414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

January 13, 2012

Dr. Burl W. Haar - VIA ELECTRONIC FILING -
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF 2012 TRANSMISSION COST RECOVERY (TCR), PROJECT ELIGIBILITY, TCR RATE FACTORS, AND 2011 TRUE-UP
Docket No. E002/M-12-_____

Dear Dr. Haar:

Enclosed is Xcel Energy's petition for approval of 2012 Transmission Cost Recovery ("TCR"), project eligibility, TCR rate factors, and 2011 true-up report.

If you have questions or need additional information, please contact me at 612) 330-6750.

Sincerely,

/S/

MARK SUEL
REGULATORY CASE SPECIALIST

Enclosures

c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR APPROVAL OF A MODIFICATION TO ITS TCR TARIFF, 2012 PROJECT ELIGIBILITY, 2012 TCR RATE FACTORS, AND 2011 TCR TRUE-UP AND COMPLIANCE FILING	DOCKET NO. E002/M-12-_____ **PETITION AND COMPLIANCE FILING**

INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") submits to the Minnesota Public Utilities Commission (the "Commission") this Petition and Compliance filing pursuant to Minnesota Statutes § 216B.16, Subd. 1 and Subd. 7b, Minnesota Statutes § 216B.1645, and Minnesota Rules 7829.1300.

We respectfully request the Commission: (1) approve the 2012 revenue requirements of $29.6 million for all projects deemed eligible for Transmission Cost Recovery ("TCR") Rider recovery; (2) approve the eligibility of the Pleasant Valley – Byron 161 kV line, the CapX2020 Brookings - Twin Cities 345 kV project ("Brookings Project"), costs associated with Buffalo Ridge Restoration Project, and costs associated with the Glencoe – Waconia 115 kV transmission project for recovery in the 2012 TCR Rider; (3) accept our 2011 TCR True-Up and Tracker Balance report; and (4) approve the proposed 2012 TCR rate adjustment factors to be included in the Resource Adjustment on customer bills for electric customers in Minnesota.

The major elements of our filing are summarized below.

2012 TCR Revenue Requirements and Adjustment Factors. In Section VII of this Petition, we propose to recover approximately $29.6 million of revenue requirements through our proposed 2012 TCR adjustment factors. We also outline our proposed TCR rate adjustment factors by customer class, and provide related discussion and the supporting calculations for our proposed adjustment factors. The proposed rate factors include a TCR demand factor (rather than energy charge) for Demand Billed customers, consistent with the Commission order in the Company's 2011 TCR Rider filing, Docket No. E002/M-10-1064.[1]

Eligible Project Additions. In Section V, we request Commission approval of the eligibility of four new projects for inclusion in the TCR in 2012.

First, the Company's portion of the CapX2020 Brookings Project should be found to be eligible for inclusion in TCR. This section discusses the criteria for rate recovery for the Brookings Project set forth in the Commission's April 27, 2010 order in Docket No. E002/M-09-1048, the Company's 2010 TCR Rider filing;[2] and the Commission's October 21, 2011 order in Docket No.E002/M-10-1064, the Company's 2011 TCR Rider Filing. On December 8, 2011, the Board of Directors of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO") resolved cost allocation issues surrounding the Brookings Project when it approved the Brookings Project in its list of Multi-Value Projects ("MVPs") eligible for regional cost allocation under the MISO Tariff.

In addition, the Company requests the Commission to approve cost recovery for two transmission projects that have been issued Certificates of Need: the Pleasant Valley - Byron 161 kV project, which received a Certificate of Need from the Commission on February 28, 2011 in Docket No. E-002/CN-08-992; and the Glencoe – Waconia transmission project that received a Certificate of Need from the Commission on November 14, 2011 in Docket No. E002-09-1390. These projects are eligible for TCR Rider recovery under the Transmission Cost Recovery statute, Minnesota Statutes § 216B.16, Subd. 7b.

Further, the Company requests the Commission to approve TCR recovery of the 2012 revenue requirements (approximately $3.9 million) associated with significant capital expenditures for the Buffalo Ridge Restoration Project, which involved rebuilding approximately 64 miles of 115 kV transmission line and approximately 30 miles of 34.5 kV feeder lines severely damaged during a storm on July 1, 2011 in

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[1] *In the Matter of Petition of Northern States Power Company*, Docket No. E002/M-10-1064, ORDER APPROVING TCR PROJECT ELIGIBILITY AND TCR RATE FACTORS (October 21, 2011).

[2] *In the Matter of Petition of Northern States Power Company*, Docket No. E002/M-09-1048, ORDER APPROVING TCR PROJECT ELIGIBILITY AND TCR RATE FACTORS (April 27, 2010); ORDER DENYING RECONSIDERATION (August 9, 2010)

Pipestone, Lincoln, and Lyon Counties. The Company informed the Commission of this required repair work in an August 1, 2011 letter from Mr. Timothy Rogers, Supervisor Siting and Permitting (enclosed as Attachment 40). The restored lines include the core portion of the transmission system that allowed for connection of two of the three Buffalo Ridge Incremental Generation Outlet ("BRIGO") 115 kV facilities previously granted a Certificate of Need by the Commission in Docket No. E002/CN-06-154 and included in the TCR.[3] The restoration project was completed in December 2011. The restoration project not only resulted in wind feeders being put back in-service that directly affected approximately 300 MW of wind, it also put back in-service in a timely manner the 64 miles of 115 kV transmission line which allows for the reliable operation and delivery of approximately 1200 MW of wind generation in the Buffalo Ridge area. The Commission should determine these costs are eligible for TCR Rider recovery under Minnesota Statutes § 216B.1645, the Environmental Cost Recovery ("ECR") statute.

Rate Case Adjustments. The proposed 2012 TCR eligible projects exclude transmission investments included in rate base in the 2011 test year for the Company's pending electric rate case (Docket No. E002/GR-10-971).

2011 TCR Tracker Compliance and True-up Report. In Section X, we request the Commission to approve our 2011 True-Up report, comparing the amounts authorized in our 2011 TCR Rider with actual expenditures and updated cost estimates.

Variance Analysis and "Cost Recovery Cap." In previous TCR filings, the Company explained any project cost increases or decreases of the smaller of ten (10) percent or $1 million, in compliance with the Commission's June 25, 2009 Order in Docket No. E002/M-08-1284, the Company's 2009 TCR Rider filing. In the Commission's April 27, 2010 ORDER in Docket No. E002/M-09-1048, the Commission changed this variance analysis requirement to a "cost cap" requirement to set a limit on the project costs that can be included in the TCR Rider. In Attachment 42, we present the comparison of the costs of transmission projects included in this TCR filing to the initial cost estimates for these same projects.

Revised Tariff Sheets. Attachments 38 and 39 provide a revised TCR Rider tariff sheet reflecting the proposed TCR Rider rate factors by customer class. The revised tariff indicates a proposed April 1, 2012 effective date. The actual effective date will be determined by the date of the Commission order regarding this petition.

I. SUMMARY OF FILING

Pursuant to Minn. Rule 7829.1300, Subp. 1, a one paragraph summary of our filing accompanies this petition.

[3] In the Matter of Application for Certificates of Need ofor Three Transmission Lines in the Buffalo Ridge area of Southwestern Minnesota. Order September 14, 2007. Docket E-002/CN-06-154.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list.

III. GENERAL FILING INFORMATION

A. Utility Information

Northern States Power Company,
a Minnesota corporation
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall – 5th Floor
Minneapolis, MN 55401
(612) 215-4592

C. Date of Filing and Date Modified Rates Take Effect

The date of this filing is January 13, 2012. The Company proposes the 2012 TCR Adjustment factors be included in the Resource Adjustment line on the Company's retail electric billing rates effective the first day of the month following the Commission's order approving this Petition. For illustrative purposes our proposed tariff sheets provide an effective date of April 1, 2012, with cost recovery of the proposed revenue requirements over the remainder of 2012, subject to Commission approval.

D. Statutes Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.16 allows a utility to place a rate change in effect upon 60-days notice to the Commission. Minn. Stat. § 216B.16, Subd. 7b (the "Transmission Statute") allows for recovery through an automatic adjustment mechanism of charges for the Minnesota jurisdictional costs of certain new transmission facilities and certain Midwest ISO charges associated with regionally planned transmission projects. Minn. Stat. § 216B.1645 (the "Renewable Energy Statute") allows for recovery through an

automatic adjustment mechanism of all investments or expenditures entered into by a public utility in connection with satisfying renewable energy mandates of the Legislature. Minn. Stat. § 216B.10 grants the Commission jurisdiction over the accounting practices of public utilities.

Since no determination of Xcel Energy's general revenue requirement is necessary, this filing falls within the definition of a "miscellaneous tariff filing" under Minn. Rule. 7829.0100, Subp. 11. Pursuant to Minn. Rule. 7829.1400, initial comments on a miscellaneous tariff filing are due within 30 days of filing, with replies due 10 days thereafter.

E. Utility Employee Responsible for Filing

Paul J Lehman
Manager Regulatory Administration
Xcel Energy Services Inc.
414 Nicollet Mall – 7th Floor
Minneapolis, MN 55401
(612) 330-7529

IV. DESCRIPTION OF FILING

A. Background

The 1997 Legislature enacted the Renewable Energy Statute, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with utility investments or costs to comply with renewable energy mandates. The 2005 Legislature enacted the Transmission Statute, authorizing the Commission to approve a tariff mechanism for an automatic adjustment of charges for costs associated with eligible utility investments in transmission facilities, and in 2008 amended this Statute to allow inclusion of the costs of regional transmission facilities determined by the Midwest ISO to benefit the Company, as provided for under a federally approved tariff.

The Commission's November 20, 2006 ORDER in Docket No. E002/M-06-1103 approved the Company's new TCR Rider tariff, combining recovery of eligible projects as defined in both the Renewable Statute and the Transmission Statute under one annual automatic adjustment mechanism, the TCR Rider.

Since 2006, the Company's TCR Rider tariff has been modified twice to allow recovery of additional costs subsequently authorized by the Minnesota Legislature. First, the Commission's March 20, 2008 Order in Docket No. E002/M-07-1156 approved recovery of greenhouse gas infrastructure costs incurred for the replacement of circuit breakers that contain sulfur hexafluoride ("SF6"), as allowed

under Minn. Stat. 216B.1637. Second, as allowed under the Transmission Statute, the Commission's June 25, 2009 Order in Docket No. E002/M-08-1284 approved recovery of Midwest ISO Regional Expansion Criteria and Benefits ("RECB") revenues and costs invoiced to the Company by Midwest ISO under Schedule 26 or Schedule 26A of the MISO Tariff related to other MISO transmission owners' regionally-planned transmission projects.

For clarity, in this Petition, we categorize all reports and calculations associated with project costs and revenue requirements in three groups: (1) Transmission Statute projects; (2) Renewable Statute projects; and (3) Greenhouse Gas projects. Although we track costs separately by Statute, we request approval for recovery of the total costs under a single recovery mechanism, the TCR Rider.

V. 2012 ELIGIBLE PROJECTS

We request the Commission approve eligibility for 2012 TCR Rider recovery for four new transmission line projects, which we describe below. We provide the required information supporting designation of eligibility request for this project as Attachment 1, Description of Eligible Projects; Attachment 2, the Implementation Schedule for new projects eligible under the Transmission Statute; and Attachment 3, Total TCR Project Capital Expenditures.

A. Transmission Statute Projects

The eligibility criteria for transmission projects are established in the Transmission Statute, Minn. Stat. § 216B.16, Subdivision 7b(a), which states that:

> *Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs of new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425.*

The following projects are eligible for TCR recovery under the Transmission Statute:

1. Brookings - Twin Cities 345 kV Project

On May 22, 2009, in Docket No. E-002/CN-06-1115, the Commission issued an Order granting Certificates of Need for the CapX2020 Fargo, Brookings, and La Crosse 345 kV transmission line projects. On July 14, 2009, the Commission granted a Certificate of Need for the Bemidji – Grand Rapids 230 kV transmission line in

Docket ET-6/CN-07-1222. The Commission's April 27, 2010 Order approving our 2010 TCR Rider Petition in Docket E002/M-09-1048 approved inclusion of the revenue requirements for the Fargo, La Crosse and Bemidji Projects in the TCR, but did not allow 2010 TCR Rider recovery for the Brookings project because of uncertainty regarding the cost allocation to be applied to the Brookings Project under the Midwest ISO Tariff.

The Commission's October 21, 2011 Order approving our 2011 TCR Rider Petition in Docket E002/M-10-1064 again deferred inclusion of the revenue requirements for the Company's expenditures on the Brookings Project. Although the Federal Energy Regulatory Commission ("FERC") had approved the MISO MVP Tariff in December 2010, the Commission's decision was based on waiting until the Midwest ISO completed its final MVP eligibility determination for the Brookings Project.

In addition to meeting the transmission cost adjustment eligibility criteria established in Minn. Stat. § 216B.16, Subdivision 7b[a], the cost allocation treatment for the Brookings project has now been resolved and TCR recovery should be allowed in 2012.

The Company will not repeat all of the history of cost allocation consideration for the Brookings Project provided in previous TCR filings and/or the Certificate of Need docket for the CapX2020 345 kV facilities. There are two key developments since the Commission's October 21, 2011 ORDER. First, FERC has issued its order on rehearing upholding the prior decision approving the Midwest ISO MVP tariff.[4] Second, the Midwest ISO Board at its meeting on December 8, 2011 approved the initial portfolio of MVP projects for regional cost allocation, including the Brookings Project.[5] This action moved the conditional approval granted the Brookings Project in June of 2011 to final approval. In January 2012, the CapX2020 participant utilities (including the Company) are scheduled to sign the Brookings Project construction agreements, allowing for construction to start in Spring 2012. Significant construction is scheduled to occur during 2012, with the Company's share of the 2012 Brookings investments expected to reach approximately $126 million by the end of the year. The 2012 TCR revenue requirement is $6.5 million.

Since the uncertainty regarding MISO cost allocation for the Brookings Project cited in the Commission's 2010 and 2011 TCR ORDERS has been resolved, we request the Commission find the Brookings Project is now eligible for recovery in the TCR Rider.

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[4] *Midwest Independent Transmission System Operator, Inc.,* 137 FERC ¶ 61,074 (2011) (appeals pending).

[5] The material used by the MISO Board can be found at the following link: https://www.midwestiso.org/Events/Pages/BOD20111208.aspx

2. Pleasant Valley Byron 161 kV Transmission Line

The Company requests the Commission approve cost recovery for the Pleasant Valley 161 kV project, which received a Certificate of Need from the Commission on February 28, 2011 in Docket No. E-002/CN-08-992. The transmission line is needed to enable two wind farms to deliver energy without operating restrictions and to help close the gap in wind outlet transmission capability in 2012 that was identified in the 2007 Minnesota Transmission Owners Biennial Report. The project will also provide additional import capacity in the Rochester area. Since the proposed facility received approval of a certificate of need by the Commission on February 28, 2011, this project is now eligible for cost recovery through the TCR. The Company thus seeks TCR recovery of approximately $356,000 in project revenue requirements for 2012. Note that of this recovery amount, $123,000 is being recovered in 2011 test year base rates and is therefore deducted from Rider recovery per Attachment 36, Page 3.

3. Glencoe – Waconia 115 kV Upgrades

The Project entails constructing approximately 2 miles of new 69 kV transmission line, 6 miles of new 115 kV transmission line, and upgrading approximately 20 miles of 69 kV transmission line to 115 kV capacity near the cities of Glencoe, Norwood Young America, and Waconia along with certain substation modifications located in the southwest metro area of the Twin Cities. The Project is located within Carver and McLeod Counties. The Southwest Twin Cities Load Serving Study Review identified the need for transmission upgrades in the Glencoe – Waconia area to prevent significant low voltage and line overload conditions. The Commission granted a Certificate of Need for this project on November 14, 2011 in Docket No. E002/CN-09-1390. The Company thus seeks TCR recovery of approximately $688,000 in project revenue requirements for 2012. Note that of this recovery amount, approximately $56,500 is being recovered in 2011 test year base rates and is therefore deducted from Rider recovery per Attachment 36, Page 4.

B. Renewable Statute Projects

The eligibility criteria for renewable projects are established in the Renewable Statute, Minn. Stat. § 216B.1645, Subdivision 1, which states that:

> *Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424,and to satisfy the renewable energy objectives set forth in section 216B.1691, including reasonable investments and expenditures made to transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, including studies necessary to identify new transmission facilities needed to transmit*

electricity to Minnesota retail customers from generation facilities constructed to satisfy the renewable energy objectives, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425for the new transmission facilities identified in the studies; or develop renewable energy sources from the account required in section 116C.779.

Further, Subdivision 2 addresses cost recovery and states in part:

…Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market…

The Company requests TCR Rider cost recovery for the following project under the Renewable Statute.

4. Buffalo Ridge Restoration Project (Storm Repair Costs)

Sixty four (64) miles of 115kV transmission lines and 30 miles of 34.5 kV wind feeder collector facilities were destroyed as a result of severe storm damage to the Company's transmission system in Pipestone, Lincoln, and Lyon Counties in southwest Minnesota on July 1, 2011. The Company incurred approximately $38 million in unanticipated 2011 transmission investment to restore these transmission facilities. Because restoration of the 115 kV lines and the 34.5 kV collector feeders was needed for renewable wind energy to be delivered from generators on the Buffalo Ridge to the Company's load centers, the Company believes the investment is eligible for TCR recovery under the Renewable Statute. In addition, since all of the restoration facilities are in service, the facilities meet the requirements established by the Commission in its early Renewable Cost Recovery ("RCR") rider orders.[6] A more detailed discussion of this restoration project is contained in Attachment 1, Project Descriptions.

These transmission restoration costs were not included in the test year in the Company's 2011 electric rates case, therefore the Company is seeking to recover approximately $3.9 million of revenue requirements in the 2012 TCR. However, the

[6] The Commission issued Orders with regard to RCR project cost recovery in the following dockets: E002/M-02-474, E002/M-03-1882 and E002/M-05-289. The Commission's Orders in these dockets allowed RCR cost recovery only after the in-service date of the project.

cost of the facilities that were damaged and removed was included in transmission rate base in the 2011 test year. Because of this, Attachment 29 provides the calculation of the credit (approximately $350,000 for the Minnesota jurisdiction) to the TCR revenue requirements to be made in order to account for the revenue requirements included in our base rates for the facilities that were removed. This credit is only needed until the cost of the previous facilities can be retired from the Company's books and taken out of base rates.

VII. Revenue Requirements and 2012 TCR Rate Adjustment Calculations

In this section of our Petition, we provide the 2012 revenue requirement and 2012 TCR rate adjustment factor calculations for the proposed TCR and ECR projects and charges. Our calculations assume proposed projects are approved for eligibility, and the TCR adjustment factors are effective April1, 2012. If implementation of the 2012 TCR adjustment factors occurs after April 1, 2012, we propose to calculate the final 2012 TCR adjustment factors to recover the 2012 revenue requirements over the remaining months of 2012, which we would provide as part of a compliance filing after the Commission's Order approving our Petition.

The projected revenue requirements we propose to recover through the 2012 TCR adjustment factors from Minnesota electric customers are approximately $29.6 million, compared to approximately $10.3 million in the 2011 TCR adjustment factors (which reflected the inclusion of facilities in base rates rather than the TCR). We provide the supporting revenue requirement calculations and projected 2012 TCR Tracker activity in Attachment 4 to this filing. Attachment 5 to this filing provides our projected 2012 TCR revenues, calculated by customer group based on forecasted 2012 State of Minnesota billing month sales. Our 2012 TCR adjustment factors are outlined below, and detailed in Attachment 6.[7] We provide an estimate of the 2013 TCR adjustment factors in Attachments 7-10, which are calculated based on the projected revenue requirements for projects that have already been approved by the Commission, or are pending approval in this Petition.

A. Proposed 2012 TCR Adjustment Factors

The costs recovered through the TCR are allocated to the NSP Companies (the Company and Northern States Power Company, a Wisconsin corporation ("NSPW")), to the Company's State Jurisdictions (Minnesota, North Dakota and South Dakota), and to the Minnesota Jurisdiction Classes (Residential, C&I Non Demand, C&I Demand and Street Lighting) based on the demand allocation factors approved by the Commission in prior TCR filings.

[7] The rate design for these factors was approved by the Commission in their November 20, 2006 Order in Docket No. E002/M-06-1103 and in their October 21, 2011 Order in Docket No. E002/M-10-1064.

Within each of the three non-demand metered classes of service, these allocated costs are recovered through a per kWh charge. We determine the per kWh charge for each of the three classes each year by applying a class-specific allocation factor to the Minnesota jurisdiction average per kWh TCR cost. The current allocation factor is based on the Commission-approved demand allocator from the Company's 2008 electric rate case in Docket No. E002/GR-08-1065 and associated forecast year sales (since the Commission has not issued a final decision in the 2011 test year rate case). The resulting annually-revised TCR adjustment factors recover the current costs.[8]

For the demand metered class, the TCR adjustment factors are determined similarly; however, the factor to be billed is instead determined by using forecast year demands instead of sales to yield a per kW factor.

We provide below, the TCR adjustment factors we propose for 2012, as well as a comparison to the 2011 TCR adjustment factors:

Customer Group	2012 Proposed Rate	2011 Actual Rate
Residential	$0.001368/kWh	$0.000931/kWh
Commercial Non – Demand	$0.001052/kWh	$0.000716/kWh
Demand Billed	$0.350/kW	$0.238/kW
Street Lighting	$0.000657/kWh	$0.000447/kWh

For an average residential customer using 750 kWh per month, the 2012 TCR adjustment factor would result in a bill impact of approximately $1.03 per month which is approximately a $0.33 per month increase as compared to the approved TCR adjustment factor for 2011.

The proposed TCR rate factors are calculated assuming they are effective April 1, 2012. If the Commission does not act on this Petition in time for rates to become effective April 1, the Company requests that rate factors be recalculated to recover 2012 revenue requirements over the remaining months of 2012 in order to match 2012 cost recovery with the eligible 2012 costs, similar to the treatment authorized in past TCR orders.

B. 2012 TCR State of Minnesota Revenue Requirements

[8] If the Commission issues a final order in the 2011 test year rate case before it makes a final determination in this TCR factor proceeding, the Company would propose to recalculate the 2012 TCR rate factors by customer class using the allocation factors used in the 2011 test year revenue requirement. The Company would reflect the updated allocation factors in its compliance filing in this docket.

The 2012 Minnesota jurisdictional revenue requirements in support of the proposed TCR adjustment rates are set forth in Attachments 14-26. Transmission Statute project revenue requirements are calculated using the guidance provided in Minn. Stat. § 216B.16, subd. 7b(b)(2); and Renewable Statute project revenue requirements are calculated consistent with past Commission Orders in the Company's previous RCR rider adjustment rate petitions.[9] As described below, the Company's revenue requirements calculations comply with the Transmission Statute, Greenhouse Gas Infrastructure Statute and the Commission's prior RCR adjustment orders.

1. Transmission Statute Revenue Requirements

The Transmission Statute requires certain information be provided in support of our request. Minn. Stat. § 216B.16, Subdivision 7b[c] states:

> *A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff proposed in paragraph [b]. In its filing, the public utility shall provide:*
>
> *(1) a description of and context for the facilities included for recovery;*

In addition to the previous descriptions, Attachment 1 contains the project descriptions for projects the Company believes are eligible for recovery under the TCR rider in 2012. The Company provides a description and context for each project included for recovery.

> *(2) a schedule for implementation of applicable projects;*

Attachment 2 contains an implementation schedule for each of the transmission projects identified in Attachment 1.

> *(3) the utility's costs for these projects;*

Attachment 3 shows the capital expenditure forecast for each identified project. Capital expenditures are accumulated from project inception through January 1, 2012 and then reported annually thereafter.

> *(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and*

[9] The Commission issued Orders with regard to RCR project cost recovery in the following dockets: E002/M-02-474, E002/M-03-1882 and E002/M-05-289. Consistent with the Commission's Orders in these dockets, cost recovery begins with the in-service date of the project.

The Company has made extensive efforts to ensure the lowest cost to ratepayers for the proposed TCR-eligible projects. These efforts are discussed in the Project Descriptions in Attachment 1.

> *(5) calculation to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph [b].*

Attachment 6 contains the calculation of the proposed 2012 TCR rate adjustment by customer class. We provide the details of these calculations under the Cost Recovery section of this Petition. (This information is also provided for projects recovered under the Renewable Statute and included in Attachments 1-3 of our Petition.)

2. Midwest ISO Revenue Requirements

In addition to allowing the Company to recover the costs of transmission projects being constructed by the NSP System, the Transmission Statute allows TCR Rider recovery of charges billed under a federal tariff (such as the Midwest ISO Tariff) associated with other transmission expansions being constructed in the Midwest ISO region by other utilities. The projected 2012 charges from the new regional transmission projects included in the 2006 through 2011 Midwest ISO Transmission Expansion Plan ("MTEP") cost allocations are presented in Attachment 27.

The NSP System pricing zone (the NSP-MN and NSP-WI integrated system) share of the MTEP costs are expected to be approximately $27.8 million in 2012, billed under Schedule 26 and Schedule 26A of the Midwest ISO Tariff. However, some of the load in the NSP System pricing zone under the Midwest ISO TEMT is not NSP System native load but instead the transmission loads of third party load serving entities. Based on actual experience, the Company expects NSP System native load to be allocated $25.0 million of these costs, with the remainder borne by others in the NSP System rate zone. We can also expect $4.2 million of cost for our loads in other pricing zones bringing our total to $29.2 million. The Company expects these charges to be offset by $27.3 million in Schedule 26 and Schedule 26A revenues from Midwest ISO tariffs associated with regional rate recovery of NSP System project investments.

The forecasts result in net estimated Schedule 26/26A expenses of $1.9 million (total NSP System). These net expenses were further reduced by an allocation to NSP-WI and other Company jurisdictions, to arrive at the Minnesota jurisdiction net expense allocation of $1.4 million.

We respectfully request that the Commission authorize 2012 TCR cost recovery for the Minnesota jurisdiction net Midwest ISO Schedule 26/26A costs in the amount of

$1.4 million pursuant to Minn. Stat. 216B.16, Subd.7b(b)(2). The Company believes the Schedule 26/26A cost recovery through the TCR has been calculated consistent with the Transmission Statute.

3. Alternative Midwest ISO RECB Revenue Requirements Cost Recovery

The MISO RECB revenue requirement calculations provided in this filing were prepared in the same way the Commission has approved treatment of these regional costs and revenues since MISO RECB revenue requirements became eligible for inclusion in the TCR. For reference, this is based on the "All-In" cost recovery method described in the on-going Otter Tail Power Company ("Otter Tail") Transmission Cost Recovery Rider filing (Docket E002/M-10-1061). The Company is aware that an alternative cost recovery method referred to as the "Split" method has been discussed in the Otter Tail TCR docket.

The Company takes no position on use of the alternative "Split" cost recovery method in this TCR filing; however, the Company does understand the potential importance of this issue as the amount of new investment the Company makes in the transmission system continues to grow, particularly for transmission projects that will receive broad cost sharing treatment as MVP projects under the MISO tariff.

It may be appropriate to further consider the issue of the appropriate cost recovery method to recognize revenue requirements associated with MISO cost shared transmission projects. The Company suggests that a broader cost recovery forum, such as a general rate case, would be a better place for that consideration. The Company would welcome Commission direction to address this issue in an appropriate forum.

4. Other Costs Included in Revenue Requirement Calculations

In addition to inclusion of the provisions in our Transmission Statute and Renewable Statute project revenue requirements models, the Company also includes costs approved by the Commission in previous TCR rate adjustment Orders. For example, we use a projection of construction expenditures and costs for the 2012 forecast period. Allowable costs other than those previously mentioned include property taxes, current and deferred taxes and book depreciation. Attachment 4 summarizes the 2012 projected revenue requirements for these projects. Attachments 14-26 show the revenue requirement calculations for projects under both statutes. Base assumptions are included in Attachment 28.

a. Interchange Agreement Allocator

For the purpose of determining the State of Minnesota jurisdictional revenue requirements for production and transmission plant investment, the Company uses a demand allocator, which reflects the sharing of costs between the Company and NSPW pursuant to the Interchange Agreement. For purposes of this filing, we are using actual allocators for 2010 and budget allocators for 2011 and 2012. Any resulting over/under recovery from customers as a result of the use of the budget demand factors will be reflected in future year TCR rate adjustment filings that will use actual allocators as they are made available.

b. OATT Calculation

We established the TCR transmission revenue requirement by also reflecting the revenue offset provided by wholesale transmission services under the Midwest ISO Tariff. The OATT revenue credit captures a portion of the revenue the Company receives from third party transmission customers who are charged the FERC-jurisdictional Midwest ISO tariff rate for use of the Company's transmission system. Our approach to this issue is consistent with the approach set in the 2008 TCR petition, Docket No. E002/M-07-1156. This is separate from the revenue credit for Midwest ISO Schedule 26 RECB revenues.

The forecast period used to calculate the transmission formula rate under the Midwest ISO TEMT is consistent with the forecast period used to develop costs recovered under our TCR rate. In addition, the basis for both the Midwest ISO revenues and Transmission revenue requirements is a 13-month average plant balance.

Additionally, pursuant to Commission Order, we include Construction Work in Progress ("CWIP") in the OATT revenue credit calculation only for those projects where FERC approved the inclusion of CWIP in our Midwest ISO formula rate: the Chisago/Apple River Project and the CapX2020 – La Crosse 1 Project.[10] Further, we exclude any projects designated as RECB projects, since all RECB costs and Company revenues are included in the TCR. To apply the OATT revenue credit to RECB projects would be reducing project revenue requirements for revenue received from others twice, once through RECB revenues and once through the OATT revenue credit. The OATT revenue credit for each project is shown in the revenue requirement calculations for each project in Attachments 14-26.

[10] FERC also approved CWIP recovery for the BRIGO project, but those projects were rolled into base OATT rates after the BRIGO projects were placed in service in 2009.

5. Preventing Double Recovery

To provide further assurance of the accuracy of our calculations, external consultants under contract with the Company have reviewed our filing. Their review consisted of the following steps: (1) review of our revenue requirements and tracker calculations; (2) review of compliance of these calculations with the intent of statutes, orders and previous filings, and (3) verification that costs proposed to be recovered through the 2012 TCR Rider adjustment factors are not being recovered under any other mechanism. The purpose of this review is to provide independent review of the Company's calculations to ensure accuracy. The review also confirmed that the revenue requirement calculations include no double recovery costs.

VIII. Allocation of the TCR Rate Adjustment Based on the Percentage of Revenue Basis

In the Commission's October 21, 2011 TCR Order, order point 5 directed the Company as follows:

> *In its next annual filing, Xcel [Energy] shall include a rate design alternative proposal reflecting the allocation of the TCR rate adjustment based on the percentage of revenue basis, illustrating comparative impacts on the customer classes and customers within the demand-billed class.*

The Company has performed the requested analysis and it is included as Attachment 41. As has been demonstrated in the past with this type of analysis, the percentage of revenue approach to allocation of the TCR rate adjustment revenue requirements results in lower TCR billing for the Demand Metered customers (about 18% lower on average) and thus higher TCR billing for the non-Demand Metered customers (about 1% higher for Residential customers and 30% higher for commercial non-Demand Metered customers).

IX. 2012 TCR Variance Analysis Report

In Docket No. E002/M-10-1048, the Commission's Order dated April 27, 2010 included the following order point:

> *4. In setting guidelines for evaluating project costs going forward, the TCR project cost recovered through the rider should be limited to the amounts of the initial estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial*

estimate may be brought forward for Commission review only if unforeseen and extraordinary circumstances arise on the project

The table below provides a comparison of the total investment expected by project in 2012 compared to the initial cost estimate provided to the Commission, and provides the docket number for the initial cost estimate.

Transmission Project	**Cost Estimate Docket**	**Initial Cost Estimate ($M)**	**Investment Through 2012 ($M)**
Chisago Apple River	CN-04-1176 M-09-1048	$ 66.4	$ 48.8
CapX Fargo	CN-06-1115	$231.0	$109.1
CapX Brookings	CN-06-1115	$544.4	$126.3
CapX La Crosse	CN-06-1115	$276.5	$ 35.6
CapX Bemidji	CN-07-1222	$ 32.4	$ 32.3
Pleasant Valley – Byron	CN-08-992	$ 4.85	$ 4.4
Glencoe -Waconia	CN-09-1390	$29.0	$13.1

A detailed project cost cap discussion for each of the above projects is provided in Attachment 42.

X 2011 TCR Compliance Filing, True-up Report & Tracker Balance

The 2011 Annual TCR Compliance Filing, TCR True-up Report and Tracker Balance are included as Attachments 30-33, and we have decreased the revenue requirements in our proposed 2012 TCR by approximately $432,000 accordingly to reflect prior period over-recoveries. Detailed calculations in support of the 2011 revenue requirements are included in Attachments 14-26. Attachment 30 provides a summary of the 2011 forecast of State of Minnesota revenue requirements for 2011 eligible projects, as well as the 2011 revenue requirements for 2012 eligible projects. Attachment 31 shows the development of the forecast of 2011 TCR adjustment revenues, based on the Commission approved 2011 TCR adjustment rates. This schedule shows actual TCR revenues recovered from customers through November 2011 and a forecast of revenue recoveries through TCR adjustment rates for December 2011. Attachments 30 -33 show the recovery of the unrecovered TCR Tracker balance at the end of each year and that was "carried over" to the next year

TCR Tracker account and returned to customers during that following year. Attachment 14-26 includes the detailed Minnesota jurisdictional revenue requirements calculations for all projects with costs in 2009-2012.

XI. Proposed Tariff Sheets

A. Proposed Revised Tariff Sheets

Attachment 38 is a red line version of our TCR tariff sheet approved in our 2011 TCR Rider Filing, updated to show the proposed 2012 TCR Adjustment Factors by customer class, and the change from the factors effective in 2011. Attachment 39 is a clean version of our proposed TCR tariff. The proposed tariff provides that the TCR Adjustment is included in the Resource Adjustment and that factors will be applied to customer bills on or after January 1 of each year. Due to the timing of this filing, the tariff sheets we have submitted provide a proposed effective date of April 1, 2012. However, the tariff sheets and revised TCR factors will not be made effective until after the Commission acts on this petition.

The TCR tariff sheet and final TCR rate factors will be revised appropriately to comply with the Commission's final order in this proceeding. If the 2012 TCR adjustment rates are not made effective April 1, 2012, or if the Commission determines certain projects are not eligible for TCR recovery, the Company proposes to calculate the final TCR factors based on the approved revenue requirement and forecasted sales over the remaining months of 2012 in an effort to match as closely as possible 2012 revenue recovery and approved 2012 revenue requirements.

B. Proposed Customer Notice

The Company plans to provide notice to customers regarding change in the TCR adjustment rate reflected in their monthly electric bill. The following is our proposed language to be included as a notice on the customers' bill the month the TCR factor is implemented:

> This month's Resource Adjustment includes an increase in the Transmission Cost Recovery Adjustment (TCR) which recovers the costs of transmission investments, including delivery of renewable energy sources to customers. The TCR portion of the Resource Adjustment is $0.001368 per kWh for Residential Customers; $0.001052 per kWh for Commercial (Non-Demand) customers; $0.350 per kW for Demand billed customers; and $0.000657 per kWh for Street Lighting customers. Questions? Contact us at 1-800-895-4999.

We will work with the Department of Commerce and the Commission Staff if there are any suggestions to modify this proposed customer notice.

XII. Miscellaneous Information

Service List

The Company will serve a copy of this petition to those persons on the electric utility general service list. Pursuant to Minnesota Rule 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

James P. Johnson
Assistant General Counsel
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CONCLUSION

The Company respectfully requests the Commission approve our petition to establish new TCR rate adjustment factors for 2012 to recover $29.6 million in revenue requirements associated with our transmission investments.

Specifically, we request approval of our:

- Proposed 2012 TCR eligible projects;
- Proposed 2012 TCR adjustment rates, subject to updating based on the TCR implementation date to allow recovery of 2012 revenue requirements in calendar year 2012;
- 2011 Annual TCR Compliance Filing TCR True-up Reports and tracker balance;
- Proposed revised TCR tariff sheet; and
- Proposed Customer notice.

The supporting documentation shows that transmission projects are eligible for recovery under Minn. Stat. § 216B.16, Subd. 7b and 216B.1645 are part of the Company's efforts to satisfy the Legislature's renewable energy mandates and therefore eligible for recovery under the provisions of Minn. Stat. § 216B.1645.

Dated: January 13, 2012

Northern States Power Company,
a Minnesota corporation

/S/

By: _____

PAUL J LEHMAN
MANAGER REGULATORY ADMINISTRATION

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR APPROVAL OF A MODIFICATION TO ITS TCR TARIFF, 2012 PROJECT ELIGIBILITY, 2012 TCR RATE FACTORS, AND 2011 TCR TRUE-UP AND COMPLIANCE FILING	DOCKET NO. E002/M-12-_____ **PETITION AND COMPLIANCE FILING**

SUMMARY OF FILING

Please take note that on January 13, 2012, Northern States Power Company, a Minnesota corporation (the "Company") submitted to the Minnesota Public Utilities Commission a Petition for: approval of the 2012 revenue requirements for all projects deemed eligible for Transmission Cost Recovery (TCR) Rider Recovery; approval of costs for the CapX2020 Brookings – Twin Cities, Pleasant Valley – Byron, Glencoe Waconia 115 kV upgrades and Buffalo Ridge Restoration transmission line projects; approval of the Company's 2011 TCR Rider True-up and Tracker Balance report; and approval of the proposed 2012 TCR rate adjustment factors to be included in the Resource Adjustment on customer bills for electric customers in Minnesota.

If approved, the total effect on the Company's electric rates of the TCR Rider and Tracker Account Proposal will be $29.6 million in 2012. The average bill impact for a residential customer using 750 kWh per month would be about $1.03 per month, an increase of $0.33 per month from the TCR rate factor approved in 2011.

2012 TCR Petition - List of Attachments

Attachment #	Attachment Description
Attachment 1	Description of Eligible Projects
Attachment 2	Implementation Schedule
Attachment 3	Total TCR Project Capital Expenditures
Attachment 4	2012 Projected Revenue Requirements & Tracker Activity
Attachment 5	Projected 2012 Revenues Calculated by Customer Group
Attachment 6	2012 TCR Adjustment Factor Calculation by Customer Group
Attachments 7-8	Estimate of the 2013 TCR Adjustment Factors
Attachments 9	Forecast Rate 2013
Attachments 10	TCR Projected Tracker Activity for 2010 - 2013
Attachments 11-13	Not Applicable - Projects are included in base rates in the 2011 test year
Attachments 14-26	2011 Revenue Requirements
Attachment 27	MISO RECB Cost Allocations
Attachment 28	Base Assumptions
Attachment 29	Buffalo Ridge Restoration Retirement Impact
Attachment 30	Summary 2011 Forecast of MN Revenue Requirements
Attachment 31	Forecast of 2011 TCR Adjustment Revenues
Attachment 32	Recovery of Unrecovered Balance at End of 2010
Attachment 33	TCR Carryover from 2009
Attachment 34	2011 OATT Revenue Credit
Attachment 35	2012 OATT Revenue Credit
Attachment 36	Revenue Requirements in Base Rates
Attachment 37	Deferred Project Amortization
Attachment 38	Red Line of Proposed Tariff
Attachment 39	Clean Version of Proposed Tariff
Attachment 40	Storm Damage Repair Notice Letter
Attachment 41	Percentage of Revenue Basis Analysis
Attachment 42	Cost Recovery Cap Analysis

TRANSMISSION COST RECOVERY RIDER
DESCRIPTION OF ELIGIBLE PROJECTS

This Attachment describes the projects proposed to be included in the 2012 TCR. The descriptions begin with Project 8, because several TCR projects were moved to base rates in either the Company's 2008 test year rate case or the 2011 test year rate case. The projects previously approved as eligible that have been incorporated in base rates are listed at the end of this Attachment.

Transmission and Renewable Projects Previously Approved as Eligible:
In its Order dated June 25, 2009 in Docket No. E002/M-08-1284, the Commission approved TCR cost recovery for the following eligible project under Minn. Stat. 216B.16, Subd. 7B and 216B.1645:

PROJECT 8. Chisago – Apple River Transmission Line

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B and 216B.1645:

PROJECT 11. CapX2020 - Fargo Project

PROJECT 13. CapX2020 - La Crosse Project

PROJECT 14. CapX2020 - Bemidji Project

Eligibility of New Transmission Statute Projects:
Xcel Energy respectfully requests that the Commission approve the following three new Transmission Statute projects for recovery in the TCR rider in 2012.

PROJECT 12. CapX2020 - Brookings Project
Estimated Project Cost: $650 - 800 million (installed cost)

Project Description and Context
The Commission granted a Certificate of Need for the CapX2020 Brookings Project in its Order dated May 22, 2009; it consists of a series of 345 kV segments between the Company's Brookings County Substation in Brookings County, South Dakota and the southeast corner of the Twin Cities area at the proposed new Hampton Substation. The Brookings Project includes an

approximately 30 mile, 345 kV circuit from the Lyon County Substation near Marshall, Minnesota to a new substation southwest of Granite Falls, Minnesota (Hazel Creek Substation), and an approximately 5 mile, 230 kV transmission line from the Hazel Creek Substation to the Company's existing Minnesota Valley Substation on the east side of Granite Falls, Minnesota.

The western-most segment will be a 345 kV circuit between the Brookings County Substation and the Lyon County Substation. As approved in the route permit, this segment will be approximately 59 miles long and constructed in a double circuit configuration by using structures capable of supporting a second circuit in the future.

The segment from Lyon County Substation to the new Hazel Creek Substation and then on to Minnesota Valley Substation near Granite Falls, Minnesota will be approximately 35 miles long and will in part replace an existing 115 kV line. It will also be constructed in a double circuit configuration by using structures capable of supporting a second 345 kV circuit in the future.

The Lyon County – Cedar Mountain segment will consist of a double circuit 345 kV transmission line between the Lyon County Substation and a new substation (Cedar Mountain) in the Franklin, Minnesota area. This segment will be approximately 52 miles long.

The Cedar Mountain - Helena segment of the Project consists of a double circuit 345 kV transmission line between the Cedar Mountain substation and a new substation (Helena Substation) generally in the vicinity of New Prague, Minnesota. This segment of the project will be approximately 69 miles long.

There are two additional 345 kV single circuit segments of the Brookings Project in the far southern part of the Twin Cities metropolitan area. From the Helena Substation, the 345 kV single circuit will continue east to the Lake Marion Substation in Scott County, Minnesota. The new portion of this substation is being called Chub Lake. From the Chub Lake Substation, the 345 kV circuit will continue to the new Hampton Substation. These two segments combined will be approximately 41 miles long and will be constructed using the double circuit compatible configuration with one circuit installed initially.

In the Commission's Order approving the Certificate of Need for the Fargo, La Crosse, and Brookings CapX2020 345 kV projects, the Commission acknowledged there are a number of lower voltage circuits that may be

overloaded once the new 345 kV lines are complete and thus will be in need of upgrade[1]. In addition, due to the nature of the interconnected transmission system, various modifications to substation relay systems may be needed as well. As part of the studies done by MISO for the portfolio of MVP projects, a number of lower voltage upgrades needs were confirmed for the Brookings Project. The table below lists the specific lower voltage upgrades that MISO and or the CapX2020 team have defined for the Brookings Project.

Brookings Lower Voltage Upgrade Requirements
Chub Lake 115/69 kV transformer replacement
Arlington to Green Isle 69 kV upgrade
Lake Marion to NW Market Tap 69 kV uprate
Franklin 115/69 kV transformer replacements
Chub Lake to Burnsville 115 kV line upgrade
Burnsville, AirLake, Faribault Energy Park, Fort Ridgely, Minnesota Valley, Granite Falls and Panther Substation relay upgrades
Chub Lake, Dakota Heights, Kenrick, Ritter Park, Franklin, and Minnesota Valley line termination work

Similar to the need for upgrades on the lower voltage system, the CapX2020 team has identified a few upgrade/addition requirements on the 345 kV system. The following table lists these requirements

Brookings System Requirements
Blue Lake and Prairie Island relay upgrades
Blue Lake to Prairie Island 345 kV line terminations at Hampton Substation
Blue Lake to Wilmarth 345 kV line terminations at Helena Substation

The combined cost for these upgrades is approximately $30 million, and is included as part of the Project cost range estimate listed above. The CapX2020 project team has identified these facilities for completion in 2014.

As stated above, all of the required facilities are necessary for the Brookings Project and as such, these costs are part of the overall cost of the project that the Company and the other CapX2020 owners are reporting to MISO for inclusion in the MVP cost allocation for the project. Similarly, because the cost of these facilities were identified as necessary for the Brookings Project in the approved

[1] See Commission Order at page 19.

Certificate of Need granted the project, the Company will include the Company's portion of the costs for these facilities in future TCR filings as those costs are incurred, again scheduled for 2014.

Efforts to Ensure Lowest Cost to Ratepayers

The CapX2020 group of utilities established a coordinated regional approach to addressing both regional and community reliability needs, and longer-term growth. To ensure cost-effective implementation of the CapX2020 projects (Fargo, Brookings, La Crosse, and Bemidji lines), the Company, through its participation in the CapX2020 Initiative, provided for a prudent means of developing the projects. The CapX2020 Initiative was formed to meet the growing transmission needs of all utilities in the region. By coordinating regional planning, the region's utilities are able to develop complete solutions to regional transmission needs instead of piecemeal solutions that could lead to duplicative transmission facilities being built. Further, by acting as a group, the CapX2020 Utilities obtain improved efficiency in permitting, routing, scheduling, material purchasing and overall project development. Overall, the Company's participation in the initiative allows us to lessen our costs and achieve greater benefits from the projects due to the strength and size of the organization. For example, by working together, the CapX2020 Utilities have been able to develop a comprehensive set of alternatives for improvement of the transmission system, as opposed to crafting piecemeal solutions that would result from individual utility solutions.

In addition, working together within the regulatory environment to jointly file applications for permits in all of the affected jurisdictions allows regulators to more fully understand the scope, benefits and impacts of the projects and not be subjected to numerous separate filings by individual utilities on separate projects that may often times work at cross purposes. The joint approach taken by the Company and the other participating CapX2020 utilities is a prudent way to proceed with developing the projects in order to spread the costs among a broad array of utilities. An investment of approximately $1.8 billion for all of the projects would be difficult for any one utility to undertake. By collaborating with a number of other regional utilities, the Company is able to successfully spread its risks and balance its costs.

Finally, the Company and the participating utilities recognize that there will be benefits arising from a coordinated effort in securing materials and services required to build the CapX2020 projects. As such, a joint sourcing approach is being utilized to pursue benefits in order to minimize or eliminate inter-project

competition for labor and material resources, maximize leverage on vendors and specification standardization, establish a common request for proposal ("RFP") process to present one "CapX2020 face" to the market and eliminate inefficiencies, maximize inter-project flexibility where possible for services. For example, utilizing a joint sourcing process across the projects creates a spend volume asset. This volume consolidation and early RFP activity allows manufactures and suppliers the ability to plan fabrication in advance of the delivery needs. This approach works to avoid the premium costs associated with orders outside of the lead time and typically garners more attractive pricing when the suppliers, manufactures and contractors are able to advance plan their production schedules or field resources.

Project 17. Pleasant Valley – Byron Transmission Line
Estimated Project Cost: $4.4 million (Xcel Energy Share)

Project Description and Context

The Pleasant Valley – Byron 161 kV transmission is 18 miles long and runs from the Byron Substation (owned by Southern Minnesota Municipal Utility Agency) in the City of Byron on the north end to the Pleasant Valley Substation (owned by Great River Energy) in Pleasant Valley Township on the south end. The line is needed for two 100 MW wind farms to deliver their full capacity to the area grid without operating restrictions. A Certificate of Need was granted by the Commission in February of 2011 in Docket No. E002/CN-08-992, and completion of this project is expected in the spring of 2012.

This project is a Generator Interconnection Project ("GIP") as defined by the MISO Tariff. Under the cost allocation tariff in effect for GIP facilities at the time the project was approved by MISO, 50% of the cost of the project is being paid for by the generation projects that required the facilities as part of their interconnection studies. Therefore, the cost listed here is the remaining 50% of the project costs assigned to Xcel Energy under the MISO tariff. These remaining costs have further been afforded RECB cost allocation treatment, again under the then effective MISO tariff, and the net expenses and revenues will be accounted for under Schedule 26 of the MISO tariff.

Efforts to Ensure Lowest Cost to Ratepayers

The Pleasant Valley – Byron project is needed to provide adequate wind outlet capability for the Company's Grand Meadow and enXco Wapsipinicon Wind farms. The project was studied along with several alternatives and it was concluded to be the low cost solution while providing the greatest benefits to the

area. As indicated, the new facilities connect to substations owned by other Minnesota utilities. The coordinated planning and operations under the MISO Tariff allow efficient expansion without duplicative facilities.

Project 19. Glencoe – Waconia 115 kV Transmission
Estimated Project Cost: $29 million

Project Description and Context

The Project entails constructing approximately 2 miles of new 69 kV transmission line, 6 miles of new 115 kV transmission line, and upgrading approximately 20 miles of 69 kV transmission line to 115 kV capacity near the cities of Glencoe, Norwood Young America, and Waconia along with certain substation modifications located in the southwest metro area of the Twin Cities. The Project is located within Carver and McLeod Counties. The *Southwest Twin Cities Load Serving Study Review* identified the need for transmission upgrades in the Glencoe – Waconia area to prevent significant low voltage and line overload conditions. The Commission granted a Certificate of Need for this project on November 14, 2011 in Docket No. E002/CN-09-1390.

Efforts to Ensure Lowest Cost to Ratepayers

The project will take advantage of the available materials and labor contracts that have been negotiated by the corporate sourcing group. These contracts were negotiated with vendors based on Xcel Energy wide needs therefore resulting in best competitive prices. In addition, the schedule of the project will be such to avoid wet areas during the wet seasons in order to take advantage of frozen grounds for transmission line construction.

Eligibility of New Renewable Statute Projects:

Project 18. Buffalo Ridge Restoration
Estimated Project Cost: $37.8 million

Project Description and Context

Sixty four (64) miles of 115kV transmission lines and 30 miles of 34.5 kV wind feeder collector facilities were destroyed as a result of severe storm damage to the Company's transmission system in Pipestone, Lincoln, and Lyon Counties in southwest Minnesota on July 1, 2011. The Company incurred approximate $38 million in unanticipated transmission investment to restore these transmission facilities. Because restoration of the 115 kV lines and the 34.5 kV collector

feeders was needed for renewable wind energy to be delivered from generators on Buffalo Ridge to the Company's load centers, the Company requests cost recovery of the 2012 revenue requirements associated with the $38 million investment, approximately $3.9 million.

These transmission restoration costs were not included in the test year in the Company's 2011 electric rates case. A rapid response and repair effort was undertaken to ensure that renewable wind energy would be curtailed for the shortest time possible and that wind turbines in the area could return to full generation output capacity as promptly as possible. Thus, the Company believes these projects are eligible for recovery under the Renewable Energy Rider.

The restoration project and the $38 million outlay to rebuild these lines is an extraordinary event and not a normal Operation and Maintenance expense. The outlay for the Buffalo Ridge Restoration Project is similar and even larger than many other capital projects needed to transmit power form renewable sources of energy that have been approved by the Commission for cost recovery through the TCR. Indeed, the restoration project rebuilt facilities that some of the BRIGO and 825 Wind Upgrade facilities connect to and without which these wind project facilities can not function for providing wind outlet capacity. The BRIGO and 825 Wind Upgrade facilities were included in the TCR prior to being included in base rates in the Company's 2011 electric rate case. The Company believes the cost of the Buffalo Ridge Restoration project should therefore be recovered in the TCR.

Efforts to Ensure Lowest Cost to Ratepayers

As a result of the need to rapidly restore these lines to service following their damage, the Company created a cross functional team and assigned some of the most experienced personnel proficient in storm damage repair and major project management. In addition, the Company made use of construction crews already mobilized for other transmission project to save on the startup efforts for this restoration. As a result, the Company was able to complete this project on time and for less cost that was expected.

Projects Previously Granted TCR Recovery

In its Order dated March 29, 2007 in Docket No. E002/M-06-1505, the Commission approved TCR cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B and 216B.1645:

PROJECT 1. **825 Wind Upgrade – Main Project**

PROJECT 2. **Yankee Wind Generation Collector Station**

PROJECT 3. **Fenton Wind Generation Collector Station**

PROJECT 4. **Series Capacitor Station**

PROJECT 5. **Nobles County Collector**

PROJECT 6. **Rock County Collector Substation**

In its Order dated March 22, 2008 in Docket No. E002/M-07-1156, the Commission approved TCR cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B and 216B.1645:

PROJECT 7. **BRIGO Transmission Lines**

PROJECT 9. **SF6 Circuit Breakers**

PROJECT 10. **Spare Wind Transformer**

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR cost recovery for the following eligible projects under Minn. Stat. 216B.16, Subd. 7B and 216B.1645:

PROJECT 15. **Blue Lake - Wilmarth - Lakefield Transmission Line**

PROJECT 16. **Nobles Wind Farm Network Upgrade**

Project Implementation Schedule
2012 Transmission Cost Recovery Rider

Project I.D.#	Project Name	Route Permit/Cert. of Need	Design/Engineering/ Procurement	ROW Acquisition	Construction Start	In-Service
Project 12	Brookings – Twin Cities	Certificate of Need 5/22/2009 Route Permit MN 9/14/2010 4/14/2011 Route Permit SD 6/17/2011	On-going	On-going	May 2012	Phase I Lyon County - Cedar Mountain – Helena 4th Qtr 2013 Phase II Helena – Chub Lake – Hampton 4th Qtr 2014 Phase III Brookings – Hazel Creek - Lyon County & Hazel Creek - Minnesota Valley 2nd Qtr 2015
Project 17	Pleasant Valley – Byron	Certificate of Need 2/28/2011	On-going	Complete	April 1, 2011	2nd Qtr 2012
Project 18	Buffalo Ridge Restoration Project	NA	Complete	NA	Complete	October 2011
Project 19	Glencoe – Waconia 115 kV Upgrades	Certificate of Need Nov. 14, 2011; Route Permit Nov.14, 2011	On-going	On-going	August 2012	June 2013

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
TCR Rider Factor Calculation

Expenditures Forecast Through the Year 2016 Only - Total Project Costs Can Be Found On Attachment 1

TCR Project	Function	Eligibility Date	AFUDC Pre-	Pre-Eligible Classification	CWIP Pre-2010	2011	2012	2013	2014	2015	2016	Total	Project Subtotal
TRANSMISSION STATUTE PROJECTS (1)													
BRIGO	Lines	9/1/2007	12,764		40,373,575	2,067	-	-	-	-	-	40,388,406	
BRIGO	Land	9/1/2007	-		892,702	(5,726)	-	-	-	-	-	886,976	
BRIGO	Subs	9/1/2007	-		23,267,120	694	-	-	-	-	-	23,267,813	64,543,196
Chisago Apple River	Lines	2/1/2008	1,647,160	(11,913)	29,572,649	1,707,165	-	-	-	-	-	32,915,061	
Chisago Apple River	Land	2/1/2008			625,257	-	-	-	-	-	-	625,257	
Chisago Apple River	Subs	2/1/2008			14,267,386	1,003,732	-	-	-	-	-	15,271,118	48,811,435
CAPX2020 - Bemidji	Lines	7/1/2009	159,658		4,569,139	12,232,621	13,851,981	292,196	-	-	-	31,105,595	
CAPX2020 - Bemidji	Land	7/1/2009	-		-	1,383,103	61,945	-	-	-	-	1,445,048	
CAPX2020 - Bemidji	Subs	7/1/2009	-		-	-	-	-	-	-	-	-	32,550,643
CAPX2020 - Brookings	Lines	1/1/2012	3,941,948		14,934,600	7,554,001	58,525,400	168,047,100	115,965,701	19,655,800	-	388,624,550	
CAPX2020 - Brookings	Land	1/1/2012	-		781,033	7,419,286	16,779,000	18,313,000	2,748,000	-	-	46,040,320	
CAPX2020 - Brookings	Subs	1/1/2012	6,186		-	275,231	16,102,000	24,188,000	21,435,000	897,000	-	62,903,417	497,568,287
CAPX2020 - La Crosse 1	Lines	5/1/2009	-		-	-	2,656,000	15,795,000	4,338,000	59,967,000	-	82,756,000	
CAPX2020 - La Crosse 1	Land	5/1/2009	-		-	-	2,578,000	-	6,385,000	-	-	8,963,000	
CAPX2020 - La Crosse 1	Subs	5/1/2009	-		-	1,974	7,693,000	15,068,000	1,088,000	-	-	23,850,974	
CAPX2020 - La Crosse 2	Lines	5/1/2009	365,693		9,563,186	3,471,527	8,136,000	42,605,000	71,814,000	29,802,001	-	165,557,408	
CAPX2020 - La Crosse 2	Land	5/1/2009	-		-	-	1,000,000	8,610,000	-	-	-	9,610,000	
CAPX2020 - La Crosse 2	Subs	5/1/2009	-		-	-	174,000	503,000	9,375,000	14,226,000	-	24,278,000	315,015,382
CAPX2020 - Fargo	Lines	5/1/2009	239,382		6,772,395	19,902,226	43,424,000	43,013,000	34,500,000	10,076,000	-	157,927,004	
CAPX2020 - Fargo	Land	5/1/2009	-		2,446,523	7,699,819	7,065,000	102,000	-	-	-	17,313,342	
CAPX2020 - Fargo	Subs	5/1/2009	-		10,544,682	8,892,342	2,074,960	11,515,000	15,599,000	5,909,000	-	54,534,983	229,775,329
Pleasant Valley - Byron	Lines	2/1/2011	597		260,490	1,946,822	1,305,737	-	-	-	-	3,513,646	
Pleasant Valley - Byron	Land	2/1/2011	-		-	924,815	-	-	-	-	-	924,815	
Pleasant Valley - Byron	Subs	2/1/2011	-		-	-	-	-	-	-	-	-	4,438,461
Glencoe - Waconia	Lines	11/1/2011	-		-	-	9,971,500	3,626,000	-	-	-	13,597,500	
Glencoe - Waconia	Land	11/1/2011	-		507,167	447,635	133,700	-	-	-	-	1,088,702	
Glencoe - Waconia	Subs	11/1/2011	-		-	-	2,018,800	563,500	-	-	-	2,582,300	17,268,502
TOTAL TRANSMISSION STATUTE PROJECTS			6,373,388	(11,913)	189,377,904	74,859,535	193,551,023	352,240,796	283,047,701	140,532,801	-	1,209,971,236	1,209,971,235
RENEWABLE STATUTE PROJECTS (2)													
Blue Lake/Wilmarth/Lakefield	Lines	12/1/2009	162,458		1,052,948	18,113	-	-	-	-	-	1,233,519	
Blue Lake/Wilmarth/Lakefield	Subs	11/1/2009	104,504		2,568,396	(834,083)	-	-	-	-	-	1,838,816	3,072,335
Nobles Network Upgrade	Subs	11/1/2010			7,142,566	64,364	-	-	-	-	-	7,206,931	7,206,931
Buffalo Ridge Restoration	Lines	12/1/2011	965,803		-	36,854,973	-	-	-	-	-	37,820,776	37,820,776
TOTAL RENEWABLE STATUTE PROJECTS			1,232,765	-	10,763,910	36,103,368	-	-	-	-	-	48,100,043	48,100,043
GREENHOUSE GAS STATUTE PROJECTS (3)													
SF6 Breaker	Subs	9/1/2007			5,129,166	797,941	2,469,600	19,600	-	-	-	8,416,307	
TOTAL GREENHOUSE GAS STATUTE PROJECTS			-	-	5,129,166	797,941	2,469,600	19,600	-	-	-	8,416,307	8,416,307
TOTAL TCR PROJECT CAPITAL EXPENDITURE PROJECTS			7,606,153	(11,913)	175,270,980	111,760,844	196,020,623	352,260,396	283,047,701	140,532,801	-	1,266,487,585	1,266,487,585

Notes:

(1) Projects recoverable under the Transmission Statute (Minn. Stat. 216B.16, Subd. 7b) include AFUDC through December 2006 with rate recovery beginning January 1, 2007 or the first month of project eligibility.

(2) Projects recoverable under only the Renewable Statute (Minn. Stat. 216B.1645) include AFUDC with rate recovery beginning with the in-service date.

(3) Projects recoverable under the Greenhouse Gas Statute (Minn. Stat. 216B.1637) include AFUDC through August 2007 with rate recovery beginning September 1, 2007, the first month of project eligibility.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider

TCR Projected Tracker Activity for 2012		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
	Beg Balance	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012 Total
Project 7 - BRIGO (1)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 8 - Chisago Apple River (2)		346,770	345,696	344,622	343,548	342,474	341,401	340,327	339,253	338,179	337,105	336,031	334,957	4,090,362
Project 11 - CAPX2020 - Fargo (5)		492,161	542,634	601,040	650,380	693,676	746,279	791,316	819,930	849,193	877,289	899,874	920,497	8,884,268
Project 12 - CAPX2020 - Brookings (6)		298,281	327,263	354,315	382,585	413,982	450,259	505,711	571,068	635,828	722,415	836,286	960,025	6,458,017
Project 13 - CAPX2020 - La Crosse 1 (7)		917	2,727	4,559	7,178	9,803	13,196	19,655	28,074	36,818	47,147	59,787	72,865	302,726
Project 13 - CAPX2020 - La Crosse 2 (7)		114,257	119,787	125,497	131,315	141,338	151,482	157,562	163,554	169,560	175,358	180,948	188,310	1,818,969
Project 14 - CAPX2020 - Bemidji (8)		154,318	169,362	187,656	204,240	218,672	229,730	239,972	249,450	254,559	256,836	258,687	261,736	2,685,218
Project 17 - Pleasant Valley - Byron (12)		21,487	24,110	26,754	28,193	30,320	32,317	32,274	32,207	32,117	32,027	31,937	31,847	355,590
Project 19 - Glencoe - Waconia (20)		10,201	16,102	24,914	34,585	44,745	52,736	57,047	69,671	84,433	92,835	98,902	102,316	688,487
RECB - Schedule 26 (10)		552,215	198,537	94,165	20,637	223,974	306,452	139,674	248,973	(50,719)	(29,311)	166,182	(449,997)	1,420,784
Subtotal Transmission Statute Projects	-	1,990,606	1,746,219	1,763,522	1,802,662	2,118,985	2,323,851	2,283,537	2,522,180	2,349,968	2,511,700	2,868,635	2,422,557	26,704,421
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		327,212	326,065	324,917	323,770	322,622	321,475	320,327	319,180	318,032	316,885	315,737	314,590	3,850,813
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	-	327,212	326,065	324,917	323,770	322,622	321,475	320,327	319,180	318,032	316,885	315,737	314,590	3,850,813
Project 9a - SF6 Breaker Replacement (3)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Greenhouse Gas Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates (14)		(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(179,322)
Rev Requirement Impact of Project 18 Retirement (19)		(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(29,135)	(349,625)
TCR True-up Carryover (15)	(432,253)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(36,021)	(432,253)
Total Expense (16)	$ (432,253)	$ 2,237,718	$ 1,992,184	$ 2,008,339	$ 2,046,331	$ 2,361,507	$ 2,565,226	$ 2,523,765	$ 2,761,260	$ 2,587,900	$ 2,748,485	$ 3,104,272	$ 2,657,047	$ 29,594,035
Revenues (17)		1,900,356	1,712,008	1,776,673	2,339,944	2,457,184	2,781,599	3,147,924	3,049,671	2,598,788	2,544,910	2,550,944	2,755,811	$ 29,615,812
Balance (18)	(432,253)	337,362	617,538	849,205	555,592	459,915	243,542	(380,617)	(669,028)	(679,916)	(476,341)	76,987	(21,777)	$ (21,777)

Notes:

(1) Revenue Requirements calculated for Project 7 for 2012 are included in the 2011 Test Year Rate Case.
(2) Revenue Requirements calculated for Project 8 on Attachment 18.
(3) Revenue Requirements calculated for Project 9a for 2012 are included in the 2011 Test Year Rate Case.
(4) Revenue Requirements for Project Amortizations ended in 2010.
(5) Revenue Requirements calculated for Project 11 on Attachment 21.
(6) Revenue Requirements calculated for Project 12 on Attachment 22.
(7) Revenue Requirements calculated for Project 13 on Attachment 23a & 23b.
(8) Revenue Requirements calculated for Project 14 on Attachment 24.
(9) Revenue Requirements calculated for Project 15 for 2012 are included in the 2011 Test Year Rate Case.
(10) Revenue Requirements calculated for RECB - Schedule 26 on Attachment 27.
(11) Revenue Requirements calculated for Project 16 for 2012 are included in the 2011 Test Year Rate Case.
(12) Revenue Requirements calculated for Project 17 on Attachment 14.
(13) Revenue Requirements calculated for Project 18 on Attachment 15.
(14) Revenue Requirements in Base Rates on Attachment 36.
(15) See Attachment 30 for the calculation of the TCR True-up Carryover.
(16) Total Expense represents the total TCR Forecasted revenue requirements for 2012.
(17) See Attachment 5 for the calculation of revenues collected under this rate adjustment rider. The factors are also shown on Attachment 6.
(18) Balance is the amount over/under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.
(19) Revenue Requirement reduction associated with retirement for Project 18 on Attachment 29.
(20) Revenue Requirements calculated for Project 19 on Attachment 16.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider
2012 Revenue Calculation

	Forecast Revenue (2)					kWh Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors											
2011 TCR Rates (1)		$0.000931	$0.000716	$0.238	$0.000447						
2012 TCR Rates (1)		$0.001368	$0.001052	$0.350	$0.000657						
Jan **2011 Rate**	1,900,356	766,698	67,812	1,057,211	8,635	2,697,760,570	823,520,687	94,709,302	1,760,211,864	19,318,717	4,442,063
Feb **2011 Rate**	1,712,008	652,802	64,613	987,180	7,413	2,451,622,026	701,183,187	90,241,909	1,643,613,369	16,583,561	4,147,815
Mar **2011 Rate**	1,776,673	645,432	66,363	1,057,887	6,991	2,562,931,082	693,267,914	92,685,738	1,761,337,115	15,640,314	4,444,903
Apr	2,339,944	798,182	85,308	1,447,613	8,841	2,316,961,038	583,466,309	81,091,627	1,638,946,486	13,456,615	4,136,038
May	2,457,184	817,123	85,333	1,546,710	8,018	2,441,773,453	597,312,489	81,114,902	1,751,141,363	12,204,699	4,419,173
Jun	2,781,599	1,066,706	88,147	1,619,528	7,218	2,708,116,368	779,756,165	83,790,327	1,833,583,176	10,986,701	4,627,222
Jul	3,147,924	1,291,751	94,723	1,754,055	7,395	3,031,450,298	944,262,695	90,040,501	1,985,890,899	11,256,204	5,011,586
Aug	3,049,671	1,196,770	93,391	1,752,208	7,302	2,958,520,447	874,831,841	88,775,177	1,983,799,625	11,113,804	5,006,308
Sep	2,598,788	910,882	82,665	1,596,817	8,424	2,565,122,088	665,849,324	78,579,354	1,807,871,049	12,822,361	4,562,335
Oct	2,544,910	883,454	78,230	1,573,426	9,800	2,516,466,298	645,799,682	74,363,009	1,781,387,913	14,915,694	4,495,503
Nov	2,550,944	949,658	76,958	1,513,306	11,022	2,497,446,973	694,194,470	73,153,798	1,713,321,832	16,776,873	4,323,731
Dec	2,755,811	1,107,563	87,745	1,548,486	12,017	2,664,471,864	809,621,763	83,408,021	1,753,151,938	18,290,142	4,424,247
Total Jan-Dec	**$ 29,615,812**	**$ 11,087,021**	**$ 971,288**	**$ 17,454,427**	**$ 103,076**	**31,412,642,506**	**8,813,066,528**	**1,011,953,664**	**21,414,256,629**	**173,365,685**	**54,040,924**
Total Apr-Dec	**$ 24,226,775**	**$ 9,022,089**	**$ 772,500**	**$ 14,352,149**	**$ 80,037**	**23,700,328,828**	**6,595,094,739**	**734,316,715**	**16,249,094,282**	**121,823,092**	**41,006,143**

Notes:

(1) 2011 TCR Adjustment Factors by customer group are those approved in Docket E002/M-10-1064 and implemented on November 1, 2011.
2012 TCR Adjustment Factors by customer group are calculated on Attachment 6.

(2) 2012 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2012 State of Minnesota budget sales for 2012 by billing month including Interdepartmental in the Demand Group.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)

Transmission Cost Recovery Rider

2012 TCR Adjustment Factor Calculation

			Customer Groups				
		Retail	Residential	Commercial Non-Demand	Demand	Street Lighting	Total
Transmission Demand Allocator	D10T	100.00%	36.84%	3.57%	59.24%	0.36%	100.00%
Sales Allocator	E99	100.00%	27.51%	3.46%	68.48%	0.55%	100.00%
Group Weighting Factor (1)	**Fixed Ratio**	**1.0000**	**1.3393**	**1.0302**	**0.8651**	**0.6434**	**1.0000**
	MN kWh retail Sales	**23,700,328,828**	6,595,094,739	734,316,715	16,249,094,282	121,823,092	23,700,328,828
	MN kW Demand				41,006,143		
State of Mn Cost per kWh	**Total Sales/Costs**	**$0.001021**					
	MN retail Cost (3)	**$24,204,998**	$9,022,090	$772,501	$14,347,950	$80,038	$24,222,579
		Basis					
TCR Adjustment Factor (2)		**per kWh**	**$0.001368**	**$0.001052**		**$0.000657**	
		per kW			**$0.350**		

Notes:

1) The Group Weighting Factors are calculated by dividing the transmission demand allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand and sales allocation percentages were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-08-1065.

2) The TCR Adjustment Factors by customer group are determined by multiplying each Group Weighting Factor by the average retail cost per kWh. The average retail cost per kWh is calculated by using the Minnesota electric retail cost divided by the annual Minnesota Retail Sales.

3) The Minnesota Retail Cost remaining to be recovered through December 2012 is equal to the total revenue requirements of $29,594,035 less the revenues through March of 2012 $5,389,037 netting to $24,204,998.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider

TCR Projected Tracker Activity for 2013		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
	Beg Balance	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Total
Project 7 - BRIGO (1)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 8 - Chisago Apple River (2)		334,075	333,069	332,062	331,056	330,049	329,043	328,036	327,029	326,023	325,016	324,010	323,003	3,942,472
Project 11 - CAPX2020 - Fargo (5)		964,166	983,344	998,074	1,020,815	1,062,523	1,111,804	1,158,133	1,200,915	1,242,153	1,324,796	1,400,023	1,441,459	13,908,207
Project 12 - CAPX2020 - Brookings (6)		1,097,640	1,233,671	1,369,335	1,492,235	1,621,376	1,769,725	1,938,048	2,097,753	2,251,840	2,403,660	2,549,212	2,727,310	22,551,804
Project 13 - CAPX2020 - La Crosse 1 (7)		93,631	109,885	126,578	143,616	154,473	168,383	182,453	208,180	233,665	248,674	270,088	285,611	2,225,236
Project 13 - CAPX2020 - La Crosse 2 (7)		208,243	218,476	228,750	239,216	257,274	299,925	346,636	385,521	419,957	446,592	496,979	582,814	4,130,381
Project 14 - CAPX2020 - Bemidji (8)		265,895	267,058	267,998	268,744	269,210	269,633	270,058	270,485	270,915	293,345	314,234	311,646	3,339,221
Project 17 - Pleasant Valley - Byron (12)		33,940	33,839	33,738	33,637	33,536	33,435	33,334	33,233	33,132	33,031	32,930	32,829	400,613
Project 19 - Glencoe - Waconia (20)		111,552	123,029	129,630	133,874	132,143	128,874	127,563	126,259	125,838	125,414	124,990	124,566	1,513,733
RECB - Schedule 26 (10)		547,507	(330,168)	(540,667)	(701,008)	(327,372)	(319,307)	(814,008)	(482,877)	(1,126,995)	(863,070)	(418,269)	(2,038,397)	(7,414,634)
Subtotal Transmission Statute Projects	-	**3,656,650**	**2,972,203**	**2,945,498**	**2,962,186**	**3,533,211**	**3,791,513**	**3,570,253**	**4,166,498**	**3,776,527**	**4,337,457**	**5,094,196**	**3,790,842**	**44,597,034**
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		313,676	312,610	311,544	310,478	309,412	308,347	307,281	306,215	305,149	304,083	303,018	301,952	3,693,765
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	-	**313,676**	**312,610**	**311,544**	**310,478**	**309,412**	**308,347**	**307,281**	**306,215**	**305,149**	**304,083**	**303,018**	**301,952**	**3,693,765**
Project 9a - SF6 Breaker Replacement (3)														-
Subtotal Greenhouse Gas Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates (14)		(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(14,943)	(179,322)
Rev Requirement Impact of Project 18 Retirement (19)		(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(26,161)	(313,935)
TCR True-up Carryover (15)	(21,777)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(21,777)
Total Expense (16)	$ (21,777)	$ 3,927,406	$ 3,241,894	$ 3,214,122	$ 3,229,745	$ 3,799,704	$ 4,056,940	$ 3,834,614	$ 4,429,794	$ 4,038,756	$ 4,598,621	$ 5,354,294	$ 4,049,874	$ 47,775,764
Revenues (17)		4,182,770	3,701,510	3,905,253	3,504,754	3,648,470	4,142,783	4,681,318	4,540,576	3,882,289	3,803,746	3,797,989	4,093,382	$ 47,884,840
Balance (18)	(21,777)	(255,364)	(714,981)	(1,406,112)	(1,681,121)	(1,529,887)	(1,615,730)	(2,462,433)	(2,573,216)	(2,416,748)	(1,621,873)	(65,568)	(109,076)	$ (109,076)

Notes:

(1) Revenue Requirements calculated for Project 7 for 2013 are included in the 2011 Test Year Rate Case.
(2) Revenue Requirements calculated for Project 8 on Attachment 10.
(3) Revenue Requirements calculated for Project 9a for 2013 are included in the 2011 Test Year Rate Case.
(4) Revenue Requirements for Project Amortizations ended in 2010.
(5) Revenue Requirements calculated for Project 11 on Attachment 10.
(6) Revenue Requirements calculated for Project 12 on Attachment 10.
(7) Revenue Requirements calculated for Project 13 on Attachment 10.
(8) Revenue Requirements calculated for Project 14 on Attachment 10.
(9) Revenue Requirements calculated for Project 15 for 2013 are included in the 2011 Test Year Rate Case.
(10) Revenue Requirements calculated for RECB - Schedule 26 on Attachment 27.
(11) Revenue Requirements calculated for Project 16 for 2013 are included in the 2011 Test Year Rate Case.
(12) Revenue Requirements calculated for Project 17 on Attachment 10.
(13) Revenue Requirements calculated for Project 18 on Attachment 10.
(14) Revenue Requirements in Base Rates on Attachment 36.
(15) See Attachment 4 for the calculation of the TCR True-up Carryover.
(16) Total Expense represents the total TCR Forecasted revenue requirements for 2013.
(17) See Attachment 8 for the calculation of revenues collected under this rate adjustment rider. The factors are also shown on Attachment 9.
(18) Balance is the amount over/under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.
(19) Revenue Requirement reduction associated with retirement for Project 18 on Attachment 29.
(20) Revenue Requirements calculated for Project 19 on Attachment 10

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider
2013 Revenue Calculation

	Forecast Revenue (2)					Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors 2013 TCR Rates (1)		$0.002028	$0.001560	$0.519	$0.000974						
Jan	4,182,770	1,691,939	149,177	2,322,696	18,958	2,722,773,506	834,289,207	95,626,377	1,773,393,766	19,464,156	4,475,329
Feb	3,701,510	1,426,086	137,146	2,122,091	16,187	2,427,962,377	703,198,165	87,914,022	1,620,230,830	16,619,360	4,088,807
Mar	3,905,253	1,431,489	144,539	2,313,886	15,339	2,580,932,139	705,862,599	92,652,975	1,766,667,895	15,748,670	4,458,355
Apr	3,504,754	1,201,849	127,169	2,162,523	13,213	2,338,812,960	592,627,738	81,518,861	1,651,101,067	13,565,294	4,166,711
May	3,648,470	1,210,107	126,912	2,299,470	11,981	2,446,015,097	596,699,892	81,353,727	1,755,660,907	12,300,571	4,430,578
Jun	4,142,783	1,589,577	131,234	2,411,174	10,798	2,719,972,829	783,815,067	84,124,569	1,840,947,312	11,085,881	4,645,807
Jul	4,681,318	1,920,298	140,906	2,609,058	11,056	3,040,601,052	946,892,702	90,324,078	1,992,033,511	11,350,760	5,027,087
Aug	4,540,576	1,778,025	139,100	2,612,533	10,918	2,971,801,456	876,738,043	89,166,917	1,994,686,801	11,209,696	5,033,783
Sep	3,882,289	1,366,716	123,364	2,379,620	12,589	2,582,783,853	673,923,042	79,079,596	1,816,856,146	12,925,069	4,585,010
Oct	3,803,746	1,314,780	117,066	2,357,267	14,633	2,538,169,030	648,313,621	75,042,252	1,799,789,326	15,023,830	4,541,940
Nov	3,797,989	1,409,560	114,491	2,257,501	16,437	2,508,933,630	695,049,334	73,391,584	1,723,617,159	16,875,554	4,349,713
Dec	4,093,382	1,642,388	130,562	2,302,523	17,909	2,669,929,240	809,856,197	83,693,698	1,757,992,037	18,387,309	4,436,461
Total Jan-Dec	**$ 47,884,840**	**$ 17,982,814**	**$ 1,581,666**	**$ 28,150,342**	**$ 170,018**	**31,548,687,169**	**8,867,265,606**	**1,013,888,655**	**21,492,976,759**	**174,556,149**	**54,239,582**

Notes:

(1) 2013 TCR Adjustment Factors by customer group are calculated on Attachment 9.

(2) 2013 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2012 State of Minnesota budget sales for 2013 by billing month including Interdepartmental in the Demand Group.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider
2013 TCR Adjustment Factor Calculation

			Customer Groups				
		Retail	Residential	Commercial Non-Demand	Demand	Street Lighting	Total
Transmission Demand Allocator	D10T	100.00%	36.84%	3.57%	59.24%	0.36%	100.00%
Sales Allocator	E99	100.00%	27.51%	3.46%	68.48%	0.55%	100.00%
Group Weighting Factor (1)	**Fixed Ratio**	**1.0000**	**1.3393**	**1.0302**	**0.8651**	**0.6434**	**1.0000**
	MN kWh retail Sales	**31,548,687,169**	8,867,265,606	1,013,888,655	21,492,976,759	174,556,149	31,548,687,169
	MN kW Demand				54,239,582		
State of Mn Cost per kWh	**Total Sales/Costs**	**$0.001514**					
	MN retail Cost	**$47,775,764**	$17,982,815	$1,581,666	$28,155,800	$170,018	$47,890,298
		Basis					
TCR Adjustment Factor (2)		**per kWh**	**$0.002028**	**$0.001560**		**$0.000974**	
		per kW			**$0.519**		

Notes:

1) The Group Weighting Factors are calculated by dividing the transmission demand allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand and sales allocation percentages were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-08-1065.

2) The TCR Adjustment Factors by customer group are determined by multiplying each Group Weighting Factor by the average retail cost per kWh. The average retail cost per kWh is calculated by using the Minnesota electric retail cost divided by the annual Minnesota Retail Sales.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)

Attachment 10

TCR Rider Factor Calculation

TCR Projected Tracker Activity for 2010-2013	Actual	Forecast	Forecast	Forecast
	2010	2011	2012	2013
Project 7 - BRIGO	5,127,439	-	-	-
Project 8 - Chisago Apple River	3,124,809	3,958,713	4,090,362	3,942,472
Project 11 - CAPX2020 - Fargo	805,119	3,293,597	8,884,268	13,908,207
Project 12 - CAPX2020 - Brookings	-	-	6,458,017	22,551,804
Project 13 - CAPX2020 - La Crosse 1	-	100	302,726	2,225,236
Project 13 - CAPX2020 - La Crosse 2	795,666	1,131,482	1,818,969	4,130,381
Project 14 - CAPX2020 - Bemidji	280,206	914,579	2,685,218	3,339,221
Project 17 - Pleasant Valley - Byron		(39,237)	355,590	400,613
Project 19 - Glencoe - Waconia		14,658	688,487	1,513,733
RECB - Schedule 26	948,958	3,068,660	1,420,784	(7,414,634)
Subtotal Transmission Statute Projects	**11,082,197**	**12,342,553**	**26,704,421**	**44,597,034**
Project 15 - Blue Lake/Wilmarth/Lakefield	460,988	-	-	-
Project 16 - Nobles Network Upgrade	91,828	-	-	-
Project 18 - Buffalo Ridge Restoration		156,999	3,850,813	3,693,765
Project Amortizations/Expenses	1,363,850	-	-	-
Subtotal Renewable Statute Projects	**1,916,665**	**156,999**	**3,850,813**	**3,693,765**
Project 9a - SF6 Breaker Replacement	286,509	-	-	-
Subtotal Greenhouse Gas Projects	**286,509**	**-**	**-**	**-**
Revenue Requirement in Base Rates	(439,788)	(122,004)	(179,322)	(179,322)
Rev Requirement Impact of Project 18 Retirement	-	(67,146)	(349,625)	(313,935)
TCR True-up Carryover	(4,429,830)	(2,029,342)	(432,253)	(21,777)
Total Expense	$ 8,415,753	$ 10,281,060	$ 29,594,035	$ 47,775,764
Revenues	10,445,095	10,713,313	29,615,812	47,884,840
Balance	(2,029,342)	(432,253)	(21,777)	(109,076)

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Pleasant Valley - Byron													
Rate Base													
Plus CWIP Ending Balance	191,792	(1,238,562)	(1,042,463)	(1,906,345)	(1,381,511)	(1,076,646)	(2,598,026)	(2,420,244)	169,932	1,854,593	2,501,536	2,092,421	2,092,421
Plus Plant In-Service	118,114	118,292	115,489	115,489	115,489	115,489	115,489	115,489	115,489	115,489	115,489	1,040,304	1,040,304
Less Book Depreciation Reserve	3,480	3,740	3,998	4,253	4,508	4,763	5,017	5,272	5,527	5,782	6,036	6,291	6,291
Less Accum Deferred Taxes	5,687	5,861	5,940	5,978	5,908	5,657	5,183	4,523	1,317	(5,845)	(14,879)	(25,929)	(25,929)
End Of Month Rate Base	300,739	(1,129,871)	(936,913)	(1,801,087)	(1,276,438)	(971,576)	(2,492,737)	(2,314,550)	278,576	1,970,145	2,625,867	3,152,363	3,152,363
Average Rate Base (BOM/EOM)	276,564	(414,566)	(1,033,392)	(1,369,000)	(1,538,763)	(1,124,007)	(1,732,157)	(2,403,643)	(1,017,987)	1,124,361	2,298,006	2,889,115	(337,122)
Calculation of Return													
Plus Debt Return	719	(1,078)	(2,687)	(3,559)	(4,001)	(2,922)	(4,504)	(6,249)	(2,647)	2,923	5,975	7,512	(10,518)
Plus Equity Return	1,316	(1,973)	(4,917)	(6,514)	(7,322)	(5,348)	(8,242)	(11,437)	(4,844)	5,350	10,935	13,747	(19,250)
Total Return	2,035	(3,051)	(7,604)	(10,074)	(11,323)	(8,271)	(12,746)	(17,687)	(7,491)	8,273	16,909	21,259	(29,768)
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	135	135	135	135	135	135	135	135	135	135	135	135	1,624
Plus Book Depreciation	260	261	258	255	255	255	255	255	255	255	255	255	3,072
Plus Deferred Taxes	212	173	80	38	(71)	(251)	(473)	(660)	(3,206)	(7,162)	(9,034)	(11,050)	(31,405)
Plus Gross Up for Income Tax	713	(1,570)	(3,551)	(4,635)	(5,094)	(3,517)	(5,331)	(7,394)	(133)	11,115	16,973	21,024	18,600
Less AFUDC	3	0	0	0	0	0	0	0	0	0	0	0	3
Less AFUDC Gross Up for Income Tax	2	0	0	0	0	0	0	0	0	0	0	0	2
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	765	3,998	6,915	11,678
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	1,315	(1,000)	(3,078)	(4,207)	(4,775)	(3,378)	(5,414)	(7,664)	(2,949)	3,577	4,331	3,449	(19,792)
Total Revenue Requirements	3,350	(4,051)	(10,682)	(14,281)	(16,097)	(11,648)	(18,160)	(25,351)	(10,439)	11,851	21,241	24,708	(49,560)
MN Jurisdictional Revenue Requirement	0	(3,004)	(7,922)	(10,590)	(11,937)	(8,638)	(13,467)	(18,800)	(7,742)	8,788	15,752	18,323	(39,234)

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

Pleasant Valley - Byron	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
Rate Base													
Plus CWIP Ending Balance	2,508,856	2,925,291	3,346,822	3,367,757	(10,576)	0	0	0	0	0	0	0	0
Plus Plant In-Service	1,040,304	1,040,304	1,040,304	1,040,304	4,434,476	4,432,246	4,438,461	4,438,461	4,438,461	4,438,461	4,438,461	4,438,461	4,438,461
Less Book Depreciation Reserve	6,546	6,801	7,055	7,310	11,308	19,048	26,792	34,543	42,293	50,044	57,795	65,546	65,546
Less Accum Deferred Taxes	(38,376)	(51,684)	(65,862)	(80,534)	(84,421)	(77,420)	(70,415)	(63,404)	(56,393)	(49,382)	(42,371)	(35,360)	(35,360)
End Of Month Rate Base	3,580,990	4,010,478	4,445,932	4,481,285	4,497,013	4,490,619	4,482,085	4,467,323	4,452,561	4,437,800	4,423,038	4,408,276	4,408,276
Average Rate Base (BOM/EOM)	3,366,676	3,795,734	4,228,205	4,463,609	4,489,149	4,493,816	4,486,352	4,474,704	4,459,942	4,445,180	4,430,419	4,415,657	4,295,787
Calculation of Return													
Plus Debt Return	8,753	9,869	10,993	11,605	11,672	11,684	11,665	11,634	11,596	11,557	11,519	11,481	134,029
Plus Equity Return	16,020	18,061	20,119	21,239	21,361	21,383	21,348	21,292	21,222	21,152	21,081	21,011	245,289
Total Return	24,773	27,930	31,113	32,845	33,033	33,067	33,012	32,926	32,818	32,709	32,600	32,492	379,318
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	1,194	1,194	1,194	1,194	1,194	1,194	1,194	1,194	1,194	1,194	1,194	1,194	14,325
Plus Book Depreciation	255	255	255	255	3,998	7,739	7,744	7,751	7,751	7,751	7,751	7,751	59,254
Plus Deferred Taxes	(12,447)	(13,308)	(14,178)	(14,672)	(3,887)	7,001	7,005	7,011	7,011	7,011	7,011	7,011	(9,431)
Plus Gross Up for Income Tax	24,065	26,388	28,733	30,029	19,058	7,911	7,882	7,836	7,787	7,737	7,688	7,638	182,751
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	8,892	9,978	11,072	11,668	12,548	13,374	13,357	13,329	13,292	13,254	13,217	13,180	147,161
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	4,174	4,551	4,931	5,138	7,815	10,471	10,468	10,463	10,451	10,438	10,426	10,414	99,739
Total Revenue Requirements	28,947	32,481	36,043	37,982	40,848	43,538	43,480	43,390	43,269	43,148	43,027	42,905	479,057
MN Jurisdictional Revenue Requirement	21,487	24,110	26,754	28,193	30,320	32,317	32,274	32,207	32,117	32,027	31,937	31,847	355,590

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Buffalo Ridge Restoration													
Rate Base													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	37,820,776	37,820,776
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	41,714	41,714
Less Accum Deferred Taxes	0	0	0	0	0	0	(3,007)	(19,375)	(49,588)	(85,027)	(122,433)	608,190	608,190
End Of Month Rate Base	0	0	0	0	0	0	3,007	19,375	49,588	85,027	122,433	37,170,873	37,170,873
Average Rate Base (BOM/EOM)	0	0	0	0	0	0	1,504	11,191	34,482	67,308	103,730	18,646,653	1,572,072
Calculation of Return													
Plus Debt Return	0	0	0	0	0	0	4	29	90	175	270	48,481	49,049
Plus Equity Return	0	0	0	0	0	0	7	53	164	320	494	88,727	89,765
Total Return	0	0	0	0	0	0	11	82	254	495	763	137,208	138,814
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	41,714	41,714
Plus Book Depreciation	0	0	0	0	0	0	(3,007)	(16,368)	(30,214)	(35,439)	(37,406)	730,622	608,190
Plus Deferred Taxes	0	0	0	0	0	0	8,302	44,445	82,179	96,659	102,351	(653,527)	(319,592)
Plus Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	44,310	44,310
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	5,294	28,077	51,966	61,220	64,945	74,500	286,003
Total Income Statement Expense	0	0	0	0	0	0	5,305	28,160	52,219	61,715	65,708	211,708	424,816
Total Revenue Requirements	0	0	0	0	0	0	0	0	0	0	0	156,999	156,990
MN Jurisdictional Revenue Requirement													

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
Buffalo Ridge Restoration													
Rate Base													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776	37,820,776
Less Book Depreciation Reserve	125,143	208,572	292,001	375,429	458,858	542,287	625,716	709,145	792,573	876,002	959,431	1,042,860	1,042,860
Less Accum Deferred Taxes	695,874	783,557	871,241	958,925	1,046,609	1,134,293	1,221,977	1,309,661	1,397,345	1,485,029	1,572,713	1,660,397	1,660,397
End Of Month Rate Base	36,999,760	36,828,647	36,657,534	36,486,422	36,315,309	36,144,196	35,973,083	35,801,971	35,630,858	35,459,745	35,288,632	35,117,520	35,117,520
Average Rate Base (BOM/EOM)	37,085,316	36,914,203	36,743,091	36,571,978	36,400,865	36,229,752	36,058,640	35,887,527	35,716,414	35,545,302	35,374,189	35,203,076	36,144,196
Calculation of Return													
Plus Debt Return	96,422	95,977	95,532	95,087	94,642	94,197	93,752	93,308	92,863	92,418	91,973	91,528	1,127,699
Plus Equity Return	176,464	175,650	174,836	174,022	173,207	172,393	171,579	170,765	169,951	169,136	168,322	167,508	2,063,834
Total Return	272,886	271,627	270,368	269,109	267,850	266,591	265,331	264,072	262,813	261,554	260,295	259,036	3,191,533
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	520,792
Plus Book Depreciation	83,429	83,429	83,429	83,429	83,429	83,429	83,429	83,429	83,429	83,429	83,429	83,429	1,001,145
Plus Deferred Taxes	87,684	87,684	87,684	87,684	87,684	87,684	87,684	87,684	87,684	87,684	87,684	87,684	1,052,208
Plus Gross Up for Income Tax	35,445	34,871	34,296	33,722	33,147	32,573	31,998	31,424	30,849	30,275	29,700	29,126	387,424
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	82,017	81,730	81,442	81,154	80,867	80,579	80,291	80,004	79,716	79,428	79,141	78,853	965,220
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	167,940	167,653	167,366	167,080	166,793	166,506	166,219	165,932	165,645	165,358	165,072	164,785	1,996,349
Total Revenue Requirements	440,826	439,280	437,734	436,188	434,642	433,096	431,550	430,005	428,459	426,913	425,367	423,821	5,187,882
MN Jurisdictional Revenue Requirement	327,212	326,065	324,917	323,770	322,622	321,475	320,327	319,180	318,032	316,885	315,737	314,590	3,850,813

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

Glencoe - Waconia	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Rate Base													
Plus CWIP Ending Balance	561,686	647,530	668,699	727,802	757,287	773,696	812,330	839,941	875,557	887,352	918,502	955,002	955,002
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	(1,730)	(1,730)
End Of Month Rate Base	561,686	647,530	668,699	727,802	757,287	773,696	812,330	839,941	875,557	887,352	918,502	956,732	956,732
Average Rate Base (BOM/EOM)	534,426	604,608	658,114	698,250	742,545	765,491	793,013	826,135	857,749	881,455	902,927	937,617	766,861
Calculation of Return													
Plus Debt Return	1,390	1,572	1,711	1,815	1,931	1,990	2,062	2,148	2,230	2,292	2,348	2,438	23,926
Plus Equity Return	2,543	2,877	3,132	3,323	3,533	3,642	3,773	3,931	4,081	4,194	4,296	4,461	43,788
Total Return	3,932	4,449	4,843	5,138	5,464	5,633	5,835	6,079	6,312	6,486	6,644	6,899	67,714
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	(1,730)	(1,730)
Plus Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Gross Up for Income Tax	1,794	2,030	2,210	2,344	2,493	2,570	2,663	2,774	2,880	2,960	3,032	4,921	32,670
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	1,794	2,030	2,210	2,344	2,493	2,570	2,663	2,774	2,880	2,960	3,032	3,191	30,940
Total Revenue Requirements	5,727	6,479	7,052	7,482	7,957	8,203	8,498	8,853	9,192	9,446	9,676	10,090	98,654
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	7,175	7,483	14,658

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

Glencoe - Waconia	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
Rate Base													
Plus CWIP Ending Balance	1,592,402	2,425,702	3,788,202	4,832,102	6,312,002	6,126,716	6,678,334	9,260,634	10,338,634	11,181,210	11,671,800	11,990,300	11,990,300
Plus Plant In-Service	0	0	0	0	0	905,685	902,868	902,868	902,868	1,089,292	1,088,702	1,088,702	1,088,702
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(4,190)	(8,076)	(14,093)	(22,454)	(33,283)	(45,390)	(57,876)	(73,434)	(92,588)	(113,673)	(136,133)	(159,477)	(159,477)
End Of Month Rate Base	1,596,591	2,433,777	3,802,295	4,854,556	6,345,284	7,077,792	7,639,078	10,236,936	11,334,090	12,384,175	12,896,635	13,238,479	13,238,479
Average Rate Base (BOM/EOM)	1,276,662	2,015,184	3,118,036	4,328,425	5,599,920	6,711,538	7,358,435	8,938,007	10,785,513	11,859,132	12,640,405	13,067,557	7,308,234
Calculation of Return													
Plus Debt Return	3,319	5,239	8,107	11,254	14,560	17,450	19,132	23,239	28,042	30,834	32,865	33,976	228,017
Plus Equity Return	6,075	9,589	14,837	20,596	26,646	31,936	35,014	42,530	51,321	56,430	60,147	62,180	417,300
Total Return	9,394	14,828	22,944	31,850	41,206	49,386	54,146	65,769	79,363	87,263	93,012	96,155	645,317
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(2,459)	(3,886)	(6,017)	(8,361)	(10,829)	(12,107)	(12,486)	(15,558)	(19,154)	(21,085)	(22,460)	(23,344)	(157,747)
Plus Gross Up for Income Tax	6,808	10,750	16,638	23,105	29,904	34,947	37,508	45,961	55,850	61,435	65,467	67,808	456,180
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	1,178	2,312	2,309	2,310	2,545	2,778	2,777	16,210
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	4,349	6,864	10,621	14,744	19,075	21,661	22,709	28,093	34,386	37,805	40,230	41,687	282,224
Total Revenue Requirements	13,743	21,693	33,564	46,594	60,281	71,047	76,855	93,862	113,749	125,068	133,242	137,842	927,541
MN Jurisdictional Revenue Requirement	10,201	16,102	24,914	34,585	44,745	52,736	57,047	69,671	84,433	92,835	98,902	102,316	688,487

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

BRIGO	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
Rate Base													
Plus CWIP Ending Balance	266,535	270,001	278,050	278,716	0	0	(11,424)	(11,424)	(11,424)	(11,424)	(11,424)	396	396
Plus Plant In-Service	64,016,005	64,088,818	64,137,294	64,184,016	64,487,646	64,522,550	64,536,948	64,527,445	64,530,292	64,532,772	64,536,665	64,545,765	64,545,765
Less Book Depreciation Reserve	427,050	566,436	705,955	845,576	985,273	1,125,035	1,264,850	1,404,669	1,544,479	1,684,295	1,824,116	1,963,934	1,963,934
Less Accum Deferred Taxes	12,939,311	12,993,197	13,047,133	13,101,109	13,155,114	13,209,144	13,263,195	13,317,246	13,371,295	13,425,345	13,479,397	13,533,449	13,533,449
End Of Month Rate Base	50,916,179	50,799,186	50,662,256	50,516,047	50,347,258	50,188,371	49,997,481	49,794,106	49,603,094	49,411,709	49,221,729	49,048,778	49,048,778
Average Rate Base (BOM/EOM)	51,294,712	50,857,682	50,730,721	50,589,151	50,431,652	50,267,814	50,092,926	49,895,793	49,698,600	49,507,402	49,316,719	49,135,253	50,151,536
Calculation of Return													
Plus Debt Return	133,366	132,230	131,900	131,532	131,122	130,696	130,242	129,729	129,216	128,719	128,223	127,752	1,564,728
Plus Equity Return	244,077	241,998	241,394	240,720	239,971	239,191	238,359	237,421	236,483	235,573	234,665	233,802	2,863,653
Total Return	377,444	374,228	373,294	372,252	371,093	369,887	368,600	367,150	365,699	364,292	362,889	361,554	4,428,381
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	73,929	73,929	73,929	73,929	73,929	73,929	73,929	73,929	73,929	73,929	73,929	73,929	887,149
Plus Book Depreciation	139,281	139,386	139,519	139,621	139,697	139,761	139,815	139,819	139,811	139,815	139,821	139,819	1,676,165
Plus Deferred Taxes	53,845	53,886	53,936	53,976	54,006	54,030	54,050	54,052	54,048	54,050	54,052	54,051	647,982
Plus Gross Up for Income Tax	117,141	115,632	115,154	114,638	114,079	113,504	112,896	112,233	111,574	110,930	110,288	109,679	1,357,749
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	171,826	170,793	170,516	170,196	169,833	169,451	169,040	168,564	168,086	167,625	167,165	166,726	2,029,819
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	212,370	212,040	212,022	211,968	211,879	211,774	211,650	211,468	211,277	211,100	210,925	210,753	2,539,227
Total Revenue Requirements	589,814	586,268	585,316	584,220	582,971	581,661	580,251	578,618	576,975	575,392	573,814	572,307	6,967,607
MN Jurisdictional Revenue Requirement	434,042	431,433	430,732	429,925	429,007	428,042	427,004	425,803	424,594	423,429	422,268	421,158	5,127,439

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

Chisago Apple River	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
Rate Base													
Plus CWIP Ending Balance	25,258,947	29,730,166	29,360,722	29,062,365	28,840,047	24,656,764	21,870,013	23,621,808	28,089,368	19,951,182	20,828,995	9,976,209	9,976,209
Plus Plant In-Service	3,594,622	3,594,622	3,832,876	5,463,121	7,174,635	13,117,005	15,769,806	15,784,194	15,807,816	24,882,373	24,904,315	36,124,329	36,124,329
Less Book Depreciation Reserve	177,934	185,062	192,223	201,213	213,889	235,006	265,513	298,869	332,264	375,578	428,807	494,435	494,435
Less Accum Deferred Taxes	125,685	82,562	44,689	7,530	(26,731)	(50,602)	30,872	206,065	383,522	874,623	1,676,823	2,504,383	2,504,383
End Of Month Rate Base	28,549,950	33,057,164	32,956,687	34,316,744	35,827,524	37,589,365	37,343,434	38,901,068	43,181,398	43,583,354	43,627,680	43,101,720	43,101,720
Average Rate Base (BOM/EOM)	28,035,882	30,803,557	33,006,925	33,636,715	35,072,134	36,708,444	37,466,400	38,122,251	41,041,233	43,382,376	43,605,517	43,364,700	37,020,511
Calculation of Return													
Plus Debt Return	72,893	80,089	85,818	87,455	91,188	95,442	97,413	99,118	106,707	112,794	113,374	112,748	1,155,040
Plus Equity Return	133,404	146,574	157,058	160,055	166,885	174,671	178,278	181,398	195,288	206,428	207,490	206,344	2,113,871
Total Return	206,297	226,663	242,876	247,510	258,072	270,113	275,690	280,516	301,995	319,222	320,864	319,092	3,268,911
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	49,498
Plus Book Depreciation	7,128	7,128	7,160	8,990	12,676	21,118	30,507	33,356	33,396	43,313	53,229	65,628	323,630
Plus Deferred Taxes	(30,313)	(43,123)	(37,873)	(37,159)	(34,261)	(23,871)	81,473	175,193	177,457	491,101	802,200	827,560	2,348,385
Plus Gross Up for Income Tax	125,233	147,631	149,659	151,064	152,963	147,927	42,766	(50,924)	(43,439)	(356,487)	(674,043)	(700,651)	(908,301)
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	43,395	45,629	48,551	51,117	53,970	58,586	66,939	72,901	79,496	96,482	108,415	110,380	835,862
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	62,778	70,133	74,519	75,903	81,532	90,713	91,932	88,849	92,042	85,569	77,096	86,283	977,350
Total Revenue Requirements	269,075	296,796	317,395	323,414	339,605	360,826	367,622	369,365	394,037	404,791	397,960	405,375	4,246,261
MN Jurisdictional Revenue Requirement	198,011	218,411	233,570	237,999	249,914	265,531	270,532	271,814	289,971	297,885	292,857	298,314	3,124,809

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

Chisago Apple River	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Rate Base													
Plus CWIP Ending Balance	10,174,150	10,529,151	10,915,359	11,497,487	8,675,688	(31,258)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Plus Plant In-Service	36,103,953	36,334,299	36,814,450	36,634,848	40,085,747	48,842,692	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435
Less Book Depreciation Reserve	572,416	650,628	729,620	808,939	891,825	988,135	1,094,069	1,199,969	1,305,869	1,411,768	1,517,668	1,623,567	1,623,567
Less Accum Deferred Taxes	2,675,177	2,844,675	3,014,672	3,185,732	3,363,857	3,586,975	3,845,104	4,103,138	4,361,172	4,619,206	4,877,241	5,135,275	5,135,275
End Of Month Rate Base	43,030,509	43,368,147	43,985,517	44,137,664	44,505,753	44,236,324	43,872,262	43,508,328	43,144,394	42,780,460	42,416,526	42,052,593	42,052,593
Average Rate Base (BOM/EOM)	43,066,115	43,199,328	43,676,832	44,061,591	44,321,709	44,371,039	44,054,293	43,690,295	43,326,361	42,962,427	42,598,493	42,234,560	43,463,587
Calculation of Return													
Plus Debt Return	111,972	112,318	113,560	114,560	115,236	115,365	114,541	113,595	112,649	111,702	110,756	109,810	1,356,064
Plus Equity Return	204,923	205,557	207,829	209,660	210,897	211,132	209,625	207,893	206,161	204,430	202,698	200,966	2,481,771
Total Return	316,895	317,875	321,389	324,220	326,134	326,497	324,166	321,488	318,810	316,132	313,454	310,776	3,837,835
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	41,453	41,453	41,453	41,453	41,453	41,453	41,453	41,453	41,453	41,453	41,453	41,453	497,432
Plus Book Depreciation	77,981	78,212	78,992	79,319	82,886	96,310	105,934	105,900	105,900	105,900	105,900	105,900	1,129,132
Plus Deferred Taxes	170,794	169,498	169,997	171,060	178,125	223,119	258,129	258,034	258,034	258,034	258,034	258,034	2,630,892
Plus Gross Up for Income Tax	(29,795)	(28,017)	(26,920)	(26,717)	(33,082)	(78,904)	(115,728)	(116,854)	(118,075)	(119,297)	(120,519)	(121,741)	(935,649)
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	142,700	142,838	143,793	144,320	150,040	157,780	159,198	158,178	157,167	156,156	155,145	154,133	1,821,449
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	117,733	118,308	119,728	120,794	119,341	124,198	130,589	130,355	130,144	129,933	129,723	129,512	1,500,358
Total Revenue Requirements	434,627	436,183	441,117	445,014	445,475	450,695	454,756	451,842	448,954	446,065	443,176	440,288	5,338,192
MN Jurisdictional Revenue Requirement	322,312	323,466	327,125	330,015	330,357	334,228	337,239	335,079	332,936	330,794	328,652	326,510	3,958,713

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

Chisago Apple River	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
Rate Base													
Plus CWIP Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Plus Plant In-Service	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435	48,811,435
Less Book Depreciation Reserve	1,729,467	1,835,367	1,941,266	2,047,166	2,153,065	2,258,965	2,364,865	2,470,764	2,576,664	2,682,563	2,788,463	2,894,363	2,894,363
Less Accum Deferred Taxes	5,205,870	5,276,465	5,347,060	5,417,654	5,488,249	5,558,844	5,629,439	5,700,034	5,770,629	5,841,224	5,911,819	5,982,414	5,982,414
End Of Month Rate Base	41,876,098	41,699,604	41,523,109	41,346,615	41,170,120	40,993,626	40,817,131	40,640,637	40,464,142	40,287,648	40,111,153	39,934,659	39,934,659
Average Rate Base (BOM/EOM)	41,964,345	41,787,851	41,611,356	41,434,862	41,258,367	41,081,873	40,905,378	40,728,884	40,552,389	40,375,895	40,199,400	40,022,906	40,993,626
Calculation of Return													
Plus Debt Return	109,107	108,648	108,190	107,731	107,272	106,813	106,354	105,895	105,436	104,977	104,518	104,060	1,279,001
Plus Equity Return	199,680	198,841	198,001	197,161	196,321	195,481	194,641	193,802	192,962	192,122	191,282	190,442	2,340,736
Total Return	308,788	307,489	306,190	304,892	303,593	302,294	300,995	299,697	298,398	297,099	295,801	294,502	3,619,737
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	56,011	56,011	56,011	56,011	56,011	56,011	56,011	56,011	56,011	56,011	56,011	56,011	672,133
Plus Book Depreciation	105,900	105,900	105,900	105,900	105,900	105,900	105,900	105,900	105,900	105,900	105,900	105,900	1,270,795
Plus Deferred Taxes	70,595	70,595	70,595	70,595	70,595	70,595	70,595	70,595	70,595	70,595	70,595	70,595	847,139
Plus Gross Up for Income Tax	69,393	68,800	68,208	67,615	67,022	66,430	65,837	65,245	64,652	64,059	63,467	62,874	793,603
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	143,511	143,067	142,622	142,178	141,733	141,289	140,844	140,400	139,956	139,511	139,067	138,622	1,692,801
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	158,387	158,239	158,091	157,943	157,795	157,647	157,498	157,350	157,202	157,054	156,906	156,758	1,890,869
Total Revenue Requirements	467,175	465,728	464,281	462,834	461,387	459,941	458,494	457,047	455,600	454,153	452,706	451,260	5,510,607
MN Jurisdictional Revenue Requirement	346,770	345,696	344,622	343,548	342,474	341,401	340,327	339,253	338,179	337,105	336,031	334,957	4,090,362

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
SF6 Breaker													
Rate Base													
Plus CWIP Ending Balance	1,219,790	1,348,533	1,455,423	1,500,957	1,515,946	16,869	20,346	147,851	463,105	1,230,580	1,559,507	1,490,202	1,490,202
Plus Plant In-Service	1,742,985	1,748,063	1,753,336	1,757,125	1,760,787	3,275,799	3,260,229	3,264,028	3,264,479	3,264,479	3,264,480	3,638,965	3,638,965
Less Book Depreciation Reserve	5,658	9,463	13,280	17,107	20,941	26,431	33,556	40,668	47,784	54,901	62,018	69,543	69,543
Less Accum Deferred Taxes	385,325	406,850	428,777	450,646	472,521	505,783	550,560	595,129	639,389	682,769	725,270	770,084	770,084
End Of Month Rate Base	2,571,792	2,680,284	2,766,702	2,790,330	2,783,270	2,760,453	2,696,459	2,776,082	3,040,411	3,757,390	4,036,698	4,289,540	4,289,540
Average Rate Base (BOM/EOM)	2,362,463	2,626,038	2,723,493	2,778,516	2,786,800	2,771,862	2,728,456	2,736,270	2,908,246	3,398,900	3,897,044	4,163,119	2,990,101
Calculation of Return													
Plus Debt Return	6,142	6,828	7,081	7,224	7,246	7,207	7,094	7,114	7,561	8,837	10,132	10,824	93,291
Plus Equity Return	11,241	12,496	12,959	13,221	13,261	13,189	12,983	13,020	13,838	16,173	18,543	19,810	170,735
Total Return	17,384	19,323	20,040	20,445	20,506	20,396	20,077	20,134	21,400	25,010	28,676	30,634	264,026
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	1,978	1,978	1,978	1,978	1,978	1,978	1,978	1,978	1,978	1,978	1,978	1,978	23,742
Plus Book Depreciation	3,779	3,805	3,817	3,827	3,835	5,490	7,125	7,112	7,116	7,117	7,117	7,525	67,664
Plus Deferred Taxes	22,264	21,525	21,927	21,869	21,876	33,261	44,778	44,569	44,260	43,379	42,502	44,813	407,023
Plus Gross Up for Income Tax	(14,847)	(13,207)	(13,291)	(13,046)	(13,026)	(24,725)	(36,654)	(36,414)	(35,521)	(32,972)	(30,402)	(31,874)	(295,978)
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	4,460	4,436	4,388	4,339	4,288	6,359	8,371	8,229	8,113	7,995	7,878	8,288	77,143
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	8,714	9,666	10,044	10,289	10,376	9,645	8,856	9,015	9,721	11,508	13,317	14,156	125,307
Total Revenue Requirements	26,098	28,989	30,084	30,734	30,882	30,042	28,933	29,150	31,121	36,518	41,993	44,789	389,333
MN Jurisdictional Revenue Requirement	19,206	21,333	22,139	22,617	22,726	22,108	21,292	21,451	22,902	26,873	30,902	32,960	286,500

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

CAPX2020 - Fargo	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
Rate Base													
Plus CWIP Ending Balance	4,188,268	4,357,390	4,588,431	4,836,917	5,195,455	5,867,078	6,526,844	7,694,684	12,405,465	15,947,809	16,111,075	17,060,538	17,060,538
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	578,204	2,942,444	2,942,444
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	638	1,923	1,923
Less Accum Deferred Taxes	(87,494)	(95,445)	(102,006)	(108,839)	(116,296)	(125,400)	(135,514)	(146,616)	(160,373)	(179,450)	(161,567)	(106,378)	(106,378)
End Of Month Rate Base	4,275,762	4,452,835	4,690,437	4,945,756	5,311,751	5,992,478	6,662,359	7,841,301	12,565,838	16,127,259	16,850,209	20,107,436	20,107,436
Average Rate Base (BOM/EOM)	4,232,264	4,364,298	4,571,636	4,818,096	5,128,753	5,652,114	6,327,418	7,251,830	10,203,569	14,346,549	16,488,734	18,478,823	8,488,674
Calculation of Return													
Plus Debt Return	11,004	11,347	11,886	12,527	13,335	14,695	16,451	18,855	26,529	37,301	42,871	48,045	264,847
Plus Equity Return	20,139	20,767	21,753	22,926	24,404	26,895	30,108	34,507	48,552	68,266	78,459	87,928	484,703
Total Return	31,142	32,114	33,640	35,453	37,739	41,590	46,559	53,361	75,081	105,567	121,330	135,973	749,550
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	638	1,285	1,923
Plus Deferred Taxes	(6,137)	(7,951)	(6,561)	(6,833)	(7,457)	(9,104)	(10,115)	(11,102)	(13,757)	(19,077)	17,884	55,188	(25,022)
Plus Gross Up for Income Tax	20,489	22,789	22,062	23,168	24,850	28,292	31,593	35,707	48,334	67,688	37,064	5,577	367,614
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	14,352	14,837	15,501	16,335	17,393	19,188	21,479	24,605	34,577	48,611	55,585	62,051	344,516
Total Revenue Requirements	45,495	46,951	49,141	51,788	55,132	60,778	68,038	77,967	109,659	154,178	176,915	198,024	1,094,066
MN Jurisdictional Revenue Requirement	33,479	34,551	36,163	38,111	40,571	44,726	50,069	57,376	80,698	113,459	130,191	145,726	805,119

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

CAPX2020 - Fargo	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Rate Base													
Plus CWIP Ending Balance	18,056,348	19,334,274	20,815,234	23,464,287	24,879,546	28,493,581	30,547,590	33,320,965	36,647,118	41,498,573	40,750,254	43,224,473	43,224,473
Plus Plant In-Service	2,981,773	2,985,191	3,410,986	3,422,557	3,422,557	3,804,789	3,803,466	3,803,466	3,803,466	4,203,466	10,392,900	13,272,895	13,272,895
Less Book Depreciation Reserve	3,262	4,648	6,500	8,830	11,172	13,936	17,120	20,302	23,485	26,667	31,047	37,313	37,313
Less Accum Deferred Taxes	(133,182)	(164,447)	(198,745)	(231,350)	(273,537)	(319,486)	(369,263)	(422,308)	(479,572)	(543,069)	(611,066)	(682,265)	(682,265)
End Of Month Rate Base	21,168,040	22,479,264	24,418,465	27,109,363	28,564,467	32,603,919	34,703,198	37,526,436	40,906,670	46,218,440	51,723,174	57,142,321	57,142,321
Average Rate Base (BOM/EOM)	20,637,738	21,823,652	23,448,864	25,763,914	27,836,915	30,584,193	33,653,558	36,114,817	39,216,553	43,562,555	48,970,807	54,432,747	33,837,193
Calculation of Return													
Plus Debt Return	53,658	56,741	60,967	66,986	72,376	79,519	87,499	93,899	101,963	113,263	127,324	141,525	1,055,720
Plus Equity Return	98,201	103,844	111,578	122,593	132,457	145,530	160,135	171,846	186,605	207,285	233,019	259,009	1,932,104
Total Return	151,859	160,586	172,545	189,579	204,833	225,049	247,634	265,745	288,568	320,548	360,344	400,534	2,987,824
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	3,376	3,376	3,376	3,376	3,376	3,376	3,376	3,376	3,376	3,376	3,376	3,376	40,517
Plus Book Depreciation	1,339	1,385	1,853	2,330	2,342	2,764	3,184	3,182	3,182	3,182	4,379	6,266	35,389
Plus Deferred Taxes	(26,803)	(31,265)	(34,298)	(32,605)	(42,187)	(45,949)	(49,777)	(53,046)	(57,264)	(63,498)	(67,997)	(71,199)	(575,887)
Plus Gross Up for Income Tax	96,759	105,313	113,878	119,915	136,695	149,774	164,003	175,616	190,352	211,332	234,102	255,722	1,953,461
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	74,671	78,810	84,809	93,017	100,227	109,966	120,786	129,129	139,648	154,394	173,860	194,165	1,453,481
Total Revenue Requirements	226,530	239,396	257,354	282,596	305,060	335,014	368,420	394,874	428,216	474,942	534,204	594,699	4,441,305
MN Jurisdictional Revenue Requirement	167,991	177,532	190,849	209,569	226,227	248,441	273,214	292,832	317,558	352,209	396,157	441,019	3,293,597

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

CAPX2020 - Fargo	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
Rate Base													
Plus CWIP Ending Balance	47,906,369	46,158,767	46,868,314	52,234,929	57,524,929	52,462,811	56,003,597	59,652,597	62,408,975	65,755,597	68,009,597	70,850,597	70,850,597
Plus Plant In-Service	13,430,919	21,323,722	26,545,375	26,576,959	26,624,159	37,355,518	37,319,732	37,319,732	38,213,354	38,210,732	38,210,732	38,210,732	38,210,732
Less Book Depreciation Reserve	44,293	59,756	88,930	123,395	157,946	204,247	262,206	320,125	378,045	435,965	493,885	551,805	551,805
Less Accum Deferred Taxes	(767,559)	(848,493)	(917,548)	(989,151)	(1,071,384)	(1,143,778)	(1,204,543)	(1,272,729)	(1,347,667)	(1,428,975)	(1,516,272)	(1,609,103)	(1,609,103)
End Of Month Rate Base	62,060,554	68,271,226	74,242,306	79,677,644	85,062,526	90,757,860	94,265,665	97,924,932	101,591,950	104,959,338	107,242,715	110,118,626	110,118,626
Average Rate Base (BOM/EOM)	59,601,438	65,165,890	71,256,766	76,959,975	82,370,085	87,910,193	92,511,762	96,095,298	99,758,441	103,275,644	106,101,027	108,680,671	87,473,932
Calculation of Return													
Plus Debt Return	154,964	169,431	185,268	200,096	214,162	228,567	240,531	249,848	259,372	268,517	275,863	282,570	2,729,187
Plus Equity Return	283,604	310,081	339,063	366,201	391,944	418,306	440,202	457,253	474,684	491,420	504,864	517,139	4,994,762
Total Return	438,567	479,512	524,331	566,297	606,107	646,873	680,732	707,101	734,056	759,937	780,727	799,709	7,723,948
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	15,231	15,231	15,231	15,231	15,231	15,231	15,231	15,231	15,231	15,231	15,231	15,231	182,768
Plus Book Depreciation	6,981	15,462	29,175	34,465	34,551	46,300	57,959	57,920	57,920	57,920	57,920	57,920	514,493
Plus Deferred Taxes	(85,294)	(80,934)	(69,055)	(71,603)	(82,233)	(72,394)	(60,764)	(68,187)	(74,938)	(81,308)	(87,297)	(92,830)	(926,837)
Plus Gross Up for Income Tax	287,563	301,775	310,050	331,814	360,876	369,390	372,917	392,558	411,779	430,120	445,746	460,080	4,474,668
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	224,480	251,534	285,400	309,906	328,425	358,527	385,342	397,522	409,992	421,962	431,599	440,400	4,245,091
Total Revenue Requirements	663,047	731,047	809,731	876,203	934,532	1,005,400	1,066,075	1,104,624	1,144,048	1,181,898	1,212,326	1,240,109	11,969,039
MN Jurisdictional Revenue Requirement	492,161	542,634	601,040	650,380	693,676	746,279	791,316	819,930	849,193	877,289	899,874	920,497	8,884,268

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
CAPX 2020 - Brookings													
Rate Base													
Plus CWIP Ending Balance	17,707,760	18,032,814	18,534,028	19,068,643	19,434,972	19,854,845	21,437,742	21,309,447	23,928,431	26,824,117	29,726,139	33,277,967	33,277,967
Plus Plant In-Service	748,628	748,634	749,039	749,628	749,628	749,628	749,628	1,634,320	1,634,320	1,634,320	1,634,320	1,634,320	1,634,320
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(247,315)	(260,799)	(272,933)	(282,496)	(298,004)	(313,778)	(329,748)	(345,842)	(362,537)	(380,444)	(399,773)	(420,714)	(420,714)
End Of Month Rate Base	18,703,704	19,042,247	19,555,999	20,100,767	20,482,604	20,918,252	22,517,118	23,289,609	25,925,288	28,838,881	31,760,232	35,333,000	35,333,000
Average Rate Base (BOM/EOM)	18,535,162	18,872,976	19,299,123	19,828,383	20,291,686	20,700,428	21,717,685	22,903,364	24,607,449	27,382,085	30,299,557	33,546,616	23,165,376
Calculation of Return													
Plus Debt Return	48,191	49,070	50,178	51,554	52,758	53,821	56,466	59,549	63,979	71,193	78,779	87,221	722,760
Plus Equity Return	88,196	89,804	91,832	94,350	96,555	98,500	103,340	108,982	117,090	130,293	144,175	159,626	1,322,743
Total Return	136,388	138,874	142,009	145,904	149,313	152,321	159,806	168,531	181,070	201,487	222,954	246,847	2,045,503
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	838	838	838	838	838	838	838	838	838	838	838	838	10,058
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(9,939)	(13,484)	(12,134)	(9,563)	(15,507)	(15,774)	(15,970)	(16,094)	(16,695)	(17,907)	(19,329)	(20,940)	(183,337)
Plus Gross Up for Income Tax	100,331	104,356	109,640	109,276	112,910	115,188	119,307	123,787	131,388	144,355	158,423	174,157	1,503,119
Less AFUDC	110,300	106,812	131,385	133,010	116,329	118,873	120,897	122,396	127,484	137,186	148,522	161,328	1,534,523
Less AFUDC Gross Up for Income Tax	77,829	75,368	92,707	93,854	82,083	83,878	85,306	86,364	89,954	96,800	104,798	113,835	1,082,777
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	(96,899)	(90,469)	(125,748)	(126,313)	(100,171)	(102,500)	(102,028)	(100,229)	(101,908)	(106,700)	(113,388)	(121,108)	(1,287,460)
Total Revenue Requirements	39,489	48,404	16,262	19,591	49,142	49,821	57,778	68,301	79,162	94,787	109,566	125,739	758,043
Total Revenue Requirements MVP Cost Allocation @ 9.1%	39,489	48,404	16,262	19,591	49,142	49,821	57,778	68,301	79,162	94,787	109,566	125,739	758,043
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2011-2012

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
CAPX2020 - Brookings													
Rate Base													
Plus CWIP Ending Balance	36,988,467	40,449,967	43,271,867	35,841,767	39,727,667	44,691,567	53,468,567	60,891,567	69,489,767	76,351,967	91,530,167	106,791,367	106,791,367
Plus Plant In-Service	1,634,320	1,634,320	2,034,320	13,225,320	13,331,320	13,331,320	13,331,320	13,331,320	13,331,320	19,319,320	19,523,320	19,527,320	19,527,320
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(468,717)	(520,118)	(574,289)	(631,471)	(693,461)	(762,756)	(843,199)	(936,377)	(1,042,862)	(1,168,654)	(1,320,397)	(1,500,564)	(1,500,564)
End Of Month Rate Base	39,091,504	42,604,404	45,880,476	49,698,558	53,752,448	58,785,643	67,643,085	75,159,264	83,863,949	96,839,941	112,373,884	127,819,250	127,819,250
Average Rate Base (BOM/EOM)	37,212,252	40,847,954	44,242,440	47,789,517	51,725,503	56,269,045	63,214,364	71,401,174	79,511,606	90,351,945	104,606,912	120,096,567	67,272,440
Calculation of Return													
Plus Debt Return	96,752	106,205	115,030	124,253	134,486	146,300	164,357	185,643	206,730	234,915	271,978	312,251	2,098,900
Plus Equity Return	177,068	194,368	210,520	227,398	246,127	267,747	300,795	339,751	378,343	429,925	497,755	571,459	3,841,256
Total Return	273,820	300,573	325,551	351,651	380,613	414,046	465,152	525,394	585,073	664,840	769,733	883,711	5,940,156
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	22,505
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(48,004)	(51,401)	(54,171)	(57,182)	(61,990)	(69,295)	(80,442)	(93,178)	(106,485)	(125,792)	(151,743)	(180,167)	(1,079,850)
Plus Gross Up for Income Tax	174,157	189,847	204,084	219,080	237,225	259,969	294,717	335,262	376,136	432,327	506,794	587,943	3,817,541
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	128,028	140,321	151,788	163,774	177,110	192,550	216,150	243,959	271,526	308,410	356,927	409,651	2,760,196
Total Revenue Requirements	401,849	440,894	477,339	515,425	557,724	606,596	681,303	769,353	856,599	973,250	1,126,659	1,293,362	8,700,352
Total Revenue Requirements MVP Cost Allocation @ 9.1%	401,849	440,894	477,339	515,425	557,724	606,596	681,303	769,353	856,599	973,250	1,126,659	1,293,362	8,700,352
MN Jurisdictional Revenue Requirement	298,281	327,263	354,315	382,585	413,982	450,259	505,711	571,068	635,828	722,415	836,286	960,025	6,458,017

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
CAPX2020 - La Crosse 1													
Rate Base													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
End Of Month Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0
Average Rate Base (BOM/EOM)	0	0	0	0	0	0	0	0	0	0	0	0	0
Calculation of Return													
Plus Debt Return	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Equity Return	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Return	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue Requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
CAPX2020 - La Crosse 1													
Rate Base													
Plus CWIP Ending Balance	0	0	0	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	0	0	0	(2)	(5)	(9)	(13)	(17)	(21)	(25)	(29)	(32)	(32)
End Of Month Rate Base	0	0	0	1,976	1,980	1,984	1,987	1,991	1,995	1,999	2,003	2,007	2,007
Average Rate Base (BOM/EOM)	0	0	0	988	1,978	1,982	1,986	1,989	1,993	1,997	2,001	2,005	1,410
Calculation of Return													
Plus Debt Return	0	0	0	3	5	5	5	5	5	5	5	5	44
Plus Equity Return	0	0	0	5	9	9	9	9	9	10	10	10	81
Total Return	0	0	0	7	15	15	15	15	15	15	15	15	124
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	0	0	0	(2)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(32)
Plus Gross Up for Income Tax	0	0	0	5	11	11	11	11	11	11	11	11	90
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	3	6	6	6	6	6	6	6	6	47
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	0	0	0	1	1	1	1	1	1	1	1	1	10
Total Revenue Requirements	0	0	0	8	16	16	16	16	16	16	16	16	135
MN Jurisdictional Revenue Requirement	0	0	0	6	12	12	12	12	12	12	12	12	100

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
CAPX2020 - La Crosse 1													
Rate Base													
Plus CWIP Ending Balance	298,974	595,974	899,974	1,204,974	1,510,974	1,817,974	3,125,974	2,740,974	4,148,974	6,103,974	8,260,974	10,350,974	10,350,974
Plus Plant In-Service	0	0	0	250,000	250,000	750,000	750,000	2,578,000	2,578,000	2,578,000	2,578,000	2,578,000	2,578,000
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(105)	(314)	(667)	(1,169)	(1,822)	(2,626)	(4,545)	(8,675)	(15,345)	(25,283)	(39,225)	(57,318)	(57,318)
End Of Month Rate Base	299,079	596,288	900,641	1,456,144	1,762,797	2,570,601	3,880,519	5,327,649	6,742,320	8,707,258	10,878,199	12,986,293	12,986,293
Average Rate Base (BOM/EOM)	150,543	447,684	748,465	1,178,392	1,609,470	2,166,699	3,225,560	4,604,084	6,034,985	7,724,789	9,792,728	11,932,246	4,134,637
Calculation of Return													
Plus Debt Return	391	1,164	1,946	3,064	4,185	5,633	8,386	11,971	15,691	20,084	25,461	31,024	129,001
Plus Equity Return	716	2,130	3,561	5,607	7,658	10,310	15,348	21,908	28,716	36,757	46,597	56,778	236,088
Total Return	1,108	3,294	5,507	8,671	11,843	15,943	23,735	33,878	44,407	56,842	72,058	87,801	365,088
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(72)	(209)	(353)	(502)	(653)	(804)	(1,918)	(4,130)	(6,670)	(9,938)	(13,941)	(18,094)	(57,286)
Plus Gross Up for Income Tax	580	1,718	2,875	4,472	6,073	8,099	12,797	19,693	27,102	36,125	47,173	58,613	225,318
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	380	1,129	1,887	2,970	4,057	5,461	8,134	11,619	15,237	19,512	24,743	30,155	125,283
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	128	380	635	999	1,363	1,834	2,744	3,944	5,194	6,675	8,488	10,364	42,749
Total Revenue Requirements	1,235	3,674	6,142	9,670	13,206	17,777	26,479	37,822	49,601	63,517	80,546	98,166	407,837
MN Jurisdictional Revenue Requirement	917	2,727	4,559	7,178	9,803	13,196	19,655	28,074	36,818	47,147	59,787	72,865	302,726

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
CAPX2020 - La Crosse 2													
Rate Base													
Plus CWIP Ending Balance	7,074,032	7,300,016	7,634,031	7,767,487	8,242,304	5,912,432	8,508,273	8,998,708	9,187,058	9,345,432	9,597,037	9,928,879	9,928,879
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(144,214)	(158,061)	(169,915)	(182,240)	(195,151)	(207,581)	(220,227)	(234,964)	(250,308)	(266,558)	(283,256)	(300,567)	(300,567)
End Of Month Rate Base	7,218,246	7,458,077	7,803,946	7,949,727	8,437,455	6,120,013	8,728,500	9,233,672	9,437,367	9,611,990	9,880,292	10,229,446	10,229,446
Average Rate Base (BOM/EOM)	7,152,075	7,338,162	7,631,012	7,876,836	8,193,591	7,278,734	7,424,256	8,981,086	9,335,519	9,524,678	9,746,141	10,054,869	8,378,080
Calculation of Return													
Plus Debt Return	18,595	19,079	19,841	20,480	21,303	18,925	19,303	23,351	24,272	24,764	25,340	26,143	261,396
Plus Equity Return	34,032	34,917	36,311	37,481	38,988	34,635	35,327	42,735	44,422	45,322	46,375	47,844	478,388
Total Return	52,627	53,997	56,152	57,960	60,291	53,559	54,630	66,086	68,694	70,086	71,715	73,987	739,784
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(11,097)	(13,847)	(11,853)	(12,325)	(12,911)	(12,430)	(12,646)	(14,737)	(15,344)	(16,249)	(16,698)	(17,311)	(167,449)
Plus Gross Up for Income Tax	35,367	38,806	37,749	39,057	40,721	37,156	37,866	45,233	47,044	48,605	49,808	51,472	508,884
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	24,270	24,959	25,896	26,732	27,809	24,727	25,220	30,496	31,700	32,356	33,110	34,161	341,435
Total Revenue Requirements	76,898	78,956	82,047	84,693	88,101	78,286	79,850	96,581	100,394	102,442	104,825	108,148	1,081,219
MN Jurisdictional Revenue Requirement	56,589	58,103	60,378	62,325	64,833	57,610	58,762	71,074	73,879	75,386	77,140	79,585	795,666

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

CAPX2020 - La Crosse 2	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Rate Base													
Plus CWIP Ending Balance	9,992,074	10,135,992	10,346,407	10,718,907	11,021,407	11,323,407	11,624,907	11,925,907	12,266,407	12,644,407	13,022,407	13,400,407	13,400,407
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(318,175)	(337,316)	(357,378)	(376,666)	(397,659)	(419,343)	(441,718)	(464,787)	(488,593)	(513,214)	(538,689)	(565,024)	(565,024)
End Of Month Rate Base	10,310,249	10,473,309	10,703,785	11,095,573	11,419,066	11,742,749	12,066,625	12,390,694	12,755,000	13,157,621	13,561,096	13,965,430	13,965,430
Average Rate Base (BOM/EOM)	10,269,847	10,391,779	10,588,547	10,899,679	11,257,319	11,580,908	11,904,687	12,228,659	12,572,847	12,956,310	13,359,358	13,763,263	11,814,434
Calculation of Return													
Plus Debt Return	26,702	27,019	27,530	28,339	29,269	30,110	30,952	31,795	32,689	33,686	34,734	35,784	368,610
Plus Equity Return	48,867	49,448	50,384	51,864	53,566	55,106	56,646	58,188	59,826	61,650	63,568	65,490	674,604
Total Return	75,569	76,466	77,914	80,203	82,835	85,216	87,599	89,983	92,515	95,337	98,303	101,275	1,043,214
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(17,608)	(19,141)	(20,062)	(19,288)	(20,994)	(21,683)	(22,375)	(23,070)	(23,806)	(24,621)	(25,475)	(26,334)	(264,457)
Plus Gross Up for Income Tax	52,525	54,506	56,110	56,361	59,310	61,103	62,899	64,698	66,608	68,731	70,960	73,197	747,008
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	34,917	35,364	36,048	37,073	38,316	39,420	40,524	41,629	42,803	44,110	45,485	46,862	482,551
Total Revenue Requirements	110,486	111,830	113,962	117,277	121,151	124,636	128,123	131,611	135,318	139,447	143,787	148,137	1,525,766
MN Jurisdictional Revenue Requirement	81,935	82,932	84,512	86,970	89,844	92,428	95,014	97,601	100,349	103,412	106,630	109,856	1,131,482

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
CAPX2020 - La Crosse 2													
Rate Base													
Plus CWIP Ending Balance	14,041,657	14,727,907	15,411,157	16,121,407	16,858,657	17,595,907	18,308,157	19,020,407	19,732,657	20,389,907	21,047,157	15,762,077	15,762,077
Plus Plant In-Service	0	0	0	0	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	6,948,330	6,948,330
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	6,561	6,561
Less Accum Deferred Taxes	(592,506)	(621,417)	(651,806)	(683,704)	(717,171)	(752,243)	(788,902)	(827,131)	(866,938)	(908,276)	(951,098)	(858,424)	(858,424)
End Of Month Rate Base	14,634,163	15,349,324	16,062,963	16,805,111	18,575,828	19,348,150	20,097,059	20,847,538	21,599,595	22,298,183	22,998,255	23,562,270	23,562,270
Average Rate Base (BOM/EOM)	14,299,797	14,991,743	15,706,143	16,434,037	17,690,469	18,961,989	19,722,604	20,472,298	21,223,566	21,948,889	22,648,219	23,280,263	18,948,335
Calculation of Return													
Plus Debt Return	37,179	38,979	40,836	42,728	45,995	49,301	51,279	53,228	55,181	57,067	58,885	60,529	591,188
Plus Equity Return	68,043	71,336	74,735	78,199	84,177	90,227	93,847	97,414	100,989	104,440	107,768	110,775	1,081,950
Total Return	105,223	110,314	115,571	120,927	130,172	139,529	145,125	150,642	156,170	161,507	166,653	171,304	1,673,138
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	6,561	6,561
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	92,674	(293,400)
Plus Deferred Taxes	(27,482)	(28,911)	(30,389)	(31,898)	(33,468)	(35,072)	(36,659)	(38,229)	(39,807)	(41,338)	(42,822)	(16,844)	1,064,248
Plus Gross Up for Income Tax	76,188	79,976	83,890	87,881	93,709	99,622	103,803	107,931	112,071	116,076	119,945	0	0
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	48,706	51,065	53,501	55,983	60,241	64,551	67,145	69,701	72,264	74,738	77,123	82,391	777,408
Total Revenue Requirements	153,928	161,379	169,072	176,910	190,413	204,079	212,270	220,343	228,434	236,245	243,776	253,695	2,450,546
MN Jurisdictional Revenue Requirement	114,257	119,787	125,497	131,315	141,338	151,482	157,562	163,554	169,560	175,358	180,948	188,310	1,818,969

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
CAPX2020 - Bemidji													
Rate Base													
Plus CWIP Ending Balance	2,210,725	2,294,916	2,402,596	2,577,184	2,607,358	2,759,734	2,949,833	3,137,873	3,254,374	3,360,785	3,647,877	4,728,798	4,728,798
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(43,950)	(48,139)	(51,589)	(55,268)	(59,109)	(63,530)	(68,210)	(72,998)	(77,997)	(83,405)	(89,145)	(95,998)	(95,998)
End Of Month Rate Base	2,254,675	2,343,055	2,454,186	2,632,452	2,666,467	2,823,264	3,018,043	3,210,871	3,332,371	3,444,190	3,737,022	4,824,796	4,824,796
Average Rate Base (BOM/EOM)	2,212,086	2,298,865	2,398,620	2,543,319	2,649,460	2,744,865	2,920,654	3,114,457	3,271,621	3,388,280	3,590,606	4,280,909	2,951,145
Calculation of Return													
Plus Debt Return	5,751	5,977	6,236	6,613	6,889	7,137	7,594	8,098	8,506	8,810	9,336	11,130	92,076
Plus Equity Return	10,526	10,939	11,413	12,102	12,607	13,061	13,897	14,820	15,567	16,123	17,085	20,370	168,510
Total Return	16,277	16,916	17,650	18,715	19,496	20,198	21,491	22,917	24,074	24,932	26,421	31,500	260,586
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(3,199)	(4,189)	(3,451)	(3,679)	(3,841)	(4,421)	(4,680)	(4,787)	(4,999)	(5,408)	(5,740)	(6,853)	(55,247)
Plus Gross Up for Income Tax	10,700	12,004	11,584	12,303	12,826	13,739	14,595	15,355	16,100	16,909	17,929	21,385	175,430
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	7,501	7,816	8,133	8,624	8,985	9,318	9,915	10,568	11,100	11,502	12,189	14,532	120,183
Total Revenue Requirements	23,779	24,731	25,783	27,339	28,480	29,516	31,406	33,485	35,174	36,434	38,609	46,032	380,769
MN Jurisdictional Revenue Requirement	17,499	18,200	18,974	20,119	20,959	21,721	23,111	24,641	25,884	26,811	28,413	33,875	280,206

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
CAPX2020 - Bemidji													
Rate Base													
Plus CWIP Ending Balance	6,377,937	5,249,560	6,219,170	8,114,927	7,412,504	7,762,109	9,179,540	11,170,714	11,758,870	12,853,760	14,827,578	18,344,522	18,344,522
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(104,955)	(115,304)	(125,920)	(137,869)	(153,210)	(168,924)	(186,447)	(206,388)	(229,061)	(252,343)	(271,961)	(301,557)	(301,557)
End Of Month Rate Base	6,482,892	5,364,864	6,345,091	8,252,796	7,565,715	7,931,033	9,365,987	11,377,102	11,987,931	13,106,102	15,099,539	18,646,079	18,646,079
Average Rate Base (BOM/EOM)	5,653,844	5,923,878	5,854,978	7,298,944	7,909,255	7,748,374	8,648,510	10,371,544	11,682,517	12,547,017	14,102,821	16,872,809	9,551,207
Calculation of Return													
Plus Debt Return	14,700	15,402	15,223	18,977	20,564	20,146	22,486	26,966	30,375	32,622	36,667	43,869	297,998
Plus Equity Return	26,903	28,188	27,860	34,731	37,635	36,869	41,152	49,351	55,589	59,703	67,106	80,286	545,374
Total Return	41,603	43,590	43,083	53,708	58,199	57,015	63,639	76,317	85,964	92,325	103,773	124,156	843,372
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(8,957)	(10,349)	(10,616)	(11,948)	(15,342)	(15,714)	(17,523)	(19,942)	(22,673)	(23,281)	(19,618)	(29,597)	(205,560)
Plus Gross Up for Income Tax	28,162	30,495	30,537	36,750	42,277	42,118	46,994	55,258	62,458	65,984	67,454	86,980	595,467
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	19,205	20,146	19,921	24,802	26,935	26,404	29,471	35,316	39,785	42,703	47,836	57,383	389,908
Total Revenue Requirements	60,807	63,736	63,004	78,510	85,134	83,419	93,110	111,633	125,749	135,028	151,609	181,539	1,233,279
MN Jurisdictional Revenue Requirement	45,094	47,265	46,723	58,222	63,134	61,862	69,049	82,785	93,254	100,135	112,431	134,626	914,579

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010-2012

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual
CAPX2020 - Bemidji													
Rate Base													
Plus CWIP Ending Balance	18,211,418	20,604,260	22,729,910	24,689,572	26,270,063	27,377,631	28,751,764	29,667,859	29,942,390	30,144,831	30,310,907	30,813,399	30,813,399
Plus Plant In-Service	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048	1,445,048
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(336,273)	(372,474)	(410,234)	(449,573)	(490,687)	(533,591)	(577,823)	(622,846)	(668,579)	(715,025)	(762,166)	(809,965)	(809,965)
End Of Month Rate Base	19,992,740	22,421,783	24,585,193	26,584,194	28,205,799	29,356,271	30,774,636	31,735,753	32,056,017	32,304,905	32,518,121	33,068,413	33,068,413
Average Rate Base (BOM/EOM)	19,319,409	21,207,261	23,503,488	25,584,693	27,394,996	28,781,035	30,065,453	31,255,194	31,895,885	32,180,461	32,411,513	32,793,267	28,032,721
Calculation of Return													
Plus Debt Return	50,230	55,139	61,109	66,520	71,227	74,831	78,170	81,264	82,929	83,669	84,270	85,262	874,621
Plus Equity Return	91,928	100,911	111,837	121,740	130,355	136,950	143,061	148,723	151,771	153,125	154,225	156,041	1,600,668
Total Return	142,159	156,050	172,946	188,261	201,582	211,780	221,232	229,986	234,701	236,795	238,495	241,304	2,475,289
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(34,715)	(36,201)	(37,760)	(39,339)	(41,114)	(42,904)	(44,232)	(45,023)	(45,733)	(46,446)	(47,141)	(47,799)	(508,407)
Plus Gross Up for Income Tax	100,457	108,319	117,627	126,233	134,132	140,620	146,294	151,100	153,979	155,666	157,153	159,110	1,650,690
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	65,742	72,118	79,867	86,894	93,017	97,716	102,062	106,077	108,246	109,219	110,013	111,311	1,142,283
Total Revenue Requirements	207,900	228,168	252,813	275,155	294,599	309,497	323,294	336,063	342,946	346,014	348,507	352,615	3,617,572
MN Jurisdictional Revenue Requirement	154,318	169,362	187,656	204,240	218,672	229,730	239,972	249,450	254,559	256,836	258,687	261,736	2,685,218

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
Blue Lake / Wilmarth / Lakefield													
Rate Base													
Plus CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Plant In-Service	6,044,080	5,066,961	5,235,054	5,283,276	5,284,522	5,486,226	5,462,831	5,462,791	5,462,987	5,463,015	3,909,791	3,906,757	3,906,757
Less Book Depreciation Reserve	42,546	54,737	66,035	77,571	89,162	100,974	112,980	124,961	136,942	148,923	159,191	167,743	167,743
Less Accum Deferred Taxes	707,918	697,481	689,337	680,674	671,886	663,342	655,053	646,738	638,422	630,106	625,803	625,510	625,510
End Of Month Rate Base	5,293,615	4,314,743	4,479,682	4,525,031	4,523,475	4,721,910	4,694,798	4,691,092	4,687,623	4,683,985	3,124,796	3,113,504	3,113,504
Average Rate Base (BOM/EOM)	5,293,246	4,804,179	4,397,213	4,502,357	4,524,253	4,622,692	4,708,354	4,692,945	4,689,357	4,685,804	3,904,391	3,119,150	4,495,328
Calculation of Return													
Plus Debt Return	13,762	12,491	11,433	11,706	11,763	12,019	12,242	12,202	12,192	12,183	10,151	8,110	140,254
Plus Equity Return	25,187	22,860	20,923	21,424	21,528	21,996	22,404	22,331	22,314	22,297	18,578	14,842	256,683
Total Return	38,949	35,351	32,356	33,130	33,291	34,015	34,646	34,532	34,506	34,480	28,730	22,952	396,938
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	6,935	6,935	6,935	6,935	6,935	6,935	6,935	6,935	6,935	6,935	6,935	6,935	83,215
Plus Book Depreciation	13,268	12,191	11,298	11,536	11,591	11,812	12,006	11,981	11,981	11,981	10,268	8,552	138,465
Plus Deferred Taxes	(13,143)	(10,437)	(8,144)	(8,663)	(8,788)	(8,544)	(8,289)	(8,315)	(8,316)	(8,316)	(4,303)	(293)	(95,552)
Plus Gross Up for Income Tax	32,069	27,614	23,859	24,761	24,959	24,871	24,730	24,704	24,693	24,681	17,868	11,046	285,857
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	17,615	16,165	14,958	15,273	15,338	15,587	15,798	15,755	15,747	15,738	13,423	11,097	182,493
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	21,515	20,137	18,989	19,296	19,359	19,488	19,584	19,549	19,546	19,543	17,345	15,142	229,492
Total Revenue Requirements	60,464	55,488	51,345	52,426	52,650	53,503	54,229	54,082	54,052	54,023	46,075	38,093	626,430
MN Jurisdictional Revenue Requirement	44,495	40,833	37,785	38,580	38,745	39,373	39,907	39,798	39,777	39,755	33,907	28,033	460,988

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
Nobles Network Upgrade													
Rate Base													
Plus CWIP Ending Balance	2,306,921	2,612,503	3,652,006	3,984,323	4,715,236	6,313,159	6,744,155	6,721,832	6,960,421	7,108,714	2,546,655	0	0
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	4,581,373	7,142,566	7,142,566
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	4,994	17,773	17,773
Less Accum Deferred Taxes	(18,379)	(23,026)	(27,680)	(33,368)	(39,853)	(48,950)	(59,633)	(70,397)	(81,467)	(93,355)	326,002	1,417,415	1,417,415
End Of Month Rate Base	2,325,300	2,635,529	3,679,686	4,017,691	4,755,089	6,362,108	6,803,789	6,792,229	7,041,889	7,202,069	6,797,032	5,707,378	5,707,378
Average Rate Base (BOM/EOM)	2,168,849	2,480,415	3,157,608	3,848,688	4,386,390	5,558,599	6,582,949	6,798,009	6,917,059	7,121,979	6,999,551	6,252,205	5,189,358
Calculation of Return													
Plus Debt Return	5,639	6,449	8,210	10,007	11,405	14,452	17,116	17,675	17,984	18,517	18,199	16,256	161,908
Plus Equity Return	10,320	11,803	15,025	18,313	20,872	26,450	31,324	32,347	32,914	33,889	33,306	29,750	296,312
Total Return	15,959	18,252	23,235	28,320	32,277	40,902	48,440	50,022	50,898	52,406	51,505	46,006	458,220
Income Statement Items													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	4,994	12,780	17,773
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	419,358	1,091,413	1,432,563
Plus Deferred Taxes	(3,232)	(4,647)	(4,654)	(5,688)	(6,485)	(9,096)	(10,684)	(10,764)	(11,070)	(11,888)	(405,570)	(1,095,701)	(1,256,664)
Plus Gross Up for Income Tax	10,588	13,083	15,364	18,742	21,363	27,970	33,034	33,838	34,551	36,076	0	0	0
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less OATT Credit to retail customers	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	7,357	8,436	10,710	13,054	14,878	18,874	22,350	23,074	23,481	24,188	18,781	8,491	193,672
Total Revenue Requirements	23,316	26,687	33,944	41,374	47,154	59,776	70,789	73,096	74,379	76,594	70,287	54,497	651,893
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	51,724	40,104	91,828

TCR RECB Schedule Detail

2010 Revenue Requirement	Actual **Jan**	Actual **Feb**	Actual **Mar**	Actual **Apr**	Actual **May**	Actual **Jun**	Actual **Jul**	Actual **Aug**	Actual **Sep**	Actual **Oct**	Actual **Nov**	Actual **Dec**	Actual **Total**
Expense	263,032	475,835	409,452	517,901	452,456	655,166	609,608	670,452	685,927	537,385	479,888	488,684	6,245,787
Revenue	(279,126)	(354,528)	(356,061)	(359,115)	(379,930)	(448,840)	(525,869)	(475,176)	(498,873)	(379,380)	(361,835)	(537,528)	(4,956,261)
Total 2010 Rev Requirement	(16,094)	121,307	53,391	158,786	72,526	206,326	83,739	195,276	187,054	158,005	118,053	(48,844)	1,289,526
Demand Allocator - State of MN Jur.	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%	73.5897%
State of MN Rev. Requirements	(11,843)	89,270	39,290	116,850	53,371	151,835	61,624	143,703	137,652	116,275	86,875	(35,944)	948,958

2011 Revenue Requirement	Actual **Jan**	Actual **Feb**	Actual **Mar**	Actual **Apr**	Actual **May**	Actual **Jun**	Actual **Jul**	Actual **Aug**	Actual **Sep**	Actual **Oct**	Actual **Nov**	Forecast **Dec**	Forecast **Total**
Expense	633,852	1,114,629	2,038,539	916,564	1,030,440	1,429,692	1,583,823	1,347,427	1,371,365	1,035,001	942,551	1,279,686	14,723,567
Revenue	(551,534)	(784,060)	(801,596)	(825,073)	(756,834)	(1,013,344)	(1,173,500)	(1,150,305)	(1,065,414)	(829,270)	(833,766)	(800,885)	(10,585,581)
Total 2011 Rev Requirement	82,318	330,569	1,236,943	91,491	273,606	416,348	410,322	197,122	305,950	205,731	108,785	478,801	4,137,986
Demand Allocator - State of MN Jur.	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%	74.1583%
State of MN Rev. Requirements	61,045	245,144	917,296	67,848	202,902	308,757	304,288	146,182	226,888	152,567	80,673	355,070	3,068,660

RECB Expense 2012	Forecast **Jan**	Forecast **Feb**	Forecast **Mar**	Forecast **Apr**	Forecast **May**	Forecast **Jun**	Forecast **Jul**	Forecast **Aug**	Forecast **Sep**	Forecast **Oct**	Forecast **Nov**	Forecast **Dec**	Forecast **Total**
Schedule 26	2,160,294	2,102,113	1,976,903	1,898,990	2,267,039	2,731,639	2,920,470	2,795,615	2,536,710	1,940,921	2,098,924	2,228,709	27,658,327
Schedule 26A	120,156	116,920	109,956	105,622	126,093	151,934	162,437	155,493	141,092	107,954	116,743	123,961	1,538,361
Net RECB Expense	2,280,450	2,219,033	2,086,859	2,004,612	2,393,132	2,883,574	3,082,907	2,951,108	2,677,803	2,048,875	2,215,666	2,352,670	29,196,688

RECB Revenue 2012	Forecast **Jan**	Forecast **Feb**	Forecast **Mar**	Forecast **Apr**	Forecast **May**	Forecast **Jun**	Forecast **Jul**	Forecast **Aug**	Forecast **Sep**	Forecast **Oct**	Forecast **Nov**	Forecast **Dec**	Forecast **Total**
Schedule 26	(977,078)	(1,241,023)	(1,246,389)	(1,257,079)	(1,329,942)	(1,571,161)	(1,840,801)	(1,663,350)	(1,746,302)	(1,328,017)	(1,266,601)	(1,881,612)	(17,349,355)
Schedule 26A	(559,418)	(710,537)	(713,610)	(719,730)	(761,447)	(899,555)	(1,053,935)	(952,337)	(999,830)	(760,345)	(725,182)	(1,077,301)	(9,933,228)
Net RECB Revenue	(1,536,497)	(1,951,560)	(1,959,998)	(1,976,810)	(2,091,389)	(2,470,716)	(2,894,735)	(2,615,687)	(2,746,132)	(2,088,363)	(1,991,782)	(2,958,913)	(27,282,583)
Total 2012 Rev Requirement	743,953	267,473	126,861	27,803	301,742	412,857	188,171	335,421	(68,330)	(39,488)	223,884	(606,244)	1,914,104
Demand Allocator - State of MN Jur.	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%
State of MN Rev. Requirements	552,215	198,537	94,165	20,637	223,974	306,452	139,674	248,973	(50,719)	(29,311)	166,182	(449,997)	1,420,784

TCR RECB Schedule Detail

RECB Expense 2013	Forecast **Jan**	Forecast **Feb**	Forecast **Mar**	Forecast **Apr**	Forecast **May**	Forecast **Jun**	Forecast **Jul**	Forecast **Aug**	Forecast **Sep**	Forecast **Oct**	Forecast **Nov**	Forecast **Dec**	Forecast **Total**
Schedule 26	4,066,922	3,956,013	3,726,547	3,574,878	4,270,659	5,124,791	5,485,491	5,254,679	4,785,460	3,632,135	3,941,670	4,184,387	52,003,652
Schedule 26A	578,813	563,028	530,370	508,784	607,809	729,371	780,706	747,857	681,079	516,933	560,986	595,530	7,401,265
Net RECB Expense	4,645,735	4,519,040	4,256,916	4,083,662	4,878,468	5,854,162	6,266,197	6,002,536	5,466,559	4,149,068	4,502,657	4,779,917	59,404,917

RECB Revenue 2013	Forecast **Jan**	Forecast **Feb**	Forecast **Mar**	Forecast **Apr**	Forecast **May**	Forecast **Jun**	Forecast **Jul**	Forecast **Aug**	Forecast **Sep**	Forecast **Oct**	Forecast **Nov**	Forecast **Dec**	Forecast **Total**
Schedule 26	(2,231,510)	(2,834,321)	(2,846,577)	(2,870,993)	(3,037,401)	(3,588,311)	(4,204,130)	(3,798,858)	(3,988,308)	(3,033,005)	(2,892,738)	(4,297,337)	(39,623,489)
Schedule 26A	(1,676,614)	(2,129,527)	(2,138,736)	(2,157,080)	(2,282,108)	(2,696,027)	(3,158,714)	(2,854,218)	(2,996,559)	(2,278,806)	(2,173,418)	(3,228,744)	(29,770,550)
Net RECB Revenue	(3,908,123)	(4,963,849)	(4,985,313)	(5,028,073)	(5,319,509)	(6,284,338)	(7,362,843)	(6,653,076)	(6,984,867)	(5,311,811)	(5,066,156)	(7,526,081)	(69,394,039)
Total 2013 Rev Requirement	737,611	(444,808)	(728,396)	(944,410)	(441,041)	(430,176)	(1,096,646)	(650,540)	(1,518,308)	(1,162,743)	(563,500)	(2,746,164)	(9,989,122)
Demand Allocator - State of MN Jur.	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%	74.2271%
State of MN Rev. Requirements	547,507	(330,168)	(540,667)	(701,008)	(327,372)	(319,307)	(814,008)	(482,877)	(1,126,995)	(863,070)	(418,269)	(2,038,397)	(7,414,634)

2010 Transmission Demand Allocator	Total	Minnesota Company	Minnesota	N Dakota	S Dakota	Wholesale	WI Co
36 Month Coin Peak Demand - 2010 Billings	100.0000%	83.6422%					16.3578%
12 Month Jurisdictional Demand - 2010 Actual	100.0000%		87.9815%	5.5779%	5.5961%	0.8445%	
2010 State of MN Transmission Demand Factor			73.5897%				

2011 Transmission Demand Allocator	Total	Minnesota Company	Minnesota	N Dakota	S Dakota	Wholesale	WI Co
36 Month Coin Peak Demand - 2011 Billings	100.0000%	83.8019%					16.1981%
12 Month Jurisdictional Demand - 2011 Budget	100.0000%		88.4924%	5.8107%	5.5779%	0.1190%	
2011 State of MN Transmission Demand Factor			74.1583%				

2012 Transmission Demand Allocator	Total	Minnesota Company	Minnesota	N Dakota	S Dakota	Wholesale	WI Co
36 Month Coin Peak Demand - 2012 Billings	100.0000%	83.9899%					16.0101%
12 Month Jurisdictional Demand - 2012 Budget	100.0000%		88.3762%	5.8349%	5.7004%	0.0885%	
2011 State of MN Transmission Demand Factor			74.2271%				

Transmission Cost Recovery
Base Assumptions

Weighted Cost of Capital
Docket No. E002/GR-08-1065

	Rate	Ratio	Weighted Cost
Long Term Debt	6.61%	46.25%	3.06%
Short Term Debt	4.41%	1.28%	0.06%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	10.88%	52.47%	5.71%
Required Rate of Return			8.83%

	Forecast 2012	Forecast 2011
Composite Income Tax Rates		
State of Minnesota Tax rate	9.80%	9.80%
Federal Statutory Tax rate	35.00%	35.00%
Federal Effective Tax Rate (1-State Rate * Fed Rate)	31.57%	31.57%
Total Minnesota Composite Tax Rate	41.3700%	41.3700%
Total Corporate Composite Tax Rate	40.7667%	40.7785%
State of MN Transmission Demand Factor (1)		
36 Month Coincident Peak Demand Allocator	74.2271%	74.1583%
State of Minnesota Retail Demand Allocator	83.9899%	83.8019%
	88.3762%	88.4924%

Transmission Cost Recovery
Base Assumptions

	Forecast 2012	Forecast 2011
Composite Depreciation Rates		
Depreciation Rate - Lines	2.6471%	2.6471%
Depreciation Rate - Substations	2.6161%	2.6161%
Property Tax Rate: MN State Electric Personal Property Tax Rate	1.377%	1.377%
OATT Revenue Credit for Non-Retail Transmission Recovery	23.5000%	25.9300%

Development of the OATT Revenue Credit is shown on Attachments 34 & 35

(1) Calculation of State of Minnesota - Demand Allocators

2011 Transmission Demand Allocator	Total	Minnesota Company	Minnesota	N Dakota	S Dakota	Wholesale	WI Co
36 Month Coin Peak Demand - 2011 Billings	100.0000%	83.8019%					16.1981%
12 Month Jurisdictional Demand - 2011 Budget	100.0000%		88.4924%	5.8107%	5.5779%	0.1190%	
2011 State of MN Transmission Demand Factor			74.1583%				

2012 Transmission Demand Allocator	Total	Minnesota Company	Minnesota	N Dakota	S Dakota	Wholesale	WI Co
36 Month Coin Peak Demand - 2012 Billings	100.0000%	83.9899%					16.0101%
12 Month Jurisdictional Demand - 2012 Budget	100.0000%		88.3762%	5.8349%	5.7004%	0.0885%	
2012 State of MN Transmission Demand Factor			74.2271%				

Xcel Energy
Annual Revenue Requirement
Buffalo Ridge Restoration Retirement Impact
Minnesota Retail Rider Adjustment
($'s)

	Capital Structure	Rate	Ratio	Weighted Cost
(1)	Long Term Debt	6.6100%	46.2500%	3.0600%
(2)	Short Term Debt	4.4100%	1.2800%	0.0600%
(3)	Preferred Stock	0.0000%	0.0000%	0.0000%
(4)	Common Equity	10.8800%	52.4700%	5.7100%
(5)	Required Rate of Return			8.8300%
(6)	Jurisdiction	Minnesota	Federal	Composite
(7)	Jurisdiction State Tax Rate	9.8000%	35.0000%	41.3700%
(8)	Corporate Composite Tax Rate	8.8718%	35.0000%	40.7667%
(9)	Jurisdictional Demand Factor	88.3762%		
(10)	Interchange Demand Factor	83.9899%		
(11)	Composite Demand Factor	74.2271%		
(12)	Property Tax Rate	1.3770%		

		2011 Total Company	2012 Total Company	2013 Total Company	2014 Total Company	2015 Total Company	2016 Total Company
	Rate Base						
(13)	CWIP	-	-	-	-	-	-
(14)	Plant Investment	(6,210,688)	(12,421,378)	(12,421,378)	(12,421,378)	(12,421,378)	(12,421,378)
(15)	Depreciation Reserve	(7,082,529)	(14,329,089)	(14,657,149)	(14,985,211)	(15,313,271)	(15,641,332)
(16)	Accumulated Deferred Taxes	864,643	1,699,707	1,650,395	1,602,567	1,578,231	1,607,673
(17)	Average Rate Base	7,198	208,004	585,376	961,266	1,313,662	1,612,281
	Revenue Requirement Components						
(18)	Debt Return	225	6,490	18,264	29,991	40,986	50,303
(19)	Equity Return	411	11,877	33,425	54,888	75,010	92,061
(20)	Current Income Tax Requirement	(1,724,492)	67,180	62,365	93,822	44,124	12,132
(21)	Book Depreciation	(52,362)	(328,061)	(328,061)	(328,061)	(328,061)	(328,061)
(22)	Annual Deferred Tax	1,729,287	(59,160)	(39,463)	(56,192)	7,521	51,362
(23)	Federal Tax Credits	-	-	-	-	-	-
(24)	State Tax Credits	-	-	-	-	-	-
(25)	Tax Depreciation & Removal Expense	4,182,992	(472,955)	(424,715)	(465,686)	(309,641)	(202,265)
(26)	Avoided Tax Interest	-	-	-	-	-	-
(27)	AFUDC Expenditure	-	-	-	-	-	-
(28)	Property Taxes	-	(171,042)	(171,042)	(171,042)	(171,042)	(171,042)
(29)	Total Revenue Requirements (*)	(46,932)	(472,717)	(424,513)	(376,594)	(331,462)	(293,245)

2011 Minnesota Jurisdiction	2012 Minnesota Jurisdiction	2013 Minnesota Jurisdiction	2014 Minnesota Jurisdiction	2015 Minnesota Jurisdiction	2016 Minnesota Jurisdiction
-	-	-	-	-	-
(4,610,012)	(9,220,026)	(9,220,026)	(9,220,026)	(9,220,026)	(9,220,026)
(5,257,155)	(10,636,065)	(10,879,574)	(11,123,085)	(11,366,594)	(11,610,104)
641,799	1,261,643	1,225,040	1,189,539	1,171,475	1,193,329
5,343	154,395	434,508	713,520	975,093	1,196,749
167	4,817	13,557	22,262	30,423	37,339
305	8,816	24,810	40,742	55,678	68,334
(1,312,350)	51,124	47,460	71,399	33,579	9,233
(38,867)	(243,510)	(243,510)	(243,510)	(243,510)	(243,510)
1,283,599	(43,913)	(29,293)	(41,710)	5,582	38,125
-	-	-	-	-	-
-	-	-	-	-	-
3,104,913	(351,061)	(315,253)	(345,665)	(229,838)	(150,136)
-	-	-	-	-	-
-	-	-	-	-	-
-	(126,960)	(126,960)	(126,960)	(126,960)	(126,960)
(67,146)	(349,625)	(313,935)	(277,777)	(245,208)	(217,440)

* This revenue requirement reduction is needed until retirement is incorporated in actual data.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider

TCR Projected Tracker Activity for 2011		Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
	Beg Balance	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011 Total
Project 7 - BRIGO (1)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 8 - Chisago Apple River (2)		322,312	323,466	327,125	330,015	330,357	334,228	337,239	335,079	332,936	330,794	328,652	326,510	3,958,713
Project 11 - CAPX2020 - Fargo (5)		167,991	177,532	190,849	209,569	226,227	248,441	273,214	292,832	317,558	352,209	396,157	441,019	3,293,597
Project 12 - CAPX2020 - Brookings (6)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 1 (7)		-	-	-	6	12	12	12	12	12	12	12	12	100
Project 13 - CAPX2020 - La Crosse 2 (7)		81,935	82,932	84,512	86,970	89,844	92,428	95,014	97,601	100,349	103,412	106,630	109,856	1,131,482
Project 14 - CAPX2020 - Bemidji (8)		45,094	47,265	46,723	58,222	63,134	61,862	69,049	82,785	93,254	100,135	112,431	134,626	914,579
Project 17 - Pleasant Valley - Byron (12)		-	(3,004)	(7,922)	(10,590)	(11,937)	(8,638)	(13,467)	(18,800)	(7,742)	8,788	15,752	18,323	(39,237)
Project 19 - Glencoe - Waconia (20)		-	-	-	-	-	-	-	-	-	-	7,175	7,483	14,658
RECB - Schedule 26 (10)		61,045	245,144	917,296	67,848	202,902	308,757	304,288	146,182	226,888	152,567	80,673	355,070	3,068,660
Subtotal Transmission Statute Projects	-	678,377	873,335	1,558,582	742,039	900,538	1,037,089	1,065,348	935,691	1,063,255	1,047,916	1,047,482	1,392,899	12,342,553
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		-	-	-	-	-	-	-	-	-	-	-	156,999	156,999
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	-	-	-	-	-	-	-	-	-	-	-	-	156,999	156,999
Project 9a - SF6 Breaker Replacement (3)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Greenhouse Gas Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates (14)		-	(10,235)	(10,235)	(10,235)	(10,235)	(10,235)	(10,235)	(10,235)	(10,235)	(10,235)	(14,943)	(14,943)	(122,004)
Rev Requirement Impact of Project 18 Retirement (19)		-	-	-	-	-	-	-	-	-	-	-	(67,146)	(67,146)
TCR True-up Carryover (15)	(2,029,342)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(169,112)	(2,029,342)
Total Expense (16)	$ (2,029,342)	$ 509,265	$ 693,988	$ 1,379,235	$ 562,692	$ 721,191	$ 857,742	$ 886,001	$ 756,344	$ 883,908	$ 868,569	$ 863,426	$ 1,298,697	$ 10,281,060
Revenues (17)		866,070	721,766	781,150	664,208	690,656	759,178	857,172	973,286	827,198	703,209	995,379	1,874,042	$ 10,713,313
Balance (18)	(2,029,342)	(356,804)	(384,583)	213,503	111,987	142,522	241,086	269,915	52,973	109,684	275,045	143,092	(432,253)	$ (432,253)

Notes:

(1) Revenue Requirements calculated for Project 7 for 2011 are included in the 2011 Test Year Rate Case.
(2) Revenue Requirements calculated for Project 8 on Attachment 18.
(3) Revenue Requirements calculated for Project 9a for 2011 are included in the 2011 Test Year Rate Case.
(4) Revenue Requirements for Project Amortizations ended in 2010.
(5) Revenue Requirements calculated for Project 11 on Attachment 21.
(6) Revenue Requirements calculated for Project 12 on Attachment 22.
(7) Revenue Requirements calculated for Project 13 on Attachment 23a & 23b.
(8) Revenue Requirements calculated for Project 14 on Attachment 24.
(9) Revenue Requirements calculated for Project 15 for 2011 are included in the 2011 Test Year Rate Case.
(10) Revenue Requirements calculated for RECB - Schedule 26 on Attachment 27.
(11) Revenue Requirements calculated for Project 16 for 2011 are included in the 2011 Test Year Rate Case.
(12) Revenue Requirements calculated for Project 17 on Attachment 14.
(13) Revenue Requirements calculated for Project 18 on Attachment 15.
(14) Revenue Requirements in Base Rates on Attachment 36.
(15) See Attachment 32 for the calculation of the TCR True-up Carryover.
(16) Total Expense represents the total TCR Forecasted revenue requirements for 2011.
(17) See Attachment 31 for the calculation of revenues collected under this rate adjustment rider. The factors are also shown on Attachment 31.
(18) Balance is the amount over/under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.
(19) Revenue Requirement reduction associated with retirement for Project 18 on Attachment 29.
(20) Revenue Requirements calculated for Project 19 on Attachment 16.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider
2011 Revenue Calculation

	Forecast Revenue (2)					kWh Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors											
2010 TCR Rates (1)		$0.000390	$0.000300	$0.000252	$0.000187						
2011 TCR Rates (1)		$0.000931	$0.000716	$0.238	$0.000447						
Jan **actual**	866,070	350,471	30,616	481,868	3,115	2,929,416,026	898,559,142	102,005,226	1,912,193,734	16,657,923	
Feb **actual**	721,766	284,368	26,250	408,546	2,603	2,451,717,477	729,121,891	87,469,133	1,621,210,049	13,916,405	
Mar **actual**	781,150	295,555	27,622	455,476	2,497	2,675,822,497	757,758,205	92,127,522	1,812,541,222	13,395,548	
Apr **actual**	664,208	234,463	22,738	404,960	2,047	2,294,893,904	601,163,925	75,799,484	1,606,986,098	10,944,397	
May **actual**	690,656	235,193	22,129	431,400	1,934	2,399,608,184	603,203,992	73,781,819	1,712,282,527	10,339,846	
Jun **actual**	759,178	274,350	22,880	460,230	1,718	2,615,830,406	703,606,642	76,348,666	1,826,700,898	9,174,200	
Jul **actual**	857,172	357,647	24,729	473,219	1,577	2,883,977,354	917,167,714	82,429,313	1,875,947,094	8,433,233	
Aug **actual**	973,286	412,445	15,360	543,792	1,689	3,330,006,858	1,070,494,733	92,073,679	2,158,403,796	9,034,650	
Sep **actual**	827,198	307,635	24,321	493,232	2,009	2,838,731,789	789,198,429	81,077,416	1,957,712,510	10,743,435	
Oct **actual**	703,209	235,016	21,427	444,477	2,289	2,450,875,507	602,883,729	71,425,663	1,764,326,232	12,239,883	
Nov **actual**	995,379	373,845	30,689	587,151	3,694	2,299,921,789	593,167,444	67,467,106	1,625,713,822	13,573,416	1,159,884
Dec **2011/2012 Rate**	1,874,042	749,986	59,543	1,056,390	8,123	2,665,748,917	805,570,066	83,160,351	1,758,845,241	18,173,258	4,438,614
Total Jan-Dec	**$ 10,713,313**	**$ 4,110,974**	**$ 328,304**	**$ 6,240,740**	**$ 33,296**	**31,836,550,708**	**9,071,895,911**	**985,165,378**	**21,632,863,224**	**146,626,194**	**5,598,498**

Notes:

(1) 2010 TCR Adjustment Factors by customer group are those approved in Docket E002/M-09-1048 and implemented on September 1, 2010.
2011 TCR Adjustment Factors by customer group are those approved in Docket E002/M-10-1064 and implemented on November 1, 2011.

(2) 2011 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2012 State of Minnesota budget sales for 2011 by billing month including Interdepartmental in the Demand Group.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider

TCR Projected Tracker Activity for 2010		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
	Beg Balance	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	2010 Total
Project 7 - BRIGO (1)		434,042	431,433	430,732	429,925	429,007	428,042	427,004	425,803	424,594	423,429	422,268	421,158	5,127,439
Project 8 - Chisago Apple River (2)		198,011	218,411	233,570	237,999	249,914	265,531	270,532	271,814	289,971	297,885	292,857	298,314	3,124,809
Project 11 - CAPX2020 - Fargo (5)		33,479	34,551	36,163	38,111	40,571	44,726	50,069	57,376	80,698	113,459	130,191	145,726	805,119
Project 12 - CAPX2020 - Brookings (6)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 1 (7)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 2 (7)		56,589	58,103	60,378	62,325	64,833	57,610	58,762	71,074	73,879	75,386	77,140	79,585	795,666
Project 14 - CAPX2020 - Bemidji (8)		17,499	18,200	18,974	20,119	20,959	21,721	23,111	24,641	25,884	26,811	28,413	33,875	280,206
RECB - Schedule 26 (10)		(11,843)	89,270	39,290	116,850	53,371	151,835	61,624	143,703	137,652	116,275	86,875	(35,944)	948,958
Subtotal Transmission Statute Projects	-	**727,776**	**849,968**	**819,107**	**905,329**	**858,655**	**969,465**	**891,102**	**994,412**	**1,032,678**	**1,053,246**	**1,037,745**	**942,714**	**11,082,197**
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		44,495	40,833	37,785	38,580	38,745	39,373	39,907	39,798	39,777	39,755	33,907	28,033	460,988
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	51,724	40,104	91,828
Project Amortizations/Expenses (4)		113,653	113,653	113,653	113,653	113,653	113,653	113,653	113,653	113,653	113,652	113,652	113,667	1,363,850
Subtotal Renewable Statute Projects	-	**158,149**	**154,487**	**151,438**	**152,233**	**152,398**	**153,026**	**153,560**	**153,452**	**153,430**	**153,407**	**199,282**	**181,804**	**1,916,665**
Project 9a - SF6 Breaker Replacement (3)		19,206	21,333	22,139	22,617	22,726	22,108	21,292	21,451	22,902	26,873	30,902	32,960	286,509
Subtotal Greenhouse Gas Projects	-	**19,206**	**21,333**	**22,139**	**22,617**	**22,726**	**22,108**	**21,292**	**21,451**	**22,902**	**26,873**	**30,902**	**32,960**	**286,509**
Revenue Requirement in Base Rates (12)		(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(36,649)	(439,788)
TCR True-up Carryover (13)	(4,429,830)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(369,152)	(4,429,830)
Total Expense (14)	$ (4,429,830)	$ 499,329	$ 619,986	$ 586,883	$ 674,378	$ 627,977	$ 738,797	$ 660,152	$ 763,513	$ 803,209	$ 827,725	$ 862,128	$ 751,677	$ 8,415,753
Revenues (15)		974,887	845,965	904,374	798,532	745,125	950,277	1,024,350	1,141,977	926,686	683,953	673,218	775,752	$ 10,445,095
Balance (16)	(4,429,830)	(475,558)	(701,538)	(1,019,029)	(1,143,182)	(1,260,330)	(1,471,809)	(1,836,008)	(2,214,471)	(2,337,948)	(2,194,177)	(2,005,267)	(2,029,342)	$ (2,029,342)

Notes:

(1) Revenue Requirements calculated for Project 7 on Attachment 17.
(2) Revenue Requirements calculated for Project 8 on Attachment 18.
(3) Revenue Requirements calculated for Project 9a on Attachment 19.
(4) Revenue Requirements calculated for Project Amortizations on Attachment 3.7
(5) Revenue Requirements calculated for Project 11 on Attachment 21.
(6) Revenue Requirements calculated for Project 12 are not applicable.
(7) Revenue Requirements calculated for Project 13 on Attachment 23a & 23b.
(8) Revenue Requirements calculated for Project 14 on Attachment 24.
(9) Revenue Requirements calculated for Project 15 on Attachment 25.
(10) Revenue Requirements calculated for RECB - Schedule 26 on Attachment 27.
(11) Revenue Requirements calculated for Project 16 on Attachment 26.
(12) Revenue Requirement in Base Rates on Attachment 36.
(13) See Attachment 33 for the calculation of the TCR True-up Carryover.
(14) Total Expense represents the total TCR Forecasted revenue requirements for 2010.
(15) Actual Revenues collected in 2010 under this rate adjustment rider.
(16) Balance is the amount over/under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider

TCR Projected Tracker Activity for 2009		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
	Beg Balance	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	2009 Total
Project 7 - BRIGO		207,750	229,117	255,580	277,821	296,103	316,508	337,925	361,002	373,885	370,201	351,357	313,544	3,690,794
Project 8 - Chisago Apple River		64,836	65,710	67,480	71,095	74,834	79,922	82,430	89,000	100,481	128,670	152,575	173,855	1,150,889
Project 11 - CAPX2020 - Fargo		-	-	-	-	23,924	24,794	25,813	27,086	28,475	29,700	30,843	32,211	222,845
Project 12 - CAPX2020 - Brookings		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 1		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 2		-	-	-	-	38,675	40,427	42,494	45,082	47,507	50,050	52,519	54,639	371,392
Project 14 - CAPX2020 - Bemidji		-	-	-	-	-	-	13,589	14,186	15,344	16,019	16,155	16,762	92,055
RECB - Schedule 26		32,562	38,964	154,763	(37,847)	45,767	52,386	76,108	75,372	94,554	71,995	55,814	40,649	701,089
Subtotal Transmission Statute Projects	-	**305,148**	**333,791**	**477,824**	**311,068**	**479,303**	**514,037**	**578,359**	**611,729**	**660,246**	**666,635**	**659,263**	**631,660**	**6,229,063**
Project 15 - Blue Lake/Wilmarth/Lakefield		-	-	-	-	-	-	-	-	-	-	10,261	28,010	38,272
Project Amortizations/Expenses	-	164,670	164,670	164,670	164,670	164,670	164,670	164,670	164,670	164,670	164,670	164,670	164,670	1,976,040
Subtotal Renewable Statute Projects	-	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**164,670**	**174,931**	**192,680**	**2,014,311**
Project 9a - SF6 Breaker Replacement		11	48	85	112	155	257	3,014	6,895	8,905	10,574	13,303	11,377	54,737
Subtotal Greenhouse Gas Projects	-	**11**	**48**	**85**	**112**	**155**	**257**	**3,014**	**6,895**	**8,905**	**10,574**	**13,303**	**11,377**	**54,737**
Revenue Requirement in Base Rates	-	-	-	-	-	(29,194)	(29,194)	(29,194)	(29,194)	(29,194)	(29,194)	(29,194)	(29,194)	(233,552)
TCR True-up Carryover	1,771,022	147,585	147,585	147,585	147,585	147,585	147,585	147,585	147,585	147,585	147,585	147,585	147,585	1,771,022
Total Expense	$ 1,771,022	$ 617,414	$ 646,095	$ 790,164	$ 623,436	$ 762,519	$ 797,356	$ 864,433	$ 901,685	$ 952,212	$ 960,271	$ 965,888	$ 954,108	$ 9,835,582
Revenues		1,657,593	1,421,283	1,468,316	1,330,869	1,228,366	1,412,414	1,338,758	934,393	921,900	877,300	757,736	916,483	$ 14,265,412
Balance (1)	1,771,022	(1,040,179)	(1,815,367)	(2,493,519)	(3,200,953)	(3,666,799)	(4,281,858)	(4,756,183)	(4,788,891)	(4,758,578)	(4,675,607)	(4,467,455)	(4,429,830)	$ (4,429,830)

Notes:

(1) Balance is the amount over/under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.

Northern States Power, a Minnesota corporation
Transmission Revenue From Others
NSP Revenue Credits for FERC Account 456
2011 Forecast

JDE Account		Description	Total 2011	Not Included in Gross Revenue Requirement	Included in Gross Revenue Requirement	Sch 26
801699	517210.1010	PTP Firm	11,815,125		11,815,125	
801699	517220.1010	PTP Non-Firm	578,637		578,637	
801699	517230.1010	Network	12,798,021		12,798,021	
801699	517231.1010	Network - Whls	3,277,590		3,277,590	
801699	517232.0000	Network - GFA	8,533,405		8,533,405	
801699	517240.1000	Joint Pricing Zone - GRE	31,498,767		31,498,767	
801699	517240.2000	Joint Pricing Zone - SMMPA	1,913,420		1,913,420	
881100	517250.1130	Facilities	152,472		152,472	
801699	517250.1160	Contracts-WPPI	37,440		37,440	
801699	517250.1170	Contracts-UPA	8,040,000		8,040,000	
801699	517250.1190	Contracts-UND	54,973		54,973	
801699	517250.1210	Contracts-Granite Falls	14,181		14,181	
801699	517250.1220	Contracts-EGF	44,843		44,843	
801699	517270.1010	Sch 1 - Sch, Sys Ctrl & D	869,544	869,544		
801699	517271.0000	Sch 1 - Sch, Sys Ctrl & D - W	58,100	58,100		
801699	517272.1000	Sch 1 - Sch, Sys Ctrl & D - GF	169,526	169,526		
200107	517280.1010	Sch 2 - Reactive Supply	8,964,040	8,964,040		
200107	517280.1240	Sch 2 - Reactive Supply	63,492	63,492		
200107	517281.1010	Sch 2 - Reactive Supply - Wh	97,251	97,251		
200107	517282.0000	Sch 2 - Reactive Supply - GF/	322,785	322,785		
801699	517322.0000	Sch 24 - Bal Auth	1,573,146	1,573,146		
801699	517322.1000	Other RTO GFA Revenue	86,608	86,608		
801699	517324.1010	Trans Expansion Plan (Sch 26	10,476,402			10,476,402
801699	517329.1000	Sch 10 - MISO Passthrough	266,474	266,474		
		Totals	101,706,242	12,470,966	78,758,874	10,476,402

Includable Transmission Revenues	78,758,874
2011 Total OATT (Attachment O) Tran Rev Req	303,692,354
OATT Adjustment Factor	25.93%

Northern States Power, a Minnesota corporation
Transmission Revenue From Others
NSP Revenue Credits for FERC Account 456
2012 Forecast

JDE Account		Description	Total 2012	Not Included in Gross Revenue Requirement	Included in Gross Revenue Requirement	Sch 26/26A
801699	517210.1010	PTP Firm	9,013,105		9,013,105	
801699	517220.1010	PTP Non-Firm	382,498		382,498	
801699	517230.1010	Network	13,423,611		13,423,611	
801699	517231.1010	Network - Whls	3,935,394		3,935,394	
801699	517232.0000	Network - GFA	8,476,122		8,476,122	
801699	517240.1000	Joint Pricing Zone - GRE	30,239,229		30,239,229	
801699	517240.2000	Joint Pricing Zone - SMMPA	5,650,883		5,650,883	
881100	517250.1130	Facilities	177,464		177,464	
801699	517250.1160	Contracts-WPPI	37,440		37,440	
801699	517250.1170	Contracts-UPA	8,040,000		8,040,000	
801699	517250.1190	Contracts-UND	55,702		55,702	
801699	517250.1210	Contracts-Granite Falls	14,345		14,345	
801699	517250.1220	Contracts-EGF	45,361		45,361	
801699	517270.1010	Sch 1 - Sch, Sys Ctrl & D	854,783	854,783		
801699	517271.0000	Sch 1 - Sch, Sys Ctrl & D - W	59,213	59,213		
801699	517272.1000	Sch 1 - Sch, Sys Ctrl & D - GI	178,114	178,114		
200107	517280.1010	Sch 2 - Reactive Supply	9,202,534	9,202,534		
200107	517280.1240	Sch 2 - Reactive Supply	126,983	126,983		
200107	517281.1010	Sch 2 - Reactive Supply - Wh	97,006	97,006		
200107	517282.0000	Sch 2 - Reactive Supply - GF/	148,454	148,454		
801699	517322.0000	Sch 24 - Bal Auth	1,516,327	1,516,327		
801699	517322.1000	Other RTO GFA Revenue	143,658	143,658		
801699	517324.1010	Trans Expansion Plan (Sch 26	17,349,355			17,349,355
801699	517324.1010	Trans Expansion Plan (Sch 26	9,933,228			9,933,228
801699	517329.1000	Sch 10 - MISO Passthrough	294,271	294,271		
		Totals	119,395,080	12,621,343	79,491,154	27,282,583

Includable Transmission Revenues	79,491,154
2012 Total OATT (Attachment O) Tran Rev Req	338,329,174
OATT Adjustment Factor	23.50%

TCR Budget Adjustment
Annual Revenue Requirement
2011 Test Year

Rate Analysis	All Projects	TCR Project P11 - 14	TCR Project P15	TCR Project 17	TCR Project 19
State of MN Rev. Requirements	**619,118**	**350,333**	**89,463**	**122,822**	**56,499**
Month Eligible		May-09	Jan-10	Feb-11	Nov-11
Monthly Rev Requirement in Base Rates		29,194	7,455	10,235	4,708

2009 Revenue Requirement in Base Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
TCR Project 11 - 14					29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	233,552
Total 2009 Rev Requirement in Base Rates	-	-	-	-	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	233,552

2010 Revenue Requirement in Base Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
TCR Project 11 - 14	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	29,194	350,328
TCR Project 15	7,455	7,455	7,455	7,455	7,455	7,455	7,455	7,455	7,455	7,455	7,455	7,455	89,460
Total 2010 Rev Requirement in Base Rates	36,649	36,649	36,649	36,649	36,649	36,649	36,649	36,649	36,649	36,649	36,649	36,649	439,788

2011 Revenue Requirement in Base Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
TCR Project 17	-	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	112,587
TCR Project 19	-	-	-	-	-	-	-	-	-	-	4,708	4,708	9,417
Total 2011 Rev Requirement in Base Rates	-	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	14,943	14,943	122,004

2012 Revenue Requirement in Base Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
TCR Project 17	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	10,235	122,822
TCR Project 19	4,708	4,708	4,708	4,708	4,708	4,708	4,708	4,708	4,708	4,708	4,708	4,708	56,499
Total 2011 Rev Requirement in Base Rates	14,943	14,943	14,943	14,943	14,943	14,943	14,943	14,943	14,943	14,943	14,943	14,943	179,322

TCR Budget Adjustment
Annual Revenue Requirement
2009 Test Year

Rate Analysis	All Projects	P11 - P14	P15
Plant Investment	839,559	(103,810)	943,369
Depreciation Reserve	(28,934)	(11,883)	(17,051)
CWIP	25,088,044	25,088,044	-
Accumulated Deferred Taxes	(265,573)	(276,245)	10,672
	25,633,096	24,696,107	936,990
Average Rate Base	25,633,096	24,696,107	936,990
Debt Return	799,753	770,519	29,234
Equity Return	1,417,510	1,365,695	51,816
Current Income Tax Requirement	464,542	458,324	6,218
Book Depreciation	33,756	(346)	34,102
Property Tax	11,778	11,778	-
Annual Deferred Tax	(257,875)	(279,219)	21,344
ITC Flow Thru	-	-	-
Tax Depreciation & Removal Expense	116,800	22,679	94,121
AFUDC Expenditure	1,867,328	1,847,100	20,228
Book Depreciation Cleared to Operating	-	-	-
Avoided Tax Interest	1,449,091	1,433,191	15,900
Total Revenue Requirements	602,136	479,650	122,486
Demand Allocator - State of MN Jur.	73.0394%	73.0394%	73.0394%
State of MN Rev. Requirements	**439,796**	**350,333**	**89,463**

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.6100%	46.2500%	3.0600%
Short Term Debt	4.4100%	1.2800%	0.0600%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.5400%	52.4700%	5.5300%
Required Rate of Return			8.6500%
Tax Rate (MN)	41.3700%		

36 Mo CP Demand	83.8829%
Tran Demand	87.0730%
State of MN Elec Jur	73.0394%

Xcel Energy
Annual Revenue Requirement
Transmission - Pleasant Valley - Byron
2011 Test Year Minnesota Electric Rate Case
$'s

Rate Analysis	Total Company	MN Jurisdiction
Plant Investment	4,120,301	3,055,546
Depreciation Reserve	24,076	17,854
CWIP	142,960	106,017
Accumulated Deferred Taxes	1,462,585	1,084,629
	2,776,600	2,059,080
Average Rate Base	2,776,600	2,059,080
Debt Return	79,688	59,096
Equity Return	158,266	117,368
Current Income Tax Requirement	(2,865,978)	(2,125,361)
Book Depreciation	46,950	34,818
Annual Deferred Tax	2,863,555	2,123,564
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	7,084,181	5,253,509
AFUDC Expenditure	116,860	86,661
Avoided Tax Interest	70,575	52,337
Property Taxes	-	-
Total Revenue Requirements	165,622	122,822

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.0936%	46.8780%	2.8600%
Short Term Debt	2.4326%	0.5604%	0.0100%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.8500%	52.5616%	5.7000%
Required Rate of Return			8.5700%
Tax Rate (MN)	41.3700%		
MN Jur Demand after IA		74.1583%	

Xcel Energy
Annual Revenue Requirement
Transmission - Glencoe - Waconia
2011 Test Year Minnesota Electric Rate Case
$'s

Rate Analysis	Total Company	MN Jurisdiction
Plant Investment	3,047,605	2,260,052
Depreciation Reserve	(83,220)	(61,715)
CWIP	4,689,328	3,477,526
Accumulated Deferred Taxes	573,904	425,597
	7,246,249	5,373,696
Average Rate Base	7,246,249	5,373,696
Debt Return	207,967	154,225
Equity Return	413,036	306,301
Current Income Tax Requirement	(1,048,871)	(777,825)
Book Depreciation	6,640	4,924
Annual Deferred Tax	1,150,598	853,264
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	2,794,180	2,072,117
AFUDC Expenditure	653,183	484,390
Avoided Tax Interest	390,618	289,675
Property Taxes	-	-
Total Revenue Requirements	76,187	56,499

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.0936%	46.8780%	2.8600%
Short Term Debt	2.4326%	0.5604%	0.0100%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	10.8500%	52.5616%	5.7000%
Required Rate of Return			8.5700%
Tax Rate (MN)	41.3700%		
MN Jur Demand after IA		74.1583%	

TRANSMISSION COST RECOVERY RIDER
RCR DEFERRED PROJECT EXPENDITURE SUMMARY

Total Project Cost Estimates for Upgrades on Other Utilities' Systems

					Approved Estimated Total Project Costs	Actual					
Deferred Accounting Requested in Docket No. E002/M-06-411											
Project Number	**Parent Project**	**Project Description**	**Utility**	**Estimated In-Service Month**	**Total**	**Project To Date Actuals July 2010**	**Remaining Forecast**	**Actual**	**Amount Over/(Under) Original Estimate**	**MN Jur Demand Allocator (1)**	**MN Jur Portion of Project Costs**
15	Split Rock to Lakefield Jct 345	Lakefield Jct substation - 345 improvements	Alliant	Mar-08	$ 1,556,446	$ 1,556,446	$ -	$ 1,556,446	$ -	73.7765%	$ 1,148,291
16	WAPA White	WAPA White substation (WAPA's ownership)	WAPA	Nov-07	$ 3,997,952	$ 3,997,952	$ -	$ 3,997,952	$ -	73.6191%	$ 2,943,258
		Subtotal 2006 Projects			**$ 5,554,398**	**$ 5,554,398**	**$ -**	**$ 5,554,398**	**$ -**		**$ 4,091,549**
Deferred Accounting Approved in Docket No. E002/M-05-289 and Supplemented in E002/M-06-411											
14	Fox Lake to Lakefield Jct	Fox Lake and Lakefield Junction Substation Improvements	Alliant	2006	$ 2,489,420	$ 2,489,420	$ -	$ 2,489,420	$ -	73.7750%	$ 1,836,570
		Subtotal 2005 Alliant Project Estimate			**$ 2,489,420**	**$ 2,489,420**	**$ -**	**$ 2,489,420**	**$ -**		**$ 1,836,570**
		Total All RCR Deferred Projects			**$ 8,043,817**	**$ 8,043,817**	**$ -**	**$ 8,043,817**	**$ -**		**$ 5,928,119**

NOTES:

(1) Calculation of State of Minnesota - Demand Allocators

The State of Minnesota portion of the total project costs were determined in the year the project expenditures were incurred. Therefore, demand allocators shown here reflect a composite of the total State of Minnesota portion as a percentage of the total project costs.

TRANSMISSION COST RECOVERY RIDER
RCR DEFERRED PROJECT AMORTIZATIONS

	RCR Project 14 Fox Lake to Lakefield Juncation	RCR Project 16 WAPA White Substation	RCR Project 15 Split Rock to Lakefield Jct 345
Actual Project Total	$ 2,489,420	$ 3,997,952	$ 1,556,446
State of MN Demand Allocator (1)	73.7750%	73.6191%	73.7765%
State of MN Portion	$ 1,836,570	$ 2,943,258	$ 1,148,291
Months of Amortization	36	36	36
Monthly Amortization	$ 51,016	$ 81,757	$ 31,897
Beginning Month of Amortization	Jan-07	Jan-08	Jan-08
Ending Month of Amortization	Dec-09	Dec-10	Dec-10

NOTES:

(1) Calculation of State of Minnesota - Demand Allocators

The State of Minnesota portion of the total project costs were determined in the year the project expenditures were incurred. Therefore, demand allocators shown here reflect a composite of the total State of Minnesota portion as a percentage of the total project costs.

Redline

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PROPOSED

TRANSMISSION COST RECOVERY RIDER

Section No. 5
~~5th~~6th Revised Sheet No. 144

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax. ~~N~~ ~~N~~

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following four customer groups: (1) Residential, (2) Commercial Non-Demand, (3) Demand Billed, and (4) Street Lighting. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW. ~~N~~ ~~N~~ ~~N~~ ~~N~~

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Minnesota Public Utilities Commission. The TCR factor for each rate schedule is:

Residential	~~$0.000931~~$0.001368 per kWh	R
Commercial (Non-Demand)	~~$0.000716~~$0.001052 per kWh	R
Demand Billed	~~$0.238~~$0.350 per kW	R~~N~~
Street Lighting	~~$0.000447~~$0.000657 per kWh	R

Recoverable Transmission Costs shall be the annual revenue requirements for transmission costs associated with transmission projects eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period. ~~N~~

(Continued on Sheet No. 5-145)

Clean

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following four customer groups: (1) Residential, (2) Commercial Non-Demand, (3) Demand Billed, and (4) Street Lighting. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Minnesota Public Utilities Commission. The TCR factor for each rate schedule is:

Residential	$0.001368 per kWh	R
Commercial (Non-Demand)	$0.001052 per kWh	R
Demand Billed	$0.350 per kW	R
Street Lighting	$0.000657 per kWh	R

Recoverable Transmission Costs shall be the annual revenue requirements for transmission costs associated with transmission projects eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

August 1, 2011

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: Storm Damage Repair of the Pipestone to Lyon County 115 Kilovolt Electric Transmission Line (Xcel Energy Line #0825)

Dear Dr. Haar:

This letter is to inform you of a significant storm damage repair project currently being performed by Northern States Power Company, a Minnesota corporation (Xcel Energy), along the 115 kilovolt (kV) transmission line (0825) that extends from the Pipestone Substation to the Lyon County Substation located in Pipestone, Lincoln, and Lyon counties in southwest Minnesota.

The project involves repairing approximately 64 miles of 115 kV transmission line that was severely damaged as a result of storm activity on July 1, 2011. The damaged transmission line (#0825) extends from Pipestone Substation to Buffalo Ridge Substation (approx. 20 miles), Buffalo Ridge Substation to Lake Yankton Substation (approx. 20 miles), and Lake Yankton Substation to Lyon County Substation (approx. 24 miles). Repair of the H-frame structures and the 115 kV conductor is occurring within existing right-of-way. The repair project is expected to take three months to complete with a projected completion of October 30, 2011.

We don't normally write to the Commission when we need to repair our transmission facilities; however, since the repairs in this case are so significant and will extend over several months, we wanted to bring this particular repair project to your attention should the Commission have any questions about the work being performed.

Should you have any questions regarding this project, please contact me at 612-330-1955.

Sincerely,

Timothy Rogers
Supervisor, Siting and Permitting

cc: Deborah Pile, Division of Energy Resources
Eugene R. Kotz, Xcel Energy
Paul J. Lehman, Xcel Energy

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota) **Attachment 41**
2012 Transmission Cost Recovery Rider
Comparison of Current Rate Design to % of Base Revenues Rate Design

TCR Revenues With Current Rate Design

		Retail	Residential	Commercial Non-Demand	Commercial & Inductrial Demand	Street Lighting
1	TCR Adjustment Factor Rate per kWh	per kWh	$0.001368	$0.001052		$0.000657
2	TCR Adjustment Factor Rate per kW	per kW			$0.350	
3	2012 MN kWh Retail Sales (April - December 2012)	23,700,328,828	6,595,094,739	734,316,715	16,249,094,282	121,823,092
4	2012 MN kW Billing Demand (April - December 2012)				41,006,143	
5	2012 Customers	1,235,006	1,100,056	86,495	44,710	3,745
6	Average kWh per Customer per Month		666	943	40,382	3,615
7	Average kW per Customer per Month				102	
8	Average TCR Revenues per Customer per Month Current Rate Design		$0.91	$0.99	$35.67	$2.37

TCR Revenues with % of Base Revenues Rate Design

9	2012 TCR Revenue Requirement (January - December 2012)	$29,594,035
10	2012 Forecast Base Revenues (January - December 2012)	$1,605,085,429
11	TCR Revenue Requirement as a % of Base Revenues	1.84380%

		Retail	Residential	Commercial Non-Demand	Commercial & Inductrial Demand	Street Lighting
12	2012 Base Revenues	$1,605,085,429	$656,918,593	$72,810,918	$850,439,010	$24,916,909
13	2012 Average Base Revenues per Customer per Month	$108.30	$49.76	$70.15	$1,585.11	$554.52
14	Avg TCR Revenues per Customer per Month from % Base Revenues Design		$0.92	$1.29	$29.23	$10.22

Transmission Project Cost Discussion for Cost Cap Purposes

Project 8. Chisago – Apple River Transmission Line
This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on February 20, 2008 in Docket No. E-002/CN-04-1176. The Order stated that the "[t]otal construction costs, for both line and associated transmission facilities, are estimated at $64,200,000 with some $47,472,000 attributable to the Minnesota portion of the line."[1] Over the course of completing the design and routing of the project, the final route approved by the Commission resulted in an increase of $2,165,000. The Commission approved this increase for Transmission Cost Recovery rider purposes in its April 27, 2010 Order in Docket No. E002/M-09-1048.[2] Therefore, for Transmission Cost Recovery Rider purposes, the approved Cost Cap for this project is $66,365,000.

Project 11. CapX2020 Fargo Project
This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on May 22, 2009 in Docket No. E002/CN-06-1115. The Order stated that the "Upsized Alternative would cost between $500 million and $640 million."[3] The Commission approved the Upsized Alternative.[4] Using the high end of this range and the Company's 36.1% ownership share for the Fargo Project, results in a $231 million Cost Cap for the Company's 2012 TCR filing. The project costs proposed to be included in the 2012 TCR are less than the Cost Cap.

While these Project cost range values are what is stated in the Order, there are two factors, however, that affect the final installed cost of the Project. First, the cost estimates in the CON were in 2007 year dollars and all Parties acknowledged that there would be some escalation in costs between 2007 and the time when the Project was to be constructed. The Company and the Department exchanged ideas regarding the effect of cost escalation on TCR transmission construction projects in the Company's 2011 TCR filing (Docket No. E002/M-10-1064) and we agreed to have future discussions on that subject.

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[1] See Page 1 of the Order
[2] See Order Point 2.F. on Page 8 of the Order
[3] See Page 14 of the Order
[4] See Order Point 3. on Page 44 of the Order

A second factor that the Commission discussed in its Order for this project is the need for "Miscellaneous Upgrades". The Order indentifies the potential for $75 million to $100 million of "upgrades throughout the transmission system" that would be needed "when the CapX2020 345 kV Group 1 projects begin operating."[5] On Page 2.18 of the CON Application, Applicants provided Figure 2-14 showing a preliminary estimate of the transmission system upgrades that would be needed as a result of the construction of the CapX2020 345 kV Group 1 projects. Some of those projects are directly attributable to the Fargo Project and thus will be part of the final total cost of the Project.

As the costs of transmission system upgrades for the Fargo Project are further defined, and as the Company and the Department reach agreement on what effect escalation has the eligibility for recovery of TCR transmission construction project costs, the Company will submit information in future TCR Rider filings to further define the true total cost of the Fargo Project.

Project 12. CapX2020 Brookings Project

This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on May 22, 2009 in Docket No. E002/CN-06-1115. The Order stated that the "Upsized Alternative would cost between $654 million and $725 million."[6] The Commission approved the Upsized Alternative.[7]

The Company proposes to include the costs of the needed transmission system upgrades attributable to the Brookings Project. Attachment 1 provides a detailed discussion of the transmission system upgrades needed for the Brookings Project. As shown there, the cost of these facilities is approximately $30 million. Using the high end of the $654 million to $725 million range listed above plus the $30 million of transmission system upgrade costs, and the Company's 72.1% ownership share for the Brookings Project, results in a $544.4 million Cost Cap for the Company's 2012 TCR filing. The project costs proposed to be included in the 2012 TCR are less than the Cost Cap.

The Brookings Project cost range will be affected by the cost escalation factor that will affect the final installed cost of the Fargo Project. Once again, the Company will address the effect of cost escalation in future TCR filings.

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[5] See Page 19 of the Order
[6] See Page 16 of the Order
[7] See Order Point 3. on Page 44 of the Order

Project 13. CapX2020 La Crosse Project
This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on May 22, 2009 in Docket No. E002/CN-06-1115. The Order stated that the Upsized Alma Crossing Alternative would cost between $389 million and $415 million[8]. The Commission approved the Upsized Alternative[9] and the Alma Crossing is expected to be approved in the Route Permit filing. Using the high end of the $389 million to $415 million range listed above, and the Company's 64% ownership share for the La Crosse Project, results in a $265.6 million Cost Cap for the Company's 2012 TCR filing. The project costs proposed to be included in the 2012 TCR are less than the Cost Cap.

The La Crosse Project cost range values are affected by the same two factors (escalation from 2007 cost levels and Miscellaneous Upgrades) that affect the final installed cost of the Fargo and Brookings Projects. The Company will address the effect of escalation in future TCR filings. Some of the Miscellaneous Upgrade projects are directly attributable to the La Crosse Project and thus will be part of the final total cost of the Project.

Project 14. CapX2020 Bemidji Project
This project is expected to cost $32.3 million which is below the Cap of $32.4 million based on what has been previously approved by the Commission.

The Commission issued its Order approving the Certificate of Need for this project on July 14, 2009 in Docket No. E002/CN-07-1222. The Order does not contain an explicit statement of the cost of the project; however, the Order did approve the Environmental Report for the Project, which identified a cost estimate of $60.6 – 99.1 million for construction of the 230 kV line and substations at the two end points (Wilton and Boswell substations).[10]

One aspect of the Project costs presented to the Commission in both the CON and Route Permit, but not included in the estimates, is the cost of right-of-way and permitting. As stated in the Environmental Report and the Route Permit application, the cost estimates presented to the Commission did not include the cost of "right-of-way, permitting and ancillary costs". The CapX2020 project team has identified these costs. Approximately $12.7 million in right-of-way and permitting costs have been incurred for the Bemidji Project.

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[8] See Page 18 of the Order
[9] See Order Point 3 on Page 44 of the Order
[10] See Page 5 of the Environmental Report

Like the CapX2020 345kV projects, the final installed cost of the Bemidji Project will be impacted by both escalation effects and the cost of needed Miscellaneous Upgrades related to the Bemidji project. The Company will address escalation issues in future TCR filings. However, because the Bemidji project is nearing completion, the needed Miscellaneous Upgrade costs are now better defined.

The Capx2020 participants and MISO (through the MTEP process) have developed the following list of required Miscellaneous Upgrades.

Bemidji Transmission System Upgrade Requirements
Cass Lake 230/115 kV Substation
Cass Lake – Nary 115 kV reconductor transmission line
Nary 115 kV Switching Station
Nary – Helga 115 kV structure improvements
Helga – Bemidji 115 kV structure improvements

The combined cost for the upgrades is approximately $11.9 million. This cost should be added to the range of project cost estimates approved by the Commission in the CON, since the CapX2020 CON orders recognized that undefined Miscellaneous Upgrades would be needed.

Therefore, using high end of the $60.6 million to $99.1 million range listed in the CON and Route Permit filings plus the $11.9 million of Miscellaneous Upgrade costs and the $12.7 million of right-of-way and permitting costs yields a total Cost Cap for the Bemidji Project of $123.7 million. Applying the Company's 26.2% ownership share for the Bemidji Project results in a $32.4 million Cost Cap for the Company's 2012 TCR filing. The project costs proposed to be included in the 2012 TCR are less than this Cost Cap even without taking into consideration what impact on the Cost Cap there will be once escalation is accounted for.

Project 17. Pleasant Valley – Byron Transmission Line

This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on February 28, 2011 in Docket No. E002/CN-08-992. The Order does not contain an explicit statement of the cost of the project. However, the March 3, 2011 Order In Docket No. E002/TL-09-1315 approved Alternative

Route 3 for the Project, which had a cost estimate of $9.7 million.[11] Because this project is a generation interconnection project, the generation interconnection customer is assigned a 50% share of the costs under the MISO Tariff in effect at the time the interconnection requirements were determined, with the other 50% paid for by the Transmission Owner (i.e., the Company). Therefore, the Cost Cap for TCR Rider purposes is one half of the estimated installed cost, or $4.85 million. The project costs proposed to be included in the 2012 TCR are less than the Cost Cap.

Project 19. Glencoe – Waconia 115 kV Project

This project is below the Cap previously approved by the Commission. The Commission issued its Order approving the Certificate of Need for this project on November 14, 2011 in Docket No. E002/CN-09-1390. The Order adopted the comments of the Minnesota Division of Commerce, Division of Energy Resources and attached them to their Order. The Department identified the estimated capital cost of the project at $29 million.[12] Therefore the Cost Cap for this project is $29 million. The project costs proposed to be included in the 2012 TCR are less than the Cost Cap.

[11] See Page 4 of the Findings of Fact, Conclusions of Law and Order for the route approved and Page 2 of the Comments and Recommendation of the Office of Energy Security Energy Facility Permitting Staff for the costs of the alternatives. Both documents are attached to the Route Permit Order.

[12] See Page 12 of the Department Comments attached to the Order.

CERTIFICATE OF SERVICE

I, Mark Suel hereby certify that I have this day served copies of the foregoing document on the attached list of persons electronically, delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

DOCKET NO. E002/M-12-____

Dated this 13th day of January, 2012

/s/

Mark Suel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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Ronald	Giteck	ron.giteck@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

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Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

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Lisa	Veith		City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric