Xcel Energy®

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August 31, 2012

—Via Electronic Filing—

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

RE: REPLY COMMENTS
PETITION FOR APPROVAL OF 2012 TRANSMISSION COST RECOVERY, PROJECT ELIGIBILITY, RATE FACTORS, AND 2011 TRUE-UP
DOCKET NO. E002/M-12-50

Dear Dr. Haar:

Northern States Power Company submits this Reply to the June 13, 2012 Comments of the Minnesota Department of Commerce – Division of Energy Resources in the above-referenced docket.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list.

Please contact me at paul.lehman@xcelenergy.com or (612) 330-7529 if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER
REGULATORY COMPLIANCE AND FILINGS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Phyllis A. Reha	Commissioner
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF 2012 TRANSMISSION COST RECOVERY, PROJECT ELIGIBILITY, RATE FACTORS, AND 2011 TRUE-UP

DOCKET NO. E002/M-12-50

REPLY COMMENTS

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the June 13, 2012 Comments of the Minnesota Department of Commerce, Division of Energy Resources on our Petition for 2012 Transmission Cost Recovery Rate Factors and 2011 True-Up.

We appreciate the Department's thorough review of our filing and recommendation that the CapX2020 Brookings, Pleasant Valley-Byron, and Glencoe-Waconia transmission projects qualify for recovery under the TCR Rider.

The Department recommends that costs associated with certain transmission projects not be allowed recovery in the TCR Rider, however. We are providing additional information we believe responds to the Department recommendations and demonstrates that TCR Rider recovery for these costs is appropriate. Specifically:

- The Commission should allow TCR recovery of the costs incurred for Buffalo Ridge restoration project under the Renewable Cost Recovery (RCR) statute;
- The Commission should not "cap" the TCR recovery of costs for the Bemidji CapX2020 project at the cost level in the 2007 Certificate of Need application, because, among other things, the Commission had not adopted a "cost cap" principle for rider recovery at the time of the CON application; and
- The Company is appropriately recording certain internal labor costs as capital costs associated with TCR eligible projects, and TCR recovery is consistent with

Minnesota statutes and the Commission's rules regarding utility accounting and the Commission's approvals of the Company's prior TCR Rider projects and cost recovery filings.

We hope this Reply provides the Department and Commission additional information that can resolve (or at least narrow) the areas of disagreement between the Company and the Department. We have organized our response and additional support for our Petition in the following sections:

- *Standard for Review,* discussing the statutes governing the Commission's decision in this case, which allow for full TCR recovery of eligible projects.
- *Buffalo Ridge Restoration Project*, providing support for our request to include these costs in the TCR Rider and providing additional information requested by the Department.
- *Project Costs for Bemidji and Brookings CapX2020 Projects*, discussing Certificate of Need cost estimate caps and providing additional information on the Bemidji and Brookings project costs in response to questions raised by the Department.
- *Capitalized Internal Labor Costs,* providing support for continued inclusion of these costs in the TCR Rider.
- *Additional Comments,* clarifying our treatment of MISO RECB charges and providing updated TCR revenue requirements and rate adjustment factors based on the allocators and rate of return approved in our most recent rate case.

REPLY

A. Standard for Review

The TCR and RCR statutes provide for timely recovery of investments and expenditures that promote the State's transmission system development goals, including those related to promoting the use of renewable energy. These statutes both govern project eligibility and provide for the recovery of all prudent costs through a tariff rider, and – along with the TCR Rider tariff language – should determine whether costs are recoverable.

1. Transmission Cost Recovery Statute – Minn. Stat. § 216B.16, subd. 7b

The TCR Statute allows the Commission to grant recovery of all costs incurred for a transmission project certified through a Certificate of Need proceeding or in a biennial transmission plan. The standard for recovery is whether the costs are prudent and in the public interest. There is no limitation such as a cost cap calculated from the project estimate included in a Certificate of Need application. The Legislature adopted this statute to encourage continued investment in the transmission system and to allow for annual rate recovery outside of a general rate case.

The TCR Statute provides (in pertinent part) as follows:

> (a) 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 (i) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243or are certified as a priority project or deemed to be a priority transmission project under section 216b.2425…
>
> ***
>
> (b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:
> (1) allows the utility *to recover on a timely basis* the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243…
>
> ***
>
> (4) provides *a current return on construction work in progress*, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;
> (5) allows for *recovery of other expenses* if shown to promote a least-cost project option or is otherwise *in the public interest*…
>
> ***
>
> (c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b).
>
> ***
>
> (d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff *were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers*.
> (Emphasis added.)

The Commission approved the TCR Rider as the annual mechanism through which the Company could recover costs under the TCR Statute in November 2006.[1]

[1] Docket No. E-002/M-06-1103, Order Approving Transmission Cost Recovery Rider (Nov. 20, 2006) ("TCR Rider Order").

2. *Renewable Cost Recovery Statute – Minn. Stat. § 216B.1645*

The RCR statute allows the Commission to grant cost recovery for transmission and other projects which support our efforts to comply with the wind and biomass mandate or the renewable energy objectives and standards. This includes reasonable investments and expenditures which allow for the transmission of electricity generated from facilities that facilitate compliance with those renewable objectives and standards. The RCR statute does not limit recovery to investments in new transmission.

The RCR Statute provides (in pertinent part) as follows:

> Subd. 1. 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 and standards set forth in section 216B.1691, *including reasonable investments and expenditures made to*:
>
> (1) *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 generating facilities constructed to satisfy the renewable energy objectives and standards, 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.2425 for the new transmission facilities identified in the studies; (Emphasis added).

The Company is permitted to recover the transmission investments needed to satisfy the renewable energy requirements through the TCR Rider. The Commission approved this approach by adopting the TCR Rider tariff (which references both the TCR Statute and the RCR Statute).[2] Thus the Company is allowed to use the TCR Rider to recover prudent investments and expenditures made under either the TCR Statute or RCR Statute.

3. *Renewable Energy Standards – Minn. Stat. § 216B.1691, subd. 2a(b)*

The RES Statute allows the Commission to grant rider recovery of, among other things, transmission costs incurred to transmit renewable energy.

[2] *See* TCR Rider Order.

> The expenses incurred by the utility over the duration of the approved contract or useful life of the investment and expenditures made pursuant to section 116C.779 shall be recoverable from the ratepayers of the utility, to the extent they are not offset by utility revenues attributable to the contracts, investments, or expenditures. 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 under subdivision 1, 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.*

For transmission projects eligible for recovery under the RCR Statute provisions of the TCR Rider, this RES statute provision limits recovery of costs to those transmission expenditures directly related to the provision of renewable generation.

We believe our proposal for TCR Rider recovery of the Buffalo Ridge Restoration Project, the current estimate of Bemidji project costs, and internal capitalized labor costs is consistent with the three governing statutes and the Commission-approved TCR Rider Tariff.

B. Buffalo Ridge Restoration Project

The Department recommends that the Commission not allow TCR Rider recovery of the costs (approximately $3.9 million of 2012 revenue requirements) associated with the 2011 Buffalo Ridge Restoration Project. We appreciate the Department's comments indicating the project costs should be recoverable, but do not agree that recovery should be deferred to our next rate case. In our reply, we provide additional information supporting our request for TCR Rider recovery.

1. Project Description

The Buffalo Ridge restoration project resulted in the reconstruction of 64 miles of 115 kV line and 30 miles of 34.5 kV wind feeder collector facilities in Southwestern Minnesota after damage due to severe storms on July 1, 2011. The storms causing the damage on Buffalo Ridge were part of the series of storms that also spawned the tornado that damaged North Minneapolis the same day. The damage to the wind collection feeders directly affected approximately 350 MW of wind generation, making it impossible for this generation to be delivered to our transmission system.[3] Further, the

[3] The affected wind generation included 50 MW being purchased by another utility.

damage to the 115 kV transmission line significantly affected the reliability of transmission service to approximately 1200 MW of wind generation in the Buffalo Ridge area because a critical component of the transmission network in the area was out of service. This was not a normal storm outage where repairs could be completed in a few days. Rather, this was a catastrophic event that led the Company to exercise *force majeure* provisions under several wind PPA contracts, a standard that is not easily met. Attachment A is a map of the affected 115 kV transmission line and collector facilities that were removed and reconstructed. Attachment B is a map showing how the 115 kV transmission line is an integral link in the wind outlet transmission network in southwest Minnesota.

Just as we mobilized to respond to the tornado damage in North Minneapolis, where we quickly restored distribution services to affected customers, the Company immediately mobilized all available transmission construction crews to reconstruct the damaged transmission and collector systems so renewable wind energy could again flow to our customers. By July 3, 2011, we had begun removal of the downed 115 kV lines and the damaged collector facilities. We also began the design process, especially related to rebuilding the 34.5 kV collector facilities to transmission standards. During the reconstruction process, we had 100 – 150 linemen and associated support personnel working 7 days a week in 14 hour construction schedules. For the 115 kV line, our crews installed 1001 wood poles, 183 miles of conductor and 118 miles of shield wire. For the 34.5 kV wind collector feeders, the crews installed 58 wood poles, 715 steel poles and 192 miles of conductor. The 115 kV line was restored by October 7, 2011, and the collector systems were mechanically restored by October 23, subject to installation of capacitors on certain wind feeders (scheduled for December 2011). In total, we incurred approximately $38 million in capital costs.

Based on our experience, construction of a 65 mile 115 kV transmission project would normally take more than a year to complete under standard construction practices. For example, the Company currently has three 115 kV projects before the Commission in various stages of the Certificate of Need process.[4] Each of these projects involve removal of an existing transmission line (albeit 69 kV) and construction of a new 115 kV line on the same right of way. Each of these projects is expected to take approximately 12 – 15 months following final permit approval for design, engineering, removal of the existing facilities, and construction of the 115 kV lines. We were able to complete the Buffalo Ridge Restoration Project in less than six months, rather than 12 to 15 months, largely due to the fact that we have extensive transmission construction projects currently underway and both labor resources and inventory. We were able to divert

[4] Bluff Creek-Westgate (Docket No. E002/CN-11-332), Chaska Area (Docket No. E002/CN-11-826); Hollydale (Docket No. E002/CN-12-113)

transmission poles, conductor and construction equipment from other projects and quickly mobilize our construction crews (both internal and contractors) to complete the 34.5 and 115 kV projects, reconnecting substantial wind energy generation to the transmission system and restoring the capability of the entire Buffalo Ridge area system to reliably transmit renewable energy much more quickly than would have been the case under normal circumstances.

We were able to rapidly complete both the North Minneapolis restoration project and the Buffalo Ridge Restoration Project, which benefitted our end use customers and the wind energy providers that would have been otherwise left without access to the transmission system. While there is no vehicle for recovery of the costs to restore the distribution system in North Minneapolis outside a general rate case, we believe the Buffalo Ridge restoration project falls squarely within the requirements under the RCR Statute and thus is eligible for recovery under the TCR Rider We believe that because the statute permits recovery and because the Company's rapid response to these extraordinary circumstances fulfilled the objectives of the statute, rider recovery is appropriate both from a legal and policy perspective.

Below we provide additional justification and support for inclusion of these costs in the TCR Rider and provide the additional information requested by the Department.

2. *Project Eligibility*

a. RCR Statute Eligibility

The Department comments assert that the Buffalo Ridge Restoration project is not eligible for recovery under the TCR Rider. We ask the Commission and the Department to consider the following response:

First, the purpose of the RCR Statute is to encourage utilities to make investments in infrastructure to meet the wind, biomass, and renewable mandates. The RCR Statute specifically allows recovery of "investments and expenditures…to transmit electricity" if directly related to the transmission of that renewable energy. The costs we are seeking to recover are directly related to transmission of renewable wind energy from Buffalo Ridge to our customers. The project costs were reasonable and necessary to restore the interconnection and transmission of renewable generation developed to comply with Minnesota's renewable energy objectives and standards. Completion of the restoration project allowed the approximately 350 MW of wind generation to reconnect to the transmission system through the restored 34.5 kV feeder collection system, and allowed approximately 1200 MW of wind generation to reliably transmit energy to our customers. Without rebuilding these facilities, wind generation on

Buffalo Ridge would have been undeliverable or subject to transmission curtailment risk for up a year or more.

Second, the RCR Statute does not limit recovery of investments to new projects.[5] In this case we are not talking about the replacement of a few poles or a small section of line, but rather an extensive rebuild of nearly 100 miles of facilities. Therefore our request is consistent with the purpose of the RCR which is for any significant transmission investments to deliver wind to market, not normal wear and tear on our system. Even if we assumed this was a limitation, the full removal and complete replacement of the existing 115 kV line and the 34.5 kV collector systems at 2011 transmission engineering and construction standards means the reconstructed facilities are new facilities.

Third, the RCR Statute also does not limit recovery to only generation facilities. If the Legislature had intended to limit rider recovery to generation facilities, it could have modified the RCR Statute when it adopted the TCR Statute. Instead, by retaining the RCR Statute (enacted in 1997) when the TCR Statute was enacted (in 2005), the Legislature allowed that there could be transmission projects not eligible for recovery under the TCR Statute that could still be recoverable under the RCR statute. We believe the Buffalo Ridge Restoration Project is one of the situations where such recovery of a transmission investment is authorized under the RCR Statute.

Fourth, granting approval of recovery under the RCR Statute in this instance will not, as the Department asserts, provide a means to assert that the costs of any transmission line restoration on our system is recoverable because any line arguably can be considered to transmit some level of renewable energy. Attachments A and B show that the reconstructed facilities were integral components of the transmission system in the Buffalo Ridge area and clearly necessary to collect and deliver wind energy from Buffalo Ridge to our customers. The wind collector systems collect the output of hundreds of wind towers and deliver this energy to the higher voltage system. The collector systems are used exclusively for wind generation. The 115 kV line is an integral part of the Buffalo Ridge outlet transmission system that includes the 425 MW Outlet, 825 MW Outlet and Buffalo Ridge Incremental Generation Outlet projects, which provided approximately 1250 MW of outlet capacity to transmit renewable energy from the Buffalo Ridge area to our customers. The extraordinary circumstances of the storm and the reconstruction project will not create precedent regarding rider recovery with unintended consequences.

[5] The only use of the term "new" in the RCR statute is related to recovery of the cost of studies necessary to identify new transmission facilities.

Fifth, with respect to the question of whether the projects eligible under the RCR Statute require pre-certification, the Company's Petition included both a request for (a) an eligibility determination, and (b) approval for TCR Rider recovery. At the time the Company initially filed and the Commission approved our RCR Rider tariff in Docket No. E002/M-02-474, the process used by the Commission was a two-step approval process: first the Company obtained an eligibility determination for each RCR project, and then we separately filed for calculation of the RCR Rider rates after the eligibility determination. That process proved cumbersome and did not allow timely cost recovery, so in 2006, the Company proposed, and the Commission approved, a TCR Rider process that included both the eligibility determination and the rate recovery calculation in a single filing.

We used this process previously when we sought TCR Rider recovery of two new RES Statute projects (the Blue Lake/Wilmarth 345 kV Reconstruction project and the Nobles Wind Farm Network Upgrades project) under the RCR Statute in Docket No. E002/M-09-1048. In that case, we requested that the Commission make both an eligibility determination and approve TCR Rider rate factors recovering the project costs of these two facilities. The Commission did so.

The Company's January 2012 Petition in this case applied the same principle to the Buffalo Ridge Restoration Project. As such, the Commission has not required pre-certification. While the Commission makes the eligibility determination at the same time it approves TCR Rider recovery under the single filing process, any project not determined to be eligible would also not receive rider recovery.

While we acknowledge that obtaining pre-certification prior to completing this work could have provided greater certainty regarding the recovery of project costs, it clearly would not have been in the best interest of our customers or wind generators to put off the restoration work until such a certification filing could be prepared and acted on by the Commission. Given the circumstances, the most prudent course of action was to mobilize our resources to rebuild the facilities as quickly as possible to restore delivery of wind energy to our system and our customers.

Finally, we do not believe the question in this case is whether repair and maintenance costs can be recovered under the TCR Rider. We agree with the Department that repair and maintenance costs – generally O&M expenditures – are not recoverable under the TCR Rider, and we have not requested recovery of such costs in our Petition. Our request in this case is for approval to recover the 2012 revenue requirement ($3.9 million) associated with the $38 million of capital costs associated with the complete demolition and reconstruction of a 65 mile 115 kV transmission line and 30 miles of 34.5 kV collector systems that are essential to collect and transmit energy from wind generation facilities to our customers.

Indeed, Xcel Energy's exercise of the *force majeure* provisions of our wind PPAs, provides additional evidence that the 34.5 kV facilities meet the statutory standard. After the July 1, 2011 storm damage, the Company sent *force majeure* notices pursuant to the terms of our wind PPAs, because we knew we would be unable to take delivery of the wind production connected to the collector systems.[6] *Force majeure* is a difficult standard to meet contractually, and the fact that our exercise of the provision was not challenged during the reconstruction period underscores both that the 34.5 kV facilities were required to deliver wind to market and that they were not re-installed as part of a normal maintenance project.

b. Conclusion

We believe the Buffalo Ridge Restoration Project costs are consistent with the overall Legislative intent to promote investment in Minnesota's transmission system in order to facilitate delivery of renewable generation, and the project costs meet the requirements of the RCR Statute. As referenced above, our TCR Rider tariff incorporates recoveries under the RCR statute. As such, the Commission should find these costs are eligible for recovery under the TCR Rider.

3. Inclusion in 2011 TCR True-up and Tracker Balance

The Department requested that we provide additional information to explain why we included the Buffalo Ridge restoration project in the 2011 TCR True-Up Report and Tracker Balance. Consistent with past practice, we included this project in the tracker balance because it went into service in 2011, with the understanding that inclusion in the 2011 tracker balance is subject to Commission approval of project eligibility under the RCR Statute in this proceeding.

The Commission approved similar treatment of the Blue Lake/Wilmarth 345 kV transmission line in their Order dated April 27, 2010 in our 2010 TCR proceeding (Docket No. E002/M-09-1048). In that case, we requested approval to include the Blue Lake/Wilmarth project in the TCR Rider in 2010 under the RCR Statute, and proposed to include the revenue requirements in the TCR Tracker Balance beginning in March 2009 for the portion of the project that went into service at that time. The Commission approved tracker balance treatment, since it found the project eligible for

[6] Certain of the wind farms also experienced extensive damage to their wind turbines and/or collector systems from the storm.

TCR Rider recovery.[7] We believe our proposed inclusion of the Buffalo Ridge restoration project costs in the 2011 tracker is consistent with this past practice, assuming the Commission agrees the Buffalo Ridge project is eligible for TCR Rider recovery.

4. *Insurance Proceeds and Other Compensation*

The Department indicated the Company should be allowed to request recovery of the Buffalo Ridge restoration costs in our next rate case, but recommended the Commission require the Company to provide information in that rate case about whether we received any insurance proceeds, other compensation, or a reduction in taxes as a result of the storm damage. We provide the information below to assure the Commission that granting recovery of the Buffalo Ridge restoration costs through the TCR Rider will not result in double recovery.

We will not receive any insurance proceeds related to the storm damage. The Company does not purchase insurance covering storm damage to either our transmission system or distribution lines. From time to time, we investigate the availability and cost of such insurance, but both factors indicate that purchasing a policy would be prohibitively expensive for our customers. For example, the last time the Company investigated such insurance, the premium for each $1 million of coverage was approximately $300,000 per year. That cost would be included in rates. While there are electric utilities that purchase such coverage, they are all located in hurricane prone areas. Since the Company experiences large scale damage less frequently than utilities in hurricane zones, and given the cost of insurance coverage, it is less expensive to our customers over the long term for the Company to repair damage to our transmission system caused by storms as it occurs than to purchase insurance.

Further, the Company has not received and does not expect to receive other compensation or a tax reduction that would offset the Buffalo Ridge restoration costs. As such, it is not necessary for the Commission to require a compliance report in the Company's next rate case.

C. Project Costs for Bemidji and Brookings CapX2020 Projects

The Department recommends that the Commission impose a "cost cap" on TCR Rider recovery of the cost of the CapX2020 Bemidji project, and requests further information regarding whether certain costs were included in the CapX2020

[7] April 27, 2010 Order at p. 4-5.

Brookings project. The Company requests that the Commission and Department consider the following reply.

1. *Certificate of Need Cost Estimate Caps*

While certain Commission orders have imposed caps on costs recovered through the TCR Riders, the statutes enabling utilities to recover transmission and renewable investments through these riders contain no provisions for such caps. As such, we believe the Commission can consider in this case whether the use of cost caps continues to be appropriate.

The Commission first considered the issue of a cost cap on a transmission project in Docket No E002/M-10-1048 related to the Blue Lake-Wilmarth 345 kV line, where the Company sought recovery under the RCR Statute. The Commission did not allow recovery in the TCR Rider of the anticipated $1.7 increase on a project initially expected to cost $6 million. The Company did not ask the Commission to reconsider the decision at the time. This was in part because we received a contribution in aid of construction which reduced our total investment to less than $6 million, meaning the Company's total investment was ultimately less than the cap.

We also recognize there may be circumstances where using cost caps on rider recovery could be appropriate. For example, the Commission initially established the cost cap concept when considering RES rider recovery of the Nobles wind project costs. The Commission limited RES Rider recovery to the cost estimates in the original Certificate of Need estimate, and ruled that costs above that level would be reviewed for possible inclusion in a subsequent rate case subject to a prudence determination. Part of the Commission's reasoning was that the initial project cost estimates were those used in a bidding process where the Nobles project competed against other generation projects. As costs were a factor related to competition with other generation projects, the Commission determined allowing RES Rider recovery of increased project costs was not appropriate without additional review in a rate case.

We do not believe, however, the same rationale is applicable to eligible transmission projects. While cost is considered in determining whether a transmission line is needed, more important are reliability and customer demand considerations. We move forward with transmission projects when needed to meet demand or improve reliability, and utilities are the only entities allowed to construct such facilities.

One of the reasons the Legislature enacted the TCR Statute to allow rider recovery was because it recognized the complexity of the transmission permitting, siting, routing, and construction process and length of time required to complete projects.

Imposing a cap on rider recovery and deferring review of certain costs to a future rate case is contrary to the intent of the statute. The estimates we include in a Certificate of Need (CON) application are outdated by the time we begin seeking rider recovery of costs for eligible transmission projects. To facilitate the need determination, we provide high-level planning cost estimates. Detailed design and engineering is not performed at this stage in order to minimize total costs in the event the CON is not granted. Permitting, land acquisition, and ancillary project costs are difficult to predict during this initial phase as well, as the route and pole alignments are not known.[8]

The Legislature foresaw significant investment in transmission was needed to accommodate projected new electric generating capacity when enacting the TCR Statute. To encourage the Company and other utilities to invest in transmission facilities, the Legislature provided the Commission with the authority to grant cost recovery through a rider outside of a general rate case. The Commission was authorized to approve an annual cost recovery mechanism and make prudency determinations as part of those proceedings. As noted, the TCR Statute provides:

> the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff *were or are expected to be prudently incurred* and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.
> (Emphasis added.)

The Department comments do not assert that specific project costs were not prudently incurred. Indeed, the Commission has never previously determined any Company transmission project costs to be ineligible for rate recovery as imprudent, and we believe the estimated Bemidji project costs reflected in our TCR Rider petition can be expected to be prudent. Our annual TCR Rider proceedings can be the appropriate forum for making any prudency determination. Alternatively, if the Commission prefers, however, prudence review for individual projects could be deferred to the rate case after a project is placed in service. However, under the "expected to be prudently incurred" standard in the TCR Statute, the Commission should not disallow TCR Rider recovery of the costs of eligible projects if there is no assertion of imprudence.

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[8] While not the norm, the Company has on occasion not included the routing, permitting, and siting-related costs in a certificate of need proceeding for a transmission project that involves a complex routing project. For example, the cost estimates provided in the recently approved Hiawatha 115 kV transmission project did not contain these costs during consideration of the certificate of need. It was not until the final route had been approved that these costs were able to be reasonably quantified and included in the total project costs. Even when such costs are included in a certificate of need application, the estimates generally will not be able to reflect all federal, state, and tribal permitting complexities, or siting and land acquisition details.

We appreciate that the Department's comments indicating some flexibility in the level of costs allowed in the TCR Rider may be appropriate. For example, the Department indicates use of an appropriate escalator to reflect increasing costs over time, or allowing recovery of additional costs incurred due to unforeseen or extraordinary circumstances may be appropriate.

However, as we make significant transmission investments going forward – for example, we plan to invest over $1 billion in the CapX2020 projects – the TCR Rider mechanism for recovering these costs is important to provide the benefit intended by the statutes. The statutes were designed to promote investment in the transmission system to improve reliability and access to renewable generation for our customers. Allowing TCR Rider to recover the capital costs incurred between rate cases is consistent with the intent of the legislation. For these reasons, we believe the Commission should reconsider whether cost caps are appropriate for major transmission projects or alternatively, how they should be established.

In light of these policy considerations, we discuss further below the specific cost increase related to the Bemidji project. We believe this additional information demonstrates our concern with applying the "cost cap" principle to individual transmission projects, and demonstrates that recovery of Bemidji project costs in 2012 TCR Rider rates should not be capped at the level in the 2007 Certificate of Need application, even adjusted for a cost escalator.

2. *Bemidji Project*

a. Eligible Project Costs

The Bemidji Project is a 70 mile 230 kV transmission line between Bemidji and Grand Rapids that will address reliability concerns in this area. Under the CapX2020 collaborative development arrangements, Otter Tail Power was designated the project manager and prepared and filed the Certificate of Need application in 2007 with assistance by the other CapX2020 project participants, including Xcel Energy. (Docket No. E017, E015 & ET-6/CN-07-1222). The project is currently approximately 98 percent complete, and the first segment of the project was energized in August 2011.

At the time of the Certificate of Need application in 2007, the estimated cost of the Bemidji project cost was $60.6 million (2007 dollars). At the time of the route permit proceeding in 2007 (Docket No. E017, E015 & ET-6/TL-07-1317) the projected cost as approved was estimated to be $66.2 million (2007 dollars). We now estimate the total cost of the project to be approximately $116 million.[9] The cost to construct the transmission line and substation – the facilities granted a Certificate of Need -- is approximately $89.5 million.

We recognize that these cost increases are significant; however, the estimates provided in the Certificate of Need application were based on Otter Tail Power's transmission estimation methodology at that time. While escalating costs over time account for part of the increase, the table below identifies other additional project costs. We also provide a discussion of the project costs, including cost increases that could not have been estimated at the time of the Certificate of Need application, that are necessary for completion of the project.

Table 1
Bemidji Project Cost Comparison
($millions)

Cost Component from Route Permit Exhibit ___ (REL), Schedule 2	**Certificate of Need**	**Route Permit**	**Current Forecast**	**Change over Route Permit**
Transmission Facilities				
Base Cost for 230 kV Line		$44.80	$53.54	$8.14
230/115 kV Double-Circuit Adder at Wilton		$0.60	In above	In above
Woodland Adder		$4.60	$5.58	$0.98
Winter Construction Adder (includes mat procurement)		$5.80	$15.40	$9.60
Pipeline Induction Management Costs			$1.94	$1.94
Transmission Line Subtotal	$58.10	$55.80	$76.46	$20.66

[9] This current projection is less than the $123 million estimate provided in our Petition filed in January 2012.

Cost Component from Route Permit Exhibit ___ (REL), Schedule 2	Certificate of Need	Route Permit	Current Forecast	Change over Route Permit
Associated Facilities				
Boswell Substation Expansion		$1.00	$0.89	($0.11)
Wilton Substation Expansion		$1.50	$1.24	($0.26)
Cass Lake Substation Expansion		$5.20	$5.70	$0.50
Nary Breaker Station		$2.70	$2.25	($0.45)
Ottertail Power Underlying Facilities			$0.24	$0.24
Minnesota Power Underlying Facilities			$0.05	$0.05
Nary to Cass Lake OTP			$1.60	$1.60
Nary to Cass Lake MPC			$1.05	$1.05
Associated Facilities Subtotal	$2.50	$10.40	$13.02	$2.62
Permitting, Right of Way and Legal				
CON and Route Permit Permitting Costs			$9.10	$9.10
Post permit legal fees			$3.22	$3.22
Environmental Permitting and Compliance			$8.38	$8.38
Right of Way			$5.70	$5.70
CapX2020 Joint Sourcing and Management			$0.50	$0.50
Total			$26.90	$26.90
Transmission Line and Facilities Total	$60.60	$66.20	$116.38	$50.18

The following discussion describes the cost increases (or decreases) related to the Bemidji Project:

Transmission Facilities

- *Winter Construction Adder*. The Project incurred $15.4 million to purchase, install and remove additional wetland protection mats due to warm winter temperatures during 2011-2012, which was $9.6 million more than originally estimated. During normal winters, wetlands in the area freeze so that construction with typical protective measures can continue. This past winter was one of the warmest on record and the wetlands in the project area did not freeze sufficiently to support construction equipment. Continuing construction was more cost-effective than waiting until spring but required additional equipment to protect the wetland areas against damage from heavy traffic and use of construction equipment. To protect the landscape, the Project purchased, installed, and removed an additional 20,000 mats.

- *Tree clearing and Road Restoration*. The Project has incurred approximately $5.6 million thus far. This is an increase of approximately $1.0 million over what was originally estimated. Trees along the route were larger and more dense than anticipated.

- *Pipeline Induction Mitigation*. Electric transmission lines located near natural gas or oil pipelines can induce electrical currents across the pipeline facilities, which can reduce the effectiveness of the pipeline's corrosion protection system. Portions of the Bemidji Project parallel the Great Lakes Gas Transmission natural gas pipeline along U.S. Highway 2. As a result, the project needed to install special equipment to protect the pipeline facilities. The Project incurred approximately $1.9 million to perform pipeline induction mitigation. This cost was not estimated at the time of the Certificate of Need or Route Permit applications because it was dependent on route alignment and determination of the specifics of the protective techniques required. However, the cost is essential to the safe operation of both the electric and pipeline facilities.

- *Transmission Line Construction*. The cost to construct the transmission line facilities is now estimated to cost approximately $8.1 million more than the $45.4 million estimate (2007 dollars) provided during the Route Permit proceeding. It is common for facility cost estimates to be updated using the Handy Whitman Index, an industry index specifically used to estimate the impacts of inflation on transmission projects over time. Applying the Handy Whitman index values for the 2007 to 2012 period to the $45.3 million estimate would result in an estimated cost increase of $8.2 million, slightly more than the current estimate. See Attachment C. Therefore, the increase in transmission line construction costs over the five years since the route permit was issued is consistent with (or slightly less than) the results experienced for similar transmission projects, demonstrating the increases are reasonable.

Associated Facilities
The costs of the substation facilities associated with the Bemidji 230 kV line have increased approximately $2.6 million from the estimate provided in the Route Permit application. For those associated facilities that were individually identified and a cost estimate was provided, the costs have actually decreased slightly. The overall increase in cost in this category is thus due to several additional associated facilities that were identified as being needed for the project to be reliably interconnected to substations and the underlying transmission system.

Permitting, Right of Way and Legal
As discussed in the Petition, the costs associated with this category of project costs were expected in the regulatory approval processes; however, the specific value of these costs were not quantified at the time of project approval in the Certificate of Need or Route Permit applications. These costs include:

- *Certificate of Need and Route Permit Costs.* The Project has spent approximately $9.1 million on activities to obtain the permits to proceed with this project, including the Certificate of Need and Route Permit.

- *Post Permit Legal Fees.* The Project has spent approximately $3.2 million on legal fees since the Certificate of Need and Route Permit were granted. This includes the legal fees to litigate our dispute with the Leech Lake Band of Ojibwe (the Tribe) over the route through tribal land, and to obtain and comply with permits. At the time the project applied for a Certificate of Need, we did not foresee a protracted litigation would be needed to site this project and reach the best outcome for all parties involved.

- *Environmental Permitting and Compliance.* Approximately $8.4 million has been spent on environmental permitting and compliance matters. For example, this includes $2.2 million paid to the U.S. Forest Service for permits, wetland restoration, hunting and gathering rights for the Tribe and agency monitoring.

- *Right of Way.* Approximately $5.7 million was spent to acquire easements to construct this project. It was specifically noted in the Certificate of Need application that right of way costs would be incurred but the costs not included in the cost estimate.

We believe all of the costs incurred to date for the Bemidji Project are necessary to complete the project, were prudently incurred and are in the public interest. The CapX2020 entities have taken all of the steps needed to construct and route a successful transmission project. The cost increases meet the "prudent or expected to be prudent" standard in the TCR Statute, and the actual cost of the project (not the 2007 estimate, even if it were adjusted) should provide the basis for the TCR Rider cost recovery.

b. A Cost Cap Should Not be Applied Retroactively

Even if the Commission were to decide to continue to apply the cost cap principle to TCR eligible projects, it would be inappropriate to apply such a cap to the CapX2020 Bemidji project. At the time the project applicants submitted the Certificate of Need application for the Bemidji line in 2007, the Commission had not applied a cost cap to a TCR eligible project. The Commission did not apply this principle to a transmission project until its April 2010 order regarding the Wilmarth/Blue Lake line. Thus, the project applicants could not have known the Commission might later seek to limit TCR Rider rate recovery to the estimates in the CON or Route Permit applications. It would be arbitrary and capricious to apply the cost cap ratemaking principle where the Certificate of Need application was submitted and approved before the Commission ever announced the cost cap principle.

Moreover, while the Bemidji project Certificate of Need estimates did not include cost estimates for all necessary work and permitting, the fact that the project would incur some additional costs was disclosed and known.[10] Consistent with Certificate of Need and Route Permitting practice at that time, the project applicants provided high-level estimates to construct the transmission line along various route alternatives. It is not feasible to estimate costs to the granularity needed for rate making purposes when a route and the issues associated with constructing a transmission line are not known.

c. Cost Cap Alternatives

We recognize that the Commission may nonetheless cap TCR Rider recovery of the Bemidji Project costs linked to the initial cost estimates provided by the project applicants during the Certificate of Need proceeding. If so, we respectfully request that the Commission consider two adjustments to the 2007 initial cost estimates.

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[10] Environmental Report, Bemidji – Grand Rapids 230 kV Transmission Project, Docket No. E017, E015, ET-6/CN-07-1222, Page 5

First, the Department suggested use of an escalator for the Bemidji cost estimates. We appreciate this recommendation. As discussed previously, we believe the appropriate escalator is the Handy Whitman index for transmission projects, rather than escalation factors based on GDP or CPI. Based on the Handy Whitman index, the cost estimate for the Bemidji Project in 2012 dollars is approximately $8.2 million higher, or $74 million, compared to the original cost estimate of $66.2 million contained in the Route Permit proceeding.

Second, this escalated 2012 estimate does not include additional critical costs – several of which the project applicants had no way of foreseeing – that were necessary and prudent to effectuate the project and actually place it in service in 2012. When the Commission first applied the cost cap principle to the Wilmarth/Blue Lake project in our 2010 TCR Rider proceeding, the Commission provided for the recovery of costs in excess of the project cap when such costs are unforeseeable and extraordinary. We believe the Bemidji Project costs eligible for TCR Rider recovery should include the unforeseeable or extraordinary events provided in the table above. Specifically the $9.6 million of additional winter construction costs incurred due to a record warm winter was an unforeseen and extraordinary situation, as were the $3.2 million of post permit legal fees. This adjustment is reasonable and would bring the cost of the project eligible for TCR Rider recovery to approximately $87.2 million.

Again, while we believe it is unreasonable to retroactively apply the cost cap principle to a transmission project approved before the Commission adopted the concept of applying cost caps to project costs recovered through the TCR Riders, if the Commission nonetheless orders a limit on TCR Rider recoveries for the Bemidji project, the cost cap for the Bemidji project should be no lower than $87.2 million.

3. Brookings Project

Our Petition identified $30 million in necessary system underbuild upgrades for the CapX2020 Brookings Project. The Department requested that we clarify whether this $30 million is included in or in addition to the $70-100 million cost range provided in the CapX2020 Certificate of Need proceeding for underbuild upgrades for the three CapX2020 345 kV projects. We confirm that the $30 million is a part of the $70-100 million estimate – it is the portion of that total required for the Brookings project underbuild upgrades. As such, we believe these costs for the Brookings project are recoverable in the TCR, even if the Commission were to impose a Certificate of Need cost estimate cap to the Brookings project.

D. Capitalized Internal Labor Costs Should be Recoverable

The Department recommends that the Commission deny TCR Rider recovery of capitalized internal labor costs of $1.5 million in 2012 revenue requirements. This recommendation is largely based on the Commission's decision in the 2010 Minnesota Power (MP) TCR docket to not allow MP recovery of capitalized labor costs in its TCR mechanism.[11] The Department comments cite the MP TCR Order, note that the Company responded to an information request indicating that we included some internal capitalized labor in the calculation of the 2012 TCR Rider revenue requirements, and assert the MP TCR Order requires these costs be excluded from the Company's TCR rates. We respectfully disagree.

We recognize and appreciate that the Department is not asserting that we should never recover the internal capitalized labor costs in rates. The Commission has not, however, previously applied this principle to the Company's TCR Rider petitions. While we recognize the Commission issued the MP TCR Order ruling, the Commission Order also stated that "The Commission's evaluation of a request for rider recovery is based on the specific facts presented in each case….."[12]

The Company believes the record in our 2012 TCR Rider Petition and this Reply demonstrates that TCR Rider recovery of capitalized labor costs is appropriate and should be approved. Our reply comments demonstrate:

- Internal labor costs incurred for capital projects after the 2011 rate case test year are not being recovered in the Company's current rates;
- Allowing recovery through the Company's TCR Rider is consistent with the state policy and statutes, Commission rules and Commission precedent; and
- Including all capitalized labor (both internal and external) for TCR Rider projects will avoid unnecessary accounting and ratemaking complexity.

We therefore believe the record in this case satisfies the standard expressed in the MP TCR Order, and the Commission should allow the Company to continue to recover internal capitalized labor costs through the TCR Rider.

1. No Double Recovery Will Occur

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[11] *In the Matter of Minnesota Power's Petition for Approval of its Transmission Cost Recovery Rider*, ORDER APPROVING COST RECOVERY, EXCLUDING INTERNAL COSTS, AUTHORIZING USE OF CURRENT FACTOR, AND REQUIRING COMPLIANCE FILING, Docket No. E015/M-10-799 (May 11, 2011) ("MP TCR Order").
[12] *Id.* at p. 4.

The Commission's concern with TCR Recovery of internal capitalized labor costs in the MP TCR Order appears to be that some "double recovery" may occur because capitalized labor costs may already be reflected in current base rates. We agree with the Department and Commission that any capital costs currently being recovered in base rates should not be eligible for TCR Rider recovery. However, none of the capital costs being requested for recovery in our 2012 TCR Rider petition are being recovered or will be recovered in the base rates established in the 2011 electric rate case.

The Company's internal costs for operating expenses (O&M) are budgeted and accounted for separately from capital projects, in strict accordance with the FERC Uniform System of Accounts (USofA) rules. Those rules require labor and overheads associated with the installation of capital projects be categorized as capital expenses not operating expenses.[13] A dollar of labor costs recorded as capital cannot also be recorded as a dollar of O&M, or vice versa. Minn. Stat. 216B.10, subd. 1, and Minn. Rule 7825.0300, subp. 2 adopt the FERC USofA standards for utility accounting in Minnesota. The Company therefore must (and does) comply with these requirements.[14]

Absent the opportunity to recover costs through a rider, the Company does not earn a return or recover depreciation expense for a capital project placed in service after the close of a rate case test year until the investment is reflected in the rate base of the next rate case. Moreover, unlike O&M costs, labor and overheads incurred as capital costs for projects after a test year *are* appropriately viewed as incremental in nature. Current base rates are only recovering the transmission capital expenditures (including capitalized labor) made through December 31, 2011, the end of the 2011 test year in our last rate case. Attachment E provides a simple example to illustrate how capitalized labor costs for a hypothetical 2012 capital project are not reflected in 2011 test year rates.[15]

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[13] See 18 CFR Ch 1, pt. 101. Attachment D provides excerpts from the FERC USofA rules.

[14] External labor costs are not treated differently from internal labor costs under the FERC USofA. If an employee of a contractor is working on a capital project, their time is charged to capital and eventually is included in rate base for that project. If, on the other hand, an outside contractor is assisting the Company with non-capital work, their costs are charged to O&M expense and are represented in a test-year.

[15] The fact that capitalized labor costs for projects not put into operation go into CWIP and that the CWIP is a representative amount reflected in current rates does not change this analysis. CWIP is merely the account into which capitalized investments are placed until the project goes into service. For all of the above-stated reasons, capitalized labor is incremental whether it is first placed into CWIP or not. To the extent CWIP was in the Company's rate base during the last rate case, that amount of CWIP reflects investments up to and including December 31, 2011. Each new expenditure placed into CWIP after that date is incremental.

We also take care that our rate riders do not recover costs included in base rates. The potential for a "double recovery" could exist if a utility did not have proper budget procedures that consistently assigned forecasted labor to construction. The Company has proper procedures that forecast Company labor to construction projects in the forecast period. Included in the forecast are the TCR eligible projects, thus excluding this cost from O&M labor costs. These procedures ensure capitalized labor costs are eliminated from the test year O&M labor costs in the Company's test year revenue requirements.

The potential for a theoretical "double recovery" (or more appropriately, the potential for a mismatch that causes overearnings) could also arise for the year a project is placed into service (and therefore stops earning AFDUC on the CWIP balance) if a utility demonstrated a pattern of having relatively higher O&M labor costs in rate case test years, and then lower O&M costs and higher capitalized labor costs in the years following a rate case test year. However, the Company has experienced very consistent levels of O&M and capitalized labor costs over the last several years, as a percentage of total labor cost. See Attachment F. This year-over-year comparison shows a consistent level of internal labor is focused on construction and therefore excluded from the O&M labor costs included in rate case test years. Indeed, the portion of labor allocated to capital fell in 2010, and O&M labor increased, the year after our 2009 rate case test year.

Accordingly, there is no risk of double recovery of the internal capital labor costs because the test year revenue requirement, upon which our current electric base rates were determined, did not include the capitalized labor costs, including the internal capitalized labor costs associated with TCR projects. The Company believes this information shows that the Commission can apply its "case by case" standard to allow the Company to recover capitalized labor costs in the TCR Rider.

2. TCR Recovery is Consistent with Statute, Past Practice and the Precedent

There is no provision in the TCR Statute or RCR Statute that precludes recovery of a utility's capitalized internal labor costs. The TCR Statute indicates a utility may recover "a current return on construction work in progress" in its TCR rider mechanism. Under the FERC USofA, internal capitalized labor is included in construction work in progress. If the Legislature had intended to exclude internal capitalized labor from CWIP eligible for TCR recovery, it could have imposed such a limitation in the statute. But it did not. There is nothing unique about the accounting for internal capitalized labor costs that warrants a treatment different than other costs to effectuate a TCR eligible project.

The Company has consistently included capitalized labor in its TCR Rider petition since 2007, and the Commission has never previously denied TCR Rider recovery of capitalized labor costs included in our annual TCR Rider petitions. For example, the Commission approved recovery of internal capitalized labor costs in our 2011 TCR Rider filing (Docket No. E002/M-10-1064, Order dated October 21, 2011). The Commission has also allowed recovery of capitalized labor costs for other utilities.[16]

3. The Proposed Adjustment Adds Unnecessary Complexity

Again, we recognize and appreciate that the Department is not recommending that we never recover the internal capitalized labor costs in rates. The MP TCR Order indicates that costs not recovered in a TCR rate could be recoverable in base rates in a future rate case. However, keeping a portion of each TCR project (internal capitalized labor) under traditional ratemaking while all other costs are recovered in the TCR Rider until a project is rolled into base rates, would introduce greater potential for errors and thereby make the Company's future rate cases and TCR Rider filings more complex. For example, internal capitalized labor costs would need to be tracked separately. We believe the better approach is to minimize complexities in regulatory accounting and future rate cases.

E. Additional Comments

1. MISO RECB Charges

The Department considers the issue of the use of the Otter Tail Power "Split" method for MISO Regional Expansion Capacity Benefit (RECB) charges to be resolved and recommends that the Commission deny the suggestion that this issue could be addressed in a broader cost recovery proceeding. While we do not believe the Commission should prejudge consideration of the Split method in a future general rate case proceeding based on the very limited record in this docket, we are not

[16] The Department comments (footnote 5 on p. 20) list a series of cases which purportedly support the recommendation regarding excluding capitalized labor. The Company does not agree the cited cases all support the Department position. For example, in Docket No. E002/M-09-1488 (the Company's request for recovery of Central Corridor costs), the Commission order (December 27, 2010) made no determination regarding recovery of internal capitalized labor in the miscellaneous docket, but instead deferred the cost recovery issues to the Company's 2011 rate case (Docket No. E002/GR-10-971). Similarly, the Commission allowed Otter Tail full recovery of internal labor costs incurred during the initial planning stages for Big Stone II (Docket No. E017/10-GR-239, order dated April 25, 2011). ("The Commission likewise agrees with the Administrative Law Judge that there is no principled basis for disallowing recovery of internal costs not reflected in rates and that it is not in the public interest to discourage Otter Tail from making the best use of its internal resources and expertise." *See* order at p. 11.)

requesting that the Commission consider applying the Split method in this proceeding.

2. *Updated Revenue Requirements and Rate Factor*

Attachments G contains our revised 2012 TCR revenue requirement calculations and rate adjustment factors using the allocators and the overall rate of return approved in the Commission's May 24, 2012 order approving the Settlement Agreement in our 2010 electric rate case. These attachments have also been updated with actual sales through June 2012 and reflect an October 1, 2012 implementation date for the TCR Rider rate factors.

CONCLUSION

We appreciate the opportunity to submit this Reply to the Department's Comments. We hope this Reply provides the Department and Commission additional information that can resolve (or at least narrow) the areas of disagreement between the Company and the Department. We continue to request that the Commission approve the project eligibility and costs requested in our Petition, approve our TCR Rate Factors as updated in this Reply, and accept our 2011 TCR Tracker True-Up.

Dated: August 31, 2012

Northern States Power Company

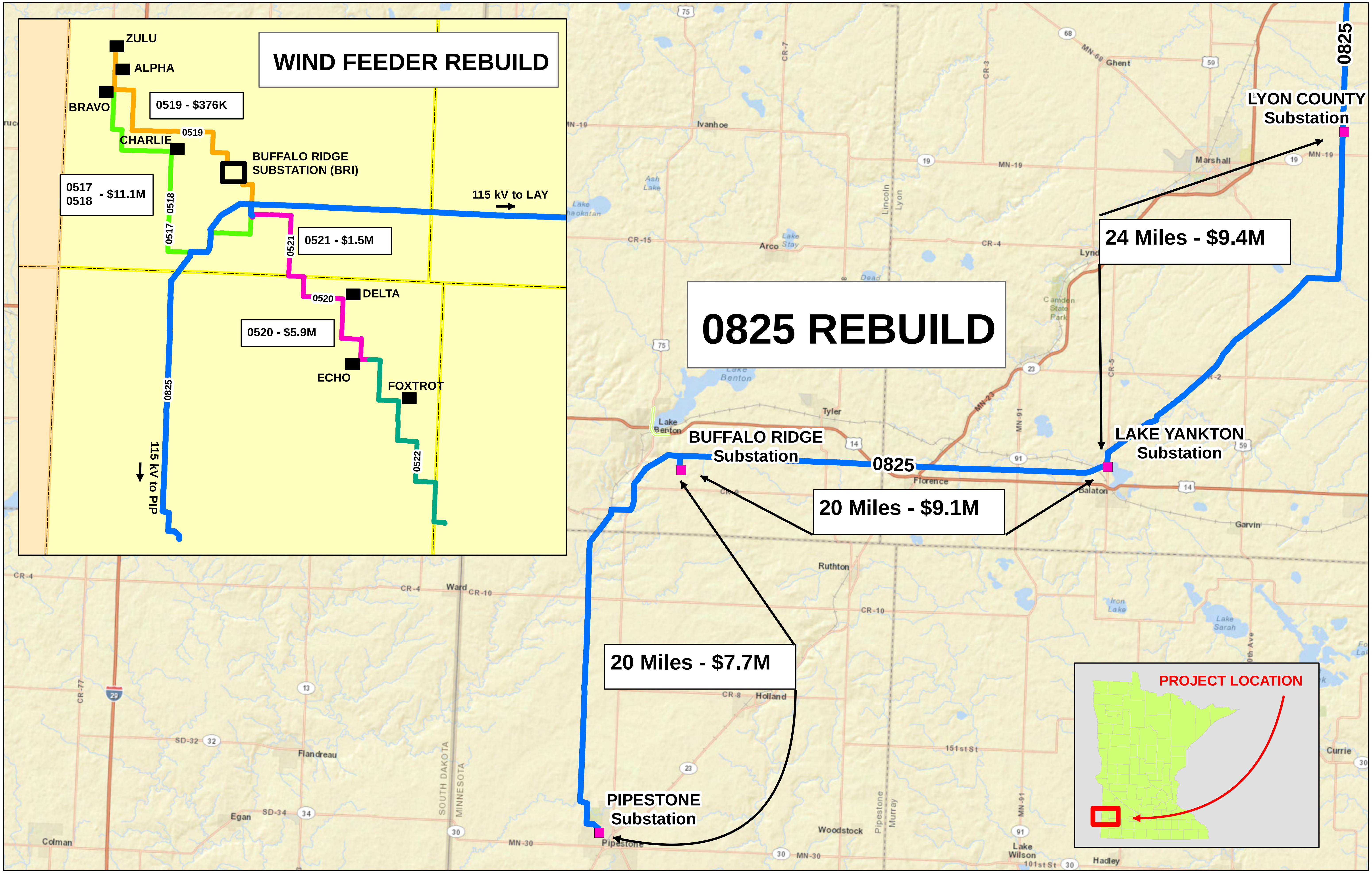
Respectfully submitted by:

/s/

PAUL J LEHMAN
MANAGER
REGULATORY COMPLIANCE AND FILINGS

Attachment A
Buffalo Ridge

Map of the 115 kV transmission line and collector facilities affected by the July 1, 2011 storm

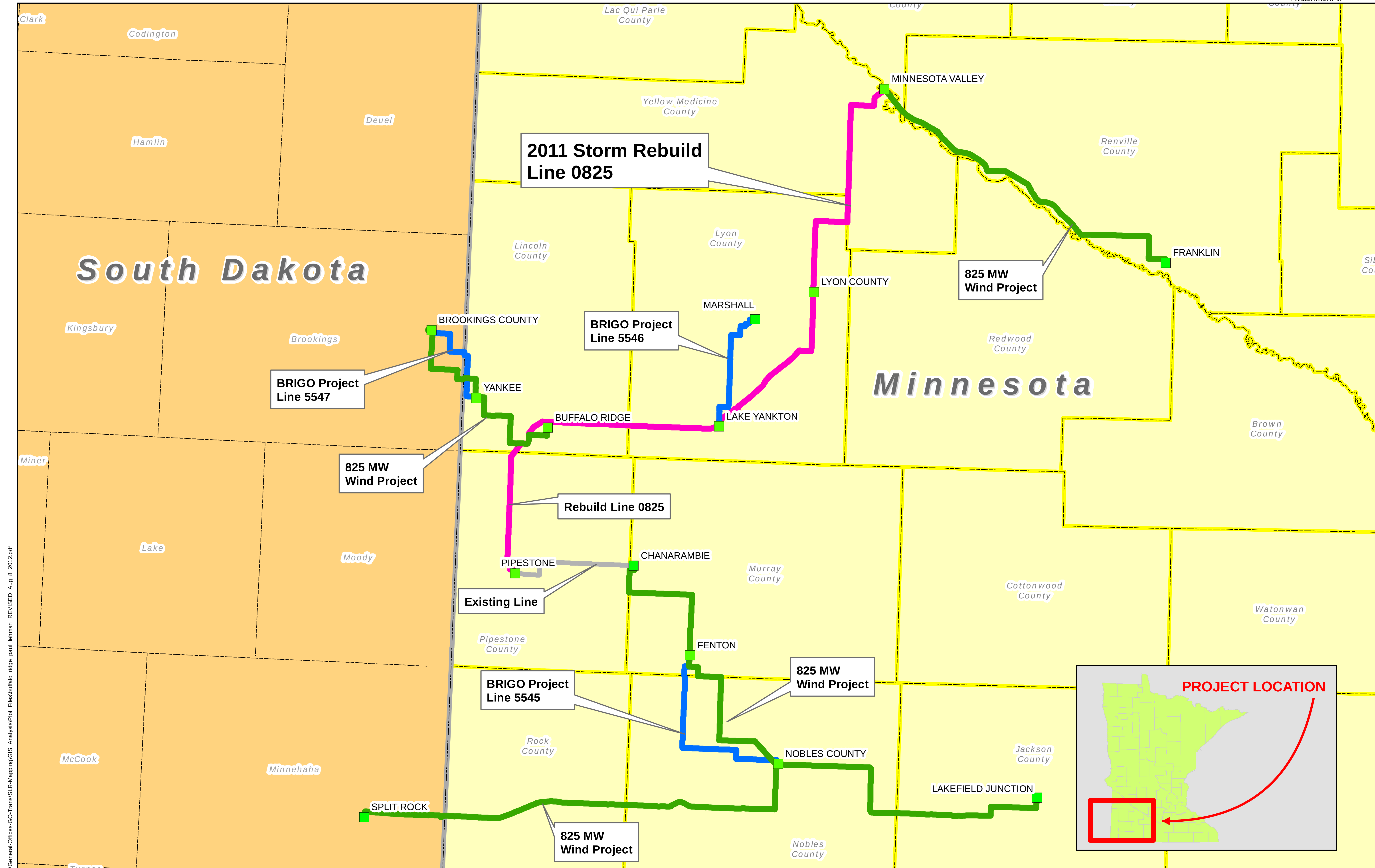


WIND FEEDER REBUILD
ZULU
ALPHA
BRAVO
CHARLIE
0519 - $376K
0519
BUFFALO RIDGE SUBSTATION (BRI)
0517
0518 - $11.1M
0518
0517
115 kV to LAY
0521
0521 - $1.5M
0520
DELTA
0520 - $5.9M
ECHO
FOXTROT
0825
0522
115 kV to PIP
0825 REBUILD
0825
LYON COUNTY Substation
24 Miles - $9.4M
LAKE YANKTON Substation
BUFFALO RIDGE Substation
0825
20 Miles - $9.1M
20 Miles - $7.7M
PIPESTONE Substation
PROJECT LOCATION
Ivanhoe
Marshall
Ghent
Arco
Lake Benton
Tyler
Florence
Balaton
Garvin
Ruthton
Holland
Ward
Flandreau
Egan
Colman
Pipestone
Woodstock
Lake Wilson
Hadley
Currie
SOUTH DAKOTA
MINNESOTA

Attachment B
Buffalo Ridge

Map showing the integration of the 115 kV transmission line with the transmission network in southwest Minnesota

Attachment B



Escalation

Source: estimate at completion 7-20-2012 (includes actuals through June 2012 of $80,052,920

	Actuals	Actuals	Acts + Fcst	Forecast	
	2010	2011	2012	2013	Total
Escalated	$ 1,104,417	$ 27,929,238	$ 34,543,229	$ 365,145	$ 63,942,029
Unescalated	$ 1,030,193	$ 24,331,964	$ 30,057,190	$ 310,804	$ 55,730,151
Dollars of escalation	$ 74,223	$ 3,597,274	$ 4,486,040	$ 54,340	$ 8,211,878

	Handy - Whitman Index						
	Actual				Forecast		
	2007	2008	2009	2010	2011	2012	2013
Factor	1.44	1.58	1.46	1.54	1.65	1.66	1.69
Increase since 2007		9.9%	1.4%	7.2%	14.8%	14.9%	17.5%
Year over year		9.9%	-7.7%	5.7%	7.1%	0.1%	2.2%

FERC Uniform System of Account Rules for Capital Projects

The FERC regulations establishing the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, 18 CFR Ch 1, pt. 101, provides in relevant part:

> 3. *Components of construction costs*
> A. For Major utilities, the cost of construction properly includible in the electric plant accounts shall include, where applicable, **the direct and overhead costs** as listed and defined hereunder:
> ****
> (1) ***Contract work*** includes amounts paid for work performed under contract by other companies, firms, or individuals, costs incidental to the award of such contracts, and the inspection of such work.
>
> (2) ***Labor*** includes the pay and expenses of employees of the utility engaged on construction work, and related workmen's compensation insurance, payroll taxes and similar items of expense. It does not include the pay and expenses included in other items hereunder.
>
> (3) ***Materials and supplies*** includes the purchase price at the point of free delivery ….
> ****
> (4) ***Transportation*** includes the cost of transporting employees, materials and supplies, tools, purchased equipment, and other equipment (when not under own power) to and from points of construction. It includes amounts paid to others as well as the cost of operating the utility's own transportation equipment.
> ***
> (11) ***Engineering and supervision*** includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.
> ***
> (12) ***General administration capitalized*** includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work. **** (Emphasis added)

In accordance with the above-referenced provision, FERC rules *require* internally-incurred costs associated with the installation of a capital item to be categorized as capital costs, and thus excluded from O&M expenses.

Illustrative Example Demonstrating No Double Recovery

The following simple example shows that internal capitalized labor costs incurred in 2012 and included in the calculation of 2012 TCR revenue requirements are not being recovered in final electric rates in Docket No. E002/GR-10-971, which used a 2011 test year.

Assume a capital project where the only costs of the project were the internal labor costs of eight Xcel Energy full-time employees with total salaries (including benefits) of $1,000,000 plus project materials of $1,000,000. Assume the project will have a 40 year life for purposes of depreciation. We show the difference between (a) a project assumed to be placed in service in 2011 and included in the 2011 test year and final rates; and (b) an identical project assumed to be placed in service in 2012.

- If those eight employees completed the project in July 2011 such that the project was included in 2011 test year rate base, the total year end plant investment would be $2,000,000 ($1 million materials plus $1 million capitalized labor), and average test year plant would be $1,000,000. Our 2011 test year revenue requirements would have included (i) depreciation of $25,000: one 40th of the $2,000,000 original investment based on a 40 year life, divided by 2 assuming the project was placed in service in July, plus (ii) a return on the average rate base of approximately $120,000 (including taxes). Total 2011 revenue requirements from this project would be approximately $145,000 and base rates would be set to collect $145,000.

  In 2012, when the project was in service for a full year, the Company would recognize a full year of depreciation ($50,000), and the revenue requirement would be $287,000. However, current rates would continue to collect only $145,000 from customers until adjusted in the next rate case to reflect the accumulated depreciation in rate base.

- If the same eight employees complete an identical project in 2012, after the 2011 test year has closed, the 2012 revenue requirement would be an additional $145,000. This new project would be incremental to the 2012 revenue requirement for the 2011 project ($287,000), even though the work was completed by the same eight employees. Thus, the total 2012 revenue requirement would be $432,000 ($145,000 for the 2012 project plus $287,000 for the 2011 project), but revenue collected would continue to be

> $145,000.
>
> The revenues included in setting 2011 rates would not recover these additional capital costs. Therefore, if the 2012 project were otherwise eligible for rider recovery, no double recovery would take place. Similarly, if there were no rider, the additional investment and depreciation would be reflected for the first time in the next rate case.

As can be seen from this simple example, capitalized labor costs incurred for a capital project in 2012 are not expensed like labor costs consumed during the period in which they were incurred and for which a representative amount has been included in operating expenses in a test year. Unless rider recovery occurs, capitalized labor costs are not recovered until the capital item is placed into service, and even then, those labor costs are not recovered all at once. Rather, the investments in capitalized labor and overheads occurring after the close of the test year, like the investment in the capital materials, is included in rate base as an incremental 2012 addition. Since the costs of the 2012 capital project were not reflected in the 2011 test year, no double recovery occurs.

Northern States Power Company, a Minnesota corporation
O&M and Capital Labor Percentages

Year		Capital Labor %	O&M Labor %	Other Labor % (1)	Total NSPM %	Non-NSPM % (2)	Total Labor %
2004	Actual	21.03	69.72	8.68	99.43	0.57	100.00
2005	Actual	21.52	69.20	8.81	99.53	0.47	100.00
2006	Actual	21.10	69.03	9.69	99.82	0.18	100.00
2007	Actual	21.21	69.44	9.24	99.89	0.11	100.00
2008	Actual	21.30	69.47	8.94	99.71	0.29	100.00
2009	Actual	22.14	67.27	9.81	99.22	0.78	100.00
2010	Actual	21.46	67.71	9.55	98.72	1.28	100.00
2011	Actual	21.95	67.15	9.23	98.33	1.67	100.00

(1) Includes Labor charged to Cost of Goods Sold, Deferred Accounts and Clearing Accounts

(2) Labor Charged to other Xcel Energy affiliates

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	71,614,000	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	447,835	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)**	**159,377,904**	**74,859,535**	**193,551,023**	**352,240,796**	**283,047,701**	**140,532,801**	**-**	**1,209,971,235**	**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)		333,000	331,984	330,968	329,952	328,936	327,920	326,904	325,888	324,872	323,856	322,840	321,824	3,928,941
Project 11 - CAPX2020 - Fargo (5)		466,595	514,682	570,474	617,369	658,343	708,570	751,634	778,710	806,402	832,989	854,363	873,879	8,434,010
Project 12 - CAPX2020 - Brookings (6)		282,318	309,741	335,337	362,086	391,795	426,122	478,596	540,441	601,722	683,659	791,416	908,510	6,111,743
Project 13 - CAPX2020 - La Crosse 1 (7)		868	2,580	4,314	6,791	9,275	12,485	18,596	26,564	34,837	44,612	56,574	68,950	286,445
Project 13 - CAPX2020 - La Crosse 2 (7)		108,123	113,357	118,760	124,266	133,750	143,349	149,102	154,773	160,456	165,943	171,233	178,324	1,721,435
Project 14 - CAPX2020 - Bemidji (8)		146,031	160,266	177,574	193,265	206,921	217,385	227,075	236,043	240,878	243,032	244,784	247,669	2,540,924
Project 17 - Pleasant Valley - Byron (12)		20,382	22,864	25,366	26,729	28,847	30,842	30,802	30,738	30,653	30,568	30,484	30,399	338,674
Project 19 - Glencoe - Waconia (20)		9,653	15,237	23,576	32,729	42,343	49,904	53,984	65,929	79,899	87,850	93,591	96,822	651,517
RECB - Schedule 26 (10)		212,187	19,070	(60,829)	7,911	60,321	407,541	235,816	322,935	173,638	40,702	197,226	(188,966)	1,427,552
Subtotal Transmission Statute Projects	-	**1,579,158**	**1,489,781**	**1,525,541**	**1,701,096**	**1,860,531**	**2,324,118**	**2,272,508**	**2,482,021**	**2,453,358**	**2,453,211**	**2,762,509**	**2,537,410**	**25,441,241**
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		313,800	312,715	311,629	310,543	309,458	308,372	307,286	306,201	305,115	304,030	302,944	301,858	3,693,952
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	-	**313,800**	**312,715**	**311,629**	**310,543**	**309,458**	**308,372**	**307,286**	**306,201**	**305,115**	**304,030**	**302,944**	**301,858**	**3,693,952**
Project 9a - SF6 Breaker Replacement (3)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Greenhouse Gas Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates (14)		(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(147,628)
Rev Requirement Impact of Project 18 Retirement (19)		(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(29,225)	(350,696)
TCR True-up Carryover (15)	(861,631)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(71,803)	(861,631)
Total Expense (16)	$ (861,631)	$ 1,779,628	$ 1,689,166	$ 1,723,841	$ 1,898,310	$ 2,056,659	$ 2,519,160	$ 2,466,465	$ 2,674,892	$ 2,645,144	$ 2,643,911	$ 2,952,123	$ 2,725,939	$ 27,775,238
Revenues (17)		1,831,746	1,688,190	1,740,445	1,576,711	1,705,822	1,892,137	2,141,367	2,074,500	3,259,753	3,192,168	3,199,743	3,456,725	$ 27,759,308
Balance (18)	(861,631)	(52,118)	(51,142)	(67,746)	253,853	604,689	1,231,712	1,556,810	2,157,202	1,542,593	994,335	746,716	15,930	$ 15,930

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)		**$0.001716**	**$0.001320**	**$0.439**	**$0.000824**						
Jan **Actual**	1,831,746	772,302	65,144	986,886	7,414	2,738,318,638	830,284,371	91,080,522	1,800,380,731	16,573,013	4,140,772
Feb **Actual**	1,688,190	658,742	58,991	964,010	6,447	2,461,515,259	708,038,342	82,411,082	1,656,650,113	14,415,723	4,147,815
Mar **Actual**	1,740,445	628,256	57,329	1,049,016	5,844	2,500,264,504	675,253,711	80,077,361	1,731,860,225	13,073,207	4,444,903
Apr **Actual**	1,576,711	516,903	49,337	1,005,820	4,651	2,271,959,891	555,578,809	68,912,379	1,637,041,847	10,426,856	4,136,038
May **Actual**	1,705,822	562,780	51,095	1,087,002	4,945	2,408,577,000	604,791,207	71,363,610	1,721,360,904	11,061,279	4,419,173
Jun **2011 Rate**	1,892,137	725,953	59,994	1,101,279	4,911	2,708,116,368	779,756,165	83,790,327	1,833,583,176	10,986,701	4,627,222
Jul **2011 Rate**	2,141,367	879,109	64,469	1,192,757	5,032	3,031,450,298	944,262,695	90,040,501	1,985,890,899	11,256,204	5,011,586
Aug **2011 Rate**	2,074,500	814,468	63,563	1,191,501	4,968	2,958,520,447	874,831,841	88,775,177	1,983,799,625	11,113,804	5,006,308
Sep	3,259,753	1,142,597	103,725	2,002,865	10,566	2,565,122,088	665,849,324	78,579,354	1,807,871,049	12,822,361	4,562,335
Oct	3,192,168	1,108,192	98,159	1,973,526	12,291	2,516,466,298	645,799,682	74,363,009	1,781,387,913	14,915,694	4,495,503
Nov	3,199,743	1,191,238	96,563	1,898,118	13,824	2,497,446,973	694,194,470	73,153,798	1,713,321,832	16,776,873	4,323,731
Dec	3,456,725	1,389,311	110,099	1,942,244	15,071	2,664,471,864	809,621,763	83,408,021	1,753,151,938	18,290,142	4,424,247
Total Jan-Dec	**$ 27,759,308**	**$ 10,389,851**	**$ 878,468**	**$ 16,395,024**	**$ 95,964**	**31,322,229,629**	**8,788,262,381**	**965,955,140**	**21,406,300,252**	**161,711,856**	**53,739,633**
Total Sept-Dec	**$ 13,108,389**	**$ 4,831,338**	**$ 408,546**	**$ 7,816,753**	**$ 51,752**	**10,243,507,224**	**2,815,465,240**	**309,504,181**	**7,055,732,733**	**62,805,069**	**17,805,816**

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	**10,243,507,224**	2,815,465,240	309,504,181	7,055,732,733	62,805,069	10,243,507,224
	MN kW Demand				17,805,816		
State of Mn Cost per kWh	**Total Sales/Costs**	**$0.001281**					
	MN retail Cost (3)	**$13,124,319**	$4,831,338	$408,546	$7,817,752	$51,751	$13,109,387
		Basis					
TCR Adjustment Factor (2)		**per kWh**	**$0.001716**	**$0.001320**		**$0.000824**	
		per kW			**$0.439**		

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 $27,775,238 less the revenues through August of 2012 $14,650,919 netting to $13,124,319.

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)		320,998	320,046	319,094	318,141	317,189	316,237	315,285	314,332	313,380	312,428	311,475	310,523	3,789,128
Project 11 - CAPX2020 - Fargo (5)		916,306	934,455	948,389	969,905	1,009,375	1,056,141	1,100,114	1,140,601	1,179,626	1,260,078	1,333,506	1,372,711	13,221,207
Project 12 - CAPX2020 - Brookings (6)		1,039,558	1,168,285	1,296,664	1,412,966	1,535,172	1,675,574	1,835,289	1,986,827	2,132,639	2,276,309	2,414,046	2,584,663	21,357,992
Project 13 - CAPX2020 - La Crosse 1 (7)		88,692	104,073	119,870	135,994	146,267	159,431	172,745	197,236	221,496	235,699	256,275	271,277	2,109,055
Project 13 - CAPX2020 - La Crosse 2 (7)		197,861	207,543	217,263	227,165	244,252	284,611	328,813	365,609	398,195	423,401	471,522	553,187	3,919,422
Project 14 - CAPX2020 - Bemidji (8)		251,672	252,773	253,662	254,369	254,809	255,210	255,612	256,017	256,423	278,870	299,856	297,405	3,166,678
Project 17 - Pleasant Valley - Byron (12)		32,496	32,401	32,305	32,209	32,114	32,018	31,923	31,827	31,732	31,636	31,541	31,445	383,647
Project 19 - Glencoe - Waconia (20)		105,601	116,462	122,709	126,725	125,521	122,867	121,706	120,553	120,154	119,753	119,352	118,951	1,440,356
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	-	**3,500,691**	**2,805,869**	**2,769,289**	**2,776,466**	**3,337,327**	**3,582,782**	**3,347,479**	**3,930,126**	**3,526,651**	**4,075,105**	**4,819,304**	**3,501,765**	**41,972,852**
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		301,004	299,996	298,987	297,979	296,971	295,962	294,954	293,946	292,937	291,929	290,921	289,912	3,545,497
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	-	**301,004**	**299,996**	**298,987**	**297,979**	**296,971**	**295,962**	**294,954**	**293,946**	**292,937**	**291,929**	**290,921**	**289,912**	**3,545,497**
Project 9a - SF6 Breaker Replacement (3)														-
Subtotal Greenhouse Gas Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates (14)		(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(12,302)	(147,628)
Rev Requirement Impact of Project 18 Retirement (19)		(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(26,412)	(316,948)
TCR True-up Carryover (15)	15,930	1,327	1,327	1,327	1,327	1,327	1,327	1,327	1,327	1,327	1,327	1,327	1,327	15,930
Total Expense (16)	$ 15,930	$ 3,764,307	$ 3,068,477	$ 3,030,888	$ 3,037,057	$ 3,596,910	$ 3,841,357	$ 3,605,046	$ 4,186,684	$ 3,782,201	$ 4,329,646	$ 5,072,838	$ 3,754,290	$ 45,069,702
Revenues (17)		3,947,556	3,493,416	3,685,767	3,307,849	3,443,527	3,909,902	4,418,067	4,285,310	3,664,153	3,590,044	3,584,529	3,863,216	$ 45,193,336
Balance (18)	15,930	(183,249)	(608,188)	(1,263,066)	(1,533,858)	(1,380,475)	(1,449,020)	(2,262,042)	(2,360,667)	(2,242,619)	(1,503,017)	(14,708)	(123,634)	$ (123,634)

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)		**$0.001913**	**$0.001472**	**$0.490**	**$0.000919**						
Jan	3,947,556	1,595,995	140,762	2,192,911	17,888	2,722,773,506	834,289,207	95,626,377	1,773,393,766	19,464,156	4,475,329
Feb	3,493,416	1,345,218	129,409	2,003,516	15,273	2,427,962,377	703,198,165	87,914,022	1,620,230,830	16,619,360	4,088,807
Mar	3,685,767	1,350,315	136,385	2,184,594	14,473	2,580,932,139	705,862,599	92,652,975	1,766,667,895	15,748,670	4,458,355
Apr	3,307,849	1,133,697	119,996	2,041,689	12,467	2,338,812,960	592,627,738	81,518,861	1,651,101,067	13,565,294	4,166,711
May	3,443,527	1,141,487	119,753	2,170,983	11,304	2,446,015,097	596,699,892	81,353,727	1,755,660,907	12,300,571	4,430,578
Jun	3,909,902	1,499,438	123,831	2,276,445	10,188	2,719,972,829	783,815,067	84,124,569	1,840,947,312	11,085,881	4,645,807
Jul	4,418,067	1,811,406	132,957	2,463,273	10,431	3,040,601,052	946,892,702	90,324,078	1,992,033,511	11,350,760	5,027,087
Aug	4,285,310	1,677,200	131,254	2,466,554	10,302	2,971,801,456	876,738,043	89,166,917	1,994,686,801	11,209,696	5,033,783
Sep	3,664,153	1,289,215	116,405	2,246,655	11,878	2,582,783,853	673,923,042	79,079,596	1,816,856,146	12,925,069	4,585,010
Oct	3,590,044	1,240,224	110,462	2,225,551	13,807	2,538,169,030	648,313,621	75,042,252	1,799,789,326	15,023,830	4,541,940
Nov	3,584,529	1,329,629	108,032	2,131,359	15,509	2,508,933,630	695,049,334	73,391,584	1,723,617,159	16,875,554	4,349,713
Dec	3,863,216	1,549,255	123,197	2,173,866	16,898	2,669,929,240	809,856,197	83,693,698	1,757,992,037	18,387,309	4,436,461
Total Jan-Dec	**$ 45,193,336**	**$ 16,963,079**	**$ 1,492,443**	**$ 26,577,396**	**$ 160,418**	**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**	**$0.001429**					
	MN retail Cost	**$45,069,702**	$16,963,079	$1,492,444	$26,565,319	$160,417	$45,181,260
		Basis					
TCR Adjustment Factor (2)		**per kWh**	**$0.001913**	**$0.001472**		**$0.000919**	
		per kW			**$0.490**		

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)
TCR Rider Factor Calculation

TCR Projected Tracker Activity for 2010-2013	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
Project 7 - BRIGO	5,127,439	-	-	-
Project 8 - Chisago Apple River	3,124,809	3,791,754	3,928,941	3,789,128
Project 11 - CAPX2020 - Fargo	805,119	3,119,587	8,434,010	13,221,207
Project 12 - CAPX2020 - Brookings	-	-	6,111,743	21,357,992
Project 13 - CAPX2020 - La Crosse 1	-	95	286,445	2,109,055
Project 13 - CAPX2020 - La Crosse 2	795,666	1,070,725	1,721,435	3,919,422
Project 14 - CAPX2020 - Bemidji	280,206	865,461	2,540,924	3,166,678
Project 17 - Pleasant Valley - Byron		(36,937)	338,674	383,647
Project 19 - Glencoe - Waconia		13,869	651,517	1,440,356
RECB - Schedule 26	948,958	2,878,813	1,427,552	(7,414,634)
Subtotal Transmission Statute Projects	**11,082,197**	**11,703,368**	**25,441,241**	**41,972,852**
Project 15 - Blue Lake/Wilmarth/Lakefield	460,988	-	-	-
Project 16 - Nobles Network Upgrade	91,828	-	-	-
Project 18 - Buffalo Ridge Restoration		150,391	3,693,952	3,545,497
Project Amortizations/Expenses	1,363,850	-	-	-
Subtotal Renewable Statute Projects	**1,916,665**	**150,391**	**3,693,952**	**3,545,497**
Project 9a - SF6 Breaker Replacement	286,509	-	-	-
Subtotal Greenhouse Gas Projects	**286,509**	**-**	**-**	**-**
Revenue Requirement in Base Rates	(439,788)	(110,136)	(147,628)	(147,628)
Rev Requirement Impact of Project 18 Retirement	-	(67,146)	(350,696)	(316,948)
TCR True-up Carryover	(4,429,830)	(2,029,342)	(861,631)	15,930
Total Expense	$ 8,415,753	$ 9,647,135	$ 27,775,238	$ 45,069,702
Revenues	10,445,095	10,508,766	27,759,308	45,193,336
Balance	(2,029,342)	(861,631)	15,930	(123,634)

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	661	(992)	(2,472)	(3,274)	(3,680)	(2,688)	(4,143)	(5,749)	(2,435)	2,689	5,496	6,910	(9,675)
Plus Equity Return	1,256	(1,883)	(4,693)	(6,218)	(6,989)	(5,105)	(7,867)	(10,917)	(4,623)	5,106	10,437	13,121	(18,373)
Total Return	1,918	(2,874)	(7,165)	(9,492)	(10,669)	(7,793)	(12,010)	(16,665)	(7,058)	7,796	15,933	20,031	(28,049)
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	670	(1,506)	(3,393)	(4,426)	(4,859)	(3,345)	(5,066)	(7,026)	23	10,943	16,622	20,582	19,218
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	732	3,791	6,551	11,074
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	1,273	(937)	(2,920)	(3,998)	(4,539)	(3,206)	(5,149)	(7,296)	(2,793)	3,439	4,187	3,371	(18,570)
Total Revenue Requirements	3,190	(3,811)	(10,085)	(13,490)	(15,208)	(10,999)	(17,159)	(23,962)	(9,851)	11,234	20,120	23,402	(46,618)
MN Jurisdictional Revenue Requirement	0	(2,826)	(7,479)	(10,004)	(11,278)	(8,157)	(12,725)	(17,770)	(7,305)	8,331	14,920	17,355	(36,937)

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
Pleasant Valley - Byron													
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	8,052	9,078	10,112	10,675	10,737	10,748	10,730	10,702	10,667	10,631	10,596	10,561	123,289
Plus Equity Return	15,290	17,239	19,203	20,272	20,388	20,409	20,376	20,323	20,256	20,189	20,121	20,054	234,120
Total Return	23,342	26,317	29,316	30,948	31,125	31,157	31,105	31,025	30,922	30,820	30,718	30,615	357,409
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	23,550	25,808	28,086	29,347	18,372	7,224	7,196	7,152	7,105	7,058	7,010	6,963	174,870
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	8,435	9,462	10,498	11,062	11,938	12,764	12,747	12,721	12,686	12,651	12,616	12,580	140,161
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	4,117	4,486	4,858	5,062	7,738	10,394	10,391	10,387	10,375	10,362	10,350	10,338	98,859
Total Revenue Requirements	27,459	30,803	34,174	36,009	38,863	41,551	41,497	41,411	41,297	41,182	41,068	40,953	456,268
MN Jurisdictional Revenue Requirement	20,382	22,864	25,366	26,729	28,847	30,842	30,802	30,738	30,653	30,568	30,484	30,399	338,674

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	27	82	161	248	44,597	45,118
Plus Equity Return	0	0	0	0	0	0	7	51	157	306	471	84,687	85,678
Total Return	0	0	0	0	0	0	10	78	239	467	719	129,283	130,796
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	41,714	41,714
Plus Deferred Taxes	0	0	0	0	0	0	(3,007)	(16,368)	(30,214)	(35,439)	(37,406)	730,622	608,190
Plus Gross Up for Income Tax	0	0	0	0	0	0	8,302	44,443	82,174	96,648	102,335	(656,378)	(322,476)
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	42,445	42,445
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	5,294	28,076	51,960	61,210	64,929	73,514	284,983
Total Revenue Requirements	0	0	0	0	0	0	5,305	28,153	52,199	61,676	65,649	202,798	415,780
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	150,391	150,391

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	88,696	88,286	87,877	87,468	87,059	86,649	86,240	85,831	85,422	85,013	84,603	84,194	1,037,338
Plus Equity Return	168,429	167,652	166,875	166,098	165,321	164,543	163,766	162,989	162,212	161,435	160,658	159,881	1,969,859
Total Return	257,125	255,938	254,752	253,566	252,379	251,193	250,007	248,820	247,634	246,447	245,261	244,075	3,007,197
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	29,776	29,227	28,679	28,130	27,582	27,034	26,485	25,937	25,389	24,840	24,292	23,744	321,115
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	78,655	78,383	78,111	77,839	77,567	77,295	77,022	76,750	76,478	76,206	75,934	75,662	925,902
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	165,632	165,356	165,080	164,804	164,527	164,251	163,975	163,699	163,423	163,146	162,870	162,594	1,969,358
Total Revenue Requirements	422,757	421,295	419,832	418,369	416,907	415,444	413,982	412,519	411,056	409,594	408,131	406,669	4,976,555
MN Jurisdictional Revenue Requirement	313,800	312,715	311,629	310,543	309,458	308,372	307,286	306,201	305,115	304,030	302,944	301,858	3,693,952

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	1,278	1,446	1,574	1,670	1,776	1,831	1,897	1,976	2,051	2,108	2,160	2,242	22,009
Plus Equity Return	2,427	2,746	2,989	3,171	3,372	3,477	3,602	3,752	3,896	4,003	4,101	4,258	41,794
Total Return	3,705	4,192	4,563	4,841	5,148	5,307	5,498	5,728	5,947	6,111	6,260	6,501	63,803
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	(1,730)	(1,730)
Plus Gross Up for Income Tax	1,713	1,938	2,109	2,238	2,380	2,453	2,541	2,647	2,749	2,825	2,894	4,778	31,264
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	1,713	1,938	2,109	2,238	2,380	2,453	2,541	2,647	2,749	2,825	2,894	3,048	29,533
Total Revenue Requirements	5,418	6,130	6,672	7,079	7,528	7,761	8,040	8,375	8,696	8,936	9,154	9,548	93,336
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	6,788	7,081	13,869

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
Glencoe - Waconia													
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	3,053	4,820	7,457	10,352	13,393	16,052	17,599	21,377	25,795	28,363	30,232	31,253	209,746
Plus Equity Return	5,798	9,152	14,161	19,658	25,433	30,482	33,420	40,593	48,984	53,860	57,409	59,348	398,299
Total Return	8,852	13,972	21,618	30,010	38,826	46,533	51,018	61,970	74,780	82,223	87,640	90,602	608,045
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	6,613	10,442	16,161	22,443	29,048	33,921	36,383	44,594	54,201	59,622	63,535	65,810	442,773
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	1,115	2,187	2,185	2,186	2,408	2,628	2,627	15,336
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	4,153	6,556	10,144	14,082	18,219	20,699	21,709	26,851	32,861	36,129	38,447	39,839	269,690
Total Revenue Requirements	13,005	20,528	31,762	44,093	57,045	67,232	72,728	88,821	107,641	118,352	126,087	130,441	877,735
MN Jurisdictional Revenue Requirement	9,653	15,237	23,576	32,729	42,343	49,904	53,984	65,929	79,899	87,850	93,591	96,822	651,517

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	$\boxed{5,127,439}$

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	103,000	103,318	104,460	105,381	106,003	106,121	105,363	104,493	103,622	102,752	101,881	101,011	1,247,405
Plus Equity Return	195,592	196,197	198,366	200,113	201,294	201,518	200,080	198,427	196,774	195,121	193,468	191,815	2,368,765
Total Return	298,592	299,515	302,826	305,494	307,297	307,639	305,443	302,919	300,396	297,873	295,350	292,826	3,616,170
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	(36,379)	(34,621)	(33,597)	(33,454)	(39,858)	(85,687)	(122,463)	(123,533)	(124,699)	(125,866)	(127,032)	(128,198)	(1,015,387)
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	136,624	136,758	137,673	138,176	143,635	151,131	152,597	151,632	150,675	149,718	148,761	147,805	1,745,185
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	117,224	117,783	119,171	120,202	118,971	124,063	130,456	130,222	130,012	129,803	129,593	129,384	1,496,883
Total Revenue Requirements	415,816	417,298	421,997	425,696	426,268	431,703	435,899	433,141	430,408	427,676	424,943	422,210	5,113,054
MN Jurisdictional Revenue Requirement	308,362	309,461	312,946	315,689	316,113	320,143	323,255	321,210	319,184	317,157	315,130	313,104	3,791,754

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	100,365	99,943	99,520	99,098	98,676	98,254	97,832	97,410	96,988	96,566	96,144	95,721	1,176,517
Plus Equity Return	190,588	189,786	188,985	188,183	187,382	186,580	185,779	184,977	184,175	183,374	182,572	181,771	2,234,153
Total Return	290,953	289,729	288,505	287,282	286,058	284,834	283,611	282,387	281,163	279,940	278,716	277,492	3,410,670
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	62,977	62,412	61,846	61,280	60,715	60,149	59,584	59,018	58,452	57,887	57,321	56,756	718,396
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	137,812	137,392	136,971	136,551	136,130	135,710	135,289	134,869	134,448	134,028	133,608	133,187	1,625,996
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	157,670	157,525	157,380	157,235	157,090	156,945	156,800	156,655	156,509	156,364	156,219	156,074	1,882,467
Total Revenue Requirements	448,623	447,254	445,886	444,517	443,148	441,779	440,410	439,042	437,673	436,304	434,935	433,566	5,293,137
MN Jurisdictional Revenue Requirement	333,000	331,984	330,968	329,952	328,936	327,920	326,904	325,888	324,872	323,856	322,840	321,824	3,928,941

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

SF6 Breaker	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	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	286,509

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 - Fargo													
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

	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 - Fargo													
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	49,359	52,195	56,082	61,619	66,577	73,147	80,488	86,375	93,793	104,187	117,122	130,185	971,127
Plus Equity Return	93,730	99,116	106,497	117,011	126,426	138,903	152,843	164,021	178,109	197,847	222,409	247,215	1,844,127
Total Return	143,088	151,311	162,579	178,630	193,003	212,050	233,331	250,396	271,901	302,034	339,531	377,400	2,815,254
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	93,604	101,976	110,293	115,977	132,439	145,098	158,858	170,095	184,357	204,673	226,615	247,400	1,891,384
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	71,516	75,473	81,224	89,078	95,971	105,290	115,641	123,608	133,652	147,734	166,374	185,843	1,391,404
Total Revenue Requirements	214,604	226,784	243,803	267,708	288,973	317,340	348,972	374,004	405,554	449,768	505,905	563,244	4,206,658
MN Jurisdictional Revenue Requirement	159,147	168,179	180,800	198,527	214,298	235,334	258,792	277,355	300,752	333,540	375,170	417,692	3,119,587

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)	(1,204,542)	(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	142,547	155,855	170,422	184,063	197,002	210,252	221,257	229,828	238,589	247,001	253,758	259,928	2,510,502
Plus Equity Return	270,690	295,962	323,624	349,527	374,097	399,259	420,158	436,433	453,070	469,044	481,875	493,591	4,767,329
Total Return	413,237	451,817	494,047	533,589	571,099	609,511	641,415	666,261	691,659	716,044	735,634	753,519	7,277,831
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	278,451	291,812	299,156	320,048	348,283	355,950	358,774	377,867	396,528	414,331	429,525	443,465	4,314,189
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	215,368	241,571	274,506	298,140	315,832	345,087	371,199	382,831	394,741	406,173	415,378	423,785	4,084,612
Total Revenue Requirements	628,605	693,388	768,553	831,730	886,931	954,598	1,012,614	1,049,092	1,086,399	1,122,217	1,151,012	1,177,304	11,362,443
MN Jurisdictional Revenue Requirement	466,595	514,682	570,474	617,369	658,343	708,570	751,634	778,710	806,402	832,989	854,363	873,879	8,434,010

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

CAPX2020 - Brookings	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	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	44,330	45,138	46,157	47,423	48,531	49,509	51,941	54,777	58,853	65,489	72,466	80,232	664,846
Plus Equity Return	84,181	85,715	87,650	90,054	92,158	94,014	98,634	104,019	111,759	124,360	137,610	152,358	1,262,513
Total Return	128,510	130,853	133,807	137,477	140,689	143,523	150,576	158,797	170,612	189,849	210,077	232,590	1,927,359
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	97,498	101,471	106,689	106,244	109,808	112,023	115,986	120,286	127,626	140,169	153,791	169,028	1,460,620
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	(99,733)	(93,355)	(128,698)	(129,344)	(103,273)	(105,664)	(105,348)	(103,731)	(105,670)	(110,886)	(118,020)	(126,237)	(1,329,959)
Total Revenue Requirements	28,778	37,498	5,109	8,132	37,416	37,859	45,228	55,066	64,942	78,963	92,057	106,353	597,400
Total Revenue Requirements MVP Cost Allocation @ 9.1%	28,778	37,498	5,109	8,132	37,416	37,859	45,228	55,066	64,942	78,963	92,057	106,353	597,400
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

CAPX2020 - Brookings	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	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	88,999	97,695	105,813	114,297	123,710	134,577	151,188	170,768	190,165	216,092	250,185	287,231	1,930,719
Plus Equity Return	169,006	185,518	200,934	217,044	234,920	255,555	287,099	324,280	361,115	410,348	475,090	545,439	3,666,348
Total Return	258,005	283,212	306,748	331,341	358,630	390,132	438,286	495,048	551,280	626,440	725,275	832,670	5,597,067
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	168,468	183,602	197,320	211,774	229,317	251,367	285,053	324,346	363,980	418,514	490,801	569,582	3,694,124
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	122,339	134,076	145,024	156,467	169,202	183,947	206,486	233,043	259,370	294,597	340,934	391,291	2,636,778
Total Revenue Requirements	380,344	417,289	451,772	487,808	527,832	574,079	644,772	728,091	810,651	921,037	1,066,209	1,223,960	8,233,845
Total Revenue Requirements MVP Cost Allocation @ 9.1%	380,344	417,289	451,772	487,808	527,832	574,079	644,772	728,091	810,651	921,037	1,066,209	1,223,960	8,233,845
MN Jurisdictional Revenue Requirement	282,318	309,741	335,337	362,086	391,795	426,122	478,596	540,441	601,722	683,659	791,416	908,510	6,111,743

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

CAPX2020 - La Crosse 1	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	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	2	5	5	5	5	5	5	5	5	40
Plus Equity Return	0	0	0	4	9	9	9	9	9	9	9	9	77
Total Return	0	0	0	7	14	14	14	14	14	14	14	14	117
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	10	10	10	10	10	10	10	10	87
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	5	5	5	5	5	5	5	5	45
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	7	15	15	15	15	15	15	15	15	128
MN Jurisdictional Revenue Requirement	0	0	0	6	11	11	11	11	11	11	11	11	95

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

CAPX2020 - La Crosse 1	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	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	360	1,071	1,790	2,818	3,849	5,182	7,714	11,011	14,434	18,475	23,421	28,538	118,664
Plus Equity Return	684	2,033	3,399	5,352	7,310	9,840	14,649	20,910	27,409	35,083	44,475	54,192	225,338
Total Return	1,044	3,104	5,189	8,170	11,159	15,022	22,364	31,922	41,843	53,559	67,896	82,730	344,002
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	557	1,649	2,760	4,292	5,827	7,768	12,304	18,989	26,179	34,944	45,676	56,789	217,733
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	359	1,068	1,785	2,810	3,838	5,167	7,696	10,993	14,417	18,463	23,413	28,535	118,545
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	125	372	622	979	1,336	1,797	2,689	3,865	5,091	6,543	8,321	10,160	41,901
Total Revenue Requirements	1,169	3,476	5,812	9,149	12,495	16,819	25,053	35,787	46,933	60,102	76,217	92,891	385,903
MN Jurisdictional Revenue Requirement	868	2,580	4,314	6,791	9,275	12,485	18,596	26,564	34,837	44,612	56,574	68,950	286,445

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

CAPX2020 - La Crosse 2	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	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	24,562	24,854	25,324	26,068	26,924	27,698	28,472	29,247	30,070	30,987	31,951	32,917	339,074
Plus Equity Return	46,642	47,196	48,090	49,503	51,127	52,597	54,067	55,538	57,102	58,843	60,674	62,508	643,887
Total Return	71,204	72,050	73,414	75,571	78,051	80,294	82,539	84,785	87,172	89,830	92,625	95,425	982,961
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	50,955	52,917	54,491	54,695	57,589	59,332	61,079	62,829	64,686	66,750	68,918	71,092	725,333
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	33,347	33,776	34,429	35,407	36,595	37,649	38,704	39,759	40,881	42,130	43,442	44,758	460,877
Total Revenue Requirements	104,551	105,825	107,843	110,978	114,646	117,944	121,243	124,545	128,052	131,960	136,067	140,183	1,443,837
MN Jurisdictional Revenue Requirement	77,533	78,478	79,974	82,299	85,019	87,465	89,912	92,360	94,961	97,859	100,905	103,958	1,070,725

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

CAPX2020 - La Crosse 2	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	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	34,200	35,855	37,564	39,305	42,310	45,351	47,170	48,963	50,760	52,494	54,167	55,679	543,817
Plus Equity Return	64,945	68,088	71,332	74,638	80,344	86,119	89,573	92,978	96,390	99,685	102,861	105,731	1,032,684
Total Return	99,145	103,943	108,896	113,943	122,654	131,470	136,743	141,941	147,150	152,179	157,028	161,410	1,576,501
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	6,561	6,561
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)	92,674	(293,400)
Plus Gross Up for Income Tax	74,002	77,684	81,489	85,368	91,004	96,723	100,788	104,801	108,826	112,720	116,483	(20,403)	1,029,485
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	46,520	48,773	51,100	53,471	57,537	61,652	64,129	66,572	69,019	71,382	73,661	78,832	742,645
Total Revenue Requirements	145,665	152,716	159,996	167,413	180,190	193,122	200,873	208,513	216,169	223,561	230,688	240,242	2,319,147
MN Jurisdictional Revenue Requirement	108,123	113,357	118,760	124,266	133,750	143,349	149,102	154,773	160,456	165,943	171,233	178,324	1,721,435

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

CAPX2020 - Bemidji	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	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

CAPX2020 - Bemidji	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	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	13,522	14,168	14,003	17,457	18,916	18,532	20,684	24,805	27,941	30,008	33,729	40,354	274,120
Plus Equity Return	25,678	26,904	26,591	33,149	35,921	35,191	39,279	47,104	53,058	56,984	64,050	76,631	520,541
Total Return	39,200	41,072	40,595	50,606	54,838	53,722	59,963	71,909	80,999	86,993	97,780	116,985	794,660
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	27,297	29,589	29,642	35,635	41,068	40,933	45,672	53,672	60,672	64,066	65,298	84,400	577,945
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	18,340	19,240	19,026	23,686	25,726	25,220	28,149	33,731	37,999	40,785	45,680	54,804	372,385
Total Revenue Requirements	57,540	60,312	59,620	74,292	80,563	78,942	88,112	105,640	118,998	127,777	143,460	171,789	1,167,046
MN Jurisdictional Revenue Requirement	42,671	44,727	44,213	55,094	59,745	58,542	65,342	78,341	88,247	94,758	106,387	127,395	865,461

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

CAPX2020 - Bemidji	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	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	46,206	50,721	56,213	61,190	65,520	68,835	71,907	74,752	76,284	76,965	77,518	78,431	804,539
Plus Equity Return	87,742	96,316	106,745	116,197	124,419	130,714	136,547	141,951	144,860	146,153	147,202	148,936	1,527,783
Total Return	133,948	147,037	162,958	177,387	189,939	199,549	208,454	216,703	221,145	223,118	224,720	227,367	2,332,322
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	97,504	105,077	114,033	122,322	129,943	136,220	141,698	146,321	149,102	150,746	152,198	154,097	1,599,262
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	62,788	68,876	76,274	82,983	88,829	93,316	97,466	101,298	103,370	104,300	105,058	106,298	1,090,854
Total Revenue Requirements	196,736	215,913	239,231	260,370	278,768	292,865	305,920	318,001	324,514	327,417	329,777	333,664	3,423,177
MN Jurisdictional Revenue Requirement	146,031	160,266	177,574	193,265	206,921	217,385	227,075	236,043	240,878	243,032	244,784	247,669	2,540,924

Transmission Cost Recovery Rider
TCR Tracker Account Calculation - 2010

Blue Lake/Wilmarth/Lakefield	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	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

Nobles Network Upgrade	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	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	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	4,994	12,780	17,773
Plus Deferred Taxes	(3,232)	(4,647)	(4,654)	(5,688)	(6,485)	(9,096)	(10,684)	(10,764)	(11,070)	(11,888)	419,358	1,091,413	1,432,563
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	(405,570)	(1,095,701)	(1,256,664)
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	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**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	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**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	1,059,954	14,503,835
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)	(837,156)	(10,621,852)
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	222,798	3,881,983
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	165,223	2,878,813

RECB Expense 2012	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Schedule 26	2,040,702	1,829,768	1,934,359	1,705,753	2,230,619	2,731,639	2,920,470	2,795,615	2,536,710	1,940,921	2,098,924	2,228,709	26,994,189
Schedule 26A	154,398	117,149	130,631	118,623	125,321	151,934	162,437	155,493	141,092	107,954	116,743	123,961	1,605,737
Net RECB Expense	2,195,100	1,946,917	2,064,990	1,824,376	2,355,940	2,883,574	3,082,907	2,951,108	2,677,803	2,048,875	2,215,666	2,352,670	28,599,926

RECB Revenue 2012	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Schedule 26	(1,151,535)	(1,268,224)	(1,480,343)	(1,214,309)	(1,639,460)	(1,571,161)	(1,840,801)	(1,663,350)	(1,746,302)	(1,328,017)	(1,266,601)	(1,881,612)	(18,051,714)
Schedule 26A	(757,703)	(653,002)	(666,597)	(599,410)	(635,215)	(763,366)	(924,411)	(852,695)	(697,572)	(666,024)	(683,360)	(725,636)	(8,624,990)
Net RECB Revenue	(1,909,238)	(1,921,226)	(2,146,940)	(1,813,719)	(2,274,675)	(2,334,527)	(2,765,211)	(2,516,045)	(2,443,874)	(1,994,041)	(1,949,961)	(2,607,248)	(26,676,704)
Total 2012 Rev Requirement	285,863	25,691	(81,950)	10,657	81,265	549,047	317,696	435,063	233,929	54,834	265,706	(254,578)	1,923,222
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	212,187	19,070	(60,829)	7,911	60,321	407,541	235,816	322,935	173,638	40,702	197,226	(188,966)	1,427,552

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	4,785,480	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-10-971	Rate	Ratio	Weighted Cost
Long Term Debt	6.0936%	46.8780%	2.86%
Short Term Debt	2.4326%	0.5604%	0.01%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	10.3700%	52.5616%	5.45%
Required Rate of Return			8.32%

	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)	74.2271%	74.1583%
36 Month Coincident Peak Demand Allocator	83.9899%	83.8019%
State of Minnesota Retail Demand Allocator	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	6.0936%	46.8780%	2.8600%
(2)	Short Term Debt	2.4326%	0.5604%	0.0100%
(3)	Preferred Stock	0.0000%	0.0000%	0.0000%
(4)	Common Equity	10.3700%	52.5616%	5.4500%
(5)	Required Rate of Return			8.3200%
(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	2011 Minnesota Jurisdiction	2012 Minnesota Jurisdiction	2013 Minnesota Jurisdiction	2014 Minnesota Jurisdiction	2015 Minnesota Jurisdiction	2016 Minnesota Jurisdiction
	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)	(4,610,012)	(9,220,026)	(9,220,026)	(9,220,026)	(9,220,026)	(9,220,026)
(15)	Depreciation Reserve	(7,082,529)	(14,329,089)	(14,657,149)	(14,985,211)	(15,313,271)	(15,641,332)	(5,257,155)	(10,636,065)	(10,879,574)	(11,123,085)	(11,366,594)	(11,610,104)
(16)	Accumulated Deferred Taxes	864,643	1,699,707	1,650,395	1,602,567	1,578,231	1,607,673	641,799	1,261,643	1,225,040	1,189,539	1,171,475	1,193,329
(17)	Average Rate Base	7,198	208,004	585,376	961,266	1,313,662	1,612,281	5,343	154,395	434,508	713,520	975,093	1,196,749
	Revenue Requirement Components												
(18)	Debt Return	207	5,970	16,800	27,588	37,702	46,272	153	4,431	12,470	20,478	27,985	34,347
(19)	Equity Return	392	11,336	31,903	52,389	71,595	87,869	291	8,415	23,681	38,887	53,143	65,223
(20)	Current Income Tax Requirement	(1,724,505)	66,808	61,317	92,101	41,773	9,247	(1,312,359)	50,841	46,663	70,090	31,790	7,037
(21)	Book Depreciation	(52,362)	(328,061)	(328,061)	(328,061)	(328,061)	(328,061)	(38,867)	(243,510)	(243,510)	(243,510)	(243,510)	(243,510)
(22)	Annual Deferred Tax	1,729,287	(59,160)	(39,463)	(56,192)	7,521	51,362	1,283,599	(43,913)	(29,293)	(41,710)	5,582	38,125
(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)	3,104,913	(351,061)	(315,253)	(345,665)	(229,838)	(150,136)
(26)	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-
(27)	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-
(28)	Property Taxes	-	(171,042)	(171,042)	(171,042)	(171,042)	(171,042)	-	(126,960)	(126,960)	(126,960)	(126,960)	(126,960)
(29)	Total Revenue Requirements (*)	(46,981)	(474,150)	(428,546)	(383,216)	(340,513)	(304,352)	(67,183)	(350,696)	(316,948)	(282,725)	(251,970)	(225,739)

* 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)		308,362	309,461	312,946	315,689	316,113	320,143	323,255	321,210	319,184	317,157	315,130	313,104	3,791,754
Project 11 - CAPX2020 - Fargo (5)		159,147	168,179	180,800	198,527	214,298	235,334	258,792	277,355	300,752	333,540	375,170	417,692	3,119,587
Project 12 - CAPX2020 - Brookings (6)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 13 - CAPX2020 - La Crosse 1 (7)		-	-	-	6	11	11	11	11	11	11	11	11	95
Project 13 - CAPX2020 - La Crosse 2 (7)		77,533	78,478	79,974	82,299	85,019	87,465	89,912	92,360	94,961	97,859	100,905	103,958	1,070,725
Project 14 - CAPX2020 - Bemidji (8)		42,671	44,727	44,213	55,094	59,745	58,542	65,342	78,341	88,247	94,758	106,387	127,395	865,461
Project 17 - Pleasant Valley - Byron (12)		-	(2,826)	(7,479)	(10,004)	(11,278)	(8,157)	(12,725)	(17,770)	(7,305)	8,331	14,920	17,355	(36,937)
Project 19 - Glencoe - Waconia (20)		-	-	-	-	-	-	-	-	-	-	6,788	7,081	13,869
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	165,223	2,878,813
Subtotal Transmission Statute Projects	**-**	**648,759**	**843,163**	**1,527,750**	**709,460**	**866,810**	**1,002,095**	**1,028,876**	**897,690**	**1,022,737**	**1,004,223**	**999,986**	**1,151,819**	**11,703,368**
Project 15 - Blue Lake/Wilmarth/Lakefield (9)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 16 - Nobles Network Upgrade (11)		-	-	-	-	-	-	-	-	-	-	-	-	-
Project 18 - Buffalo Ridge Restoration (13)		-	-	-	-	-	-	-	-	-	-	-	150,391	150,391
Project Amortizations/Expenses (4)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Renewable Statute Projects	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**150,391**	**150,391**
Project 9a - SF6 Breaker Replacement (3)		-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Greenhouse Gas Projects	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Revenue Requirement in Base Rates (14)		-	(9,504)	(9,504)	(9,504)	(9,504)	(9,504)	(9,504)	(9,504)	(9,504)	(9,504)	(12,302)	(12,302)	(110,136)
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)	$ 479,647	$ 664,548	$ 1,349,135	$ 530,844	$ 688,194	$ 823,480	$ 850,261	$ 719,075	$ 844,122	$ 825,608	$ 818,572	$ 1,053,650	$ 9,647,135
Revenues (17)		866,070	721,766	781,150	664,208	690,656	759,178	857,172	973,286	827,198	703,209	995,379	1,669,495	$ 10,508,766
Balance (18)	(2,029,342)	(386,423)	(443,641)	124,344	(9,020)	(11,481)	52,820	45,909	(208,302)	(191,378)	(68,979)	(245,786)	(861,631)	$ (861,631)

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**	**$0.000447**						
Jan **actual**	866,070	350,471	30,616	481,868	3,115	2,929,416,026	898,559,142	102,005,226	1,912,193,734	16,657,923	
Feb **actual**	721,766	284,368	26,250	408,546	2,603	2,451,717,477	729,121,891	87,469,133	1,621,210,049	13,916,405	
Mar **actual**	781,150	295,555	27,622	455,476	2,497	2,675,822,497	757,758,205	92,127,522	1,812,541,222	13,395,548	
Apr **actual**	664,208	234,463	22,738	404,960	2,047	2,294,893,904	601,163,925	75,799,484	1,606,986,098	10,944,397	
May **actual**	690,656	235,193	22,129	431,400	1,934	2,399,608,184	603,203,992	73,781,819	1,712,282,527	10,339,846	
Jun **actual**	759,178	274,350	22,880	460,230	1,718	2,615,830,406	703,606,642	76,348,666	1,826,700,898	9,174,200	
Jul **actual**	857,172	357,647	24,729	473,219	1,577	2,883,977,354	917,167,714	82,429,313	1,875,947,094	8,433,233	
Aug **actual**	973,286	412,445	15,360	543,792	1,689	3,330,006,858	1,070,494,733	92,073,679	2,158,403,796	9,034,650	
Sep **actual**	827,198	307,635	24,321	493,232	2,009	2,838,731,789	789,198,429	81,077,416	1,957,712,510	10,743,435	
Oct **actual**	703,209	235,016	21,427	444,477	2,289	2,450,875,507	602,883,729	71,425,663	1,764,326,232	12,239,883	
Nov **actual**	995,379	373,845	30,689	587,151	3,694	2,299,921,789	593,167,444	67,467,106	1,625,713,822	13,573,416	1,159,884
Dec **actual**	1,669,495	676,236	56,759	930,041	6,459	2,523,766,647	728,461,876	80,634,402	1,699,993,266	14,677,103	77,506
Total Jan-Dec	**$ 10,508,766**	**$ 4,037,223**	**$ 325,520**	**$ 6,114,391**	**$ 31,632**	**31,694,568,438**	**8,994,787,720**	**982,639,429**	**21,574,011,249**	**143,130,039**	**1,237,390**

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 - GI	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 Rec	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 Rec	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	**587,424**	**350,333**	**89,463**	**114,042**	**33,586**
Month Eligible		May-09	Jan-10	Feb-11	Nov-11
Monthly Rev Requirement in Base Rates		29,194	7,455	9,504	2,799

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	-	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	104,539
TCR Project 19	-	-	-	-	-	-	-	-	-	-	2,799	2,799	5,598
Total 2011 Rev Requirement in Base Rates	-	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	12,302	12,302	110,136

2012 Revenue Requirement in Base Rates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
TCR Project 17	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	9,504	114,042
TCR Project 19	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	33,586
Total 2011 Rev Requirement in Base Rates	12,302	12,302	12,302	12,302	12,302	12,302	12,302	12,302	12,302	12,302	12,302	12,302	147,628

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	151,325	112,220
Current Income Tax Requirement	(2,870,876)	(2,128,993)
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	153,782	114,042

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	**10.3700%**	**52.5616%**	**5.4500%**
Required Rate of Return			**8.3200%**
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	394,921	292,866
Current Income Tax Requirement	(1,061,654)	(787,304)
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	45,289	33,586

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	**10.3700%**	**52.5616%**	**5.4500%**
Required Rate of Return			**8.3200%**
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.

CERTIFICATE OF SERVICE

I, Lindsey L. Didion, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. **E002/M-12-50**

DATED THIS 31ST DAY OF AUGUST 2012

/S/

LINDSEY L. DIDION

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