Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

August 1, 2014

Burl W. Haar **—Via Electronic Filing—**
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: PETITION
GAS UTILITY INFRASTRUCTURE COST RIDER
DOCKET NO. G002/M-14-336

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition to the Minnesota Public Utilities Commission (Commission) requesting approval of recovery of gas utility infrastructure costs (GUIC) through a GUIC Rider pursuant to Minn. Stat. § 216B.1635. Specifically, we seek Commission approval of:

- An ongoing GUIC Rider;
- 2015 GUIC revenue requirements of $14.94 million for the projected transmission and distribution natural gas infrastructure investments and associated O&M costs, which includes costs for which the Commission previously granted deferred accounting;
- 2015 GUIC rate factors by class to be included in the Resource Adjustment on bills for gas customers in Minnesota beginning January 1, 2015; and
- Proposed GUIC tariff sheets and customer notice.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists. Please contact me at (612) 330-6613 or amy.a.liberkowski@xcelenergy.com if you have any questions regarding this matter.

SINCERELY,

/s/

AMY A. LIBERKOWSKI
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipshultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER

DOCKET NO. G002/M-14-336

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this petition to the Minnesota Public Utilities Commission (Commission) to request approval for the use of a Gas Utility Infrastructure Cost (GUIC) Rider, on a recurring basis, effective January 1, 2015. If the Commission allows the Company to use the GUIC Rider, we further request to be allowed to recover our forecasted costs of $14.9 million for 2015. These costs, which are significant and also include amounts the Commission previously allowed us to defer, are to further the safety of our natural gas system and are consistent with the eligibility requirements set forth in the recently amended GUIC statute.

Since Xcel Energy's last natural gas rate case in 2010, the natural gas industry has continued to undergo a major regulatory transformation. Due to concerns over the age of the country's natural gas infrastructure, federal and state regulators are requiring natural gas companies, including Xcel Energy, to implement integrity management programs to assess and improve the safety, reliability, and integrity of their natural gas infrastructure.

To comply, the Company developed the Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP). TIMP complies with federal regulations that set standards for how operators validate the integrity of gas transmission assets by identifying risks, systematically performing health and condition assessments, and evaluating and prioritizing repairs to mitigate the risks and threats. Like TIMP, our DIMP helps us identify, prioritize, and evaluate risks; identify and implement measures to address risk, and validate the integrity of our gas distribution system. In conjunction with our TIMP and DIMP efforts, the Company also initiated a required state-wide project to identify and remediate situations where its natural gas distribution infrastructure intersected with sewer lines.

Xcel Energy has incurred, and continues to accumulate, substantial expenses in connection with these transmission and distribution safety-related initiatives. As it pertains to this petition, the Company respectfully requests to recover $14.94 million in projected transmission and distribution natural gas infrastructure investments, and associated O&M costs, for 2015, which includes costs for which the Commission previously granted deferred accounting.[1] The average bill impact for a typical residential customer would be $2.22 per month or about 3 percent of the total bill.

We believe Minnesota Statute § 216B.1635 (GUIC Rider Statute) allows us to recover the capital and related O&M costs associated with natural gas infrastructure projects we are required to undertake. The GUIC Rider Statute provides specific criteria for determining whether a utility's costs are eligible for recovery. Specifically, our capital and related O&M costs must be reasonable, and we must demonstrate that it is in the public interest to recover our costs through this rider as opposed to through a general rate case.

We believe our request meets the applicable standard of review. We have initiated our DIMP, TIMP, and other state-wide efforts in response to the requirements of our state and federal regulators. Thus, the projects, and more importantly associated capital and related O&M costs, are reasonable and eligible for rider recovery under the GUIC Statute. Furthermore, these costs will be trued up to our actual costs on an annual basis, which should allay potential concerns about over-recovery or over-earning.

We believe using the GUIC Rider to recover these significant costs is in the public interest, as it will ease administrative burdens by allowing the Company an opportunity to avoid a general rate case, should the Company's request be granted. Additionally, the recovery of significant costs in the future could be more efficiently accomplished through this rider and thereby signaling continued regulatory support for investments that support the safety of our natural gas system.

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[1] *See* Order Approving Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs, Docket No. G002/M-12-248 (Jan. 28, 2013); Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011).

We therefore respectfully request approval to use the GUIC Rider, on a recurring basis, effective January 1, 2015, and to recover our 2015 forecasted cost of $14.9 million through the rider. For the $23.8 million representing deferred costs, we are proposing that they be amortized over five years.

The balance of this petition is organized as follows:

- *Section I* – we identify the parties and state agencies that are being served with this petition.
- *Section II* – we provide information that is required under the Commission's rules.
- *Section III* – we provide pertinent background information about the TIMP legislation, our TIMP projects, DIMP legislation, our DIMP projects, and the recent amendments to the GUIC Statute; and the applicable standard of review.
- *Section IV* – we demonstrate that our request to begin using the GUIC Rider and recovering certain costs through the rider comply with the applicable standard of review.
- *Section V* – we provide additional accounting details pertinent to our request.
- *Section VI* – we summarize our request and the reasons supporting our request.

I. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the appropriate general service list, the Department of Commerce, and the Antitrust and Utilities Division of the Office of the Attorney General.

II. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

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

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401
612-215-4662
alison.c.archer@xcelenergy.com

C. Date of Filing and Proposed Effective Date

The date of this filing is August 1, 2014. The proposed effective date for the Rider is January 1, 2015.

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

D. Statutes Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.1635 governs Xcel Energy's submission of a petition to recover gas infrastructure costs. The provision does not establish an explicit time deadline for Commission action.

E. Utility Employee Responsible for Filing

Amy Liberkowski
Manager, Regulatory Analysis
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(612) 330-6613
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III. DESCRIPTION AND PURPOSE OF FILING

A. Background

We file this GUIC Rider noting the Commission's approval of deferred accounting treatment for the costs associated with the Company's gas pipeline integrity management plans. We also describe the legislation which gave rise to these investments, and we describe the scope and nature of our TIMP and DIMP projects. Finally, we describe the GUIC statute which establishes the legal standard for the Company's request.

1. Deferral Orders

The Company's TIMP and DIMP activities were initiated at the behest of federal regulators, and include a variety of projects to assess and mitigate safety risks associated with gas pipelines. In recent years, the Commission has granted the Company deferred accounting treatment for its TIMP and DIMP activities with the possibility of future recovery for these expenses.[2]

The Company's DIMP activities include sewer line conflict remediation work. We performed this work in a transparent manner and provided the Minnesota Office of Pipeline Safety (MNOPS) updates and a proposed remediation plan that MNOPS accepted, as part of "a comprehensive plan that addresses potential sewer/gas line conflicts" meant to address the conditions that led up to a natural gas incident in Saint Paul on February 1, 2010. The Commission approved deferred accounting for the sewer line conflict remediation activities with the possibility of recovery for prudently incurred expenditures.[3] In so doing, the Commission recognized that the costs associated with these activities are unusual, unforeseeable, significant, and incurred to meet important public policy mandates.

2. TIMP Legislation

Integrity management programs were introduced pursuant to the Pipeline Safety Improvement Act, passed by the U.S. Congress in 2002. The law directed the U.S. Department of Transportation (USDOT), through the Pipeline and Hazardous Materials Safety Administration (PHMSA), to promulgate rules to address integrity programs for gas transmission lines. The rulemaking and subsequent addition to the Code of Federal Regulations (CFR) required operators of gas transmission systems to implement a Transmission Integrity Management Program (TIMP).

A TIMP is a prescriptive risk-based program and its goal is to assess the health and condition of the operator's gas transmission assets. The TIMP is particularly focused on highly-populated areas known as High Consequence Areas (HCAs). Under the TIMP, an operator must conduct prescribed assessments of its assets and take

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[2] *See* Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011) and Order Approving Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs, Docket No. G002/M-12-248 (Jan. 28, 2013).

[3] *See* Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011).

appropriate actions to address identified issues. Pipelines, for example, are initially assessed and then subject to reassessment within seven years. Operators are required to mitigate risks to the pipeline identified through the assessments. In addition to mitigating identified risks, an operator must also implement preventative measures to increase the operational safety of its gas systems. In this way, a TIMP uses risk-based strategies to increase safety.

A TIMP's overall strategy for system operators is straightforward: a) understand your assets, b) identify the risks (or threats) to your assets, and c) be proactive in addressing threats against your assets. It sets forth prescriptive measures to implement the strategy.

3. TIMP Projects

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 83 miles of transmission pipeline in the state of Minnesota. TIMP complies with federal regulations that set standards for how operators validate the integrity of gas transmission assets by identifying risks, systematically performing health and condition assessments, and evaluating and prioritizing repairs to mitigate the risks and threats.[4] TIMP focuses on giving the Company a comprehensive understanding of the health and condition of its gas transmission pipelines, with those located in HCAs as a higher priority.

a. Assessments

There are three primary methods to assess transmission pipelines recognized under the code requirements. Those are:

- In-line inspection (ILI), utilizing pipeline inspection gadgets (PIGs) or "smart tools;"
- Pressure testing, typically a hydrostatic pressure test; and
- Direct Assessment, which specifically targets internal or external pipeline corrosion.

The determination of an assessment method is largely based on the threats identified for a given pipeline segment. Threats might include corrosion, third-party damage, manufacturing defects, construction defects, natural forces, or equipment failure. In most cases, one of the three methods is executed, but secondary assessments may be conducted if multiple risks are present.

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[4] *See* 49 C.F.R. 192, Subpart O.

The Company has elected to use ILI as the preferred assessment method wherever practicable. The advantages of ILI are that the pipelines need not be taken out of service while the tool is run, assessments can be completed in a cost-effective manner for longer distances, and the information from the assessments is more thorough than information available through other methods. After an initial capital investment to prepare a pipeline for an ILI tool, the Company is able to perform subsequent runs on the same line in the future. As tool technology continues to improve, the Company expects to more effectively evaluate risks over time, thereby reducing overall system risk.

b. Other Major Initiatives

In addition to assessments, the Company currently has two other major TIMP initiatives under way: replacement of the East Metro pipeline and installation of Automatic Shutoff Valves/Remote Controlled Valves (ASV/RCV). The East Metro Pipeline Replacement Project is systematically replacing an aging high-pressure transmission pipeline that runs through the heavily populated urban corridor between St. Paul and Roseville. The installation of ASV/RCVs provides the Company with a mechanism to more expediently shut off the flow of gas in the event of an incident, thereby limiting the amount of natural gas escaping from the pipeline, and having the potential to ignite.

An index of attachments to this petition is provided as Attachment A to this filing. Project descriptions, scopes, estimated costs and in-service dates for specific TIMP projects are provided as Attachment B. Attachment C reports the capital expenditure forecast for incremental TIMP activities between March 2012 and December 2019. Attachment D shows the development of 2015 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment C.

4. DIMP Legislation

The PHMSA published the final Distribution Integrity Management Program (DIMP) rule establishing integrity management requirements for gas distribution pipeline systems in 2009 (74 FR 63906)[5]. Pipeline operators, like the Company, were required to establish and file their plans in 2011. Similar to TIMP, the DIMP rules require operators of distribution pipelines to a) understand their systems, b) continually identify and assess risks on their distribution lines, c) remediate conditions that present a potential threat to pipeline integrity, and d) monitor program effectiveness.

[5] *See* 74 Federal Register (FR) 63906.

Rather than setting forth prescriptive requirements for DIMP, PHMSA concluded that more general requirements for operator-specific programs to manage pipeline system integrity is more effective, given the diversity in distribution systems and the specific threats to which they may be exposed.

5. DIMP Projects

DIMP ensures and improves the safety and reliability of gas delivery in compliance with federal rules issued by the PHMSA.[6] The DIMP rules are intended to help gas utilities identify, prioritize, and evaluate risks; identify and implement measures to address risk, and validate the integrity of their gas distribution system.

One example of DIMP activity as previously noted is the Company's sewer and gas line conflict remediation program. Through its plan, we comprehensively inspect sewer lines in locations where conflicts are more likely, reviewing records to determine if the scope of inspections should be expanded, and updating the Company's construction practices to minimize risk and comply with industry standards. We also educate the public about potential conflicts between sewer and natural gas lines.

Though similar to TIMP, the DIMP program is less prescriptive. As noted previously, federal DIMP rules include more general requirements that recognize the diversity of distribution systems and the threats to which they are exposed. Like TIMP, DIMP is data intensive and requires an operator to know its assets. Improvements in data quality and Company processes are helping the Company to transition from a reactive approach to a predictive approach. The goal of the Company's risk analysis is to anticipate issues and address them before they become problems on the system.

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided at Attachment E. Attachment C reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2019. Attachment F shows the development of 2015 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment C.

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[6] *See* 49 C.F.R. 192, Subpart P.

6. Minnesota's GUIC Statute

In recognition of the urgency and importance of gas infrastructure projects, the 2013 Minnesota Legislature enacted revisions to the GUIC law (the 2013 GUIC amendment) authorizing gas utilities to recover TIMP and DIMP expenses outside a rate case.[7]

The 2013 GUIC amendment creates a cost-effective and prompt mechanism for recovery of GUIC costs. The 2013 GUIC amendment is legislative recognition of the importance and priority of prompt recovery of GUIC costs such as those contained in this request. The Company believes that this subsequently enacted law can fairly stand as a substitute for the "next general rate case" requirement governing the term of the deferred regulatory asset contained in the Orders in Docket Nos. G002/M-10-422 and G002/M-12-248.

Xcel Energy's TIMP and DIMP activities are precisely the type of expenditures for which Minn. Stat. § 216B.1635 authorizes prompt recovery. Each of these initiatives involves Xcel Energy taking vital yet cost-intensive steps to ensure the ongoing integrity of its gas assets. With this Rider request, the Company asks the Commission for permission to implement an ongoing rider, recover its projected TIMP and DIMP expenses for 2015, as well as the costs for which the Commission granted deferred accounting with the possibility of future recovery.[8] The text of Minn. Stat. § 216B.1635 is provided as Attachment G.

B. Standard of Review

The legal standard of review for the Company's petition for its GUIC Rider is found at Minn. Stat. § 216B.1635 Subd. 5.

> *Upon receiving a gas utility report and petition for cost recovery under subdivision 2 and assessment and verification under subdivision 4, the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.*

This Petition will demonstrate to the Commission that the Company's gas facility improvements are made at the lowest reasonable and prudent cost to ratepayers.

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[7] *See* Minn. Stat. § 216B.1635.

[8] *See* Order Approving Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs, Docket No. G002/M-12-248 (Jan. 28, 2013); Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011).

The return on investment for GUIC costs is found at Minn. Stat. § 216B.1635 Subd. 6:

> The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

The Company is using a rate of return of 8.28 percent since this is the rate that was authorized in the 2010 rate case.[9] We acknowledge the Commission can establish a different rate of return if it is in the public interest and that our cost of debt has decreased since the time our 2010 gas rate case was before the Commission.

In addition to specific provisions of the GUIC statute, Minnesota's pipeline safety statutes recognize the importance of safety related cost recovery. Minn. Stat. §216B.16, Subd. 11 states:

> All costs of a public utility that are necessary to comply with state pipeline safety programs under sections 216D.01 to 216D.07, 299F.56 to 299F.64, or 299J.01 to 299J.17 must be recognized and included by the commission in the determination of just and reasonable rates as if the costs were directly incurred by the utility in furnishing utility service.

All of the costs sought for recovery in this rider either directly or indirectly qualify for this mandatory rate treatment.

IV. COMPLIANCE WITH COMMISSION ORDERS AND STATUTE

Inherent in the federal and state regulations and the integrity management rules is the requirement that pipeline operators do what is reasonably necessary for the safe operation of natural gas systems. What this means is the health and condition of the assets, along with the Company's assessment of the public risk, should dictate the inspection, maintenance, and remedial activities to remove risk and increase the safe operation of its natural gas pipeline systems. Implementation of the current integrity management programs is a significant adjustment for the entire gas industry, as it strives to transform from a historically reactive mode to a more proactive and predictive mode.

Here we address why cost recovery through a rider for these activities is in the public interest, we demonstrate the reasonableness and prudence of costs associated with

[9] *See* Findings of Fact, Conclusions of Law, and Order, Docket No. G-002/GR-09-1153 (Dec. 6, 2010).

these activities, and we further address the Company's compliance with the Orders and Statute. For ease of review, the Company provides a compliance matrix at Attachment H which sets forth the requirements of the enabling statute and the relevant Orders, and directs the reader to the portion of the Company's petition which address each requirement.

A. GUIC Recovery Through a Rider Promotes Safety and Reliability Consistent with the Public Interest

The GUIC Rider is in the public interest, as it will enable the Company to continue efforts to improve the safety and reliability of gas utility assets. Furthermore, the GUIC enables the Commission and the Company to use resources efficiently to complete critical work. Approval of the Rider allows the Company to take advantage of improved economies of scale, to engage in better regional planning, to minimize inconvenience to impacted communities, and to efficiently deploy human and capital resources.

Additionally, the GUIC adjustment rate calculation is consistent with overall rate design, as the methodology used to allocate the costs by class and calculate the class factors closely resembles how these costs would be assigned to class as part of base rates in a natural gas general rate case.

The Company's most recent rate case was in 2010.[10] Since that time, we have undertaken several infrastructure improvement projects, including sewer and gas line conflict remediation and other proactive measures that are in direct support of the federal mandates of TIMP and DIMP. The costs of these initiatives have substantially exceeded any expenses anticipated at the time of the rate case, but the programs have conveyed significant benefits to ratepayers.

Prompt recovery promotes both prudent investment in utility infrastructure and efficient use of the Commission's time and resources. Though we have encountered significant infrastructure inspection and replacement costs, well in excess of those presented in our previous rate case, other expenses remain true to the expectations evaluated in the 2010 rate case. Reevaluating all rate case conditions and expectations would be time consuming, expensive, and redundant at this time.

Federal regulators and the National Association of Regulatory Utility Commissioners (NARUC) have also acknowledged the need for commissions to be flexible and prompt in responding to utility infrastructure improvement projects. With input from

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[10] *See* Findings of Fact, Conclusions of Law, and Order, Docket No. G002/GR-09-1153 (Dec. 6, 2010).

the U.S. Department of Energy, NARUC created model rules to enhance cost-recovery for vital infrastructure projects.[11]

B. The Public Interest Supports Ongoing GUIC Investments

Although significant progress has been made in identifying and mitigating threats to the gas system, the Company is still confronting several challenges through TIMP and DIMP.

1. *Addressing Aging Assets*

First, the vintage of the Company's gas utility assets, including the varied material types and construction methods utilized at the time of installation, pose a level of uncertainty and risk. For example, steel pipes are prone to corrosion and have a higher risk of failure for assets installed before there was effective cathodic protection. Older assets also have a higher risk of material or construction flaws. Approximately 50 percent of the Company's gas transmission system was constructed prior to the use of what is now considered modern welding techniques, which emerged in the industry in the 1970s. While age alone is no indication of failure, legacy construction techniques and materials are susceptible to threats that have been identified as posing a risk to be mitigated.

2. *Confronting Population Growth*

Second, many communities with older gas utility assets have sustained significant population growth since initial installation. Development around aging transmission and higher-pressure distribution lines has an impact on the level of effort and related expense to safely and reliably operating these systems.[12]

3. *Remaining in Step with Peer Integrity Management Activities*

Third, a "Call to Action to Improve the Safety of the Nation's Energy Pipeline System"[13] was issued by the USDOT and PHMSA in 2011 in response to incidents in California, Michigan, and Pennsylvania. In particular, U.S. Secretary of Transportation Ray LaHood announced a "Pipeline Safety Action Plan," calling for pipeline operators, including local

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[11] *Available at* http://www.naruc.org/Publications/costrecovery0804.pdf.

[12] The East Metro Pipeline project is an example of this. The project is replacing an aging high pressure transmission pipeline that runs through the heavily populated urban corridor between St. Paul and Roseville.

[13] *See* U.S. Department of Transportation, *Call to Action to Improve the Safety of the Nation's Energy Pipeline System, available at* http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/110404%20Action%20Plan%20Executive%20Version%20_2.pdf.

distribution companies, to conduct a comprehensive review of their pipeline systems to identify the highest risk pipelines and prioritize critical repair needs. Pipeline operators were asked to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of network facilities to prevent potentially catastrophic incidents. The Call to Action also called upon state regulators to provide timely recovery of pipeline replacement investments, recognizing that reliance on traditional cost recovery approaches is likely to impede efforts to accelerate these activities.

Xcel Energy is not alone in answering the Call to Action by proactively replacing a significant number of its higher risk gas assets. Local distribution companies across the country have implemented similar measures as part of their comprehensive integrity management programs. These programs require substantial investments in human resources, including engineers and construction crews. In pursuing TIMP and DIMP, the Company has had to compete nationally to obtain the specialized equipment, engineers, and construction crews it needs to complete necessary renewal work.

4. Confronting Unpredictability

Finally, with TIMP in particular, the Company is confronting unpredictability. Though TIMP and DIMP are improving the Company's knowledge of system and asset conditions, much remains unknown until the systems are actually inspected. As inspections are conducted, we continue to discover new risks to the system that may require more immediate intervention. The variability of these needs puts the Company in a position of requiring some flexibility with respect to O&M and other resources to address conditions as they are identified.

The Company has a responsibility to its customers and the public to provide safe and reliable service. Through its comprehensive integrity management programs, Xcel Energy seeks to proactively minimize risk to the public and our employees through prudent management of the life cycle of our assets. TIMP and DIMP compliance are an iterative process, through which we are gaining greater knowledge about our assets, a better understanding of risks on the gas system, and proactively taking action to manage and mitigate those risks.

With aging infrastructure and new federal mandates, the Company needs flexibility to address emerging conditions and the uncertainty inherent in these types of programs that traditional rate making methods cannot offer. The GUIC Rider will provide this flexibility by enabling the Company to recover on a current basis prudently-incurred incremental O&M and capital costs of projects that maintain and enhance the safety of our gas distribution and transmission systems.

C. GUIC Activities Are Prudent

In its review of Company's request, we believe the Commission may wish to make note of the GUIC controls and oversight methods the Company uses to ensure prudent cost management.

1. Cost Controls

Projects in the proposed GUIC Rider have gone through the Company's capital and O&M budgeting process, which is approved by Company officers and the Board of Directors. The Gas Engineering and Operations business unit includes a project controls department that monitors all capital dollars to ensure that authorized projects align with the established budget to achieve the lowest reasonable and prudent cost to rate payers. On a monthly basis, they compare actual spending to budget as well as update forecasts for programs and projects. The Company also leverages past experience with assessments and repairs to assist in developing budgets for future assessment work.

Additionally, the Company has formed a dedicated Gas Project Management Department to handle large gas projects and programs. This new department provides centralized project management to address overall scope, scheduling, and budgeting for major capital projects.

2. Oversight Methods

We also employ a variety of oversight methods. Company executives conduct a monthly status review of major capital programs and projects, including the GUIC. We review actual overall capital spending in comparison with forecasted spending month-to-date and year-end. Evaluation and approval of the status of the capital budget is conducted monthly.

The Company is in the process of establishing a Rider Review Committee (RRC) tasked with ensuring that any future modifications to GUIC projects meet the intent of the Company's DIMP and TIMP Rider. The committee will be led by the Director of Gas System Strategy and will include the relevant integrity management personnel, as well as senior managers and executives.

Finally, Xcel Energy employs standard practices for all master contracts and change orders. We also use competitive bidding to select project partners. All of these efforts aim to ensure prudent management and ratepayer value.

D. GUIC Activities Are Reasonable

The Commission recognized the reasonableness of Xcel Energy's activities when it authorized deferred accounting for past TIMP and DIMP expenses, which include the Gas Safety Costs and the Sewer/Gas Line Conflict Remediation Project in Dockets Nos. G002/M-12-248 and G002/M-10-422, respectively. Of course these Commission actions predated the Legislature's GUIC Rider amendment in 2013.

Additionally, the Company's commitment and response to the federal "Call to Action" for the review, assessment, and prioritization of initiatives to address high-risk gas-utility assets further substantiates the reasonableness of the activities proposed within the GUIC. The benefits of these evaluation and replacement efforts are several-fold: immediate safety and reliability benefits to customers and the public,[14] cost savings through economies of scale, comprehensive planning to preempt reactive (emergency) replacements, geographically-focused initiatives, efficient use of outside contractor services, efficient deployment of capital, and improved coordination with affected municipalities.

E. O&M Costs Are Specifically Authorized

At subd. 4, the GUIC statute authorizes approval of incremental O&M cost recovery. With this GUIC Rider request, the Company seeks to recover those O&M costs over and above the $480,000 allowed in the previous rate case in Docket No. G002/GR-09-1153.

The Company provides the TIMP and DIMP budgets for 2015, as well as estimated and actual cost data for previous program years in Attachment I.

Precise budgeting within these programs remains challenging. This is particularly true of TIMP assessments and with conflict remediation, where the Company cannot be sure of the condition of the pipe it will encounter—or the immediacy of needed repairs—until inspection occurs. As noted, the Company values flexibility in O&M budgeting to address conditions as they are identified.

F. Estimated Costs for TIMP- and DIMP-Related Activities

Table 1 below presents Xcel Energy's 2015 total estimated costs of $14.94 million for TIMP- and DIMP-related activities. Incremental capital-related revenue requirements and operations and maintenance expenses total $5.64 million and $4.54 million,

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[14] *See* 49 C.F.R. 192, Subparts O and P.

respectively. Costs associated with the amortization of deferred accounting treatment approved in Docket Nos. G002/M-10-422 and G002/M-12-248 total $4.76 million.

Table 1
2015 Gas Utility Infrastructure Costs (GUIC)
(In Millions - $M)

Capital-Related Revenue Requirements	
TIMP	4.96
DIMP	0.69
Total	5.64
Operations & Maintenance (O&M) Expenses	
TIMP	0.22
DIMP	4.32
Total	4.54
5-Year Amortization of Deferred Costs	
TIMP	0.90
DIMP	3.87
Total	4.76
GUIC - Grand Total	**14.94**

We provide further support for our request in keeping with the Commission's Deferral Order and statutory requirements here.

G. Outsourcing

As discussed in the annual reports and pre-filing, while the Company seeks to minimize outsourcing, in certain instances additional expertise from outside our organization is needed. For example, certain pipeline assessment techniques require specialized tools and equipment operated by uniquely skilled technicians. The Company does not have this equipment or this expertise. To the extent that additional equipment and expertise are needed to ensure the safe and efficient completion of assessments, the Company seeks and relies on outside assistance.

There are three main aspects of the sewer and gas line conflict remediation program: administrative management, sewer line inspections using specialized equipment and cameras, and excavations in instances where conflicts have been identified. Only the camera inspection aspect of the program is outsourced. At present, the Company has neither the internal expertise nor the equipment available to perform this specialized aspect of the program. By outsourcing the inspections, the Company has spared ratepayers the cost of expensive, specialized equipment, and ensured that those with the expertise are conducting the investigations.

H. Notice of Probable Violation

The Commission requested that the Company explain "any legal actions or settlements regarding the natural gas explosion that led to the Notice of Probable Violation." Although the Minnesota Office of Pipeline Safety did not issue a final report regarding an incident on February 1, 2010, there was a Compliance Order, and Xcel Energy paid a penalty.[15] Two civil suits filed in connection with the February 1, 2010 events were confidentially settled.

I. Potential Third-Party Recovery

At this time, Xcel Energy does not believe third-party recovery is feasible. Federal pipeline safety regulations require operators to take steps to minimize the likelihood of recurrence of an event, such as the sewer-gas line conflict that caused the fire at 2014 Villard Avenue. It is our responsibility to maintain a safe and reliable natural gas system. The sewer and gas line conflict remediation program has greatly assisted in these efforts. Xcel Energy carefully considered and assessed whether a viable third-party claim would exist to recover some of the costs of the plan, but for several reasons the Company concluded there was no viable third-party claim.

Many of the conflicts identified by this program are created historically by third-party service providers, some of which are no longer in business. Litigating the fault for those conflicts would require enforcing service contracts executed more than 10 years ago, after express warranties have lapsed. For example, the gas line involved in the fire at 2014 Villard Avenue in 2010 was installed in 1991. Given the passage of time, there are significant legal hurdles to identify and prove a party responsible. For these reasons, we believe pursuing third-party recovery is unlikely to be cost effective.

J. Analysis of What It Would Have Cost to Conduct the Plan Over a 10-Year Period Beginning in 2003

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[15] Letter from William Kaphing, Jr., Sr. Dir. Gas Governance Northern States Power Co., to Jerry Rosendahl, State Fire Marshal and Director MNOPS (Dec. 21, 2012).

Unfortunately, sound statistical data does not exist to compare the costs of Xcel Energy's actual remediation program with a hypothetical program initiated in 2003. On average, the current program costs approximately $180 per inspection. If initiated earlier, it is possible that this work could have been spread out to cost less per year.

K. TIMP and DIMP Estimated Costs and Salvage Value

The Company's cost and salvage estimates related to actual and planned GUIC capital investments are shown in Table 2 below. Further descriptions of the costs can be found in Attachment J.

Table 2
GUIC Capital Expenditures and Net Salvage: 2012-2019
(In Thousands - $000)

	TIMP			DIMP			Total
Year	Transmission	Distribution*	Total	Distribution	Software	Total	Expenditures
2012	97	2	99	133	-	133	232
2013	71	9,644	9,716	602	-	602	10,317
2014	1,430	13,923	15,353	607	-	607	15,960
2015	3,186	20,044	23,230	7,016	1,741	8,757	31,986
2016	6,086	14,303	20,390	10,168	-	10,168	30,558
2017	4,264	-	4,264	17,906	-	17,906	22,170
2018	27,539	-	27,539	17,128	-	17,128	44,667
2019	33,150	-	33,150	17,128	-	17,128	50,278
	-	-					
Total	**75,825**	**57,915**	**133,740**	**70,687**	**1,741**	**72,428**	**206,168**
Salvage Rate**	-15.00%	-15.74%		-15.74%	0.00%		
Net Salvage	**11,374**	**9,113**	**20,487**	**11,123**	**-**	**11,123**	**31,610**

*The East Metro Pipeline project was originally borne out of activities related to TIMP transmission pipeline assessment activities; therefore it is classified under the TIMP category. However, as segments of the pipeline are being replaced, there is new plant being installed on the system that is considered distribution plant from both an engineering and regulatory accounting perspective.

**2014 depreciation lives and salvage rates approved in Docket No. E,G002/D-12-858.

Capital expenditure estimates between 2012 and 2019 total $133.7 million for TIMP and $72.4 million for DIMP, reflecting an estimated total of $206.2 million. Xcel Energy calculates a depreciation rate of 2.5258 percent and 1.5333 percent for distribution mains and transmission mains, respectively. The Company's calculations assume an average depreciable life of 45.82 years and a net salvage rate of 15.7353 percent for distribution mains and average depreciable life of 75.00 years and net salvage rate of 15.0000 percent for transmission mains. The Commission has approved Xcel Energy's proposed depreciation lives and salvage rates in Docket No. E, G002/D-12-858 (Order dated June 16, 2014).

L. Known Future Gas Utility Projects

1. TIMP

As stated previously, the federal TIMP is an ongoing program that will continue indefinitely. Projects under TIMP, specifically, the Transmission Pipeline Assessment project, will continue beyond 2015. Further, PHMSA has been working on establishing a comprehensive program to effectively address a number of Congressional mandates and National Transportation Safety Board (NTSB) recommendations that will likely raise compliance standards for pipeline operators beyond the current TIMP rule.

a. Assessments

Elements of anticipated future Transmission Assessment Projects include:

- Continue to make transmission lines accessible to ILI tools where the current technology is available;
- Continue to assess pipeline segments required by risk analysis per the Federal code;
- Continue to perform validation excavations based on assessment results;
- Continue to perform repairs based on assessment results;
- Continue to improve records and processes to ensure adequate knowledge of gas transmission assets to perform assessments and threat evaluations; and
- Continue to incorporate data from assessments into risk models and update plans accordingly.

Future costs associated with assessments could vary between $0.5 million and $7.5 million depending on the specific segments being assessed. Additionally, the costs incurred will likely be a combination of capital expenditures and O&M expenses, which depends on the type of work being performed and specific capital asset accounting associated with the types of repairs or remediation work done as a result of the assessments.

b. East Metro Pipeline Project

Work associated with the East Metro Pipeline project is currently planned for a four-year completion schedule. We expect that the majority of costs associated with this project will end in late 2016 with the possibility of some carry-over costs incurring in 2017. We currently estimate East Metro Pipeline capital expenditures from $15 million to $23 million annually. The annual costs for this project can vary based both on the length of pipeline segments being replaced each year and specific construction activity that tends to fluctuate year over year.

c. Automatic Shut-off Valve/Remote Controlled Valve

Finally, we expect the ASV/RCV installation project to commence in 2015 and continue over the next five years. We anticipate capital expenditures related to the project to range from $0.5 - $1.5 million per year. The actual number of valves installed per year, and the specific type of valves installed, will impact the annual expenditures. The Company is still evaluating the scope of this project and performing a risk-based engineering analysis to determine the overall duration of the project.

d. TIMP Summary

While the Company has made progress in improvements to the safety of its pipeline system, it will continue to identify existing or new threats, evaluate the risk, and develop mitigation methods to address the risk. The Company's TIMP includes not only assessing the physical assets and executing mitigation plans to reduce or eliminate risks, but also the data associated with the asset. Although the "start" of the cycle was prescribed with the promulgation of federal requirements for TIMP, as new regulations are introduced, they must be included in the process.

Further details regarding expected costs are provided at Attachment B, TIMP Overview and Project Detail.

2. DIMP

a. Poor Performing Main and Service Replacement

Within the category of DIMP projects, the Poor Performing Main and Service Replacement Projects are expected to be multi-year initiatives, likely spanning a decade. Future capital expenditures associated with Poor Performing Mains will range from $4 million to $11 million annually, while the Poor Performing Services expenses will likely fall between $2 million and $8 million annually. Both projects will require a period of design and construction resource procurement and deployment, with capital expenditures gradually increasing from 2015 to 2017. Combined O&M for the project will range from $400,000 to $1.1 million annually.

b. Distribution Valves and Pipeline Data

DIMP projects focused on Distribution Valves and Pipeline Data are currently planned to have a limited duration. In particular, we expect the Pipeline Data Project to conclude by 2016. The estimated expenditure for the Pipeline Data Project is $1.75 million. The estimated capital expenditure for Distribution Valves that are within the current scope of the project is $770,000 in 2015.

c. Sewer and Gas Line Conflict Remediation

Between 2011 and 2013, the annual cost for the sewer and gas line conflict remediation program averaged $3.5 million. We anticipate that costs for inspections will continue at this level for the next few years. We plan to continue inspections at the historic level until such time that it is appropriate to modify the number of annual inspections. In part, the expenses of the program in the future will reflect the results of those inspections. Depending on the number of conflicts found, the Company will evaluate the associated level of risk and adjust the number of inspections as needed.

d. Distribution Pipeline Inspection

Finally, distribution pipeline inspection work is expected to continue for several years. We will continue to regularly inspect key segments of our gas distribution system. The Company will continue efforts to obtain important asset health data from these inspections. We will use the data to develop plans for additional mitigation actions to address risk and prioritize potential replacement of pipeline segments. Future costs associated with distribution pipeline inspections could vary between $0.2 million and $0.8 million, depending on the specific pipeline segments being assessed.

Further details regarding expected costs are provided at Attachment E, DIMP Overview and Project Detail.

M. Magnitude of GUIC in Relation to the Gas Utility's Approved Base Revenue

On December 6, 2010, Xcel Energy's most recent gas general rate case was approved by the Minnesota Public Utilities Commission in Docket No. G002/GR-09-1153. In that proceeding, the Commission approved a total retail related revenue of $592.87 million for the test year ending December 31, 2010. Excluding $4.69 million of other operating income for customer-related charges not included in retail rates and $429.08 million for gas purchase and transportation charges, the total approved base revenue was $159.10 million. The revenue collection estimates using the Company's most recent sales forecast based on a proposed 2015 GUIC rate generates $14.94 million of GUIC-related revenues in 2015. The GUIC revenue estimates reflect 9.39 percent of the base revenues of $159.10 million approved in the previous general rate case. Please reference Attachment L for details.

N. Magnitude of GUIC in Relation to the Gas Utility's Capital Expenditures

The Company's capital expenditures (construction work in progress or "CWIP" only) included in the 2010 test year approved in Docket No. G002/GR-09-1153 totaled $29.89 million. The 2015 forecasted GUIC-related capital expenditures (CWIP only) total $31.99 million. Accordingly, the incremental costs proposed in this filing reflect a 107.01 percent increase over currently approved levels. Please reference Attachment L for details.

V. GUIC RIDER - FACTOR CALCULATIONS, TIMING OF IMPLEMENTATION, TRACKER ACCOUNTING, AND TARIFF PAGES

A. Calculations for Revenue Requirements and Proposed 2015 GUIC Rate Adjustment Factors

In this section, we provide the 2015 revenue requirement and 2015 rate adjustments factor calculations for the proposed GUIC. The calculations assume that proposed GUIC projects as discussed in this petition are approved for eligibility, and the GUIC adjustment factors are effective January 1, 2015. If implementation of the 2015 GUIC adjustment factors occurs after January 1, 2015, the Company proposes to calculate the final rate adjustment factors to recover the 2015 revenue requirements over the remaining months of 2015, which would be provided as part of a compliance filing after the Commission's Order approving the Petition.

1. Revenue Requirements

The projected GUIC revenue requirements for 2015 through 2019 are summarized in Attachment M to this filing. The projected revenue requirements proposed for recovery through the 2015 GUIC adjustment factors from Minnesota gas customers are approximately $14.94 million. The supporting revenue requirements and projected 2015 GUIC Tracker activity are provided in Attachment N. The 2016-2019 monthly trackers have also been included as Attachment O. The Company has calculated the revenue requirements consistent with the capital structure approved in our last natural gas rate case.[16] In addition, the eligible revenue requirements also include property taxes, current and deferred taxes, and book depreciation. Attachments D and F summarize the 2015 projected revenue requirements for the TIMP and DIMP projects respectively. Attachment P provides descriptions of the rate base and return calculation categories included in Attachments D and F.

2. GUIC Rate Adjustment Factor

The Company's GUIC adjustment factor rate design provides for rates specific to five customer groups (residential, commercial firm, commercial demand billed, interruptible, and transportation) and allocates the 2015 tracker balance to class using a rate base allocator based on the Class Cost of Service Study in our most recent natural gas rate case.[17] TIMP and DIMP expenses would be, in large part, included in the rate base as part of a natural gas general rate case. We believe class allocation using rate base most closely resembles how these costs would be assigned to class as part of base rates and is therefore an appropriate method of class allocation.

We propose to calculate class factors by dividing the class revenue responsibility by the forecasted Minnesota sales for the recovery period and include the GUIC Adjustment Factor as part of the Resource Adjustment line on customer bills. The 2015 GUIC Adjustment Factor calculation is shown in Attachment K. We propose the following 2015 GUIC adjustment factors in Table 3 below:

[16] *Findings of Fact, Conclusions of Law, and Order* dated December 6, 2010, page 29, Docket No. G002/GR-09-1153.
[17] Docket No. G002/GR-09-1153.

Table 3
Proposed 2015 GUIC Adjustment Factors
(Dollars per therm)

Residential	$0.031253
Commercial Firm	$0.012901
Commercial Demand Billed	$0.005367
Interruptible	$0.004111
Transportation	$0.003933

Under the proposed adjustment factor, the average bill impact for a typical residential customer would be $2.22 per month or about 3 percent of the total bill. We propose these factors be effective January 1, 2015, and the above rates are calculated based on implementation of the new GUIC adjustment rate starting January 1, 2015. If the Commission does not act on this Petition in time for rates to become effective January 1, 2015, we request that the rate factors be recalculated to recover the 2015 revenue requirements over the remaining months of 2015 in order to match the 2015 cost recovery with the eligible 2015 costs.

To provide further assurance of the accuracy of our calculations, external consultants under contract with the Company have reviewed the GUIC revenue requirement and factor calculation model. This third-party review consisted of the following steps: (1) review of our revenue requirements and tracker calculations; (2) review of compliance of these calculations with the intent of statutes, orders, and previous filings, and (3) verify that costs proposed to be recovered through the 2015 GUIC Rider adjustment factors are not being recovered under any other mechanism. In addition to verifying the accuracy of the Company's calculations, the review also confirmed that the revenue requirement calculations include no double recovery costs.

B. Timing of GUIC Factor Calculation

We request approval to implement GUIC factors in this petition, effective January 1, 2015, pending review and approval of the GUIC Rider and factors by the Commission. In subsequent years, we will file a request for approval of changes to the GUIC factors by November 1st, with rates proposed to be effective April 1st of the following year upon Commission approval. This timeframe allows for the 150-day review provided for in statute.

The Company believes this approach is beneficial as it is consistent with the Legislature's intent to provide timely cost recovery to support the significant and mandatory natural gas infrastructure investments. It also maintains appropriate regulatory protections and oversight by allowing the Commission and other state agencies the time required to audit and review costs sought for recovery, thus ensuring that any regulatory adjustments will be recognized and implemented appropriately.

C. GUIC Tracker Account

To ensure that customers are not under- or overcharged, we will record the actual GUIC revenue recovery and requirements in a tracker account as the accounting mechanism for eligible GUIC project costs. As revenues are collected from retail customers each month, the Company tracks the amount of recovery under the GUIC rate factor and compares that amount with the monthly revenue requirements. The difference is recorded in the tracker account as the amount of over- or under-recovery. The tracker also records differences in revenue requirements from forecasted to actual. Any over- or under-recovery balance at the end of the year is used in the calculation of the rate factor for the next year's forecasted revenue requirement. In other words, over-recovery is taken into account by reducing the subsequent year's rate factor calculation. Under-recovery is similarly taken into account by increasing the subsequent year's rate factor calculation. The revenue requirements included in the tracker are only those related to Minnesota's jurisdictional share of eligible GUIC projects.

We will calculate the monthly Minnesota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes, and depreciation), compare them with monthly GUIC Rider recoveries from customers, and place the under-recovered amounts in FERC Account 182.3, Other Regulatory Assets and over-recovered amounts in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts). Tracker balances for GUIC activity estimated in 2015 are shown on Attachment N.

D. Proposed Tariff Sheet and Customer Notice

1. *Proposed Revised Tariff Sheet*

The proposed GUIC Adjustment Rider can be found on Tariff Sheets Nos. 5-64 and 5-65 in Attachment Q. Attachment Q also contains red-line and clean versions of all tariff language changes associated with the proposed GUIC Adjustment.

2. *Proposed Customer Notice*

We will provide notice to customers regarding inclusion of this cost on their monthly bill. The following is our proposed language to be included as a notice on customers' bills the month the GUIC factor is implemented:

> "This month's Resource Adjustment includes the addition of the Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $x.xxxx per therm for Residential customers; $x.xxxx per therm for Commercial Firm customers; $x.xxxx per therm for Commercial Demand Billed customers; and $x.xxxx per therm for Interruptible customers. Questions? Contact us at 1-800-895-4999."

We will work with the Department and Commission staff if there are any suggestions to modify this notice.

CONCLUSION

Recent events involving gas pipelines have focused efforts nationwide on the need to increase utility investments in system safety and reliability. This focus has resulted in increasing federal and state regulatory standards for transmission and distribution integrity management. We have responded to these increased standards with plans for prudent investments in our gas transmission and distribution systems, pursuant to detailed integrity management plans.

The legislature recognized the importance of allowing prompt recovery mechanisms for these investments in 2013, when it authorized utilities to request recovery for integrity management expenses outside of general rate cases. In this filing, the Company describes its reasonable and prudent investments in pipeline safety and reliability planning and outlines its cost recovery proposal for these investments. Xcel Energy respectfully requests that the Commission grant recovery of its gas utility infrastructure costs through a GUIC Rider and approve the proposed 2015 GUIC Rider factors.

Dated: August 1, 2014

Northern States Power Company

Respectfully submitted by:

/s/

Amy A. Liberkowski
Manager, Regulatory Analysis

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipshultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER

DOCKET NO. G002/M-14-336

PETITION

SUMMARY OF FILING

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits this Petition to the Minnesota Public Utilities Commission for approval of recovery of gas utility infrastructure costs (GUIC) through a GUIC Rider. (Rider). Xcel Energy intends to pursue a variety of threat evaluation, assessments, and risk mitigation activities to promote the safe and reliable operation of its gas infrastructure assets. The Company is conducting these activities in compliance with federal regulations. In recent years, the Commission has granted the Company deferred accounting treatment for its TIMP and DIMP activities with the possibility of future recovery for these expenses. *See* Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011); Order Approving Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs, Docket No. G002/M-12-248 (Jan. 28, 2013). Xcel Energy is filing this petition for cost recovery of its projected 2015 and deferred gas utility infrastructure costs pursuant to Minn. Stat. § 216B.1635, which permits a utility to petition the Commission for recovery.

Index of Attachments

Number	Item
Attachment A	Index of Attachments
Attachment B	TIMP Overview and Project Detail
Attachment C	Capital TIMP and DIMP Expenditure Forecast Through 2019
Attachment D	TIMP Revenue Requirements for 2015-2019
Attachment E	DIMP Overview and Project Detail
Attachment F	DIMP Revenue Requirements for 2015-2019
Attachment G	Minnesota Statute § 216B.1635
Attachment H	Compliance Matrix
Attachment I	O&M Budget Estimates for 2015 and Cost Data for Previous Years
Attachment J	Salvage Estimates - Universal Inputs
Attachment K	GUIC Rate Factor Determination for 2015-2017
Attachment L	Magnitude of GUIC in Relation to Most Recent Rate Case Docket No. G002/GR-09-1153
Attachment M	Annual Revenue Requirements Tracker Summary for 2015-2019
Attachment N	Revenue Requirements Tracker for 2015
Attachment O	Revenue Requirements Trackers for 2016-2019
Attachment P	TIMP and DIMP Revenue Requirement Category Descriptions
Attachment Q	List of Proposed Tariffs and Red-Line and Clean Tariff Sheets

Transmission Integrity Management Program (TIMP) Overview and Project Detail

I. TIMP OVERVIEW

Xcel Energy's TIMP was developed pursuant to the Pipeline Safety Improvement Act of 2002 and the regulations promulgated by the Department of Transportation's Office of Pipeline Safety. On December 17, 2004, Xcel Energy published a TIMP Manual, in accordance with 49 C.F.R. § 192, Subpart O. The purpose of the TIMP Manual is to specify the procedures for gathering, integrating, and analyzing data; assessing pipelines; and implementing remedial actions to improve pipeline safety. At its core, TIMP can be summarized in three steps: 1) understand your assets, 2) understand the threats to those assets (risk evaluation) and, 3) proactively address threats against those gas transmission assets (risk mitigation). Xcel Energy's processes for these three steps are outlined below.

1. *Understand Your Assets*

A fundamental requirement of TIMP is to gather, evaluate, and continually integrate data relative to a transmission system. This includes not only fundamental aspects about the physical and operating characteristics of a system such as date installed, length, size, material, and operating pressure, but also understanding data related to the ongoing integrity of the pipeline and transmission system.

Xcel Energy established a Baseline Assessment Plan (BAP), identifying those pipelines or segments of pipelines in the system that are located in a High Consequence Area ("HCA"). Simply put, HCAs are areas surrounding a pipeline where, in the event of a pipeline failure, the consequence could be high due to the number of people in the vicinity. These segments are our highest priority to understand, assess, and mitigate risk. Maintaining the BAP is an iterative process, with new information regarding areas where persons congregate, or the construction or change in usage of buildings integrated into the BAP.

2. *Risk Evaluation*

The Company performs evaluations to determine the threat(s) to a given pipeline that may pose a safety or reliability risk, with pipeline segments in HCA's receiving the highest priority. The Company initially used pipeline asset information from existing records, operating data, and input from Subject Matter Experts (SME) to identify potential threats. Industry guidance materials, such as those published by the

American Society of Mechanical Engineers, were also incorporated into the threat identification process.

The following threats to the Company's transmission pipelines were evaluated:

- External corrosion
- Internal corrosion
- Stress corrosion cracking
- Manufacturing and related defects
- Construction defects
- Equipment failures
- Third-party damage
- Incorrect operations
- Weather-related and outside force damage

Xcel Energy's risk assessment process identifies events or conditions that could cause or increase the likelihood or consequence of pipeline failure. This risk assessment process provides information to facilitate decisions such as the prioritization of pipelines and/or segments of pipelines for assessment, the frequency of an assessment, which assessment methodology is most appropriate, and, in certain cases, information to substantiate the need for replacement of an asset.

The Company also takes into consideration knowledge of the condition and physical characteristics of its gas assets, as well as industry guidance materials and directives, and it incorporate this information into its risk evaluation and subsequent risk mitigation strategies.

3. Risk Mitigation

After the health and condition assessment, the Company evaluates anomalous conditions. Typical measures to address the risk include excavation of the pipeline and the repair or complete removal of the anomaly, and/or reducing the operating pressure of the system. We integrate the results from those assessments along with other asset knowledge into decisions about alternate or supplemental assessment tools, the frequency of performing a re-assessment, and/or the systematic planned replacement of the entire asset.

As referenced in the Petition portion of this filing, one element of the "Pipeline Safety Action Plan" issued by the Department of Transportation called for operators to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of network facilities. In direct support of that, the Company's evaluation of the East Metro Pipeline revealed that replacement of that gas transmission line was in the best interest of public safety. Replacement would eliminate construction and manufacturing threats posed by the existing compression (or mechanical) couplings used for construction of the line when it was installed in the 1940s and 1950s.

Another type of risk mitigation activity is one that reduces the consequences in the event of a failure. An example is the installation of specialized valves that can remotely or automatically shut down a pipeline, limiting or reducing the consequence in the event of a pipeline failure or rupture. These specific valves are commonly referred to in the industry as automatic shut-off or remote controlled valves (ASV/RCVs).

In summary, risk mitigation can include initiating preventative measures, performing assessments using specialized technology, repair or replacement of anomalous conditions along a pipeline, or complete replacement of a given asset. As part of its comprehensive integrity management program, the Company has identified different risk mitigation strategies intended to reduce the likelihood of or consequences posed by a particular threat or multiple threats.

II. 2015 TIMP SUB-PROJECTS

For 2015, there are three projects proposed under the TIMP: 1) East Metro Pipeline Replacement; 2) Transmission Pipeline Assessments; and 3) Automatic Shut-Off/Remote Control Valves. Following are the estimated project costs:

2015 Estimated TIMP Project Costs

$ Millions	**2015 Estimated Capital**	**2015 Estimated O&M**
East Metro Pipeline **Replacement**	$23.10	$0.04
Transmission Pipeline Assessments	$0.35	$0.75
ASV/RCV	$0.50	$0.00
TOTAL 2015 TIMP Capital Expenditures and O&M	**$23.95***	**$0.79**
TOTAL 2015 MN TIMP Incremental Revenue Requirements	**4.96****	**0.22*****

** Total estimated capital expenditures, including removal costs RWIP*

***Capital Cost represents the eligible calculated revenue requirements, which include: debt and equity return on rate base, property taxes, current and deferred taxes, and book depreciation*

****Excludes TIMP O&M recovered in base rates*

Estimated Project Start Date
05/01/2015

Estimated In-Service Date
TIMP is an ongoing program to reduce operating risk and improve overall public safety. Projects planned for completion in 2015, and outlined below will generally begin during the 2nd quarter of 2015 and begin service during the 3rd and 4th quarters of 2015.

(1) Sub-Project: East Metro Replacement Project
Parent Projects: 11615874 and 11676981 (Capital); 11984262 (O&M)

2015 Estimated Project Costs:
$23.1 million Capital expenditure
$0.04 million O&M expenditure

Estimated Project Start Date
05/01/2015

Estimated In-Service Date
The East Metro pipeline project is a four-year effort that began in 2013. The phase that is planned for 2015 will begin during the 2nd quarter and will generally begin service during the 3rd and 4th quarters.

Scope
The 2015 scope of work will replace approximately 4.5 miles of gas transmission line at Rose Avenue and Park Street to Pleasant Avenue and St. Albans Street. Capital and O&M expenditure estimates provided above are only for the 2015 phase of the project.

Project Summary
The Company owns and operates about 11-½ miles of gas transmission line in the cities of St. Paul and Roseville. These lines are the backbone of the gas delivery system in the East Metro area, serving approximately 100,000 homes and businesses. The health and condition of this pipe type cannot be assessed with any current in-line inspection tools, as it was constructed using compression couplings, which prevent the travel of an inspection tool. The risk analysis includes corrosion, manufacturing threats, the aforementioned construction threat, and third party damage. The Company has determined that pipeline replacement will ensure future safety and reliability and allow for more effective in-line inspections and pressure testing of this key asset in a highly populated area.

The capital investment for this sub-project is approximately $69 million. It is being executed over a four-year period starting in 2013 with about 4-½ miles of gas main replaced in a given year, allowing switch over to new segments before winter. This will avoid gas delivery interruptions during the heating season.

(2) Sub-Project: Transmission Pipeline Assessments
Parent Project: 11649521 (Capital); 11984286 (O&M)

<u>2015 Estimated Project Costs</u>
$0.35 million Capital expenditure
$0.75 million O&M expenditure

<u>Scope</u>
In 2015, the Company plans to perform health and condition assessments on over seven miles of gas transmission pipeline using Direct Assessment or Pressure Testing. The Company will also evaluate and remediate anomalous conditions found during the assessments. The Company will also modify the configuration of one line to prepare for an ILI assessment in an upcoming year. The scope of work in 2015 includes the following lines:

- County Road B Line
- Crossover Line
- Granite City Line

<u>Project Summary</u>
Within the overall TIMP category of projects, transmission pipeline assessment and remediation work is expected to occur indefinitely, as the Company is required by code to assess segments of its gas transmission system at intervals not to exceed every seven years.

The Company's comprehensive strategy to use in-line inspection, where feasible, will take place over a number of years. ILI requires unique inspection equipment and specialized knowledge. For example, a single ILI tool may be valued at $1 million. Outside vendors maintain fleets of such tools and have the expertise needed to conduct an ILI. Xcel Energy has neither the technology nor the expertise to conduct an ILI in a thorough or cost-effective manner. Accordingly, Xcel Energy works with outside contractors to complete this work safely and efficiently.

While the initial investment incurred to make the lines accessible to ILI assessment tools can be significant, the benefit of this investment is the ability to monitor changes to the integrity of a line over the course of the asset's lifetime, and it provides us with an understanding of the threats and risks from a broader system perspective.

(3) Sub-Project: Automatic Shut-off Valve/Remote Controlled Valves (ASV/RCV) Parent Project: 11503515 (Capital)

2015 Estimated Project Costs:
$0.50 million Capital expenditure

Scope
The scope includes installation of either ASV or RCV mainline isolation valves on high pressure, natural gas transmission pipelines. The determination of the applicable type of valve to install in each situation will be based on an overall risk analysis, evaluation of system operational needs, and engineering review. The current estimate is for the installation of two valves during calendar year 2015.

Project Summary
The Company plans to install these types of valves at locations where they can provide an efficient means of adding protection in the event of a sudden, unplanned gas release. This will be a multi-year project, and we anticipate installing 2-4 valves per year over the next five years.

III. TIMP MULTI-YEAR PLAN

As previously stated, some of the TIMP sub-projects will span multiple years. As such, the Company has formulated a multi-year plan for those that will expand beyond 2015.

The table below depicts the estimated costs related to this multi-year plan broken out by annual capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates only. Many of these projects require more detailed design and engineering work that has not yet been performed to improve the quality of the estimate. Other factors, including coordination with city entities, securing rights-of-way and permits, resource and equipment availability, and unforeseen circumstances all can have an impact on a final construction estimate.

TIMP 2016-2019 Plan

$ millions

	2016 Estimates		**2017 Estimates**		**2018 Estimates**		**2019 Estimates**	
Sub-Project	**Capital***	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
East Metro Pipeline Replacement	$15.9	$0.02	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transmission Pipeline Assessments	$4.7	$0.0	$0.9	$1.6	$1.6	$1.1	$7.5	$1.7
ASV/RCV	$0.5	$0.0	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0
*Programmatic Replacement / MAOP Remediation***	*$0.0*	*$0.0*	*$2.5*	*$0.0*	*$25.5*	*$0.0*	*$25.5*	*$0.0*
TOTAL	**$21.1**	**$0.02**	**$4.4**	**$1.6**	**$28.1**	**$1.1**	**$34.0**	**$1.7**

**Capital figures denoted represent total estimated capital expenditures, including removal costs (RWIP)*

***The Programmatic Replacement / MAOP Remediation project does not have any activity in 2015. This estimate provides an initial high-level budgeting estimate related to the potential need for capital intensive repairs or replacement efforts needed on transmission pipelines that are being assessed for asset health and condition in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures. Additionally, current PHMSA rules are in process of being finalized regarding the validation of Maximum Allowable Operating Pressure (MAOP). This budget line item includes the assumption that remediation of final MAOP requirements may be needed on vintage gas transmission pipelines.*

Capital Expenditure (CWIP Only)
Forecast Through 2019 ($s)

Project Name	Sub Project	Eligibility Date	Pre-2013	2013	2014	2015	2016	2017	2018	2019	Total by Subproject	Total by Project
Total: GUIC Statute Projects			**232,229**	**10,317,189**	**15,959,969**	**31,986,400**	**30,557,600**	**22,170,400**	**44,666,700**	**50,277,600**	**206,168,087**	**206,168,087**
TIMP	Transmission	Jan-15	97,376	71,370	1,430,376	3,185,850	6,086,400	4,264,400	27,539,100	33,150,000	75,824,872	-
TIMP	Distribution	Jan-15	1,526	9,644,232	13,922,551	20,043,800	14,303,100	-	-	-	57,915,208	133,740,081
DIMP	Distribution	Jan-15	133,327	601,587	607,043	7,015,500	10,168,100	17,906,000	17,127,600	17,127,600	70,686,756	-
DIMP	Software	Jan-15	-	-	-	1,741,250	-	-	-	-	1,741,250	72,428,006
											-	-

TIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Rate Base													
Plant In-Service	25,283,809	25,530,203	25,744,766	26,251,322	27,583,250	29,532,691	31,403,787	36,177,173	39,884,236	43,606,983	46,355,378	47,909,384	47,909,384
Less Accumulated Book Depreciation Reserve	473,559	525,716	578,353	631,746	687,072	745,806	808,492	877,669	955,069	1,039,910	1,131,305	1,226,927	1,226,927
Less Accumulated Deferred Taxes	789,491	858,272	927,696	997,980	1,070,382	1,146,889	1,228,511	1,318,443	1,420,538	1,533,042	1,654,790	1,783,107	1,783,107
End Of Month Rate Base	**24,020,760**	**24,146,215**	**24,238,717**	**24,621,596**	**25,825,796**	**27,639,996**	**29,366,784**	**33,981,062**	**37,508,629**	**41,034,030**	**43,569,282**	**44,899,350**	**44,899,350**
Return on Rate Base													
Debt Return	59,347	59,807	60,078	60,668	62,639	66,387	70,783	78,657	88,766	97,524	105,049	109,849	919,554
Equity Return	105,351	106,168	106,648	107,696	111,194	117,848	125,652	139,629	157,575	173,121	186,480	195,000	1,632,363
Total Return on Rate Base	**164,699**	**165,975**	**166,726**	**168,364**	**173,833**	**184,234**	**196,436**	**218,286**	**246,342**	**270,645**	**291,529**	**304,848**	**2,551,918**
Income Statement Items													
Property Taxes	40,382	40,382	40,382	40,382	40,382	40,382	40,382	40,382	40,382	40,382	40,382	40,382	484,587
Book Depreciation	51,527	52,158	52,637	53,393	55,326	58,733	62,686	69,177	77,400	84,842	91,395	95,622	804,896
Deferred Taxes	67,867	68,781	69,424	70,284	72,402	76,507	81,622	89,932	102,095	112,504	121,748	128,317	1,061,484
Gross Up for Income Tax	3,881	3,609	3,367	3,262	3,497	3,884	4,104	5,158	5,348	5,613	5,608	5,079	52,410
Total Income Statement Expense	**163,658**	**164,930**	**165,811**	**167,321**	**171,608**	**179,506**	**188,793**	**204,650**	**225,225**	**243,341**	**259,133**	**269,400**	**2,403,377**
Revenue Requirement													
Total	**328,357**	**330,906**	**332,537**	**335,686**	**345,441**	**363,740**	**385,229**	**422,936**	**471,567**	**513,986**	**550,662**	**574,248**	**4,955,295**

TIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
Plant In-Service	48,434,471	48,687,617	48,865,570	49,236,004	50,190,055	51,671,084	53,074,088	57,437,436	60,777,114	63,964,359	66,804,340	68,127,875	68,127,875
Less Accumulated Book Depreciation Reserve	1,324,478	1,422,767	1,521,480	1,620,758	1,721,425	1,824,584	1,930,663	2,042,030	2,160,319	2,284,701	2,414,857	2,548,783	2,548,783
Less Accumulated Deferred Taxes	1,899,707	2,017,478	2,135,834	2,254,800	2,375,138	2,498,183	2,624,698	2,757,756	2,901,156	3,053,333	3,213,687	3,380,128	3,380,128
End Of Month Rate Base	**45,210,285**	**45,247,372**	**45,208,256**	**45,360,446**	**46,093,491**	**47,348,317**	**48,518,727**	**52,637,650**	**55,715,640**	**58,626,325**	**61,175,796**	**62,198,964**	**62,198,964**
Return on Rate Base													
Debt Return	111,886	112,318	112,316	112,456	113,555	116,024	119,035	125,603	134,539	141,975	148,754	153,190	1,501,650
Equity Return	198,617	199,384	199,379	199,629	201,580	205,961	211,307	222,966	238,829	252,029	264,064	271,939	2,665,682
Total Return on Rate Base	**310,503**	**311,702**	**311,695**	**312,085**	**315,135**	**321,985**	**330,342**	**348,568**	**373,367**	**394,003**	**412,818**	**425,129**	**4,167,332**
Income Statement Items													
Property Taxes	77,638	77,638	77,638	77,638	77,638	77,638	77,638	77,638	77,638	77,638	77,638	77,638	931,656
Book Depreciation	97,552	98,289	98,713	99,278	100,667	103,158	106,080	111,367	118,289	124,382	130,156	133,926	1,321,856
Deferred Taxes	116,600	117,771	118,357	118,965	120,339	123,045	126,514	133,059	143,399	152,178	160,354	166,441	1,597,021
Gross Up for Income Tax	16,162	15,663	15,204	14,865	14,847	15,099	15,276	16,457	16,944	17,215	17,328	16,826	191,887
Total Income Statement Expense	**307,952**	**309,360**	**309,912**	**310,746**	**313,490**	**318,940**	**325,508**	**338,521**	**356,271**	**371,413**	**385,475**	**394,831**	**4,042,419**
Revenue Requirement													
Total	**618,454**	**621,062**	**621,607**	**622,831**	**628,625**	**640,925**	**655,850**	**687,089**	**729,638**	**765,416**	**798,293**	**819,960**	**8,209,751**

TIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
Plant In-Service	68,473,737	68,659,657	68,777,604	68,836,808	68,878,838	68,969,819	69,147,656	70,298,591	71,191,701	71,856,902	72,318,987	72,713,873	72,713,873
Less Accumulated Book Depreciation Reserve	2,683,953	2,819,464	2,955,168	3,090,985	3,226,867	3,362,834	3,498,973	3,635,961	3,774,255	3,913,544	4,053,554	4,194,111	4,194,111
Less Accumulated Deferred Taxes	3,522,804	3,666,414	3,810,530	3,954,946	4,099,529	4,244,269	4,389,307	4,535,530	4,684,407	4,835,636	4,988,603	5,142,847	5,142,847
End Of Month Rate Base	**62,266,979**	**62,173,780**	**62,011,906**	**61,790,877**	**61,552,441**	**61,362,716**	**61,259,375**	**62,127,099**	**62,733,039**	**63,107,721**	**63,276,830**	**63,376,916**	**63,376,916**
Return on Rate Base													
Debt Return	154,545	154,514	154,197	153,722	153,151	152,620	152,256	153,205	155,035	156,252	156,927	157,262	1,853,686
Equity Return	274,344	274,288	273,726	272,882	271,869	270,925	270,280	271,964	275,213	277,374	278,573	279,166	3,290,604
Total Return on Rate Base	**428,889**	**428,802**	**427,923**	**426,604**	**425,021**	**423,545**	**422,535**	**425,169**	**430,247**	**433,626**	**435,500**	**436,428**	**5,144,289**
Income Statement Items													
Property Taxes	110,402	110,402	110,402	110,402	110,402	110,402	110,402	110,402	110,402	110,402	110,402	110,402	1,324,828
Book Depreciation	135,170	135,510	135,704	135,817	135,882	135,967	136,139	136,988	138,294	139,289	140,009	140,557	1,645,327
Deferred Taxes	142,677	143,609	144,116	144,416	144,583	144,740	145,038	146,223	148,876	151,229	152,967	154,244	1,762,719
Gross Up for Income Tax	36,647	35,889	35,191	34,504	33,828	33,198	32,617	32,601	32,282	31,611	30,902	30,227	399,496
Total Income Statement Expense	**424,896**	**425,411**	**425,415**	**425,139**	**424,696**	**424,307**	**424,197**	**426,214**	**429,854**	**432,532**	**434,281**	**435,430**	**5,132,371**
Revenue Requirement													
Total	**853,785**	**854,213**	**853,338**	**851,743**	**849,716**	**847,852**	**846,732**	**851,383**	**860,101**	**866,159**	**869,781**	**871,857**	**10,276,660**

TIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
Plant In-Service	72,912,093	73,137,171	73,501,311	73,684,096	73,901,427	74,323,614	75,803,713	83,218,598	89,438,101	94,052,931	97,197,215	100,303,582	100,303,582
Less Accumulated Book Depreciation Reserve	4,335,046	4,476,253	4,617,836	4,759,768	4,901,956	5,044,552	5,188,364	5,337,859	5,496,064	5,661,192	5,831,276	6,005,355	6,005,355
Less Accumulated Deferred Taxes	5,291,947	5,441,819	5,592,602	5,744,395	5,896,909	6,050,378	6,206,369	6,373,495	6,562,870	6,772,222	6,996,321	7,233,069	7,233,069
End Of Month Rate Base	**63,285,099**	**63,219,100**	**63,290,872**	**63,179,933**	**63,102,562**	**63,228,684**	**64,408,980**	**71,507,244**	**77,379,167**	**81,619,518**	**84,369,618**	**87,065,158**	**87,065,158**
Return on Rate Base													
Debt Return	157,272	157,076	157,083	157,035	156,801	156,861	158,483	168,763	184,867	197,423	206,103	212,865	2,070,633
Equity Return	279,184	278,836	278,849	278,763	278,348	278,455	281,335	299,582	328,170	350,460	365,868	377,871	3,675,720
Total Return on Rate Base	**436,456**	**435,912**	**435,932**	**435,797**	**435,148**	**435,316**	**439,818**	**468,345**	**513,038**	**547,883**	**571,971**	**590,736**	**5,746,353**
Income Statement Items													
Property Taxes	117,834	117,834	117,834	117,834	117,834	117,834	117,834	117,834	117,834	117,834	117,834	117,834	1,414,009
Book Depreciation	140,936	141,206	141,583	141,932	142,188	142,596	143,812	149,495	158,206	165,127	170,085	174,078	1,811,244
Deferred Taxes	149,100	149,871	150,784	151,793	152,514	153,469	155,991	167,126	189,375	209,352	224,099	236,748	2,090,222
Gross Up for Income Tax	34,246	33,458	32,753	31,920	31,134	30,448	30,032	31,178	29,229	25,658	22,459	19,062	351,577
Total Income Statement Expense	**442,116**	**442,369**	**442,954**	**443,479**	**443,670**	**444,347**	**447,669**	**465,633**	**494,643**	**517,972**	**534,477**	**547,723**	**5,667,052**
Revenue Requirement													
Total	**878,572**	**878,281**	**878,886**	**879,276**	**878,819**	**879,664**	**887,487**	**933,977**	**1,007,681**	**1,065,855**	**1,106,448**	**1,138,459**	**11,413,405**

TIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Rate Base													
Plant In-Service	100,476,675	100,814,231	101,359,179	101,381,074	101,642,731	102,352,067	105,003,632	119,214,182	125,434,941	129,288,695	131,586,070	133,740,081	133,740,081
Less Accumulated Book Depreciation Reserve	6,181,528	6,358,028	6,535,091	6,712,517	6,890,124	7,068,351	7,248,725	7,439,872	7,644,073	7,854,710	8,069,277	8,286,689	8,286,689
Less Accumulated Deferred Taxes	7,442,212	7,652,213	7,863,566	8,075,779	8,288,422	8,502,374	8,721,246	8,963,663	9,235,940	9,523,482	9,820,372	10,123,730	10,123,730
End Of Month Rate Base	**86,852,935**	**86,803,990**	**86,960,522**	**86,592,779**	**86,464,185**	**86,781,343**	**89,033,661**	**102,810,647**	**108,554,928**	**111,910,502**	**113,696,421**	**115,329,662**	**115,329,662**
Return on Rate Base													
Debt Return	215,948	215,624	215,758	215,495	214,879	215,113	218,304	238,207	262,446	273,745	280,129	284,374	2,850,021
Equity Return	383,344	382,769	383,006	382,540	381,446	381,862	387,526	422,857	465,885	485,943	497,275	504,812	5,059,265
Total Return on Rate Base	**599,293**	**598,393**	**598,764**	**598,036**	**596,325**	**596,975**	**605,829**	**661,064**	**728,331**	**759,687**	**777,404**	**789,186**	**7,909,285**
Income Statement Items													
Property Taxes	162,544	162,544	162,544	162,544	162,544	162,544	162,544	162,544	162,544	162,544	162,544	162,544	1,950,524
Book Depreciation	176,173	176,500	177,063	177,426	177,607	178,227	180,374	191,147	204,201	210,637	214,567	217,411	2,281,334
Deferred Taxes	209,143	210,001	211,353	212,213	212,643	213,952	218,872	242,417	272,277	287,543	296,889	303,358	2,890,661
Gross Up for Income Tax	43,529	42,550	41,624	40,703	39,778	38,982	38,197	38,867	38,760	37,661	36,477	35,493	472,621
Total Income Statement Expense	**591,389**	**591,594**	**592,584**	**592,885**	**592,572**	**593,705**	**599,986**	**634,975**	**677,782**	**698,384**	**710,477**	**718,806**	**7,595,139**
Revenue Requirement													
Total	**1,190,682**	**1,189,987**	**1,191,347**	**1,190,921**	**1,188,897**	**1,190,680**	**1,205,815**	**1,296,039**	**1,406,112**	**1,458,072**	**1,487,881**	**1,507,991**	**15,504,425**

Distribution Integrity Management Program (DIMP)
Overview and Project Detail

I. DIMP OVERVIEW

Managing the integrity and safe operation of Xcel Energy's gas systems is a continuous cycle. At its core, DIMP can be summarized in three steps: 1) understand your assets, 2) understand the threats to those assets (risk evaluation), and 3) and proactively address threats against those assets (risk mitigation). Xcel Energy's processes for these three steps are outlined below.

The progression of these steps is part of the Company's proactive integrity management program and continually evolves as new data is obtained. We incorporate knowledge gained about our assets through normal operations as well as routine maintenance activities, pipeline surveys, inspections, proactive mitigation measures, industry trends, and regulatory guidance. Using the processes identified below, Xcel Energy is continually updating its DIMP plans and projects to address the evolving needs of its gas distribution system.

1) Understand Your Assets

The first step toward understanding the threats and evaluating the associated risks is to have knowledge and an understanding of the distribution assets. Xcel Energy collects specific data and information about its facilities and the environment in which the asset operate. Much of this information comes from the Company's records, including paper documents, electronic databases, and the experience of subject matter experts (SMEs). Information, such as the design, material, type of construction, operating conditions, maintenance history, environment, and other relevant factors, is referred to collectively as "knowledge" of the gas distribution system.

Using the knowledge of the system, the Company considers each of the following eight threat categories:

- Corrosion
- Natural Forces
- Excavation Damage
- Other Outside Force
- Materials, Weld, or Joint Failure
- Equipment Failure

- Incorrect Operation
- Other Threats

The Company also evaluates the historical cause of leaks to gain an understanding of the presence of particular threats to the system.

2) Risk Evaluation (Assessment of Risk)

Xcel Energy uses computerized risk modeling software to evaluate relative risk based on variables including pipe material, pipe size, prior failures (leaks), and failure causes. The Company also considers historical incidents, industry trends, Pipeline Hazardous Materials Safety Administration (PHMSA) advisory bulletins, regulatory commitments, and knowledge from other distribution operators and industry members. A calculated "relative risk" value is assigned and is used as guidance by Company SME's, enabling stratification or ranking of projects based on predetermined pipe characteristics and forecasted pipe failures.

3) Risk Mitigation

Using the information gathered and industry best practices, we take appropriate measures to reduce or remove the risks to the distribution system - either by reducing the likelihood or lessening the consequences of a particular threat or threats. One such method is the targeted replacement of pipe segments that are considered to be poor performing or problematic. A variety of other strategies are used to promote the goals of DIMP, as well:

- Replacement of poor performing coated steel pipelines (*corrosion*);
- Renewal of mechanical/compression coupled mains and services (*material and welds, corrosion*);
- Renewal of a poor performing type of polyethylene pipe material, Aldyl-A (PEA) pipelines *(material and welds, equipment);*
- Replacement of copper loop risers *(corrosion);*
- Inspecting intermediate pressure (IP) pipelines; repairing or replacing as needed (*corrosion, material and welds*)

Risk mitigation is not solely focused on pipe replacement programs, but can also include initiating preventative measures, performing inspections utilizing specialized technology, or more frequent inspections of equipment of pipelines. As part of its comprehensive integrity management program, the Company has identified different risk mitigation strategies, all of which have the intent of reducing the likelihood or consequences posed by a particular threat or multiple threats.

II. 2015 DIMP SUB-PROJECTS

The various DIMP sub-projects are described below in more detail. These projects represent the expected scope of Xcel Energy's DIMP activities for the next few years. Some of the sub-projects are anticipated to commence and be completed in 2015, while others will take place over the course of multiple years. Individual DIMP priorities may shift based on information the Company gathers while conducting DIMP assessment and inspection activities.

For 2015, there are six projects proposed under the DIMP with an estimated total cost of $9.1 million in capital expenditures and $4.3 million in O&M expenditures (which includes $3.5 million related to continued sewer conflict investigation activity). A summary of the estimated capital and O&M expenditures are provided in the table, followed by individual project summaries.

2015 Estimated DIMP Project Costs

$ Millions	**2015 Estimated Capital**	**2015 Estimated O&M**
Poor Performing Main Replacements	$4.50	$0.27
Poor Performing Service Replacements	$2.10	$0.13
Intermediate Pressure (IP) Line Assessments	$0.00	$0.43
Distribution Valve Replacement Project	$0.77	$0.00
Pipeline Data Project (PDP) – Distribution	$1.75	$0.00
Sewer & Gas Line Conflict Investigation	$0.00	$3.50
TOTAL 2015 DIMP Capital Expenditures and O&M	**$9.12***	**$4.32**
TOTAL 2015 MN DIMP Incremental Revenue Requirement	**$0.69****	**$4.32**

**Total estimated capital expenditures, including removal costs RWIP*

***Capital Cost represents the eligible calculated revenue requirements, which include: debt and equity return on rate base, property taxes, current and deferred taxes, and book depreciation*

1) Poor Performing Main Replacements

2015 Estimated Project Costs
$4.50 million Capital expenditure
$0.27 million O&M expenditure

Scope
As described previously, through an annual risk analysis, the Company identifies system threats, ranks these threats, and identifies actions to address these threats. The systematic renewal of poor performing mains and services allows for optimized resource utilization and coordination with local communities, reducing the inconvenience of street construction for our customers. For 2015, the poor performing mains materials will include Aldyl-A (PEA) and vintage coated steel, but additional material types may be included as necessary based on their overall relative risk.

Project Summary
The Company is continually evaluating the threats on the pipeline system and identifying distribution main segments that pose a risk due to on-going pipe material deterioration or leaks. Main replacement is a multi-year project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

PHMSA has issued several Advisory Bulletins about a certain polyethylene pipe material type called Aldyl-A. This plastic material becomes brittle over time and is subject to sudden failure from cracking. The Company has also identified segments of vintage coated steel pipe that need to be removed due to the mechanical couplings that were used to join the pipe. Many of these mains appear to pose no risk unless they have been disturbed through third-party damage (excavation hits) or the threat of natural forces (frost heave). Once disturbed, the mechanical couplings can begin to leak, resulting in property damage, outages, and other consequences. The removal of these pipe segments will reduce operating risk and reduce the likelihood of incidents.

The Company utilizes the aforementioned risk model for the initial relative ranking of poor performing mains. This list is then reviewed by SMEs to appropriately identify and prioritize projects. SMEs consist of engineering, cathodic protection, construction, and integrity management employees. When possible, the Company coordinates work with city and county road maintenance activities and other utility work, to avoid or minimize paving costs and disruption to the community where the work is being performed. Both main and service replacements are considered for simultaneous construction to minimize overall costs.

Main projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified main projects will generally begin during the 2nd quarter and assets will typically be in-service during the 3rd and 4th quarters. For example, 2015 project identification will occur in the 2nd and 3rd quarters of 2014, construction will commence during the 2nd quarter of 2015, and in-service will occur during the 3rd and 4th quarters of 2015. Currently, the Company is in the process of identifying specific projects for the 2015 construction season.

2) Poor Performing Service Replacements

2015 Estimated Project Costs
$2.10 million Capital expenditure
$0.13 million O&M expenditure

Scope
Through an annual risk analysis, the Company identifies system threats, ranks these threats, and identifies measures to address these risks. Replacing poor performing or problematic services in a reasonable timeframe is a practical way to ensure public safety and decrease risk. For 2015, the primary service-related material types that will be addressed include Aldyl-A, vintage coated steel, and copper risers. Additional material types may be included as necessary based on their overall risks.

Project Summary
As with the analysis of poor performing mains, the Company utilizes the aforementioned risk model to provide a relative ranking of problematic service segments. These problematic segments are then reviewed by SMEs to appropriately identify and prioritize projects. SMEs consist of engineering, cathodic protection, construction, and integrity management employees. This is a multi-year program with the areas identified as higher risk, as measured by leak ratios and other factors, being mitigated in an appropriate order. Where appropriate, service replacements are considered for simultaneous construction along with main replacements to minimize construction costs.

Service replacement projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be brought in service during the 3rd and 4th quarters. As an example, 2015 project identification will occur in 2nd and 3rd quarter 2014, construction will commence 2nd quarter 2015 and in-service will occur 3rd or 4th quarter 2015. Currently, the Company is in the process of identifying specific projects for the 2015 construction season.

3) Intermediate Pressure ("IP") Line Assessments

2015 Estimated Project Costs
$0.00 million Capital expenditure
$0.43 million O&M expenditure

Scope
Project will be limited to pipeline assessments on IP lines. There is currently one IP assessment project planned for the 2015 time period. This assessment will be performed on the 12-mile Anoka IP line.

Project Summary
The purpose of this overall project is to perform health and condition assessments on the IP pipelines. Many of the Company's IP lines are in close proximity to homes and businesses and operate at pressures that are higher than the majority of the typical gas distribution mains and services. While the impact of a line break can be less than a gas transmission line, the risk of serious consequences to people and property is elevated in the event of an IP line failure. Additionally, many of these IP lines are critical in maintaining natural gas service to key metropolitan areas.

In 2015, the Company plans to assess the Anoka IP line using External Corrosion Direct Assessment (EDCA). The total scope of the project covers 12.3 miles of pipeline ranging in size from 2" to 24" in diameter.

4) Distribution Valve Replacement Project

2015 Estimated Project Costs
$0.77 million Capital expenditure

Scope
We estimate that nearly 460 new emergency distribution valves will be installed, ranging in size from 2-inch to 6-inch. In 2012 and 2013, the Company installed a total of 157 emergency distribution valves. Through May 2014, the Company has installed 53 emergency valves and plans to install another 47 valves. In 2015, the Company intends to install the remaining 203 identified emergency distribution valves.

Project Summary
The placement, accessibility, and functionality of valves in the gas distribution system are critical components of gas operations, as valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections, the utility minimizes customer impacts during these events. The Company has identified a need to add, replace, or otherwise rehabilitate existing distribution valves.

5) Pipeline Data Project ("PDP") - Distribution

2015 Estimated Project Costs
$1.75 million Capital expenditure

Scope
This project includes researching hard-copy records and performing data entry on gas distribution mains and services into the Company's Geographic Information System (GIS) for gas distribution pipelines.

Project Summary
Integrity programs are essentially risk management programs which require significant data about system assets, including construction and installation data, pipe material characteristics, and operating data.

The primary purpose of the project is to develop improved asset knowledge of aging distribution systems, and store this information electronically. Improving the availability and quality of our data related to the distribution assets also supports the Company's ability to utilize the risk model, which is vital for identifying poor performing mains and services.

Improved data quality overall, along with improved solid data collection processes going forward, will allow for better predictive models. Unfortunately, some historical data is unavailable. Key data gaps that cannot be resolved can be incorporated into the overall integrity plan. This approach reduces overall system risk, improves operating efficiency, and provides the basis for programs to renew or repair pipe before significant issues develop.

6) Sewer and Gas Line Conflict Investigation

2015 Estimated Project Costs
$3.5 million O&M expenditure

Scope
Both the Minnesota Public Utilities Commission and PHMSA have asked Xcel Energy to develop and implement safety plans to reduce the risk to customers and minimize the threat of future cross bore-related catastrophes. In particular, PHMSA's Gas Distribution Pipeline Integrity Management Enforcement Guidance notes, "Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in proximity of each other. As such, operators must determine the potential for cross bore of sewers resulting in gas lines intersecting with sewers."

Xcel Energy is currently assessing these potential conflicts. The Company has been inspecting sewer laterals and mains since 2010 and has found 138 incidences of conflicts between sewer and gas lines. Through May of 2014, the Company has discovered four conflicts, leading to a determination that further inspections are not only prudent but necessary in order to understand and mitigate the risk posed by a cross bore.

Consistent with the level of effort for 2010-2013, the current plan estimates that approximately 20,000 services will be inspected for conflicts. We review the results of the previous year's inspections and target those areas determined to have a higher probability of conflicts, as confirmed either through camera inspections or excavation of the service line and visual affirmation. Since the 2014 inspections are still being performed, the exact communities in which the inspections are to be performed in 2015 have not yet been determined.

The inspection program is anticipated to be a 10-year program, subject to change. This program has risk mitigation at its core, and as such the Company will continue to monitor circumstances that may indicate a need to accelerate or scale back inspections.

III. DIMP MULTI-YEAR PLAN

As mentioned above, many of the DIMP sub-projects are initiatives that will span multiple years. As such, the Company has formulated a five-year plan for those sub-projects that will extend beyond 2015. As the Company continues to execute its risk-based strategy, replacement projects planned for 2015 and beyond will target pipe segments displaying the highest level of relative risk (versus replacements at a broader system level). Therefore, it is anticipated that there will be an increase in the number of overall projects.

The table below depicts the estimated costs related to this multi-year plan broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates only. Many of these projects require detailed design and engineering that has not yet been performed to improve the quality of the estimate. Additionally, coordination with city entities, securing rights-of-way and permits, resource and equipment availability and unforeseen circumstances all can have an impact on a final construction estimates.

DIMP 2016-2019 Plan

$ millions

	2016 Estimates		**2017 Estimates**		**2018 Estimates**		**2019 Estimates**	
Sub-Project	**Capital***	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$6.7	$0.4	$11.2	$0.7	$11.2	$0.7	$11.2	$0.7
Poor Performing Services	$4.1	$0.2	$7.0	$0.4	$7.0	$0.4	$7.0	$0.4
Intermediate Pressure Line Assessments	$0.0	$0.8	$0.8	$0.0	$0.0	$0.0	$0.0	$0.2
Distribution Valve Replacement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pipeline Data Project (PDP)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Sewer & Gas Line Conflict Remediation	$0.0	$3.5	$0.0	$3.5	$0.0	$3.5	$0.0	$3.5
TOTAL	**$10.8**	**$4.9**	**$19.0**	**$4.6**	**$18.2**	**$4.6**	**$18.2**	**$4.8**

**Capital figures denoted represent total estimated capital expenditures, including removal costs (RWIP).*

DIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Rate Base													
Plant In-Service	1,165,897	1,295,408	1,425,723	1,741,712	2,409,734	3,248,569	4,106,933	5,257,410	6,439,040	7,679,529	8,663,078	9,758,195	9,758,195
Less Accumulated Book Depreciation Reserve	32,837	35,427	38,291	41,514	45,443	50,517	56,937	65,031	75,083	87,133	101,138	117,040	117,040
Less Accumulated Deferred Taxes	149,980	153,753	157,968	162,604	167,867	174,305	182,296	192,192	204,476	219,206	236,576	256,967	256,967
End Of Month Rate Base	**983,080**	**1,106,229**	**1,229,465**	**1,537,593**	**2,196,424**	**3,023,747**	**3,867,700**	**5,000,187**	**6,159,481**	**7,373,189**	**8,325,364**	**9,384,189**	**9,384,189**
Return on Rate Base													
Debt Return	2,318	2,594	2,900	3,436	4,636	6,482	8,557	11,011	13,857	16,803	19,492	21,989	114,075
Equity Return	4,114	4,605	5,148	6,099	8,230	11,506	15,190	19,546	24,598	29,828	34,602	39,035	202,502
Total Return on Rate Base	**6,432**	**7,199**	**8,048**	**9,535**	**12,867**	**17,988**	**23,747**	**30,557**	**38,454**	**46,631**	**54,095**	**61,024**	**316,578**
Income Statement Items													
Property Taxes	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719	20,624
Book Depreciation	2,343	2,590	2,864	4,095	7,415	12,047	16,880	22,040	27,925	34,289	39,298	43,495	215,281
Deferred Taxes	3,381	3,773	4,215	4,637	5,262	6,438	7,992	9,896	12,284	14,730	17,370	20,390	110,368
Gross Up for Income Tax	(420)	(461)	(513)	(330)	330	1,177	1,950	2,811	3,670	4,579	5,092	5,125	23,009
Total Income Statement Expense	**7,023**	**7,621**	**8,284**	**10,120**	**14,726**	**21,381**	**28,540**	**36,466**	**45,597**	**55,317**	**63,479**	**70,729**	**369,282**
Revenue Requirement													
Total	**13,454**	**14,820**	**16,332**	**19,655**	**27,593**	**39,369**	**52,286**	**67,023**	**84,051**	**101,948**	**117,574**	**131,753**	**685,860**

DIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
Plant In-Service	10,045,988	10,295,963	10,508,638	10,840,963	11,579,104	12,585,772	13,602,995	15,035,653	16,407,765	17,851,460	19,135,162	19,785,137	19,785,137
Less Accumulated Book Depreciation Reserve	134,217	151,960	170,189	188,993	208,922	230,689	254,585	281,059	310,485	342,874	378,134	415,429	415,429
Less Accumulated Deferred Taxes	272,288	288,395	305,157	322,619	341,363	362,287	385,851	412,457	442,704	476,664	514,324	554,827	554,827
End Of Month Rate Base	**9,639,484**	**9,855,609**	**10,033,291**	**10,329,351**	**11,028,818**	**11,992,797**	**12,962,560**	**14,342,136**	**15,654,577**	**17,031,921**	**18,242,703**	**18,814,881**	**18,814,881**
Return on Rate Base													
Debt Return	23,621	24,206	24,695	25,284	26,520	28,585	30,986	33,903	37,246	40,586	43,799	46,013	385,445
Equity Return	41,931	42,970	43,838	44,883	47,077	50,743	55,006	60,184	66,118	72,046	77,751	81,681	684,230
Total Return on Rate Base	**65,552**	**67,177**	**68,534**	**70,166**	**73,597**	**79,329**	**85,992**	**94,087**	**103,364**	**112,632**	**121,550**	**127,694**	**1,069,675**
Income Statement Items													
Property Taxes	15,813	15,813	15,813	15,813	15,813	15,813	15,813	15,813	15,813	15,813	15,813	15,813	189,760
Book Depreciation	46,198	46,764	47,251	47,824	48,951	50,787	52,917	55,495	58,447	61,410	64,281	66,316	646,639
Deferred Taxes	15,321	16,107	16,762	17,462	18,745	20,924	23,564	26,606	30,246	33,961	37,660	40,502	297,860
Gross Up for Income Tax	10,636	10,583	10,540	10,557	10,738	11,014	11,251	11,668	12,025	12,322	12,510	12,411	136,255
Total Income Statement Expense	**87,968**	**89,267**	**90,366**	**91,656**	**94,247**	**98,538**	**103,545**	**109,582**	**116,532**	**123,507**	**130,265**	**135,042**	**1,270,514**
Revenue Requirement													
Total	**153,521**	**156,444**	**158,899**	**161,822**	**167,843**	**177,866**	**189,537**	**203,670**	**219,896**	**236,139**	**251,815**	**262,737**	**2,340,189**

DIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
Plant In-Service	20,239,643	20,650,798	21,008,880	21,582,074	22,867,378	24,626,387	26,408,362	28,935,109	31,359,973	33,913,309	36,180,168	37,396,724	37,396,724
Less Accumulated Book Depreciation Reserve	453,886	493,254	533,432	574,589	617,703	664,021	714,064	768,643	828,432	893,461	963,562	1,037,330	1,037,330
Less Accumulated Deferred Taxes	594,668	635,740	677,868	721,129	766,466	815,398	868,760	927,177	991,747	1,062,637	1,139,869	1,222,181	1,222,181
End Of Month Rate Base	**19,191,089**	**19,521,804**	**19,797,580**	**20,286,355**	**21,483,209**	**23,146,968**	**24,825,538**	**27,239,290**	**29,539,794**	**31,957,211**	**34,076,736**	**35,137,213**	**35,137,213**
Return on Rate Base													
Debt Return	47,191	48,069	48,822	49,771	51,864	55,416	59,566	64,647	70,501	76,359	81,992	85,941	740,137
Equity Return	83,771	85,330	86,666	88,352	92,067	98,372	105,739	114,760	125,151	135,550	145,550	152,559	1,313,867
Total Return on Rate Base	**130,962**	**133,398**	**135,488**	**138,123**	**143,931**	**153,788**	**165,305**	**179,407**	**195,651**	**211,908**	**227,542**	**238,500**	**2,054,004**
Income Statement Items													
Property Taxes	32,062	32,062	32,062	32,062	32,062	32,062	32,062	32,062	32,062	32,062	32,062	32,062	384,746
Book Depreciation	67,478	68,389	69,198	70,179	72,134	75,338	79,065	83,599	88,810	94,049	99,122	102,788	970,151
Deferred Taxes	39,841	41,073	42,128	43,261	45,337	48,933	53,361	58,417	64,570	70,890	77,232	82,311	667,354
Gross Up for Income Tax	14,053	13,931	13,828	13,853	14,235	14,827	15,342	16,258	17,057	17,730	18,172	17,987	187,275
Total Income Statement Expense	**153,433**	**155,455**	**157,217**	**159,354**	**163,769**	**171,161**	**179,830**	**190,337**	**202,500**	**214,732**	**226,588**	**235,148**	**2,209,525**
Revenue Requirement													
Total	**284,396**	**288,853**	**292,705**	**297,477**	**307,700**	**324,949**	**345,136**	**369,744**	**398,151**	**426,641**	**454,130**	**473,648**	**4,263,529**

DIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
Plant In-Service	38,030,022	38,527,029	38,924,310	39,505,484	40,763,605	42,469,985	44,190,459	46,604,461	48,914,258	51,343,564	53,505,288	55,300,406	55,300,406
Less Accumulated Book Depreciation Reserve	1,113,044	1,189,947	1,267,792	1,346,667	1,427,477	1,511,407	1,598,943	1,690,831	1,787,690	1,889,536	1,996,214	2,107,056	2,107,056
Less Accumulated Deferred Taxes	1,299,429	1,378,254	1,458,264	1,539,400	1,622,421	1,708,651	1,798,819	1,893,417	1,993,401	2,098,913	2,209,994	2,326,660	2,326,660
End Of Month Rate Base	**35,617,549**	**35,958,828**	**36,198,253**	**36,619,418**	**37,713,707**	**39,249,928**	**40,792,696**	**43,020,213**	**45,133,167**	**47,355,114**	**49,299,081**	**50,866,690**	**50,866,690**
Return on Rate Base													
Debt Return	87,854	88,874	89,595	90,415	92,297	95,563	99,386	104,068	109,457	114,840	120,012	124,372	1,216,734
Equity Return	155,955	157,766	159,046	160,502	163,843	169,641	176,427	184,738	194,305	203,860	213,042	220,782	2,159,907
Total Return on Rate Base	**243,809**	**246,640**	**248,641**	**250,918**	**256,140**	**265,204**	**275,814**	**288,805**	**303,762**	**318,699**	**333,054**	**345,155**	**3,376,640**
Income Statement Items													
Property Taxes	60,602	60,602	60,602	60,602	60,602	60,602	60,602	60,602	60,602	60,602	60,602	60,602	727,224
Book Depreciation	104,735	105,924	106,866	107,895	109,831	112,951	116,557	120,908	125,880	130,867	135,699	139,863	1,417,976
Deferred Taxes	77,249	78,825	80,010	81,135	83,022	86,229	90,168	94,598	99,984	105,512	111,080	116,667	1,104,480
Gross Up for Income Tax	23,762	23,508	23,274	23,181	23,509	24,131	24,715	25,737	26,690	27,525	28,130	27,943	302,103
Total Income Statement Expense	**266,348**	**268,860**	**270,751**	**272,813**	**276,964**	**283,913**	**292,042**	**301,845**	**313,155**	**324,507**	**335,511**	**345,074**	**3,551,784**
Revenue Requirement													
Total	**510,157**	**515,500**	**519,393**	**523,731**	**533,103**	**549,117**	**567,856**	**590,650**	**616,917**	**643,206**	**668,565**	**690,229**	**6,928,424**

DIMP **Revenue Requirements 2015-2019 ($s)** **Transmission, Distribution & Software**	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Rate Base													
Plant In-Service	55,533,982	55,829,858	56,125,734	56,764,162	58,321,270	60,283,230	62,073,914	65,172,310	67,492,250	70,030,142	71,914,178	72,428,006	72,428,006
Less Accumulated Book Depreciation Reserve	2,220,033	2,333,567	2,447,725	2,562,865	2,680,316	2,801,470	2,926,574	3,056,823	3,192,774	3,333,837	3,479,554	3,627,795	3,627,795
Less Accumulated Deferred Taxes	2,435,775	2,545,466	2,655,801	2,767,153	2,880,896	2,998,469	3,120,127	3,247,107	3,379,986	3,518,153	3,661,134	3,806,725	3,806,725
End Of Month Rate Base	**50,878,174**	**50,950,825**	**51,022,209**	**51,434,144**	**52,760,059**	**54,483,292**	**56,027,214**	**58,868,380**	**60,919,490**	**63,178,152**	**64,773,490**	**64,993,486**	**64,993,486**
Return on Rate Base													
Debt Return	126,333	126,438	126,617	127,217	129,374	133,160	137,217	142,662	148,737	154,088	158,873	161,127	1,671,843
Equity Return	224,263	224,448	224,766	225,831	229,661	236,382	243,584	253,249	264,032	273,532	282,027	286,028	2,967,802
Total Return on Rate Base	**350,596**	**350,886**	**351,382**	**353,048**	**359,036**	**369,543**	**380,801**	**395,911**	**412,769**	**427,620**	**440,900**	**447,155**	**4,639,646**
Income Statement Items													
Property Taxes	89,615	89,615	89,615	89,615	89,615	89,615	89,615	89,615	89,615	89,615	89,615	89,615	1,075,383
Book Depreciation	141,998	142,555	143,178	144,161	146,472	150,175	154,124	159,270	164,972	170,084	174,738	177,262	1,868,989
Deferred Taxes	109,115	109,691	110,335	111,352	113,742	117,573	121,658	126,980	132,879	138,167	142,981	145,591	1,480,065
Gross Up for Income Tax	35,704	35,355	35,024	34,804	35,004	35,637	36,330	37,386	38,595	39,588	40,410	40,530	444,366
Total Income Statement Expense	**376,432**	**377,216**	**378,152**	**379,933**	**384,833**	**393,000**	**401,728**	**413,251**	**426,061**	**437,454**	**447,744**	**452,997**	**4,868,802**
Revenue Requirement													
Total	**727,028**	**728,102**	**729,534**	**732,980**	**743,869**	**762,543**	**782,529**	**809,163**	**838,830**	**865,074**	**888,644**	**900,153**	**9,508,448**

216B.1635 RECOVERY OF GAS UTILITY INFRASTRUCTURE COSTS.

Subdivision 1. **Definitions.** (a) "Gas utility" means a public utility as defined in section 216B.02, subdivision 4, that furnishes natural gas service to retail customers.

(b) "Gas utility infrastructure costs" or "GUIC" means costs incurred in gas utility projects that:

(1) do not serve to increase revenues by directly connecting the infrastructure replacement to new customers;

(2) are in service but were not included in the gas utility's rate base in its most recent general rate case, or are planned to be in service during the period covered by the report submitted under subdivision 2, but in no case longer than the one-year forecast period in the report; and

(3) do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

(c) "Gas utility projects" means:

(1) replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota, or a political subdivision; and

(2) replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure that is required by a federal or state agency.

Subd. 2. **Gas infrastructure filing.** A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c). The report and petition must be made at least 150 days in advance of implementation of the rate schedule, provided that the rate schedule will not be implemented until the petition is approved by the commission pursuant to subdivision 5. The report must be for a forecast period of one year.

Subd. 3. **Gas infrastructure project plan report.** The gas infrastructure project plan report required to be filed under subdivision 2 shall include all pertinent information and supporting data on each proposed project including, but not limited to, project description and scope, estimated project costs, and project in-service date.

Subd. 4. **Cost recovery petition for utility's facilities.** Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section, including a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs. A gas utility's petition for approval of a rate schedule to recover gas utility infrastructure costs outside of a general rate case under section 216B.16 is subject to the following:

(1) a gas utility may submit a filing under this section no more than once per year; and

(2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:

(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;

(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;

(iii) a description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;

(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;

(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;

(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;

(vii) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges;

(viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and

(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.

Subd. 5. **Commission action.** Upon receiving a gas utility report and petition for cost recovery under subdivision 2 and assessment and verification under subdivision 4, the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.

Subd. 6. **Rate of return.** The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

Subd. 7. **Commission authority; rules.** The commission may issue orders and adopt rules necessary to implement and administer this section.

History: *2005 c 97 art 10 s 1,3; 2013 c 85 art 7 s 2,9*

NOTE: This section expires June 30, 2023. Laws 2005, chapter 97, article 10, section 3, as amended by Laws 2013, chapter 85, article 7, section 9.

Compliance Matrix

Petition Requirements	Reference
Minnesota Statute § 216B.1635	
Subd. 2. **Gas infrastructure filing.** A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c). The report and petition must be made at least 150 days in advance of implementation of the rate schedule, provided that the rate schedule will not be implemented until the petition is approved by the commission pursuant to subdivision 5. The report must be for a forecast period of one year.	*See* In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider. Report and Petition Submitted August 1, 2014 Docket No. G002/M-14-336
Subd. 3. **Gas infrastructure project plan report.** The gas infrastructure project plan report required to be filed under subdivision 2 shall include all pertinent information and supporting data on each proposed project including, but not limited to, project description and scope, estimated project costs, and project in-service date.	Section IV.F.,L. Attachments B,C,D,E,F,I
Subd. 4. **Cost recovery petition for utility's facilities.** Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section, including a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs. A gas utility's petition for approval of a rate schedule to recover gas utility infrastructure costs outside of a general rate case under section 216B.16 is subject to the following: (1) a gas utility may submit a filing under this section no more than once per year; and (2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:	____________________

Compliance Matrix

Petition Requirements	Reference
(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;	Section IV.F.,L. Attachments B,C,D,E,F,H
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	Executive Summary Section III.A. Section IV.A.,B.
(iii) a description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;	Section IV.K. Attachment J
(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;	Section IV.C.,D.,E.,F. Conclusion Attachment I
(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;	Section IV.A. Section V.A. Attachments D,F,J,K,M,N,O,P
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	Section III.A.3.,5. Section IV.E.,F.,L. Attachments B,C,D,E,F,I
(vii) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges;	Section IV.M. Attachment L
(viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and	Section IV.N. Attachment L
(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.	Executive Summary Section III.A.6. Section IV.A. Conclusion
Subd. 6. **Rate of return.** The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case.	Section III.B.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company for Deferred Accounting Treatment of Costs Relating to Identifying and Eliminating Sewer/Natural Gas Line Conflicts **Minnesota Public Utilities Commission** ORDER GRANTING DEFERRED ACCOUNTING TREATMENT SUBJECT TO CONDITIONS AND REPORTING REQUIREMENTS **January 12, 2011 Docket G002/M-10-422**	
5. At least 60 days before filing its next general rate case, the Company shall file a summary of all costs deferred under this order, using a format similar to the one used in Attachment C, attached to its petition.	*See* Gas Utility Infrastructure Costs-- Deferred Cost Summary Compliance Filing Submitted April 24, 2014 Docket No. G002/M-14-336
6. In any future filing seeking rate recovery of costs deferred under this order, the Company shall include the following:	___________________
A. Justification for the outsourcing of any tasks required to implement the inspection and remediation plan.	Section IV.G.
B. Details of the final resolution of the Notice of Probable Violation and the status of any proposed penalties.	Section IV.H.
C. Discussion and explanation of any legal actions or settlements regarding the natural gas explosion that led to the Notice of Probable Violation.	Section IV.H.
D. Discussion and analysis regarding any potential third-party recovery for the costs of the plan.	Section IV.I.
E. Discussion, analysis, and documentation demonstrating that plan costs were prudent.	Section IV.C.,D.,E. Conclusion Attachment I
F. Analysis of what it would have cost to conduct the plan over a ten-year period beginning in 2003.	Section IV.J.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company for Approval of Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs **Minnesota Public Utilities Commission** ORDER **January 28, 2013 Docket G002/M-12-248**	
f. Require Xcel Energy to provide a filing with a summary of all deferred TIMP and DIMP costs in this same format 60 days prior to the Company's next general gas rate case. [Xcel and Department recommendation]	*See* Gas Utility Infrastructure Costs-- Deferred Cost Summary Compliance Filing Submitted April 24, 2014 Docket No. G002/M-14-336
g. Xcel shall include in the initial filing in its next natural gas rate case, justification and supporting testimony regarding all deferred TIMP and DIMP costs for which it seeks rate recovery.	Executive Summary Section III.A. Section IV.A.,B.,F.,K.,L. Attachments B,C,D,E,F,I

MN GUIC RIDER - O&M BUDGET ESTIMATES

DEFERRED ITEMS (Actual O&M Expense Only)		2010	2011	2012	2013	Jan-Dec 2014	Total	
11990774 - MN Rider Amortization	713050 Contract LT Outside Vendor							
TIMP		$ -	$ -	$ 580,929	$ 3,180,143	$ 718,834	$ 4,479,906	[A]
DIMP		$ 4,175,186	$ 3,639,148	$ 3,538,635	$ 3,630,020	$ 4,349,678	$ 19,332,667	[B]

Subledger Full Desc	Posting Full Acct Desc	2015 YE Budget	2016 YE Budget	2017 YE Budget	2018 YE Budget	2019 YE Budget	Total
5 Year Amortization							
TIMP	Annual Amt. Equals [A] / 5	$ 895,981	$ 895,981	$ 895,981	$ 895,981	$ 895,981	$ 4,479,906
DIMP	Annual Amt. Equals [B] / 5	$ 3,866,533	$ 3,866,533	$ 3,866,533	$ 3,866,533	$ 3,866,533	$ 19,332,667
	Grand Total	**$ 4,762,515**	**$ 4,762,515**	**$ 4,762,515**	**$ 4,762,515**	**$ 4,762,515**	**$ 23,812,573**

MN GUIC RIDER - INCREMENTAL O&M BUDGET ESTIMATES

Subledger Full Desc	Posting Full Acct Desc	2015 YE Budget	2016 YE Budget	2017 YE Budget	2018 YE Budget	2019 YE Budget	Total
TIMP							
11984286 - MN Transmission Pipeline Assessments	713050 Contract LT Outside Vendor	$ 750,000	$ -	$ 1,600,000	$ 1,140,000	$ 1,700,000	$ 5,190,000
11984262 - MN East Metro Pipeline Replacement	713050 Contract LT Outside Vendor	$ 40,000	$ 20,000	$ -	$ -	$ -	$ 60,000
	Total TIMP	$ 790,000	$ 20,000	$ 1,600,000	$ 1,140,000	$ 1,700,000	$ 5,250,000
	MN Allocator (2015-2019 Load Dispatch)	88.6354%	88.3903%	88.3187%	88.1727%	88.1781%	
	Estimated MN TIMP O&M	$ 700,220	$ 17,678	$ 1,413,100	$ 1,005,169	$ 1,499,028	$ 4,635,195
	less TIMP incl in MN base rates	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (2,400,000)
	MN TIMP not in base rates	$ 220,220	$ (462,322)	$ 933,100	$ 525,169	$ 1,019,028	$ 2,235,195
DIMP							
11984278 - MN IP Line Assessments	713050 Contract LT Outside Vendor	$ 425,000	$ 750,000	$ -	$ -	$ 200,000	$ 1,375,000
11984282 - MN Sewer Conflict Investigation	713050 Contract LT Outside Vendor	$ 3,500,000	$ 3,500,000	$ 3,500,000	$ 3,500,000	$ 3,500,000	$ 17,500,000
11984265 - MN Poor Performing Mains	713050 Contract LT Outside Vendor	$ 270,000	$ 402,000	$ 670,000	$ 670,000	$ 670,000	$ 2,682,000
11984268 - MN Poor Performing Services	713050 Contract LT Outside Vendor	$ 126,000	$ 243,000	$ 420,000	$ 420,000	$ 420,000	$ 1,629,000
	MN DIMP not in base rates	$ 4,321,000	$ 4,895,000	$ 4,590,000	$ 4,590,000	$ 4,790,000	$ 23,186,000
	Incremental TIMP + DIMP O&M	**$ 4,541,220**	**$ 4,432,678**	**$ 5,523,100**	**$ 5,115,169**	**$ 5,809,028**	**$ 25,421,195**
	Total TIMP + DIMP O&M	**$ 9,303,734**	**$ 9,195,193**	**$ 10,285,614**	**$ 9,877,683**	**$ 10,571,543**	**$ 49,233,768**

Salvage Estimates - Universal Inputs

Dates				Jan-15 Forecast	Jan-16 Forecast	Jan-17 Forecast	Jan-18 Forecast	Jan-19 Forecast
Depreciation								
Current	Software	Distribution	Transmission					
2015 Book Depreciation Life (yrs)	5.00	45.82	75.00					
2015 Net Salvage %	0.00%	-15.74%	-15.00%					
Net Salvage %								
Software				0.00%	0.00%	0.00%	0.00%	0.00%
Distribution				-15.74%	-15.74%	-15.74%	-15.74%	-15.74%
Transmission				-15.00%	-15.00%	-15.00%	-15.00%	-15.00%
Book Depreciation Lives								
Software				5.00	5.00	5.00	5.00	5.00
Distribution				45.82	45.82	45.82	45.82	45.82
Transmission				75.00	75.00	75.00	75.00	75.00
Book Depreciation Rates								
Software				20.00%	20.00%	20.00%	20.00%	20.00%
Distribution				2.53%	2.53%	2.53%	2.53%	2.53%
Transmission				1.53%	1.53%	1.53%	1.53%	1.53%
Book Depreciation Rate: Final Period								
Software	100%							
Distribution	100%							
Transmission	100%							
Tax Rates								
Income Tax Rates								
State Income Tax Rate				9.8000%	9.8000%	9.8000%	9.8000%	9.8000%
Federal Income Tax Rate				35.0000%	35.0000%	35.0000%	35.0000%	35.0000%
Composite Income Tax Rate								
State Composite Income Tax Rate				35.0000%	35.0000%	35.0000%	35.0000%	35.0000%
Company Composite Income Tax Rate				40.8549%	40.8549%	40.8549%	40.8549%	40.8549%

Tax Depreciation Schedule: MACRS

Annual	
0	0.00%
1	5.00%
2	9.50%
3	8.55%
4	7.70%
5	6.93%
6	6.23%
7	5.90%
8	5.90%
9	5.91%
10	5.90%
11	5.91%
12	5.90%
13	5.91%
14	5.90%
15	5.91%
16	2.95%

Tax Depreciation Schedule: MACRS

Mid-Quarter 2010

Year	Q1	Q2	Q3	Q4
1	8.75%	6.25%	3.75%	1.25%
2	9.13%	9.38%	9.63%	9.88%
3	8.21%	8.44%	8.66%	8.89%
4	7.39%	7.59%	7.80%	8.00%
5	6.65%	6.83%	7.02%	7.20%
6	5.99%	6.15%	6.31%	6.48%
7	5.90%	5.91%	5.90%	5.90%
8	5.91%	5.90%	5.90%	5.90%
9	5.90%	5.91%	5.91%	5.90%
10	5.91%	5.90%	5.90%	5.91%
11	5.90%	5.91%	5.91%	5.90%
12	5.91%	5.90%	5.90%	5.91%
13	5.90%	5.91%	5.91%	5.90%
14	5.91%	5.90%	5.90%	5.91%
15	5.90%	5.91%	5.91%	5.90%
16	0.74%	2.21%	3.69%	5.17%

Bonus Depreciation Rate

2014	50.00%
2015	50.00%

Cap Structure (Based on Previous Year's Actual Structure)	Jan-15 Forecast	Jan-16 Forecast	Jan-17 Forecast	Jan-18 Forecast	Jan-19 Forecast
Long Term Debt %	46.7400%	46.7400%	46.7400%	46.7400%	46.7400%
Long Term Debt Cost ($s as a % of total)	6.3600%	6.3600%	6.3600%	6.3600%	6.3600%
Short Term Debt %	0.8000%	0.8000%	0.8000%	0.8000%	0.8000%
Short Term Debt Cost ($s as a % of total)	1.3600%	1.3600%	1.3600%	1.3600%	1.3600%
Weighted Cost of Debt	2.98%	2.98%	2.98%	2.98%	2.98%
Common Stock %	52.46%	52.46%	52.46%	52.46%	52.46%
Common Stock Cost ($s as a % of total)	10.09%	10.09%	10.09%	10.09%	10.09%
Preferred Stock %	0.00%	0.00%	0.00%	0.00%	0.00%
Preferred Stock Cost ($s as a % of total)	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Cost of Equity	5.29%	5.29%	5.29%	5.29%	5.29%
Rate of Return	8.27%	8.27%	8.27%	8.27%	8.27%
Property Tax Rates					
Percent Taxable	100.00%	100.00%	100.00%	100.00%	100.00%
Asset Rate	1.945%	1.945%	1.945%	1.945%	1.945%
Property Tax Rate	1.945%	1.945%	1.945%	1.945%	1.945%

GUIC Factor Calculations - Revenues

2015, 2016, 2017	Jan-15 Forecast	Feb-15 Forecast	Mar-15 Forecast	Apr-15 Forecast	May-15 Forecast	Jun-15 Forecast	Jul-15 Forecast	Aug-15 Forecast	Sep-15 Forecast	Oct-15 Forecast	Nov-15 Forecast	Dec-15 Forecast
Monthly Inputs												
Revenue Requirement	1,117,123	1,121,037	1,124,181	1,130,652	1,148,345	1,178,420	1,212,827	1,265,270	1,330,930	1,391,246	1,443,547	1,481,312
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Carried-forward balance	-1,608,187	-2,727,547	-3,465,598	-3,401,490	-2,945,976	-2,195,465	-1,351,666	-492,290	430,816	1,012,184	858,470	-220
Weighting												
Group Weighting (Rate Base Allocator - Docket No. G002/GR-09-1153)												
Residential	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Commercial Firm	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Commercial Demand Billed	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Interruptible	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Transport	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Allocated Revenue Requirements												
Residential	812,978.48	815,827.17	818,114.95	822,824.39	835,700.36	857,587.61	882,626.55	920,791.73	968,575.15	1,012,469.79	1,050,531.63	1,078,014.84
Commercial Firm	183,134.39	183,776.09	184,291.45	185,352.31	188,252.80	193,183.19	198,823.55	207,420.78	218,184.64	228,072.50	236,646.44	242,837.41
Commercial Demand Billed	11,253.79	11,293.23	11,324.90	11,390.09	11,568.32	11,871.30	12,217.91	12,746.22	13,407.67	14,015.29	14,542.16	14,922.60
Interruptible	35,212.57	35,335.96	35,435.05	35,639.03	36,196.72	37,144.73	38,229.24	39,882.29	41,951.94	43,853.15	45,501.72	46,692.10
Transport	74,543.36	74,804.56	75,014.33	75,446.14	76,626.76	78,633.64	80,929.50	84,428.93	88,810.28	92,835.05	96,325.00	98,844.98
Total	1,117,122.58	1,121,037.01	1,124,180.67	1,130,651.95	1,148,344.97	1,178,420.47	1,212,826.76	1,265,269.95	1,330,929.66	1,391,245.77	1,443,546.96	1,481,311.94
Sales by Customer Group (Billed by total Usage)												
Residential	66,624,750	55,074,296	45,218,127	24,252,085	13,971,322	8,258,226	5,699,234	6,179,320	8,031,748	19,075,218	38,792,389	56,826,624
Commercial Firm	35,372,058	29,763,844	24,656,293	14,040,930	8,224,105	4,374,815	3,869,999	4,255,246	4,893,515	9,969,834	19,598,983	30,890,457
Commercial Demand Billed	3,403,494	3,159,304	2,765,395	2,807,015	2,106,008	1,602,653	1,422,827	1,456,444	1,465,827	1,939,721	2,597,880	3,324,340
Interruptible	14,702,379	13,489,782	10,825,359	9,711,220	7,751,020	6,624,175	6,097,689	6,325,903	5,718,807	7,789,797	11,907,646	13,658,353
Transport	27,470,993	15,958,227	18,203,566	18,424,269	27,185,182	19,715,624	27,530,974	31,541,339	15,840,073	10,848,003	17,579,452	23,262,366
Total Therm Sales in Month	147,573,674	117,445,452	101,668,741	69,235,519	59,237,636	40,575,494	44,620,723	49,758,252	35,949,970	49,622,573	90,476,351	127,962,140
Flags												
Rate Change	X											
Rate Periods	1	1	1	1	1	1	1	1	1	1	1	1
Rate Period Calculations												
Revenue Requirement for Rate Period	14,944,889											
Remaining true-up in current calendar year	0											
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period	14,944,889											
Retail Dth Sales in Rate Period	934,126,524											
Allocated Cost Per therm												
Residential	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253	$ 0.031253
Commercial Firm	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901	$ 0.012901
Commercial Demand Billed	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367	$ 0.005367
Interruptible	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111	$ 0.004111
Transport	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933	$ 0.003933
Revenues												
Residential	2,082,223	1,721,237	1,413,202	757,950	436,646	258,094	178,118	193,122	251,016	596,158	1,212,379	1,776,002
Commercial Firm	456,335	383,983	318,091	181,142	106,099	56,439	49,927	54,897	63,131	128,621	252,846	398,518
Commercial Demand Billed	18,267	16,956	14,842	15,065	11,303	8,601	7,636	7,817	7,867	10,410	13,943	17,842
Interruptible	60,441	55,456	44,503	39,923	31,864	27,232	25,068	26,006	23,510	32,024	48,952	56,149
Transport	108,043	62,764	71,595	72,463	106,919	77,542	108,279	124,052	62,299	42,665	69,140	91,491
Forecast Revenues	2,725,310	2,240,396	1,862,233	1,066,543	692,832	427,909	369,028	405,894	407,824	809,878	1,597,260	2,340,002
Actual Revenues												
Actual & Forecast Total	2,725,310	2,240,396	1,862,233	1,066,543	692,832	427,909	369,028	405,894	407,824	809,878	1,597,260	2,340,002
Annual Total												14,945,109

GUIC Factor Calculations - Revenues

2015, 2016, 2017	Jan-16 Forecast	Feb-16 Forecast	Mar-16 Forecast	Apr-16 Forecast	May-16 Forecast	Jun-16 Forecast	Jul-16 Forecast	Aug-16 Forecast	Sep-16 Forecast	Oct-16 Forecast	Nov-16 Forecast	Dec-16 Forecast
Monthly Inputs												
Revenue Requirement	1,538,223	1,543,754	1,546,754	1,550,901	1,562,716	1,585,040	1,611,635	1,657,006	1,715,781	1,767,803	1,816,356	1,848,944
Remaining true-up in current calendar year	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18
Revenue Carried-forward balance	-2,041,774	-3,512,896	-4,435,516	-4,308,863	-3,658,496	-2,678,474	-1,568,613	-436,242	746,043	1,450,220	1,210,291	141
Weighting												
Group Weighting (Rate Base Allocator - Docket No. G002/GR-09-1153)												
Residential	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Commercial Firm	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Commercial Demand Billed	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Interruptible	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Transport	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Allocated Revenue Requirements												
Residential	1,119,417.93	1,123,443.32	1,125,626.74	1,128,644.36	1,137,243.11	1,153,488.54	1,172,842.95	1,205,861.88	1,248,634.96	1,286,493.26	1,321,827.34	1,345,543.62
Commercial Firm	252,164.01	253,070.79	253,562.63	254,242.39	256,179.38	259,838.88	264,198.72	271,636.68	281,271.89	289,799.99	297,759.47	303,101.88
Commercial Demand Billed	15,495.73	15,551.46	15,581.68	15,623.45	15,742.48	15,967.36	16,235.28	16,692.35	17,284.44	17,808.50	18,297.62	18,625.92
Interruptible	48,485.40	48,659.75	48,754.32	48,885.02	49,257.46	49,961.10	50,799.40	52,229.55	54,082.18	55,721.94	57,252.36	58,279.59
Transport	102,641.30	103,010.40	103,210.60	103,487.29	104,275.72	105,765.29	107,539.93	110,567.49	114,489.43	117,960.72	121,200.56	123,375.15
Total	1,538,204.37	1,543,735.71	1,546,735.97	1,550,882.51	1,562,698.15	1,585,021.17	1,611,616.28	1,656,987.94	1,715,762.90	1,767,784.40	1,816,337.36	1,848,926.15
Sales by Customer Group (Billed by total Usage)												
Residential	65,966,366	54,270,280	44,967,625	25,214,053	14,569,317	8,936,142	5,496,906	6,191,443	7,996,131	19,101,106	38,329,749	56,543,309
Commercial Firm	35,869,658	30,590,978	24,856,518	14,326,345	8,064,160	4,389,769	4,231,621	3,791,170	4,787,572	10,267,979	19,322,136	31,194,942
Commercial Demand Billed	3,453,090	3,196,393	2,795,808	2,847,485	2,127,658	1,622,888	1,445,995	1,468,451	1,484,470	1,967,484	2,624,429	3,374,815
Interruptible	14,782,142	13,308,591	10,513,961	9,986,194	7,335,969	6,641,498	6,514,086	5,974,554	5,745,172	8,100,192	11,477,929	13,888,385
Transport	25,845,765	28,990,599	20,638,866	11,902,432	21,575,766	20,651,954	28,543,159	29,335,085	14,575,042	7,742,082	11,705,944	17,325,875
Total Therm Sales in Month	145,917,021	130,356,840	103,772,778	64,276,508	53,672,870	42,242,252	46,231,767	46,760,704	34,588,387	47,178,843	83,460,189	122,327,326
Flags												
Rate Change	X											
Rate Periods	2	2	2	2	2	2	2	2	2	2	2	2
Rate Period Calculations												
Revenue Requirement for Rate Period	19,744,913											
Remaining true-up in current calendar year	-18											
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period	19,744,895											
Retail Dth Sales in Rate Period	920,785,484											
Allocated Cost Per therm												
Residential	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340	$ 0.041340
Commercial Firm	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885	$ 0.016885
Commercial Demand Billed	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002	$ 0.007002
Interruptible	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447	$ 0.005447
Transport	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517	$ 0.005517
Revenues												
Residential	2,727,050	2,243,533	1,858,962	1,042,349	602,296	369,420	227,242	255,954	330,560	789,640	1,584,552	2,337,500
Commercial Firm	605,659	516,529	419,702	241,900	136,163	74,121	71,451	64,014	80,838	173,375	326,254	526,727
Commercial Demand Billed	24,179	22,381	19,576	19,938	14,898	11,363	10,125	10,282	10,394	13,776	18,376	23,630
Interruptible	80,518	72,492	57,270	54,395	39,959	36,176	35,482	32,543	31,294	44,122	62,520	75,650
Transport	142,591	159,941	113,865	65,666	119,033	113,937	157,473	161,842	80,411	42,713	64,582	95,587
Forecast Revenues	3,579,997	3,014,876	2,469,374	1,424,248	912,349	605,018	501,773	524,635	533,497	1,063,626	2,056,284	3,059,094
Actual Revenues												
Actual & Forecast Total	3,579,997	3,014,876	2,469,374	1,424,248	912,349	605,018	501,773	524,635	533,497	1,063,626	2,056,284	3,059,094
Annual Total												19,744,772

GUIC Factor Calculations - Revenues

2015, 2016, 2017	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast
Monthly Inputs												
Revenue Requirement	1,995,327	2,000,213	2,003,189	2,006,366	2,014,562	2,029,947	2,049,014	2,078,273	2,115,399	2,149,945	2,181,058	2,202,652
Remaining true-up in current calendar year	12	12	12	12	12	12	12	12	12	12	12	12
Revenue Carried-forward balance	-2,533,421	-4,239,550	-5,371,475	-5,187,030	-4,287,936	-2,991,311	-1,546,181	-105,879	1,333,687	2,115,055	1,680,408	-100
Weighting												
Group Weighting (Rate Base Allocator - Docket No. G002/GR-09-1153)												
Residential	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Commercial Firm	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Commercial Demand Billed	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Interruptible	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Transport	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Allocated Revenue Requirements												
Residential	1,452,094.10	1,455,650.13	1,457,816.05	1,460,128.19	1,466,092.53	1,477,288.97	1,491,164.71	1,512,457.98	1,539,475.89	1,564,616.99	1,587,258.60	1,602,973.47
Commercial Firm	327,103.81	327,904.86	328,392.76	328,913.60	330,257.15	332,779.30	335,905.00	340,701.59	346,787.74	352,451.12	357,551.44	361,091.43
Commercial Demand Billed	20,100.86	20,150.09	20,180.07	20,212.07	20,294.64	20,449.62	20,641.70	20,936.46	21,310.46	21,658.48	21,971.90	22,189.43
Interruptible	62,894.61	63,048.64	63,142.45	63,242.59	63,500.93	63,985.88	64,586.88	65,509.16	66,679.38	67,768.32	68,749.00	69,429.66
Transport	133,144.94	133,471.00	133,669.59	133,881.60	134,428.48	135,455.10	136,727.39	138,679.80	141,157.12	143,462.35	145,538.40	146,979.32
Total	1,995,338.33	2,000,224.70	2,003,200.92	2,006,378.06	2,014,573.72	2,029,958.87	2,049,025.68	2,078,284.99	2,115,410.60	2,149,957.25	2,181,069.33	2,202,663.31
Sales by Customer Group (Billed by total Usage)												
Residential	66,049,366	53,035,710	44,982,589	25,189,720	14,127,687	8,672,950	5,053,609	5,870,471	7,788,259	18,718,669	38,013,940	56,774,308
Commercial Firm	35,913,781	30,132,393	24,955,820	14,589,104	7,893,748	4,412,850	4,202,630	3,799,126	4,937,097	10,139,577	19,267,227	31,632,508
Commercial Demand Billed	3,488,995	3,240,295	2,830,502	2,888,834	2,149,758	1,643,549	1,464,154	1,487,133	1,505,677	1,989,597	2,657,347	3,425,784
Interruptible	14,397,940	13,158,749	10,355,394	10,281,963	7,009,219	6,740,366	6,507,815	6,032,720	5,932,720	7,886,454	11,362,083	14,093,808
Transport	26,376,202	25,428,796	22,972,145	14,571,045	21,495,045	19,063,119	29,540,790	29,978,805	16,689,937	15,327,558	17,054,928	16,316,213
Total Therm Sales in Month	146,226,285	124,995,944	106,096,451	67,520,666	52,675,457	40,532,833	46,768,998	47,168,255	36,853,691	54,061,855	88,355,526	122,242,622
Flags												
Rate Change	X											
Rate Periods	3	3	3	3	3	3	3	3	3	3	3	3
Rate Period Calculations												
Revenue Requirement for Rate Period	24,825,945											
Remaining true-up in current calendar year	12											
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period	24,825,956											
Retail Dth Sales in Rate Period	933,498,584											
Allocated Cost Per therm												
Residential	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478	$ 0.052478
Commercial Firm	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211	$ 0.021211
Commercial Demand Billed	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692	$ 0.008692
Interruptible	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879	$ 0.006879
Transport	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501	$ 0.006501
Revenues												
Residential	3,466,139	2,783,208	2,360,596	1,321,906	741,393	455,139	265,203	308,071	408,712	982,318	1,994,896	2,979,402
Commercial Firm	761,767	639,138	529,338	309,449	167,434	93,601	89,142	80,583	104,721	215,071	408,677	670,957
Commercial Demand Billed	30,326	28,165	24,603	25,110	18,686	14,286	12,726	12,926	13,087	17,294	23,098	29,777
Interruptible	99,043	90,519	71,235	70,730	48,216	46,367	44,767	41,499	40,811	54,251	78,160	96,951
Transport	171,472	165,313	149,342	94,726	139,739	123,929	192,045	194,892	108,501	99,644	110,874	106,072
Forecast Revenues	4,528,747	3,706,342	3,135,114	1,821,921	1,115,468	733,322	603,884	637,971	675,833	1,368,578	2,615,704	3,883,159
Actual Revenues												
Actual & Forecast Total	4,528,747	3,706,342	3,135,114	1,821,921	1,115,468	733,322	603,884	637,971	675,833	1,368,578	2,615,704	3,883,159
Annual Total												24,826,044

Gas Utility - Minnesota Retail Jurisdiction

" Minn. Stat. 216B.1635 Subd. 3 (VII) magnitude of GUIC in relation to gas utility's rate base revenue approved by the Commission in gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges "

" Minn. Stat. 216B.1635 Subd. 3 (VIII) magnitude of GUIC in relation to gas utility's capital expenditures since its most recent general rate case"

2010 Rate Case, Cost of Service Study - Docket G002/GR-09-1153
($000s)

Operating Revenues	**2010 TY**	
Retail	588,179	Fn 1
Operating Expenses:		
Fuel & Purchased Energy	429,081	
Base Revenue, Net of Gas Purchase Costs & Transportation Charges	**159,098**	[A]
Capital Expenditures (CWIP)	**29,890**	[B]

Proposed Gas Utility Infrastructure Costs (GUIC) Rider
(Dollars in Thousands)

	2015	2016	2017	2018	2019	
Revenue Collection Forecast	**14,945**	**19,745**	**24,826**	**28,219**	**35,584**	[C] Fn 2
% of GUIC Revenue as Compared to Base Revenue Approved in Docket G-002/GR-09-1153 (2010 TY)	9.39%	12.41%	15.60%	17.74%	22.37%	= [C] / [A]
Capital Expenditures Forecast	**31,986**	**30,558**	**22,170**	**44,667**	**50,278**	[D]
% of GUIC Capital Expenditures as Compared to Expenditures Approved in Docket G-002/GR-09-1153 (2010 TY)	107.01%	102.23%	74.17%	149.44%	168.21%	= [D] / [B]

Notes

Fn 1 Excludes $4.69 million of other operating income for customer-related charges not included in retail rates. See Compliance Filing in Docket G002/GR-09-1153: “Income Statement Adjustment Schedules”, Page 13, Line No. 4

Fn 2 Reflects forecasted revenue recovery for gas costs eligible for rider recovery under Minnesota 2013 Statute 216B.1635 Recovery of Gas Utility Infrastructure Costs, including:
(a) revenue requirements associated with new gas utility infrastructure projects, and
(b) deferred costs include implementation of the inspection and remediation of sewer/natural gas line conflicts approved in Docket No. G002/M-10-422 and costs to comply with gas pipeline safety programs approved in Docket No. G-002/M-12-248

GUIC Rider
Annual Revenue Requirements Tracker Summary for 2015-2019
(In dollars - $)

	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2015 - 2019 Total
Incremental Gas Utility Projects:						
Operations & Maintenance Expenses						
TIMP	220,220	(462,322)	933,100	525,169	1,019,028	2,235,195
DIMP	4,321,000	4,895,000	4,590,000	4,590,000	4,790,000	23,186,000
Gas O&M - Total	4,541,220	4,432,678	5,523,100	5,115,169	5,809,028	25,421,195
Capital-Related Revenue Requirements						
TIMP	4,955,295	8,209,751	10,276,660	11,413,405	15,504,425	50,359,536
DIMP	685,860	2,340,189	4,263,529	6,928,424	9,508,448	23,726,449
Gas Utility Projects - Capital RR Total	5,641,154	10,549,940	14,540,189	18,341,829	25,012,873	74,085,985
5-Year Amortization of Deferred Costs						
TIMP	895,981	895,981	895,981	895,981	895,981	4,479,906
DIMP	3,866,533	3,866,533	3,866,533	3,866,533	3,866,533	19,332,667
Gas Deferral Costs - Total	4,762,515	4,762,515	4,762,515	4,762,515	4,762,515	23,812,573
Revenue Requirement in Base Rates	-	-	-	-	-	
GUIC True-up Carryover	-	(220)	141	(100)	-	
Revenue Requirement (RR)	**14,944,889**	**19,744,913**	**24,825,945**	**28,219,413**	**35,584,416**	**123,319,753**
Revenue Collections (RC)	14,945,109	19,744,772	24,826,044	28,219,413	35,584,416	123,319,753
Balance	(220)	141	(100)	-	-	-

Northern States Power Company

Docket No. G002/M-14-336
Gas Utility Infrastructure Cost Rider Petition
Attachment N - Page 1 of 1

GUIC Rider
Revenue Requirements Tracker for 2015
(In dollars - $)

	Carryover	Jan-15 Forecast	Feb-15 Forecast	Mar-15 Forecast	Apr-15 Forecast	May-15 Forecast	Jun-15 Forecast	Jul-15 Forecast	Aug-15 Forecast	Sep-15 Forecast	Oct-15 Forecast	Nov-15 Forecast	Dec-15 Forecast	Annual Total Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		18,352	18,352	18,352	18,352	18,352	18,352	18,352	18,352	18,352	18,352	18,352	18,352	220,220
DIMP		360,083	360,083	360,083	360,083	360,083	360,083	360,083	360,083	360,083	360,083	360,083	360,083	4,321,000
Gas O&M - Total		378,435	378,435	378,435	378,435	378,435	378,435	378,435	378,435	378,435	378,435	378,435	378,435	4,541,220
Capital-Related Revenue Requirements														
TIMP		328,357	330,906	332,537	335,686	345,441	363,740	385,229	422,936	471,567	513,986	550,662	574,248	4,955,295
DIMP		13,454	14,820	16,332	19,655	27,593	39,369	52,286	67,023	84,051	101,948	117,574	131,753	685,860
Gas Utility Projects - Capital RR Total		341,811	345,726	348,869	355,341	373,034	403,109	437,516	489,959	555,618	615,935	668,236	706,001	5,641,154
5-Year Amortization of Deferred Costs														
TIMP		74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	895,981
DIMP		322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	3,866,533
Gas Deferral Costs - Total		396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	4,762,515
Revenue Requirement in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)		**1,117,123**	**1,121,037**	**1,124,181**	**1,130,652**	**1,148,345**	**1,178,420**	**1,212,827**	**1,265,270**	**1,330,930**	**1,391,246**	**1,443,547**	**1,481,312**	**14,944,889**
Revenue Collections (RC)		2,725,310	2,240,396	1,862,233	1,066,543	692,832	427,909	369,028	405,894	407,824	809,878	1,597,260	2,340,002	14,945,109
Monthly RR - RC		(1,608,187)	(1,119,359)	(738,052)	64,109	455,513	750,512	843,799	859,376	923,106	581,368	(153,713)	(858,690)	
Balance (RR - RC)		(1,608,187)	(2,727,547)	(3,465,598)	(3,401,490)	(2,945,976)	(2,195,465)	(1,351,666)	(492,290)	430,816	1,012,184	858,470	(220)	

GUIC Rider
Revenue Requirements Tracker for 2016
(In dollars - $)

	Carryover	Jan-16 Forecast	Feb-16 Forecast	Mar-16 Forecast	Apr-16 Forecast	May-16 Forecast	Jun-16 Forecast	Jul-16 Forecast	Aug-16 Forecast	Sep-16 Forecast	Oct-16 Forecast	Nov-16 Forecast	Dec-16 Forecast	Annual Total Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(38,527)	(462,322)
DIMP		407,917	407,917	407,917	407,917	407,917	407,917	407,917	407,917	407,917	407,917	407,917	407,917	4,895,000
Gas O&M - Total		369,390	369,390	369,390	369,390	369,390	369,390	369,390	369,390	369,390	369,390	369,390	369,390	4,432,678
Capital-Related Revenue Requirements														
TIMP		618,454	621,062	621,607	622,831	628,625	640,925	655,850	687,089	729,638	765,416	798,293	819,960	8,209,751
DIMP		153,521	156,444	158,899	161,822	167,843	177,866	189,537	203,670	219,896	236,139	251,815	262,737	2,340,189
Gas Utility Projects - Capital RR Total		771,975	777,506	780,507	784,653	796,469	818,792	845,387	890,759	949,533	1,001,555	1,050,108	1,082,697	10,549,940
5-Year Amortization of Deferred Costs														
TIMP		74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	895,981
DIMP		322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	3,866,533
Gas Deferral Costs - Total		396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	4,762,515
Revenue Requirement in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC True-up Carryover	(220)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(220)
Revenue Requirement (RR)		**1,538,223**	**1,543,754**	**1,546,754**	**1,550,901**	**1,562,716**	**1,585,040**	**1,611,635**	**1,657,006**	**1,715,781**	**1,767,803**	**1,816,356**	**1,848,944**	**19,744,913**
Revenue Collections (RC)		3,579,997	3,014,876	2,469,374	1,424,248	912,349	605,018	501,773	524,635	533,497	1,063,626	2,056,284	3,059,094	19,744,772
Monthly RR - RC		(2,041,774)	(1,471,122)	(922,620)	126,653	650,367	980,022	1,109,862	1,132,371	1,182,284	704,177	(239,929)	(1,210,150)	
Balance (RR - RC)		(2,041,774)	(3,512,896)	(4,435,516)	(4,308,863)	(3,658,496)	(2,678,474)	(1,568,613)	(436,242)	746,043	1,450,220	1,210,291	141	

GUIC Rider
Revenue Requirements Tracker for 2017
(In dollars - $)

	Carryover	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast	Annual Total Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		77,758	77,758	77,758	77,758	77,758	77,758	77,758	77,758	77,758	77,758	77,758	77,758	933,100
DIMP		382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	4,590,000
Gas O&M - Total		460,258	460,258	460,258	460,258	460,258	460,258	460,258	460,258	460,258	460,258	460,258	460,258	5,523,100
Capital-Related Revenue Requirements														
TIMP		853,785	854,213	853,338	851,743	849,716	847,852	846,732	851,383	860,101	866,159	869,781	871,857	10,276,660
DIMP		284,396	288,853	292,705	297,477	307,700	324,949	345,136	369,744	398,151	426,641	454,130	473,648	4,263,529
Gas Utility Projects - Capital RR Total		1,138,180	1,143,067	1,146,043	1,149,220	1,157,416	1,172,801	1,191,868	1,221,127	1,258,253	1,292,799	1,323,911	1,345,505	14,540,189
5-Year Amortization of Deferred Costs														
TIMP		74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	895,981
DIMP		322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	3,866,533
Gas Deferral Costs - Total		396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	4,762,515
Revenue Requirement in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC True-up Carryover	141	12	12	12	12	12	12	12	12	12	12	12	12	141
Revenue Requirement (RR)		**1,995,327**	**2,000,213**	**2,003,189**	**2,006,366**	**2,014,562**	**2,029,947**	**2,049,014**	**2,078,273**	**2,115,399**	**2,149,945**	**2,181,058**	**2,202,652**	**24,825,945**
Revenue Collections (RC)		4,528,747	3,706,342	3,135,114	1,821,921	1,115,468	733,322	603,884	637,971	675,833	1,368,578	2,615,704	3,883,159	24,826,044
Monthly RR - RC		(2,533,421)	(1,706,130)	(1,131,924)	184,445	899,094	1,296,625	1,445,130	1,440,302	1,439,566	781,368	(434,647)	(1,680,508)	
Balance (RR - RC)		(2,533,421)	(4,239,550)	(5,371,475)	(5,187,030)	(4,287,936)	(2,991,311)	(1,546,181)	(105,879)	1,333,687	2,115,055	1,680,408	(100)	

GUIC Rider
Revenue Requirements Tracker for 2018
(In dollars - $)

	Carryover	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual Total
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		43,764	43,764	43,764	43,764	43,764	43,764	43,764	43,764	43,764	43,764	43,764	43,764	525,169
DIMP		382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	382,500	4,590,000
Gas O&M - Total		426,264	426,264	426,264	426,264	426,264	426,264	426,264	426,264	426,264	426,264	426,264	426,264	5,115,169
Capital-Related Revenue Requirements														
TIMP		878,572	878,281	878,886	879,276	878,819	879,664	887,487	933,977	1,007,681	1,065,855	1,106,448	1,138,459	11,413,405
DIMP		510,157	515,500	519,393	523,731	533,103	549,117	567,856	590,650	616,917	643,206	668,565	690,229	6,928,424
Gas Utility Projects - Capital RR Total		1,388,729	1,393,782	1,398,279	1,403,007	1,411,922	1,428,780	1,455,343	1,524,628	1,624,598	1,709,061	1,775,013	1,828,688	18,341,829
5-Year Amortization of Deferred Costs														
TIMP		74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	895,981
DIMP		322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	3,866,533
Gas Deferral Costs - Total		396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	4,762,515
Revenue Requirement in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC True-up Carryover	(100)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(100)
Revenue Requirement (RR)		**2,211,861**	**2,216,914**	**2,221,411**	**2,226,139**	**2,235,054**	**2,251,912**	**2,278,475**	**2,347,760**	**2,447,730**	**2,532,193**	**2,598,145**	**2,651,820**	**28,219,413**
Revenue Collections (RC)		2,211,861	2,216,914	2,221,411	2,226,139	2,235,054	2,251,912	2,278,475	2,347,760	2,447,730	2,532,193	2,598,145	2,651,820	28,219,413
Monthly RR - RC		-	-	-	-	-	-	-	-	-	-	-	-	
Balance (RR - RC)		-	-	-	-	-	-	-	-	-	-	-	-	

GUIC Rider
Revenue Requirements Tracker for 2019
(In dollars - $)

	Carryover	Jan-19 Forecast	Feb-19 Forecast	Mar-19 Forecast	Apr-19 Forecast	May-19 Forecast	Jun-19 Forecast	Jul-19 Forecast	Aug-19 Forecast	Sep-19 Forecast	Oct-19 Forecast	Nov-19 Forecast	Dec-19 Forecast	Annual Total Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		84,919	84,919	84,919	84,919	84,919	84,919	84,919	84,919	84,919	84,919	84,919	84,919	1,019,028
DIMP		399,167	399,167	399,167	399,167	399,167	399,167	399,167	399,167	399,167	399,167	399,167	399,167	4,790,000
Gas O&M - Total		484,086	484,086	484,086	484,086	484,086	484,086	484,086	484,086	484,086	484,086	484,086	484,086	5,809,028
Capital-Related Revenue Requirements														
TIMP		1,190,682	1,189,987	1,191,347	1,190,921	1,188,897	1,190,680	1,205,815	1,296,039	1,406,112	1,458,072	1,487,881	1,507,991	15,504,425
DIMP		727,028	728,102	729,534	732,980	743,869	762,543	782,529	809,163	838,830	865,074	888,644	900,153	9,508,448
Gas Utility Projects - Capital RR Total		1,917,709	1,918,089	1,920,881	1,923,901	1,932,766	1,953,223	1,988,344	2,105,201	2,244,942	2,323,146	2,376,525	2,408,144	25,012,873
5-Year Amortization of Deferred Costs														
TIMP		74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	74,665	895,981
DIMP		322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	322,211	3,866,533
Gas Deferral Costs - Total		396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	396,876	4,762,515
Revenue Requirement in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)		**2,798,671**	**2,799,051**	**2,801,843**	**2,804,863**	**2,813,728**	**2,834,185**	**2,869,306**	**2,986,163**	**3,125,904**	**3,204,108**	**3,257,487**	**3,289,106**	**35,584,416**
Revenue Collections (RC)		2,798,671	2,799,051	2,801,843	2,804,863	2,813,728	2,834,185	2,869,306	2,986,163	3,125,904	3,204,108	3,257,487	3,289,106	35,584,416
Monthly RR - RC		-	-	-	-	-	-	-	-	-	-	-	-	
Balance (RR - RC)		-	-	-	-	-	-	-	-	-	-	-	-	

Revenue Requirements Category Descriptions

Attachments D and F to this petition respectively provide the TIMP and DIMP annual revenue requirements for 2015-2019. The rate base categories in our proposed revenue requirements analysis and rationale for including or excluding costs in each category are explained below.

Plus Plant in Service: This is an addition to rate base. This category reflects the original cost of gas plant that has been put into service. In the specific case of the annual 2015 plant in service for gas utility infrastructure projects (GUIC), the $47,909,384 for TIMP (Attachment D) and $9,758,195 for DIMP (Attachment F) reflect the dollar value portion of the project in service as of December 31, 2015, which results in an increase to rate base. Standard ratemaking methodology calls for the inclusion of this item in the determination of rate base.

Less Book Depreciation Reserve: This is a reduction to rate base. It reflects the accumulated recovery of the amount invested in plant in service. In the specific case of the 2015 book depreciation reserve for GUIC projects, the $1,226,927 for TIMP (Attachment D) and $117,040 for DIMP (Attachment F) reflect the amount of the plant in service that has been recovered as of December 31, 2015, which results in a decrease to rate base. Standard ratemaking methodology calls for the exclusion of this credit balance in an asset account (contra-asset) from plant in service in the determination of rate base.

Less Accum Deferred Taxes: This is a reduction to rate base. It reflects the tax timing differences between book and tax depreciation lives and other non-plant book/tax timing differences, multiplied by the tax rate. Over the life of an asset, the Accumulated Deferred Tax is zero. In the specific case of the 2011 accumulated deferred taxes for GUIC projects, the $1,783,107 for TIMP (Attachment D) and $256,967 for DIMP (Attachment F) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2015 which results in a decrease to rate base. Standard ratemaking methodology calls for the exclusion of this timing related asset in the determination of rate base.

Below we describe the categories we use to calculate the return in our proposed revenue requirements analysis, and our rationale for including costs in each category. We note that for both items below, standard ratemaking methodology calls for the inclusion of these items in the calculation of revenue requirements.

Plus Debt Return: This category reflects the return the Company is allowed in order to recover its weighted cost of debt for financing its capital investments. In the specific case of the annual 2015 debt return for GUIC projects, the $919,554 for TIMP (Attachment D) and $114,075 for DIMP (Attachment F) reflect the amount of debt return the Company is allowed for January 2015 - December 2015 based on the overall cost of capital approved in the most recent gas rate filing (Docket no. G002/GR-09-1153).

Plus Equity Return - This category reflects the return the Company is allowed in order to recover its weighted cost of equity for financing its capital investments. In the specific case of the annual 2015 equity return for GUIC projects, the $1,632,363 for TIMP (Attachment D) and $202,502 for DIMP (Attachment F) reflects the amount of return on equity the Company is allowed for January 2015 - December 2015 based on the overall cost of capital approved in the most recent gas rate filing (Docket no. G002/GR-09-1153).

The types of income statement categories, description and rationale for including costs in each category in the Company's proposed revenue requirements analysis are described below. For all three items, standard ratemaking methodology calls for the inclusion of these items in the calculation of revenue requirements.

Plus Property Taxes: This category reflects the estimated property taxes billed from local taxing authorities that the Company must pay based on the original cost of the Company's assets. Property taxes accrued are based on the original cost at December 31 from the prior year, then paid the following year. In the specific case of the estimated annual 2015 property tax amount for GUIC projects, the $484,587 for TIMP (Attachment D) and $20,624 for DIMP (Attachment F) reflect property tax rates from the pay 2014 tax year using plant in service as of December 31, 2012 for property taxation.

Plus Book Depreciation: This category reflects the monthly/annual depreciation expense that is accumulated in the book depreciation reserve defined in part a) subsection ii). In the specific case of the annual 2015 book depreciation for GUIC projects, the $804,896 for TIMP (Attachment D) and

$215,281 for DIMP (Attachment F) reflect the amount of plant in service that is being recovered through depreciation expense from January 2015 - December 2015 and results in an increase to revenue requirements.

Plus Deferred Taxes: This category reflects the monthly/annual deferred tax expense that is accumulated in the accumulated deferred reserve defined in part a) subsection iii). In the specific case of the annual 2015 deferred taxes for GUIC projects, the $1,061,484 for TIMP (Attachment D) and $110,368 for DIMP (Attachment F) reflect the January 1, 2015 – December 31, 2015 tax timing difference when book expense differs from tax expense and results in an increase to revenue requirements.

Plus Current Taxes: This category reflects the current income taxes the Company is anticipated to pay based on its taxable income. In the specific case of the annual 2015 current taxes for GUIC projects, the $52,410 for TIMP (Attachment D) and $23,009 for DIMP (Attachment F) reflect the amount of current income taxes the Company is anticipating to pay as a result of the taxable income being generated by GUIC projects.

Proposed Tariff Sheets

We provide as Attachment Q to this filing proposed tariff sheets in redline and clean format as follows:

Minnesota Gas Rate Book—MPUC No. 2

Sheet No. 1-1, revision 8
Sheet No. 5-TOC, revision 2
Sheet No. 5-1.1, revision 4
Sheet No. 5-2.1, revision 4
Sheet No. 5-4, revision 7
Sheet No. 5-6.1, revision 6
Sheet No. 5-11.1, revision 2
Sheet No. 5-18, revision 7
Sheet No. 5-24, revision 1
Sheet No. 5-30, revision 1
Sheet No. 5-54.1, revision 6
Sheet No. 5-64, revision 2
Sheet No. 5-65, revision 2

Redline

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Section No. 1
~~7th~~8th Revised Sheet No. 1

(Continued on Sheet No. 1-2)

Item	Sheet No.

RATE SCHEDULES

RIDERS

DETERMINATION OF CUSTOMER BILLS (Continued)

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~

N
ND
D

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

LOW INCOME ENERGY DISCOUNT
Discount is available to qualified low-income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider; see separate sheets in this section.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

DETERMINATION OF MONTHLY BILLING DEMAND
The demand in Therms for billing purposes for the month in which bill is rendered shall be the greater of:

1. The highest daily consumption recorded during the billing month; or
2. The firm contract quantity specified in the service agreement between Company and customer; or
3. The highest daily consumption previously recorded at customer's meter location.

A customer who installs equipment which would verifiably reduce customer's firm demand under this service schedule may request a restated firm contract quantity by providing such verification to Company and entering into new service agreement with Company.

Where customer has alternate fuel capability for load in excess of contract demand, additional volumes will be provided on an interruptible basis at rates equal to the applicable rates for equivalent interruptible service.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in Section 5.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

(Continued on Sheet No. 5-4.1)

DETERMINATION OF MONTHLY BILLING DEMAND
The demand in Therms for billing purposes for the month in which bill is rendered shall be the greater of:

1. The highest daily consumption recorded during the billing month; or
2. The firm contract quantity specified in the service agreement between Company and customer; or
3. The highest daily consumption previously recorded at customer's meter location.

A customer who installs equipment which would verifiably reduce customer's firm demand under this service schedule may request a restated firm contract quantity by providing such verification to Company and entering into new service agreement with Company. Where customer has alternate fuel capability for load in excess of contract demand, additional volumes will be provided on an interruptible basis at rates equal to the applicable rates for equivalent interruptible service.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

~~D~~

(Continued on Sheet No. 5-6.2)

RESOURCE ADJUSTMENT

All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE

In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

(Continued on Sheet No. 5-12)

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

NOMINATIONS
Customer shall, on a daily basis, provide Company with daily gas volumes, or nominations, to be delivered during the following gas day commencing at 9:00 a.m. CCT. Customer shall submit nominations to Company at least ten minutes in advance of the following standardized nomination times: ~~T~~

Timely	11:30 a.m.
Evening	6:00 p.m.
Intra-day 1	10:00 a.m.
Intra-day 2	5:00 p.m.
Final a.m.	8:00 a.m.

The Timely and Evening nominations are prior to the start of a Gas Day. The Timely nomination is mandatory. The remaining four nomination times are optional. Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules. EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination. EPSQ rules divide a daily nomination into 24 hourly increments. Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5:00 p.m.). Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9:00 p.m.). Final a.m. nominations are allowed by Northern Natural Gas Company (NNG) and can only be used in conjunction with injections or withdrawals from storage. The Company reserves the right to refuse nominations to maintain balance of its system.

(Continued on Sheet No. 5-18.1)

RATE ~~L~~

	Interruptible		Firm*	
	Minimum	Maximum	Minimum	Maximum
Customer Charge per Month	$75.00	$525.00	$75.00	$525.00
Flexible Distribution Charge per Therm	$0.002934	$0.083988	$0.004594	$0.092332

~~R~~

*Rate includes both demand and commodity cost components.

Company may negotiate customer specific rates within these ranges to compete with customer's bypass cost. The specific charges for service under this classification shall be stated in the Agreement executed with each customer served hereunder.

In addition, customer bills under this rate are subject to the following adjustments and/or changes. ~~L~~

THERM ADJUSTMENT ~~N~~
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility. ~~N~~

RESOURCE ADJUSTMENT ~~L~~
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider~~, and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider.~~ For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND ~~L~~ D

SURCHARGE ~~N~~
In certain communities, customer bills under this rate are subject to surcharges provided for in the Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations. ~~N~~

(Continued on Sheet No. 5-25)

Date Filed: ~~11-12-09~~08-01-14 By: ~~Judy M. Poferl~~David M. Sparby Effective Date: ~~05-01-11~~
President and CEO of Northern States Power Company, a Minnesota corporation
Docket No. G002/~~GR-09-1153~~M-14-336 Order Date: ~~12-06-10~~

DETERMINATION OF CUSTOMER BILLS

Customer bills under this rate are based on the distribution cost that varies with customer usage determined in Therms, in addition to a monthly minimum charge equal to the monthly customer charge. Details regarding these specific charges are listed below. ~~N~~

MONTHLY MINIMUM CHARGE

The minimum monthly charge is the customer charge. If mutually agreed, the customer may be subject to a minimum annual commodity quantity at the agreed to distribution rate in lieu of a fixed monthly or annual distribution charge. ~~N~~

RATE

Monthly Customer Charge	$32.00
Commodity Charge	Negotiated Rate not Less than $0.05000 per Mcf Negotiated Rate not More than $2.7678 per Mcf
Default Rates	When the Company and the customer cannot reach a negotiated price agreement, the rate shall be $2.7678 per Mcf.

In addition, customer bills under this rate are subject to the following adjustments and/or changes. ~~N~~

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

RESOURCE ADJUSTMENT

All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, ~~and~~ the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. ~~For information on the Conservation Improvement Program Adjustment Rider and the State Energy Policy Rate Rider, see separate sheets in this section.~~ N ND D

SURCHARGE

In certain communities, customer bills under this rate are subject to surcharges provided for in the Surcharge Rider. See additional information on the Surcharge Rider in this section.

~~N~~
~~L~~
~~D~~

(Continued on Sheet No. 5-31)

RESOURCE ADJUSTMENT

Bills are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider applicable to the customer's current interruptible service~~, and~~ the State Energy Policy Rate Rider T
and the Gas Utility Infrastructure Cost Rider. N

SURCHARGE

In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.4.

TERM OF AGREEMENT

Limited Firm Service Agreement shall be for a period up to 12 months terminating June 30.

~~CANCELED~~ D

APPLICABILITY ~~T~~N

Applicable to bills for natural gas service provided under the Company's retail rate schedules.

RIDER

The Gas Utility Infrastructure Cost (GUIC) Rider is designed to collect the costs of assessments, modifications, and replacement of natural gas facilities as required to comply with state and federal pipeline safety programs. There shall be included on each customer's monthly bill a GUIC charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Factor for the appropriate customer group.

DETERMINATION OF GUIC FACTORS

A separate GUIC Factor shall be calculated for the following five customer groups: (1) Residential, (2) Commercial Firm, (3) Commercial Demand Billed, (4) Interruptible, and (5) Transportation. The GUIC Factor for each customer group shall be the value obtained by multiplying the balance of the GUIC Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period.

The GUIC Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). On November 1, the Company will file a GUIC Annual Report with request to change the GUIC Factor.

The current GUIC Factor for each customer group is:

Residential	$0.031253 per therm
Commercial Firm	$0.012901 per therm
Commercial Demand Billed	$0.005367 per therm
Interruptible	$0.004111 per therm
Transportation	$0.003933 per therm

Recoverable GUIC Expenses

Recoverable GUIC Expenses shall be the annual revenue requirements for costs associated with natural gas infrastructure projects eligible for recovery under Minnesota Statute Sections 216B.1635 or 216B.16, subd. 11 that are determined by the Commission to be eligible for recovery under this GUIC Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the GUIC Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Factor shall be credited to the GUIC Tracker Account. The GUIC Tracker Account includes adjustments for forecasted revenue requirements compared to actual revenue requirements and for actual revenue requirements compared to actual revenue recovery. N

(Continued on Sheet No. 5-65)

~~CANCELED~~ ~~D~~

~~T~~D

Allocation of GUIC Expenses to Customer Group N
For the purposes of developing the GUIC Rider rate factors, GUIC expenses will be allocated to customer group based on rate base as determined in the Class Cost of Service Study in the Company's most recently approved Minnesota natural gas general rate case.

Adjustment to GUIC Tracker Account with Changes in Base Rates
Whenever the Company implements changes in base rates as the result of a final Commission order in a natural gas general rate case setting new rates based on approved revenue requirements, the Company shall simultaneously adjust the GUIC Tracker Account to remove all costs that have been included in base rates. N

~~(Continued on Sheet No. 5-66)~~

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(Continued on Sheet No. 1-2)

RATE SCHEDULES Section No. 5
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DETERMINATION OF CUSTOMER BILLS (Continued)

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. N ND

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

LOW INCOME ENERGY DISCOUNT
Discount is available to qualified low-income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider; see separate sheets in this section.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. N ND

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

DETERMINATION OF MONTHLY BILLING DEMAND
The demand in Therms for billing purposes for the month in which bill is rendered shall be the greater of:

1. The highest daily consumption recorded during the billing month; or
2. The firm contract quantity specified in the service agreement between Company and customer; or
3. The highest daily consumption previously recorded at customer's meter location.

A customer who installs equipment which would verifiably reduce customer's firm demand under this service schedule may request a restated firm contract quantity by providing such verification to Company and entering into new service agreement with Company.

Where customer has alternate fuel capability for load in excess of contract demand, additional volumes will be provided on an interruptible basis at rates equal to the applicable rates for equivalent interruptible service.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. N ND

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in Section 5.

LOW INCOME ENERGY DISCOUNT RIDER
All customer bills under this rate are subject to the adjustment provided for in the Low Income Energy Discount Rider. For information on the Low Income Energy Discount Rider, see separate sheets in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

(Continued on Sheet No. 5-4.1)

DETERMINATION OF MONTHLY BILLING DEMAND

The demand in Therms for billing purposes for the month in which bill is rendered shall be the greater of:

1. The highest daily consumption recorded during the billing month; or
2. The firm contract quantity specified in the service agreement between Company and customer; or
3. The highest daily consumption previously recorded at customer's meter location.

A customer who installs equipment which would verifiably reduce customer's firm demand under this service schedule may request a restated firm contract quantity by providing such verification to Company and entering into new service agreement with Company. Where customer has alternate fuel capability for load in excess of contract demand, additional volumes will be provided on an interruptible basis at rates equal to the applicable rates for equivalent interruptible service.

RESOURCE ADJUSTMENT

All customer bills under this rate are subject to the adjustment provided for in the Conservation
Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility N
Infrastructure Cost Rider. ND

SURCHARGE

In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE

Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

(Continued on Sheet No. 5-6.2)

RESOURCE ADJUSTMENT

All customer bills under this rate are subject to the adjustment provided for in the Conservation
Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility N
Infrastructure Cost Rider. ND

SURCHARGE

In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

(Continued on Sheet No. 5-12)

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. N ND

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in a Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

NOMINATIONS
Customer shall, on a daily basis, provide Company with daily gas volumes, or nominations, to be delivered during the following gas day commencing at 9:00 a.m. CCT. Customer shall submit nominations to Company at least ten minutes in advance of the following standardized nomination times:

Timely	11:30 a.m.
Evening	6:00 p.m.
Intra-day 1	10:00 a.m.
Intra-day 2	5:00 p.m.
Final a.m.	8:00 a.m.

The Timely and Evening nominations are prior to the start of a Gas Day. The Timely nomination is mandatory. The remaining four nomination times are optional. Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules. EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination. EPSQ rules divide a daily nomination into 24 hourly increments. Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5:00 p.m.). Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9:00 p.m.). Final a.m. nominations are allowed by Northern Natural Gas Company (NNG) and can only be used in conjunction with injections or withdrawals from storage. The Company reserves the right to refuse nominations to maintain balance of its system.

(Continued on Sheet No. 5-18.1)

RATE

	Interruptible		Firm*	
	Minimum	Maximum	Minimum	Maximum
Customer Charge per Month	$75.00	$525.00	$75.00	$525.00
Flexible Distribution Charge per Therm	$0.002934	$0.083988	$0.004594	$0.092332

*Rate includes both demand and commodity cost components.

Company may negotiate customer specific rates within these ranges to compete with customer's bypass cost. The specific charges for service under this classification shall be stated in the Agreement executed with each customer served hereunder.

In addition, customer bills under this rate are subject to the following adjustments and/or changes.

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation
Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility N
Infrastructure Cost Rider. ND

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in the Surcharge Rider. See additional information on the Surcharge Rider in this section.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in Section 6 of the General Rules and Regulations.

(Continued on Sheet No. 5-25)

DETERMINATION OF CUSTOMER BILLS
Customer bills under this rate are based on the distribution cost that varies with customer usage determined in Therms, in addition to a monthly minimum charge equal to the monthly customer charge. Details regarding these specific charges are listed below.

MONTHLY MINIMUM CHARGE
The minimum monthly charge is the customer charge. If mutually agreed, the customer may be subject to a minimum annual commodity quantity at the agreed to distribution rate in lieu of a fixed monthly or annual distribution charge.

RATE

Monthly Customer Charge	$32.00
Commodity Charge	Negotiated Rate not Less than $0.05000 per Mcf Negotiated Rate not More than $2.7678 per Mcf
Default Rates	When the Company and the customer cannot reach a negotiated price agreement, the rate shall be $2.7678 per Mcf.

In addition, customer bills under this rate are subject to the following adjustments and/or changes.

THERM ADJUSTMENT
Customer’s Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. For additional information regarding metering and billing adjustments, see Section 6.

SUPERCOMPRESSIBILITY ADJUSTMENT
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RESOURCE ADJUSTMENT
All customer bills under this rate are subject to the adjustment provided for in the Conservation
Improvement Program Adjustment Rider, the State Energy Policy Rate Rider and the Gas Utility N
Infrastructure Cost Rider. ND

SURCHARGE
In certain communities, customer bills under this rate are subject to surcharges provided for in the Surcharge Rider. See additional information on the Surcharge Rider in this section.

(Continued on Sheet No. 5-31)

RESOURCE ADJUSTMENT
Bills are subject to the adjustment provided for in the Conservation Improvement Program Adjustment Rider applicable to the customer's current interruptible service, the State Energy Policy Rate Rider and the Gas Utility Infrastructure Cost Rider. T N

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

The following are additional terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.4.

TERM OF AGREEMENT
Limited Firm Service Agreement shall be for a period up to 12 months terminating June 30.

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N

APPLICABILITY
Applicable to bills for natural gas service provided under the Company's retail rate schedules.

RIDER
The Gas Utility Infrastructure Cost (GUIC) Rider is designed to collect the costs of assessments, modifications, and replacement of natural gas facilities as required to comply with state and federal pipeline safety programs. There shall be included on each customer's monthly bill a GUIC charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Factor for the appropriate customer group.

DETERMINATION OF GUIC FACTORS
A separate GUIC Factor shall be calculated for the following five customer groups: (1) Residential, (2) Commercial Firm, (3) Commercial Demand Billed, (4) Interruptible, and (5) Transportation. The GUIC Factor for each customer group shall be the value obtained by multiplying the balance of the GUIC Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period.

The GUIC Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). On November 1, the Company will file a GUIC Annual Report with request to change the GUIC Factor.

The current GUIC Factor for each customer group is:

Residential	$0.031253 per therm
Commercial Firm	$0.012901 per therm
Commercial Demand Billed	$0.005367 per therm
Interruptible	$0.004111 per therm
Transportation	$0.003933 per therm

Recoverable GUIC Expenses

Recoverable GUIC Expenses shall be the annual revenue requirements for costs associated with natural gas infrastructure projects eligible for recovery under Minnesota Statute Sections 216B.1635 or 216B.16, subd. 11 that are determined by the Commission to be eligible for recovery under this GUIC Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the GUIC Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Factor shall be credited to the GUIC Tracker Account. The GUIC Tracker Account includes adjustments for forecasted revenue requirements compared to actual revenue requirements and for actual revenue requirements compared to actual revenue recovery.

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(Continued on Sheet No. 5-65)

D

Allocation of GUIC Expenses to Customer Group N
For the purposes of developing the GUIC Rider rate factors, GUIC expenses will be allocated to customer group based on rate base as determined in the Class Cost of Service Study in the Company's most recently approved Minnesota natural gas general rate case.

Adjustment to GUIC Tracker Account with Changes in Base Rates
Whenever the Company implements changes in base rates as the result of a final Commission order in a natural gas general rate case setting new rates based on approved revenue requirements, the Company shall simultaneously adjust the GUIC Tracker Account to remove all costs that have been included in base rates. N

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list(s) 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. G002/M-14-336
Docket No. G002/GR-09-1153
Xcel Energy Miscellaneous Gas Service List

Dated this 1st day of August 2014

/s/

____

SaGonna Thompson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_14-336_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_14-336_Official
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_14-336_Official
Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy	414 Nicollet Mall 7th Floor Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_14-336_Official
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_14-336_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_14-336_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_9-1153_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
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Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_9-1153_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_9-1153_Official
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_9-1153_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Paper Service	No	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_9-1153_Official
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_9-1153_Official
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_9-1153_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	90 South 7th Street Suite #4800 Minneapolis, MN 554024129	Electronic Service	No	OFF_SL_9-1153_Official
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_9-1153_Official
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	Yes	OFF_SL_9-1153_Official
Matthew P	Loftus	matthew.p.loftus@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_9-1153_Official
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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