0.53%	1.69%	2.63%	3.80%	4.19%
2008	1.66%	0.78%	1.91%	1.03%	2.56%
2009	1.21%	0.29%	0.79%	-0.13%	0.94%
2010	9.57%	0.62%	1.22%	-7.73%	1.70%
2011	3.77%	0.37%	2.04%	-1.36%	2.28%
2012	4.76%	0.60%	1.83%	-2.33%	2.30%
2013	3.57%	0.76%	1.62%	-1.19%	2.24%
2014	2.56%	0.80%	1.63%	-0.13%	2.30%
1997-2014	3.09%	1.29%	1.93%	0.14%	3.09%
2008-2014	3.87%	0.60%	1.58%	-1.69%	2.04%

[8] Data Sources: FERC Form 1 (cost data), the Edison Electric Institute (allowed ROE), EIA Form 861 (customers), and the Bureau of Economic Analysis (GDPPI). Cost is calculated as reported O&M expenses less fuel, purchased power, transmission by others, miscellaneous power supply and transmission expenses, and customer service and information expenses plus an estimate of capital cost. O&M expenses considered include those for distribution, customer account, generation, and most transmission functions plus administrative and general cost. Capital cost was calculated as the product of rate base and a rate of return, plus depreciation and taxes.

[9] Growth rates are calculated logarithmically.

Figure 1

Trends in VIEU Cost, VIEU Customers, and Inflation



3.2. Decoupling Precedents

Revenue decoupling has been widely adopted in the United States and abroad. States that have tried gas and electric revenue decoupling are shown in Figures 2a and 2b, respectively. Table 3 details current revenue decoupling precedents in the US and Canada.

Inspecting the figures, it can be seen that decoupling is currently used to regulate at least one gas or electric utility in more than twenty-five US jurisdictions. Decoupling is particularly widespread in the gas distribution industry, where it is used in twenty-three jurisdictions. This reflects the fact that declining average use by residential and commercial customers has been chronic in that industry.

Figure 2a Electric Revenue Decoupling by State

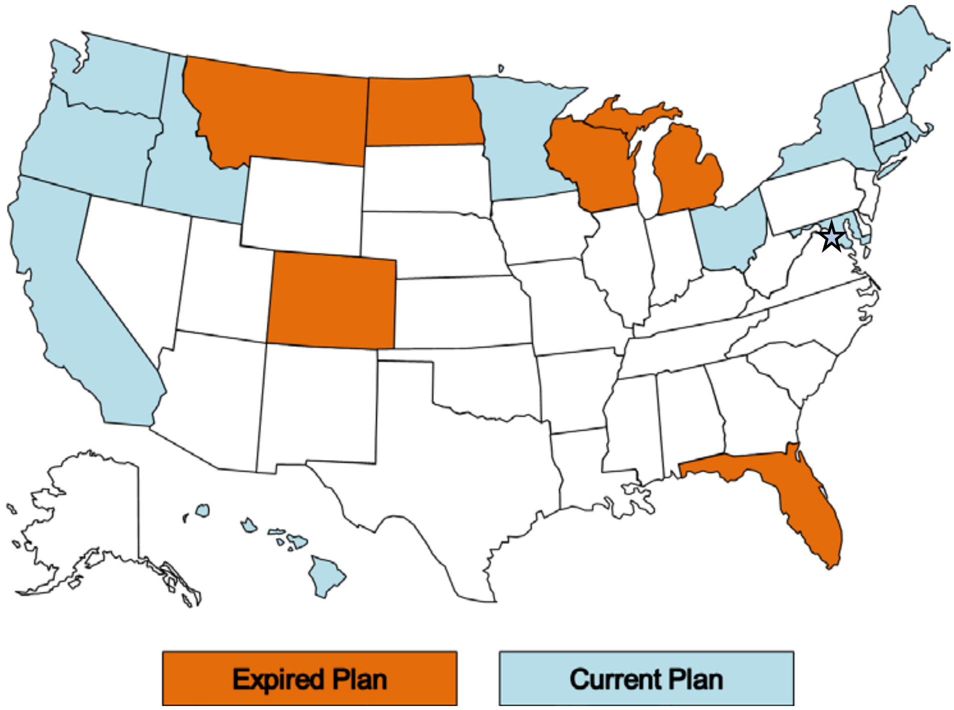


Figure 2b Gas Revenue Decoupling by State

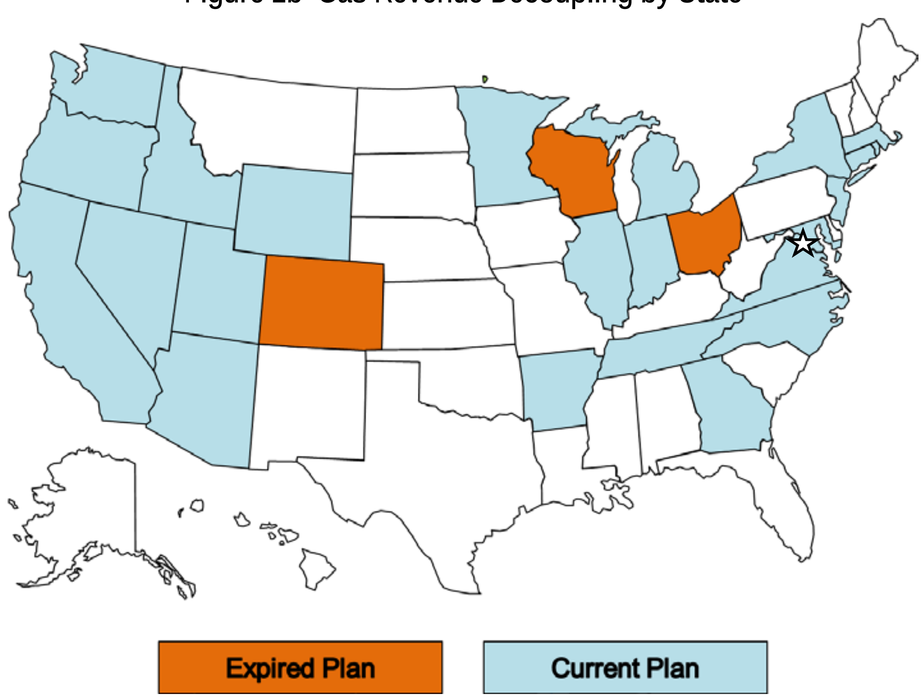


Table 3

Current Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
United States					
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2017	Stairstep through 2016, No RAM thereafter	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-open	Indexing through 2015, No RAM thereafter	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2016-2018	Stairstep	Decision 16-06-054
CA	Southern California Edison	Electric	2015-2017	Hybrid	Decision 15-11-021
CA	Southern California Gas	Gas	2016-2018	Stairstep	Decision 16-06-054
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Avista	Electric & Gas	2016-2018	Customers	Cases AVU-E-15-05, AVU-G-15-01
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IL	Ameren Illinois	Gas	2016-open	No RAM but broad-based capital cost tracker	Case 15-0142
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep through 2016, RPC Freeze thereafter	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	New England Gas	Gas	2011-open	Customers	DPU 10-114
MA	Nstar Gas	Gas	2016-open	Customers	DPU 14-150
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999

Table 3 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
United States (cont'd)					
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-open	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-open	Revenue per Customer Stairstep through 2014, Customers thereafter	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2016-2019	Revenue per Customer Stairstep	Case 15-E-0283
NY	New York State Electric & Gas	Electric	2016-2019	Stairstep	Case 15-G-0184
NY	Niagara Mohawk	Gas	2013-2018	Revenue per Customer Stairstep through 2016, Customers thereafter	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2018	Stairstep through 2016, No RAM thereafter	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2016-2019	Revenue per Customer Stairstep	Case 15-E-0285
NY	Rochester Gas & Electric	Electric	2016-2019	Stairstep	Case 15-G-0286
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Avista	Gas	2016-open	Customers	Order 16-076
OR	Cascade Natural Gas	Gas	2016-2019	Customers	Order 15-412
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2016-2018	Customers	Case PUE-2015-00072
VA	Virginia Natural Gas	Gas	2016-2019	Customers	Case PUE-2015-00129
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Cascade Natural Gas	Gas	2016-open	Customers	Docket UG-152286
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202

In the electric utility industry, decoupling is currently used in fourteen jurisdictions. It has been particularly favored in states that strongly support DSM. The use of decoupling for electric utilities is growing, with recent approvals in Maine, Minnesota, and Washington state.

Minnesota's PUC has approved revenue decoupling for electric services of Xcel Energy and for two gas distributors (CenterPoint Energy and Minnesota Energy Resources Corporation). In approving decoupling for Xcel Energy, the Commission stated that "revenue decoupling has substantial potential to align the Company's interests with the public's interest in conservation and energy efficiency."[10] The approved decoupling system for Xcel Energy has the following provisions.

- Decoupling applies to residential service with space heating, residential service without space heating, and small general service (non-demand). Each service has its own basket.
- Revenue per customer is decoupled, so that revenue requirements rise gradually with growth in the number of customers.
- There is a soft cap on upward RDM rate adjustments equal to 3% of the service group's revenues, excluding revenues from the fuel clause and other riders. Where the cap is exceeded, eligibility for additional revenue in future periods is contingent on a showing that "demand-side management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other non-conservation factors were not the primary factors for the declining sales."[11]
- Each RDM otherwise achieves *full* decoupling and makes adjustments only to *usage* charges.
- Xcel must file a plan to implement an education and outreach program to customers explaining the goals and operations of its RDM program.

In several jurisdictions utilities are *required* to operate under revenue decoupling by legislation or commission policy. California's return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk

[10] MNPUC, Docket No. E-002/GR-13-868, Order (May 8, 2015), p. 73.
[11] ibid, p. 73.

in the midst of the state's bulk power market crisis.[12] More recent legislation in Rhode Island required use of revenue decoupling for the state's gas and electric utilities. Commission policies mandating the use of revenue decoupling mechanisms have been adopted in Massachusetts and New York.

Revenue decoupling appears to have played a role in motivating utilities to embrace DERs. For example, in its most recent State Scorecard, the American Council for an Energy Efficient Economy ("ACEEE") reports net incremental savings from electricity efficiency programs as a share of 2014 retail sales.[13] Setting aside the states in which DSM programs are mainly administered by third parties, 7 of the 12 top-performing states employed electric decoupling in that year.[14] Among the remaining 29 states, only one had decoupling.

3.3. Decoupling Advantages

The numerous advantages of revenue decoupling have prompted Fresh Energy to strongly advocate its use in Minnesota regulation. We discuss here some of decoupling's salient advantages.

Throughput Incentive

Decoupling can reduce or eliminate a utility's throughput-related disincentive for the full array of actions it can take to facilitate DERs. A soft cap on decoupling adjustments is more effective in addressing the throughput incentive than a hard cap, since it assures the utility that variances between expected and actual revenues will eventually be addressed. Under decoupling, revenue is insensitive to a 1% drop in volume growth whether it results from a conventional utility conservation program, less conventional market transformation initiatives, or increased DGS penetration.

[12] See California Public Utilities Code, Division 1, Part 1, Chapter 4, Article 2, Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The commission shall ensure that errors in estimates of demand elasticity or sales not result in material over or undercollections of the electrical corporations."

[13] See American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015. In cases where 2014 data were unavailable, the ACEEE utilized 2013 data instead. This is the latest ACEEE report on this topic.

[14] Third parties, rather than utilities, are primarily responsible for DSM program administration in Delaware, Hawaii, Maine, New Jersey, New York, Oregon, Vermont and Wisconsin, as well as in Washington DC.

The size of the benefit from eliminating the throughput incentive depends on the role utilities play in DSM promotion. If DSM programs are undertaken by independent agencies rather than by utilities, the impact of decoupling on DSM outcomes is lessened. However, utilities have many other ways to influence DSM, including rate design and their support for large DSM budgets and tighter appliance efficiency standards and building codes. One indication of the importance of these other activities is that decoupling has been used in several jurisdictions (e.g., Hawaii, Maine, New Jersey, New York, Oregon, Washington DC, and Wisconsin) in which a sizable portion of DSM programs is not administered by utilities. Decoupling encourages utilities to work more closely with third party administrators. Utilities also have a great deal of influence on policies that affect DGS penetration.

One sign of the contribution decoupling makes to wide-ranging efforts to foster DSM is the commitments some utilities have made to unconventional DSM initiatives as a condition for gaining decoupling plan approval.

- In a decoupling settlement with Wisconsin's Citizens Utility Board, Wisconsin Public Service agreed to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force. These addressed residential and commercial energy efficient building codes, state appliance efficiency standards, and non-regulated fuels efficiency and conservation.
- The Hawaii Clean Energy Initiative Agreement involved the three Hawaiian Electric companies, the state of Hawaii, and its Division of Consumer Advocacy.[15] The agreement contained commitments in more than thirty areas.

In addition, in an order approving a decoupling plan for United Illuminating ("UI"), the Connecticut Department of Public Utility Control stated that it was approving the plan *not* because of its effect on the company's DSM program itself, but for its effect on "areas where UI does not already receive incentives."[16] The Department goes on to explain that

[15] "Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies," 2008.
[16] Connecticut DPUC, Decision in Docket 08-07-04, February 2009, p. 121.

> UI is still viewed as *the* energy provider by the general body of ratepayers. The Department believes that this will not change… Success in achieving Connecticut's energy policy goals requires that the Department take advantage of this relationship to promote the energy-related programs and policies that have been recently set in place.[17]

Rate Design

Another benefit of decoupling is its ability to dovetail with rate designs that encourage efficient DERs. Decoupling imposes no restrictions on the rate designs themselves. Additionally, decoupling can reduce or eliminate the risk of revenue requirement recovery that may result from innovative rate designs that encourage efficient DERs. The maximum reduction in the risk of these rates is achieved when revenue is decoupled from *all* sources of demand volatility, including the business cycle and weather. This benefit of *full* decoupling is not widely recognized.

Some regulators have rejected proposals by utilities operating under decoupling for changes in rate designs intended to achieve goals that decoupling already accomplishes. For example, CenterPoint Energy Minnesota Gas has operated for several years under revenue decoupling. In a recent rate case, the Commission rejected CenterPoint's proposal to raise customer charges, stating that

> Increasing CenterPoint's customer charges would place too little emphasis on the need to set rates to encourage conservation. This is particularly true since the Company has a full-decoupling mechanism… decoupling already guarantees that CenterPoint will not fail to recover its revenue requirement due to lower-than-predicted sales.
>
> Furthermore, a major goal of revenue decoupling is to align a utility's interests with the public's interest in energy efficiency. Increasing the customer charge undermines this goal by incrementally reducing customers' incentive to conserve energy since, with a higher customer charge and relatively lower volumetric charge, they are less able to control the size of their bills by using less energy. Keeping CenterPoint's customer charges at current levels will maintain the existing incentive to conserve without affecting the Company's revenue stability.[18]

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[17] *Ibid*, pp. 121-122.
[18] MNPUC, G-008/GR-15-424, June 2016, pp. 64.

Attrition Relief and Revenue Stabilization

An additional advantage of decoupling is that it automatically addresses the financial attrition that occurs when average use is declining. Declining average use can result from large utility DSM programs, but also from DSM programs managed by third parties, DGS, high prices for energy commodities, and stricter appliance efficiency standards and building codes. The ability of decoupling to address declining average use from various sources helps to explain its popularity. For example, decoupling is popular with many gas distributors even though the declining average use that they have experienced has not been driven chiefly by their DSM programs.

Decoupling can also stabilize revenue in the face of short-run usage fluctuations resulting from changes in weather, the business cycle, and other economic conditions. Revenue from time-sensitive base rates can be particularly sensitive to demand fluctuations.

While decoupling reduces revenue risk, it does not guarantee that a utility will recover all of its costs. A utility operating under decoupling must still manage its costs to ensure that they don't exceed allowed revenue. This can be challenging, especially when the firm is operating under a multiyear rate plan.

Efficient Regulation

Decoupling also has an impact on regulatory efficiency. On the one hand, it adds items to the regulatory agenda. Rates must be reset to effect revenue reconciliations, and a RAM is usually developed and instituted. However, the administrative cost of a decoupling true-up is not very different from administering a cost tracker. For both, the appropriate revenue adjustment must first be ascertained, and then allocated to service classes and recovered through a change in rates.[19]

On the other hand, by addressing important sources of financial attrition, decoupling can permit a reduction in the frequency of rate cases when average use is declining and/or the

[19] The administrative cost and rate churn resulting from decoupling can be reduced by timing them to occur when rates are adjusted for other reasons.

RAM is broad-based. A single rate case can result in thousands of pages of testimony and discovery documents. The desire to reduce the frequency of rate cases is an important impetus for approving cost trackers as well.

Decoupling can also help streamline rate cases when they do occur. Controversy over billing determinant forecasts in rate cases with future test years is reduced. Moreover, decoupling does not require complicated calculations to estimate load savings from DSM programs.

3.4. Criticisms of Decoupling

Decoupling does have critics. Some concerns are substantive but can be addressed by regulators in straightforward ways. Other concerns are misplaced.

Rate Stability

Some critics of decoupling express concern that it can destabilize rates. However, soft caps on revenue adjustments can mitigate this problem without weakening the incentive and attrition relief benefits of decoupling. Experience has shown that the increased rate volatility due to revenue decoupling is manageable. In a recent study of US electric and gas decoupling true-ups, Pamela Morgan found that most rate adjustments have been small (64% were within ±2% of retail rates, and roughly 80% were within ±3%). She also found that a significant share (37%) of these adjustments represented rate *reductions* rather than *increases*.[20]

Another substantive concern is that decoupling true-ups may cause customers in one rate class to absorb the impact of reduced loads in other classes. A drop in business sector demand, for example, might lead to an increase in residential bills, or vice versa. However, this issue can be addressed through the use of separate service baskets.

Tailored Service

Another substantive concern is that decoupling may decrease the utility's attentiveness to customer needs and preferences. Firms in competitive markets can suffer sharp reductions in sales when their rates or product quality are not competitive. However, the monopoly

[20] Pamela Morgan, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations, Graceful Systems LLC, May 2013.

character of utility service limits the ability of customers to go elsewhere, and revenue decoupling can further reduce the chance of losing revenue when customer needs aren't met. As a result, utilities that operate under decoupling may feel less pressure to offer services tailored to customer needs. Concern about service quality repercussions can be addressed by developing service quality monitoring or incentive mechanisms and/or by permitting the Commission to disallow compensation for certain revenue losses due to outages.

Uneconomic Bypass

The demand of some customers *is* sensitive (i.e., elastic) with respect to a utility's rate and service offerings. An example is an establishment that consumes large amounts of power, and which can develop self-generation capabilities or shift its operations to another service territory. If decoupling revenue from serving such customers makes the utility less responsive to their needs it could trigger the unnecessary loss of some loads, and/or a failure to attract new loads. These are both forms of uneconomic bypass that can result unnecessarily in higher rates for other customers. Concerns about the treatment of demand-elastic customers can be mitigated by applying decoupling selectively to residential and commercial customers, who generally have less elastic demands.

Rate Case Frequency

Though static or declining average use by R&C customers is generally the rule for US electric utilities today, some utilities still experience *rising* average use. This can be true for reasons unrelated to the effectiveness of DSM programs. For example, customers in the service territory may have been slow to invest in air conditioning and the latest consumer electronics.

Where average use is rising, revenue per customer decoupling slows revenue growth and the frequency of rate cases will tend to increase. Utilities are more likely to oppose decoupling. The tendency of decoupling to increase rate case frequency and erode utility earnings between rate cases under these circumstances can be addressed with a broad-based RAM.

Electric Vehicles

Though decoupling tends to improve a utility's environmental footprint, for some services the opposite is true. For example, decoupling can weaken a utility's incentive to promote electric vehicle ("EV") loads. Such loads can be encouraged by targeted performance incentive mechanisms or their exclusion from decoupling.

Weakened Customer Conservation Incentives

It is sometimes argued that decoupling weakens customer incentives to pursue DSM. This argument is untrue. Under decoupling, customers *as a group* must pay for lost margins from DERs but *individual* customers can still reduce their bills by conserving. The upward drift in volumetric and other usage charges that often results from decoupling can also incent individual customers to conserve more. In effect, the revenue requirement is a "hot potato" and individual customers are incentivized to toss as much of it as possible to their neighbors.

4. Tracking of DSM Expenses

DSM expenses of utilities are usually tracked, for several reasons. One is that DSM programs are costly and often mandated. Tracking is fair for mandated costs, and encourages policymakers to make mandates reasonable. Another reason is that DSM expenses sometimes rise rapidly, and trackers can then reduce the need for frequent rate cases.

There is also a strong incentive argument for DSM cost trackers. Even when decoupling removes the throughput incentive, we have seen that a utility's incentive to contain load-related costs is often not strong. Utilities, additionally, have some incentive to trim untracked expenses between rate cases. Tracker treatment for utility DSM expenses removes the incentive utilities have to contain DSM spending between rate cases, helping to tip the balance of utility incentives in favor of DSM solutions.

5. DSM Performance Incentive Mechanisms

5.1. The Basic Idea

A targeted performance incentive mechanism ("PIM") links a utility's revenue mechanically to its performance as measured using metrics and targets. PIMs can strengthen performance incentives by providing awards and/or penalties. This is a popular form of performance-based regulation in the United States.

A demand-side management PIM links a utility's revenue to its performance as a DSM service provider. Demand-side management PIMs typically involve awards but no penalties. Awards may be granted for all load savings, but are typically contingent on attainment of a threshold level of savings. Awards are sometimes capped. Compensation for load savings can take several forms.

Shared savings. This approach grants the utility a share of the estimated net benefits that result from a DSM initiative. Net benefits are the difference between benefits and costs, so this approach encourages utilities to choose more cost-effective programs and to manage them more efficiently. However, the estimation of net benefits can be a complex and controversial issue in regulatory proceedings.

Bonus. Another possibility is to compensate the utility at a predetermined rate for each unit of load savings achieved (or for each unit of another desired outcome). The bonus rate may differ for different kinds of projects in the utility's portfolio. Though this approach does not require the estimation of net benefits, load savings must still be calculated.

Management fees. This alternative grants the utility an incentive equal to a specific share of program expenditures. Under this approach, the incentive calculation depends on the costs incurred (specifically, expenditures by the utility) but not on the benefits achieved. The utility is rewarded for spending money. However, its simplicity makes it an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), but its ease of administration has encouraged its use for other types of DSM programs as well. For example, in California a complex shared-savings PIM was recently replaced with a PIM based on management fees.[21]

Amortization. Under this approach, DSM expenses are amortized. A premium (also known as an "adder") is sometimes added to the ROE applied to these expenditures. This premium may be contingent on achieving certain performance goals. The return may be earned immediately through a tracker or accumulate in a regulatory asset. As is the case with management fees, the size of the incentive payment is determined by costs incurred (i.e., utility expenditures) rather than benefits achieved.

Several types of demand-side management PIMs require estimates of load savings. Load savings can be estimated using engineering models, off-the-shelf estimates of typical savings (aka "deemed savings"), or statistical analysis of customer billing data. Even with high-quality data, however, reliably estimating savings can be challenging due to several factors. These include free riders (customers who would have implemented the DSM measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient). The difficulty of measuring load savings varies by program.

5.2. Precedents for Demand-Side Management PIMs

The 2015 ACEEE survey found that demand-side management PIMs are common for US energy utilities.[22] Figures 3a and 3b indicate states that had such PIMs for retail electric and gas utilities respectively, along with those that had revenue decoupling. On the electric side, it can be seen that a majority of retail jurisdictions had some form of demand-side management PIM. At least ten jurisdictions that had implemented demand-side management PIMs had also adopted revenue decoupling for the same industry. For example, Minnesota recently approved

[21] California Public Utilities Commission (2013). Decision 13-09-023, Rulemaking 12-01-005.

[22] American Council for an Energy-Efficient Economy, *op. cit.,* pp. 43-44

Figure 3a DSM Performance Incentive Mechanisms: Electric

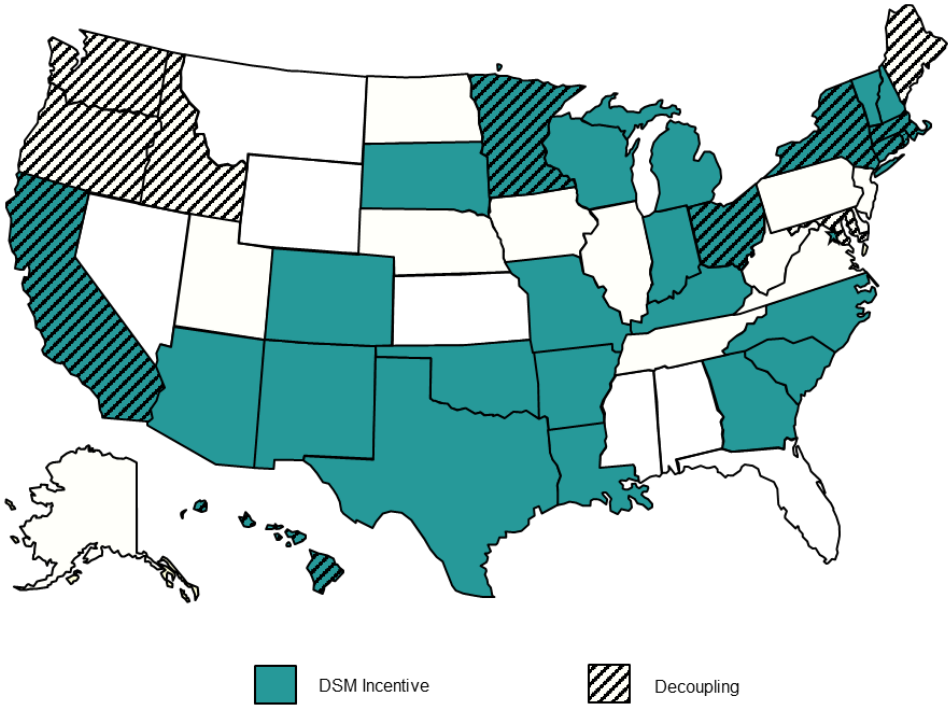

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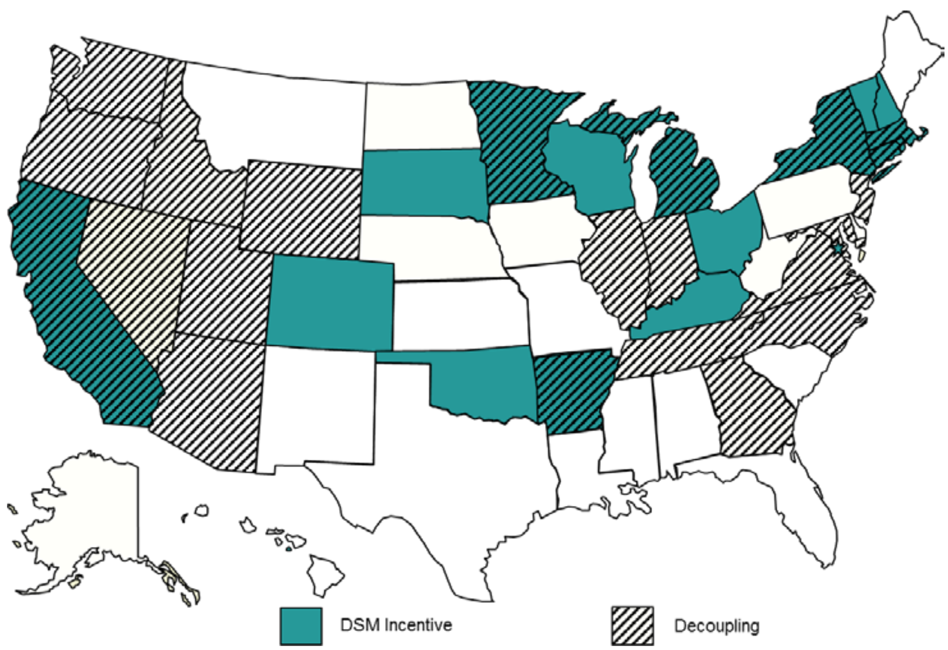
Figure 3b DSM Performance Incentive Mechanisms: Gas



REFERENCES

DSM precedents drawn from American Council for an Energy-Efficient Economy, *The 2015 State Energy Efficiency Scorecards*, Report U1509, October 2015.

revenue decoupling for Xcel Energy but retained a demand-side management PIM for the company. Some states (e.g., Oregon and Maine) that have revenue decoupling but no demand-side management PIMs have an independent DSM program administrator. On the gas side, the ACEEE reported demand-side management PIMs in seventeen jurisdictions. Eight of these states also had revenue decoupling.

Most demand-side management PIMs focus on conservation programs and some states have decades of experience with them. Some existing PIMs also address peak-load management programs, but few if any address distributed generation or storage.

Most demand-side management PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, like those where transmission and distribution capex will otherwise be needed in the near future to replace aging assets or accommodate growing load. Consolidated Edison of New York's Brooklyn Queens Demand Management Program is a geographically targeted program with incentives in the form of amortization with an ROE adder.

Peak-Load Management

There is growing interest in metrics and PIMs for peak-load management, for several reasons.

- Peak load is an important driver of utility cost.
- The load peakedness of many utilities is growing. Peakedness can be exacerbated by high penetration of distributed solar generation.
- Most utilities purchase power in managed markets with volatile prices. Low prices typically occur at night when demand is weakest and generation from wind resources tends to be highest. High prices generally occur in the early evening hours of summer and winter business days when demand is stronger and any solar power supplies are diminishing. Shifting demand to low-price periods can substantially reduce purchased-power costs.

- With AMI increasingly widespread, there are expanded opportunities to reduce load peakedness. Regulators are showing increased interest in using AMI more aggressively for this purpose.[23]
- With the cost of distributed storage falling, the responsiveness of customers to peak-load management initiatives may increase.

PIMs for peak-load savings are likely to be based on the reduction in peak kW. Calculation of such savings can be complicated since peak loads are sensitive to volatile external business conditions, such as the temperature on the hottest summer days. Permitting utilities to keep some of the revenue obtained from successful demand-side bids in managed bulk power markets is an alternative to a peak-load reduction PIM.

5.3. Pros and Cons of Demand-Side Management PIMs

PIMs offer both advantages and disadvantages as a way to incentivize utilities to foster DSM. On the plus side, they can in principle compensate utilities for base rate revenue losses from DSM programs that they cover. This reduces the utility’s disincentive to foster DSM. Rate design freedom is preserved, and utility incentives to promote EVs aren’t attenuated.

Where the throughput incentive is addressed by other Altreg tools like revenue decoupling, these PIMs are still quite useful because they can provide a *positive* incentive to embrace DSM. PIMs can encourage utilities to use DSM to reduce load-related costs like those for fuel, purchased power, load-related capex, and environmental damages. This principle has been recognized by the MNPUC. In its 2016 order adopting modifications to its demand-side management PIM, the Commission stated that

> The Commission may authorize a utility to recover CIP-related costs via a Conservation Cost Recovery Charge built into the utility’s rates. And the Commission may authorize a utility to implement revenue decoupling, a rate design that helps ensure that a utility recovers certain fixed costs regardless of how much energy it sells. But while these cost-recovery mechanisms may

[23] See, for example, “California Regulators Approve Major Overhaul of Residential Electric Rate Design,” *SNL Electric Utility Report*, 13 July 2015 and “California Mandates TOU Pricing for Residential Customers,” *PUR Utility Regulatory News,”* Letter #4229, 17 July 2015.

> reduce a utility's *disincentive* to depress its own sales via conservation, they do not affirmatively *encourage* the practice of promoting conservation.[24]

Shared savings PIMs have the additional advantage of encouraging *efficient* DSM programs. This is particularly beneficial due to the fact that DSM program expenses are typically tracked.

In contrast to decoupling and fixed/variable pricing, demand-side management PIMs permit compensation for DSM programs without denying utilities the benefit of any growth in average use that occurs due to demand growth. This helps to explain the popularity of these PIMs with electric utilities since, as we have seen, many of these utilities experienced rising average use until recently.

Demand-side management PIMs also have drawbacks. Award rates may not be set high enough to eliminate the throughput incentive and provide sufficient encouragement to use DSM for cost containment. In addition, some PIM styles can allow the rewards granted to utilities for load savings to become sizable over the years.

A bigger problem is that many types of PIMs can involve complex calculations that invite controversy in regulatory proceedings. As a consequence, the scope of DSM programs addressed by PIMs is often limited to those where it is practical to estimate load savings and net benefits. Some jurisdictions sidestep the chore of calculating net benefits.

Simplicity is an important goal, but in this case encourages utilities to focus on DSM programs with more easily measured impacts. Other DSM initiatives that are equally or more cost effective may be neglected. Neglected initiatives may include changes in rate designs, campaigns to tighten state and federal building codes and appliance efficiency standards, cooperation with third party vendors of energy services, and other efforts to transform energy service markets. By motivating utilities to improve their performance with respect to specific programs and metrics, PIMs may thus lead to mediocre and even poor performance in other DSM areas.[25] For example, utilities with sizable conservation programs may nonetheless

[24] MNPUC, Docket E,G-999/CI-08-133, August 2016, p. 3.
[25] This was a concern of the New York PSC in its Track 2 decision in its Reforming the Energy Vision ("REV") proceeding, NYPSC, Case 14-M-0101, p. 63.

propose rate designs with low usage charges that discourage DSM or may be slow to adopt time-sensitive pricing. Designing PIMs that encourage a wider range of DSM initiatives is a contemporary challenge in regulation.

Demand-side management PIMs also do not address declining average use that results from external business conditions. For example, they have not offered gas distributors relief from declining average use from drivers other than their own DSM programs. They are similarly of limited use in protecting utilities from demand volatility.

These deficiencies of demand-side management PIMs help to explain why they are rarely been used to encourage DGS. Calculation of DGS benefits is complex, and utilities often lack the power to steer DGS to times and places where net benefits are substantial. Load impacts and benefits attributable to utility effort can be difficult to ascertain. Consequently, utilities with demand side management PIMs can have still have a weak incentive to use DGS as a cost containment tool, and may oppose DGS. Efforts to discourage DGS can also discourage DSM.

On balance, demand-side management PIMs have many benefits in modern regulation, and this helps to explain their popularity. Some commentators have described the combination of revenue decoupling, DSM cost trackers, and demand-side management PIMs as the three legs of a stool incentivizing utilities to aggressively pursue DSM.[26]

6. Fixed/Variable Rate Designs

6.1 Fixed/Variable Basics

Fixed/variable pricing is an approach to rate design that limits recovery through variable charges of costs that are fixed, in the *short* run, with respect to system use. A greater proportion of fixed costs are recovered through fixed charges, such as customer and facilities charges. Customers pay a substantial fixed monthly charge for service regardless of their usage

[26] See, for example, Nowak, S., Baatz, B., Gilleo, A., Kushler, M., Molina, M., & York, D. (2015). *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, American Council for an Energy-Efficient Economy, Report U1504.

and thus have less ability to reduce their bills with lower usage than under legacy rate designs. *Straight* fixed/variable ("SFV") rate designs recover *all* fixed costs through fixed charges. A rate design that involves fixed charges, but does not recover all fixed costs through them is sometimes called "*modified*" fixed/variable ("MFV") pricing.

6.2 Fixed/Variable Precedents

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Current precedents for fixed/variable pricing in retail energy utility ratemaking are shown below in Figure 4. It can be seen that fixed/variable pricing has been considerably more common for gas distributors than electric utilities. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida and Oklahoma have fixed charges that vary with long-term consumption patterns.

6.3 Pros and Cons and Fixed/Variable Pricing

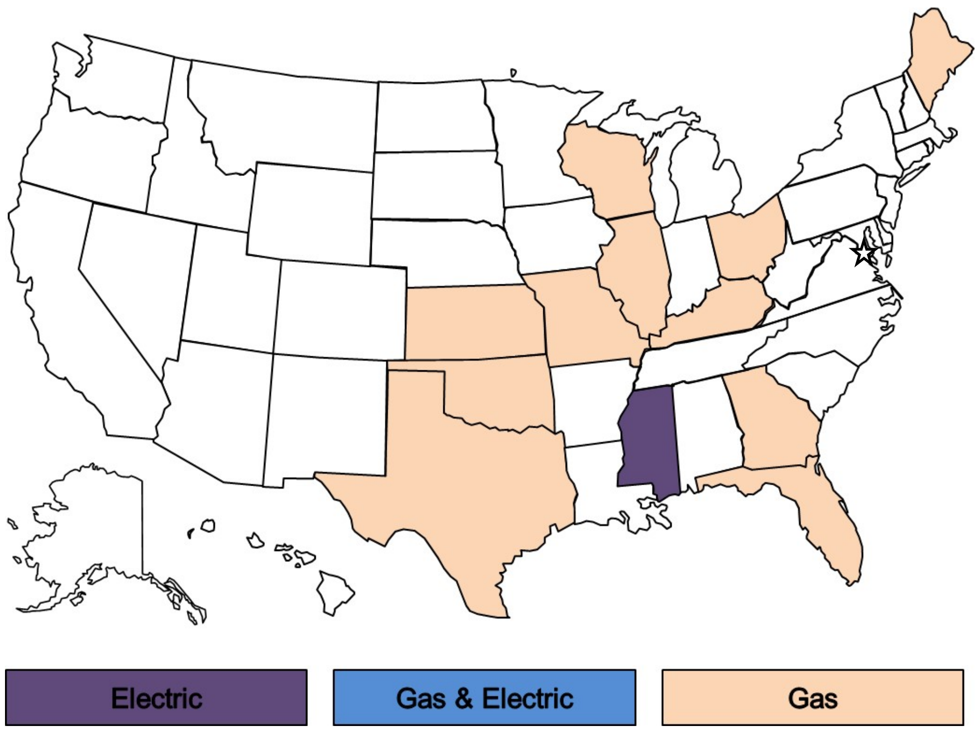
Advantages

Straight fixed/variable pricing can remove the throughput incentive, decreasing utility reluctance to pursue a wide range of actions that could foster DERs. As we discussed in the section on revenue decoupling, this benefit is greater when utilities undertake DSM programs, but is still substantial when they do not. SFV pricing also reduces the earnings risk of demand volatility.

The impact of SFV pricing on revenue growth is similar to that of revenue-per-customer decoupling. Base-rate revenue grows between rate cases at roughly the pace of customer growth. When average use is *declining*, base revenue will therefore grow more rapidly with fixed/variable pricing than with legacy rate designs so that rate cases are less frequent. This benefit is achieved even if the decline is largely driven by external business conditions.[27] Controversy over future billing determinants in rate cases with forward test years is reduced. In contrast to revenue decoupling, these outcomes are achieved with stable rates. Moreover,

[27] This helps to explain the popularity of fixed/variable pricing amongst gas distributors.

Figure 4 Fixed/Variable Pricing Precedents by State



administrative cost is unusually low since fixed/variable pricing requires neither decoupling true-ups nor load impact calculations.

Is SFV Pricing Efficient?

Other touted advantages of fixed/variable pricing include its ability to foster efficient DERs by sending customers better price signals. It is sometimes argued as a matter of principle that fixed charges should address fixed costs. These claims are more controversial. Usage charges should communicate to customers the cost of system use. Many costs of base rate inputs that are fixed in the *short* run with respect to system use are not in the *medium* and *long* run. For example, the costs of many distribution facilities (e.g., substations and transformers) vary with local circuit coincident peaks.

The question then arises as to when usage rates should rise to reflect marginal costs, if they are to elicit the behavior from customers that permits containment of these costs. Many customers need price signals well in advance of a rise in short-run marginal cost if they are to change their behavior in a timely fashion. Having high usage charges for base rate inputs only when and where marginal costs are high can confuse customers and violate rate gradualism principles.

In addition to restricting the use of volumetric charges that are fixed or seasonally varying, SFV pricing also restricts the potential for rates to send time-varying price signals that reflect longer run marginal costs. It thus reduces regulators' ability to use time-varying rates to encourage rooftop solar PV owners to boost evening output or install storage, or customers with EVs to charge their vehicles at night.

Another consideration is the environmental and other externalities that system use gives rise to. While these are traditionally disregarded in utility rate designs, environmental groups are correct to point out that a truly efficient price to the customer per kWh of power delivered from the grid would reflect marginal environmental costs, and that these are not reflected in energy prices in most parts of North America today. Large volume residential customers do more damage to the environment than small volume customers, and bear more responsibility for costly measures that may ultimately be required to contain damage. If recovery of a utility's revenue requirement can be assured by other means, such as revenue decoupling, utilities can, in the absence of appropriate emissions taxes, take some account of externalities in the design of their rates for producing and delivering power.

Disadvantages

The various disadvantages of fixed/variable pricing have prompted environmental organizations to oppose it in many proceedings. The preceding discussion suggests that a salient disadvantage of fixed/variable pricing is the restrictions it places on rate designs. Rate designs have an important impact on customer incentives for DERs because they affect the payback period on investments (e.g., those for better insulation) that these initiatives involve. DERs are generally encouraged by high usage charges. While volumetric charges are not ideal for sending signals concerning the long-run cost of coincident (system or circuit) peak demand, they can be made more cost-causative to the extent that they are higher in seasons and hours of the week when marginal costs are highest. Implementation of SFV pricing can also produce sharp increases in bills for low income and other small-volume customers.

In view of these disadvantages, and the widely accepted principle of rate gradualism, commissions accepting the merit of fixed/variable pricing are nonetheless likely to phase in higher customer charges gradually. Fixed charges may never be permitted to address some costs that are largely fixed in the short run but vary with system use in the long run. The resultant *modified* fixed/variable pricing is considerably less effective than revenue decoupling in removing the throughput incentive and the risk of demand volatility and time-sensitive rates, and in addressing potential attrition from declining average use. The utility will accordingly be less likely than under revenue decoupling to embrace all cost effective DERs and more likely to take steps to discourage DERs.

In addition, while modified fixed/variable pricing restricts rate design less than the SFV approach, to the extent that it ignores long run marginal costs and external costs it can nevertheless limit the potential for rates to send appropriate price signals to customers concerning DER decisions. Modified fixed/variable pricing is thus suboptimal from an incentive point of view, in relation to both utility and customer behavior.

Other disadvantages of fixed/variable pricing also merit note. Like revenue per customer decoupling, for example, fixed/variable pricing increases financial attrition and the frequency of rate cases when and where average use is rising.

7. Multiyear Rate Plans

7.1. The Basic Idea

DSM and other DERs can reduce load-related cost like those for generation and transmission investments. This suggests that a utility's incentive to embrace DERs can also be strengthened by increasing its motivation to contain load-related costs. Multiyear rate plans ("MRPs") are one means of accomplishing this.[28] The basic idea of an MRP is to compensate a utility for its services over several years with revenue that, while reflective of changing cost pressures, does not closely track the utility's *own* cost of service closely. MRPs utilize two tools to relax the link between a utility's own cost and its revenue:

[28] Incentivization of trackers and formula rates for load-related costs is an another means of accomplishing this.

1. A moratorium is imposed on general rate cases that typically lasts two to four years.
2. Between rate cases, an attrition relief mechanism (“ARM”) automatically adjusts rates or the revenue requirement for changing business conditions (e.g., inflation and customer growth) without linking the relief to the utility’s own cost growth. Methodologies for the design of ARMs include cost forecasting and inflation and productivity indexing.

The combination of a rate-case moratorium and the ARM approach to rate escalation can strengthen a utility’s cost containment incentives, despite a material reduction in regulatory cost. MRPs nonetheless typically address some costs separately from ARMs using trackers. A “tracker/freeze” approach is popular today, which combines tracker treatment of some rapidly rising costs with a rate freeze.

Some MRPs feature earnings sharing mechanisms which share surplus and/or deficit earnings between utilities and customers. Surplus or deficit earnings result when the ROE deviates from its commission-approved target. Off-ramp mechanisms may permit suspension of a plan under pre-specified outcomes such as persistently extreme ROEs.

Most MRPs also include PIMs. These have in the past been used chiefly to balance the incentives for cost containment with incentives to pursue other goals, such as the maintenance or improvement of service quality, which matter to customers and the public. Many MRPs have also included demand-side management PIMs, which further strengthen utility incentives to use DSM to reduce load-related costs. In the future, MRPs are likely to include PIMs that address new concerns. For example, PIMs may afford utilities a share the benefit of peak-load management and DGS, or address the quality of connections and other services provided to DGS customers.

7.2. MRP Precedents

MRPs are the most common approach to Altreg around the world. They were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies.[29] In these industries, a major attraction of these plans was their ability to protect core customers so that utilities could have more flexibility in fashioning rates and services for markets with diverse competitive pressures and complex, changing customer needs.

US and Canadian precedents for MRPs in the electricity and gas utility industries are shown in Figures 5a and 5b. In the US, MRPs have traditionally been most common in California and the Northeast. Plans have recently been adopted by vertically integrated electric utilities in several other states, including Florida, North Dakota, Virginia, and Washington. The FERC uses MRPs to regulate oil pipelines.

Canada is moving towards MRPs for gas and electric power distribution in its four most populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Great Britain, and New Zealand are long-time practitioners.

7.3. Advantages of MRPs for Encouraging DERs

MRPs can improve utility incentives to embrace DERs if they are properly designed. Their chief advantage is the general incentive they can provide to slow growth in the rate base. Since DERs can be an effective tool for reducing rate-base growth, utilities operating under MRPs have more incentive to embrace them. For example, if a utility uses DSM or DGS to reduce its need for substation capex during a plan, it can keep some of the resultant cost savings for several years.

MRPs can also incorporate mechanisms to weaken the throughput incentive. For example, it is easy to add revenue decoupling. When an MRP features decoupling, the ARM escalates allowed revenue and thus operates as a broad-based revenue adjustment mechanism, as discussed in Section 3. Utilities in California and Hawaii operate under MRPs with decoupling and have experienced some of the highest levels of distributed solar generation penetration in the United States.[30] Utilities in New York and Washington state also

[29] Several MRPs have been approved over the years for Minnesota phone companies.
[30] Solar generation is also encouraged in these states by other conditions, including strong sunlight.

Figure 5a Recent US Multiyear Rate Plan Precedents by State[31]

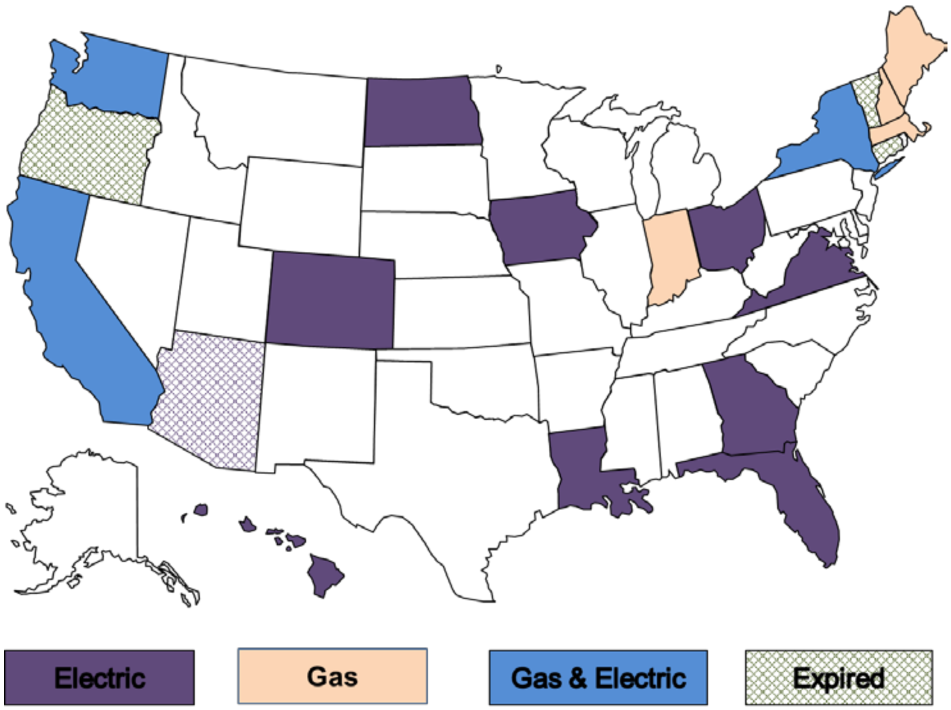
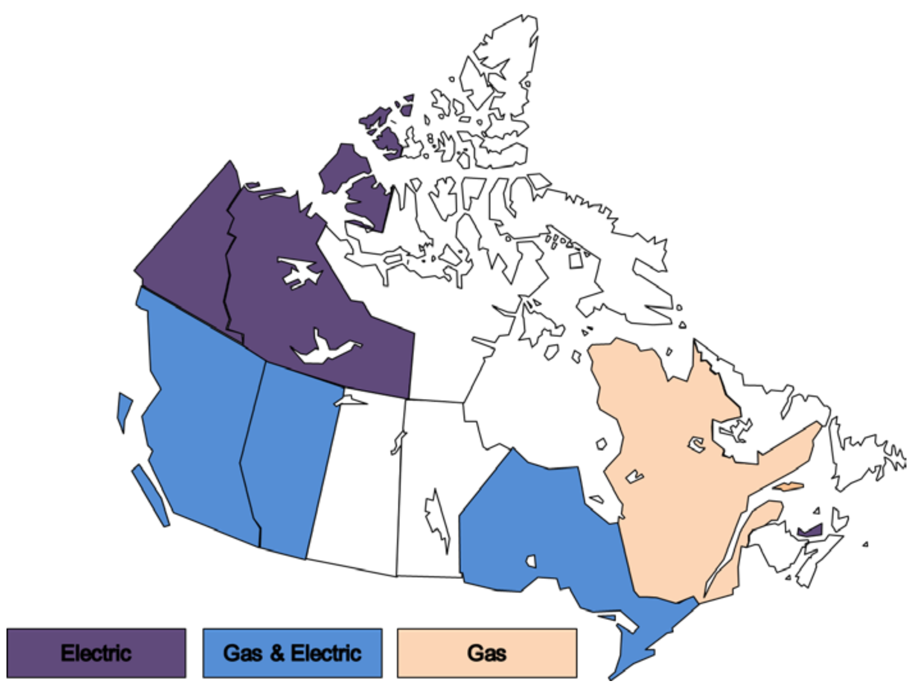


Figure 5b Recent Canadian Multiyear Rate Plan Precedents by Province



[31] We do not include the Xcel Energy (MN) plan on this map because its recently approved MRP has a term of only two years.

operate under MRPs with decoupling. The "RIIO" approach to utility regulation in Britain combines MRPs and decoupling as well.[32]

Additional positive incentives to embrace DERs are desirable since the cost containment incentives generated by MRPs can still be muted by provisions like cost trackers, earnings sharing, and the occasional rate cases. These additional incentives can be achieved with a combination of demand-side management PIMs and tracker treatment of DSM expenditures. The combination of an MRP, revenue decoupling, DSM performance incentive mechanisms, and the tracking of DSM-related costs can provide *four* "legs" for the DSM "stool." While MRPs are often complex, they can nonetheless materially reduce the cost of regulation by reducing the frequency of rate cases.

7.4. Limitations of MRPs

MRPs also have certain limitations that merit mention. For example, many US jurisdictions have limited experience with these plans. Design of the ARM and cost tracker provisions of MRPs can be controversial. Utility operating risk can increase. Measures to contain risk such as earnings sharing mechanisms can reduce the touted performance incentives.

8. Application to Otter Tail Power

8.1. Background

OTP is a small investor-owned electric utility based in Fergus Falls, MN. It serves about 131,000 customers, most located in small towns and nearby rural areas of western Minnesota and the eastern Dakotas.[33] The company has vertically integrated electric operations. In 2015, OTP's generation equaled 40% of its power supplies, and under Minnesota regulation OTP can still qualify to build new generation capacity to serve native loads. [34]

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[32] The acronym RIIO stands for Revenue = Incentives + Innovation + Outputs.

[33] Direct Testimony of Thomas R. Brause in Docket E017/GR-15-1033, p. 3. Most rural areas of the region are served by cooperatives, however.

[34] OTP 2015 FERC Form 1, p. 401a.

Low-cost wind resources for generating power are unusually abundant in OTP's service territory and a promising source of exports that can stimulate the local economy. However, coal-fired power plants still accounted for about 78% of OTP's generation volume in 2015.[35] Wind and hydro facilities accounted for about 21% of the volume and combustion turbines and small diesel units for about 1%. The Company estimates that in 2015 about 19% of the electricity consumed by its retail customers was generated from renewable resources.[36]

The demand mix of OTP is diverse. In 2015, commercial customers accounted for around 35% of electric revenues. Residential customers accounted for 32% of revenues while industrial customers accounted for around 30%.[37]

OTP is a member of the Midcontinent Independent System Operator ("MISO") and purchases sufficient power in MISO's energy market to offset its retail supply deficit. The Company has a generation capacity requirement based on MISO Module E requirements. It must have sufficient Zonal Resource Credits to meet its monthly weather normalized demand, plus a reserve margin. This is achieved through a combination of Company-owned generation capacity, additional capacity secured by bilateral contracts, and load management control capabilities.[38]

OTP recovers its transmission cost from MISO using a MISO Tariff Attachment O formula rate. It is then charged by MISO for its use of the transmission system under the Network Integration Transmission Service ("NITS") and Network Upgrade Charge ("NUC") rates. Both of these charges are assessed on the basis of OTP's monthly peak demands. These rates do not vary seasonally even though the demand for transmission service in the region has summer and winter peaks.

Retail base rates in Minnesota are adjusted in occasional rate cases that often feature forward test years. Costs of OTP's fuel, purchased power, environmental compliance,

[35] Otter Tail Corp., Form 10-k, February 2016, p. 7.
[36] Brause, *op. cit.,* p. 4.
[37] Otter Tail Corp., *op. cit.*, p. 6.
[38] Otter Tail Corp., *op. cit.,* p 7.

renewable energy, transmission capex, and DSM are addressed by cost trackers.[39] OTP proposes continuance of these trackers. The Company is not proposing major Altreg reforms, like revenue decoupling or a multiyear rate plan, which were recently proposed by Xcel Energy in Minnesota.[40]

Each regulated electric utility in Minnesota is required by Section 216B.241 of the Minnesota Statutes to make annual investments and expenditures in cost-effective energy conservation. The law provides a default annual goal of achieving cost-effective energy savings equivalent to 1.5% of average retail sales. The Minnesota Conservation Improvement Program ("MNCIP") also includes a Financial Incentive Mechanism that encourages utilities to pursue conservation. This mechanism, as modified in Docket E,G99/CI-08-133, shares the estimated net benefits of conservation programs between customers and utilities. For an electric utility that achieves energy savings of at least 1.0 percent of retail sales, the mechanism awards the utility a share of the net benefits, increasing by an additional 0.75 percent for each additional 0.1 percent of energy savings the utility achieves, up to 1.7 percent of retail sales. The Net Benefit Caps are set at 13.5 percent in 2017, 12.0 percent in 2018, and 10.0 percent in 2019.[41] For OTP, incentive payments were about $2.6 million in 2012, about $4 million in 2013, and about $2.9 million in 2014.[42]

Section 216B.1611 Subdivision 2(b) of the Minnesota Statutes states that "The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation." However, no such mechanisms have been approved.

OTP currently operates under a 2014-2016 Triennial MNCIP plan approved by Deputy Commissioner William Grant of the Minnesota Department of Commerce. The Company has received rewards for its conservation programs. Its saving goals for the 2014-2016 period were just a little above the statutory minimum goal, but the proposed Triennial MNCIP plan for the

[39] Some costs of fuel, purchased power, and DSM are included in base rates.
[40] A public utility may propose a multiyear rate plan under Minn. Stat. 216B.16.19.
[41] Docket No. E,G999/CI-08-133, Order (Aug. 5, 2016), p. 28.
[42] Docket No. E,G999/CI-08-133, DOC DER Report (Jul. 14, 2015), p. 29.

2017-2019 period features 1.75% average annual load savings. In OTP's rate case filing the Company forecasts flat average use for residential and small commercial customers for many years in the future.

Another section of Minnesota law permits investor-owned utilities to apply for a Value of Solar ("VOS") tariff in lieu of net metering for customers with solar facilities, and as a rate for community solar gardens.[43] The legislation requires that the VOS tariff take into account environmental benefits.

Minnesota law favors conservation over the addition of new resources and the use of renewable resources where practicable when new supplies are needed. A state renewable energy standard requires OTP to generate or procure sufficient renewable generation to provide retail electric customers with 20% of their power supplies by 2020 and 25% by 2025.[44] Each utility must obtain approval from the MNPUC of a 15-year advance integrated resource plan ("IRP"). In its latest IRP ruling, the Commission authorized OTP to prepare for the retirement of the aging Hoot Lake coal-fired generating station and to increase its gas-fired, wind-powered, and solar generation capacity.[45]

Section 216B.03 of the Minnesota Statutes states that "to the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use." OTP's standard tariffs for residential, farm, and small general service customers are fairly traditional. A substantial portion of base rate revenue is raised from seasonally varying volumetric charges. The Company also has rates in Minnesota for residential demand control, general service time of use and time of day, real time pricing, and controlled and interruptible services.

OTP's current rate case filing is its first since 2010 and its second since 2007. A 2016 test year is employed. The Company is requesting a 9.8% revenue increase. Costs, chiefly for capex, that are currently recovered in OTP's Transmission Cost Recovery Rider and Environmental Cost

[43] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.
[44] Otter Tail Corporation, *op. cit.*, p. 11.
[45] MNPUC, Docket E-017/RP-13-961, December 2014.

Recovery Rider would be transferred to base rates at the conclusion of the case. After the rate case, the sizable cost associated with the recent capex would then gradually decline with depreciation while the associated revenue would gradually grow with billing determinants.

According to policy witness Brause, OTP has been engaged in an extensive capex program since 2012 which is expected to continue through 2020.[46] $536 million was invested from 2012 to 2015. Most of this capex has been for environmental compliance [e.g., on an air quality control system ("AQCS") for the Big Stone (coal-fired) power plant] and transmission (including MISO CapX2020 projects), along with routine replacements, upgrades and extensions.

Another $858 million of capex is planned between 2016 and 2020. The planned capex includes gas-fired generation ($162 million), wind- and solar-powered generation ($190 million), and transmission ($213 million) projects.[47] Some of the transmission projects facilitate the flow of North Dakota's wind-generated power surpluses across OTP's service territory to the Twin Cities and other markets to the east. The more than $480 million Minnesota rate base proposed in this rate case is more than double the $215 million rate base approved for 2009.

The Company also proposes new rate designs. Customer charges would rise much more rapidly than volumetric charges for services to small volume customers. Will Nissen, in his testimony on behalf of Fresh Energy, notes that the proposed increased residential customer charge diminishes the customer's financial incentive to conserve energy by reducing the volumetric portion of the customer's rate.[48] It also reduces the incentive to adopt DGS.

Rate design evidence was also submitted by Amparo Nieto of NERA Economic Consulting. She prepared estimates of OTP's marginal cost for the 2016-2020 period. Her estimates of the marginal costs of customer services for each rate class are considerably higher than the proposed new customer charges, suggesting a rationale for further hikes in customer charges and cuts in volumetric charges in the future.

[46] Brause, *op. cit.*, p. 5.
[47] Otter Tail Corp., *op. cit.,* p. 23.
[48] Nissen Direct, p. 4.

The testimony of Mr. Prazak and the marginal cost research and testimony of Ms. Nieto are controversial in several respects.

- In addition to the recovery of customer-related expenses like those for metering, billing, and the service drop, Ms. Nieto notes that fixed charges "*may also be used* to recover the cost of connecting to the local delivery system, involving the required transformers, secondary lines or local primary lines that may need to be added or expanded to accommodate the expected customer's maximum demand over the life of the facilities" (italics added), even though she elsewhere states that these costs are driven by the kW of "design demand."[49] David Prazak notes in his testimony that winter space heating loads cause the company to purchase larger transformers.[50]. OTP does not propose to address local delivery costs with fixed charges.
- Ms. Nieto's marginal cost study addresses only the marginal cost of distribution in the near term. This depends on OTP's forecasted need for distribution capex in the next few years. A volumetric charge based on the *long run* marginal cost of distribution would be higher.
- Ms. Nieto's study suggests that OTP's marginal cost varies substantially by time of use, being far higher in peak periods than in other periods. While this could provide a rationale for a buildout of advanced metering infrastructure and default use of time-sensitive pricing, the biggest change in rate design that OTP proposes on the basis of the study is a reduction in volumetric charges.
- Ms. Nieto provides a discourse on pp. 4-5 on the *general merits* of marginal cost pricing, stating on p. 5, for example, that "keeping volumetric prices at marginal costs is justified by economic theory." She goes on to state that when volumetric rates are set above marginal costs they encourage suboptimal levels of consumption and self-generation. With regard to the latter she states on p. 10 that

[49] Direct Testimony of Amparo Nieto in Docket E017/GR-15-1033, p. 3.
[50] Direct Testimony of David Prazak in Docket E017/GR-15-1033, p. 23.

Attachment 3

> Rates that recover marginal costs in volumetric charges and recover local facilities costs and customer costs in a fixed charge will help ensure that consumer decisions to install rooftop solar are based on economically efficient incentives. Minnesota has an opportunity to be a leader in promoting clean distributed resources in a way that serves environmental goals without unduly burdening non-participant customers. Getting the right rate structure in place as the market gets ready to embrace DG will be critical in ensuring that outcome.

However, her marginal cost study does not consider environmental externalities or long-run marginal costs. Hence, some of her general statements on the merits of marginal cost pricing can be correct even though her study is insufficient to devise rates that send correct price signals to customers concerning DERs.

With respect to revenue decoupling, Ms. Nieto states on p. 9 of her testimony that revenue decoupling is not a substitute for appropriately designed fixed charges. She explains this position with the following commentary.

> Decoupling may be an appropriate mechanism to remove a utility's disincentive to promote energy efficiency or conservation, but it perpetuates cross subsidies, as the mechanism does nothing to make sure customers see the right price signals. All customers will see rate surcharges to recover the lost revenue between rate cases, meaning there are still intra-class subsidies and inefficient use of resources.

We have seen, however, that revenue decoupling can encourage utilities to improve the efficiency of their rate designs.

As for the testimony of Mr. Prazak, he counts among his "rate structure objectives" the following.

> The rate design should give OTP a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
>
> The rate design should promote efficient use of resources, conservation, and use of renewables. This implies giving consumers price signals that reflect marginal

> costs, including seasonal differences and, where reasonably possible, time-of-day (TOD) differences.[51]

On p. 6 Mr. Prazak states, relatedly, that "rates must give the utility the opportunity to recover its embedded costs."

These goals sometimes conflict. Correctly calculated marginal cost rates do not ensure cost recovery or encourage revenue to track costs, and rates that do ensure cost recovery may not promote efficient use of resources, conservation, and use of renewables. Fortunately, revenue decoupling is available to permit rate designs that encourage efficient DERs even if they do not ensure cost recovery.

How does Mr. Prazak propose to balance these competing goals? He notes on p. 4 that "Consistent with *OTP's* rate design objectives, I based our rate structures on the structure of *OTP's* marginal costs (italics added)". Thus, recovery of the revenue requirement has taken precedent over optimal price signals in the Company's rate design proposals.

8.2. Analysis and Recommendations

Our general analysis of utility performance incentives and our review of the Company's situation suggests that Otter Tail does not have appropriately strong incentives to embrace efficient DERs. This is particularly worrisome since the Company takes the lead on DSM programs. Starting with the throughput incentive, we find that even with the proposed hikes in customer charges, most revenue addressing costs that are fixed in the short run with respect to system use would continue to be addressed by usage charges. There is thus potentially a strong throughput incentive and a concomitant disincentive to embrace DERs.

Forward test years can reduce the throughput incentive by helping rates reflect slowing growth in system use in the rate effective years following rate cases. However, with a substantial share of its capex cost addressed by trackers and the addition of recent high capex to its rate base, OTP does not need to file frequent rate cases. Company witness David Prazak states in his testimony that "OTP anticipates rates to remain unchanged for at least 3 years."[52]

[51] Direct Testimony of David Prazak in Docket E017/GR-15-1033 p. 4
[52] Prazak, *op. cit*., p. 13.

Another cause for concern is the Company's weak incentive to contain many load-related costs. While the expected rate case cycle would provide some incentive to contain some load-related costs (e.g., distribution substation and transformer capex), most of OTP's load-related costs are subject to cost trackers or formula rates. Otter Tail's finances are also insensitive to many kinds of environmental damage that its operations cause.

The MNCIP Financial Incentive Mechanism substantially improves the incentive balance with respect to conservation programs it covers. However, the mechanism doesn't encourage DGS or a wide range of initiatives OTP can take to promote conservation and peak demand management.

Otter Tail thus has weak incentives to take many measures that can foster efficient DERs. Perhaps reflecting this, the Company's conservation goals only slightly exceed the statutory minimum. Instead of moving in the direction of time-sensitive pricing that could encourage efficient DERs, the Company is proposing a reduction in volumetric charges that discourages all forms of DERs for small-volume customers.

Based on this analysis, we believe that reforms to OTP's regulatory system are needed to encourage efficient DERs. Most importantly, revenue decoupling should be instituted. This can immediately and completely remove the throughput-related disincentive to embrace efficient DGS and peak load management and the full range of initiatives that encourage conservation. Debate over future billing determinants can be reduced in forward test year rate cases. We also believe that the MNCIP Financial Incentive Mechanism and tracker treatment of DSM expenses should continue in order to provide some positive incentive to use DSM for cost management.

Additional reforms are needed to improve DER incentives that may go beyond what can be addressed in this rate case. These include the development of positive financial incentives for OTP to encourage efficient DGS and a wider range of DSM initiatives. A multiyear rate plan can further strengthen incentives to contain load-related capex. A multiyear revenue per customer freeze is one approach that merits consideration for Otter Tail.

We propose a revenue decoupling system broadly similar to that which the Commission approved for Xcel Energy in its last rate case.[53]

- Decoupling would apply to residential, farm, and general services (excluding large general services).
- Separate service baskets would apply to residential and farm services and to general services. The use of multiple baskets protects customers in each basket from rate adjustments resulting from the demand trends of dissimilar customers.
- The proposed RDM would adjust all usage charges in a given service basket equiproportionately. Charges that fluctuate only with the number of customers (e.g., customer charges) would not be included in the RDM, as revenue collected through them is already decoupled from usage.
- The RDM would effect *full* decoupling subject to the constraint that surcharge adjustments due to the revenue decoupling system would be capped at 3% annually. Residual revenue variances would be eligible for true-up in the following year.
- Revenue per customer would be decoupled, so that the revenue requirement of each service basket rises gradually with the number of customers in that basket.
- Decoupling adjustments would be applied in each month of the following April-March period.
- OTP would be required to file a plan proposing education and outreach program to customers explaining the goals and operations of its RDM program.
- The decoupling adjustment would appear as a separate rider on customers' bills to enhance transparency.
- Sales volumes attributable to electric vehicle loads would be exempted from decoupling.

An illustrative tariff sheet is found in Appendix 2.

[53] MNPUC (2015) op cit.

8.3. Decoupling Illustration

RDM demonstration models have been prepared for two service baskets: Residential and Farm, and General Service. These models can be found in Appendix 1. The RDMs featured in these models true up actual revenues to allowed revenues on a per-customer basis within each basket. While the operation of the models is demonstrated for 2016, the first year for which decoupling would apply would likely be 2017.

The RDM for each basket first generates a forecast of net usage-charge revenue per customer in the test year (2016).[54] This is done by first multiplying the forecasted test-year sales volume and (where applicable) billing demand and facilities charge demand of each rate class by OTP's proposed charges for that class.[55] The resulting revenue forecast is then adjusted to remove the components of usage-charge revenue that recover MNCIP and energy costs. This adjustment avoids double counting, since the MNCIP and energy cost components are subject to periodic true-ups of their own that expedite recovery of these costs.

Next, the RDM for each service basket calculates the test year net usage-charge revenue *per customer* that OTP is authorized to recover by taking the ratio of forecasted net usage-charge revenue to the forecasted number of customers served. The net usage-charge revenue ultimately authorized for each service basket in 2016 is then obtained by multiplying the authorized net usage-charge revenue per customer by the actual number of customers served. The data representing actual customers in the models are constructed for demonstration purposes and intentionally differ slightly from the forecasts; in a real RDM these should be historical numbers.

Next, the RDM computes the deferral amount (labeled “RDM deferral” in the models) for each service basket. This is the positive or negative variance between the *authorized* net usage-charge revenue and the *actual* net usage-charge revenues.[56] The method used to

[54] The forecasts ultimately used should be the ones approved by the Commission in the present proceeding, if available.

[55] Use of OTP's proposed rates is for demonstration purposes, and does not constitute an endorsement of their propriety. At the end of this proceeding, the usage rates and billing determinant forecasts approved by the Commission should be used.

[56] The actual revenues used in the models are constructed for demonstration purposes, but in a real RDM these should be historical numbers.

compute the actual net usage-charge revenues is analogous to that used for the forecasted net usage-charge revenues. First, each usage charge is multiplied by the actual value of its corresponding billing determinant to obtain the actual gross usage-charge revenues for each rate code. Next, these are summed to obtain the actual gross usage-charge revenues for the service basket as a whole. Finally, the components of the usage-charge revenue that recover MNCIP and energy costs are netted off, yielding the actual net usage-charge revenues.[57]

Each month the RDM places the deferral amount in a balancing account, which tracks the unrecovered net variances for later true-up. Following the example of other Minnesota utility RDMs, the demonstration models do not apply a carrying charge to the monthly deferral amounts. Although this simplifies the calculation, it prevents the full decoupling of revenue from usage by ignoring the time value of money. For this reason, the application of an appropriate carrying charge to deferrals should be considered.

At the end of the year, the RDM uses the tracker account balance to compute the 2017 RDM adjustment. As is done for the RDM of Xcel Energy, this adjustment would be applied to bills between April 2017 and March 2018. The size of customer surcharges is subject to a 3% soft cap, such that any amount in excess of the cap is retained in the RDM deferral account for recovery the following year. No cap is applied to customer refunds.

The impact on customer bills is shown in the final two rows of each demonstration model. These rows display the adjustment as a percentage of both the 2017 net usage charges (i.e., with the CIP and energy cost components removed) and the 2017 total usage charges. The RDM adjustment is calculated as a percentage applied uniformly to all usage charges in the service basket. For example, in the case of a 2% RDM adjustment, a 10 cents/kWh volumetric charge, and an $8.00/kW demand charge, the adjustment applied to customer bills would be 0.2 cents/kWh and 16 cents/kW, respectively.

[57] Note that the actual net usage-charge revenues are not calculated as the authorized revenue-per-kWh times the total kWh sold (and its demand equivalent) as is done in the RDM of Xcel Energy, since this could create an incentive for the Company to displace sales under low rates to sales under high rates (e.g., from large to small customers, from off-peak to on-peak). To avoid this, the RDM calculation should use actual usage-charge revenue data.

Appendix

A.1 Revenue Decoupling Mechanism Models

Table A1 Residential & Farm: 2016 RDM Calculation

TY 2016 Forecasted Usage & Customers		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
9.01. Residential Service [Rate 101][1]	[A]	kWh													
9.02. Residential Demand Control Service [Rate 241][1]	[B]	kWh													
9.02. Residential Demand Control Service [Rate 241][1]	[C]	kW													
9.03. Farm Service [Rate 361][1]	[D]	kWh													
Forecasted Volumes	[E = A+B+D]	kWh													
Forecasted Demand	[C]	kW													
Forecasted Customers[1]	[F]	Customers													NA

TY 2016 Usage Charges		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
9.01. Residential Service: Volumetric[2]	[H]	$/kWh	0.09305	0.09305	0.09305	0.09305	0.09305	0.11205	0.11205	0.11205	0.11205	0.09305	0.09305	0.09305	NA
9.02. Residential Demand Control Service: Volumetric[2]	[I]	$/kWh	0.06324	0.06324	0.06324	0.06324	0.06324	0.06031	0.06031	0.06031	0.06031	0.06324	0.06324	0.06324	NA
9.02. Residential Demand Control Service: Demand[2]	[J]	$/kW	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	8.00000	NA
9.03. Farm Service: Volumetric[2]	[K]	$/kWh	0.09005	0.09005	0.09005	0.09005	0.09005	0.10905	0.10905	0.10905	0.10905	0.09005	0.09005	0.09005	NA

TY 2016 Forecasted Net Revenues		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
9.01. Residential Service: Volumetric	[L = A*H]	$													
9.02. Residential Demand Control Service: Volumetric	[M = B*I]	$													
9.02. Residential Demand Control Service: Demand	[N = C*J]	$													
9.03. Farm Service: Volumetric	[O = D*K]	$													
Forecasted Gross Revenues	[P = L+M+N+O]	$													
Adjustment for Conservation Improvement Program (CIP)[3]	[Q = E*(-0.00172)]	$													
Adjustment for Energy Cost Recovery[4]	[R = E*(-0.02464)]	$													
Forecasted Net Revenues	[S = P+Q+R]	$													

2016 Authorized Net Revenues		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Actual Customers[5]	[T]	Customers													NA
Authorized Net Revenues per Customer	[U = S/F]	$/Customer													NA
Authorized Net Revenues	[V = T*U]	$													

2016 Actual Net Revenues & RDM Deferral		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
9.01. Residential Service: Volumetric[6]	[W]	$													
9.02. Residential Demand Control Service: Volumetric[6]	[X]	$													
9.02. Residential Demand Control Service: Demand[6]	[Y]	$													
9.03. Farm Service: Volumetric[6]	[Z]	$													
Actual Gross Revenues	[AA = W+X+Y+Z]	$													
Actual Volumes[7]	[AB]	kWh													
Adjustment for Conservation Improvement Program (CIP)	[AC = AB*(-0.00172)]	$													
Adjustment for Energy Cost Recovery	[AD = AB*(-0.02464)]	$													
Actual Net Revenues	[AE = AA+AC+AD]	$													
RDM Deferral[8]	[AF = V-AE]	$													

2017 RDM Adjustments		Unit	Annual
RDM Deferral Account Balance	[AG]	$	
Forecasted Volumes : April 2017-March 2018[9]	[AH]	kWh	
Forecasted Net Revenues: April 2017-March 2018[10]	[AI]	$	
Cap on Customer RDM Surcharges	[AJ = AI*(0.03)]	$	
Total RDM Adjustment: April 2017-March 2018[11]	[AK = min(AG,AJ)]	$	
RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[12]	[AL = AK/AI]	%	
RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[12]	[AM = AK/(AI+AH*(0.00172+0.02464))]	%	

[1] Source: Attachment 2 to IR MN-FE-011_NOT PUBLIC.xlsx. Use of these forecasts for illustrative purposes does not indicate our endorsement of their propriety. The forecasted usage and customers used in the actual RDM should be those approved by the Commission in this proceeding.

[2] The usage charges [H, I, J, & K] shown are those proposed by OTP (Required Information, Volume 2D: Proposed Tariff Sheets - Redlined). Use of these rates for illustrative purposes does not indicate our endorsement of their propriety. The usage charges in the actual RDM should be those approved by the Commission in this proceeding.

[3] The CIP adjustment [Q] utilizes OTP's current CCRC . The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[4] The Energy Cost Recovery adjustment [R] utilizes OTP's current base-rate energy charge. The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[5] Actual Customers [T] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Customers [F].

[6] Actual revenues by rate class [W, X, Y, & Z] are constructed for demonstration purposes. They are based on arbitrary adjustments to TY 2016 billing determinants.

[7] Actual Volumes [AB] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Volumes [F].

[8] A positive RDM deferral [AF] value represents revenues to be recovered from customers, while a negative value represents revenues to be refunded to customers. Following the methodology used for other utilities in Minnesota, no carrying charge is applied.

[9] Forecasted volumes during the RDM adjustment period [AH] is calculated as a weighted average of forecasted 2017 and 2018 volumes (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted volumes in the actual RDM should be those approved by the Commission in a subsequent proceeding.

[10] Forecasted net revenues during the RDM adjustment period [AI] is constructed for demonstration purposes. It is a weighted average of forecasted 2017 and 2018 net revenues, which are approximations based on available data (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted net revenues in the actual RDM should be calculated on the basis of the forecasted billing determinants approved by the Commission in a subsequent proceeding.

[11] A positive RDM adjustment [AK] is a customer surcharge, a negative adjustment a customer refund.

[12] The RDM adjustment is computed as a percentage of volumetric and demand rates, and applied uniformly to all rates in the service basket.

Table A2 General Service: 2016 RDM Calculation

TY 2016 Forecasted Usage & Customers		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
10.01. Small General Service (Metered Secondary) [Rate 404][1]	[A]	kWh													
10.01. Small General Service (Metered Primary) [Rate 405][1]	[B]	kWh													
10.01. Small General Service (Non-Metered) [Rate 408][1]	[C]	kWh													
10.02. General Service (Secondary) [Rate 401][1]	[D]	kWh													
10.02. General Service (Secondary) [Rate 401][1]	[E]	kW													
10.02. General Service (Secondary) [Facilities][1]	[F]	Annual kW													
10.02. General Service (Primary) [Rate 403][1]	[G]	kWh													
10.02. General Service (Primary) [Rate 403][1]	[H]	kW													
10.02. General Service (Primary) [Facilities][1]	[I]	Annual kW													
10.03. General Service-Time of Use (Declared Peak) [Rate 708][1]	[J]	kWh													
10.03. General Service-Time of Use (Intermediate) [Rate 709][1]	[K]	kWh													
10.03. General Service-Time of Use (Intermediate) [Rate 709][1]	[L]	kW													
10.03. General Service-Time of Use (Off Peak) [Rate 710][1]	[M]	kWh													
10.03. General Service-Time of Use [Facilities][1]	[N]	Annual kW													
Forecasted Volumes	[O = A+B+C+D+G+J+K+M]	kWh													
Forecasted Demand[2]	[P = E+H+L]	kW													
Forecasted Facilities Demand[3]	[Q = F+I+N]	Annual kW													
Forecasted Customers[1]	[R]	Customers													NA

TY 2016 Usage Charges		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
10.01. Small General Service (Metered Secondary): Volumetric[4]	[S]	$/kWh	0.08526	0.08526	0.08526	0.08526	0.08526	0.10426	0.10426	0.10426	0.10426	0.08526	0.08526	0.08526	NA
10.01. Small General Service (Metered Primary): Volumetric[4]	[T]	$/kWh	0.08149	0.08149	0.08149	0.08149	0.08149	0.10049	0.10049	0.10049	0.10049	0.08149	0.08149	0.08149	NA
10.01. Small General Service (Non-Metered): Volumetric[4]	[U]	$/kWh	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	0.08843	NA
10.02. General Service (Secondary): Volumetric[4]	[V]	$/kWh	0.08167	0.08167	0.08167	0.08167	0.08167	0.07788	0.07788	0.07788	0.07788	0.08167	0.08167	0.08167	NA
10.02. General Service (Secondary): Demand[4]	[W]	$/kW	1.39000	1.39000	1.39000	1.39000	1.39000	3.63000	3.63000	3.63000	3.63000	1.39000	1.39000	1.39000	NA
10.02. General Service (Secondary): Facilities Demand[4]	[X]	$/Annual kW	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	NA
10.02. General Service (Primary): Volumetric[4]	[Y]	$/kWh	0.07829	0.07829	0.07829	0.07829	0.07829	0.07527	0.07527	0.07527	0.07527	0.07829	0.07829	0.07829	NA
10.02. General Service (Primary): Demand[4]	[Z]	$/kW	1.89000	1.89000	1.89000	1.89000	1.89000	4.02000	4.02000	4.02000	4.02000	1.89000	1.89000	1.89000	NA
10.02. General Service (Primary): Facilities Demand[4]	[AA]	$/Annual kW	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	0.65000	NA
10.03. General Service-Time of Use (Declared Peak): Volumetric[4]	[AB]	$/kWh	0.28109	0.28109	0.28109	0.28109	0.28109	0.53978	0.53978	0.53978	0.53978	0.28109	0.28109	0.28109	NA
10.03. General Service-Time of Use (Intermediate): Volumetric[4]	[AC]	$/kWh	0.07478	0.07478	0.07478	0.07478	0.07478	0.07414	0.07414	0.07414	0.07414	0.07478	0.07478	0.07478	NA
10.03. General Service-Time of Use (Intermediate): Demand[4]	[AD]	$/kW	2.69000	2.69000	2.69000	2.69000	2.69000	2.67000	2.67000	2.67000	2.67000	2.69000	2.69000	2.69000	NA
10.03. General Service-Time of Use (Off Peak): Volumetric[4]	[AE]	$/kWh	0.04997	0.04997	0.04997	0.04997	0.04997	0.04179	0.04179	0.04179	0.04179	0.04997	0.04997	0.04997	NA
10.03. General Service-Time of Use: Facilities Demand[4]	[AF]	$/Annual kW	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	0.97000	NA

TY 2016 Forecasted Net Revenues		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
10.01. Small General Service (Metered Secondary): Volumetric	[AG = A*S]	$													
10.01. Small General Service (Metered Primary): Volumetric	[AH = B*T}	$													
10.01. Small General Service (Non-Metered): Volumetric	[AI = C*U]	$													
10.02. General Service (Secondary): Volumetric	[AJ = D*V]	$													
10.02. General Service (Secondary): Demand	[AK = E*W]	$													
10.02. General Service (Secondary): Facilities Demand	[AL = F*X]	$													
10.02. General Service (Primary): Volumetric	[AM = G*Y]	$													
10.02. General Service (Primary): Demand	[AN = H*Z]	$													
10.02. General Service (Primary): Facilities Demand	[AO = I*AA]	$													
10.03. General Service-Time of Use (Declared Peak): Volumetric	[AP = J*AB]	$													
10.03. General Service-Time of Use (Intermediate): Volumetric	[AQ = K*AC]	$													
10.03. General Service-Time of Use (Intermediate): Demand	[AR = L*AD]	$													
10.03. General Service-Time of Use (Off Peak): Volumetric	[AS = M*AE]	$													
10.03. General Service-Time of Use: Facilities Demand	[AT = N*AF]	$													
Forecasted Gross Revenues	[AU = sum(AG:AT)]	$													
Adjustment for Conservation Improvement Program (CIP)[5]	[AV = O*(-0.00172)]	$													
Adjustment for Energy Cost Recovery[6]	[AW = O*(-0.02464)]	$													
Forecasted Net Revenues	[AX = AU+AV+AW]	$													

2016 Authorized Net Revenues		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Actual Customers[7]	[AY]	Customers													NA
Authorized Net Revenues per Customer	[AZ = AX/R]	$/Customer													NA
Authorized Net Revenues	[BA = AY*AZ]	$													

2016 Actual Net Revenues & RDM Deferral		Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
10.01. Small General Service (Metered Secondary): Volumetric[8]	[BB]	$													
10.01. Small General Service (Metered Primary): Volumetric[8]	[BC]	$													
10.01. Small General Service (Non-Metered): Volumetric[8]	[BD]	$													
10.02. General Service (Secondary): Volumetric[8]	[BE]	$													
10.02. General Service (Secondary): Demand[8]	[BF]	$													
10.02. General Service (Secondary): Facilities[8]	[BG]	$													
10.02. General Service (Primary): Volumetric[8]	[BH]	$													
10.02. General Service (Primary): Demand[8]	[BI]	$													
10.02. General Service (Primary): Facilities[8]	[BJ]	$													
10.03. General Service-Time of Use (Declared Peak): Volumetric[8]	[BK]	$													
10.03. General Service-Time of Use (Intermediate): Volumetric[8]	[BL]	$													
10.03. General Service-Time of Use (Intermediate): Demand[8]	[BM]	$													
10.03. General Service-Time of Use (Off Peak): Volumetric[8]	[BN]	$													
10.03. General Service-Time of Use: Facilities[8]	[BO]	$													
Actual Gross Revenues	[BP = sum(BB:BO)]	$													
Actual Volumes[9]	[BQ]	kWh													
Adjustment for Conservation Improvement Program (CIP)	[BR = BQ*(-0.00172)]	$													
Adjustment for Energy Cost Recovery	[BS = BQ*(-0.02464)]	$													
Actual Net Revenues	[BT = BP+BR+BS]	$													
RDM Deferral[10]	[BU = BA-BT]	$													

2017 RDM Adjustments		Unit	Annual
RDM Deferral Account Balance	[BV]	$	
Forecasted Volumes : April 2017-March 2018[11]	[BW]	kWh	
Forecasted Net Revenues: April 2017-March 2018[12]	[BX]	$	
Cap on Customer RDM Surcharges	[BY = BX*(0.03)]	$	
Total RDM Adjustment: April 2017-March 2018[13]	[BZ = min(BV,BY)]	$	
RDM Adjustment as a % of Usage Charges (Excluding CIP & Energy Cost Recovery Charges)[14]	[CA = BZ/BX]	%	
RDM Adjustment as a % of Usage Charges (Including CIP & Energy Cost Recovery Charges)[14]	[CB = BZ/(BX+BW*(0.00172+0.02464))]	%	

[1] Source: Attachment 2 to IR MN-FE-011_NOT PUBLIC.xlsx. Use of these forecasts for illustrative purposes does not indicate our endorsement of their propriety. The forecasted usage and customers used in the actual RDM should be those approved by the Commission in this proceeding.

[2] Billing demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use). For simplicity, these are summed to obtain the Forecasted Demand [P]. Forecasted Demand is not used in subsequent RDM calculations.

[3] Facilities charge demand is determined somewhat differently under Section 10.02 (General Service) than it is under Section 10.03 (General Service - Time of Use). For simplicity, these are summed to obtain the Forecasted Facilities Demand [Q]. Forecasted Facilities Demand is not used in subsequent RDM calculations.

[4] The usage charges [S-AF] shown are those proposed by OTP (Required Information, Volume 2D: Proposed Tariff Sheets - Redlined). Use of these rates for illustrative purposes does not indicate our endorsement of their propriety. The usage charges in the actual RDM should be those approved by the Commission in this proceeding.

[5] The CIP adjustment [AV] utilizes OTP's current CCRC . The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[6] The Energy Cost Recovery adjustment [AW] utilizes OTP's current base-rate energy charge. The rate used in the actual RDM should be that approved by the Commission in this proceeding.

[7] Actual Customers [AY] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Customers [R].

[8] Actual revenues by rate class [BB-BO] are constructed for demonstration purposes. They are based on arbitrary adjustments to TY 2016 billing determinants.

[9] Actual Volumes [BQ] is constructed for demonstration purposes. It is based on arbitrary adjustments to Forecasted Volumes [O].

[10] A positive RDM deferral [BU] value represents revenues to be recovered from customers, while a negative value represents revenues to be refunded to customers. Following the methodology used for other utilities in Minnesota, no carrying charge is applied.

[11] Forecasted volumes during the RDM adjustment period [BW] is calculated as a weighted average of forecasted 2017 and 2018 volumes (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted volumes in the actual RDM should be those approved by the Commission in a subsequent proceeding.

[12] Forecasted net revenues during the RDM adjustment period [BX] is constructed for demonstration purposes. It is a weighted average of forecasted 2017 and 2018 net revenues, which are approximations based on available data (Source: Attachment 3 to IR MN-FE-011_NOT PUBLIC.pdf). The forecasted net revenues in the actual RDM should be calculated on the basis of the forecasted billing determinants approved by the Commission in a subsequent proceeding.

[13] A positive positive RDM adjustment [BZ] is a customer surcharge, a negative adjustment a customer refund.

[14] The RDM adjustment is computed as a percentage of volumetric, demand and facilities demand rates, and applied uniformly to all rates in the service basket.

A.2 Revenue Decoupling Tariff

Minnesota Public Utilities ***Commission***
Section **13.__**
ELECTRIC RATE SCHEDULE
Revenue Decoupling Mechanism Rider

Fergus Falls, Minnesota

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REVENUE DECOUPLING MECHANISM (RDM) RIDER

DESCRIPTION	RATE CODE
Revenue Decoupling Mechanism Rider	32-XXX

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to bills for electric service provided under the Company's retail rate schedules in Sections 9.01 (Residential), 9.02 (Residential Demand Control), 9.03 (Farm), 10.01 (Small General Service), 10.02 (General Service), and 10.03 (General Service - Time of Use).

RDM ADJUSTMENT: There shall be included on the monthly bills for each of these Minnesota rate schedules a Revenue Decoupling Mechanism (RDM) Rider. Its purpose is to adjust the Company's actual per-customer revenues from usage charges to the level needed to recover its authorized revenue requirement, preventing either under- or over-recovery. The adjustment will require either a surcharge or refund. The adjustment shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service, and is applicable in addition to all charges for service being taken under the Company's standard rate schedules.

The adjustment shall be calculated separately for two Service Baskets.

1. **Residential & Farm:** Rate Schedules 9.01 (Residential Service), 9.02 (Residential Demand Control Service), and 9.03 (Farm Service).

2. **General Service:** Rate Schedules 10.01 (Small General Service), 10.02 (General Service), and 10.03 (General Service - Time of Use).

Usage by customers in one Service Basket shall not affect the adjustment applied to another Service Basket.

For purposes of this section the following definitions apply:

Net Usage Charges (NUC): The dollar amount billed per kWh of electric consumption, any kW of billing demand, and any kW of facilities charge demand, excluding the 2.4640¢ per kWh base-rate energy charge (Section 13.01) and 0.172¢ per kWh CCRC (Section 13.02).

MINNESOTA PUBLIC UTILITIES COMMISSION
Approved:
Docket No. E017/GR-15-1033

EFFECTIVE with bills rendered on and after

in Minnesota

RDM Factor: The number multiplied by the NUC to compute the RDM adjustment.

RDM Deferral Account: The account used to track variances between the Company's authorized NUC revenues and actual NUC revenues each month for a given Service Basket, deferring them for use in the next RDM adjustment calculation. The authorized NUC are equal to the average per-customer NUC revenues approved for that month by the Minnesota Public Utilities Commission (Commission) in the Company's last rate case, multiplied by the actual number of customers that month.

Monthly RDM Deferral: The amount placed in the RDM Deferral Account in a given month.

Annual RDM Deferral: The balance in the RDM Deferral Account on December 31. This balance is equal to the sum of the 12 Monthly RDM Deferrals plus any under- or over-recovery of the previous Annual RDM Deferral.

Each year during the term of this rider the Company shall compute an RDM Factor for each Service Basket. The factor is based on the balance in the RDM Deferral Account on December 31 and the total forecasted NUC for April 1 through March 31 of the following year:

RDM Factor = Annual RDM Deferral / Forecasted NUC

A positive RDM Factor yields a customer surcharge, and a negative RDM Factor a customer refund. Surcharges shall be capped at 3% of the total forecasted NUC for each Service Basket, unless the Company is granted approval from the Commission to recover revenues in excess of the cap. Customer refunds shall not be capped. Any under- or over-recovery of the Annual RDM Deferral will be included in the RDM Deferral Account for the applicable Service Basket, and reflected in the following year's RDM Factor.

The RDM Factor is multiplied by the customer's NUC in a given month to calculate the customer's RDM adjustment in that month.

RDM FACTOR		
Residential & Farm	**(a)**	0.0000
General Service	**(b)**	0.0000

(a) Rate Schedules 9.01 Residential Service, 9.02 Residential Demand Control Service, and 9.03 Farm Service.
(b) Rate Schedules 10.01 Small General Service, Rate Schedule 10.02 General Service, and Rate Schedule 10.03 General Service - Time of Use.

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CERTIFICATE OF SERVICE

RE: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota
Docket No. E017/GR-15-1033

I, Jana Hrdlicka, hereby certify that I have this day served a copy of the following, or a summary thereof, on Daniel P. Wolf and Sharon Ferguson by e-filing, and to the Office of Attorney General – Antitrust & Utilities Division and all other persons on the attached service lists by electronic service or by First Class mail.

Otter Tail Power Company
Supplemental Compliance Filing

Dated this **20th** day of **June, 2018**

/s/ JANA HRDLICKA

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