EXHIBIT
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PSC-5

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of Northern States Power Company,
A Minnesota Corporation
For Authority to Increase Rates for
Electric Service in North Dakota
Case No. PU-12-813

DIRECT TESTIMONY OF
KARL RICHARD PAVLOVIC
July 2013

On Behalf of the Advocacy Staff of the
North Dakota Public Service Commission

shows corrections
provided during
hearing

July 17, 2013

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Exhibit PSC-5 from Aug. 27, 28, & 29, 2013 formal hearing
Public Service Commission

DIRECT TESTIMONY OF
KARL R. PAVLOVIC

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 8100 Professional Place, Suite 306, Hyattsville, MD 20785. I am a Senior Consultant with Snavely King Majoros & Associates, Inc. ("Snavely King").

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King was founded by Charles W. King and the late Carl M. Snavely in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 10 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 42-year history, members of the firm have participated in over 1000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachments A and B to my testimony summarize my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a list of my engagements as an expert and/or expert witness before state and federal regulatory agencies.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. No.

Q. BEFORE WHICH AGENCIES HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Corporation Commission of the State of Kansas, the Delaware Public Service Commission, the Maryland Public Service Commission, and the Public Service Commission of the District of Columbia.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS?

A. I received undergraduate and graduate degrees in Philosophy from Yale College and Purdue University. By education and professional experience I have expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. In the course of my professional career I have gained knowledge in the areas of commercial and industrial operations in the energy, transportation, and telecommunications industries and am familiar with a wide range of experimental and investigative methods in science and engineering. For over 25 years I have served as a consultant on the economics of regulated industries to clients in the public and private sectors. In that capacity I have been responsible for the design and execution of statistical, economic and financial analyses of discrete commercial operations, individual firms, and industry sectors for use by management and counsel in formulating and implementing commercial and litigation strategy. In a number of cases, these analyses have been the basis for testimony by me or others in regulatory and court proceedings. My consulting assignments in the energy field have included analyses of crude oil and petroleum product markets, the operations and costs of petroleum pipelines, investigations of operating and plant investment costs and least cost planning of electric and natural gas utilities, and all aspects of the restructuring of electric markets.

Q. PLEASE SUMMARIZE YOUR ELECTRIC REGULATORY EXPERIENCE.

Until recently my electric regulatory experience has been primarily before the Public Service Commission of the District of Columbia with regard to the Potomac Electric Power Company (Pepco). I have testified in numerous cases regarding (a) planning reserve margin, (b) "lost revenues" attributable to Demand-Side Management ("DSM") programs, (c) weather emergency response, (d) operational and financial issues with regard to Pepco's divestiture of its generating assets and the subsequent unbundling of its retail rates, (e) performance of renewable and energy efficiency programs, (f) the performance of Pepco's transmission and distribution facilities, (g) the cost and benefits of the Pepco-Conectiv merger, (h) the procurement of Standard Offer Service ("SOS") electric supply and retail SOS rates, (i) the need for new transmission lines to serve load, and (j) issues of cost allocation, revenue requirement distribution, and rate design. I also served for a number of years as the technical representative of the Office of the People's Counsel of the District of Columbia to Pepco's Productivity Improvement Working Group and on various member working groups within PJM. Most recently I have testified in Maryland and Delaware regarding Baltimore Gas and Electric's and Delmarva Power and Light's electric costs of service, rate designs and reliability investment recovery mechanisms.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. I have been asked by the Advocacy Staff of the North Dakota Public Service Commission (Staff) to examine the assertions and proposals in this proceeding by Northern States Power (NSP) regarding its North Dakota jurisdictional and class costs of service, rate design, and proposed Transmission Cost Recovery (TCR) tracker.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have included eight exhibits.

Exhibit KRP-1: NSP Jurisdictional Allocators by FERC Account

Exhibit KRP-2: 2007 to 2013 NSP System Peak Demand

Exhibit KRP-3: Jurisdictional Rate Base Adjustment Factors

Exhibit KRP-4: Jurisdictional O&M Expense Adjustment Factors

Exhibit KRP-5: Class Cost of Service Cost Classifications and Allocators

Exhibit KRP-6: Rate Structure Matrix

Exhibit KRP-7: Class Rate Component Matrix

Exhibit KRP-8: "How Should Regulators View Cost Trackers"

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four sections. In the first section I address NSP's jurisdictional allocation of costs to North Dakota. In the second section I address NSP's allocation of North Dakota jurisdictional costs to North Dakota customer classes. In the third section I address NSP's rate design proposals. In the fourth section I address NSP's proposed Transmission Cost Recovery tracker.

I. <u>SUMMARY OF TESTIMONY AND CONCLUSIONS</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As explained in my testimony below, NSP's jurisdictional cost assignment methods and procedures are, with the exception of the use of a 12 coincident peak demand allocator, appropriate and in accordance with the principles enunciated in the NARUC Cost Allocation Manual. The 12 coincident peak demand over-allocates system costs to the North Dakota jurisdiction. NSP's class cost assignment methods and procedures are appropriate and consistent with the NARUC cost allocation principles. NSP's proposed customer class revenue distribution is cost based and reasonable. The class cost study does not, however, directly support the current rate structure. NSP's proposed modifications to the rate components, moving customer and demand charges towards full cost recovery, are appropriate and reasonable. NSP's rate structure, however, is overly complex and the tariff is virtually incomprehensible. NSP's application for a Transmission Cost Recovery (T~~RC)~~ CR rider does not comport with the statutory requirements for Commission consideration and lacks a demonstration that the costs proposed for the tracker meet the criteria for inclusion in a tracker.

My recommendations are:

- The Commission should direct NSP to use a single coincident peak demand allocator for purposes of assigning system costs to the North Dakota jurisdiction.
- The Commission should adopt NSP's class cost study for the purposes of class revenue requirement distribution.
- The Commission should direct NSP to eliminate the rate classes for which it has no North Dakota customers, eliminate the Residential Time of Day rate

classes, and eliminate the customer charge distinction between standard, underground and space heating customers.

- The Commission should also direct NSP to further simplify its rate structure, reducing the number of rate classes and aligning its class cost study so as to directly support the simplified rate structure.
- The Commission should direct NSP to overhaul its tariff substituting plain language for technical terms wherever possible, include a section defining in plain language the technical terms that are used in the tariff, and place specific tariff sheet references wherever rate schedules and riders make reference to other riders or rate schedules.
- The Commission should direct NSP to remove its Account Service Charge as it is in violation of Administrative Rules: 69-09-02-02.1
- The Commission should defer consideration of NSP's ~~TRC~~ TCR proposal until such time as NSP submits an application that comports with the statutory requirements and demonstrates that the tracker costs meet the criteria for inclusion in a tracker.

II. <u>DISCUSSION</u>

<u>NSP'S NORTH DAKOTA JURISDICTIONAL ALLOCATION</u>

Q. HAVE YOU EXAMINED NSP'S METHODS AND PROCEDURES UNDERLYING ITS ASSIGNMENT OF COSTS TO THE NORTH DAKOTA JURISDICTION?

A. Yes. NSP's North Dakota costs are summarized in Schedule 8 of Exhibit___(AEH-1), the Direct Testimony of Anne E. Heuer. NSP's jurisdictional methods and procedures are set forth in Schedule 12 of Exhibit ___(AEH-1). I have also examined the electronic files which calculate the North Dakota costs assignments and allocations that are summarized in Schedule 8 and the workpapers to those files.[1]

Q. PLEASE BRIEFLY SUMMARIZE NSP'S JURISDICTIONAL METHODS AND PROCEDURES?

A. The NSP electric system comprises assets and operations in Minnesota, North Dakota and South Dakota. Those assets and operations produce, transmit and deliver electricity to retail and wholesale customers. NSP first functionalizes its facilities investment and operating expenses as distribution, transmission, production, fuel and purchased energy, customer accounts, customer sales, property taxes, and administrative & general based on the Federal Energy Regulatory Commission (FERC) system of accounts. The functionalized system costs are then either directly assigned based on NSP location coding or allocated by FERC account to the North Dakota jurisdiction. For the allocation of costs NSP uses three allocation methods: (1) 12 coincident peak demand, (2) energy delivered, and (3) number of customers. The allocation method selected for each FERC account is based on cost-causation. Exhibit KRP-1 lists by FERC account the allocators used by NSP.

Q. WHAT IS YOUR ASSESSMENT OF NSP'S JURISDICTIONAL METHODS AND PROCEDURES?

A. NSP's jurisdictional methods and procedures are, with one exception, appropriate and conceptually in accordance with the principles enunciated in the NARUC Electric Utility Cost Allocation Manual, particularly the principle of cost-causation. The exception is NSP's use of 12 coincident peak demand to allocate production capacity costs and transmission costs, which is inappropriate given NSP's system operation and performance.

[1] Responses to NDPSC 6-001 – 6-007, 10-007 – 10-010, and 11-001 – 11-004.

Q. WHY IS THE 12 COINCIDENT PEAK DEMAND METHOD INAPPROPRIATE FOR NSP'S SYSTEM?

A. There are several different methods of calculating coincident peak demand,[2] each of which is appropriate to the specific peaking pattern experienced by a system. The 12 coincident peak method calculates system and jurisdictional coincident peak demands as the average of the system's monthly coincident peak demands and is appropriate for a transmission system where "significant variations in monthly peak demands are <u>not present</u>"[3] or generation systems where "monthly peaks lie within a narrow range."[4] NSP's system, however, experiences significant variation in its monthly peak demand – NSP is a strongly summer peaking system as can be seen on page 1 of Exhibit KRP-2 where I have graphed NSP's historical monthly peak demands for the years 2007 through 2012 and NSP's forecast monthly peak demands for 2013.

Q. WHAT IS THE APPROPRIATE METHOD FOR NSP'S SYSTEM?

A. For a strongly summer peaking system like NSP's the appropriate method for calculating coincident peak demand is the single system coincident peak method[5] which calculates system and jurisdictional peak demands as the highest monthly system peak demand. As the NARUC Manual states,

> "[t]he single highest peak demand is the overriding consideration that drives power supply cost decisions. Customer contribution to this single annual system peak is used to measure customer responsibility. The result is that those customers which most heavily contribute to the single monthly peak will pay proportionally large amounts of the cost …"

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[2] NARUC Manual at 44-48 and 77 – 79.
[3] NARUC Manual at 79 (emphasis added)..
[4] NARUC Manual at 46.
[5] NARUC Manual at 77.

Q. HAVE YOU QUANTIFIED AND COMPARED THE IMPACT ON THE NORTH DAKOTA ALLOCATION OF THE SINGLE COINCIDENT PEAK AND 12 COINCIDENT PEAK METHODS?

A. Yes. On page 2 of Exhibit KRP-2 I have calculated NSP's jurisdictional allocation factors using both methods for the historical years 2007 – 2012 and the forecast year 2013. For all these years the single coincident peak allocation to the North Dakota jurisdiction is significantly less than the 12 coincident peak allocation. For forecast 2013, the test year in this proceeding, the single coincident peak produces a North Dakota allocation factor of 5.4942% compared to NSP's 12 coincident peak allocation factor of 6.0227%.

Q. DO YOU RECOMMEND THAT THE TEST YEAR NORTH DAKOTA JURISDICTIONAL COSTS BE ADJUSTED TO REFLECT A COINCIDENT PEAK DEMAND ALLOCATION FACTOR OF 5.4924%?

A. No. For consistency with the adjustments that Staff proposes that are based three-year financial averages, I recommend that the test year North Dakota jurisdictional costs be adjusted to reflect a single coincident peak allocation factor of 5.0864%, which is the average single coincident peak allocation factor for the years 2010 through 2012. The calculation of this allocation factor is shown on page 2 of Exhibit KRP-2. In Exhibit KRP-3 and Exhibit KRP-4, I have calculated adjustment factors for, respectively, rate base items and production and transmission O&M expense items. Table 1, below, summarizes these adjustment factors.

TABLE 1 – Rate Base and O&M Adjustment Factors

Plant in Service Adjustment Factor	87.1%
Reserve Adjustment Factor	87.2%

CWIP Adjustment Factor	84.8%
Accumulated Deferred Taxes Adjustment Factor	87.1%
Production O&M Adjustment Factor	83.3%
Transmission O&M Adjustment Factor	84.5%

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING NSP'S ALLOCATIONS TO THE NORTH DAKOTA JURISDICTION?

A. Yes. The costs of NSP's Wind2Battery Project and high cost Purchased Power Agreements (PPAs) should be excluded from the North Dakota jurisdictional costs.

Q. WHY SHOULD THE WIND2BATTERY PROJECT BE EXCLUDED FROM NORTH DAKOTA JURISDICTIONAL COSTS?

A. This project is not cost effective. While part of the project was paid for with MN renewable development funds, there is no reason to allocate any of these costs to the North Dakota jurisdiction. While Advocacy Staff has ignored some of the high priced projects that NSP is involved in, it can no longer recommend that the Commission accept such projects into NSP's North Dakota jurisdictional costs. The Commission should send in this proceeding a strong signal to both NSP and the Minnesota Commission that North Dakota will no longer tolerate projects that are uneconomical and, therefore, not in the best interests of North Dakota customers.

Q. WHAT HIGH COST PPAS DO YOU RECOMMEND BE EXCLUDED FROM THE NORTH DAKOTA JURISDICTIONAL COSTS?

A. Best Power, Outland Solar, FibroMinn, Laurentian Energy Authority I, St. Paul Cogeneration, KODA Energy LLC, Adams, Danielson Wind Farm, Grant County Wind, LLC, North Community Turbines, North Wind Turbines, Ridgewood Power Partners LLC, Uilk Wind Farm, Valley View Transmission, Winona County Wind, Community Wind South, and Moraine Wind II.

Q. WHY DO YOU RECOMMEND THAT NORTH DAKOTA CUSTOMERS NO LONGER PAY THE COSTS OF THESE PPAs?

A. With the exception of the Community Wind South and Moraine Wind II projects, all of the other projects are priced over $60 per MWH. A number of these high priced projects are MN CBED projects. North Dakota customers shouldn't have to pay for high priced Minnesota contracts that are designed to benefit local Minnesota communities. There are also solar projects in this mix. Solar has not been shown to be cost effective in most states and NSP's current solar PPAs are not an exception to this. There are also projects in this mix that have Minnesota legislative mandated prices which again, should not be the responsibility of North Dakota customers. In looking at the Community Wind South and Moraine Wind II projects, while these are below the $60 per MWH cut off, the PPAs were approved at a time when the costs were considered above market. The Minnesota Commission reluctantly approve both of these contracts because of prior commitments which should not be the responsibility of ND customers.

Q. ARE THERE ANY SILVER LININGS IN THE ADVOCACY STAFF'S POSITIONS ON PPAs?

A. Yes. The Commission has not yet allowed recovery for the Prairie Rose PPA in the fuel clause. While the Company claims that it filed an ADP and recovery should be allowed, the Company didn't file the ADP until early 2012 in spite of signing the contract in mid-2011 and obtaining Minnesota Commission approval a few months later. While the Company claims that it did nothing wrong, Advocacy Staff notes that the Company later promised to file ADPs within 30 days of making filings in Minnesota. Advocacy Staff reminds the Company that in a February 5, 2013 letter to the Minnesota Commission they stated that they have enough RECs through 2020 to comply in all states. And because the North Dakota objective is only 10 percent, the Company will be in compliance for many years beyond 2020 without needing new renewable resources.

Advocacy Staff also notes that the Prairie Rose project uses a net zero interconnection with the Anson plant. Prairie Rose is 240 MW and Angus Anson is a 405 MW generating station. It is not clear that there is any need for this wind project and that money could not be saved by operating the Angus Anson Plant?

In spite of these concerns and the fact that customers are currently receiving benefits by not including this contract currently in the fuel clause, Staff believes over the long run the project will be acceptably priced and reasonable. Staff recommends its recovery in the fuel clause going forward once final rates are approved in this case. The Company should not, however, be allowed recovery for the costs prior to the conclusion of this case considering that the ADP was not timely and the project is more expensive than current prices.

<u>NSP'S CLASS COST OF SERVICE</u>

Q. HAVE YOU EXAMINED NSP'S METHODS AND PROCEDURES UNDERLYING ITS ASSIGNMENT OF COSTS TO THE NORTH DAKOTA RATE CLASSES?

A. Yes. NSP's assignment of the North Dakota jurisdictional costs to its North Dakota rate classes is presented and summarized in Schedules 3-5 of Exhibit___(MAP-1), the Direct Testimony of Michael A. Peppin. NSP's class cost of service methods and procedures are set forth in Schedule 2 of Exhibit ___(MAP-1). I have also examined the electronic files which calculate the class costs assignments and allocations that are presented and summarized in Schedule 3, the workpapers to those files, and NSP system planning documents.[6]

Q. PLEASE BRIEFLY SUMMARIZE NSP'S CLASS COST OF SERVICE METHODS AND PROCEDURES.

A. NSP takes the standard three-step approach to class cost assignment of functionalizing, classifying, and then directly assigning or allocating costs , as appropriate, the North Dakota jurisdictional costs to its customer classes. NSP begins by assigning individual cost items to operational functions, i.e., generation, transmission, distribution, or customer. Within each function individual cost items are then classified as to cost drivers, i.e., capacity required, energy delivered, or customers served. NSP classifies generation plant costs as capacity-driven or energy-driven using ratios based on current replacement costs for each type of generation. In addition, the capacity-driven plant costs are further separated into summer and winter components using an average and excess analysis. Transmission costs and distribution substation and transformer costs are classified as capacity-driven. Distribution primary line, secondary facilities, and services costs are classified into capacity and customer components using the Minimum Distribution System (MDS) method. Distribution metering and customer service costs are classified as customer-driven. Finally, specific customer-dedicated cost items are directly assigned, while the remainder of the

[6] Responses to NDPSC 6-013 – 6-016 and 1-019.

classified cost items are allocated to the customer classes using allocations factors that reflect the classes' cost-causative characteristics, i.e., class kW demand for costs classified as capacity-driven, class kWh delivered for costs classified as energy-driven, and number of customers for costs classified as customer-driven. Exhibit KRP-5 reproduces pages from Schedule 2 that show NSP's cost classification matrix, list and describe the allocators used, and list the customer classes used.

Q. WHAT IS YOUR ASSESSMENT OF NSP'S CLASS COST OF SERVICE METHODS AND PROCEDURES?

A. NSP's class cost of service methods and procedures are conceptually in accordance with the principles enunciated in the NARUC Electric Utility Cost Allocation Manual. There are theoretical issues regarding the determination of capacity and energy components of generation plant costs and the determination of capacity/customer components of distribution plant costs. Most of these issues are a matter of whether class contributions to system diversity are accurately reflected in NSP's capacity/demand allocators. Resolution of these issues, however, would require detailed studies and analyses of NSP's system that I have not undertaken. I found no overt indications of problems in NSP's class cost of service results.

<u>RATE DESIGN</u>

Q. HAVE YOU EXAMINED NSP'S PROPOSED RATE DESIGN?

A. Yes. NSP's rate design for the North Dakota jurisdiction is presented and summarized in pages 3-16 and Schedules 2-8 of Exhibit___(SVH-1), the Direct Testimony of Steven V.

Huso and the proposed tariff sheets provided in NSP's application. I have also examined the electronic files which calculate NSP's proposed rates and the workpapers to those files.[7]

Q. PLEASE BRIEFLY SUMMARIZE NSP'S CLASS COST OF SERVICE METHODS AND PROCEDURES.

A. NSP proposes to distribute revenue responsibility to the Residential and C&I classes based on full cost of service. For the Lighting classes, NSP proposes what it characterizes as "a modest movement to cost," which results from its proposed reduction in the range of cost differentials for the Lighting classes.[8] As regards rate structure, NSP proposes no changes to its current rate schedules,[9] but does propose changes to the level of the individual components. Specifically, NSP proposes to move the customer charges closer to cost and a relative reduction in the energy charges for the Residential and Non-Demand C&I schedules and to increase demand charges relative to energy and fuel costs charges for the C&I Demand schedules. For the Lighting schedules NSP proposes a significant increase in the Full Service schedule charges, a very slight increase in the Energy schedule charges, and no increase in the Protective schedule charges.

Q. WHAT IS YOUR ASSESSMENT OF NSP'S PROPOSED REVENUE RESPONSIBILITY DISTRIBUTION?

A. The cost of service study results demonstrate that the Residential and C&I classes under the current rates are very close to full cost recovery, while the Lighting classes fall significantly short of full recovery.[10] Bringing the lighting classes to full recovery would, as Mr. Huso

[7] Responses to NDPSC 7-001 – 7-009.
[8] Page 5, lines 9-15 of Exhibit___(SVH-1).
[9] Page 6, lines 15-169-15 of Exhibit___(SVH-1).
[10] Exhibit___(MAP-1), Schedule 3.

notes, result in significant rate shock to the Full Service subclass.[11] My recommendation is that NSP's proposed revenue responsibility distribution be adopted by the Commission and that the revenue requirement approved in this proceeding be distributed to the classes in proportion to the revenue responsibility proposed in Table 2 of Mr. Huso's testimony.[12]

TABLE 2 - REVENUE RESPONSIBILITY DISTRIBUTION

Class	NSP 2013 Proposed Revenue (000) /1	Percent Distribution
Residential	**$76,777**	**38.5%**
Non-Demand	**12,537**	**6.3%**
C&I Demand	**108,334**	**54.3%**
Lighting	**1,948**	**0.9%**
Total	**$199,597**	**100.0%**
/1: Source – Table 2, page 6 of Exhibit___(SVH-1)		

Q. **WHAT IS YOUR ASSESSMENT OF NSP'S PROPOSED RATE STRUCTURE AND PROPOSED RATE COMPONENT MODIFICATIONS?**

A. Conceptually, the proposed modifications, all of which move customer and demand rate components towards full cost recovery, are appropriate and wholly consistent with the goal of having rate components in fact reflect full cost of service and thereby send proper price signals to customers. NSP's current rate structure, however, is overly complex, produces component rate distinctions not clearly based on cost and, as presented in NSP's tariff, virtually incomprehensible.

Q. **PLEASE GIVE SOME EXAMPLES OF HOW THE RATE STRUCTURE IS OVERLY COMPLEX.**

[11] Page 14, lines 14-27, Exhibit___(SVH-1).
[12] Responses to NDPSC 7-001 – 7-009.

A. In Exhibit KRP-6 I have constructed a matrix of NSP's North Dakota rate classes versus rate structure components and rider applications as presented in NSP's Tariff No. 2. What this matrix reveals is that NSP has effectively 30 rate classes that are distinguished from each other by rate structure and/or, in the case of classes with the same structure, different rates. Examples of the latter are the Residential classes which have different customer charges depending on whether the customer is served by underground or overhead facilities. In Exhibit KRP-7 I have constructed a matrix showing the charges for the various rate components of the rate classes shown in Exhibit KRP-7. Of these 30 rate classes, four have no customers (D19, D 34, D62, and D63). Of the four Residential Time of Use rate classes, two have, respectively 1 and 2 customers (D02Res and D02 Rsh) and two have, respectively, 9 and 15 customers (D04Res and D04Rsh). The two D02 rate classes, standard and space heating, are distinguished by (1) energy charges, which is consistent with cost causation and (2) customer charge, which is not consistent with cost causation. Similarly, the two D04 rate classes, standard and space heating, are distinguished by (1) energy charges, which is consistent with cost causation and (2) customer charge, which is not consistent with cost causation. Given the number of customers that have selected the Residential Time of Use rate classes over the regular Residential rate schedules, I question whether even the time of day energy charges reflect the actual cost of service. The customer charge situation is similar with regard to the four regular Residential rate schedules, where the customer charges differ between standard, underground and space heating and also the customer charges for the Residential Time of Day rate classes. On the basis of which I question whether any of Residential rate class customer charges can be said to be cost based, given that the class cost study develops costs for a single Residential customer class without regard of the rate structure underlying the eight residential rate classes. A similar situation arises with regard to the twelve commercial rate classes are elaborated upon just three customer classes in the class cost of service study.

Q. PLEASE GIVE SOME EXAMPLES OF THE INCOMPRENESIBILITY OF THE TARIFF.

A. "Commercial" and "non-residential", which are equivalent terms, are used indiscriminately to no discernible purpose in the tariff. Similarly "Oct-May" and "Other Months", which are equivalent terms, are used indiscriminately to no discernible purpose in the tariff. There is no clear indication in the tariff that the Energy Controlled Service Rider applies to rate schedule D21. The rider tariff sheets lack specific tariff sheet references to the applicable rate schedule tariff sheets and the rate schedule tariff sheets lack specific tariff sheet references to the rider tariff sheets. There are a large number of technical terms used in the tariff sheets that are nowhere defined (e.g., Tier 1, Tier 2, secondary, primary, transmission, transmission transformed, disconnecting means, control period, single phase, three phase, etc). There is an apparently arbitrary mixture of rate component charges that are stated in either dollars or cents. All of this turns reading the tariff into a task akin to biblical exegesis.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING RATE STRUCTURE AND TARIFF NDPSC NO. 2?

A. NSP should overhaul its rate structure, reducing the number of rate classes and redesign its class cost study so as to directly support the simplified rate structure and improve the comprehensibility of the tariff in the ways discussed above. As a practical matter, it is not possible to affect such an overhaul within this proceeding. As a consequence my recommendation to the Commission is that it direct NSP to eliminate the rate classes for which it has no North Dakota customers, eliminate the Residential Time of Day rate classes, and eliminate the customer charge distinction between standard, underground and space heating customer charges purposes of this proceeding. I also recommend that the Commission direct NSP to undertake at the conclusion of this proceeding to simplify its rate structure and align its class cost study with the simplified rate structure. As regards the tariff, I recommend that the Commission direct NSP to substitute plain language for technical terms wherever possible in the tariff, include a section defining in plain language the technical terms that are used, and place specific tariff sheet references where ever rate schedules and riders make reference to other riders of rate schedules.

The Commission should also direct NSP to remove its Account History Charge from its tariff as it doesn't conform to the Commission Administrative Rules: 69-09-02-02.1.

<u>TRANSMISSION COST RECOVERY (TRC) TRAC ER</u>

Q. PLEASE DESCRIBE NSP'S TRANSMISSION COST RECOVERY TRACKER.

A. NSP witnesses McCarten and Heuer present NSP's proposed Transmission Cost Recovery (TRC) tracker. [13] The TRC is a hybrid cost tracker designed to recover both (1) transmission investment and operating expenses associated with new or modified electric transmission facilities that are not included in rate base in this proceeding and (2) federally regulated transmission costs for MISO facilities that increase regional transmission capacity or reliability. On pages 1 and 2 of Schedule 22 of Exhibit ___(AEH-1), Ms Heuer presents an example of the calculation of the tracker revenue requirement. The revenue requirement for each transmission project is forecasted on a total company basis and a portion then allocated to NSP's North Dakota jurisdiction. The revenue requirement includes calculation of

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[13] McCarten Direct at 3; Heuer Direct at 84-94; Exhibit ___(AEH-1) Schedule 22.

separate debt and equity return components to which are added various income statement items. The jurisdictional revenue requirements for individual projects are then summed and netted against forecast revenues received under MISO 26 and 26A tariffs.

Q. PLEASE DESCRIBE THE SURCHARGE THROUGH WHICH NSP PROPOSES TO RECOVER TRANSMISSION COSTS.

A. Ms Heuer presents an example calculation of the surcharge on page 3 of Schedule 22 of Exhibit ___(AEH-1) and NSP witness Huso presents the rider tariff page. The surcharge is a single per kWh charge applicable to all customer classes that is calculated by dividing the forecast net revenue requirement by the forecast jurisdictional sales kWh. The tariff page presented by witness Huso reflects a single $0.000000 per-kWh charge applicable to all classes. NSP intends separately to file later this year for approval of a non-zero surcharge covering unspecified transmission investments to be effective January 1, 2014.[14]

Q. CAN YOU BRIEFLY DESCRIBE THE REGULATORY STATUS OF COST RECOVERY TRACKERS?

A. While trackers depart from the standard regulatory model in very important ways that result in a reduction of the utility's risk, they are not new to the world of regulated utilities. A succinct summary of the regulatory pros and cons of trackers can be found in a 2009 whitepaper from the National Regulatory Research Institute[15], which I have included as Exhibit KRP-8 to my testimony. In the past trackers have been instituted only under extraordinary circumstances which Commissions have noted in justifying departures from the traditional regulatory model. There are two types of tracker. The first and older type of tracker is an expense tracker. Examples of extraordinary cost circumstances justifying a

[14] Huso Direct at 15.
[15] "How Should Regulators View Cost Trackers," National Regulatory Research Institute, September 2009.

departure from the traditional model have been costs that: (1) are outside the control of a utility; (2) are unpredictable and volatile; or (3) are substantial and recurring. In the electric industry the classic examples of this kind of tracker are the ubiquitous fuel adjustment clauses. These clauses recognize that the electric generation fuel (gas, petroleum, and coal) commodity costs are substantial, unpredictable, volatile, and beyond the control of utility management. The other and more recent type is an investment or capital expenditure tracker. Recently, capital expenditure trackers have been accepted in a number of jurisdictions for recovery of "infrastructure investments." However, Commissions have generally approved investment trackers only after a showing that: (1) the tracker targets incremental investment; (2) the tracker is needed; (3) the tracker will address the identified need; and (4) the tracker represents a quantifiable benefit to ratepayers.

Q. ARE THERE STATUTORY PROVISIONS IN NORTH DAKOTA THAT ARE RELEVANT TO THE PROPOSED ~~TRC~~ TCR TRACKER?

A. Yes. Section 49-05-04.3 of the North Dakota Century Code provides that "[t]he commission may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities." [16] The tariff must:

> a. Allow the public utility to recover on a timely basis its investment and associated costs for new or modified electric transmission facilities not reflected in the utility's general rate schedule;
>
> b. Allow a return on the public utility's investment made for new or modified electric transmission facilities at the level approved in the utility's most recent general rate case;
>
> c. Provide a current return on construction work in progress for new or modified

[16] N.D.C.C. 49-05-04.3, sub. 1.

> electric transmission facilities, provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means; and
>
> d. Terminate cost recovery after the public utility's costs for new or modified electric transmission facilities have been recovered fully or have been reflected in the utility's general rate tariffs.

The rate adjustment, i.e., surcharge, under the tariff must be accompanied by:

> a. A description and quantification of the costs incurred by the public utility for new or modified electric transmission facilities which are subject to recovery;
>
> b. A schedule for implementation of the applicable transmission facility projects;
>
> c. Calculations to establish that the rate adjustment is consistent with the terms of the tariff;

Q. WHAT IS YOUR ASSESSMENT OF NSP'S ~~TRC~~ TCR TRACKER PROPOSAL?

A. Based on my review of the materials presented by Ms. Heuer and Mr. Huso and received in discovery,[17] NPSM's proposal is premature because it is incomplete. The Section 49-05 statutory authority cited by NSP clearly requires that the tracker application to the Commission be documented by quantification of the costs proposed for inclusion, a schedule for implementation the costs, and calculation of the rate adjustment that would result from those costs. NSP states it intends to make a filing later this year that will presumably include these items, but has not provided them here.

Q. BASED ON THE INFORMATION NSP DID SUBMIT IN THIS PROCEEDING WHAT IS YOUR ASSESSMENT OF THE PROPOSED TRACKER?

A. As regards to the operating expense portion of the ~~TRC,~~ TCR the transmission operating expenses NSP proposes to include in the ~~TRC~~ TCR do not meet three of the four the criteria for inclusion in a tracker. Transmission operating expenses are not unpredictable, not volatile, and not beyond the control of management. While it is not possible at this point to determine

[17] NSP responses to NDPSC 6-010, 6-011, and 6-012.

whether the operating expenses would be substantial, because NSP has not provided a quantification of those expenses, measured against NSP's total transmission operating expenses, the operating expenses are not likely to be substantial. As regards the investment portion of the TRC, the type of transmission investment NSP proposes to include in the TRC is appropriate for treatment in tracker providing it is shown that the investment is (1) incremental, (2) needed, (3) will meet the identified need, and (4) that tracker recovery will provide a benefit to ratepayers over revenue requirement recovery.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE TRC PROPOSAL?

A. I recommend that the Commission defer any consideration of the TRC in this proceeding. On the assumption that NSP will file an application at some later time that does comport with the statutory authority and in the interest of the Commission's most efficient consideration of such an application, I also recommend that the Commission direct NSP to file with any such application analyses demonstrating that the investment costs and operating expenses proposed meet the criteria for inclusion in a tracker.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Karl Richard Pavlovic

Experience

Snavely King Majoros & Associates, Inc.

Senior Consultant (2010-Present)

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation.

Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, and electric and gas reliability.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With over 25 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

FTI Consulting, Inc., *Director (2008-2010)*

Responsible for consulting engagements in the energy industry.

DOXA, Inc., *President (1994-2008)*

Management and Direction of small consulting firm; responsible for the design and execution of statistical, economic and financial analyses of discrete commercial operations, individual firms, and industry sectors for use by management and counsel in formulating and implementing commercial and litigation strategy.

Snavely, King & Associates, Inc.

Vice President (1988-1994), Consultant (1983-1987)

Responsible for economic analysis in civil court and regulatory proceedings, and consulting assignments in corporate strategic planning including investigations of rate structures, cost of service studies, market identification, and economic projections.

University of Florida, Gainesville FL

Associate Director, Center for Applied Philosophy (1982-1983)

Responsible for implementation and management of daily operations of the Center. Major projects included reorganization of finances of the Humanities and Agriculture Project, assembly and direction of a multi-disciplinary team in design of the Caribbean Inter-Sector Forecasting Project, and conception and direction of the Applied Philosophy Feasibility and Implementation Project.

Research Associate, Civil Engineering (1980-1983)

Responsible for direction of the Caribbean Agricultural Transportation Study, design of the planning component of the Honduran Water Port Project, and redesign and completion of the Florida Domestic and Export Agricultural Transportation Projects.

Associate Professor, Philosophy (1978-1983)

Responsible for undergraduate and graduate courses in scientific methodology, epistemology, hermeneutics and ethics and professionalism as well as research on the social context and impact of scientific and technological growth.

Education

Purdue University – Ph.D. and MA in Philosophy
Karl-Ruprecht Universität, Heidelberg, Germany
Yale University – BA in Philosophy

Dr. Pavlovic was an active member of the Board of Trustees of the Legal Aid Society of the District of Columbia from 1994 to 2008 and served as Treasurer from 1999 to 2008.

Karl Richard Pavlovic

PROJECTS AND APPEARANCES

In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013)
DE Public Service Commission Docket No. 13-115

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013)
ND Public Service Commission Case No. PU-12-813

In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013)
MD Public Service Commission Case No. 9316

In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (2012)
MD Public Service Commission Case No. 9299

In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2012)
DE Public Service Commission Docket No. 11-528

In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1 and for Other Appropriate Relief (2011 -)
New Jersey BPU Docket No. ER11080469

In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2011 -)
D.C. Public Service Commission Formal Case No. 1087

Electric Transmission Rate Annual Informational Filing of Central Maine Power Company (2011)
Federal Energy Regulatory Commission Docket No. ER09-934-000 (2011)

Electric Transmission Rate Annual Informational Filing of Bangor Hydro Electric Company (2011)
Federal Energy Regulatory Commission Docket No. ER09-938-000

Pennsylvania Public Utility Commission Office of Consumer Advocate Office of Small Business Advocate v. City of Bethlehem – Bureau of Water (2011)
Pennsylvania PUC Docket Nos. R-2011-2244756, C-2011-2246910, and C-2011-2248241

Southern California Edison Company Transmission Owners Tariff (2011 -)
Federal Energy Regulatory Commission Docket No. ER11-2061-000

In the Matter of the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities under K.S.A. 66-1239 (2011)
Kansas Corporation Commission Docket No. 11-KCPE-581-PRE

Midwest Independent Transmission System Operator, Inc., and Ameren Illinois Company (2011 -)
Federal Energy Regulatory Commission Docket No. ER11-2788-000

Electric Generation Plant Valuation Study (2010 - 2012)
California Department of Water Resources

Karl Richard Pavlovic

Tampa Electric Company Wholesale Power Tariff (2010 - 2011)
Federal Energy Regulatory Commission Docket No. ER10-2061-000

Pacific Gas & Electric Company, Transmission Owner Tariff (2010-2011)
Federal Energy Regulatory Commission Docket No. ER10-2026-000

Impact Evaluation Study of the District of Columbia Department of the Environment's Two-Year Pilot Reliable Energy Trust Fund Programs (2007 - 2008)
D.C. Public Service Commission Formal Case No. 945

In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2007 - 2008)
D.C. Public Service Commission Formal Case No. 1053

In the Matter of the Investigation of Interconnection Standards in the District of Columbia (2006)
D.C. Public Service Commission Formal Case No. 1050

In the Matter of the Investigation into the Omnibus Utility Emergency Amendment Act of 2005, Specifically Regarding the Establishment of the Natural Gas Trust Fund Programs (2006)
D.C. Public Service Commission Formal Case No. 1037

Emergency Application of the Potomac Electric Power Company For A Certificate of Public Convenience and Necessity To Construct Two 69kV Overhead Transmission Lines and Notice of The Proposed Construction of Two Underground 230kV Transmission Lines (2005 - 2006)
D.C. Public Service Commission Formal Case No. 1044

Investigation Into Potomac Electric Power Company's Distribution Service Rates (2003 - 2005)
D.C. Public Service Commission Formal Case No. 1032

Investigation of the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating Them Underground in the District of Columbia (2003)
D.C. Public Service Commission Formal Case No. 1026

Guadalupe L. Garcia v. Ann Veneman, Secretary, US Department of Agriculture (2003 - 2006)
U.S. District Court for the District of Columbia

Mirant Corporation, et al., Debtors (2003 - 2005)
U.S. District Court for the Northern District of Texas

Complaint: Office of the People's Counsel of the District of Columbia v. Mirant Americas Energy Marketing, L.P. (2003)
Federal Energy Regulatory Commission

Investigation into the Effect of the Bankruptcy of Mirant Corporation on Retail Electric Service in the District of Columbia (2003 - 2005)
D.C. Public Service Commission Formal Case No. 1023

Development and Designation of Standard Offer Service in the District of Columbia (2003 - 2007)
D.C. Public Service Commission Formal Case No. 1017

Independent Review Panel, Project Management Plan, Ohio River Main Stem Study (2003 - 2005)
U.S. Army Corps of Engineers

Karl Richard Pavlovic

Investigation into Affiliated Activities, Promotional Practices, and Codes of Conduct of Regulated Gas and Electric Companies (2002 - 2004)
D.C. Public Service Commission Formal Case No. 1009

Independent Review Panel, Ohio River Main Stem Study, System Investment Plan (2001)
U.S. Army Corps of Engineers

Joint Application of PEPCO and New RC, Inc. for Authorization and Approval of Merger Transaction (2001 - 2002)
D.C. Public Service Commission Formal Case No. 1002

Investigation into Explosions Occurring in Underground Distribution Systems of PEPCO (2001 - 2006)
D.C. Public Service Commission Formal Case No. 991

Trans Alaska Pipeline System 1996 Quality Bank Complaint Remand (2000 - 2008)
Federal Energy Regulatory Commission

Ohio River Main Stem Study, Independent Technical Review (1999)
U.S. Army Corps of Engineers

Investigation of January 1999 Electric Service Interruption (1999 - 2004)
D.C. Public Service Commission Formal Case No. 982

Trans Alaska Pipeline System 1996 Quality Bank Complaint Appeal (1998 -2000)
U.S. Court of Appeals for the District of Columbia

Electric Retail Competition Investigation (1997 -)
D.C. Public Service Commission Formal Case No. 945

Trans Alaska Pipeline System 1996 Quality Bank Complaint (1996 - 1998)
Federal Energy Regulatory Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint Remand (1995 - 1998)
Federal Energy Regulatory Commission

Prudhoe Bay Unit Operating Agreement Hearings (1995)
Alaska Oil and Gas Conservation Commission

Prudhoe Bay Unit Natural Gas Liquids Hearings (1995)
Alaska Department of Natural Resources/Department of Revenue (1995)

Potomac Electric Power Co. 3rd Integrated Least-Cost Plan (1995)
D.C. Public Service Commission Formal Case No. 917, Phase II

All American Pipeline Quality Bank Complaint (1994-1995)
Federal Energy Regulatory Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint Appeal (1994-1995)
U.S. Court of Appeals for the District of Columbia

Investigation of the January 1994 Energy Crisis (1994)
D.C. Public Service Commission Formal Case No. 936

Washington Gas Light Co. Gas Rate Case (1994)
D.C. Public Service Commission Formal Case No. 934

Karl Richard Pavlovic

Washington Gas Light Co. 3rd Integrated Least-Cost Plan (1994)
D.C. Public Service Commission Formal Case No. 921

Potomac Electric Power Co. Electric Rate Case (1993)
D.C. Public Service Commission Formal Case No. 929

Washington Gas Light Co. Gas Rate Case (1993)
D.C. Public Service Commission Formal Case No. 922

Trans Alaska Pipeline System Pumpability Complaint (1992)
Federal Energy Regulatory Commission

Potomac Electric Power Co. 2nd Integrated Least-Cost Plan (1992)
D.C. Public Service Commission Formal Case No. 917

Potomac Electric Power Co. Electric Rate Case (1992)
D.C. Public Service Commission Formal Case No. 912

Potomac Electric Power Co. Fuel Clause Audit and Productivity Improvement Plan (1991- 2008)
D.C. Public Service Commission Formal Case No. 766

Potomac Electric Power Co. Electric Rate Case (1991)
D.C. Public Service Commission Formal Case No. 905

Anchorage Telephone Utility (1991-1995)
Federal Communications Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint (1990-1993)
Federal Energy Regulatory Commission

Telefonica Larga Distancia de Puerto Rico International Service Tariffs (1990-1992)
Federal Communications Commission

Southern Bell Intrastate Depreciation Study (1989-1990)
Florida Public Service Commission

Lake Erie Iron Ore Antitrust Litigation: Erie-Western Pennsylvania Port Authority v.
Penn Central et al. (1988-1989)
U.S. District Court for the Eastern District of Pennsylvania

Unimar International Chapter 11 Reorganization (1988)
U.S. Bankruptcy Court for the Western District of Washington at Seattle

National Forest Road Cost Analysis System (1986)
U.S. Department of Agriculture, Forest Service

Puerto Rico Telephone Company Long Distance Facilities and Service Applications (1985-1990)
Federal Communications Commission

All American Cable and Radio/ AT&T de Puerto Rico International Rate Complaint (1985-1990)
Federal Communications Commission

Caribbean Telecommunications Facilities Planning Docket (1984-1990)
Federal Communications Commission

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of
NORTHERN STATES POWER COMPANY,
A Minnesota Corporation for authority to
Increase Rates for Electric Service in North Dakota

Case No. PU-12-813

AFFIDAVIT OF
Karl Richard Pavlovic

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Karl Richard Pavlovic

Subscribed and sworn to before me, this 17 day of July, 2013

Notary Public

District of Columbia: SS
Subscribed and sworn to before me, in my presence,
this 17 day of July, 2013

Notary Public, D.C.
My commission expires 7/12/2015

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-12-813
NDPSC Data Request 6-007
Attachment A - Page 1 of 6

O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
A&G	920	A&G Salaries	ECustomerMN/SD/ND
A&G	920	A&G Salaries	EDemandProd
A&G	920	A&G Salaries	EDemandTran
A&G	920	A&G Salaries	EDirectMN
A&G	920	A&G Salaries	EDirectND
A&G	920	A&G Salaries	EDirectSD
A&G	920	A&G Salaries	ETwoFactorAlloc
A&G	921	A&G Office & Supplies	ECustomerMN/SD/ND
A&G	921	A&G Office & Supplies	EDemandProd
A&G	921	A&G Office & Supplies	EDemandTran
A&G	921	A&G Office & Supplies	EDirectMN
A&G	921	A&G Office & Supplies	EDirectND
A&G	921	A&G Office & Supplies	EDirectSD
A&G	921	A&G Office & Supplies	ETwoFactorAlloc
A&G	922	A&G Admn Transfer Crdt	EDemandProd
A&G	922	A&G Admn Transfer Crdt	ETwoFactorAlloc
A&G	923	A&G Outside Services	ECustomerMN/SD/ND
A&G	923	A&G Outside Services	EDemandProd
A&G	923	A&G Outside Services	EDirectMN
A&G	923	A&G Outside Services	EDirectND
A&G	923	A&G Outside Services	ETwoFactorAlloc
A&G	924	A&G Property Insurance	EDemandProd
A&G	924	A&G Property Insurance	ETwoFactorAlloc
A&G	925	A&G Injuries & Damages	ECustomerMN/ND
A&G	925	A&G Injuries & Damages	ECustomerMN/SD/ND
A&G	925	A&G Injuries & Damages	EDemandProd
A&G	925	A&G Injuries & Damages	EDemandTran
A&G	925	A&G Injuries & Damages	EDirectMN
A&G	925	A&G Injuries & Damages	EDirectND
A&G	925	A&G Injuries & Damages	EDirectSD
A&G	925	A&G Injuries & Damages	ETwoFactorAlloc
A&G	926	A&G Pen & Ben	ECustomerMN/ND
A&G	926	A&G Pen & Ben	ECustomerMN/SD/ND
A&G	926	A&G Pen & Ben	EDemandProd
A&G	926	A&G Pen & Ben	EDemandTran
A&G	926	A&G Pen & Ben	EDirectMN
A&G	926	A&G Pen & Ben	EDirectND
A&G	926	A&G Pen & Ben	EDirectSD
A&G	926	A&G Pen & Ben	ETwoFactorAlloc
A&G	928	A&G Regulatory Comm Exp	ECustomerMN/SD/ND
A&G	928	A&G Regulatory Comm Exp	EDemandTran
A&G	928	A&G Regulatory Comm Exp	EDirectMN
A&G	928	A&G Regulatory Comm Exp	EDirectND
A&G	928	A&G Regulatory Comm Exp	EDirectSD
A&G	929	A&G Duplicate Chrg Crdt	ETwoFactorAlloc
A&G	930.1	A&G General Advertising	ECustomerMN/SD/ND
A&G	930.1	A&G General Advertising	EDirectND
A&G	930.1	A&G General Advertising	EDirectSD
A&G	930.1	A&G General Advertising	ETwoFactorAlloc

Northern States Power Company
Electric Utility - State of North Dakota

O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
A&G	930.2	A&G Misc General Exp	ECustomerMN/SD/ND
A&G	930.2	A&G Misc General Exp	EDemandProd
A&G	930.2	A&G Misc General Exp	EDemandTran
A&G	930.2	A&G Misc General Exp	EDirectMN
A&G	930.2	A&G Misc General Exp	EDirectND
A&G	930.2	A&G Misc General Exp	EDirectSD
A&G	930.2	A&G Misc General Exp	ETwoFactorAlloc
A&G	931	A&G Rents	ECustomerMN/SD/ND
A&G	931	A&G Rents	EDemandProd
A&G	931	A&G Rents	EDemandTran
A&G	931	A&G Rents	EDirectMN
A&G	931	A&G Rents	EDirectND
A&G	931	A&G Rents	EDirectSD
A&G	931	A&G Rents	ETwoFactorAlloc
A&G	935	A&G Maint of Gen PLT	ECustomerMN/SD/ND
A&G	935	A&G Maint of Gen PLT	EDemandProd
A&G	935	A&G Maint of Gen PLT	EDirectMN
A&G	935	A&G Maint of Gen PLT	ETwoFactorAlloc
Customer Accounts	901	Cust Acct Supervise	ECustomerMN/SD/ND
Customer Accounts	902	Cust Acct Meter Read	ECustomerMN/SD/ND
Customer Accounts	902		EDirectMN
Customer Accounts	902		EDirectND
Customer Accounts	902		EDirectSD
Customer Accounts	903	Cust Acct Recrds &Coll	ECustomerMN/SD/ND
Customer Accounts	904	Cust Acct Uncollect	ECustomerMN/SD/ND
Customer Accounts	904		EDirectMN
Customer Accounts	904		EDirectND
Customer Accounts	904		EDirectSD
Customer Accounts	905	Cust Acct Misc	ECustomerMN/SD/ND
Customer Accounts	905		EDirectMN
Customer Information	908	Customer Asst Expense	ECustomerMN/SD/ND
Customer Information	908	Customer Asst Expense	EDirectMN
Customer Information	908	Customer Asst Expense	EDirectND
Customer Information	908	Customer Asst Expense	EDirectSD
Customer Information	909	Cust Serv Instruct Adver	ECustomerMN/SD/ND
Customer Information	909	Cust Serv Instruct Adver	EDirectMN
Customer Information	909	Cust Serv Instruct Adver	EDirectND
Customer Information	909	Cust Serv Instruct Adver	EDirectSD
Customer Sales	912	Sales Demo & Sales	ECustomerMN/SD/ND
Customer Sales	912	Sales Demo & Sales	EDirectMN
Distribution	580	Dist Oper Sup & Eng	ECustomerMN/ND
Distribution	580	Dist Oper Sup & Eng	ECustomerMN/SD/ND
Distribution	580	Dist Oper Sup & Eng	EDirectMN
Distribution	580	Dist Oper Sup & Eng	EDirectND
Distribution	580	Dist Oper Sup & Eng	EDirectSD
Distribution	581	Dist Load Dispatching	ECustomerMN/SD/ND
Distribution	581	Dist Load Dispatching	EDirectMN
Distribution	582	Dist Op Station Exp	ECustomerMN/SD/ND
Distribution	582	Dist Op Station Exp	EDirectMN

Northern States Power Company
Electric Utility - State of North Dakota

O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
Distribution	582	Dist Op Station Exp	EDirectND
Distribution	582	Dist Op Station Exp	EDirectSD
Distribution	583	Dist Oper Overhead Lines	ECustomerMN/ND
Distribution	583	Dist Oper Overhead Lines	ECustomerMN/SD/ND
Distribution	583	Dist Oper Overhead Lines	EDirectMN
Distribution	583	Dist Oper Overhead Lines	EDirectND
Distribution	583	Dist Oper Overhead Lines	EDirectSD
Distribution	584	Dist Op UG Elec lines	ECustomerMN/ND
Distribution	584	Dist Op UG Elec lines	ECustomerMN/SD/ND
Distribution	584	Dist Op UG Elec lines	EDirectMN
Distribution	584	Dist Op UG Elec lines	EDirectND
Distribution	584	Dist Op UG Elec lines	EDirectSD
Distribution	585	Dist Oper Streetlight	ECustomerMN/ND
Distribution	585	Dist Oper Streetlight	ECustomerMN/SD/ND
Distribution	585	Dist Oper Streetlight	EDirectMN
Distribution	585	Dist Oper Streetlight	EDirectND
Distribution	585	Dist Oper Streetlight	EDirectSD
Distribution	586	Dist Oper Meter Exp	ECustomerMN/ND
Distribution	586	Dist Oper Meter Exp	ECustomerMN/SD/ND
Distribution	586	Dist Oper Meter Exp	EDirectMN
Distribution	586	Dist Oper Meter Exp	EDirectND
Distribution	586	Dist Oper Meter Exp	EDirectSD
Distribution	587	Dist Oper Cust Install	ECustomerMN/ND
Distribution	587	Dist Oper Cust Install	ECustomerMN/SD/ND
Distribution	587	Dist Oper Cust Install	EDirectMN
Distribution	587	Dist Oper Cust Install	EDirectND
Distribution	587	Dist Oper Cust Install	EDirectSD
Distribution	587	Dist Oper Cust Install	ECustomerMN/SD/ND
Distribution	588	Dist Oper Misc Exp	ECustomerMN/ND
Distribution	588	Dist Oper Misc Exp	ECustomerMN/SD/ND
Distribution	588	Dist Oper Misc Exp	EDirectMN
Distribution	588	Dist Oper Misc Exp	EDirectND
Distribution	588	Dist Oper Misc Exp	EDirectSD
Distribution	589	Dist Rents	ECustomerMN/ND
Distribution	589	Dist Rents	ECustomerMN/SD/ND
Distribution	589	Dist Rents	EDirectMN
Distribution	589	Dist Rents	EDirectND
Distribution	589	Dist Rents	EDirectSD
Distribution	590	Dist Mtc Super & Eng	ECustomerMN/SD/ND
Distribution	590	Dist Mtc Super & Eng	EDirectMN
Distribution	590	Dist Mtc Super & Eng	EDirectND
Distribution	592	Dist Mt of Station Equip	ECustomerMN/ND
Distribution	592	Dist Mt of Station Equip	ECustomerMN/SD/ND
Distribution	592	Dist Mt of Station Equip	EDirectMN
Distribution	592	Dist Mt of Station Equip	EDirectND
Distribution	592	Dist Mt of Station Equip	EDirectSD
Distribution	593	Dist Mtc of Overhead LInes	ECustomerMN/ND
Distribution	593	Dist Mtc of Overhead LInes	ECustomerMN/SD/ND
Distribution	593	Dist Mtc of Overhead LInes	EDirectMN

Northern States Power Company
Electric Utility - State of North Dakota

O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
Distribution	593	Dist Mtc of Overhead LInes	EDirectND
Distribution	593	Dist Mtc of Overhead LInes	EDirectSD
Distribution	594	Dist Mt of Undergrnd Line	ECustomerMN/ND
Distribution	594	Dist Mt of Undergrnd Line	EDirectMN
Distribution	594	Dist Mt of Undergrnd Line	EDirectND
Distribution	594	Dist Mt of Undergrnd Line	EDirectSD
Distribution	594	Dist Mt of Undergrnd Line	ECustomerMN/SD/ND
Distribution	595	Dist Mt of Line Transform	ECustomerMN/ND
Distribution	595	Dist Mt of Line Transform	ECustomerMN/SD/ND
Distribution	595	Dist Mt of Line Transform	EDirectMN
Distribution	595	Dist Mt of Line Transform	EDirectND
Distribution	595	Dist Mt of Line Transform	EDirectSD
Distribution	596	Dist Mtc of Streetlights	ECustomerMN/ND
Distribution	596	Dist Mtc of Streetlights	ECustomerMN/SD/ND
Distribution	596	Dist Mtc of Streetlights	EDirectMN
Distribution	596	Dist Mtc of Streetlights	EDirectND
Distribution	596	Dist Mtc of Streetlights	EDirectSD
Distribution	597	Dist Mtc of Meters	ECustomerMN/SD/ND
Distribution	597	Dist Mtc of Meters	EDirectMN
Distribution	597	Dist Mtc of Meters	EDirectND
Distribution	597	Dist Mtc of Meters	EDirectSD
Distribution	598	Dist Maint of Dist Plant	EDirectMN
Fuel and PE	501	Stm Gen Fuel	EEnergy
Fuel and PE	501.1	Fuel Forecast	EEnergy
Fuel and PE	501.2	Fuel Forecast	EEnergy
Fuel and PE	501.3	Fuel Forecast	EEnergy
Fuel and PE	501.5	Fuel Forecast	EEnergy
Fuel and PE	501.7	Fuel Forecast	EEnergy
Fuel and PE	518	Fuel Forecast	EEnergy
Fuel and PE	518	Fuel Forecast	EEnergy
Fuel and PE	547	Fuel Forecast	EEnergy
Fuel and PE	555.02	Fuel Forecast	EDirectMN
Fuel and PE	555.02	Fuel Forecast	EEnergy
Fuel and PE	557	Fuel Forecast	EEnergy
Production	500	Stm Prod Op & Supr	EDemandProd
Production	502	Steam Expenses Major	EDemandProd
Production	505	Stm Gen Elec Exp. Major	EDemandProd
Production	506	Misc Steam Pwr Exp	EDemandProd
Production	507	Stm Pow Gen Rents	EDemandProd
Production	510	Stm Maint Super&Eng	EEnergy
Production	511	Stm Maint of Structures	EDemandProd
Production	512	Stm Maint of Boiler Plt	EEnergy
Production	513	Stm Maint of Elec Plant	EEnergy
Production	514	Stm Maint of Misc Stm Plt	EDemandProd
Production	517	Nuc Oper Super & Eng	EDemandProd
Production	519	Nuclear coolants & Wtr	EDemandProd
Production	520	Nuclear Steam Expense	EDemandProd
Production	523	Nuclear Electric Expense	EDemandProd
Production	524	Nuclear Power Misc Exp	EDemandProd

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-12-813
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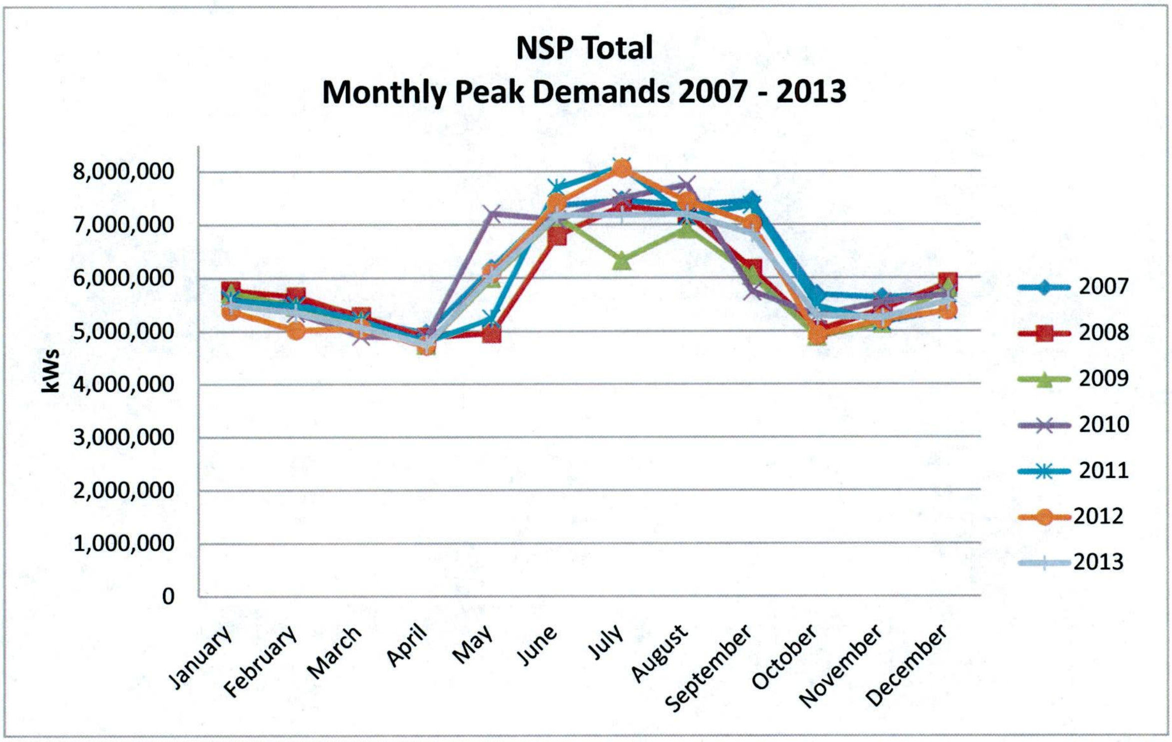
O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

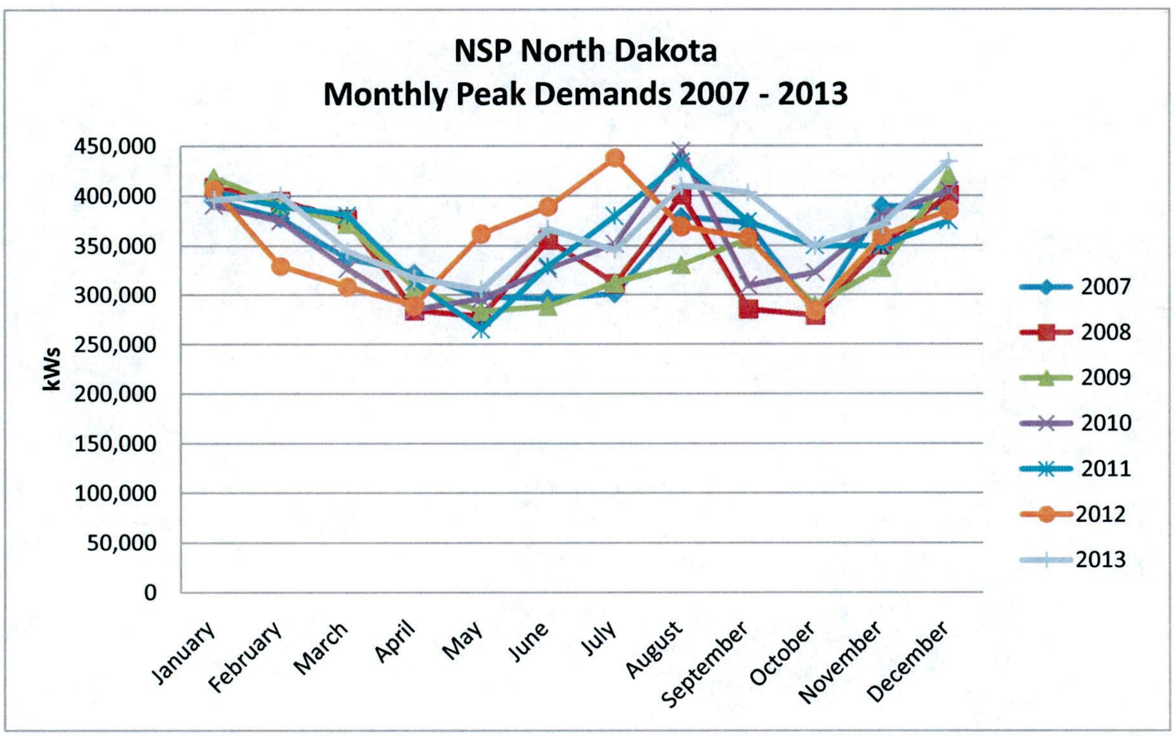
Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
Production	525	Nuclear Gen Rents	EDemandProd
Production	528	Nuc Maint Super & Eng	EEnergy
Production	529	Nuc Maint of Structures	EDemandProd
Production	530	Nuc Mtc of React Plt Equip	EEnergy
Production	531	Nuc Maint of Elect Plant	EEnergy
Production	532	Nuc Mtc of Misc Nuc Plant	EDemandProd
Production	535	Hyd Oper Super & Eng	EDemandProd
Production	538	Hyd Oper Electric Exp	EDemandProd
Production	539	Hydro Oper Misc Gen Exp	EDemandProd
Production	540	Hyd Oper Rents	EDemandProd
Production	541	Hydro Mtc Super& Eng	EDemandProd
Production	543	Hydro Mtc Resv, Dams	EDemandProd
Production	544	Hyd Maint of Elec Plant	EEnergy
Production	545	Hyd Mt Misc Hyd Plnt Mjr	EDemandProd
Production	546	Oth Oper Super&Eng	EDemandProd
Production	548	Oth Oper Gen Exp	EDemandProd
Production	549	Oth Oper Misc Gen Exp	EDemandProd
Production	550	Oth Oper Rents	EDemandProd
Production	551	Oth Maint Super & Eng	EDemandProd
Production	552	Oth Maint of Structures	EDemandProd
Production	553	Oth Mtc of Gen & Ele Plant	EDemandProd
Production	554	Oth Mtc Misc Gen Plt Mjr	EDemandProd
Production	555.01	Fuel Forecast	EDemandProd
Production	556	Load Dispatch	EDemandProd
Production	557	Other Power Oth Exp	EDemandProd
Production	557	Other Power Oth Exp	EEnergy
Production	575.1	Operation Supervision	EDemandProd
Production	575.2	DA & RT Mkt Admin	EDemandProd
Production	575.3	Trans Rights Mkt Admin	EDemandProd
Production	575.5	Ancillary Serv Mkt Admin	EDemandProd
Production	575.6	Mkt Monitoring/Compliance	EDemandProd
Production	575.7	Transmission Exp Budget	EDemandProd
Production	575.8	Regional Market Rents	EDemandProd
Transmission	560	Trans Oper Super & Eng	EDemandTran
Transmission	561.1	Load Disp-Reliability	EDemandTran
Transmission	561.2	Load Disp-Monitor/Operate	EDemandTran
Transmission	561.3	Load Disp-Trans Serv/Sch	EDemandTran
Transmission	561.4	Transmission Exp Budget	EDemandTran
Transmission	561.5	Rel/Plan/Standards Dev	EDemandTran
Transmission	561.6	Trans Service Studies	EDemandTran
Transmission	561.7	Gen Interconn Studies	EDemandTran
Transmission	561.8	A&G Regulatory Comm Exp	EDemandTran
Transmission	561.8	A&G Regulatory Comm Exp	EDemandTran
Transmission	562	Trans Oper Station Exp	EDemandTran
Transmission	563	Trans Oper OH Lines	EDemandTran
Transmission	565.5	Transmission Exp Budget	EDemandTran
Transmission	565.64	Transmission Exp Budget	EDemandTran
Transmission	565.81	Transmission Exp Budget	EDemandTran
Transmission	566	Trans Oper Misc Exp	EDemandTran

Northern States Power Company
Electric Utility - State of North Dakota

O&M Expenses and Cost of Goods Sold
FERC Code and Associated Jurisdictional Allocator

Cost of Service Income Statement Line	FERC Code	FERC Code Description	Jurisdictional Allocator
Transmission	567	Trans Rents	EDemandTran
Transmission	568	Trans Mtce Super & Eng	EDemandTran
Transmission	570	Tran Mnt of Station Equip	EDemandTran
Transmission	571	Trans Mt of Overhead Line	EDemandTran
Transmission	573	Trans Mtc of Misc Plt Mjr	EDemandTran
PTax	408.1	Tax Oth than Inc Tx-Ut	ECustomerMN/ND
PTax	408.1	Tax Oth than Inc Tx-Ut	ECustomerMN/SD/ND
PTax	408.1	Tax Oth than Inc Tx-Ut	EDemandProd
PTax	408.1	Tax Oth than Inc Tx-Ut	EDemandTran
PTax	408.1	Tax Oth than Inc Tx-Ut	EDirectMN
PTax	408.1	Tax Oth than Inc Tx-Ut	EDirectND
PTax	408.1	Tax Oth than Inc Tx-Ut	EDirectSD
PTax	408.1	Tax Oth than Inc Tx-Ut	ETwoFactorAlloc
A&G	426.1	Donations	ECustomerMN/SD/ND
A&G	426.1	Donations	EDirectMN
A&G	426.1	Donations	EDirectND
A&G	426.1	Donations	EDirectSD


NSP Total
Monthly Peak Demands 2007 - 2013
kWs
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
January
February
March
April
May
June
July
August
September
October
November
December
2007
2008
2009
2010
2011
2012
2013


NSP North Dakota
Monthly Peak Demands 2007 - 2013
kWs
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
January
February
March
April
May
June
July
August
September
October
November
December
2007
2008
2009
2010
2011
2012
2013

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2012	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,662,883	4,390,662	4,471,605	4,126,402	5,345,374	6,518,707	7,188,169	6,556,374	6,221,267	4,351,210	4,546,028	4,683,441
North Dakota	406,845	328,842	307,812	288,840	361,845	388,794	437,821	368,824	357,795	283,858	359,864	384,820
South Dakota	304,800	288,998	265,663	305,897	371,904	495,901	415,902	501,925	419,913	272,917	298,878	306,993
NSP-MN Total Retail	5,374,528	5,008,502	5,045,080	4,721,139	6,079,123	7,403,402	8,041,892	7,427,123	6,998,975	4,907,985	5,204,770	5,375,254
NSP-MN Total Wholesale	5,716	4,461	3,383	3,492	4,737	6,150	7,138	6,303	5,558	3,478	5,352	5,405
TOTAL	5,380,244	5,012,963	5,048,463	4,724,631	6,083,860	7,409,552	8,049,030	7,433,426	7,004,533	4,911,463	5,210,122	5,380,659
											Av	

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2011	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,847,661	4,766,735	4,513,420	4,216,962	4,702,910	6,936,044	7,215,460	6,265,403	6,525,027	4,800,869	4,522,601	4,699,973
North Dakota	403,752	389,716	380,715	312,764	264,818	328,814	379,852	433,870	373,848	349,880	349,875	374,829
South Dakota	313,998	312,703	293,581	248,831	261,874	418,907	476,917	444,911	454,896	309,902	288,834	309,823
NSP-MN Total Retail	5,565,411	5,469,154	5,187,716	4,778,557	5,229,602	7,683,765	8,072,229	7,144,184	7,353,771	5,460,651	5,161,310	5,384,625
NSP-MN Total Wholesale	11,589	11,306	10,509	8,377	3,502	6,575	7,711	6,149	6,478	3,980	4,462	4,925
TOTAL	5,577,000	5,480,460	5,198,225	4,786,934	5,233,104	7,690,340	8,079,940	7,150,333	7,360,249	5,464,631	5,165,772	5,389,550
											Av	

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2010	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,855,345	4,618,707	4,272,750	4,295,367	6,464,148	6,285,031	6,658,483	6,782,962	5,040,249	4,644,459	4,822,487	4,921,372
North Dakota	390,763	374,773	325,779	284,833	295,837	325,812	351,805	444,784	308,824	321,859	379,861	404,897
South Dakota	309,997	297,713	256,609	250,888	382,998	421,745	423,957	450,924	325,913	290,929	303,810	318,741
NSP-MN Total Retail	5,556,105	5,291,193	4,855,138	4,831,088	7,142,983	7,032,588	7,434,245	7,678,670	5,674,986	5,257,247	5,506,158	5,645,010
NSP-MN Total Wholesale	56,395	52,312	44,258	42,341	60,080	60,914	66,785	70,542	59,434	35,155	36,354	39,911
TOTAL	5,612,500	5,343,505	4,899,396	4,873,429	7,203,063	7,093,502	7,501,030	7,749,212	5,734,420	5,292,402	5,542,512	5,684,921
											Av	

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2009	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,857,751	4,677,394	4,433,044	4,083,809	5,268,158	6,403,822	5,522,393	6,049,661	5,242,899	4,264,315	4,443,641	4,941,794
North Dakota	418,726	391,553	371,808	306,750	282,814	287,840	311,820	329,854	356,710	288,861	326,851	420,779
South Dakota	310,743	281,684	275,624	239,999	335,837	325,823	374,914	411,922	330,912	235,891	259,863	318,719
NSP-MN Total Retail	5,587,220	5,350,631	5,080,476	4,630,558	5,886,809	7,017,485	6,209,127	6,791,437	5,930,521	4,789,067	5,030,355	5,681,292
NSP-MN Total Wholesale	121,076	113,181	111,378	106,702	102,408	133,540	116,623	124,860	105,821	102,314	102,882	119,888
TOTAL	5,708,296	5,463,812	5,191,854	4,737,260	5,989,217	7,151,025	6,325,750	6,916,297	6,036,342	4,891,381	5,133,237	5,801,180
											Av	

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2008	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,898,388	4,815,105	4,488,015	4,221,060	4,297,705	5,920,448	6,457,770	6,254,346	5,473,413	4,376,334	4,664,415	5,024,454
North Dakota	408,720	394,733	376,786	283,768	277,784	355,821	310,834	400,808	284,815	278,866	349,942	400,867
South Dakota	311,403	297,711	273,739	254,945	256,869	351,908	405,902	386,916	256,998	222,946	255,751	326,709
NSP-MN Total Retail	5,618,511	5,507,549	5,138,540	4,759,773	4,832,358	6,628,177	7,174,506	7,042,070	6,015,226	4,878,146	5,270,108	5,752,030
NSP-MN Total Wholesale	146,109	141,199	136,313	128,041	123,991	157,810	170,512	161,126	148,350	128,473	138,734	152,573
TOTAL	5,764,620	5,648,748	5,274,853	4,887,814	4,956,349	6,785,987	7,345,018	7,203,196	6,163,576	5,006,619	5,408,842	5,904,603
											Av	

NSPM Total Company Electric Utility -Demand Allocations
Actual kW

2007	January	February	March	April	May	June	July	Au ust	September	October	November	December
							Production					
Minnesota	4,665,376	4,754,977	4,458,971	4,258,565	5,415,894	6,521,696	6,560,648	6,475,642	6,499,772	4,928,509	4,813,435	4,850,555
North Dakota	395,660	377,656	336,745	321,690	297,770	295,776	300,778	378,794	372,815	280,804	389,833	387,719
South Dakota	278,738	285,999	266,631	247,999	315,721	358,920	413,905	323,915	398,915	338,921	280,997	303,997
NSP-MN Total Retail	5,339,774	5,418,632	5,062,347	4,828,254	6,029,385	7,176,392	7,275,331	7,178,351	7,271,502	5,548,234	5,484,265	5,542,271
NSP-MN Total Wholesale	140,943	143,743	136,572	131,640	147,181	172,984	177,966	175,306	174,746	133,091	141,297	145,164
TOTAL	5,480,717	5,562,375	5,198,919	4,959,894	6,176,566	7,349,376	7,453,297	7,353,657	7,446,248	5,681,325	5,625,562	5,687,435
											Av	

Source: 6-003 Att A

Xcel Ener y North (Minnesota Company) - Demand Allocations
(Based on Au ust 2012 Forecast)
2013

	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013	2013
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PRODUCTION												
MN	4,772,950	4,637,538	4,422,958	4,171,717	5,384,966	6,404,884	6,396,444	6,305,151	5,980,461	4,628,964	4,580,846	4,793,538
ND	396,111	400,990	344,834	316,381	305,174	366,900	345,220	409,827	403,276	348,717	370,703	434,187
SD	316,533	300,413	295,796	258,318	341,097	399,289	431,462	473,288	438,474	296,561	295,090	334,445
RETAIL	5,485,595	5,338,940	5,063,587	4,746,416	6,031,237	7,171,073	7,173,127	7,188,266	6,822,212	5,274,242	5,246,639	5,562,170
WHOLESALE	3,456	3,926	3,103	2,627	3,165	3,927	4,637	4,270	3,860	2,809	3,509	3,588
TOTAL	5,489,051	5,342,866	5,066,690	4,749,043	6,034,402	7,175,000	7,177,763	7,192,536	6,826,072	5,277,052	5,250,149	5,565,758

1-CP 3-Yr Average: 2010 - 2012

System Peak kW	Allocation Factors	Trans Loss Multipliers	HSDS Demand	Production
21,186,591	88.7278%	0.9670	20,487,399	88.8616%
1,262,457	5.2871%	0.9289	1,172,687	5.0864%
1,343,743	5.6275%	0.9781	1,314,381	5.7010%
23,792,791	99.6424%		22,974,467	99.6489%
85,391	0.3576%	0.9479	80,944	0.3511%
23,878,182	100.0000%		23,055,410	100.0000%

NSPM Total Company Electric Actual kW 2012	12-CP Total kW	Allocation Factors	Trans Loss Multipliers	HSDS Demand	Production	1-CP System Peak kW	Allocation Factors	Trans Loss Multipliers	HSDS Demand	Production
Minnesota	63,062,122	88.02%	0.9646	60,829,723	88.1030%	7,188,169	89.3048%	0.9646	6,933,708	89.3903%
North Dakota	4,275,960	5.97%	0.9294	3,974,077	5.7559%	437,821	5.4394%	0.9294	406,911	5.2459%
South Dakota	4,249,691	5.93%	0.9841	4,182,121	6.0572%	415,902	5.1671%	0.9841	409,289	5.2766%
NSP-MN Total Retail	71,587,773	99.91%		68,985,921	99.9161%	8,041,892	99.9113%		7,749,908	99.9128%
NSP-MN Total Wholesale	61,173	0.09%	0.9472	57,943	0.0839%	7,138	0.0887%	0.9472	6,761	0.0872%
TOTAL	71,648,946	100.00%		69,043,864	100.0000%	8,049,030	100.0000%		7,756,669	100.0000%
	5,970,746									

NSPM Total Company Electric Actual kW 2011	Total kW	Allocation Factors								
Minnesota	64,013,065	88.20%	0.9676	61,939,042	88.3621%	7,215,460	89.3009%	0.9676	6,981,679	89.4151%
North Dakota	4,342,733	5.98%	0.9283	4,031,359	5.7511%	379,852	4.7012%	0.9283	352,617	4.5160%
South Dakota	4,135,177	5.70%	0.9783	4,045,444	5.7712%	476,917	5.9025%	0.9783	466,568	5.9754%
NSP-MN Total Retail	72,490,975	99.88%		70,015,844	99.8844%	8,072,229	99.9046%		7,800,864	99.9065%
NSP-MN Total Wholesale	85,563	0.12%	0.9469	81,020	0.1156%	7,711	0.0954%	0.9469	7,302	0.0935%
TOTAL	72,576,538	100.00%		70,096,864	100.0000%	8,079,940	100.0000%		7,808,165	100.0000%
	6,048,045									

NSPM Total Company Electric Actual kW 2010	Total kW	Allocation Factors								
Minnesota	63,661,360	87.77%	0.9689	61,681,492	87.9815%	6,782,962	87.5310%	0.9689	6,572,012	87.7371%
North Dakota	4,209,827	5.80%	0.9289	3,910,508	5.5779%	444,784	5.7397%	0.9289	413,160	5.5157%
South Dakota	4,034,224	5.56%	0.9725	3,923,283	5.5961%	450,924	5.8190%	0.9725	438,524	5.8543%
NSP-MN Total Retail	71,905,411	99.14%		69,515,283	99.1555%	7,678,670	99.0897%		7,423,695	99.1071%
NSP-MN Total Wholesale	624,481	0.86%	0.9481	592,070	0.8445%	70,542	0.9103%	0.9481	66,881	0.8929%
TOTAL	72,529,892	100.00%		70,107,353	100.0000%	7,749,212	100.0000%		7,490,576	100.0000%
	6,044,158									

NSPM Total Company Electric Actual kW 2009	Total kW	Allocation Factors								
Minnesota	60,188,681	86.80%	0.9686	58,298,756	87.0760%	6,403,822	89.5511%	0.9686	6,202,742	89.7637%
North Dakota	4,094,366	5.90%	0.9279	3,799,162	5.6745%	287,840	4.0252%	0.9279	267,087	3.8652%
South Dakota	3,701,931	5.34%	0.9627	3,563,849	5.3230%	325,823	4.5563%	0.9627	313,670	4.5393%
NSP-MN Total Retail	67,984,978	98.04%		65,661,768	98.0736%	7,017,485	98.1326%		6,783,499	98.1681%
NSP-MN Total Wholesale	1,360,673	1.96%	0.9479	1,289,782	1.9264%	133,540	1.8674%	0.9479	126,583	1.8319%
TOTAL	69,345,651	100.00%		66,951,550	100.0000%	7,151,025	100.0000%		6,910,081	100.0000%
	5,778,804									

NSPM Total Company Electric Actual kW 2008	Total kW	Allocation Factors								
Minnesota	60,891,453	86.55%	0.962	58,577,578	86.7317%	6,457,770	87.9204%	0.962	6,212,375	88.0490%
North Dakota	4,123,744	5.86%	0.9279	3,826,422	5.6655%	310,834	4.2319%	0.9279	288,423	4.0879%
South Dakota	3,601,797	5.12%	0.9627	3,467,450	5.1340%	405,902	5.5262%	0.9627	390,762	5.5383%
NSP-MN Total Retail	68,616,994	97.54%		65,871,450	97.5312%	7,174,506	97.6785%		6,891,559	97.6751%
NSP-MN Total Wholesale	1,733,231	2.46%	0.962	1,667,368	2.4688%	170,512	2.3215%	0.962	164,033	2.3249%
TOTAL	70,350,225	100.00%		67,538,818	100.0000%	7,345,018	100.0000%		7,055,592	100.0000%
	5,862,519									

NSPM Total Company Electric Actual kW 2007	Total kW	Allocation Factors								
Minnesota	64,204,040	86.79%	0.9665	62,053,205	86.6511%	6,560,648	88.0234%	0.9665	6,340,866	87.9043%
North Dakota	4,136,040	5.59%	0.985	4,073,999	5.6889%	300,778	4.0355%	0.985	296,266	4.1072%
South Dakota	3,814,658	5.16%	0.976	3,723,106	5.1989%	413,905	5.5533%	0.976	403,971	5.6003%
NSP-MN Total Retail	72,154,738	97.54%		69,850,310	97.5390%	7,275,331	97.6123%		7,041,104	97.6118%
NSP-MN Total Wholesale	1,820,633	2.46%	0.968	1,762,373	2.4610%	177,966	2.3877%	0.968	172,271	2.3882%
TOTAL	73,975,371	100.00%		71,612,683	100.0000%	7,453,297	100.0000%		7,213,375	100.0000%
	6,164,614									

Source: 6-003 Att A

PRODUCTION	FORECAST BUDGET 12 Month Total KW	Allocation Factors PRODUCTION								
MN	62,480,417	87.8195%	0.9646	60,268,610	87.9164%	6,305,151	87.66%	0.9646	6,081,949	87.7291%
ND	4,442,319	6.2439%	0.9294	4,128,692	6.0227%	409,827	5.70%	0.9294	380,893	5.4942%
SD	4,180,766	5.8763%	0.9841	4,114,292	6.0017%	473,288	6.58%	0.9841	465,763	6.7184%
RETAIL	71,103,503	99.9397%		68,511,594	99.9408%	7,188,266	99.94%		6,928,605	99.9417%
WHOLESALE	42,879	0.0603%	0.9472	40,615	0.0592%	4,270	0.06%	0.9472	4,045	0.0583%
TOTAL	71,146,382	100.0000%		68,552,209	100.0000%	7,192,536	100.00%		6,932,649	100.0000%

Northern States Power Adjustment Factors

Plant in Service (01)

	Total NSPM	Factor	North Dakota	Factor	North Dakota
Production	8,882,259,668	6.0633%	538,557,286	5.0864%	451,787,256
Transmission	2,135,197,421	6.0056%	128,230,656	5.0864%	108,604,682
Distribution	3,591,567,206	4.4218%	158,813,020	4.4218%	158,813,020
Total	14,609,024,295	5.6513%	825,600,962	**4.9230%**	719,204,957

Adjustment Factor: **87.1129%**

Reserve (02)

	Total NSPM	Factor	North Dakota	Factor	North Dakota
Production	4,879,327,102	6.0302%	294,231,701	5.0864%	248,182,094
Transmission	662,943,053	6.0102%	39,843,990	5.0864%	33,719,935
Distribution	1,500,886,284	4.9152%	73,772,087	4.9152%	73,772,087
Total	7,043,156,439	5.7907%	407,847,778	**5.0499%**	355,674,116

Adjustment Factor: **87.2076%**

CWIP (03)

	Total NSPM	Factor	North Dakota	Factor	North Dakota
Production	834,156,667	6.0227%	50,238,754	5.0864%	42,428,545
Transmission	341,863,288	6.0227%	20,589,400	5.0864%	17,388,534
Distribution	46,612,482	3.6224%	1,688,494	3.6224%	1,688,494
Total	1,222,632,437	5.9312%	72,516,648	**5.0306%**	61,505,573

Adjustment Factor: **84.8158%**

Accumulated Deferred Taxes (05)

	Total NSPM	Factor	North Dakota	Factor	North Dakota
Production	997,751,660	6.1477%	61,338,348	5.0864%	50,749,640
Transmission	351,217,178	6.0037%	21,086,025	5.0864%	17,864,311
Distribution	558,031,908	4.3523%	24,287,186	4.3523%	24,287,186
Total	1,907,000,747	5.5958%	106,711,560	**4.8716%**	92,901,137

Adjustment Factor: **87.0582%**

COSS Input Rate Base & Income Statement
2013 Budget ND Rules

		Mn Co Electric												Mn Co Gas		Jur Electric				Jur Gas	
		Production				Transmission				Distribution											
	Period	MN	ND	SD	Whls	MN	ND	SD	Whls	MN	ND	SD	Whls	MN	ND	MN	ND	SD	Whls	MN	ND
Rate Base																					
Plant Investment	BOY	8,882,260	8,882,260	8,882,260	8,882,260	2,135,197	2,135,197	2,135,197	2,135,197	3,591,567	3,591,567	3,591,567	3,591,567	1,123,587	1,123,587	12,891,513	825,601	884,631	7,279	1,019,425	104,162
Plant Investment	EOY	9,849,187	9,849,187	9,849,187	9,849,187	2,471,915	2,471,915	2,471,915	2,471,915	3,749,871	3,749,871	3,749,871	3,749,871	1,161,113	1,161,113	14,178,559	912,281	972,025	8,108	1,054,143	106,970
Depreciation Reserve	BOY	4,879,327	4,879,327	4,879,327	4,879,327	662,943	662,943	662,943	662,943	1,500,886	1,500,886	1,500,886	1,500,886	545,673	545,673	6,204,864	407,848	426,090	4,356	494,046	51,627
Depreciation Reserve	EOY	5,148,542	5,148,542	5,148,542	5,148,542	703,968	703,968	703,968	703,968	1,570,647	1,570,647	1,570,647	1,570,647	582,372	582,372	6,538,443	429,926	450,709	4,081	527,235	55,137
C.W.I.P.	BOY	834,157	834,157	834,157	834,157	341,863	341,863	341,863	341,863	46,612	46,612	46,612	46,612	4,118	4,118	1,076,352	72,517	73,068	696	3,739	379
C.W.I.P.	EOY	511,545	511,545	511,545	511,545	539,612	539,612	539,612	539,612	67,239	67,239	67,239	67,239	13,305	13,305	982,694	64,849	70,230	623	12,904	401
Accumulated Deferred Taxes	BOY	997,754	997,754	997,754	997,754	351,217	351,217	351,217	351,217	558,032	558,032	558,032	558,032	149,967	149,967	1,683,233	106,712	116,453	606	136,502	13,465
Accumulated Deferred Taxes	EOY	1,100,759	1,100,759	1,100,759	1,100,759	397,792	397,792	397,792	397,792	566,369	566,369	566,369	566,369	148,339	148,339	1,822,968	115,857	125,200	896	135,176	13,163
Materials & Supplies	BOY																				
Materials & Supplies	EOY																				
Fuel Inventory	BOY																				
Fuel Inventory	EOY																				
Non-Plant Assets & Liab	BOY																				
Non-Plant Assets & Liab	EOY																				
Prepaids & Other	BOY																				
Prepaids & Other	EOY																				
Statement of Income																					
Operating Expenses:																					
Fuel & Purchased Energy	Annual																				
Power Production	Annual																				
Transmission	Annual																				
Distribution	Annual																				
Customer Accounting	Annual																				
Customer Service & Information	Annual																				
Sales, Econ Dvlp & Other	Annual																				
Administrative & General	Annual																				
Total Operating Expenses:	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	Annual	228,757	228,757	228,757	228,757	50,950	50,950	50,950	50,950	97,059	97,059	97,059	97,059	42,529	42,529	331,333	21,241	24,479	(287)	38,556	3,973
Amortization	Annual																				
Taxes:																					
Property	Annual																				
Gross Earnings Tax	Annual																				
Deferred Income Tax & ITC	Annual	102,043	102,043	102,043	102,043	46,024	46,024	46,024	46,024	7,514	7,514	7,514	7,514	(1,951)	(1,951)	137,582	9,054	8,656	289	(1,650)	(302)
Payroll & other	Annual																				
Total Taxes:	Annual	102,043	102,043	102,043	102,043	46,024	46,024	46,024	46,024	7,514	7,514	7,514	7,514	(1,951)	(1,951)	137,582	9,054	8,656	289	(1,650)	(302)
AFUDC	Annual	47,168	47,168	47,168	47,168	34,991	34,991	34,991	34,991	4,600	4,600	4,600	4,600	546	546	76,368	5,080	5,262	49	523	23
Juris Income Tax																					
Tax Additions:																					
Nuclear Fuel Burn (ex D&D)	Annual																				
Nuclear Outage Accounting	Annual																				
Avoided Tax Interest	Annual	28,627	28,627	28,627	28,627	24,652	24,652	24,652	24,652	2,829	2,829	2,829	2,829	277	277	49,397	3,272	3,408	32	273	4
Open	Annual																				
Open	Annual																				
Open	Annual																				
Open	Annual																				
Open	Annual																				
Other Book Additions	Annual																				
Total Tax Additions	Annual	28,627	28,627	28,627	28,627	24,652	24,652	24,652	24,652	2,829	2,829	2,829	2,829	277	277	49,397	3,272	3,408	32	273	4
Tax Deductions:																					
Tax Depreciation & Removal	Annual	607,813	607,813	607,813	607,813	179,246	179,246	179,246	179,246	125,003	125,003	125,003	125,003	39,583	39,583	804,188	52,587	54,792	495	36,328	3,255
Manufacture Production Deduction	Annual																				
Open	Annual																				
Open	Annual																				
Open	Annual																				
Other Tax/Book Timing Differences	Annual																				
Total Tax Deductions	Annual	607,813	607,813	607,813	607,813	179,246	179,246	179,246	179,246	125,003	125,003	125,003	125,003	39,583	39,583	804,188	52,587	54,792	495	36,328	3,255
Tax Credits:																					
State R&E Credits																					
Other State Credits																					
Federal Production Tax Credit (PTC)																					
Other Federal Tax Credits																					
Total Tax Credits	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jurisdiction Cash Working Capital																					
Fuel Expenses																					
Coal & Rail Transport	Annual																				
Gas for Generation	Annual																				
Oil	Annual																				
Nuclear & EOL	Annual																				
Nuclear Disposal	Annual																				
Total Fuel Expenses	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power																					
Purchases	Annual																				
Interchange	Annual																				
Total Purchased Power	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Labor Related																					
Regular Payroll	Annual																				
Incentive Compensation	Annual																				
Pension & Benefits	Annual																				
Total Labor & Related	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxes																					
State Sales Tax Customer Billings	Annual																				
Employer's Payroll Taxes	Annual																				
All Other Operating Expenses	Annual																				
Property Tax	Annual																				
Gross Earnings Tax	Annual																				
Federal Income Tax	Annual																				
State Income Tax	Annual																				
Total Taxes	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Revenues																					
Actual Revenues	Annual																				
Total Retail Revenues	Annual																				
Retail (Computer Billed)	Annual																				
Retail (Hand Billed)	Annual																				
Asset & Non-Asset Based Adj	Annual																				
Interdepartmental	Annual																				
Total Retail Related Revenues	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Operating Revenues																					
Late Payment	Annual																				
Connect and Trouble Charges	Annual																				
CIP Incentive	Annual																				
Rentals	Annual																				
Interchange Production - Capacity	Annual																				
Interchange Production - Energy	Annual																				
Interchange Transmission - Capacity	Annual																				
Interchange Ag - Decomm	Annual																				
Sales for Resale - Non Asset	Annual																				
Sales for Resale - Asset	Annual																				
Sales for Resale - Mkt Whsle	Annual																				
Production Associated Revenues	Annual																				
MISO	Annual																				
Point to Point Firm	Annual																				
Services & Facilities	Annual																				
Ancillary	Annual																				
Distribution Associated Revenues	Annual																				
Other	Annual																				
JOA - Rev fr/to PSC	Annual																				
Total Other Operating Revenues	Annual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total Company	Jurisdiction
01Electric Distribution	01ElectricMinnesota
01Electric Distribution	01ElectricNorth Dakota
01Electric Distribution	01ElectricSouth Dakota
01Electric Distribution	01ElectricWholesale
01Electric Transmission	01ElectricMinnesota
01Electric Transmission	01ElectricNorth Dakota
01Electric Transmission	01ElectricSouth Dakota
01Electric Transmission	01ElectricWholesale
01Production	01ElectricMinnesota
01Production	01ElectricNorth Dakota
01Production	01ElectricSouth Dakota
01Production	01ElectricWholesale
02Electric Distribution	02ElectricMinnesota
02Electric Distribution	02ElectricNorth Dakota
02Electric Distribution	02ElectricSouth Dakota
02Electric Distribution	02ElectricWholesale
02Electric Transmission	02ElectricMinnesota
02Electric Transmission	02ElectricNorth Dakota
02Electric Transmission	02ElectricSouth Dakota
02Electric Transmission	02ElectricWholesale
02Production	02ElectricMinnesota
02Production	02ElectricNorth Dakota
02Production	02ElectricSouth Dakota
02Production	02ElectricWholesale
03Electric Distribution	03ElectricMinnesota
03Electric Distribution	03ElectricNorth Dakota
03Electric Distribution	03ElectricSouth Dakota
03Electric Distribution	03ElectricWholesale
03Electric Transmission	03ElectricMinnesota
03Electric Transmission	03ElectricNorth Dakota
03Electric Transmission	03ElectricSouth Dakota
03Electric Transmission	03ElectricWholesale
03Production	03ElectricMinnesota
03Production	03ElectricNorth Dakota
03Production	03ElectricSouth Dakota
03Production	03ElectricWholesale
05Electric Distribution	05ElectricMinnesota
05Electric Distribution	05ElectricNorth Dakota
05Electric Distribution	05ElectricSouth Dakota
05Electric Distribution	05ElectricWholesale
05Electric Transmission	05ElectricMinnesota
05Electric Transmission	05ElectricNorth Dakota
05Electric Transmission	05ElectricSouth Dakota
05Electric Transmission	05ElectricWholesale
05Production	05ElectricMinnesota
05Production	05ElectricNorth Dakota
05Production	05ElectricSouth Dakota
05Production	05ElectricWholesale
02Production	02ElectricWisconsin
05Production	05ElectricWisconsin
01Gas Distribution	01GasMinnesota
02Gas Distribution	02GasMinnesota
03Gas Distribution	03GasMinnesota
05Gas Distribution	05GasMinnesota
01Gas Distribution	01GasNorth Dakota
02Gas Distribution	02GasNorth Dakota
03Gas Distribution	03GasNorth Dakota
05Gas Distribution	05GasNorth Dakota

ReportViewCode	RelatedItem	Utility	SubBU	Jurisdictional	2013	2014	2013 ND % of Tota	2014 ND % of Total
PE13N	01	Electric	Electric Distribution	Minnesota	3,207,545,538.21	3,348,388,628.54		
PE13N	01	Electric	Electric Distribution	North Dakota	158,813,019.95	167,017,157.81	4.4218%	4.4539%
PE13N	01	Electric	Electric Distribution	South Dakota	224,415,921.52	233,614,581.56		
PE13N	01	Electric	Electric Distribution	Wholesale	792,726.26	850,773.91		
PE13N	01	Electric	Electric Transmission	Minnesota	1,877,922,784.45	2,174,042,526.86		
PE13N	01	Electric	Electric Transmission	North Dakota	128,230,655.96	148,465,573.73	6.0056%	6.0061%
PE13N	01	Electric	Electric Transmission	South Dakota	127,783,540.26	147,947,902.74		
PE13N	01	Electric	Electric Transmission	Wholesale	1,260,440.47	1,459,339.16		
PE13N	01	Electric	Production	Minnesota	7,806,044,877.67	8,656,127,636.94		
PE13N	01	Electric	Production	North Dakota	538,557,286.18	596,798,347.58	6.0633%	6.0594%
PE13N	01	Electric	Production	South Dakota	532,431,177.31	590,462,166.28		
PE13N	01	Electric	Production	Wholesale	5,226,326.93	5,798,695.17		
PE13N	02	Electric	Electric Distribution	Minnesota	1,333,131,712.14	1,393,654,338.01		
PE13N	02	Electric	Electric Distribution	North Dakota	73,772,086.66	76,988,919.53	4.9152%	4.9017%
PE13N	02	Electric	Electric Distribution	South Dakota	93,662,189.19	99,667,578.36		
PE13N	02	Electric	Electric Distribution	Wholesale	320,296.26	335,940.40		
PE13N	02	Electric	Electric Transmission	Minnesota	583,002,354.52	619,082,592.76		
PE13N	02	Electric	Electric Transmission	North Dakota	39,843,990.39	42,308,303.11	6.0102%	6.0100%
PE13N	02	Electric	Electric Transmission	South Dakota	39,705,062.04	42,160,782.17		
PE13N	02	Electric	Electric Transmission	Wholesale	391,645.64	415,868.55		
PE13N	02	Electric	Production	Minnesota	4,288,729,443.21	4,525,706,288.41		
PE13N	02	Electric	Production	North Dakota	294,231,701.20	310,628,806.48	6.0302%	6.0333%
PE13N	02	Electric	Production	South Dakota	292,722,456.78	308,880,369.51		
PE13N	02	Electric	Production	Wholesale	3,643,501.06	3,327,666.82		
PE13N	03	Electric	Electric Distribution	Minnesota	42,437,183.44	58,555,153.50		
PE13N	03	Electric	Electric Distribution	North Dakota	1,688,493.77	1,541,147.97	3.6224%	2.2920%
PE13N	03	Electric	Electric Distribution	South Dakota	2,486,787.69	7,142,654.98		
PE13N	03	Electric	Electric Distribution	Wholesale	17.26	20.31		
PE13N	03	Electric	Electric Transmission	Minnesota	300,553,895.80	474,407,233.20		
PE13N	03	Electric	Electric Transmission	North Dakota	20,589,400.25	32,499,197.46	6.0227%	6.0227%
PE13N	03	Electric	Electric Transmission	South Dakota	20,517,608.96	32,385,878.99		
PE13N	03	Electric	Electric Transmission	Wholesale	202,383.07	319,450.16		
PE13N	03	Electric	Production	Minnesota	733,360,511.69	449,731,979.98		
PE13N	03	Electric	Production	North Dakota	50,238,753.56	30,808,822.88	6.0227%	6.0227%
PE13N	03	Electric	Production	South Dakota	50,063,580.66	30,701,398.42		
PE13N	03	Electric	Production	Wholesale	493,820.75	302,834.66		
PE13N	05	Electric	Electric Distribution	Minnesota	500,062,891.32	508,459,285.27		
PE13N	05	Electric	Electric Distribution	North Dakota	24,287,186.50	24,433,148.02	4.3523%	4.3140%
PE13N	05	Electric	Electric Distribution	South Dakota	33,568,818.18	33,359,362.45		
PE13N	05	Electric	Electric Distribution	Wholesale	113,012.30	116,907.19		
PE13N	05	Electric	Electric Transmission	Minnesota	308,911,385.78	349,873,478.51		
PE13N	05	Electric	Electric Transmission	North Dakota	21,086,025.23	23,883,375.98	6.0037%	6.0040%
PE13N	05	Electric	Electric Transmission	South Dakota	21,012,502.31	23,800,099.23		
PE13N	05	Electric	Electric Transmission	Wholesale	207,264.63	234,761.13		
PE13N	05	Electric	Production	Minnesota	874,256,302.23	964,635,105.37		
PE13N	05	Electric	Production	North Dakota	61,338,347.84	67,540,063.34	6.1477%	6.1358%
PE13N	05	Electric	Production	South Dakota	61,871,754.97	68,040,315.09		
PE13N	05	Electric	Production	Wholesale	285,255.26	544,199.73		
PE13N	02	Electric	Production	Wisconsin	0.00	0.00		
PE13N	05	Electric	Production	Wisconsin	0.00	0.00		
PE13N	01	Gas	Gas Distribution	Minnesota	1,019,424,966.10	1,054,143,023.98		
PE13N	02	Gas	Gas Distribution	Minnesota	494,046,294.64	527,235,115.76		
PE13N	03	Gas	Gas Distribution	Minnesota	3,739,004.63	12,903,516.24		
PE13N	05	Gas	Gas Distribution	Minnesota	136,502,252.53	135,176,444.27		
PE13N	01	Gas	Gas Distribution	North Dakota	104,162,245.80	106,969,546.02		
PE13N	02	Gas	Gas Distribution	North Dakota	51,626,931.56	55,136,986.93		
PE13N	03	Gas	Gas Distribution	North Dakota	379,476.47	401,407.34		
PE13N	05	Gas	Gas Distribution	North Dakota	13,464,683.51	13,163,038.81		

Total Company	Jurisdiction	ReportViewCode	RelatedItem	Utility	SubBU	Jurisdictional	2013	Sort Code	Jurisdiction
10Electric Distribution	10ElectricMinnesota	PE13N	10	Electric	Electric Distribution	Minnesota	85,117,836.47	1	ElectricMinnesota
10Electric Transmission	10ElectricMinnesota	PE13N	10	Electric	Electric Transmission	Minnesota	44,809,163.92	5	ElectricMinnesota
10Production	10ElectricMinnesota	PE13N	10	Electric	Production	Minnesota	201,406,161.57	9	ElectricMinnesota
11Electric Distribution	11ElectricMinnesota	PE13N	11	Electric	Electric Distribution	Minnesota	4,137,366.13	15	ElectricMinnesota
11Electric Transmission	11ElectricMinnesota	PE13N	11	Electric	Electric Transmission	Minnesota	30,762,734.67	19	ElectricMinnesota
11Production	11ElectricMinnesota	PE13N	11	Electric	Production	Minnesota	41,467,693.37	23	ElectricMinnesota
12Electric Distribution	12ElectricMinnesota	PE13N	12	Electric	Electric Distribution	Minnesota	8,396,394.35	29	ElectricMinnesota
12Electric Transmission	12ElectricMinnesota	PE13N	12	Electric	Electric Transmission	Minnesota	40,962,094.40	33	ElectricMinnesota
12Production	12ElectricMinnesota	PE13N	12	Electric	Production	Minnesota	90,378,634.74	37	ElectricMinnesota
20Electric Distribution	20ElectricMinnesota	PE13N	20	Electric	Electric Distribution	Minnesota	112,319,449.25	43	ElectricMinnesota
20Electric Transmission	20ElectricMinnesota	PE13N	20	Electric	Electric Transmission	Minnesota	157,641,951.26	47	ElectricMinnesota
20Production	20ElectricMinnesota	PE13N	20	Electric	Production	Minnesota	534,226,823.14	51	ElectricMinnesota
21Electric Distribution	21ElectricMinnesota	PE13N	21	Electric	Electric Distribution	Minnesota	2,555,793.93	57	ElectricMinnesota
21Electric Transmission	21ElectricMinnesota	PE13N	21	Electric	Electric Transmission	Minnesota	21,673,490.22	61	ElectricMinnesota
21Production	21ElectricMinnesota	PE13N	21	Electric	Production	Minnesota	25,167,749.87	65	ElectricMinnesota
23Electric Distribution	23ElectricMinnesota	PE13N	23	Electric	Electric Distribution	Minnesota	(822,879.77)	71	ElectricMinnesota
23Electric Transmission	23ElectricMinnesota	PE13N	23	Electric	Electric Transmission	Minnesota	(484,257.36)	75	ElectricMinnesota
23Production	23ElectricMinnesota	PE13N	23	Electric	Production	Minnesota	(847,633.60)	79	ElectricMinnesota
10Electric Distribution	10ElectricNorth Dakota	PE13N	10	Electric	Electric Distribution	North Dakota	4,218,280.28	2	ElectricNorth Dakota
10Electric Transmission	10ElectricNorth Dakota	PE13N	10	Electric	Electric Transmission	North Dakota	3,060,683.08	6	ElectricNorth Dakota
10Production	10ElectricNorth Dakota	PE13N	10	Electric	Production	North Dakota	13,962,074.72	10	ElectricNorth Dakota
11Electric Distribution	11ElectricNorth Dakota	PE13N	11	Electric	Electric Distribution	North Dakota	131,650.29	16	ElectricNorth Dakota
11Electric Transmission	11ElectricNorth Dakota	PE13N	11	Electric	Electric Transmission	North Dakota	2,107,396.60	20	ElectricNorth Dakota
11Production	11ElectricNorth Dakota	PE13N	11	Electric	Production	North Dakota	2,840,847.78	24	ElectricNorth Dakota
12Electric Distribution	12ElectricNorth Dakota	PE13N	12	Electric	Electric Distribution	North Dakota	145,960.23	30	ElectricNorth Dakota
12Electric Transmission	12ElectricNorth Dakota	PE13N	12	Electric	Electric Transmission	North Dakota	2,797,350.88	34	ElectricNorth Dakota
12Production	12ElectricNorth Dakota	PE13N	12	Electric	Production	North Dakota	6,201,703.97	38	ElectricNorth Dakota
20Electric Distribution	20ElectricNorth Dakota	PE13N	20	Electric	Electric Distribution	North Dakota	5,038,148.38	44	ElectricNorth Dakota
20Electric Transmission	20ElectricNorth Dakota	PE13N	20	Electric	Electric Transmission	North Dakota	10,767,899.70	48	ElectricNorth Dakota
20Production	20ElectricNorth Dakota	PE13N	20	Electric	Production	North Dakota	36,780,503.90	52	ElectricNorth Dakota
21Electric Distribution	21ElectricNorth Dakota	PE13N	21	Electric	Electric Distribution	North Dakota	62,805.15	58	ElectricNorth Dakota
21Electric Transmission	21ElectricNorth Dakota	PE13N	21	Electric	Electric Transmission	North Dakota	1,484,739.25	62	ElectricNorth Dakota
21Production	21ElectricNorth Dakota	PE13N	21	Electric	Production	North Dakota	1,724,193.56	66	ElectricNorth Dakota
23Electric Distribution	23ElectricNorth Dakota	PE13N	23	Electric	Electric Distribution	North Dakota	(240.56)	72	ElectricNorth Dakota
23Electric Transmission	23ElectricNorth Dakota	PE13N	23	Electric	Electric Transmission	North Dakota	(33,173.98)	76	ElectricNorth Dakota
23Production	23ElectricNorth Dakota	PE13N	23	Electric	Production	North Dakota	(58,067.01)	80	ElectricNorth Dakota
10Electric Distribution	10ElectricSouth Dakota	PE13N	10	Electric	Electric Distribution	South Dakota	7,699,358.56	3	ElectricSouth Dakota
10Electric Transmission	10ElectricSouth Dakota	PE13N	10	Electric	Electric Transmission	South Dakota	3,050,011.06	7	ElectricSouth Dakota
10Production	10ElectricSouth Dakota	PE13N	10	Electric	Production	South Dakota	13,729,436.97	11	ElectricSouth Dakota
11Electric Distribution	11ElectricSouth Dakota	PE13N	11	Electric	Electric Distribution	South Dakota	331,321.44	17	ElectricSouth Dakota
11Electric Transmission	11ElectricSouth Dakota	PE13N	11	Electric	Electric Transmission	South Dakota	2,100,048.51	21	ElectricSouth Dakota
11Production	11ElectricSouth Dakota	PE13N	11	Electric	Production	South Dakota	2,830,819.97	25	ElectricSouth Dakota
12Electric Distribution	12ElectricSouth Dakota	PE13N	12	Electric	Electric Distribution	South Dakota	(209,454.39)	31	ElectricSouth Dakota
12Electric Transmission	12ElectricSouth Dakota	PE13N	12	Electric	Electric Transmission	South Dakota	2,787,597.02	35	ElectricSouth Dakota
12Production	12ElectricSouth Dakota	PE13N	12	Electric	Production	South Dakota	6,168,548.62	39	ElectricSouth Dakota
20Electric Distribution	20ElectricSouth Dakota	PE13N	20	Electric	Electric Distribution	South Dakota	7,614,336.12	45	ElectricSouth Dakota
20Electric Transmission	20ElectricSouth Dakota	PE13N	20	Electric	Electric Transmission	South Dakota	10,730,354.08	49	ElectricSouth Dakota
20Production	20ElectricSouth Dakota	PE13N	20	Electric	Production	South Dakota	36,447,538.91	53	ElectricSouth Dakota
21Electric Distribution	21ElectricSouth Dakota	PE13N	21	Electric	Electric Distribution	South Dakota	210,134.05	59	ElectricSouth Dakota
21Electric Transmission	21ElectricSouth Dakota	PE13N	21	Electric	Electric Transmission	South Dakota	1,479,562.24	63	ElectricSouth Dakota
21Production	21ElectricSouth Dakota	PE13N	21	Electric	Production	South Dakota	1,718,091.68	67	ElectricSouth Dakota
23Electric Distribution	23ElectricSouth Dakota	PE13N	23	Electric	Electric Distribution	South Dakota	(229.54)	73	ElectricSouth Dakota
23Electric Transmission	23ElectricSouth Dakota	PE13N	23	Electric	Electric Transmission	South Dakota	(33,058.31)	77	ElectricSouth Dakota
23Production	23ElectricSouth Dakota	PE13N	23	Electric	Production	South Dakota	(57,864.55)	81	ElectricSouth Dakota
10Electric Distribution	10ElectricWholesale	PE13N	10	Electric	Electric Distribution	Wholesale	23,175.59	4	ElectricWholesale
10Electric Transmission	10ElectricWholesale	PE13N	10	Electric	Electric Transmission	Wholesale	30,084.92	8	ElectricWholesale
10Production	10ElectricWholesale	PE13N	10	Electric	Production	Wholesale	(339,800.03)	12	ElectricWholesale
11Electric Distribution	11ElectricWholesale	PE13N	11	Electric	Electric Distribution	Wholesale	1.06	18	ElectricWholesale
11Electric Transmission	11ElectricWholesale	PE13N	11	Electric	Electric Transmission	Wholesale	20,714.61	22	ElectricWholesale
11Production	11ElectricWholesale	PE13N	11	Electric	Production	Wholesale	27,922.11	26	ElectricWholesale
12Electric Distribution	12ElectricWholesale	PE13N	12	Electric	Electric Distribution	Wholesale	3,894.98	32	ElectricWholesale
12Electric Transmission	12ElectricWholesale	PE13N	12	Electric	Electric Transmission	Wholesale	27,496.50	36	ElectricWholesale
12Production	12ElectricWholesale	PE13N	12	Electric	Production	Wholesale	258,944.30	40	ElectricWholesale
20Electric Distribution	20ElectricWholesale	PE13N	20	Electric	Electric Distribution	Wholesale	30,945.70	46	ElectricWholesale
20Electric Transmission	20ElectricWholesale	PE13N	20	Electric	Electric Transmission	Wholesale	105,842.81	50	ElectricWholesale
20Production	20ElectricWholesale	PE13N	20	Electric	Production	Wholesale	358,284.74	54	ElectricWholesale
21Electric Distribution	21ElectricWholesale	PE13N	21	Electric	Electric Distribution	Wholesale	0.24	60	ElectricWholesale
21Electric Transmission	21ElectricWholesale	PE13N	21	Electric	Electric Transmission	Wholesale	14,594.21	64	ElectricWholesale
21Production	21ElectricWholesale	PE13N	21	Electric	Production	Wholesale	16,946.50	68	ElectricWholesale
23Electric Distribution	23ElectricWholesale	PE13N	23	Electric	Electric Distribution	Wholesale	(0.00)	74	ElectricWholesale
23Electric Transmission	23ElectricWholesale	PE13N	23	Electric	Electric Transmission	Wholesale	(326.08)	78	ElectricWholesale
23Production	23ElectricWholesale	PE13N	23	Electric	Production	Wholesale	(570.77)	82	ElectricWholesale
10Gas Distribution	10GasMinnesota	PE13N	10	Gas	Gas Distribution	Minnesota	38,555,858.55	13	GasMinnesota
11Gas Distribution	11GasMinnesota	PE13N	11	Gas	Gas Distribution	Minnesota	523,195.59	27	GasMinnesota
12Gas Distribution	12GasMinnesota	PE13N	12	Gas	Gas Distribution	Minnesota	(1,325,807.76)	41	GasMinnesota
20Gas Distribution	20GasMinnesota	PE13N	20	Gas	Gas Distribution	Minnesota	36,328,323.95	55	GasMinnesota
21Gas Distribution	21GasMinnesota	PE13N	21	Gas	Gas Distribution	Minnesota	272,926.35	69	GasMinnesota
23Gas Distribution	23GasMinnesota	PE13N	23	Gas	Gas Distribution	Minnesota	(324,231.41)	83	GasMinnesota
10Gas Distribution	10GasNorth Dakota	PE13N	10	Gas	Gas Distribution	North Dakota	3,973,253.24	14	GasNorth Dakota
11Gas Distribution	11GasNorth Dakota	PE13N	11	Gas	Gas Distribution	North Dakota	22,653.63	28	GasNorth Dakota
12Gas Distribution	12GasNorth Dakota	PE13N	12	Gas	Gas Distribution	North Dakota	(301,643.70)	42	GasNorth Dakota
20Gas Distribution	20GasNorth Dakota	PE13N	20	Gas	Gas Distribution	North Dakota	3,254,924.06	56	GasNorth Dakota
21Gas Distribution	21GasNorth Dakota	PE13N	21	Gas	Gas Distribution	North Dakota	4,240.51	70	GasNorth Dakota
23Gas Distribution	23GasNorth Dakota	PE13N	23	Gas	Gas Distribution	North Dakota	(238.25)	84	GasNorth Dakota

Exhibit___(KRP-4)
Case No. PU-12-813

Northern States Power Co (MN)
Elec O&M Summary
2013 Budget

	Total Company	Minnesota	N. Dakota	S. Dakota	Wholesale	Total Company	Factor	N. Dakota	Factor	N. Dakota
Fuel & Purchased Energy	1,278,735,356	1,119,826,660	82,971,027	75,240,184	697,485	1,278,735,356				
Power Production Expense	746,064,243	655,430,175	45,529,729	44,668,054	436,285	746,064,243	6.1027%	45,529,729	5.0864%	37,947,812
Transmission Expense	241,889,523	212,660,630	14,568,264	14,517,467	143,162	241,889,523	6.0227%	14,568,264	5.0864%	12,303,469
Distribution Expense	110,589,443	96,728,524	6,527,750	7,333,166	3	110,589,443				
Customer Accounting Expense	58,988,968	50,539,251	4,357,576	4,092,110	31	58,988,968				
Cust Service & Info Expense	119,066,190	117,553,566	504,700	1,007,923	1	119,066,190				
Sales Expense	54,580	49,773	2,461	2,346	0	54,580			**Production Adjustment Factor:**	**83.347%**
Administrative & General	246,243,879	215,247,038	15,599,968	15,302,395	94,478	246,243,879				
						0			**Transmission Adjustment Factor:**	**84.4539%**
Total Elec O&M	2,801,632,182	2,468,036,617	170,061,475	162,163,645	1,371,445	2,801,632,182				
Total Elec O&M without COGS	1,522,896,826	1,348,209,957	87,090,448	86,923,461	673,960					
Payroll Taxes	31,397,750	27,512,686	1,931,929	1,938,506	14,629					

Administrative & General	Total Company	Production	Tranmission	Distribution
NOTE: Entry for Total Company PTD	246,243,879	147,147,963	20,148,028	78,947,888

Payroll Taxes	Total Company	Production	Tranmission	Distribution
NOTE: Entry for Total Company PTD	31,397,750	22,994,884	2,113,123	6,289,744

Source: Base ND 2013 ALS Elec Budget O&M.xls

The table below shows how each of the functional and sub-functional costs was classified:

Function/Sub-Function	Cost Classification		
	Demand	Energy	Customer
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum-size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum-sized cost.

The table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Equipment Type	% Classified as "Customer" Related
Overhead Lines Primary	38.8%
Primary Transformers	0%
Overhead Lines Secondary	50.2%
Underground Lines Primary	83.0%
Underground Lines Secondary	52.5%
Line Transformers Secondary	45.6%
Services	72.7%

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

Code	Allocator For:	Description	Allocator Rationale and Background
C11	**Connection charge revenues**	**Average monthly customers for the Test Year**	**Customer connection revenues are driven by number of customer services.**
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C11WA	**Customer accounting costs**	**Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF**	**<u>Customer accounting</u> costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.**
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C12WM	**Meter costs**	**Number of meters multiplied by each class' average meter costs: C12 X C12WMF**	**<u>Metering</u> costs are driven by the number of customers in each class and the respective metering costs.**
C61PS	**The "customer" (minimum system) portion of <u>primary</u> distribution line costs**	**Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers**	**The number of customers served at secondary and primary voltages drives the customer-related portion of <u>primary distribution line</u> costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system**

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale and Background
C62Sec	**The "customer" (minimum system) portion of secondary (not primary) distribution line costs**	**Average monthly customers served at secondary voltage. C61PS less primary voltage customers**	**The number of customers served at secondary voltage drives the customer related portion of secondary distribution line costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.**
C62NL	**The "customer" (minimum system) portion of service-line costs.**	**Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers**	**The number of secondary customers drives the customer portion of service line costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.**
D60Sub	**Distribution substation costs**	**Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers**	**Distribution substation costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.**
D61PS	**The capacity portion of primary distribution line costs.**	**D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.**	**The driver of primary distribution line costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.**
D62Sec	Used to calculate the D62SecL allocator	D61PS less class coincident demands of primary voltage customers	
D62SecL	**The capacity portion of secondary distribution line costs**	**D62SecL equals the average of D62Sec percent and non-coincident (or "individual customer peak") secondary voltage percent.**	**Capacity related secondary distribution line costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is classified as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.**

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
D10W	Winter season portion of capacity-related generation costs	Each class' % contribution to the single winter system peak. Winter months are October through May.	The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.
D10T	Transmission plant costs	Weighted Class Contributions to Summer and Winter Peak loads. Allocator equals (D10W% plus (D10S% times 1.3649)) divided by (1 + 1.3649). The 1.3649 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for transmission costs is class contribution to the summer and winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.
D10C	Capacity-related generation costs	Weighted of Class Contributions to Summer and Winter system peak loads. Allocator equals (D10W% plus (D10S% times 2.7846) divided by (1 + 2.7846). The 2.7846 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
E8760	**Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also allocator for fuel, purchased energy and energy-related fixed generation costs.**	Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.	The driver of these **costs is energy requirements,** which is measured **by hourly energy requirements** weighted by hourly **marginal energy costs.**

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.

Code	Allocator For:	Description	Allocator Rationale
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by number of customers, and since most assistance pertains to helping customers reduce energy use, it affects production plant investment.
D57E43	Economic development expenses	This allocator is based on the weighted average of the generation capacity and energy allocators. The weighting is based on an analysis of the fixed-cost-contribution margin of the General service tariff. D57E43 = (% Demand Impacts x D10C) + (% Energy Impacts x E8760). $ Energy Impacts = kWh sales x (Base Energy Charge + Fuel Costs – Marginal Energy Costs) $ Demand Impacts = Annual Billing kW x (((4 x Summer Demand Charge)+ (8 x Winter Demand Charge))/12) The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Total $ Impacts = $ Energy Impacts + $ Demand Impacts	Economic development program costs and benefits are assumed to be a function of the fixed cost (margin) contribution of the demand and energy charges that result from the ED program.
D40E60	CIP expenses	D99E1 = (.99 x D10C)+(.01 x E8760).	CIP program expenses are split between capacity and energy according to whether the purpose and result of program is to reduce peak load or energy requirements. In North Dakota, 99% of program impacts are demand-related. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of $ expenses.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Description	Allocator Rationale
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims	Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation.	Property insurance is driven by net electric plant in service.
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision and engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8)	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.
OXTS	Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of "General" plant	All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 40 & 41 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid circular references.	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies	Total Production Plant: Original Plant in Service (line 6 of page 4)	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues.
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company costs	Total Production Plant less Nuclear Fuel: Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4)	Since Wisconsin does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses.
P5161A	Used to allocate Step-up sub transmission labor costs	Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Generation step-up plant investment drives step-up generation labor costs.
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4)	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
P68	All costs related to Distribution Plant "Line Transformers"	Distribution Plant: Line Transformers Original Plant in Service (line 37 of page 4)	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Distribution Plant "Services"	Customer-Connection "Services" Original Plant in Service (line 40 of page 4)	Distribution "Services" plant investment drives all costs of "Services".
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 42 of page 4)	Street Lighting plant investment drives all Street Lighting costs.
POL	All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues	Distribution Plant: Overhead Lines Original Plant in Service (line 26 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Real Estate & Property Taxes (line 50 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Production + Transmission + Distribution Plant Original Plant Investment (lines 6, 13 and 43 of page 4)	Total investment in production, transmission and distribution plant is the best allocator for general and common plant.
PUL	All costs related to Underground Distribution Lines	Distribution Plant: Underground Lines Original Plant in Service (line 33 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 43 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Appendix 3: CCOSS Customer Classes Vs. Tariff Cross Reference

A. Summary Customer Classes

	Customer Class	Rate Codes	Voltage Specifications
1	Residential	D01, D02, D03, D04, D05 (if residential), D10 (if residential)	
2	Commercial Not Demand Metered	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	
3	C&I Secondary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Secondary
4	C&I Primary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Primary
5	Street Lighting	D11, D30, D31, D32, D33	

B. Detailed Customer Sub-Classes

	Customer Class	Rate Codes	kW Size	Voltage Specifications
1	Residential without Space Heating	D01, D02, D03, D04		
2	Residential with Space Heating	D01, D02, D03, D04		
3	Load Management	D05, D10		
4	Small Commercial Not Demand Metered	D12, D14, D15, D18, D19, D34,		
5	Small C&I Secondary Voltage	D16, D17, D62	< 1,000 kW	Secondary
6	Small C&I Primary Voltage	D16, D17, D62	< 1,000 kW	Primary
7	Large C&I Secondary Voltage	D16, D17, D62	> 1,000 kW	Secondary
8	Large C&I Primary Voltage	D16, D17, D62	> 1,000 kW	Primary
9	Interruptible All Voltages	D20, D21, D22, D63	All sizes	All Voltages
10	Municipal not Demand Metered	D40, D42		
11	Municipal Demand Metered	D41		
12	Auto Protective Lighting	D11		
13	Street Lighting – Company Owned	D30		
14	Street Lighting – Customer Owned	D31, D32, D33		

Exhibit___(KRP-6)
Case No. PU-12-813

NSP North Dakota Tariff Matrix																				
Case No. PU-12-813			Billing Components									Riders								
	Rate Code(s)	No. of customers	Customer Charge	Demand Charge	Controllable Demand	Energy Charge	Per Unit	Energy Charge Credit	Voltage Discounts	Limited Energy Surcharge	Per Horsepower	FCR	Surcharge	CAC & WH	C&I CAC	Off-Season Load	Standby Service Rider	Economic Development (closed)	TRC	Energy-Controlled Service
Residential Service																				
Standard	D01OH	48158	X			X						X	X	X					X	
Electric Spaceheating	D01OH	17990	X			X						X	X	X					X	
Standard	D03UG	8544	X			X						X	X	X					X	
Electric Spaceheating	D03UG	2344	X			X						X	X	X					X	
Residential Time of Day Service																				
Standard	D02OH	9	X			X						X	X	X					X	
Electric Spaceheating	D02OH	15	X			X						X	X	X					X	
Standard	D04UG	1	X			X						X	X	X					X	
Electric Spaceheating	D04UG	2	X			X						X	X	X					X	
Energy -Controlled Service	D05	327	X			X						X	X						X	
Limited-Off Peak Service	D10	146	X			X						X	X						X	
Automatice Protective Lighting Service	D11	NA					X					X	X						X	
Small General Service	D12	8162	X	(X)		X						X	X		X				X	
Small General Time of Day Service (Metered and Non-Metered)																				
Time of Day	D14	344	X			X						X	X		X				X	
kWh Metered	D18	40	X			X						X	X		X				X	
Unmetered	D19		X			X						X	X		X				X	
Low Wattage	D34		X			X						X	X		X				X	
General Service	D16	3200	X	X		X		X	X			X	X		X	X	X	(X)	X	
General Time of Day Service	D17	170	X	X		X		X	X			X	X				X	(X)	X	
Peak-Controlled Service	D20	74	X	X	X	X		X	X			X	X					(X)	X	
Peak-Controlled Time of Day Service	D21	15	X	X		X		X	X			X	X					(X)	X	
Peak-Controlled Time of Day Service Tier 1	D22	89	X	X		X		X	X			X	X					(X)	X	
Real-Time Pricing Service																				
Firm	D62		X	X		X		X	X	X		X	X				X		X	
Controllable	D63		X	X	X	X		X	X	X		X	X				X		X	
Street Lighting System Service	D30	NA					X					X								
Street Lighting System Service (Purchased Equipment)	D31	NA					X					X								
Street Lighting System Service (Purchased Equipment) (Closed)	D32	NA					X					X								
Street Lighting Energy Service - Metered	D33	76	X			X						X							X	
Small Municipal Pumping	D40	91	X			X													X	
Municipal Pumping	D41	97	X	X		X		X	X			X							X	
Fire and Civil Defense Siren	D42		X MIN								X									

NSP North Dakota Rate Component Charge Matrix															
Case No. PU-12-813															
	Rate Code(s)	No. of customers	Customer Charge	Contract Demand Charge	On Peak Demand Charge (June - Sept)	On Peak Demand Charge (Oct - May)	Off Peak Demand Charge in Excess of On-Peak (June - Sept)	Off Peak Demand Charge in Excess of On-Peak (Oct - May)	Demand Charge (June - Sept)	Demand Charge (Oct - May)	Controllable Demand Level A	Controllable Demand Level B	Controllable Demand Level C	Off Peak Demand in Excess of On-Peak	Distribution Demand Charge - Secondary
Residential Service															
Standard	D01OH	48158	10.00												
Electric Spaceheating	D01OH	17990	13.00												
Standard	D03UG	8544	12.00												
Electric Spaceheating	D03UG	2344	15.00												
Residential Time of Day Service															
Standard	D02OH	9	12.00												
Electric Spaceheating	D02OH	15	15.00												
Standard	D04UG	1	14.00												
Electric Spaceheating	D04UG	2	17.00												
Energy -Controlled Service															
Residential	D05	279	4.60												
Commercial	D05	48	4.60												
Limited-Off Peak Service															
Secondray Voltage - Single Phase	D10														
Residential	D10	109	4.60												
Commercial	D10	25	4.60												
Secondray Voltage - Three Phase	D10														
Residential	D10	0	6.50												
Commercial	D10	12	6.50												
Primary Voltage	D10														
Commercial	D10	0	30.00												
Small General Service	D12	8162	13.00							(1.48)					
Small General Time of Day Service (Metered and Non-Metered)															
Time of Day	D14	344	15.00												
kWh Metered	D18	40	13.00												
Unmetered	D19	0	10.00												
Low Wattage															
Less than 100 Watts	D34	0	per unit												
More than 100 Watts	D34	0	per unit												
General Service	D16	3200	24.35						13.40	9.40					
General Time of Day Service	D17	170	27.35		13.40	9.40	1.50	1.50							
Peak-Controlled Service	D19	11 est	54.00						13.40	9.40					
Tier 1 Controllable	D20	50 est	54.00						13.40	9.40	7.22	6.50	5.97		
Tier 2 Controlable	D20	12 est	54.00						13.40	9.40	7.78	7.14	6.70		
Peak-Controlled Time of Day Service															
Tier 1 Controllable	D21	15	54.00						13.40	9.40	7.22	6.50	5.97	1.50	
Tier 2 Controlable	D21	0	54.00						13.40	9.40	7.78	7.14	6.70	1.50	
Peak-Controlled Time of Day Service Tier 1	D22	89													
Real-Time Pricing Service															
Firm	D62		330.00	9.30											1.30
Controllable															
Jun - Sept	D63	0	330.00	9.30							5.11	5.71	6.09		
Oct - May	D63	0	330.00	9.30							1.11	1.71	2.09		
Automatice Protective Lighting Service															
Area Nightwatch - 100W High Pressure Sodium	D11	N/A													
Area Nightwatch - 175W Mercury	D11	N/A													
Area Nightwatch - 250W High Pressure Sodium	D11	N/A													
Area Nightwatch - 400W Mercury	D11	N/A													
Directional Nightwatch - 250W High Pressure Sodium	D11	N/A													
Directional Nightwatch - 400W Mercury	D11	N/A													
Directional Nightwatch - 400W High Pressure Sodium	D11	N/A													
Street Lighting System Service		NA													
100W High Pressure Sodium															
Overhead	D30														
Underground	D30														
Decorative Underground	D30														
150W High Pressure Sodium															
Overhead	D30														
Underground	D30														
Decorative Underground	D30														
250W High Pressure Sodium															
Overhead	D30														
Decorative Underground	D30														
400W High Pressure Sodium															
Overhead	D30														
Street Lighting System Service (Purchased Equipment)		NA													
175W Mercury	D31														
250W Mercury	D31														
400W Mercury	D31														
70W High Pressure Sodium	D31														
100W High Pressure Sodium	D31														
150W High Pressure Sodium	D31														
200W High Pressure Sodium	D31														
250W High Pressure Sodium	D31														
310W High Pressure Sodium	D31														
400W High Pressure Sodium	D31														
1,000W High Pressure Sodium	D31														
70W High Pressure Sodium (Closed)	D31														
400W High Pressure Sodium (Closed)	D31														
Street Lighting System Service (Purchased Equipment) (Closed)		NA													
1,000 Lumen Incandescent	D32														
4,000 Lumen Incandescent	D32														
Street Lighting Energy Service - Metered	D33	76	5.00												
Small Municipal Pumping	D40	91	13.00												
Municipal Pumping	D41	97	24.35						13.40	9.40					
Fire and Civil Defense Siren	D42		2.58 min												

NSP North Dakota Rate Component Charge Matrix															
Case No. PU-12-813		Billing Components													
	Rate Code(s)	Distribution Demand Charge - Primary	Distribution Demand Charge - Transmission Transformed	Distribution Demand Charge - Transmission	Energy Charge	Energy Charge (Optional)	Energy Charge (June - Sept)	Energy Charge (Oct - May)	On-Peak Energy Charge (June - Sept)	On-Peak Energy Charge (Oct - May)	On-Peak Energy Charge	Off-Peak Energy Charge	Continuous 24 Hour Energy (June - Sept)	Continuous 24 Hour Energy (Oct - May)	Controllable On Peak Period Energy
Residential Service															
Standard	D01OH						7.233	5.733							
Electric Spaceheating	D01OH						7.233	4.583							
Standard	D03UG						7.233	5.733							
Electric Spaceheating	D03UG						7.233	4.583							
Residential Time of Day Service															
Standard	D02OH								14.988	10.977		2.600			
Electric Spaceheating	D02OH								14.988	8.170		2.600			
Standard	D04UG								14.988	10.977		2.600			
Electric Spaceheating	D04UG								14.988	8.170		2.600			
Energy -Controlled Service															
Residential	D05					3.663	7.233	3.663							
Commercial	D05					3.663	7.159	3.663							
Limited-Off Peak Service															
Secondray Voltage - Single Phase	D10														
Residential	D10				2.300										
Commercial	D10				2.300										
Secondray Voltage - Three Phase	D10														
Residential	D10				2.300										
Commercial	D10				2.300										
Primary Voltage	D10														
Commercial	D10				2.199										
Small General Service	D12						7.159	5.659							
Small General Time of Day Service (Metered and Non-Metered)															
Time of Day	D14								12.352	9.143		2.600	6.013	4.890	
kWh Metered	D18								12.352	9.143		2.600	6.013	4.890	
Unmetered	D19								12.352	9.143		2.600	6.013	4.890	
Low Wattage															
Less than 100 Watts	D34				contract per unit										
More than 100 Watts	D34				contract per unit										
General Service	D16				2.854										
General Time of Day Service	D17										3.846	2.113			
Peak-Controlled Service	D19														
Tier 1 Controllable	D20				2.854										
Tier 2 Controlable	D20				2.854										
Peak-Controlled Time of Day Service															
Tier 1 Controllable	D21										3.846	2.113			
Tier 2 Controlable	D21										3.846	2.113			
Peak-Controlled Time of Day Service Tier 1	D22						X				3.846	2.113			3.626
Real-Time Pricing Service															
Firm	D62	0.64	0.25	0.00	Day/Period (48)										
Controllable															
Jun - Sept	D63														
Oct - May	D63														
Automatice Protective Lighting Service															
Area Nightwatch - 100W High Pressure Sodium	D11														
Area Nightwatch - 175W Mercury	D11														
Area Nightwatch - 250W High Pressure Sodium	D11														
Area Nightwatch - 400W Mercury	D11														
Directional Nightwatch - 250W High Pressure Sodium	D11														
Directional Nightwatch - 400W Mercury	D11														
Directional Nightwatch - 400W High Pressure Sodium	D11														
Street Lighting System Service															
100W High Pressure Sodium															
Overhead	D30														
Underground	D30														
Decorative Underground	D30														
150W High Pressure Sodium															
Overhead	D30														
Underground	D30														
Decorative Underground	D30														
250W High Pressure Sodium															
Overhead	D30														
Decorative Underground	D30														
400W High Pressure Sodium															
Overhead	D30														
Street Lighting System Service (Purchased Equipment)															
175W Mercury	D31														
250W Mercury	D31														
400W Mercury	D31														
70W High Pressure Sodium	D31														
100W High Pressure Sodium	D31														
150W High Pressure Sodium	D31														
200W High Pressure Sodium	D31														
250W High Pressure Sodium	D31														
310W High Pressure Sodium	D31														
400W High Pressure Sodium	D31														
1,000W High Pressure Sodium	D31														
70W High Pressure Sodium (Closed)	D31														
400W High Pressure Sodium (Closed)	D31														
Street Lighting System Service (Purchased Equipment) (Closed)															
1,000 Lumen Incandescent	D32														
4,000 Lumen Incandescent	D32														
Street Lighting Energy Service - Metered	D33				3.600										
Small Municipal Pumping	D40						7.159	5.659							
Municipal Pumping	D41				2.854										
Fire and Civil Defense Siren	D42														

NSP North Dakota Rate Component Charge Matrix Case No. PU-12-813	Rate Code(s)	Controllable Off Peak Period Energy	Control Period Energy	Per Unit	Energy Charge Credit	Primary Voltage Discounts (Per kW)	Primary Voltage Discounts (Per kWh)	Trans. Transformed Voltage Discounts (Per kW)	Trans. Transformed Voltage Discounts (Per kWh)	Trans. Voltage Discounts (Per kW)	Trans. Voltage Discounts (Per kWh)	Limited Energy Surcharge	Limited Energy Surcharge - Level A	Limited Energy Surcharge - Level B	Limited Energy Surcharge - Level C	Per Horsepower
Residential Service																
Standard	D01OH															
Electric Spaceheating	D01OH															
Standard	D03UG															
Electric Spaceheating	D03UG															
Residential Time of Day Service																
Standard	D02OH															
Electric Spaceheating	D02OH															
Standard	D04UG															
Electric Spaceheating	D04UG															
Energy -Controlled Service																
Residential	D05															
Commercial	D05															
Limited-Off Peak Service																
Secondray Voltage - Single Phase	D10															
Residential	D10															
Commercial	D10															
Secondray Voltage - Three Phase	D10															
Residential	D10															
Commercial	D10															
Primary Voltage	D10															
Commercial	D10															
Small General Service	D12															
Small General Time of Day Service (Metered and Non-Metered)																
Time of Day	D14															
kWh Metered	D18															
Unmetered	D19															
Low Wattage																
Less than 100 Watts	D34			0.30												
More than 100 Watts	D34			1.24												
General Service	D16				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
General Time of Day Service	D17				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
Peak-Controlled Service	D19															
Tier 1 Controllable	D20				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
Tier 2 Controlable	D20				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
Peak-Controlled Time of Day Service																
Tier 1 Controllable	D21				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
Tier 2 Controlable	D21				1.000	0.60	0.101¢	1.10	0.210¢	1.50	0.240¢					
Peak-Controlled Time of Day Service Tier 1	D22	2.013	10.000¢		1c		X									
Real-Time Pricing Service																
Firm	D62				0.86c		0.101c		0.210c		0.240c	17.90c				
Controllable																
Jun - Sept	D63				0.86c		0.101c		0.210c		0.240c		12.700c	8.900c	7.300c	
Oct - May	D63				0.86c		0.101c		0.210c		0.240c		12.700c	8.900c	7.300c	
Automatice Protective Lighting Service																
Area Nightwatch - 100W High Pressure Sodium	D11			6.16												
Area Nightwatch - 175W Mercury	D11			6.16												
Area Nightwatch - 250W High Pressure Sodium	D11			10.66												
Area Nightwatch - 400W Mercury	D11			10.66												
Directional Nightwatch - 250W High Pressure Sodium	D11			11.84												
Directional Nightwatch - 400W Mercury	D11			13.54												
Directional Nightwatch - 400W High Pressure Sodium	D11			14.47												
Street Lighting System Service																
100W High Pressure Sodium																
Overhead	D30			9.94												
Underground	D30			19.23												
Decorative Underground	D30			30.81												
150W High Pressure Sodium																
Overhead	D30			10.92												
Underground	D30			20.25												
Decorative Underground	D30			31.75												
250W High Pressure Sodium																
Overhead	D30			13.74												
Decorative Underground	D30			34.04												
400W High Pressure Sodium																
Overhead	D30			16.41												
Street Lighting System Service (Purchased Equipment)																
175W Mercury	D31			4.23												
250W Mercury	D31			5.26												
400W Mercury	D31			7.45												
70W High Pressure Sodium	D31			2.72												
100W High Pressure Sodium	D31			3.17												
150W High Pressure Sodium	D31			3.83												
200W High Pressure Sodium	D31			4.67												
250W High Pressure Sodium	D31			5.54												
310W High Pressure Sodium	D31			6.66												
400W High Pressure Sodium	D31			7.72												
1,000W High Pressure Sodium	D31			15.81												
70W High Pressure Sodium (Closed)	D31			1.47												
400W High Pressure Sodium (Closed)	D31			7.44												
Street Lighting System Service (Purchased Equipment) (Closed)																
1,000 Lumen Incandescent	D32			2.58												
4,000 Lumen Incandescent	D32			4.78												
Street Lighting Energy Service - Metered	D33															
Small Municipal Pumping	D40															
Municipal Pumping	D41				1.000	0.60	0.101¢									
Fire and Civil Defense Siren	D42															57¢

National Regulatory
Research Institute

How Should Regulators View Cost Trackers?

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Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

Executive Summary

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case. This paper discusses the major issues that state public utility commissions face in evaluating the costs and benefits of these devices.

Several state commissions have approved new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. State commissions have traditionally limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals depart from past regulatory practices that sanction trackers only under highly restricted conditions.

The author asserts that state commissions have not given adequate attention to the negative features of cost trackers, which are at odds with the public interest. Specifically, cost trackers diminish the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. Trackers also could reduce regulatory scrutiny in evaluating cost prudence.

This paper contends that regulators should view cost recovery in a rate case as the "default" practice. A rate case assures scrutiny of a utility's costs and provides strong motivation for the utility to control those costs between rate cases. The utility therefore bears burden to show why a cost tracker is in the public interest. The utility should demonstrate that it would suffer severe financial difficulties under "extraordinary circumstances" without the tracker.

This paper also recommends that regulators consider the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative can overcome some of the problems with cost trackers, namely perverse or weak incentives for cost control, the mismatching of total costs and revenues, and inadequate regulatory oversight of costs. An earnings-sharing mechanism also achieves the major objective of cost trackers, which is to prevent a utility from suffering serious financial problems between rate cases.

Table of Contents

How Should Regulators View Cost Trackers?

This paper discusses the major issues regulators face in evaluating the costs and benefits of cost trackers.[1] This paper responds to state public utility commissions' recent actions in approving new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. Historically, state commissions have limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals differ from past regulatory practices that sanctioned trackers only under highly restricted conditions.

The author contends that state commissions have not given adequate attention to the negative features of cost trackers. By conflicting with certain regulatory objectives, cost trackers thwart the public interest. Cost trackers undercut the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. They also could lessen regulatory scrutiny in evaluating the prudence of costs.

This paper defines cost trackers and discusses how they benefit utilities. It then provides the rationales for cost trackers and how they relate to regulatory principles for cost recovery. The paper examines two scenarios; in the first, regulators allow comprehensive cost trackers, while in the second they allow none. The paper ends by recommending a regulatory policy and identifying questions regulators should ask when investigating cost trackers.

I. The Definition and Mechanics of a Cost Tracker

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case.[2] A tracker, in other words, involves the recovery of a utility's actual costs in the periods between rate cases. These costs could include

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[1] Regulators sometimes refer to cost trackers as "riders."

[2] A cost tracker can either provide interim rate relief for a utility or be a permanent fixture that adjusts rates between rate cases based on upward and downward movements in those costs specified in a tracker. As an alternative to a cost tracker, a utility can file for emergency rate relief whenever it encounters a serious financial problem. The commission can specify conditions under which a utility can file an emergency or interim rate filing petitioning for immediate rate relief. This paper does not examine the different regulatory approaches to relieving utilities of any temporary or more permanent serious financial problems. Such a study could compare each approach, including cost trackers, based on its effect on different regulatory objectives.

those that deviate from some baseline or are zero-based.[3] Baseline costs, for example, could include bad debt costs[4] reflected in present rates as determined in the last rate case. A cost tracker could allow adjustments in rates when actual bad-debt costs depart from the baseline level. These adjustments would occur periodically as prescribed previously by a commission.

To benefit customers when actual cost falls below the baseline level, a cost tracker must be "symmetrical." The unpredictability of a cost item—which, as this paper discusses later, is one underlying rationale for a cost tracker—means that test-year cost estimates can overstate or understate the actual costs. Virtually all fuel and purchased gas cost trackers are symmetrical, with customers benefiting when commodity-energy costs fall (e.g., since the autumn of 2008).

Cost trackers also could apply to all of the costs associated with a particular business function or task. Under this zero-based approach, for example, the entire cost of a gas utility's new investments in upgrading the safety of its distribution system would be amortized and recovered later from customers in lieu of inclusion in base rates. The same cost recovery procedure can occur for a utility's energy-efficiency initiatives.

Some cost trackers, such as fuel adjustment clauses (FAC) and purchased gas adjustments (PGAs), adjust rates in response to changes in the price of fuels used by generating facilities and purchased gas for gas utilities.[5] Certain cost trackers approved over the last couple of years allow for rate adjustments when the cost for a particular business function, for whatever reason, changes. A tracker for bad debt, for example, does not distinguish between an increase because of a greater number of nonpaying customers or higher debt per customer.

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[3] "Zero-based" refers to *all* the costs associated with a specific function, rather than just increments or decrements from test-year costs.

[4] These costs represent money owed by customers to a utility that the utility has determined to be uncollectible.

[5] NRRI has conducted several studies on FACs and PGAs. *See*, for example, Robert E. Burns, Mark Eifert, Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, Ohio: NRRI, November 1991), NRRI 91-13; Robert E. Burns and Mark Eifert, "Designing Fuel and Purchased Gas Adjustment Clauses to Provide for Incentive Compatibility in a More Competitive Environment," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference* (Columbus, Ohio: NRRI, September 1992); Kevin A. Kelly, Timothy Pryor, Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, Ohio: NRRI, 1979), NRRI 79-3; and Douglas N. Jones, Russell J. Profozich, Timothy Biggs, *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1978 and 1979* (Columbus, Ohio: NRRI, 1981), NRRI 81-5.

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

State commissions have applied myriad criteria for utility cost recovery. Regulators are legally bound to allow utilities the opportunity to recover prudently incurred costs. Prudent costs reflect utility management that makes rational and well-informed decisions. The word "opportunity" can refer to the utility having a good chance of earning its authorized rate of return and is distinct from an entitlement.[6] "Earning the authorized rate of return" means that the utility recovers its prudent variable costs (e.g., operations and maintenance) and earns a return of and on prudently incurred fixed costs, including its cost of capital as determined in the last rate case.

B. Incentive effects of cost trackers

Commissions traditionally allow cost recovery only after a rate case review. Other alternatives such as a cost tracker would require that a utility show violation of the "opportunity" condition for particular cost items. A violation can occur when a certain cost is substantial, unpredictable, and generally beyond a utility's control. Other than costs relating to fuel and purchased power and gas, few other costs fall within the confines of "special circumstances."[7] Parties to regulatory proceedings naturally disagree over when these circumstances exist. To clarify their positions to utilities, intervening groups, and the general public, commissions should consider issuing policy statements articulating standards for the recovery of costs through trackers.

Regulators, until recently, have taken a cautious approach to trackers, partially because they weaken the incentive of a utility to control its costs.[8] Controlling utility costs is a primary

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[6] One interpretation is that the utility earns its authorized rate of return over a number of years, rather than each year. Regulators, investors, and utilities do not expect uniform rates of return across years. Instead, they ostensibly presume that in some years the rate of return will be below the authorized level, while in other years it would be above the authorized level. Regulators, for example, set rates based on "normal" weather. They expect that summer weather will be hotter than normal in some years and cooler than normal in others. For a typical electric utility, having a hotter-than-normal summer and a cooler-than-normal summer often means the utility earns a high rate of return and a low rate of return for those years respectively. But regulators expect normal weather over a number of years.

[7] An exception also might include the costs associated with a major storm causing extensive damage to a utility's infrastructure.

[8] The cost trackers discussed in this paper assume price adjustments based on changes in the actual cost of the utility. If instead price adjustments relate to cost changes for a peer group or other factors outside the control of the utility, the incentive problems identified in this paper would mostly disappear. Some cost trackers attempt to incorporate benchmarks that reflect performance exogenous to an individual utility. Defining the appropriate benchmark is a crucial but difficult task in designing a performance-based tracker. *See*, for example, Ken Costello and

objective of regulators because it contributes to lower rates and reflects efficient utility management. Cost trackers can, in various ways, result in higher utility costs.[9] First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently.[10] As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their

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James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[9] Theoretical and empirical studies provide some evidence of the incentive problems associated with one kind of cost trackers, FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause bias in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC.

[10] Regulatory lag is a less-than-ideal method, however, for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). As discussed elsewhere in this paper, regulators are more receptive to cost trackers when: (1) regulatory lag can cause a substantial movement in a utility's rate of return between rate cases, and (2) the utility has little control over how much its actual costs will deviate from its test-year costs.

opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[11]

Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.[12] This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control.

When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities.[13] The result is higher rates to utility customers. A utility with a FAC might postpone maintenance of a power plant even when it would cost less than the savings in fuel costs. The utility could not immediately (or even at any time) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

Cost trackers, in the long run, can bias a utility's technological and investment decisions. A utility recovering fuel costs through a FAC, for example, might want to adopt fuel-intensive generation technologies even if they are more expensive from a life-cycle perspective.[14] The result, again, is higher rates to utility customers.

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[11] Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.

[12] I assume here that reducing cost has no effect on the quality or quantity of utility service. Controlling costs, therefore, refers to eliminating or reducing "wasteful" expenses that would result in no decline in the value of utility service. The author imagines a situation in which utilities would attempt to defer maintenance costs until the commission sets new base rates that account for those costs.

[13] In the example above, regulators could eliminate any perverse incentive by simply allowing a cost tracker for maintenance expenses.

[14] *See*, for example, the Baron and DeBondt studies cited in footnote 9.

Cost trackers also could motivate utilities to shift more of their costs to functions subject to trackers.[15] They might, for example, want to classify routine maintenance costs as a capital expense that receives tracker cost recovery. Such shifts could lead to earning an excessive rate of return. Regulators implementing trackers should carefully define applicable costs. They should also examine costs claimed under trackers to ensure that the utility recovers only appropriate costs through the tracker.[16]

An important incentive for cost control by regulated utilities is the threat of cost disallowance from retrospective review.[17] To the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over the costs it incurs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance.

If a utility has a number of cost trackers, the regulator might want to consider staggering the timing of retrospective reviews to avoid having inadequate staff resources to review the adjustments for individual cost trackers. Some utilities have comprehensive trackers that recover a wide array of costs (e.g., purchased gas, bad debt, energy-efficiency activities, and environmental activities). For these trackers, it would be especially challenging for a regulator to conduct an adequate retrospective review of each item simultaneously.[18]

A contradiction seemingly exists between the criterion that trackers should apply only to those costs beyond the control of a utility and the assertion that the modified incentives caused by trackers can lead to inflated costs. One response is that a utility has at least some control over most of its costs. Except for certain taxes and some other cost items, the actions of utility

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[15] One example is when a tracker for new capital expenditures creates an incentive for a utility to shift labor costs from maintenance to capital projects. In this instance, the utility can schedule employees to work on the capital projects, and maintenance is delayed. The utility consequently reduces its maintenance costs and thereby keep the savings, and increase its capital expenditures, which it recovers through the tracker. I thank Michael McFadden for this example.

[16] I thank Adam Pollock for this insight.

[17] Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty—for example, making the utility more diligent and careful in its planning and procurement. Given asymmetric information, where a utility knows more about its operations and market supply/demand conditions than the commission, some analysts characterize retrospective views as a second-best mechanism to market-like incentives. For most gas utilities, the strong incentives for controlling purchased gas costs derive mainly from the time lag between the incurrence of a cost and its recovery from retail customers, and regulatory prudence reviews where, for example, abnormal costs attract special attention and a review.

[18] I thank Joseph Rogers for this insight.

management can affect costs. Even for fuel or purchased gas, utility management's actions can affect their total costs. Although for the most part the marketplace determines the price paid for these items, utilities can negotiate prices under long-term contracts and decide on the mix and sources of different fuels and purchased gas.[19]

Commissions also tend to avoid cost recovery that results in radical price volatility to utility customers. Such a policy could preclude monthly price adjustments from changes in fuel costs or purchased gas costs. It also might result in a phase-in of the construction costs of a new base-load-generating facility.

III. Utilities' Perspective on Cost Trackers

Under traditional ratemaking, the utility recovers all costs after a rate case review. It requires no commission activity between rate cases. Traditional ratemaking provides base rates based on the test year. A commission relies heavily on cost-of-service studies to determine base rates. Base rates have two characteristics: (1) a commission sets them in a formal rate case, and (2) they remain fixed until the utility files a new rate case and the commission makes a subsequent decision. The costs represent those calculated for a designated test year and exclude those costs recovered in trackers and other mechanisms. No matter how much the actual utility's costs and revenues deviate from their test-year levels, rates remain fixed until the commission approves new ones in a subsequent rate case. The exception is when a commission allows for interim rate relief under highly abnormal conditions that jeopardize a utility's financial condition.

Utilities have argued that a more dynamic market environment, characterized by the increased unpredictability and volatility of certain costs, justifies the recovery of certain costs through a tracker rather than in base rates.[20] Utilities have also asserted that the static nature of the "test year" sometimes denies them a reasonable opportunity to earn their authorized rate of return. They contend that cost trackers advance the ratemaking goals by matching revenues to actual costs.

In contrast to base rates, cost trackers offer a utility the advantages of: (1) shortening the time lag between the incurrence of a cost and its recovery in rates (i.e., curtailing regulatory lag),

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[19] A utility, for example, might be lax in finding the best deals for gas supplies, in applying more resources by employing more highly qualified staff, or in acquiring superior market intelligence. *See,* for example, Ken Costello, *Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach*, NRRI 08-07, June 2008, at http://nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf.

[20] *See*, for example, Russell A. Feingold, "Rethinking Natural Gas Utility Rate Design: A Framework for Change," presented at the American Gas Foundation Executive Forum, held at The Ohio State University, May 23, 2006.

(2) increasing cost-recovery certainty,[21] and (3) lessening the regulatory scrutiny of its costs. Normally, in a rate case a regulator closely reviews the utility's costs before approving them for recovery from customers. Regulators often less rigorously scrutinize a utility's costs when recovered through a tracker.[22] Overall, cost trackers lower a utility's financial risk by stabilizing its earnings and cash flow.

Utilities increasingly have asked their state public utility commissions to depart from traditional regulation by approving new cost-recovery mechanisms for different business activities. Some gas utilities want to expand the scope of their PGA clauses to include a wider array of costs. Current cost trackers in the natural gas sector, other than those for purchased gas costs, apply to functions including pipeline integrity management, pipeline replacement costs (e.g., accelerated cast iron main replacement program), bad debt, energy-efficiency costs, general infrastructure costs, manufactured gas plant remediation, stranded restructuring costs, property taxes, post-retirement employee benefits, and environmental costs.

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

State commissions have traditionally approved cost trackers only under "extraordinary circumstances." Commissions recognize the special treatment given to costs recovered by a tracker; they consider cost trackers an exception to the general rule for cost recovery. This view places the burden on a utility to demonstrate why certain costs require special treatment.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved have been for costs that are: (1) largely outside the control of a utility, (2) unpredictable and volatile,[23] and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker. Fuel costs were a good candidate because of their influence by factors beyond

[21] Between rate cases, for example, a utility might incur costs unanticipated by the test-year calculation and thus not recovered from its customers.

[22] The regulator, for example, might have less time to review these costs or just might consider them too unimportant to warrant a separate review. Another explanation might be that rate cases are transparent and well-publicized, putting pressure on regulators to closely review all aspects of a rate case filing. These reasons are just the author's speculations. A pertinent research question is whether this hypothesis has validity.

[23] Even if the forecast of a cost item is highly accurate in the long run, it can fluctuate widely in the short run, causing possible serious cash-flow problems for the utility. The utility might then have to purchase short-term debt and other financing. The author thanks Carl Peterson for this insight.

the control of a utility, their volatility, and their large size. Commissions recently have approved cost trackers when not meeting all three conditions, especially the third (substantial and recurring costs).[24]

The last "extraordinary circumstance," substantial and recurring costs, greatly restricts the costs eligible for cost tracker recovery. Differences between their test year and actual cost can have a material effect on a utility's rate of return. Legal precedent dictates that regulators must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors commensurate with the risks involved.[25] A utility should recover revenues in excess of its operating expenses to provide a "fair return" to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.[26]

Some state commissions have softened or ignored the "substantial and recurring" component of the "extraordinary circumstances" standard. Bad debt, the subject of recent cost trackers, features financial effects that are typically not substantial. Utilities have contended that the unpredictability of this cost makes it difficult to incorporate it accurately into the base rate. Yet, even if this assertion is true, it is questionable whether any bad-debt cost unaccounted for in the test year would inflict substantial financial harm on a typical utility.[27]

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[24] Commissions' rulings seem to reflect the view that regulators have much discretion in approving cost trackers as long as these actions reflect reasonable ratemaking given the facts and circumstances.

[25] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[26] The return on equity for a utility corresponds to the term "normal profits." Both terms involve the cost a utility incurs to attract funds from investors.[26] Let us assume that utility performance should replicate the performance of competitive firms where firms receive normal profits in the long run. A utility would, therefore, earn a return that is reasonable but not excessive. A reasonable return should allow the utility to maintain its credit quality and attract needed capital on reasonable terms, but do no more. Commissions usually consider a rate of return within a "zone of reasonableness" as sufficient but not excessive. They do not guarantee that the utility will earn within this zone; they merely give the utility the opportunity if it performs efficiently and economically.

[27] The outcome would vary across utilities and by period. Especially in bad economic times in conjunction with high energy prices, bad debt can quickly soar, making test-year estimates grossly inaccurate. "Substantial financial harm" has no definitive meaning. It can refer to a situation where a utility has difficulties in raising funds for new investments or faces severe cash flow problems. Such situations can harm customers in the long run, for example, by reducing service reliability and diminishing the utility's credit quality, which in turn can lead to the utility having a higher cost of capital. A tracker for bad debt can also affect how the utility responds to customers who are behind in their payments. It can, for example, make the utility

B. "Severe financial consequences"

Historically, commissions have approved cost trackers to avoid the possibility of a utility suffering a serious financial problem because of cost increases unforeseen at the time of the last rate case.[28] Justification for cost trackers is, therefore, greater when a commission relies on a historical test year that does not recognize the volatility of certain costs or their upward trend over time. Let us assume that a certain operating cost has trended upward (e.g., 2 percent per year) over the past several years. Let us also assume that the commission allows only a historical test year. In this example the utility is likely to under-recover this particular cost. What effect this outcome would have on the utility's overall rate of return depends on the magnitude of any cost increase relative to the utility's earnings and whether other costs fell while rates were in effect.

Commissions do not expect utilities to earn the authorized rate of return during each future period over which new prices are in effect.[29] Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for the earnings volatility from fluctuations in costs or revenues from the test year. Trackers affect what is called "business risk." Business risk refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. In the Capital Asset Pricing Model (CAPM), for example, the lower the utility's expected earnings volatility, the lower the measure of the utility's risk relative to the market portfolio (i.e., "beta"). Because

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more lax in its credit policies, which could result in fewer service disconnections, especially for low-income households. In the absence of a tracker, the utility presumably would intensify its efforts to collect money owed by delinquent customers. I thank Michael McFadden for this insight.

[28] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327. A premise behind the wide acceptance of fuel adjustment clauses was that because electric utilities were not responsible for the escalation of fuel costs, commissions should not hold them accountable. Virtually all electric utilities in the 1970s experienced an unprecedented rise in fuel costs, for example, inferring an exogenous event beyond the control of any single utility. Prior to this time, even though FACs were common but fuel prices were much more stable, commissions generally associated changes in the utility's rate of return between rate cases with utility-management performance. A lower rate of return reflected poor performance and a higher rate of return superior performance. (A 1974 study found that 42 out of 51 jurisdictions had some form of fuel adjustment clause. *See* National Economic Research Associates, "The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and Its Applications in the Various Jurisdictions," 1974.)

[29] This statement supports the contention that commissions do not intend the prices they set in a rate case to reflect the utility's actual cost of service for each future year. Commissions, however, judge that the prices they set will allow the utility an opportunity (i.e., a reasonable chance) to earn its authorized rate of return or some return close to the authorized level.

trackers reduce a utility's business risk, a regulator might want to consider revising downward the risk premium of a utility with additional cost trackers or a revenue-decoupling tracker, resulting in a lower return on equity.

If a commission wants to guarantee that the utility will recover its authorized earnings, it would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge.[30] Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility has the right to file a general rate increase.

The previous discussion explains why most regulators have favored adjusting rates between rate cases only when such adjustments avoid serious financial situations for utilities. If a commission wanted to assure the utility that it will always earn its authorized rate of return, it would allow the utility to recover all of its actual costs through trackers.[31] Commissions generally do not allow the tracking of all costs because of incentive and other problems, which this paper discusses in Section II.B.

C. An illustration: FACs and PGAs

The wide popularity of FACs and PGAs among utilities and most commissions reflects the perception that these mechanisms are necessary to prevent a utility from earning a rate of return substantially below what was authorized. This perception stems from the magnitude of fuel and purchased gas costs relative to a utility's earnings. Other categories of costs, such as bad debt, are much smaller in size and therefore have smaller earnings consequences.

Until fuel costs started to fluctuate sharply in the 1970s, some energy utilities had to operate without the ability to adjust prices outside a rate case.[32] These utilities shouldered the risks of events between rate cases, but they also retained any high returns from favorable happenings. Prior to around 1970, for example, many electric utilities earned rates of return that were much higher than the authorized levels because of technological improvements, high sales growth, and economies of scale, in addition to the acquiescence of commissions.[33]

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[30] Such a rate design would not guarantee the utility earning its authorized rate of return, as unexpected variable costs would cause the utility's earnings to decline.

[31] This recovery would include fixed costs the commission found prudent in the last rate case. Guarantee of full recovery of all costs would also require a revenue tracker such as revenue decoupling, assuming that the utility recovers some of its fixed costs in the volumetric or commodity charge.

[32] The genesis for these dramatic fuel-cost increases was the Oil Embargo by OPEC and the other Persian Gulf troubles of the 1970s.

[33] Although most state commissions had authority to initiate proceedings to reduce rates, few chose to exercise it.

Not surprisingly, virtually all state commissions believed that trackers for large items such as fuel costs and purchased gas costs were necessary to prevent inordinate rate-of-return fluctuations. Implicit in this belief is the view that the burden on utility shareholders would otherwise be onerous. This factor overwhelmed the arguments against trackers. The major objective of FACs and PGAs, implanted during that era, was to shield the utility's earnings from commodity price volatility. Both debt and equity investors favor these mechanisms in reducing the riskiness of a utility's earnings and cash flow.

V. Two Extreme States of the World: Several and No Cost Trackers

A. A hodgepodge of cost trackers, or a single rate-of-return tracker

If a commission wants a utility always to earn close to its authorized rate of return, it would favor rate adjustments between rate cases for both: (1) actual costs deviating from test-year costs, and (2) actual revenues deviating from test-year revenues. This outcome would require cost trackers covering all of the utility's costs in addition to a revenue decoupling mechanism. (The revenue decoupling mechanism would allow the utility to recover all fixed costs that the commission approved for recovery in the last rate case.)

Putting the utility's future on "autopilot" seems like a reasonable course of action if financial stability is the prime regulatory objective. Considering incentive problems and excessive risk-shifting to customers, this option comes across as much less appealing.

An earnings-sharing mechanism (ESM), which consolidates different cost and revenue trackers, is one ratemaking procedure for stabilizing a utility's rate of return between rate cases. Under this mechanism, the utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. As an illustration, if the band encompasses a 10 to 14 percent rate of return on equity (with 12 percent as the utility's authorized rate of return established in the last rate case) when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to, or bring it closer to, 10 percent.[34]

An ESM helps to stabilize a utility's rate of return without a full-scale rate case review. Earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to reflect recent market developments, including those affecting a utility's costs.[35] Compared to

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[34] The band implicitly reflects the range for the return on equity that the regulator deems both adequate to keep the utility from financial jeopardy and not so excessive as to be exorbitant. The interpretation of these financial conditions is subjective and open to debate.

[35] Under traditional ratemaking, reducing the frequency of rate cases might allow the utility to over-earn by a substantial amount because of the multi-year accumulation of higher-than-expected sales or lower-than-expected costs, or both. Commissions probably are not so concerned when the utility over-earns for a one- or two-year period, but would be when it over-earns by a "significant" amount over several consecutive years. This reaction would be more

traditional ratemaking, where rates remain fixed between rate cases, ESM weakens regulatory lag and thereby reduces the incentive of a utility to control its costs between rate cases.[36] A commission can lessen this problem by requiring the utility to demonstrate its prudence and offer reasons why specific cost items were higher than their test-year levels.[37]

In sum, an ESM would trigger a price adjustment between rate cases only when the aggregation of revenue and cost departures from test-year levels cause the utility's rate of return to fall outside a specified "band" region. An ESM takes into account the overall profitability of a utility. It assumes the role of a rate-of-return tracker that, in effect, amalgamates different cost trackers into a single cost-recovery mechanism.

The ESM differs from conventional trackers, which account for specific costs or functions in isolation from the utility's overall financial position. Trackers' focus on an individual cost categories can cause utilities to delay coming in for rate cases, with the utility earning an "excessively" high rate of return in the interim. Let us assume that the commission has approved a tracker for new infrastructure expenditures. The new infrastructure expects to lower the utility's maintenance and other operating costs. If the last rate case did not recognize these lower operating costs, the utility's rate of return would be higher, yet because of the tracker, the utility suffers no interim financial losses from incurring infrastructure expenditures.

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acute if the commission believes that fortuitous cirscumstances, rather than superior utility management, caused the high earnings.

[36] This incentive problem exists only when the utility is outside the "band" region and the mechanism requires sharing of "excessive "or "deficient" earnings with customers. This fact suggests a wide "band," as the utility operating within the "band" would have "high-powered" incentives to manage costs because it retains all the economic gains.

[37] The incentive problem would be less pronounced compared to a conventional cost tracker. As long as the utility's rate of return is within the "band" region, it has a similar incentive for cost control as it would between rate cases with fixed prices. (The word "similar" is used because if the "band region" is wide enough, it could defer the next rate case to either increase or decrease rates. This deferral would further strengthen the incentive of the utility to control costs.) Outside the "band" region, the utility's incentive depends upon whether ESM requires the sharing of high or low rates of return between the utility and its customers. Assume, for example, that the "band" region is a 10 to 14 percent rate of return on equity. During the year, the utility earns 15 percent; if the utility has to split the difference between the higher boundary of the "band" region and the actual rate of return by adjusting its prices down, in the example the utility would realize a 14.5 percent rate of return. We assume that the mechanism is symmetrical, so if the utility earns below the lower boundary of the "band" region, say, a 9 percent rate of return, it can adjust prices up to realize a rate of return closer to the lower boundary. This sharing arrangement means that if the utility allows its costs to rise, it either suffers the full consequence (when it operates within the 'band" region) or the partial consequence (when it operates outside). The latter condition creates an incentive problem relative to traditional ratemaking with regulatory lag and fixed prices between rate cases.

On net, the utility benefits and its customers immediately pay for the infrastructure costs without benefiting from the lower operating costs (at least until new rates reflect the lower costs). Such an outcome would violate any common meaning of "fairness" and seriously calls into question the merits of using a single-function tracker without readjusting rates for the effect on a utility's other functional areas.[38] This dynamic suggests that commissions implementing trackers should require their utilities to file rate cases on predetermined intervals.

B. No cost trackers

Under the traditional approach to ratemaking, a utility cannot adjust its rates outside a rate case. No matter what happens to a utility's costs or revenues between rate cases, rates remain fixed. Let us assume that a utility's costs and revenues are volatile and difficult to predict. The utility's rate of return can then deviate substantially (on the upside or downside) from the authorized level.

It is one thing to prohibit trackers for costs that are substantial, volatile and unpredictable, and generally beyond the control of a utility; it is another to reject trackers for costs that lack one or more of these features. *Good regulatory policy rejects cost trackers that are not essential for protecting a utility from a dire financial situation.* The utility, in justifying a cost tracker, should present the regulator with credible information showing that a nontrivial probability exists that the cost item under review will rise sufficiently above the test-year level to place the utility in financial jeopardy.[39] This showing is more likely when the regulator uses a historical test year and the cost item recently has exhibited an upward trend or substantial volatility.[40]

Another conceivable justification for a cost tracker is that it transmits better price signals to a utility's customers. Prices would correspond closer to a utility's actual costs and thus improve economic efficiency. For economic efficiency, customers should see costs reflected in their rates, such that they consume less when costs are higher. The validity of this argument for

38 Such a non-uniform treatment of costs could also cause perverse incentives. A utility, for example, might overspend on infrastructure structures to receive the gains from lower operating or other costs that the utility retains for itself until the next rate case.

39 The term "financial jeopardy" has different interpretations. This state, no matter how it is defined, has the potential to harm customers as well as the utility shareholders. It could cause the deferment of needed capital investments to maintain reliable service, lowering of the utility's credit rating, and an increase in the utility's cost of capital. The time period over which these effects would cause injury to utility shareholders generally would be more immediate than the injury to customers.

40 A future test year might not improve matters much if the cost item is inherently difficult to predict with any forecast and therefore susceptible to large error.

a cost tracker also depends upon the magnitude and nature of the costs involved.[41] This outcome assumes that a tracker involves a variable cost such as fuel or purchased gas costs. When a tracker relates to a fixed cost (e.g., infrastructure costs), the argument turns more to the "fairness" of a cost-recovery mechanism to the utility. Is a tracker justified because test-year cost calculations expose the utility to potentially high financial risk from unanticipated costs that fall primarily outside the control of a utility?

VI. Putting It All Together

Cost trackers have both positive and negative features that regulators must evaluate.[42] In reaching a decision, the regulator needs to weigh these features to determine what is in the public interest based on how they shift risks, ensure cost recovery, and affect incentives. The main challenge for regulators is to evaluate whether the positives outweigh the negatives to justify a cost tracker.[43]

A. The positive side of cost trackers

The primary benefit of cost trackers, as discussed earlier in this paper, is that they reduce the likelihood that a utility will encounter serious financial problems. If test-year costs fail to reflect accurate projections of a utility's actual cost for future periods, then the utility's earnings can deviate substantially from what a commission approved in the last rate case. Some cost items are difficult to project, as they exhibit high volatility and depend on different variables that by themselves are uncertain.

By reducing regulatory lag and the likelihood of prudence reviews, cost trackers can lower a utility's risk and thus increase its access to capital. The utility could then have a higher credit rating that, in turn, could lower the cost of financing capital projects.[44]

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[41] Distortive price signals can relate to the difference between the utility's short-run marginal cost and the marginal price charge to customers in consuming more electricity or natural gas.

[42] For a thorough and excellent discussion of the advantages and disadvantages of cost trackers, with a focus on fuel adjustment clauses, *see* Michael Schmidt, *Automatic Adjustment Clauses: Theory and Applications* (East Lansing, MI: Michigan State University Press, 1981).

[43] For an analysis of similar issues faced by regulators in evaluating different ratemaking mechanisms in general, *see* Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

[44] This argument is similar to the one used to support including construction work in progress (CWIP) in rate base for electricity transmission.

Cost trackers also coincide with the regulatory objective of setting prices based on the actual cost of service. This condition transmits the right price signal to customers deciding how much of the utility's services to consume.[45]

The development of infrastructure such as the smart grid or other new technology costs might warrant that commissions consider cost-recovery mechanisms such as a cost tracker to guarantee minimum cash flow for a utility. Investors might otherwise perceive excessive regulatory risks that preclude committing funding to a utility.[46] A cost tracker in this instance also might cut down on the frequency of future rate cases. Regulators in the future might want to explore less traditional ways for utilities to recover their costs for new technologies with inherently high operational and financial uncertainties.

As a final benefit, cost trackers can reduce regulatory and utility costs by reducing the number of future rate cases. Rate cases absorb substantial staff resources and time, diverting those scarce resources from other commission activities. Yet it is doubtful that many of the recently proposed trackers involving non-major cost items would have any effect on the timing of future rate cases. Another comment is that the costs associated with serious and continuing audits and the monitoring of costs recovered through a tracker could require substantial resources, either in the form of commission staff or outside consultants.

B. The negative side of cost trackers: the case for traditional ratemaking as a default policy or earnings sharing as a preferred alternative

Cost trackers can reduce utility efficiency, as described above. "Just and reasonable" rates require that customers do not pay for costs the utility could have avoided with efficient or prudent management. Regulation attempts to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting a retrospective review of costs, applying performance-based incentives, and instituting regulatory lag. Cost trackers diminish one or more of these regulatory activities. In some instances, they diminish all of them. The consequence is the increased likelihood that customers will pay for excessive utility costs.

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[45] One issue that has emerged in states where trackers have become a major method for cost recovery relates to the allocation of those costs across customer classes. Cost allocation determines the actual prices that different customers pay for utility service.

[46] One alternative to reducing regulatory risk through trackers would be for a commission to articulate in a policy statement or other document that it would not apply 20-20 hindsight to determine the cost recovery of new investments. A commission can express, for example, that it will not subject specific utility decisions to prudence reviews. One method of doing so is providing pre-approval for projects before they enter service. For a more detailed discussion of pre-approval mechanisms, *see* Scott Hempling and Scott Strauss, *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* NRRI 08-12, November 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

This paper recommends that regulators approve cost trackers only in special situations where the utility would have to show that alternate cost-recovery mechanisms could cause extreme financial problems. This showing requires utilities to provide a distribution of possible cost futures and an assessment of their likelihood. If a certain cost item has high volatility and unpredictability, represents a large component of the utility's revenue requirement and is recurring, and is generally beyond a utility's costs, it becomes a candidate for "tracker" recovery.

Even then, the regulator should consider the adverse incentive effects and how he or she can compensate for this problem.[47] Regulators should condition any approval of a cost tracker on the utility's filing information on its performance for those functional areas directly or indirectly affected by the tracker. For example, has the FAC caused a utility to spend less money on plant maintenance costs, jeopardizing reliability and inflating total utility costs because of higher avoidable fuel costs? These conditions can harm the utility's customers in the long run.

No other rationale merits departing from cost recovery through rate cases. This limited application of cost trackers provides the benefits of:

1. using the same cost-recovery mechanisms for all utility functions to prevent perverse incentives (perverse incentives can lead to a higher cost of service and utility rates);

2. balancing a utility's total costs and total revenues (without this balancing, it is conceivable that the utility could recover one cost item through a tracker and over-recover other costs set in the last rate case to result in the utility earning above its authorized rate of return); a rate case has the attractive feature of matching revenue with costs on an aggregate basis;

3. retaining sufficient regulatory lag to provide the utility with more motivation to control costs (regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases); and

4. scrutinizing a utility's costs and performance in different areas of operation (commissions review costs more rigorously in a rate case setting, decreasing the likelihood that customers will recover a utility's imprudent costs).[48]

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[47] The commission can monitor the utility's performance or include a performance-based incentive component in the tracker mechanism. *See* the NRRI study cited in footnote 8 for a description and analysis of incentive-based gas procurement mechanisms.

[48] In theory, a commission can expend the same resources and effort toward inspecting a utility's costs recovered through a tracker as it does for costs determined in a rate case. In practice, however, the author shares the widely held view that commissions and non-utility parties devote fewer resources to this task for costs recovered through a tracker. Confirmation of this view would require a systematic study that would compare, among other things, the resources expended by the commission and non-utility stakeholders per dollar recovered under trackers and in a rate case.

The earlier discussion points to the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative overcomes some of the problems with cost trackers, namely perverse incentives and weak incentives for cost control, the mismatching of a utility's *total* costs and revenues, and inadequate regulatory oversight of costs.[49] An earnings-sharing mechanism is also able to achieve the major objective of cost trackers, namely preventing utilities from suffering serious financial problems between rate cases.

A single rate-of-return tracker can also address the "fairness" issue of why a utility should not recover from customers a cost increase (e.g., property taxes) between rate cases that is completely beyond its control. This mechanism would, in effect, allow the utility to recover the increased costs, but only if it was already earning a "low" rate of return (i.e., a return below the "band" region discussed above). One major problem with cost trackers is that they allow a utility to increase its prices even if the utility is already earning a higher-than-authorized rate of return (or beyond the "zone of reasonableness" set in the last rate case). A commission would not allow this outcome under traditional regulation.

VII. Questions Regulators Should Ask

This paper discusses the major issues regulators face in evaluating cost trackers. Well-informed decisions require regulators to ask certain questions, for which this paper provides some introductory responses. The following is a list of the most pertinent questions:

1. Does a cost-tracker proposal meet the regulatory test of acceptability? What minimum threshold should a regulator set for consideration of a cost tracker?

2. What special circumstances exist to warrant cost recovery outside of a rate case?

3. What evidence does a utility present showing that the absence of a tracker for a particular cost could place it in financial jeopardy?

4. In addition to cost trackers, what other cost-recovery mechanisms can regulators rely on to allow a utility to recover substantial unexpected costs between rate cases? What are the public-interest effects of these mechanisms relative to cost trackers?

5. What advantages does a cost tracker offer? What are its disadvantages?

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[49] Regulators can overcome some of these problems. They can, for example, require that a utility with cost trackers file a rate case no less often than every three years or however often frequency regulators consider appropriate. Regulators can also require prudence reviews of utility activities associated with trackers on a regular basis. I thank Michael McFadden for these insights.

6. How should regulators weigh the downsides of cost trackers relative to the upsides? How important are adverse incentive effects relative to the value of stabilizing a utility's rate of return?

7. How should a regulator account for the net-cost effects of a new investment (e.g., capital costs less savings in operating costs) for which the utility wants cost recovery through a tracker?

8. How would the accumulation of cost trackers for a utility motivate the utility to take risks and improve its overall cost performance?

9. If a cost tracker is justified, how can regulators structure it to mitigate potential problems such as weakened incentives for cost control?

10. What conditions should a regulator attach to the approval of a cost tracker?

    a. Should it require the utility to report on its cost performance in functional areas directly and indirectly affected by the tracker?

    b. Should the regulator also require that all costs recovered through trackers be subject to a thorough prudence review?

    c. Should the regulator reduce the utility's return on equity to account for the lower risk resulting from the tracker?