Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

—Via Electronic Filing—

RE: GAS UTILITY INFRASTRUCTURE COST RIDER
TRUE-UP REPORT FOR 2017, REVENUE REQUIREMENTS FOR 2018,
AND REVISED ADJUSTMENT FACTORS
DOCKET NO. G002/M-17-____

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Annual Report and Petition for approval of recovery of updated gas utility infrastructure costs (GUIC) through the GUIC Rider for 2018.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, which also constitutes service on the Department of Commerce and the Office of the Attorney General – Residential Utilities and Antitrust Division. A copy of this filing has been served on all parties on the attached service lists.

If you have any questions regarding this filing, please contact Lisa Peterson at (612) 330-7681 or lisa.r.peterson@xcelenergy.com.

SINCERELY,

/s/

AMY A. LIBERKOWSKI
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2017, REVENUE REQUIREMENTS FOR 2018, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-17-____

PETITION, COMPLIANCE FILING, AND ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Petition, Compliance Filing, and Annual Report to the Minnesota Public Utilities Commission (Commission) to request recovery of our 2018 Gas Utility Infrastructure Cost (GUIC) revenue requirement.

The requested 2018 revenue requirements, totaling approximately $27.5 million, are incurred to promote the safety of our natural gas system and are consistent with the eligibility requirements set forth in the GUIC statute. The $27.5 million in revenue requirements includes a $2.9 million increase in Transmission and Integrity Management Programs (TIMP) and a $2.5 million increase in Distribution Integrity Management Programs (DIMP) over the $22.0 million amounts from 2017.

In our previous GUIC filings, the Commission approved the Company's plan to implement Transmission and Distribution Integrity Management Programs (TIMP and DIMP) to assess and improve the safety, reliability, and integrity of our natural gas infrastructure pursuant to federal regulatory requirements. Pursuant to the Pipeline Safety Improvement Act of 2002[1] and the Pipeline Safety Act of 2011,[2] the

[1] The Pipeline Safety Improvement Act of 2002 was signed into law by President Bush on December 17, 2002 and tightened federal inspection and safety requirements of pipeline facilities which transport natural gas or hazardous liquids in interstate commerce, and gathering facilities in populated areas.

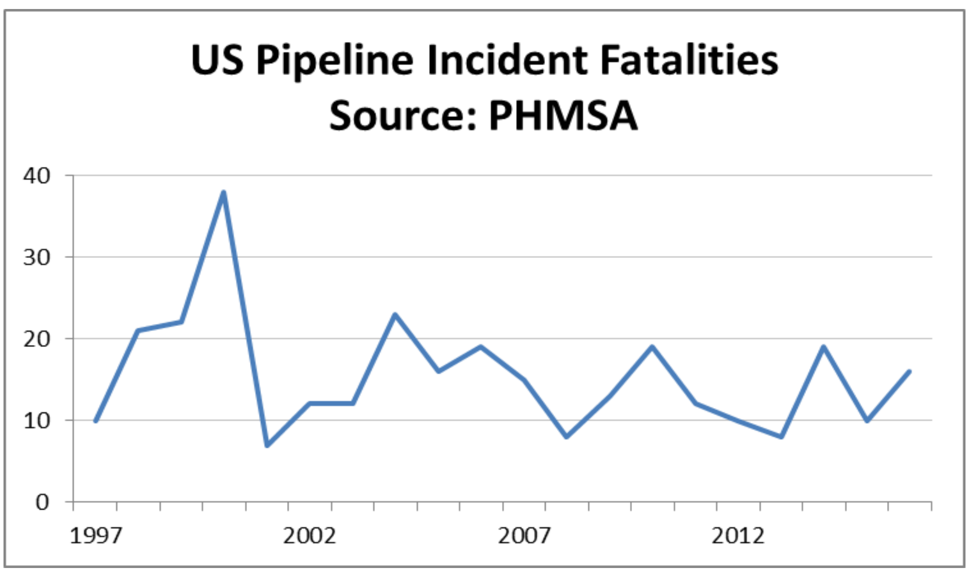
[2] Signed into law by President Obama on January 3, 2012, and provided a number of strong pipeline safety measures designed to accelerate the rehabilitation, repair, and replacement of high-risk pipeline infrastructure.

TIMP and DIMP require that operators not only know their systems in order to understand the threats to the systems, but also that they put programs in place to address those threats. The Company takes that obligation seriously as we work to address threats to our gas delivery infrastructure.

Indeed, the Company is dedicated to operating a safe and reliable gas system for our customers. With an aging gas infrastructure combined with a system that runs primarily through high-density urban and suburban areas, it is of tantamount importance that the Company dedicates investments to assessing the integrity of our system and repairing and replacing problematic equipment. GUIC projects are aimed at updating our gas infrastructure to have greater structural integrity, and permit increasingly more efficient assessments going forward. The system projects planned as a part of GUIC will help ensure a safer gas system that will reduce the likelihood of incidents within the community.

For context, Figure 1 below shows the trend in fatalities over the past two decades resulting from U.S. pipeline incidents. While the overall trend in fatalities has been decreasing, infrastructure work is critically needed to bring that number down further.

Figure 1



In this filing we also provide updated information on GUIC metrics included in our January 13, 2017 Supplement to the Company's 2017 GUIC Rider Petition submitted in Docket No. G002/M-16-891. The Commission required the Company to, with stakeholder involvement, develop TIMP and DIMP metrics to evaluate the performance of GUIC investments. The metrics that emerged measure the performance of the Company's integrity management initiatives to help ensure the appropriateness of GUIC expenditures, and additionally support safety by providing the Company quantitative measurements that monitor program effectiveness aligned with TIMP and DIMP program goals.

1. *Progress and Accomplishments to Date*

The GUIC continues to play an important role in pipeline safety. Indeed, since the GUIC Rider was established in 2015, significant progress has been made identifying pipeline risks and taking necessary corrective action to repair, rehabilitate, and replace the highest risk infrastructure. To date, our TIMP and DIMP efforts have resulted in a number of completed projects.

In 2017, for example, the Company completed work on replacing its 11.5-mile East Metro gas transmission line in the cities of St. Paul and Roseville. The project enhanced system safety through the use of updated engineering and welding techniques while eliminating the need for leak-prone compression couplings. The upgrades also provide benefits on a going-forward basis, allowing for more efficient assessments of the lines—helping to ensure its integrity and reliability. Lastly, the pipeline includes remote control valves that provide system operators the ability to isolate the pipeline in the event of an emergency, thereby reducing the outage impact on customers as well as mitigating the potential consequences of a failure. In short, this initiative improves the long-term safety and reliability of the East Metro gas delivery system—an area that serves around 100,000 homes and businesses.

In addition, from the inception of the GUIC Rider in 2015 to the close of 2017, the Company expects to have completed the replacement of over 160 miles of high-risk, aging, corroded, and otherwise damaged gas distribution pipeline as well as the replacement of over 10,000 aging distribution service lines. The Company is committed to continuing to work proactively to identify high-risk areas in order to help ensure the safety of our distribution system. As a result of this work and continued replacement work in the future, we expect distribution pipeline leaks to decrease over time.

Finally, by the end of 2017 the Company expects to have performed over 200,000 sewer line inspections since the inception of the program in 2010. Through August 2017, a total of 149 known sewer and gas line conflicts have been identified and cleared as a result of these inspections. As with our other TIMP and DIMP projects, the end result of these projects is a gas infrastructure system that is safer and more reliable.

2. *Continued Work is Needed*

Although significant progress has been made identifying and mitigating threats to the Company's gas system, there is still more work that needs to be done. With the completion of the East Metro pipeline, the backbone of the Company's gas system, we can shift our focus to portions of our high pressure distribution and transmission pipeline systems that are in need of evaluation and remediation. To that end, we plan to reallocate existing resources as well as add resources with the objective of completing this important work.

Upcoming major renewal and replacement projects include the Montreal/Island Line Replacement Project and replacing the Langdon Line. These replacement projects address several risk factors including, external corrosion, legacy manufacturing techniques, legacy construction techniques, and third party damage. These types of renewal and replacement projects will deliver an enhanced level of safety to our gas system.

Beyond the major renewal and replacement projects, major upcoming TIMP work will include continued In Line Inspections (ILI) and pressure tests, valve replacements, and Programmatic Replacements and Maximum Allowable Operating Pressure (MAOP) remediation. Major upcoming DIMP work will include poor performing main and service replacements, sewer line conflict remediation, and pipeline inspections.

The Company respectfully requests recovery of $27.5 million in projected transmission and distribution natural gas infrastructure capital investments and associated O&M costs for 2018, including $4.6 million in amortized costs the Commission previously approved to be recovered in this rider. We also seek approval of our proposed capital structure and Return on Equity (ROE) of 10.00 percent. Finally, we seek approval of the 2018 GUIC Rider Adjustment Factors, and the true-up for 2017.

We submit this petition for a 2018 request despite the pendence of our 2017 request. However, we are mindful of the statutory requirement for filing at least 150 days prior to the implementation of a new GUIC rate and the urgent need to continue systemic safety improvements. Accordingly, we file this petition looking ahead to 2018 system improvements and associated cost recovery.

The balance of this Petition is organized as follows:

- *Section I* – we identify the parties and state agencies that are being served with this filing.
- *Section II* – we provide general information that is required under the Commission's rules.
- *Section III* – we provide the purpose of our TIMP projects and DIMP projects and the applicable standard of review.
- *Section IV* – we demonstrate that our request to continue recovering certain costs through the Rider complies with the applicable standard of review and complies with previous Commission orders.

- *Section V* – we provide additional accounting details pertinent to our request, including our true-up report and our adherence to an April-March fiscal year.
- *Section VI* – we provide support for our proposed capital structure and ROE and request the Commission issue a procedural schedule.
- *Section VII* – we provide a summary of our proposed GUIC metrics.

Finally, 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 Residential Utilities and Antitrust 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

Amanda J. Rome
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
(612) 215-5331
amanda.rome@xcelenergy.com

C. Date of Filing and Proposed Effective Date

The date of this filing is November 1, 2017. The proposed effective date for the 2018 GUIC Rider factors is April 1, 2018. 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 timing requirement for Commission action.

E. Utility Employee Responsible for Filing

Amy Liberkowski
Director, Regulatory Pricing and Analysis
Xcel Energy
414 Nicollet Mall (401-7th Floor)
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amy.a.liberkowski@xcelenergy.com

F. Miscellaneous Information

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Amanda J. Rome Lead Assistant General Counsel Xcel Energy 414 Nicollet Mall (401-8th Floor) Minneapolis, MN 55401 amanda.rome@xcelenergy.com	Carl J. Cronin Regulatory Records Xcel Energy 414 Nicollet Mall (401-7th Floor) Minneapolis, MN 55401 regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to the Regulatory Records email address above.

III. DESCRIPTION AND PURPOSE OF FILING

A. Background

In its August 18, 2016 Order,[3] the Commission ordered that the Company include in future GUIC filings "specific information about each individual project in the GUIC Rider." For ease of review, the Company provides a compliance matrix as Attachment A setting 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

[3] Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808.

each requirement. An index of attachments to this petition is provided as Attachment B to this filing. Attachments C, C1(a-e) and C2, and Attachments D, D1(a-m), D2(a) and D2(b), provide detailed information describing each project and explain the necessity and benefit to customers, and identify the agency, regulation, or order that required the project.

Recognizing that the Company incurs expenses in connection with state and federal transmission and distribution safety-related initiatives, the Commission approved the recovery of these costs under the GUIC Rider Statute, Minn. Stat. § 216B.1635, as they found our costs to be reasonable and in the public interest, noting:

> *The Commission concurs with the Department that the investments proposed for rider recovery—including the new FCM* [Federal Code Mitigation] *project—meet the statutory requirements for rider recovery as gas utility infrastructure costs. These costs were incurred in the replacement or modification of existing facilities required by federal and state agencies. They were not included in Xcel's last rate case. And the costs are reasonable and prudent in view of the public safety purpose served by the TIMP and DIMP initiatives.*[4]

Recovery of these costs through the GUIC Rider continues to be in the public interest, as it provides annual regulatory review as the Company pursues safety investments. Additionally, by allowing the efficient recovery of these costs, the Commission signals continued regulatory support for investing in the safety of our natural gas system.

1. Deferral Orders

The Company's approved 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. Activities include assessments, and specific projects, such as pipeline replacement and sewer line conflict remediation work. The Commission approved deferred accounting treatment for the sewer line conflict remediation activities and other safety-related work, thereby acknowledging that the Company may recover prudently incurred expenditures.[5] In so doing, the Commission recognized that the costs associated with these TIMP and DIMP activities are unusual, unforeseeable, significant, and incurred to meet important

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[4] *See* Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808 (August 18, 2016) at page 6.
[5] *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); Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011).

public policy mandates. As the deferred costs were prudent and stem from the required TIMP and DIMP initiatives, the Commission granted Rider recovery of the deferred costs in the Company's 2015 GUIC Filing.[6]

2. TIMP Projects

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 73 miles[7] of transmission pipeline in the state of Minnesota. TIMP complies with federal regulations by identifying risks, systematically performing health and condition assessments, and evaluating and prioritizing preventative or corrective actions to mitigate identified risks and threats.[8] TIMP focuses on giving the Company a comprehensive understanding of the health and condition of its gas transmission pipelines, while assigning higher priority to those located in highly populated areas.

When performing assessments, the Company conducts ILI wherever practicable. There are advantages to using ILI. First, the pipelines need not be taken out of service while the inspection is in process. Second, assessments can be completed in a cost-effective manner for longer distances and, third, 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, subsequent assessments will be performed on the same line in the future using ILI.

In addition to assessments, the Company currently has two other major TIMP initiatives under way: the Programmatic Replacement and MAOP Remediation Program and installation of Automatic Shutoff Valves (ASV) and Remote Controlled Valves (RCV).

The installation of ASVs and RCVs provides the Company with a mechanism to more expediently shut off the flow of gas in the event of an incident, thereby reducing the potential for any negative impact to public safety.

In 2017, the Company began work on a major TIMP initiative: Programmatic Replacement and MAOP Remediation Program. The planning for the program was presented to the Commission in the Company's 2015, 2016, and 2017 GUIC Rider Petitions.[9] The MAOP initiative focuses on the requirement to have traceable, verifiable, and complete records of a pipeline's MAOP and targets capital intensive

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[6] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 8.
[7] Total miles of gas transmission pipeline has decreased from the 77 miles reported in our last annual report due to a portion of our gas transmission system being replaced by high-pressure gas distribution lines.
[8] *See* 49 C.F.R. 192, Subpart O.
[9] Docket Nos. G002/M-14-336, G002/M-15-808, and G002/M-16-891.

repairs or replacement efforts needed on transmission pipelines that have been assessed for asset health and condition in prior years. PHMSA defines traceable records as those which can be clearly linked to original information about a pipeline segment or facility and defines verifiable records as information confirmed by other complementary, but separate, documentation. The revised federal regulations[10] requiring operators to re-establish MAOP are highly prescriptive and go well beyond the standards operators previously employed to maintain their transmission systems.[11]

Through the initiative, the Company is gathering and validating existing MAOP records for the Company's transmission pipelines, and remediating any gaps[12] in such records. Remediating gaps includes addressing missing records associated with pipe diameter, wall thickness, grade, seam type, manufacturer, component ratings and historic pressure test data. Other record gaps could include design, fabrication, construction, maintenance, and testing. Record keeping can be further complicated by assets with a history of multiple owners, as the seller's pipeline records can be incomplete or inaccurate and intimate asset knowledge is not necessarily passed on to future owners. Incomplete or partial records are not an adequate basis for establishing MAOP. If records are unknown or unknowable, a more conservative approach is warranted. The diversity of the transmission pipe is complex and no single process will provide solutions for every pipeline operator.

All data related to the design and construction of a given pipeline is being stored in a central database per industry standards where the software will access the data to calculate MAOP and class location as well as identify high consequence areas. To validate MAOP, the Company utilizes pressure tests to establish baseline operating pressures and will replace assets, when applicable, due to lack of historical MAOP documentation needed to meet criteria established by the Pipeline and Hazardous Materials Safety Administration (PHMSA).[13]

Project descriptions, scopes, estimated costs and in-service dates for specific TIMP projects are provided as Attachment C. Attachment E reports the capital expenditure costs and forecasted costs for incremental TIMP activities between March 2012 and

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[10] On May 7, 2012, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Advisory Bulletin to clarify the record verification requirements for establishing Maximum Allowable Operating Pressure (MAOP) for natural gas pipelines. See http://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[11] The regulations were created in response of the high-pressure natural gas pipeline that ruptured in a residential neighborhood of San Bruno, CA, causing 8 fatalities and numerous injuries, destroying 38 homes and damaging 70 more. In part, the National Transportation Safety Board concluded that Pacific Gas and Electric's integrity management program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information.

[12] There are approximately 300,000 miles of natural gas transmission pipelines in the United States and a significant portion of these lines were installed prior to federal pipeline safety regulations being codified in 1970. Therefore, it is expected that there will be gaps in MAOP records.

[13] PHMSA requires companies to have traceable, verifiable, and complete records.

December 2022. Attachment F shows the development of 2016-2019 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment E.

3. DIMP Projects

The Company's DIMP is grounded in federal rules issued by PHMSA and aims to help ensure safe and reliable gas delivery to our customers.[14] The DIMP rules are intended to help gas system operators identify, prioritize, and evaluate risks; identify and implement measures to address those risks; and validate the integrity of the gas distribution system.

The Company's Sewer and Gas Line Conflict Remediation Program has been a major DIMP initiative that seeks to identify conflicts that are low probability but high consequence. As outlined in greater detail below, the program has succeeded in identifying over 100 conflicts. The Company has seen the conflict rate decrease steadily from 0.20 percent in 2010 down to a 0.02 percent in 2016. As a result of finding fewer sewer and gas line conflicts in recent years, the Company will reduce the amount of inspections in 2018 and 2019, the final two years of the program. Beyond conducting inspections, we also educate the public about potential conflicts between sewer and natural gas lines through our "Call before you Clear" program and on our website.[15]

DIMP work also includes assessing and potentially remediating high and medium[16] risk mains. The Company deems a main or service line to be high or medium risk through our risk ranking methodology as well as monitoring industry trends and issues. The Company monitors and reviews the leak history of pipe material types and year of installation. Trends of increasing leak ratio or cause associated with certain pipe types are studied further to determine if proactive action is required. The scope of this work is discussed in Attachment D.

The goal of the Company's risk analysis is to anticipate issues and proactively address them before they become problems on the system. Improvements in data quality and Company processes are helping the Company to transition to a more predictive approach. A proactive approach benefits customers in that work undertaken systematically and planfully reduces costs compared to work undertaken in a reactionary or immediate threat mode.

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[14] *See* 49 C.F.R. 192, Subpart P. PHMSA is a DOT agency created in 2004, responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of the US' 2.6 million mile pipeline transportation.
[15] *See* https://www.xcelenergy.com/energy_portfolio/natural_gas/projects/sewer-and-septic-line-investigation-project.
[16] Medium risk for mains is a new risk standard established in our proposed performance metrics proposal.

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided at Attachment D. Attachment E reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2022. Attachment G shows the development of 2016-2019 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment E.

4. Minnesota's GUIC Statute

The 2013 GUIC amendment creates a mechanism for the timely recovery of GUIC expenditures. The text of Minn. Stat. § 216B.1635 is provided as Attachment H. The Commission has recognized that the Company's TIMP and DIMP activities fall within the scope of the statute, including the work approved for deferred accounting.

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.*

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.*

The standard of review for 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.*

As the Commission has already recognized, Xcel Energy's TIMP and DIMP activities are precisely the type of expenditures for which Minn. Stat. § 216B.1635 authorizes prompt recovery. With this request, the Company asks the Commission for permission to continue to recover its projected TIMP and DIMP expenses for 2018, including the costs for which the Commission previously granted deferred accounting through the GUIC Rider.[17] The Company's revenue requirement reflects the impact of ongoing projects already approved by the Commission.

The Commission also found that 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 was not a barrier to recovery under the GUIC. The Commission reasoned:

> Since there was no option for Xcel to seek rider recovery of the TIMP and DIMP program costs in 2010 and 2012 when it originally sought deferred-accounting treatment of those costs, the Company should not be barred from seeking rider recovery now.[18]

The Company's proposed rate of return, 7.52 percent, is based on the capital structure and cost of debt recently approved by the Commission in its August 2016 Order when it last considered the Company's GUIC Petition and Annual Report, and our proposed Return on Equity of 10.00 percent discussed in Section VI.

IV. COMPLIANCE WITH COMMISSION ORDERS AND STATUTE

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

The GUIC Rider continues to be in the public interest, as it enables ongoing improvements that help ensure the safety and reliability of the Company's gas utility assets. Furthermore, because the Commission has recognized the value of proactively addressing system risks, the Company can more systematically and efficiently tackle this critical work. Indeed, working from a proactive stance allows the Company to take advantage of improved economies of scale, engage in regional planning, minimize inconvenience to impacted communities, and efficiently deploy human and capital resources.

For instance, when the work is proactive in nature, construction crews can be optimized to reduce mobilization and demobilization costs, coordinate permitting and street construction with impacted communities, and minimize traffic control and rerouting to reduce the overall inconvenience of this type of work for our customers.

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[17] *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).
[18] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at pages 8-9.

Additionally, we can leverage economies of scale by embarking on particular initiatives that utilize equipment that can be purchased at a competitive price. When work must be completed due to a reactive or emergency driven situation, there is less ability to plan strategically about costs, efficiencies or community impact.

The Company believes this work is prudent, and would be prudent regardless of the recovery mechanism utilized. The primary advantage of a rider mechanism is the ability for added flexibility, more frequent regulatory review, and promptness of recovery. The rider also provides additional certainty by allowing the Company to develop multiyear programs of work that are more comprehensive and cost effective, thus providing benefits beyond safety to our customers.

Additionally, the GUIC adjustment rate calculation is consistent with revenue apportionment in the most recent natural gas general rate case. When the Commission approved the rate design in our 2015 GUIC Petition, it reasoned, "There is nothing in the record to indicate that circumstances have changed [since the last natural-gas rate case] such that the allocation is no longer appropriate."[19] The Commission also approved the same methodology for the Company's GUIC customer class allocation in its 2016 Petition.

B. The Public Interest Supports Ongoing GUIC Investments

The public and customer benefits of increased safety and reliability that are delivered through the GUIC are significant and ongoing. However, there is still more work that needs to be done. For instance, aging infrastructure remains an issue that needs to be addressed. Additionally, we continue to see population growth in areas served by aging infrastructure.

1. *Addressing Aging Assets*

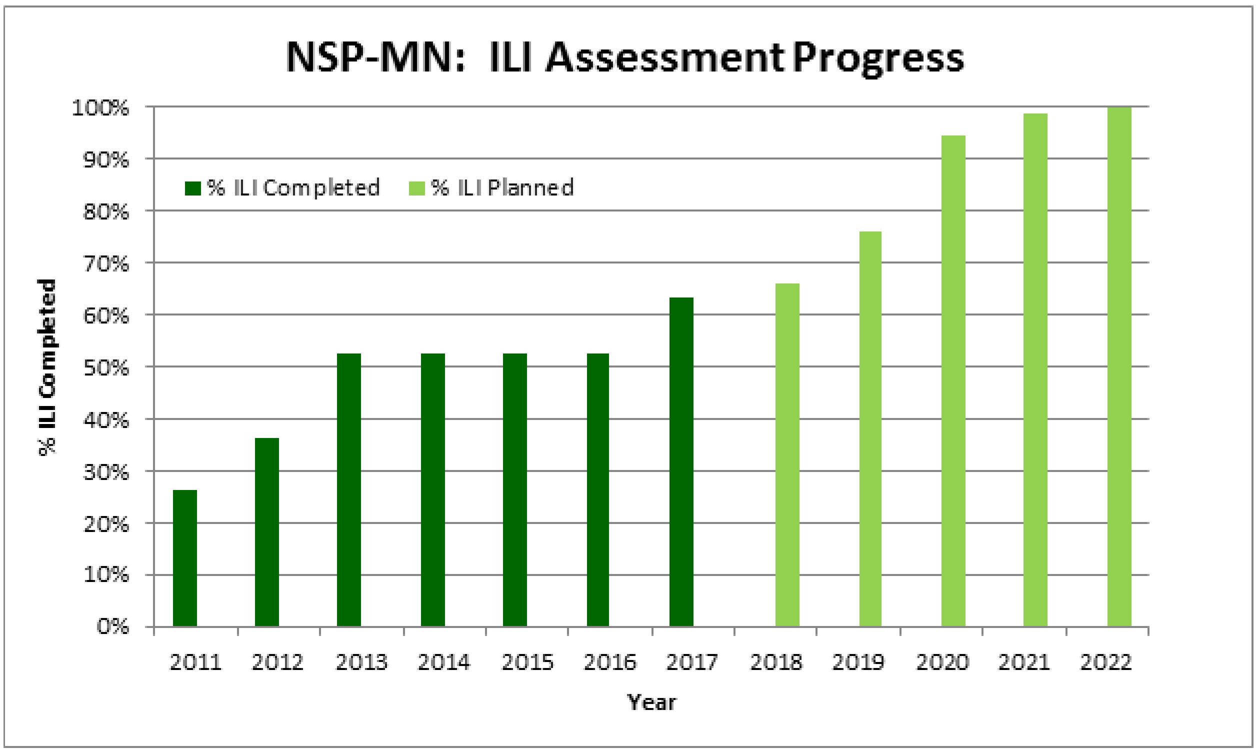
Federal regulation requires pipeline operators to assess the integrity of their pipelines based on the threats to which the pipeline is susceptible. The vintage of the Company's gas utility assets, including the varied material types and construction methods used at the time of installation, introduce similarly varied levels of risk. For example, steel pipes that were installed prior to the requirements or implementation of effective cathodic protection are prone to corrosion and therefore, have a higher risk of failure. 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 does not indicate an imminent risk of failure, it is a predictive factor and we must address risks posed by

[19] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 12.

legacy construction techniques and materials. What follows is our commitment to mitigate system risk through systematic inspections, assessments and replacements.

In order to assess these aging assets, the Company primarily utilizes ILI for line assessment due to its superior ability to provide detailed information regarding the current pipeline condition. As shown in Figure 2 below, approximately 63 percent of the Company's gas system has been assessed using ILI. The portions of the line not yet assessed using ILI will be once those parts of the system have been made accessible by the ILI tools. The Company's current TIMP assessment plan projects 100 percent ILI accessibility and assessment by 2022.

Figure 2



2. *Safety and Population Density*

Many communities with older gas utility assets have grown significantly since initial pipeline installation. Increased population density brings with it a higher risk of catastrophic consequences in the event of a failure. These pipeline assets (both transmission and higher-pressure distribution lines) require increased effort and related expense as the Company works to help ensure the safe and reliable operation of these systems.[20]

3. Conferring Public Benefits

By performing GUIC activities, the Company confers immediate safety and reliability benefits to customers and the public as described above, cost savings through economies of scale, and comprehensive planning to preempt reactive, emergency replacements. GUIC projects benefit customers through geographically-focused initiatives, the efficient use of outside contractor services, the efficient deployment of capital, and improved coordination with affected municipalities. All of these benefits support the public's interest in the GUIC's ongoing safety investments.

C. GUIC Activities Are Reasonable and Prudent

1. Cost Controls

Future expenditures for GUIC projects must successfully pass through the Company's capital and O&M budgeting process, which is approved by Company officers and the Board of Directors. The Company leverages past experience with assessments and repairs to assist in developing budgets for future assessment work. Additionally, the Company's dedicated Gas Project Management department handles large gas projects and programs. This department provides centralized project management to address overall scope, scheduling, and budgeting for major capital gas projects.

The project controls department of the Gas Engineering and Operations business unit monitors all capital dollars to ensure that authorized projects align with the established budget to achieve the lowest reasonable and prudent cost to customers. On a monthly basis, budget to actual spend is compared and financial forecasts are updated for programs and projects.

GUIC projects follow the Company's sourcing policy which provides that, with few exceptions, all standard goods and services agreements with a value greater than $50,000[21] are awarded on a documented competitive basis. In the limited circumstances where a competitive process is not required (e.g., emergencies, absence

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[20] The East Metro 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.

[21] Including cumulative amounts in multi-year agreements.

of competitive firms, etc.), written justification and director level authorization from the business area and Supply Chain is required.[22]

Furthermore, where practical, the Company establishes bid-units contracts for activities that are reproducible and are awarded to the vendors that provide the best overall value, resource availability and proven strong safety performance. Where impractical to utilize a bid-unit structure, the Company employs project-specific lump sum bids or written proposals against existing contractual agreements that establish the intended work activities through a written Scope of Work and confirm the vendor's understanding in their written proposals and schedules.[23]

Importantly, given the national "Call to Action" issued by the United States Department of Transportation (DOT) and PHMSA in 2011, we are competing nationally to secure the specialized equipment, engineers, and construction crews required to complete this necessary renewal work. Aging infrastructure across the country has resulted in a large number of gas operators responding to the Call to Action with multi-year replacement programs. The contractors that will complete work as a part of these multi-year replacement programs have been unable to support the total amount of work being done. This has put stress on available engineers, construction contractors, and other needed resources. To that end, we have invested not only in robust supply chain procedures, but in substantial investments in human resources, including engineers and construction crews. Notably, the federal Call to Action was not limited to prompting the necessary renewal work; it also called upon state regulators to recognize the critical nature of these safety-related pipeline investments by providing timely cost recovery.

2. *Oversight Methods*

In addition to competitive bidding, we also employ significant and ongoing oversight. The Company conducts a monthly status review of major capital programs and projects, including the GUIC. We review actual overall capital spending in comparison with forecasted spending monthly and at year-end.

In 2014, the Company established a Rider Review Committee (RRC) tasked with ensuring that modifications made to GUIC projects met the intent of the Company's GUIC Rider. The RRC process was designed to formalize the structure and documentation practices as well as increase the transparency around capital and O&M

[22] The bid process also ensures compliance with Xcel Energy policies regarding the use of diverse contractors and suppliers as specified within the Company's corporate policy on Supplier Diversity.
[23] Agreements with a value less than $50,000 are awarded on an informal competitive basis to the extent reasonable to obtain goods and services from a source whose offer is most advantageous to Xcel Energy considering the administrative cost of the purchase.

expenditures related to gas integrity initiatives utilizing rider cost-recovery mechanisms. Program proposals modifying original plans are subject to review, approval, and sign-off based on cost thresholds governed by the RRC's approval matrix guidelines.

In addition to the financial oversight and controls mentioned above, the Company also employs various levels of operational oversight and controls to meet internal standards, and external requirements set forth by the federal Code of Regulations. All gas projects completed by contractors have assigned inspectors that assist in oversight and validate that the contractor is performing work in accordance with the Xcel Energy Pipeline and Compliance Standards Manual.

Other oversight methods include scheduled and unscheduled inspection from members of the Minnesota Office of Pipeline Safety (MNOPS). Each year, there are scheduled field and records inspections conducted by MNOPS throughout the service territory. Additionally, the Company provides MNOPS with information regarding active projects and inspectors have authority to make unannounced inspections at any time. For example, MNOPS performed 25 planned inspections and evaluated 7 unplanned events in 2016. Inspections included a review of field locations and records, operations and maintenance procedures, safety-related concerns, and outages.

Additionally, GUIC activities have internal personnel identified that oversee those activities. Those personnel work closely with Gas Engineering, Design and our contractors prior to construction, during construction and after construction to plan and schedule the work, discuss efficiency opportunities and communicate challenges that may impact the work and the cost of that work. The personnel responsible for oversight also review and approve all project-related invoices to ensure the costs are accurate and reasonable. Similarly, the Company monitors the sewer mitigation project by tracking progress, expenditures, and outcomes. The governance team overseeing the sewer mitigation work meets on a monthly basis, and provides an annual update to the MNOPS of progress and findings.

3. Outsourcing

While the Company seeks to minimize outsourcing TIMP and DIMP work when possible, in certain instances external expertise is needed. To help ensure the safe and efficient completion of assessments. In these instances the Company seeks and relies on outside assistance.

The Company utilizes internal resources when the work falls within the Company's core competencies. For example, we utilize internal resources for administrative management and excavations to remediate conflicts for the sewer and gas line conflict remediation program. However, the camera inspection and a small amount of the administrative aspect of projects are outsourced. The Company has neither the internal expertise nor the equipment available to perform the specialized inspection aspect of the program. By outsourcing the specialized portion of the sewer line remediation inspections, the Company has spared customers the cost of purchasing expensive, specialized equipment, and ensured that those with the expertise are conducting the investigations.

When outsourcing is needed, contractor performance is managed through contractor scorecard meetings. Performance is tracked using high-level categories of Timeliness, Quality and Cost Specific goals such as:

1) Work is completed and invoiced in a timely manner and invoicing is accurate.
2) Contractor Safety performance is acceptable; damages to existing Xcel Energy and customer facilities, and customer outages are reported accurately, managed and resolved in a timely manner.
3) Cost per unit and total spend by work activity are reasonable and explainable, and that the contractors adhere to the contract structure, and identify and explain discrepancies.

The Company's contractual agreements include terms and conditions that address each of the goals listed above. Indeed, the contract covers situations such as work changes, suspension of work, work warranties, and insurance requirements that insulate Xcel Energy and its customers from cost overruns due to circumstances within the contractor's control. Once the work is complete, the general conditions specify actions required for final acceptance of the work and price and payment terms. For instance, the Company is not obligated to pay the contractor for work performed incorrectly, work that was beyond the scope of the agreement, or damage caused by the contractor's negligence. These contractual protections serve an important role in protecting against unreasonable and inappropriate cost overruns.

The use of contractors in specialized situations such as this has proven to be cost-effective. It is estimated that by the end of 2018, the Company will have saved over $2.3 million through the use of contract work for sewer inspections. This is especially evident as we begin to ramp down the amount of resources dedicated to sewer inspections due to a decrease in conflicts detected over time. The use of contractors prevents the Company from incurring sunk costs on specialized equipment that will be needed less and less as time goes on. A detailed analysis of the savings reaped from contract work in sewer inspections can be found in Attachment I to this filing.

D. GUIC Activities Are Incremental to Activities in Approved General Rates

The projects for which recovery is being requested in this filing are incremental expenditures not included in the Company's last rate case.[24] The federal Call to Action leading to the emergence of TIMP and DIMP post-dated the Company's last rate case and the work is uniquely targeted at assessing and improving the safety, reliability, and integrity of our natural gas infrastructure pursuant to state and federal regulatory requirements. The Commission has agreed that these costs are new,[25] above and beyond what was previously requested in our last rate case as discussed earlier on page 6. There have been no foundational changes to the TIMP and DIMP programs that would counsel toward a different result. As such, the Commission should again conclude that the TIMP and DIMP projects that are the subject of this petition were not requested in our previous rate case, and—in that way—are appropriate for rider recovery.

For example, the valve replacement costs included in this filing for which we are seeking GUIC recovery have arisen only after the replacement program was initiated in response to new federal standards in 2011.[26] However, these costs are incremental to the small amount of valve-related work in base rates established under the 2010 Test Year filed in our last rate case.

E. O&M Costs Are Specifically Authorized

With this GUIC Rider request, the Company seeks to recover its O&M costs, consistent with the statute and the Commission's approval of this cost treatment in our 2016 GUIC Petition.[27]

The Company provides the TIMP and DIMP actual and estimated cost data for 2016-2022 in Attachment J. As outlined above, the Company utilizes a rigorous budgeting process that endeavors to adequately forecast future O&M costs. That said, and though we enter our TIMP and DIMP building cycles with a concrete plan of action, ongoing pipeline inspections may result in the reprioritization of projects as we discover risks that may require more immediate intervention. The need for flexibility in planning is critical in pipeline work, and emergent projects can result in fluctuating O&M costs year over year. The Commission has previously recognized this dynamic, noting "[t]he costs of these investments can vary widely from year to year and are difficult to forecast with accuracy. Approving a rider will give Xcel the ability to implement multi-year pipeline-replacement programs, adjusting the rates annually to correct for over- or under-recovery."[28]

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[24] Base rates in the 2010 Gas Rate Case included $480,000 in annual O&M expenditures for TIMP. As this amount is already collected through base rates, it has been removed from the GUIC revenue requirement in this case.
[25] Most recently in Docket No. G002/M-15-808.
[26] *See* 49 C.F.R. 192, Subpart P.
[27] *See* Minn. Stat. § 216B.1635 Subd. 4.
[28] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 7.

F. Deferred Accounting Projects

This rider request includes $4.6 million in previously deferred TIMP and DIMP costs. The Commission approved a five-year amortization schedule and 2018 will represent the fourth year of amortization. A description of the projects approved for deferred accounting is available in our Annual Reports filed in the deferred accounting dockets.[29] The deferred amounts and five-year amortization are provided in Attachment J.

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

Table 1 below presents Xcel Energy's 2018 total estimated costs of $27.5 million for TIMP and DIMP activities. Capital-related revenue requirements and operations and maintenance expenses total $18.5 million and $4.9 million, respectively. Costs associated with the amortization of deferred costs total $4.6 million as approved in Docket Nos. G002/M-10-422 and G002/M-12-248. An additional $0.08 million is included for prorated accumulated deferred income taxes (ADIT) and O&M totaling $0.48 million of TIMP costs already being recovered in base rates is removed from this rider request.

[29] *See* 2014 Annual Report, Gas Safety Deferred Accounting, Docket No. G002/M-12-248, March 2, 2015. See also Annual Report, Sewer Conflict Deferred Accounting, Docket No. G002/M-10-422, January 30, 2015.

Table 1
2017-2018 Gas Utility Infrastructure Costs
($ Millions)

	2017 Forecast	2017 Estimated Actual	2018 Forecast
Capital-Related Revenue Requirements			
TIMP	7.86	8.48	10.51
DIMP	4.14	4.81	7.96
Total	**12.0**	**13.29**	**18.47**
O&M Expenses			
TIMP	1.15	0.44	1.33
DIMP	4.55	4.20	3.53
Total	**5.70**	**4.64**	**4.86**
5-Year Amortization of Deferred Costs			
TIMP	0.82	0.82	0.82
DIMP	3.73	3.73	3.73
Total	**4.55**	**4.55**	**4.55**
ADIT Prorate	0.11	0.01	0.08
O&M Recovery in Base Rates	(0.48)	(0.48)	(0.48)
Revenue Requirement Subtotal	**21.88**	**22.01**	**27.48**
True-up Carryover	0.26	0.86	0
Total Revenue Requirement	**22.14**	**22.87**	**27.48**
Recovery		22.87	27.48
Difference – Under/(Over) Recovery		0	0
GUIC - Grand Total			**27.48**

H. 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.

Table 2
GUIC Capital Expenditures (CWIP only) and Net Salvage: 2012-2021
(In Thousands - $000)

	TIMP			DIMP			Total
Year	Transmission	Distribution*	**Total**	Distribution	Software	**Total**	Expenditures
2012	95	0	95	83	-	83	178
2013	65	9,497	9,562	343	-	343	9,906
2014	-24	11,651	11,628	240	-	240	11,868
2015	1,073	17,937	19,010	10,011	1,852[30]	11,863	30,873
2016	4,556	14,196	18,752	12,628	171	12,799	31,551
2017	8,214	712	8,926	12,969	-	12,969	21,895
2018	8,715	-	8,715	36,813	-	36,813	45,528
2019	28,781	-	28,781	31,940	-	31,940	60,721
2020	21,105	-	21,105	25,908		25,908	47,013
2021	30,941	-	30,941	17,268		17,268	48,209
2022	30,787	-	30,787	17,268		17,268	48,055
Total	**134,308**	**53,994**	**188,302**	**165,472**	**2,023**	**167,495**	**355,797**
Salvage Rate**	(15.00%)	(16.39%)		(16.39%)	0.00%		
Net Salvage	**(20,146)**	**(8,850)**	**(28,996)**	**(27,121)**	**-**	**(27,121)**	**(56,117)**

** The East Metro Project was originally identified from activities related to TIMP assessment activities; therefore it is classified under the TIMP category. However, the new plant being installed is considered distribution plant from a regulatory accounting perspective.*

*** 2014 depreciation lives and salvage rates approved in Docket No. E,G002/D-12-858. These percentages can be found in Attachment K*

[30] 2015 amount has been adjusted from what was reported in last year's filing. Expenditures of $49,945 that should have been assigned to another affiliated Operating Company were inadvertently included in the numbers for NSPM.

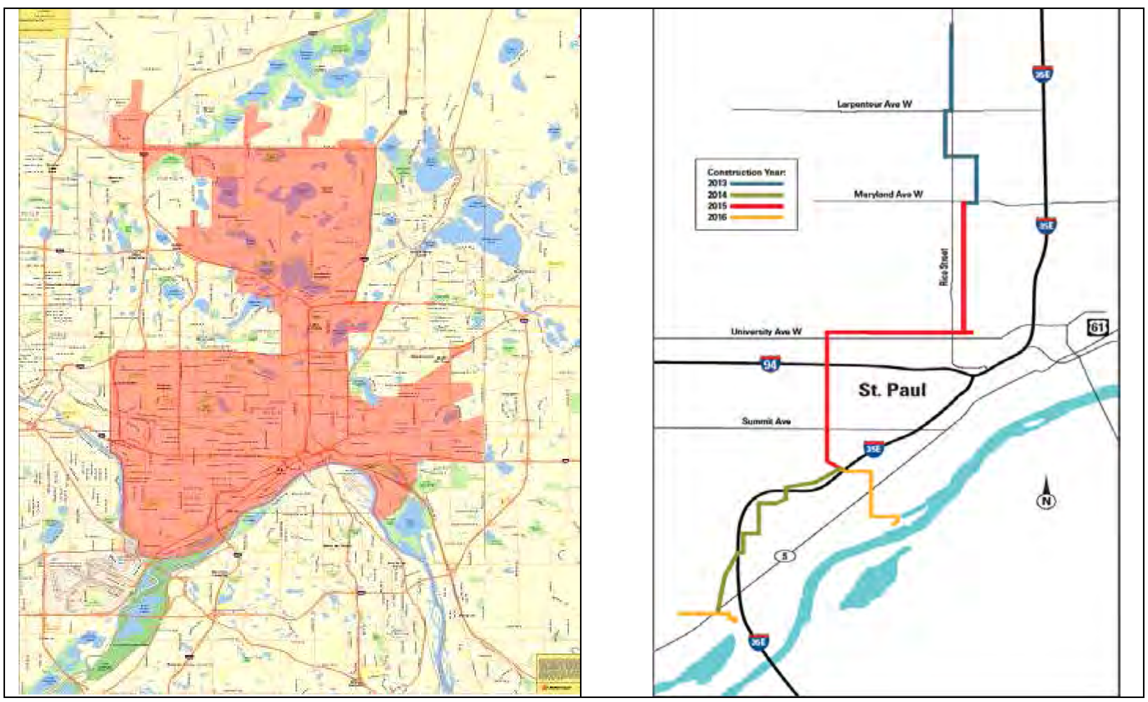
Capital expenditure estimates between 2012 and 2022 total $188.3 million for TIMP and $167.5 million for DIMP, reflecting an estimated total of $355.8 million. Xcel Energy calculates a depreciation rate of 2.52 percent and 1.53 percent for distribution mains and transmission mains, respectively. The Company's calculations assume an average depreciable life of 46.14 years and a net salvage rate of 16.39 percent for distribution mains and average depreciable life of 75 years and net salvage rate of 15.00 percent for transmission mains.[31]

I. Gas Utility Projects

1. East Metro Project

Over four years, the Company replaced 11.5 miles of pipeline and concluded the East Metro Project in 2017. Figure 3 shows the area served by these critical assets.

Figure 3



This project offers multiple benefits to our customers. The new pipeline incorporates updated engineering and welding techniques rather than the previous joining method, mechanical compression couplings which were leak-prone. The new pipeline is also built to allow the use of advanced ILI technology resulting in more efficient monitoring that will help ensure the continued integrity and reliability of replied pipe. Lastly, the pipeline includes remote control valves that provide system operators the

[31] The rates in this paragraph are rounded to two decimal places for ease of reading and tie back to the four decimal place rates as approved by the Commission in Docket No. E, G002/D-12-858.

ability to isolate the pipeline in the event of an emergency, thereby reducing the outage impact on customers as well as mitigating the consequences of a failure.

In addition to engineering advancements, the East Metro project also accomplished notable project management milestones that achieved efficiencies by working closely with the City of St. Paul. For example, in 2015 the Company executed a joint project with the St. Paul Regional Water Department to replace approximately 1.7 miles of water main simultaneously with the pipeline replacement. Benefits of this coordination included reducing risk of damaging the 1885 vintage water main during pipeline replacement construction and reducing the disruption to public roadways.

The Company's work on the East Metro Project was located in some of the most densely populated areas of its gas system. Despite this, the Company was able to complete the project both on-time but also under budget. This project was originally planned as a $69 million capital investment. The total capital at completion was about $63 million; 8 percent or $6 million lower than originally anticipated. The lower cost was a result of lower contractor costs through the use of a competitive bidding process, utilizing a unit pricing approach as opposed to lump sum pricing, and performing air tests on certain segments of pipe versus hydro testing.

2. TIMP

TIMP is an ongoing program and will continue in 2018 and beyond. Further, PHMSA is currently working to address a number of Congressional mandates and National Transportation Safety Board (NTSB) recommendations that will likely increase and clarify compliance standards for pipeline operators beyond the current TIMP rule. A number of new regulatory requirements are expected to be enacted during 2017 that may impact Xcel Energy's obligations and required work activities to safely maintain and operate the gas system. These include:

- Safety of Gas Transmission and Gathering Pipelines[32] - This is considered to be one of the more significant rules since the inception of the TIMP and DIMP and contains 16 elements, including potentially impactful new rules related to corrosion control, TIMP risk assessment and risk modeling, gathering lines, material verification, record keeping and expansion of integrity management assessments. The Advanced Notice of Proposed Rule Making (NPRM) was published in 2011, with an estimated final rule publication date of late 2018;
- Excess Flow Valves (EFV) beyond Single Family Residences[33] - This final rule went into effect April 2017. The Company complied with the requirement to

[32] https://www.phmsa.dot.gov/regulations-fr/rulemaking/2016-11240.
[33] https://www.phmsa.dot.gov/regulations-fr/rulemaking/2016-24817

notify eligible existing service line customers of their right to request an EFV be installed on their service line;

- Operator Qualification, Cost Recovery and other Pipeline Safety Proposed Changes Plastic Pipe Rupture Detection and Valve Rule[34] - The estimated final rule publications for these are expected in the fourth quarter of 2017. Some of the more notable proposals include plastic pipe rupture detection, which would require SCADA systems to be equipped with tools to assist in recognizing and pinpointing leaks, and a requirement to install ASV or RCV on new or fully replaced transmission lines to improve overall incident response; and
- Quality Management Systems (QMS)– PHMSA is currently considering a separate rulemaking on how to impose requirements related to QMS. Quality management[35] includes the activities and processes that an organization implements to achieve quality. These included formulating policies, setting objectives, planning, quality control and assurance, performance monitoring, and quality improvement.

The most significant of these is the Safety of Gas Transmission and Gathering Pipelines. PHMSA issued the NPRM on April 8, 2016.

PHMSA describes the Proposed Rule as a response to multiple Congressional mandates from the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act), recommendations from the NTSB, as well as addressing other aspects of natural gas pipeline operations that PHMSA has identified as requiring additional guidance. The proposed rules are expected to be issued as rulemaking in late 2018 or 2019. PHMSA's proposal represents the most significant revision to the regulation of gas transmission and gathering pipelines since 1970 when PHMSA's predecessor first developed minimum pipeline safety standards.

Specifically, PHMSA is proposing to issue new regulations and revise existing regulations to address the following topics:

- Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs);
- Requirements for re-establishing MAOP;
- Integrity Management Program Process Clarifications;
- Management of Change;
- Corrosion Control;

[34] https://www.phmsa.dot.gov/regulations-fr/rulemaking/2016-31461.

[35] More information about PHMSA's definition of quality management can be found in the federal register at https://www.federalregister.gov/documents/2016/04/08/2016-06382/pipeline-safety-safety-of-gas-transmission-and-gathering-pipelines#h-186.

- Inspection of Pipelines Following Extreme Events;
- MAOP Exceedance Reports and Records Verification;
- Launcher/Receiver Pressure Relief; and
- Expansion of Regulated Gas Gathering Pipelines.

Xcel Energy expects to continue spending related to compliance activities in the following area of integrity assessments and remediation for segments outside of HCAs. In particular, the Company expects additional regulations of transmission assessment projects will require additional advances in the areas of:

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

Future costs associated with these assessments could vary between $1.8 million and $7.1 million depending on the specific segments being assessed. Additionally, the costs incurred will likely be a combination of capital expenditures and O&M expenses, depending on the type of work being performed.

The Company's capital and O&M costs for assessments in 2016, 2017, and 2018 included in the last three GUIC filings are shown in Table 3.

Table 3
GUIC Transmission Pipeline Assessments
(In Millions - $M)

Filing	Assessment (Miles)	Capital Expenditures	O&M Expenditures
2016 (15-808)	10.5	$4.9	$0.0
2017 (16-891)	13.7	$1.6	$1.1
2018 (17-____)	20.9	$0.3	$1.5

** Assessment methods include In-Line Inspection, Pressure Testing, and Direct Assessment.*[36]

[36] The Company's costs and mileage amounts included in the 2016 and 2017 GUIC Filings differ from actual and forecasted amounts as a result from program modifications approved through the RRC.

Figure 4

Transmission Integrity Assessments					
NSPMN: 2015-18 Number of Projects					
	2015	**2016**	**2017**	**2018**	**Total**
ILI	0	0	2	3	**5**
Pressure Test	2	1	0	1	**4**
Direct Assessment	1	0	0	0	**1**
Total	**3**	**1**	**2**	**4**	**10**
NSPMN: 2015-18 Mileage					
	2015	**2016**	**2017**	**2018**	**Total**
ILI	0	0	7.8	20.6	**28.4**
Pressure Test	3.1	0.1	0	0.3	**3.5**
Direct Assessment	6.5	0	0	0	**6.5**
Total	**9.6**	**0.1**	**7.8**	**20.9**	**38.4**

As shown in Figure 4, the Company expects to complete one Direct Assessment project, four Pressure Test projects, and five ILI projects in 2018. The 2017 capital work includes initial ILI assessments and validation digs, whereas most of the 2018 work involves second time ILI assessments[37] and a hydrostatic pressure test. Hydrostatic pressure tests utilize liquid to aid in visual leak detection. Based on the current assessment plan, the Company expects to complete between three to five projects each year through 2022.

a. Automatic Shut-off and Remote Controlled Valves

The ASV and RCV installation project began in 2015 and we expect it to continue through 2022. We anticipate the associated capital expenditures to range from $0.5 - $1.0 million per year. In 2017, the Company installed actuating equipment on four valves. 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.

b. Programmatic Replacement and MAOP[38] Remediation

The Programmatic Replacement and MAOP Remediation program addresses validation of the MAOP and/or replacement of vintage transmission pipelines where risks cannot be mitigated with repairs. The results of the transmission pipeline

[37] ILI is required every seven years according to Subpart O – Gas Transmission Pipeline Integrity Management 192.939. The first batch of second run ILI assessments is planned for 2018 to meet this requirement. Once an initial ILI assessment is completed on a specific section of pipeline, all costs for subsequent assessments by ILI are considered O&M expenses.

[38] MAOP verification and testing for transmission pipelines were initially defined in the Pipeline Safety Act of 2011.

assessment will drive the overall scope and timing of these capital expenditures. In 2017, the Company entered the pre-work phase of the initiative, completing the design and engineering work as well as Right-Of-Way and easement acquisitions for several transmission line replacement projects. Following the conclusion of the pre-work phase, the capital construction phase will begin and the annual expenditures will span from a low of $8 million to a high of $28 million, based on the respective construction schedules for these projects.

c. TIMP Summary

The Company has made significant progress in improving the safety and reliability of its pipeline system. But our work is not done. The Company will continue to identify existing and emerging risks, evaluate those risks, and develop mitigation methods to address them. We are committed to continuing the important work that grew out of the federal Call to Action and, as new regulations are passed, we are committed to incorporating that work into our integrity program.

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

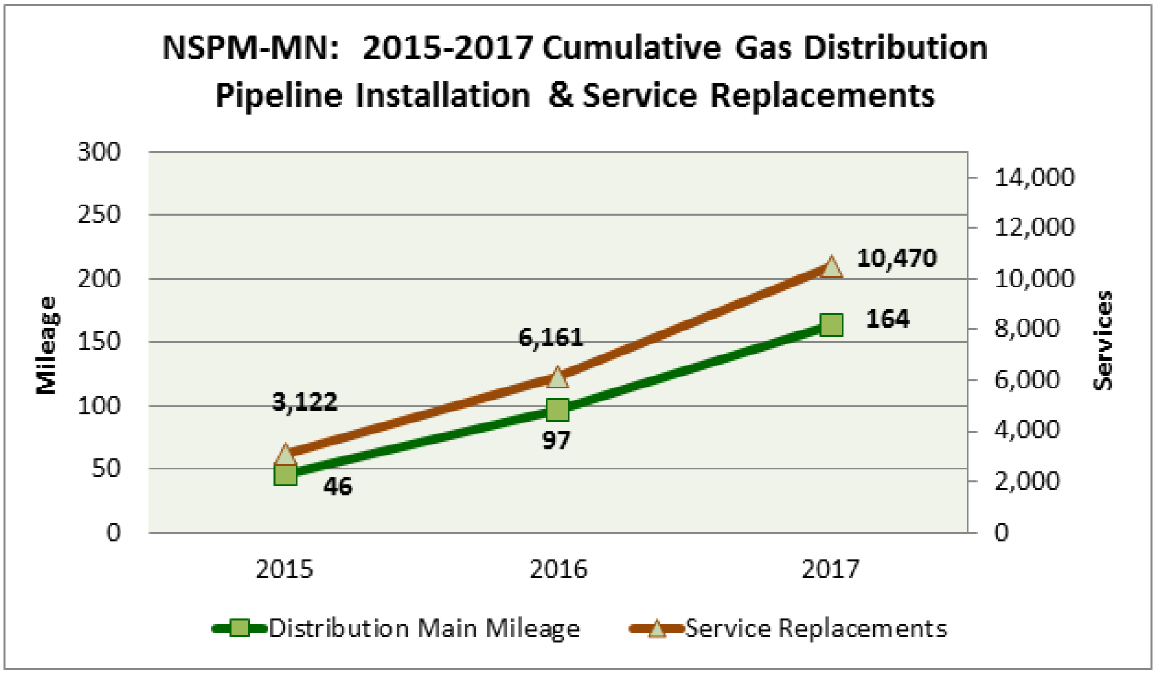
3. DIMP

a. Poor Performing Main and Service Replacement

Under Code 49 CFR Part 192.1007(d), the Company must determine and implement measures designed to reduce the risks from failures of its gas distribution pipeline. Gas distribution systems are not designed to allow for the technologically advanced in-line inspection assessment methods used for larger diameter transmission pipelines. As a result, the Company uses subject matter expertise, historical leak data and industry information to identify risk factors that may lead to gas pipeline leaks or failures. The annual replacement levels of high and medium risk pipe are based on these factors.

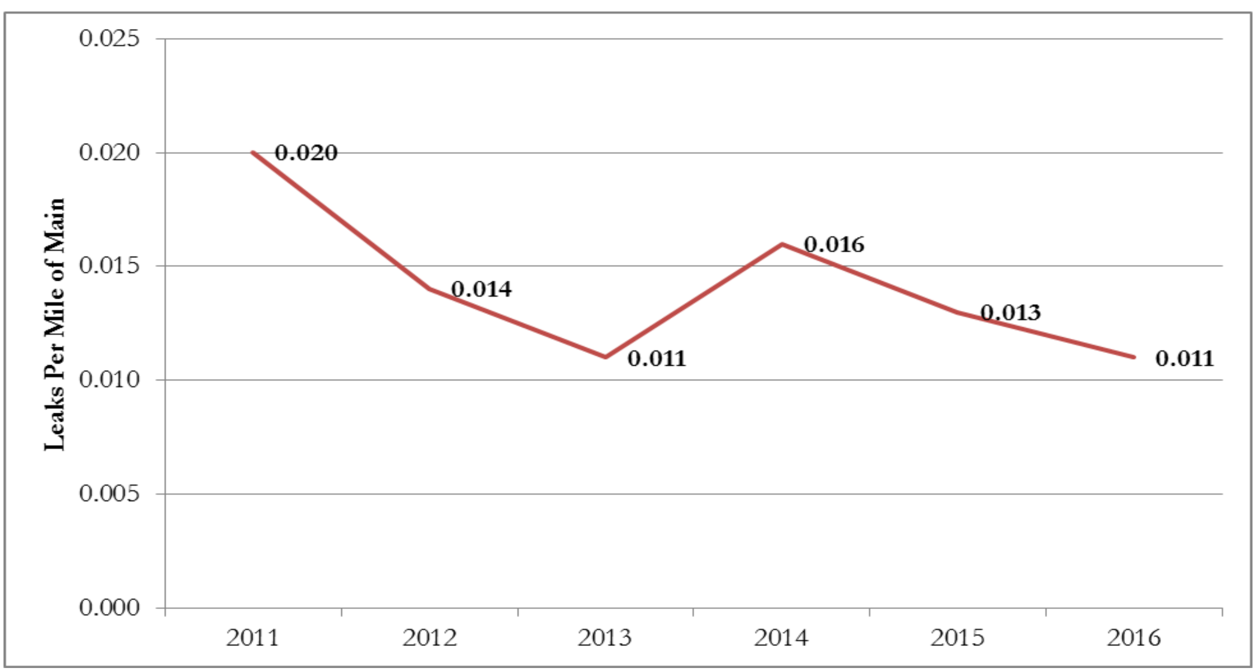
The Poor Performing Main and Service Replacement Projects are multi-year initiatives. Future capital expenditures associated with Poor Performing Mains are estimated at $11 million annually, while the Poor Performing Services investment is estimated at $7 million annually. Both projects will require design and construction resource procurement and deployment. The Company does not expect to incur significant O&M costs for the project as a result of a change in its capitalization policy. Figure 5 illustrates the progress of the Company's integrity-related main and service distribution replacement work:

Figure 5



As discussed previously, the Company continually collects data to help identify and remove distribution pipe segments that are most susceptible to failure. One of these data collection methods is periodic leak surveys to monitor system integrity and remediate known leaks that have the potential to result in an event. Figure 6 reflects leak data submitted to the DOT for the years 2011-2016:

Figure 6
Distribution Mains Leak Rate



As evidenced in Figure 6, the performance of the Company's distribution system continues to gradually improve, as measured by an overall declining leak rate per mile of main. The Company expects to maintain current annual investments for distribution mileage and service line replacements through at least 2022.

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, the Pipeline Data Project concluded in 2015.[39] The new valve installation component of the Distribution Valve Replacement Project concluded in 2016.[40] In addition to new valve installations, the proposed 2017-2018 program, roughly $0.5 million annually, is designed to replace existing distribution system isolation valves which have reached the end of useful life.

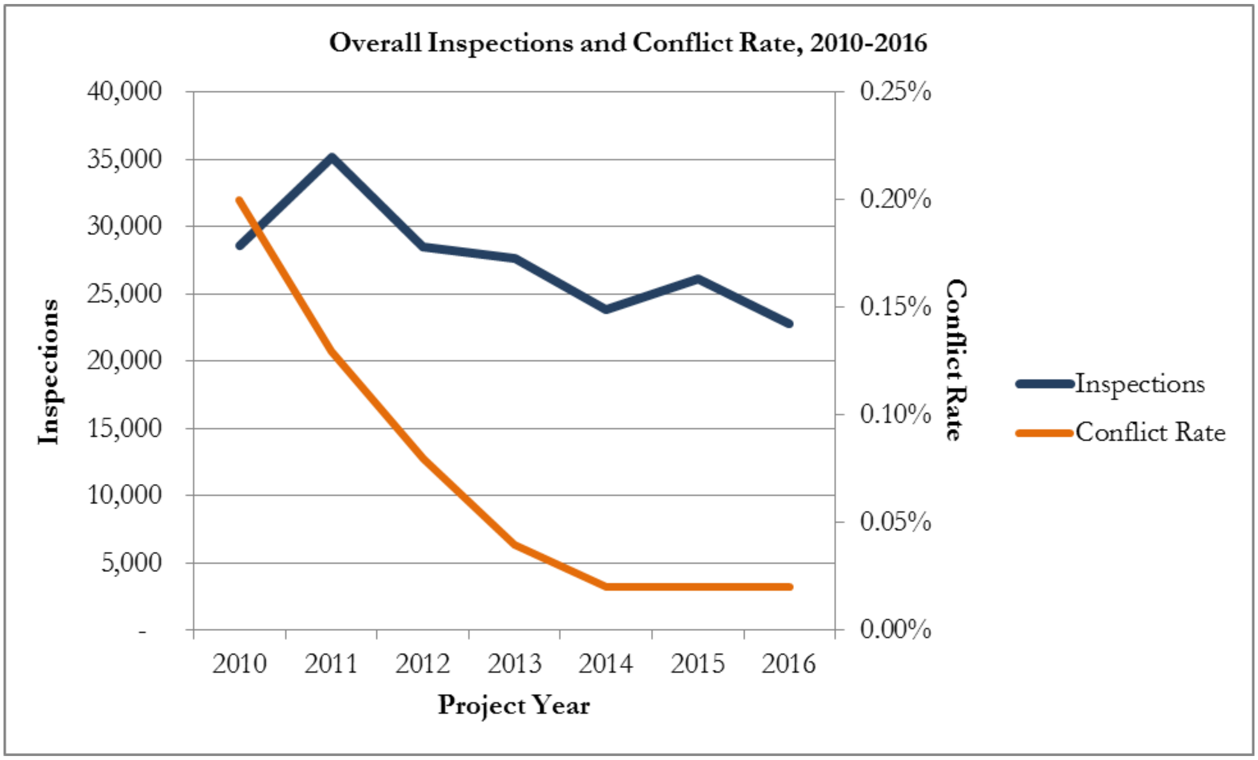
c. Sewer and Gas Line Conflict Remediation

This program was developed in response to an incident on February 1, 2010 when a sewer cleaning contractor working in Saint Paul perforated a natural gas main that intersected the sewer line (i.e., conflict), resulting in a fire, property damage, and injury. During the initial three-year program, 123 conflicts were identified. The risk associated with a sewer conflict is considered to be a low probability but a high consequence. Based on the number of conflicts found during the initial three years and the significant risk posed by a single conflict, the Company continued inspections. The sewer conflict inspection program is now in the eighth year of an anticipated ten year program.

By the end of 2017, the Company expects to have performed roughly 211,412 sewer line inspections. Through August 2017, a total of 149 known conflicts have been identified and cleared. Figure 7 illustrates the progress of the Company's Sewer and Gas Line Inspection Program between 2010 and 2016.

[39] Although this program concluded in 2015, late invoices carried into 2016 caused roughly $0.2 million of capital charges.
[40] With the exception of minor restoration activities in 2017.

Figure 7



As shown in Figure 7, the conflict rate has decreased steadily from 0.20 percent in 2010 down to 0.02 percent in 2016. The Company reviews the results of the program every year to determine whether the program should continue. As such, the Company will reduce the annual scope of this program from \$3.5 million for 18,880 inspections, down to \$2.3 million for 11,500 inspections, a \$1.2 million annual reduction in 2018. The Company continues to believe conflict threats exist with sewer laterals. However, the continuing reduction in the conflict rate and lack of conflicts through August of 2017 suggest that a scope reduction is appropriate.

Between 2011 and 2017, the average annual cost for the sewer and gas line conflict remediation program was \$3.5 million. As a result of finding fewer sewer and gas line conflicts in recent years, the Company will reduce the amount of inspections in 2018 and 2019, the final two years of the program.

d. Distribution Pipeline Inspection and Replacement

Distribution pipeline inspections or “Intermediate Pressure Line Assessment” is expected to be an ongoing program. We will continue to regularly inspect and replace high and medium risk segments to satisfy the Federal pipeline safety regulations set forth by the

PHMSA's Title 49, Code of Federal Regulations, § 192, Part 192.921 (a).[41] The asset health data collected from these inspections will be used to develop plans for additional mitigation actions as needed to protect public safety.

Figure 8

Distribution Integrity Assessments					
NSPMN: 2015-18 Number of Projects					
	2015	**2016**	**2017**	**2018**	**Total**
ILI	0	0	0	0	**0**
Pressure Test	0	0	0	0	**0**
Direct Assessment	0	2	1	2	**5**
Total	**0**	**2**	**1**	**2**	**5**
NSPMN: 2015-18 Mileage					
	2015	**2016**	**2017**	**2018**	**Total**
ILI	0	0	0	0	**0**
Pressure Test	0	0	0	0	**0**
Direct Assessment	0	30.7	11.1	5	**46.8**
Total	**0**	**30.7**	**11.1**	**5**	**46.8**

As shown in Figure 8, the Company expects to complete five Direct Assessment projects by the conclusion of 2018. Since the GUIC was established in 2015, the Company has assessed a total of 46.8 miles. The 2017 work includes a direct assessment and validation digs. The 2018 work will include direct assessment work, validation digs and a hydrostatic pressure test. Based on the current plan, the Company expects to complete between three and five projects annually through 2022.

Additionally, in 2018 the Company will begin several large-scale replacement projects. The most significant project in 2018 and 2019 replaces the Langdon Line from a Northern Natural Gas Town Border Station in Cottage Grove to 1st Street in Newport Minnesota, at an estimated cost of $21 million. Future costs associated with distribution pipeline inspections and replacement could vary between $9 million and $20 million annually, depending on the specific pipeline segments being assessed and/or replaced.

e. Federal Code Mitigation

Federal Code mitigation began in 2016. Over time, as the Federal Code[42] governing the operation and maintenance of the gas system has changed the Company's

[41] Part (a) Assessment methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the approved methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment.

standards and compliance manual also evolved. Additional field work related to repairs or changes to legacy assets has been needed to maintain compliance with the Federal Code. Some of these items are relatively minor while others are more significant. We estimate the 2018 costs for corrective actions to be approximately $0.2 million in O&M, the last year of this program. Further details regarding expected costs are provided at Attachment D, DIMP Overview and Project Detail.

J. Magnitude of GUIC in Relation to the Gas Utility's Approved Base Revenue and Capital Expenditures

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 2018 GUIC rate generates $36.1 million of GUIC-related revenues in 2018. The GUIC revenue estimates reflect 22.7 percent of the base revenues of $159.10 million approved in the previous general rate case. Please reference Attachment L for details.

The Commission has also directed the Company to file "a cost/revenue study based on 2016 actuals reconciled back to Xcel's 2016 Jurisdictional Annual Report." The Company has included Attachment M, which provides this cost/revenue reconciliation to the 2016 Jurisdictional Annual Report. We note the 2016 GUIC revenue requirements are less than 4 percent of the calculated 2016 Annual Report revenue requirements.

The 2018 forecasted GUIC-related capital expenditures total $45.5 million. Accordingly, the incremental costs proposed in this filing reflect a 152.3 percent increase over the currently approved base rate level of capital expenditures of $29.89 million. Please reference Attachment L for details.

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[42] Inclusive of Title 49 of the Code of Federal Regulations (CFR) Part 192 Subparts A through P, PHMSA Advisory Bulletins, and other guidance provided by Federal institutions.

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

A. Calculations for Revenue Requirements and Proposed 2017 GUIC Rate Adjustment Factors

In this section, we provide the 2018 revenue requirement and 2018 rate adjustments factor calculations for the proposed GUIC.

1. Revenue Requirements

The projected GUIC revenue requirements for 2016 through 2022 are summarized in Attachment N to this filing. The projected 2018 revenue requirements proposed for recovery through the 2017 GUIC adjustment factors from Minnesota gas customers are approximately $27.5 million. The supporting revenue requirements and projected 2016-2019 GUIC Tracker activity are provided in Attachment O. In addition, the eligible revenue requirements also include property taxes, current and deferred taxes, and book depreciation. Attachments F and G summarize the 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 F and G.

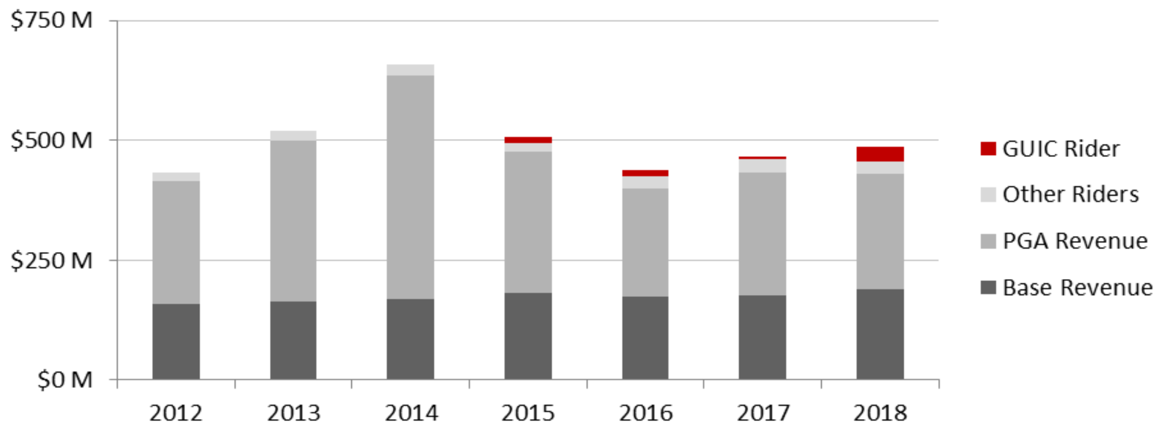
2. GUIC as a Part of Overall Gas Utility Recovery

The recovery of GUIC revenue requirements through the rider is a critical component in the Company's gas utility business and represents an important tool that facilitates construction and assessment activities that help keep the gas system operating safely and efficiently. However, the total revenue requirement related to GUIC represents only a portion of the overall gas utility recovery. At a high level, the Company's gas utility recovery can be broken down into three components. These components are:

- Base rates recovery, stemming from the approved revenue requirement from the last general gas rate case,
- Purchased Gas Adjustment (PGA), and
- GUIC rider annual revenue requirement, and

Comments in previous dockets requested more clarity about how the GUIC fits as a part of the total recovery within the Company's gas utility. To provide some context to this question, Figure 9 below shows the total gas utility revenue collections by recovery mechanism, split among Base Rates, PGA, and GUIC.

Figure 9
Annual Revenue Collections by Recovery Mechanism

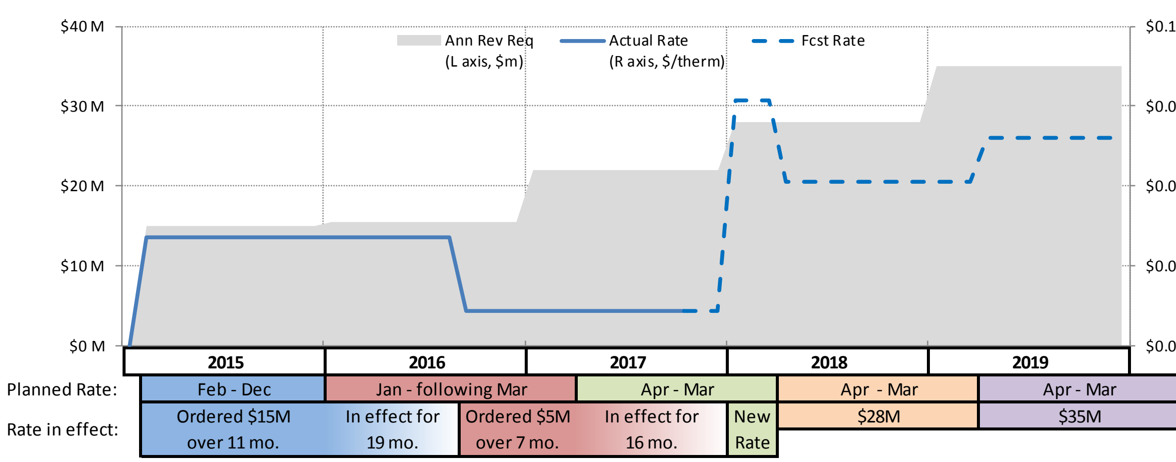


	2012	2013	2014	2015	2016	2017	2018
GUIC % of total	0.0%	0.0%	0.0%	2.8%	3.0%	1.3%	6.6%
Earned ROE	10.02%	9.76%	9.08%	9.71%	8.12%		

GUIC represents 6.6 percent of total bill collections forecasted in 2018. We also provide the earned ROE as reported in our jurisdictional annual reports. The reported earned ROEs includes the costs and revenues across all of the shown recovery methods. Purchased gas costs peaked in 2014 and therefore total customer bills are down significantly from that peak. We further note that though recovery through the GUIC has been increasing due to gas safety program implementation, the Company has a remaining deficiency that is unrecovered.

Figure 10 below shows a graphical representation of our overall gas utility recovery from 2015 through 2019. The chart shows how our actual approved rates track with annual revenue requirement for all of these components.

Figure 10
Annual Revenue Requirement and Actual/Forecast Rates



3. Proposed 2017 Rate and Carryover Balance

As of the filing date in this docket, the Company's 2017 GUIC Rider Petition[43] is still open in front of the Commission. Until an order is issued from that filing, the Company will continue to recover GUIC costs based on the factors presented in its 2016 GUIC Rider Petition.[44] Since the recovery requested in our 2017 petition was higher than that requested in our 2016 petition, the continued usage of 2016 GUIC factors during 2017 has caused under-recovery in 2017. To mitigate the impact of a large carryover balance in 2018 rates, we propose a rate that will collect the remainder of the 2017 revenue requirements in January 2018 through March 2018 (see rate factors below). However, we recognize that the Commission's calendar is congested and this option may not be available. In that instance, the Company requests implementation of a carrying charge to relieve financial pressure.

4. Accumulated Deferred Income Tax (ADIT) Prorate

Since the time of our last GUIC petition in November 2016, several utilities have requested Private Letter Rulings from the Internal Revenue Service (IRS) to clarify the appropriate method of proration of the ADIT, including Otter Tail Power. During this time, we have been working with the Department to explore the issue, document the fact pattern for NSP-Minnesota, and evaluate whether a common approach to the issue is possible among the Minnesota-based utilities.

For the purposes of this filing, while these discussions are ongoing, the Company presents actual ADIT for the historic calculations in 2016 and the actual months of 2017. The Company calculated the forecasted portions of 2017 and 2018 revenue requirements in accordance with our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6).[45] However, we will continue to work with the Department and other stakeholders towards a reasonable resolution and will update these calculations, as needed.

5. 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). The 2018 tracker balance is allocated to class in the

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[43] Docket No. G002/M-16-891.
[44] Docket No. G002/M-15-808.
[45] A technical description of this issue can be found in Docket No. E002/GR-15-826, Exhibit___(LHP-1), pages 53-56.

same manner as revenues were apportioned in our most recent natural gas rate case,[46] consistent with the Commission's 2015 and 2016 GUIC orders.

Proposed class factors are calculated 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 2018 GUIC Adjustment Factor calculation is shown in Attachment Q. Table 4 below shows the currently approved GUIC adjustment factors, 2017 pending factors, and proposed 2018 factors.

Table 4
Proposed 2018 GUIC Adjustment Factors
(Dollars per therm)

	Current Factors	2017 Proposed Factors (16-891)	2017 Factors (Jan 2018-Mar 2018)	2018 Proposed Factors (Apr 2018-Mar 2019)
Residential	$0.010922	$0.041689	$0.076669	$0.051492
Commercial Firm	$0.006110	$0.023070	$0.044635	$0.029056
Commercial Demand Billed	$0.005274	$0.017177	$0.042697	$0.021298
Interruptible	$0.003860	$0.012162	$0.030999	$0.015774
Transportation	$0.001570	$0.004639	$0.016588	$0.004929

The residential bill impacts under each factor are listed in Table 5:

Table 5
Residential Bill Impacts

	Current Factors	2017 Proposed Factors (16-891)	2017 Factors (Jan 2018-Mar 2018)	2018 Proposed Factors (Apr 2018-Mar 2019)
Dollars per Month	$9.24	$35.27	$64.86	$43.56
Bill Impact from Prior Rate		3.90%	7.97%	-3.15%*
*Reduction from factors assumed to be in place January 1, 2018 through March 31, 2018 for 2017 revenue requirement.				

[46] Docket No. G002/GR-09-1153.

We propose the 2018 factors be effective April 1, 2018. The above rates are calculated assuming the 2017 revenue requirement is collected by March 31, 2018 under the 2017 Factors noted in the table above, and the implementation of the 2018 Proposed Factors begins on April 1, 2018.

B. Timing of 2018 GUIC Factor Implementation

We request approval to implement GUIC factors in this annual report, effective April 1, 2018, pending review and approval by the Commission. The factor calculations assume that the 2017 costs are recovered using the 2017 factors shown above starting January 1, 2018 through March 31, 2018, and the proposed 2018 factors effective April 1, 2018 through March 31, 2019.

If implementation of the 2018 GUIC adjustment factors occurs after April 1, 2018, the Company proposes to calculate the final rate adjustment factors to recover the remaining 2018 revenue requirements over the remaining months through March 31, 2019, which would be provided as part of a compliance filing after the Commission's order approving the Petition.

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 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 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 2017 are shown on Attachment Q within the carryover rollforward section.

D. Proposed Tariff Sheet and Customer Notice

1. *Proposed Revised Tariff Sheet*

The proposed GUIC Rider factors can be found, in both clean and redline formats, on Tariff Sheet No. 5-64 in Attachment R.

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 an updated 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; $x.xxxx per therm for Interruptible customers, and $x.xxxx per therm for Transportation customers."

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

VI. RATE OF RETURN

The GUIC statute states that "[t]he return on investment for the rate adjustments 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."[47]

In this filing, the Company supports the capital structure and cost of debt approved by the Commission in its August 18, 2016 Order in our 2016 GUIC Rider Petition.[48] In that order, the Commission found:

1. the cost of long-term debt of 4.94 approved in our 2014 GUIC case, was appropriate;
2. the cost of short-term debt should be updated to reflect the 1.12 percent cost in the Company's electric rate case in Docket No. E-002/GR-13-868; and
3. the overall rate of 7.34 percent is appropriate.

The Company retained an independent expert, Concentric Energy Advisors (Concentric), to perform an assessment of the appropriateness of the Company's proposed use of the 10.00 percent ROE in the ROR calculation for the 2018 GUIC revenue requirement. The report from Concentric is Attachment S to this Petition. The propose ROE results in an overall 7.52 percent ROR.

The independent consultant applied three commonly-used analytical tools to assess the reasonableness of the Company's proposed 10.00 percent ROE: (1) the Constant Growth Discounted Cash Flow (DCF) model, (2) the Capital Asset Pricing Model (CAPM), and (3) a Risk Premium model. Utilizing a weighted mix of three separate analysis methods to calculate ROE is a proper way to mitigate potential anomalous market conditions that may skew the results of any single ROE calculation method and result in incongruous ROE results

This concern is currently evident in the DCF model. Current dividend yields for utility companies are well below historical levels. That, in turn, results in a DCF model that produces depressed ROE results. By utilizing three different methods, we are able to use models that focus on historical market data (DCF model) as well as models that focus on forecasted market conditions(Risk Premium model and CAPM). This mitigates the risk of short term market conditions having an overweighted

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[47] Minn. Stat. § 216B.1635, Subd. 6.

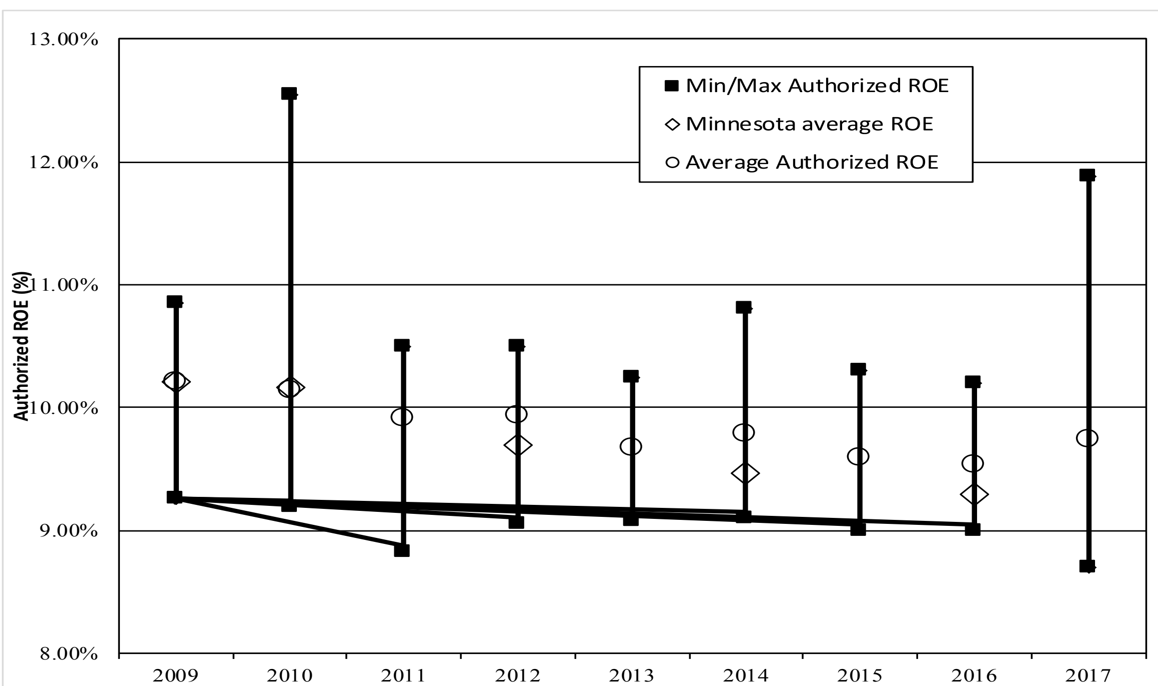
[48] *See* Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808 (August 18, 2016) at page 7.

impact on future results, especially in a period where interest rates are expected to increase in the long term future.

Northern States Power Company-Minnesota competes for capital on two fronts. The first is within the overall Xcel Energy corporate structure. Xcel Energy will naturally focus capital investments in the jurisdictions that offer the most advantageous return on investment. Beyond that, Xcel Energy as a whole needs to compete for capital with other utilities and businesses in the external investment market. If the Company is placed at the low end of authorized ROEs, both within Xcel Energy and the market as a whole, investments in Minnesota become a less attractive option. In the long term, this would hamper the Company's ability to access capital for necessary construction within Minnesota, and would raise the cost of financing projects.

For frame of reference, Figure 11 below shows a comparison of the average authorized ROEs in the state of Minnesota in comparison to those in other markets. As can be seen here, Minnesota average authorized ROEs tend to be lower than the average in the United States utility market, are far below the maximum authorized ROEs, and have steadily declined since 2009.

Figure 11
Comparison of Minnesota and U.S. Authorized ROEs



Consistent with the ALJ's ruling (which was later upheld by the Commission) in the Company's last gas rate case, Concentric used appropriate tools and weighting for analyzing the cost of equity for the comparison groups and considered the returns and the risks offered by rival investment opportunities.

The Company's proposed 7.52 percent ROR is (1) expressly authorized by statute, (2) is consistent with comparable utility proxy groups, and (3) is within the range required by equity investors to invest in utilities similar to the Company under current capital market conditions. The Company's proposed capital structure and return on equity is reasonable, in line with the market and consistent with the public interest.

The Company believes it would be helpful for the Commission to issue a procedural schedule that allows for an evaluation of the Company's proposed ROR and supporting analysis, as well as an evaluation of any analysis provided by parties which support their recommendations in an efficient manner. The Company recommends that all intervening parties provide their analysis of the Company's recommended ROE and ROR in their initial comments, which the Company will respond to in their reply comments. After that, the Commission should only allow for additional ROE and ROR analysis to enter the record, up to the point where the Commission takes up consideration of the filing, if changing market conditions necessitate additional analysis.

VII. PROPOSED GUIC METRICS

In its August 18, 2016 Order,[49] the Commission requested that:

> The Company develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC filings, and provide stakeholders the opportunity for meaningful involvement.

The Commission also instructed that:

> Each metric should include reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.

As the previous GUIC docket is still awaiting an order, we are providing an updated version of the metrics proposed in that docket. Please reference Attachment T for a full review of the TIMP and DIMP objectives and the results of the performance metrics along with the updated results of the performance metrics

[49] Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808.

CONCLUSION

The Company implemented transmission and distribution integrity management plans to be able to follow ever increasing federal and state regulatory standards. Our TIMP and DIMP plans are prudent investments that have resulted in the replacement of aging pipeline. By completing these replacements, the Company has minimized public safety risks associated with aging assets that deliver gas service.

The legislature authorized the prompt recovery of integrity management costs in 2013, and the Commission validated the importance of that prompt recovery in their previous GUIC Rider orders. In this filing, the Company provides updates on the status of our TIMP and DIMP activities by describing the safety and reliability the Company brings to our gas system with the planned work. We further highlight our plan to recover the remaining 2017 investment that has not yet been recovered and outline our proposal to recover the 2018 investments. Xcel Energy respectfully requests that the Commission, consistent with its previous GUIC Order, grant recovery of its gas utility infrastructure costs through the GUIC Rider and approve the updated proposed 2017 GUIC Rider factors and proposed 2018 GUIC Rider factors.

Dated: November 1, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2017, REVENUE REQUIREMENTS FOR 2018, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-17-____

PETITION, COMPLIANCE FILING, AND ANNUAL REPORT

SUMMARY OF FILING

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits this Petition, Compliance Filing, and Annual Report to the Minnesota Public Utilities Commission. In order to promote a safe and reliable gas system, Xcel Energy has undertaken approved threat evaluation, assessment, and risk mitigation activities, in compliance with federal regulations. We request approval to recover gas utility infrastructure costs (GUIC) through the GUIC Rider. Xcel Energy requests cost recovery of its projected 2018 Transmission and Distribution Integrity Management Programs costs (including deferred costs) pursuant to Minn. Stat. § 216B.1635, which permits a utility to petition the Commission for recovery. The Company also seeks approval of its updated 2017 GUIC adjustment factors, 2018 GUIC adjustment factors, and its proposed capital structure and ROE for 2018.

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 True-up Report for 2017, Revenue Requirements for 2018, and Revised Adjustment Factors* Report and Petition Submitted November 1, 2017 Docket No. G002/M-17-____
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.	Introduction Section III.A. Sections IV.B.,E.,F.,G.,H.,I.,J. Attachments C,C1,C2,D,D1, D2(a),D2(b),E,F,G,I,J
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;	Introduction Section III.A. Sections IV.B.,E.,F. ,G.,H.,I.,J. Attachments C,C1,C2,D,D1, D2(a),D(2b),E,F,G,I,J
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	Introduction Section III.A. Sections IV.B.,C.1.,I.2.,3. Attachments C,C1,C2,D,D1, D2(a),D2(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.H. Attachment K
(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;	Introduction Sections IV.A.,B.,C.,D.,E.,F.,G.,H. Conclusion Attachments C,C1,D,D1,E,I,J
(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. Sections V.A.,B.,C. Attachments E,F,G,J,K,N,O,Q,S
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	Introduction Section III.A. Sections IV.B.,D.,E.,F.,G.,H.,I., J. Attachments C,C1,D,D1,E, F,G,I,J,L,N,O
(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.J. 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.J. Attachment L

Compliance Matrix

Petition Requirements	Reference
(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.	Introduction Section III.A.. Sections IV.A.,D.,J. Sections VI.A.,B. 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. Section VI. Attachment S

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**	
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.	Current Petition Section IV.C. Attachment I
B. Details of the final resolution of the Notice of Probable Violation and the status of any proposed penalties. C. Discussion and explanation of any legal actions or settlements regarding the natural gas explosion that led to the Notice of Probable Violation. D. Discussion and analysis regarding any potential third-party recovery for the costs of the plan.	*See In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider* Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.H.,I. Petition Submitted in Docket No. G002/M-15-808 Section IV.I. Petition Submitted in Docket No. G002/M-16-891 Section IV.I. Current Petition Coverage omitted as no update from previous Petitions

Compliance Matrix

Petition Requirements	Reference
E. Discussion, analysis, and documentation demonstrating that plan costs were prudent.	Current Petition Introduction Sections III.A.3., IV.C., I.3.c. Attachment I
F. Analysis of what it would have cost to conduct the plan over a ten-year period beginning in 2003.	Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.J. Current Petition Section IV.I.3.c. Attachment I
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**	
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.	Current Petition Introduction Sections III.A.1.,B.,F.,G. Attachment J

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for approval of a Gas Utility Infrastructure Cost Rider (GUIC) True-up Report for 2015, Forecasted 2016 GUIC Revenue Requirement, and Revised GUIC Adjustment Factors **Minnesota Public Utilities Commission** ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES **August 18, 2016 Docket G002/M-15-808**	
1. Xcel shall provide an updated 2015 GUIC True-up Report for informational purposes.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Current Petition Attachments N,O
2. Xcel shall develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and provide stakeholders the opportunity for meaningful involvement. Each metric should include reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.	Petition Submitted in Docket No. G002/M-16-891 Section VII. Attachments B2,C2(a),C2(b) Supplement to Petition in Docket No. G002/M-16-891 Submitted January 17, 2017 Current Petition Introduction Section VII. Attachment T

Compliance Matrix

Petition Requirements	Reference
4. The Federal Code Mitigation (FCM) project is an eligible GUIC project. Xcel may recover the costs of this project through the GUIC Rider to the extent its costs are not included in base rates.	Petition Submitted in Docket No. G002/M-16-891 Section IV.K. Attachments C,C1,C2(a),C2(b) Current Petition Sections III.A., IV.I.e. Attachment D
5. The Commission approves a GUIC tracker year ending March 31. Xcel is authorized to recover the Commission-approved 2016 revenue requirements over the 15-month period, January 1, 2016 through March 31, 2017. Xcel shall recalculate the GUIC rate adjustment factors to recover the remaining Commission-approved 2016 revenue requirements over the remaining months through March 31, 2017.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Docket No. G002/M-16-891 MPUC Decision Pending
6. Xcel shall adjust the projected GUIC true-up over recovery to actual amounts, both the 2015 recovery and revenue requirement amounts and the 2016 recovery activity balances, proximate to the implementation date of the 2016 factors.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Docket No. G002/M-16-891 MPUC Decision Pending Current Petition Attachments N,O
7. Within ten days of the date of this order, Xcel shall make a compliance filing to provide the final rate adjustment factors that reflect the Commission's decisions in this matter, including any underlying schedules and all related tariff changes.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Docket No. G002/M-16-891 MPUC Decision Pending

Compliance Matrix

Petition Requirements	Reference
8. Xcel shall modify the proposed customer notice to read: This month's Resource Adjustment includes ~~the addition of the~~ an updated 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.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Current Petition Section V.D.
9. Xcel shall use the following capital structure: 52.50 percent equity, 45.61 percent long-term debt, and 1.89 percent short-term debt.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Docket No. G002/M-16-891 MPUC Decision Pending
10. The Commission makes the following determinations concerning the rate of return and its components: a. the cost of long-term debt approved in the last GUIC case, 4.94%, is appropriate. b. the cost of short-term debt should be updated to reflect the 1.12% cost in Xcel's electric rate case in Docket No. E-002/GR-13-868. c. a cost of equity of 9.64% as recommended by the Department is appropriate. d. an overall rate of return of 7.34% is appropriate.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Docket No. G002/M-16-891 MPUC Decision Pending
11. As part of Xcel's next GUIC petition, the Company shall file a cost/revenue study based on 2015 actuals reconciled back to Xcel's 2015 Jurisdictional Annual Report.	Petition Submitted in Docket No. G002/M-16-891 Section IV.I. Attachment J Current Petition Section IV.J Attachment M

Compliance Matrix

Petition Requirements	Reference
12. In future GUIC filings, Xcel shall provide specific information about each individual project in the GUIC Rider that sufficiently, (1) describes what the project is, (2) explains why the project is necessary, (3) discusses what benefits ratepayers will receive from the project, and (4) identifies the agency, regulation, or order that requires the project.	Current Petition Introduction Sections III.A.2.,3. Sections IV.B.,C.,I. Attachments C,C1,C2,D,D1 D2(a),D2(b)

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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 (DOT) 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 TIMP Manual specifies the procedures for gathering, integrating, and analyzing data; assessing pipelines; and implementing remedial actions to improve pipeline safety.

At its core, the TIMP can be summarized in three steps: understand your assets, risk evaluation and, risk mitigation. Xcel Energy's processes for these three steps are outlined below.

1. *Understand Your Assets*

For the TIMP to be successful, the Company needs to gather, evaluate, and integrate data in order to better understand our gas transmission system. The TIMP process has allowed us to update asset records and improve overall asset knowledge, as well as information on the surrounding area. Fundamentally, aspects about the physical and operating characteristics of a system need to be known. These aspects include date of installation and length, size, material, and operating pressure of the pipeline. In addition, information about the area the gas transmission assets are installed is also important, including class location, geotechnical data and structures in the area. Finally information related to the ongoing integrity and operating characteristics of the gas pipeline system is a part of understanding our gas transmission assets.

Managing the risk of gas transmission assets is an ongoing process and evolves over time. The Company's baseline assessment plan prioritizes pipeline segments based on many factors, including proximity to population, and the likelihood and severity of potential failure. The plan is updated regularly, incorporating new information on the health and condition of the assets and other system information.

2. *Risk Evaluation*

The Company evaluates the threats to a given pipeline that may pose a safety or reliability risk, with pipeline segments in populated areas, known as high consequence areas (HCAs), receiving the highest priority. The Company initially used pipeline asset information from existing records, operating data, and input from subject matter experts (SMEs) to identify potential threats. Industry guidance materials, such as those published by the American Society of Mechanical Engineers, have also been incorporated into the threat identification process.

The Company evaluates our gas transmission pipelines for the following threats:

- External corrosion,
- Internal corrosion,
- Stress corrosion cracking,
- Manufacturing and related defects,
- Construction defects,
- Equipment failures,
- Third-party damage,
- Incorrect operations, and
- 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. The Company also takes the condition and physical characteristics of its gas assets into consideration, as well as industry guidance and directives. All of this information is incorporated into risk evaluation and subsequent risk mitigation strategies. This risk evaluation process provides information to facilitate decisions about the prioritization of health and condition assessments, the frequency of assessment, which assessment methodology is most appropriate, and in certain cases information to substantiate the need for replacement of an asset.

3. Risk Mitigation

We integrate the results from the risk evaluation process into determining planned risk mitigation activities. Typical risk mitigation measures include excavation of the pipeline and the repair or complete removal of the anomaly, and/or reducing the operating pressure of the system.

The Pipeline Safety Action Plan[1] issued by the DOT in 2011 called for operators to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of natural gas facilities. For example, in direct support of that action plan the Company's evaluation of the Montreal South and Island South pipelines. The health assessment resulted in the decision to replace certain sections of those gas transmission lines to protect the safety of the public. These pipelines have legacy manufacturing and construction practices that increase the likelihood of a leak. In addition, replacement mitigates potential third-party damage resulting from a proposed railroad trestle reconstruction project occurring within 18 inches of the lines.

Other risk mitigation activities focus on reducing 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 valves (ASVs) or remote-controlled valves (RCVs).

In March of 2016, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking (NPRM) under Docket No. PHMSA-2011-0023. This NPRM proposes to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposes changes to the integrity management (IM) requirements as well as changes to non-IM requirements. The Company anticipates the final PHMSA Gas Transmission rule will not be effective until late 2018 or 2019.

The potential specific IM requirement changes include:

- Expansion of IM beyond HCAs,
- Maximum Allowable Operating Pressure (MAOP) validation,
- Repair criteria for assessments in HCAs and Moderate Consequence Areas (MCAs),
- Corrosion control,
- Risk models,
- New construction and repairs,
- Spike testing,
- Inspection of pipelines following weather events,
- Gas gathering lines.

[1] http://opsweb.phmsa.dot.gov/Pipelineforum/dot-action/index.html.

In summary, risk mitigation can include initiating preventative measures, more frequent inspections and health and condition assessments, utilizing specialized technology to address a specific threat, 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 threat or multiple threats.

The 2016-2018 TIMP project detail is presented in Attachment C1(a-e) and the risk assessment scores for 2018 TIMP projects are presented in Attachment C2.

II. 2018 TIMP PROJECTS

In this filing, the Company requests recovery of the following O&M and capital expenditures associated with three 2018 TIMP programs:

2018 Estimated TIMP Project Costs
($ Millions)

Program	2018 Capital	2018 O&M
Transmission Pipeline Assessments	$0.29	$1.51
ASV/RCV	$0.97	$0.00
Programmatic Replacement / MAOP Remediation	$7.77	$0.00
TOTAL 2018 TIMP Capital Expenditures and O&M	**$9.03***	**$1.51**
TOTAL 2018 MN TIMP Revenue Requirements	**$10.51****	**$1.51*****

** 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.*

**** $480,000 of TIMP O&M are recovered in base rates.*

These projects were included in the Company's 2015, 2016, and 2017 Gas Utility Infrastructure Cost (GUIC) Rider petitions.[2] Projects planned for completion in 2018 and outlined below will begin during the 2nd and 3rd quarters of 2018 and will be placed in service during the 3rd and 4th quarters of 2018.

1) Transmission Pipeline Assessments
Parent Project: 11649521 (Capital); 11984286 (O&M)

<u>2018 Estimated Project Costs</u>:
$0.29 million Capital expenditure
$1.51 million O&M expenditure

<u>Project Summary and Scope</u>
This project is an ongoing program, beginning in 2002, of health and condition assessments on gas transmission lines in the NSPM gas system. Federal regulations require assessment of gas transmission pipelines using In Line Inspection (ILI), pressure testing or direct assessment. The requirements are further defined in the Company's TIMP manual. Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of other operating information.

The Company met the HCA Baseline Assessment requirements[3], and is now focusing on the re-assessment of pipelines in HCAs as well as assessing remaining transmission pipe beyond HCAs. The program includes requirements to ensure the safe operation of all gas transmission pipelines under American Society of Mechanical Engineers Standard B31.8S.[4]

The Company has selected ILI as the primary approved assessment methodology due to its superior ability to provide detailed information regarding the current pipeline condition over the entire length of the line. However, based on the threats to which a pipeline is susceptible and the feasibility of assessment methodologies, the Company may choose to utilize direct assessment and pressure testing as complementary assessment methodologies.

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[2] Docket Nos. G002/M-14-336, G002/M-15-808, and G002/M-16-891.
[3] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012.
[4] This standard is incorporated by reference into 49 C.F.R. § 192, Subpart O.

The Company's preferred ILI method requires unique inspection equipment and specialized knowledge. Outside vendors maintain fleets of such tools, which may cost in upwards of $1 million, and have the expertise needed to conduct an ILI. Additionally, ILI tools are constantly being re-engineered to gather more information about the health and condition of pipelines which makes owning such tools uneconomic at this time. Working with outside contractors to complete this work, provides access to specialized expertise and equipment that is outside of the Company's normal scope of business and ensure that assessments are completed safely and efficiently.

Federal regulation requires the Company to apply knowledge gained from all assessments to all similar pipelines within the system both inside and outside HCAs. While the initial investment incurred to make the lines accessible to ILI tools can be significant, the benefit of this investment is the ability to assess for multiple threats, gather a more comprehensive profile of the integrity of a pipeline, and complete assessments over longer distances including pipe inside and outside HCAs.

There are two distinct elements in the selection and prioritization of work to be performed in this program: the assessment of pipelines and addressing issues found during the assessment. Assessment work in prior years was primarily driven by the date and type of the previous assessment. Findings from initial assessments can and do impact the timing of subsequent assessments, with a maximum interval of at least once every seven years. The objective is to monitor anomalies found on the pipelines, assess if they are stable or deteriorating, and mitigate the anomaly before it becomes a threat to public safety.

The Company evaluates anomalous conditions found during the assessment including the location of the anomaly, severity, nature (threat cause), and type of feature (e.g., dent or metal loss). The potential for other locations along the pipeline or in the system where similar conditions may exist is also considered and evaluated. Based on this evaluation, the Company categorizes the anomaly into an immediate condition, one–year condition, or monitored condition. These conditions are used to prioritize when and how an anomaly will be excavated and remediated. Typical remediation may include excavation and repair or removal of the anomaly, and/or reducing the operating pressure of the system.

The cost of TIMP assessments is highly variable and depends on the assessment method, pipeline age, configuration, as well as seasonal and operational constraints.

The scope of work in 2018 includes four projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Island Line (South of River)	First time ILI and O&M Repairs	1.9	Capital/O&M
Rosemount Line	Second time ILI and Clearing Runs	7.9	O&M
Blue Lake Line	Second time ILI and Clearing Runs	10.9	O&M
Montreal Line North - Transmission	Hydrostatic Pressure Test	0.3	O&M

- **Island Line (South of River):** This project is an ILI of a 20-inch pipeline, installed in 1952, that connects Mendota Station to the south side of the Island Line Mississippi River crossing. This is the first assessment of this line and will cover 1.9 miles of 20-inch pipeline using smart tool technology. A "proving pig" was run in 2017 and used to identify points at which a smart pig would not be able to pass. No issues were identified that might compromise a full ILI assessment.

- **Rosemount Line:** This project is an ILI of the 7.9-mile line located in Eagan and Inver Grove Heights, MN. This is the second time for an ILI on the Rosemount Line, with the first run being completed in 2011. Running a second ILI allows the Company to compare results and determine the effectiveness of our pipeline protection program, identify any new anomalies or the growth of any existing anomalies. This project was initially scheduled for 2017, but due to other parts of the line being out of service due to construction, there were concerns about taking this part of the system offline and removing an additional redundancy built in to ensure system integrity. In order to avoid jeopardizing the integrity of the gas system, the ILI was postponed to 2018. The Rosemount Line is a critical line for gas supply to the St Paul metro area, which limits the timeframe an ILI can be performed.

- **Blue Lake Line:** This project is an ILI of the 10.9-mile line located in Shakopee, MN. This is the second time that the Blue Lake Line will have an

ILI conducted, with the first run completed in 2011. Running a second ILI allows the Company to compare the results with the first ILI in 2011 to determine the effectiveness of our pipeline protection program and identify any new anomalies or the growth of any existing anomalies.

- **Montreal Line North – Transmission:** This project is a hydrostatic pressure test of a 0.3-mile section of pipeline in St. Paul starting at the intersection of Elway and Shepard Road and continuing along Shepard Road to the east side of Interstate 35E. The pipeline is a combination of 20-inch and 24-inch pipe that was originally installed in 1962 during construction of Interstate 35E. The entire line had an external corrosion direct assessment conducted in 2011. Most of the line assessed in 2011 was replaced during the East Metro Replacement Project. The final 0.3 miles scheduled for pressure testing in 2018 is the remaining portion of the vintage line. Performing a hydrostatic pressure test allows the Company to complete required baseline testing for the Montreal Line. The results of this pressure test will drive potential future work on the Montreal Line.

Costs for assessment by direct assessment are O&M per the Company's capitalization policy. Due to the generally non-invasive nature of direct assessment activities, the cost is generally related to the length of pipe evaluated with some variability due to the route, depth, and environment of the pipeline (open field, natural forest, in the road ditch, under a major highway, etc.).

The costs to modify pipelines for an initial suite of ILI runs are capital per the Company's capitalization policy. This includes the vendor costs associated with the use of the specialized ILI tools and the advanced analysis required to interpret the results. Once an initial ILI assessment is completed on a specific section of pipeline, all costs for subsequent assessment by ILI will be O&M.

Like ILI, the costs to modify a pipeline to permit a pressure test are capital per the capitalization policy if the section of pipeline has not been assessed previously by pressure testing. The cost of the pressure test including test equipment, test medium, and disposal of medium will be O&M in all cases.

The number of digs required to validate an assessment and repair critical anomalies is estimated by evaluating the history of each pipeline, including installation date, and its environment. The length of the assessment will also play a role in increasing or decreasing the number of anticipated digs. The actual number of selected digs is prescriptive and is defined by federal code requirements[5] and pipeline condition.

Repairs to existing pipelines that do not involve cut-out of the existing pipe are defined by the capitalization policy as O&M. If a cut-out is required, capitalization policy defines the O&M or capital designation based upon pipe diameter and the length of the required cut-out.

2) ASVs and RCVs
Parent Project: 11503515 (Capital)

2018 Estimated Project Costs:
$0.97 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
This project installs mainline isolation valves or adds actuators to existing valves to quickly minimize the impact of an unplanned gas release from gas transmission pipelines. Long lead times on valve equipment and availability of construction resources could affect the exact timing of the proposed valve installations. However, any planned installation work not completed as scheduled in a current year would be completed into a subsequent year, which could ultimately extend the full duration of this multiyear project. Changes to PHMSA rules may also have an impact on the overall scope of the program.

Section 4 of the Pipeline Safety Act calls for the Secretary of the DOT to require by regulation the use of ASV or RCV, or equivalent technology, where it is economically, technically, and operationally feasible. On August 25, 2011, PHMSA issued an advanced notice of proposed rulemaking addressing ASVs and RCVs and seeking comments on several broad areas for potentially expanding the TIMP rules. PHMSA has completed its study[6] on ASVs and RCVs, but has not yet issued a ruling.

[5] Code 49 CFR Parts 192.927, 192.929, and 192.933.
[6] https://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Final%20Valve_Study.pdf.

Code 49 CFR Part 192.935(c) requires each company to perform a risk analysis to determine if adding an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release. The following criteria are evaluated:

- Swiftness of leak detection and pipe shutdown capabilities;
- Type of gas being transported;
- Operating pressure;
- Rate of potential release;
- Pipeline profile;
- Potential for ignition; and
- Location of nearest response personnel.

SMEs from the engineering department performed a risk analysis based on risk factors to identify and rank the sites. Further site-specific items were considered, including whether a pipeline was scheduled for replacement in the near future. As a result, it may be appropriate to install an ASV or RCV at a location with a lower risk prior to one at a higher-risk location, if the higher-risk location is on a pipeline scheduled for replacement.

The determination of the applicable type of ACV or RCV to install in each situation is based on an overall risk analysis, evaluation of system operational needs, and engineering review. The Company generally anticipates installing two to four valves each year through 2022. The number of valves, valve sizes, and activity occurring at each of the locations listed below was determined because of that survey. Per the Company's capitalization policy, the cost of these installations is considered capital. O&M expenses are not expected or estimated in future years.

The 2018 scope of work includes the following valves:

Valve Location	Size	Description
Rich Valley Station Inlet	16"	Install new valve and actuator on the Rosemount line at the Rich Valley Station Inlet
Hwy 55 and Babcock	16"	Install new actuator on the Rosemount line at Hwy 55 and Babcock Rd
South St. Paul Station Inlet	16"	Install new actuator on the Rosemount line at the South St. Paul Station Inlet

The locations proposed for installation in 2018 are based on the original scope of work that was planned to be completed in 2017. This resulted from the Company not completing the 2016 scope of work as planned. Four ASV and RCV valves originally planned for completion in 2016 were completed in 2017.[7] As a result, the original 2017 scope was moved into 2018.

3) Programmatic Replacement and MAOP Remediation
Parent Project: 11651650, 11810375 & 34003261 (Capital)

2018 Estimated Project Costs:
$7.77 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
MAOP Remediation Advisory Bulletin (ADB-12-06, Docket No. PMHSA-2012-0068) issued by PHMSA and contained in the Federal Register specifically addressed Pipeline Safety in terms of verification of records. The initial language in the advisory required operators to "take action as appropriate to assure that all MAOP and MOP [Maximum Operating Pressure] are supported by records that are traceable, verifiable and complete."

The codes and rules around material testing, welding standards, and record keeping have evolved over time. Consequently, the Company is left with a significant history of facilities in service with varying data gaps. Some data gaps are more critical than others. For instance, the construction and maintenance data of gas transmission pipelines and operating pressures are critical to support the safe operation of these assets. The MAOP initiative focuses on obtaining adequate proof of MAOP records and ensuring that they become part of the Company's official system of record. Remediation of data gaps is also part of the scope.

Pipelines are prioritized for renewal and pressure tested based on a variety of factors and competing demands, including:

- Location within or outside of HCAs,
- Type of documentation missing,
- Criticality to system, and
- Vintage of pipeline.

[7] All four valve sets were installed in 2016. However, the actuating equipment was not installed until 2017.

All the pipelines have been prioritized using the criteria described above to develop a schedule and budget to complete the work in an appropriate amount of time.

The MAOP review portion of the work will be completed by direct hiring contract engineering and research analysts. The Company's internal engineering department will handle the design of the remediation projects with project management's oversight. Material procurement will be completed using our current agreements with our vendors and using our company sourcing group to ensure we receive the best prices and schedule.

The cost estimates for this program are based on our experience with similar assets in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures.

Funding for 2018 will be used for replacement work on four of the Company's existing transmission lines:

Line/Loop	Type	Project Length (mi)	Project Type
County Road B (NSP to Rice)	Replacement	6.5	Capital
East County Line (30"Maplewoood Propane to North Saint Paul)	Replacement	1.4	Capital
East County Line Renewal – S. St. Paul Station to RR Tracks	Replacement	0.6	Capital
Crossover Line - Repl 12in Upper 55 to S. St Paul Reg Station	Replacement	0.8	Capital

- **County Road B (NSP to Rice):** This project is along County Road B in North Saint Paul and Maplewood, MN and entails replacing 6.5 miles of 30-inch, 24-inch and 20-inch pipe with a standardized 20-inch pipe. Design and construction are anticipated to be completed over a three-year span from 2018 through 2020.

This pipeline was originally installed in the 1950s with service lines directly connected to it, multi diameter piping and mechanical couplings. Since the pipeline was installed, area growth has placed the pipeline under roadway for much of its length, making it difficult to inspect and repair. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. Multi diameters, short radius elbows, valve configurations, and old service taps prevent the line from being inspected with ILI tools currently.

- **East County Line (30-inch Maplewood Propane to North Saint Paul):** This project is primarily along Century Avenue from our Maplewood Propane facility to North Saint Paul Station in the communities of Maplewood, Oakdale and North Saint Paul, MN. It replaces 1.4 miles of 30-inch pipe with 20-inch pipe. Design and construction are to be completed in 2018 and 2019.

  This pipeline was originally installed in 1957. Growth in the area has placed much of the piping under roadway making it difficult to inspect and repair. Replacement with standardized piping will make the line accessible to ILI tools.

- **East County line (30-inch South Saint Paul Reg Station to Railroad Tracks):** This project began in 2017, with the Company performing design, engineering, and easement acquisition requirements. The 2018 scope of work will replace 0.6 miles of 30-inch pipe with 24-inch pipe from the South Saint Paul regulator station near Concorde Street in South Saint Paul. Construction is expected to be completed in 2018 and will be coordinated with the Crossover Line renewal.

  The pipeline was originally installed in 1957 and is not capable of being inspected using ILI. Replacement with standardized 24-inch pipe will make the line accessible to ILI tools on not only the replaced pipe but also connected piping to the Mississippi River Crossing.

- **Crossover Line – (Replace 12-inch Upper 55th to South Saint Paul Reg Station):**
  This project replaces 0.8 miles of 12-inch pipe from Carmen and 65th to Upper 55th Street and 9th Ave South in Inver Grove Heights, MN. Project design will be complete in 2017 and construction is planned for 2018.

  This pipeline was originally installed in 1946 by Northern Natural Gas Company. The existing piping has significant encroachment and limited access due to easements running through various properties. Renewal of the pipeline being relocated to within the street right of way will make the line more accessible and reduce future risks to the public.

III. 2017 TIMP PROJECTS

In 2017, there are four projects under the TIMP:

1) East Metro Pipeline Replacement,
2) Transmission Pipeline Assessments,
3) ASVs and RCVs, and
4) Programmatic Replacements and MAOP Remediation.

Following are the TIMP project costs included in the Company's 2017 GUIC Rider Petition, Docket No. G002/M-16-891, as compared to updated 2017 cost estimates[8] based on emerging project developments and actual construction activity:

[8] Based on actual costs as of 8/31/2017 and estimates from 9/1/2017 through 12/31/2017.

2017 Estimated TIMP Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Estimates	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Estimates	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$0.00	$0.60	$0.60	100.00%	$0.00	$0.00	$0.00	n/a
Transmission Pipeline Assessments	$1.61	$0.90	($0.71)	(44.10%)	$1.30	$0.50	($0.80)	(61.54%)
ASV/RCV	$0.90	$0.17	($0.73)	(81.11%)	$0.00	$0.00	$0.00	n/a
Programmatic Replacements/ MAOP Remediation	$2.91	$7.63	$4.72	162.20%	$0.00	$0.00	$0.00	n/a
TOTAL 2017 TIMP Capital Expenditures and O&M	**$5.42***	**$9.31***	**$3.89**	**71.59%**	**$1.30**	**$0.50**	**($0.80)**	**(61.54%)**
TOTAL 2017 MN TIMP Revenue Requirements	**$7.86****	**$8.48****	**$0.62**	**7.89%**	**$1.30*****	**$0.50*****	**($0.80)**	**(61.54%)**

** 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.*

**** $480,000 of TIMP O&M are recovered in base rates.*

TIMP projects planned for completion in 2017, and outlined below generally began during the 2nd and 3rd quarters of 2017 and will begin service during the 3rd and 4th quarters of 2017.

1) East Metro Replacement Project
Parent Projects: 11615874, 11676981, 11706370, 11819647, 12013233 (Capital); 11984262 (O&M)

Project Summary and Scope
The 2017 scope for East Metro Replacement Project included constructing the Highland regulator station and completing certain restoration activities originally planned for completion in 2016. The East Metro Replacement Project will be completed in 2017.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$0.00	$0.60	$0.00	$0.60	$0.60	100.00%
O&M Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The main driver for the increase in capital expenditures was a delay in the construction of the Highland regulator station from 2016.

O&M: N/A.

2) Transmission Pipeline Assessments
Parent Project: 11649521, 11649797, and 34000342 (Capital); 11984286 (O&M)

Project Summary and Scope
The scope of work in 2017 includes three projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Island Line (South of River)	ILI	1.9	Capital
Inver Hills Lateral	ILI	2.0	Capital / O&M
Lake Elmo Line	ILI	5.8	Capital / O&M

** Island Line S and Inver Hills Lateral were made ILI assessable in 2016. ILI runs will be completed in 2017. The O&M activities planned for the projects above are for the associated validation digs, which are not capitalized.*

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$1.61	$0.86	$0.04	$0.90	($0.71)	(43.10%)
O&M Expenditure	$1.30	$0.02	$0.48	$0.50	($0.80)	(61.54%)

Variance Explanation

Capital: The main driver for the decrease in capital expenditures is delaying the Wescott 8-inch ILI and the Montreal Line North assessment into 2018. The delay of the Wescott 8-inch ILI will allow both the Wescott 8-inch and 12-inch lines, which run parallel to each other, to be assessed at the same time, currently estimated for 2021. Running the ILIs in the same timeframe is more efficient and allows the Company to mobilize one crew and support equipment. Additional cost savings for contemporaneous assessment include a single excavation at either end of the lines as well as validation digs completed in the same excavation window.

In addition, the 2017 scope of the Island Line South ILI project was reduced to running an ILI "proving" tool rather than both the "proving" and "smart" tools. Records review on the pipeline has identified the potential for restrictive fittings in difficult access areas. Current schedules do not allow sufficient time to mitigate expected findings from the proving tool runs prior to running a smart tool in 2018.

O&M: The main driver for the decrease in O&M expenditures is a result of the Rosemount line ILI, initially scheduled for 2017, being delayed until 2018. This assessment is a second time ILI run with an assessment deadline of 2018.

3) ASVs and RCVs
Parent Project: 11503515 (Capital)

Project Summary and Scope
The determination of the applicable type of ASV or RCV to install in each situation is based on an overall risk analysis, evaluation of system operational needs, and engineering review. The Company generally anticipates installing two to four valves each year through 2022. The locations proposed for installation in 2017 were originally based on discovery work completed in January 2016.

However, based on emerging resource constraints and a reassessment of relative risk among GUIC-related projects, the original 2017 scope of work has been delayed until 2018. As a result, the 2017 scope of work has been modified to only include work installing the electronic actuating controls and subsequent commissioning to confirm operations on valves previously installed in 2016. These valves include:

Subproject	Size	Description
Rosemount Line Take-off	16"	Add a remote-controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off
Rosemount TBS (St. Paul 1P)	16"	Add a remote-controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS
Lake Elmo 1B TBS	12"	Add a valve and remote-controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS
Maplewood plant	12"	Add a valve and remote-controlled actuator on the Lake Elmo Line at the Maplewood Plant

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$0.90	$0.12	$0.05	$0.17	($0.73)	(81.11%)
O&M Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The 2017 scope of this program has been delayed into 2018 because of resource constraints and a reassessment of risk priorities among GUIC projects. Additional scope and risk contingencies associated with the Montreal South and Island South pipeline replacement projects required the resources originally scheduled to complete the ASV and RCV work.

O&M: N/A.

4) Programmatic Replacement and MAOP Remediation
Parent Project: 11651650 & 11810375(Capital)

Project Summary and Scope

In 2017, the Company plans on completing construction activities associated with the replacement of the Montreal Line South and the Island Line South. These lines provide the bulk of gas service to the City of St. Paul and north suburbs. A loss of these facilities would make it impossible to meet winter heating requirements. These pipelines have known leak concerns that have required mitigation over the years. A proposed railroad trestle reconstruction is expected to create additional risk to the pipeline. The Company will also be completing design, engineering, and permitting activities associated with a segment of the East County Line.

A summary of planned 2017 activities includes:

Line/Loop	Type	Project Length (mi)	Project Type
Montreal Line South	Replacement	0.2	Capital
Island Line South	Replacement	1.5	Capital
East County Line – South Saint Paul Station to RR Tracks	Replacement	0.5	Capital

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$2.91	$0.56	$7.07	$7.63	$4.72	162.20%
O&M Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	n/a

<u>Variance Explanation</u>

Capital: The main driver for the increase in capital expenditures results from a significant change of scope and additional risk contingencies needed for the Montreal and Island Line Replacement projects. The original scope and cost estimate for the Montreal Line South replacement was 0.24 miles at a unit cost of $920 per foot with a total cost of $1.2 million. The Montreal Line South scope has increased to 0.4 miles at a unit cost of $1,230 per foot, or a 33% increase, for a total cost of $2.6 million. Cost increases are a result of the new alignment, difficult construction requirements, and significant hard surface restoration.

The original high-level estimate has been updated to include the complexity of working in this location. Environmental concerns with constructing in the easement altered the alignment of the pipeline and required the closing and eventual full restoration of the entire segment of Lillydale Road by the Yacht Club that was not included in original plans.

Additionally, the original scope and cost estimate for the Island Line South replacement was 1.5 miles at a unit cost of $920 per foot with a total cost of $7.3 million (of which $1.1 million was anticipated in 2017 and the balance in 2018). The Island Line South scope remains at 1.5 miles but has an updated unit cost of $1,160 per foot for a total cost of $9.2 million (of which $3.0 million is anticipated in 2017 and the remaining balance in 2018). This is a 26% increase as compared to the original unit cost projection of $920 per foot, which was the initial high-level budgeting estimate prior to final route selection and site-specific engineering. This increase is similarly caused by the new alignment of the pipeline and difficult construction requirements.

It is critical to complete both projects in 2017 to reduce risks of failure that may occur with Union Pacific Railroad trestle work using pile driving equipment within 18 inches of the Company's pipelines. The alignment and location of these pipelines will change because of completing this work and therefore will significantly reduce the risk of 3rd party damage by the railroad reconstruction work.

Additional issues contributing to higher cost estimates overall are for additional risk contingencies, including permitting, environmental, E&S considerations, and impact of construction on the Yacht Club operations.

Finally, the scope has been changed to replace both the Montreal Line South and the Island Line South from Mendota Station to the river bottom. This is the least disruptive environmentally and for the roadway. It also represents significant savings because of a joint trench installation and resolves concerns with operations and redundancy during trestle and road renewal work.

O&M: None.

IV. 2016 TIMP PROJECTS

In 2016, there were three projects under TIMP:

1) East Metro Pipeline Replacement,
2) Transmission Pipeline Assessments, and
3) ASVs and RCVs.

Following are the TIMP project costs included in the Company's 2017 GUIC Rider Petition, Docket No. G002/M-16-891, as compared to actual 2016 costs.

2016 Actual TIMP Project Costs
($ Millions)

	2016 Capital, As Filed	2016 Capital Actuals	Capital Variance	Capital Variance %	2016 O&M, As Filed	2016 O&M Actuals	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$15.70	$14.73	($0.97)	(6.18%)	$0.00	$0.00	$0.00	n/a
Transmission Pipeline Assessments	$5.38	$6.79	$1.41	26.21%	$0.20	$0.04	($0.16)	(80.00%)
ASV/RCV	$0.45	$0.19	($0.26)	(57.78%)	$0.00	$0.00	$0.00	n/a
TOTAL 2016 TIMP Capital Expenditures and O&M	**$21.53***	**$21.71**	**$0.18**	**0.84%**	**$0.20**	**$0.04**	**($0.16)**	**(80.00%)**
TOTAL 2016 MN TIMP Revenue Requirements	**$5.93****	**$6.52****	**$0.59**	**9.95%**	**$0.20*****	**$0.04*****	**($0.16)**	**(80.00%)**

** 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.*
**** $480,000 of TIMP O&M are recovered in base rates.*

TIMP projects completed in 2016 and outlined below generally began during the 2nd and 3rd quarters of 2016 and were placed into service during the 3rd and 4th quarters of 2016.

1) East Metro Replacement Project
Parent Projects: 11615874, 11676981, 11706370, 11819647, 12013233 (Capital); 11984262 (O&M)

Project Summary and Scope
The scope of work in 2016 included replacing approximately 1.9 miles of gas transmission line at Montreal Avenue and Edgecumbe Road to Elway Street and Shepard Road, as well as at Pleasant Avenue and St. Albans Street Randolph Avenue and James Avenue.

In 2016, construction activities occurred in areas with significant rock impediments. The removed pipe was at a much shallower depth than current standards in various locations, requiring rock excavation to obtain a safer depth of cover. Additionally, construction activities took place in urban environments which required significant efforts to coordinate traffic control and perform hard surface restoration work. Key restoration activities and the construction of the Highlands regulator station, originally planned for completion in 2016 as part of the East Metro project, were delayed into 2017 to reduce the risk of cost overruns and construction integrity associated with potentially cold months in late Fall.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actuals	Variance	Variance %
Capital Expenditure	$15.70	$14.73	($0.97)	(6.18%)
O&M Expenditure	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The main driver for the reduction in capital expenditures is delays with key restoration activities and the construction of the

Highland Regulator Building. Winter construction on a masonry building presents additional costs, jeopardizes quality, and introduces unnecessary safety and gas service interruption risks. The nature of completing a project of this size during the fall requires follow-up restoration activities in the spring of the following year. Additionally, in-servicing of the East Metro pipeline took priority over completing the Highland regulator building.

O&M: N/A.

2) Transmission Pipeline Assessments
Parent Project: 11649521, 11649521, & 34000342 (Capital); 11984286 (O&M)

<u>Project Summary and Scope</u>
In 2016, the Company modified three lines to prepare for an ILI assessment in an upcoming year. The Company also performed replacement work on three other lines. The scope of work in 2016 included the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Rosemount Line – Inverhills Lateral	ILI	2.0	Capital
Lake Elmo Line	ILI	5.8	Capital
Island Line (South of River)	ILI & Replacement	1.9	Capital
High Bridge Lateral Replacement	Replacement	0.8	Capital
East County Line Casing Removal	Renewal	n/a	Capital/O&M

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actuals	Variance	Variance %
Capital Expenditure	$5.38	$6.79	$1.41	26.21%
O&M Expenditure	$0.20	$0.04	($0.16)	(80.00%)

Variance Explanation

Capital: A primary driver for the increase in capital expenditures is contractor crews enduring higher than normal levels of rain, which caused construction delays. The weather conditions combined with the project's close proximity to the Mississippi River[9] meant that a significant amount of pumping needed to take place each day, further exacerbating delays. Some pumping needs were expected due to the location, but the forecast did not take this unexpected level of pumping into account. Additional delays were caused by permitting issues which pushed the project completion into December, requiring overtime to complete prior to the onset of cold weather.

O&M: The main driver for the reduction in O&M expenditures is lower than anticipated pressure testing costs for the East County Line Casing project. The Company utilized nitrogen as the pressure testing medium instead of water, which eliminated water disposal fees and the time required to dry the pipe segment after the test.

[9] The location of the project is below the waterline of the river itself.

3) ASVs and RCVs
Parent Project: 11503515 (Capital)

Project Summary and Scope
In 2016, the Company installed valves at four different locations:

Subproject	Size	Description
Rosemount Line Take-off	16"	Add a remote-controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off
Rosemount TBS (St. Paul 1P)	16"	Add a remote-controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS
Lake Elmo 1B TBS	12"	Add a valve and remote-controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS
Maplewood plant	12"	Add a valve and remote-controlled actuator on the Lake Elmo Line at the Maplewood Plant

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actuals	Variance	Variance %
Capital Expenditure	$0.45	$0.19	($0.26)	(57.78%)
O&M Expenditure	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The main driver for the decrease in capital expenditures was delaying the completion of these projects into 2017, from 2016. All four installations had actuators installed, but the installation of electronic actuating controls and commissioning to confirm operation was not conducted until 2017. Crews originally scheduled to complete this work at the end of 2016 were re-deployed to perform in-servicing related work on the East Metro pipeline.

O&M: N/A.

V. TIMP MULTI-YEAR PLAN

As previously stated, some of the TIMP projects will span multiple years. As such, the Company has formulated a multi-year plan for those that will extend beyond 2018.

The table below depicts the estimated capital and O&M costs for this multi-year plan. Many of these projects require more detailed design and engineering work 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.

The information provided below is an initial high-level budgeting estimate for each program. As described in the Petition, the current PHMSA rules are in process of being finalized regarding the validation of MAOP. This program and estimated budget assumes vintage gas transmission pipelines will be required to have a current and valid MAOP test performed.

TIMP 2019-2022 Plan
($ Millions)

	2019 Estimates		2020 Estimates		2021 Estimates		2022 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Transmission Pipeline Assessments	$1.0	$2.9	$3.6	$1.7	$2.3	$1.7	$5.3	$1.7
ASV/RCV	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0
Programmatic Replacement / MAOP Remediation	$27.5	$0.0	$17.2	$0.0	$28.5	$0.0	$25.5	$0.0
TOTAL	**$29.5**	**$2.9**	**$21.8**	**$1.7**	**$31.8**	**$1.7**	**$31.8**	**$1.7**

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

TIMP 2016-2018 Project Detail

CAPITAL

Program	Regulation	Parent Number	2016 Actuals	Cost Per Unit (CPU) Assumptions	2017 Actuals [1]	2017 Forecast	2017 Total	Cost Per Unit (CPU) Assumptions	2018 Plan	Cost Per Unit (CPU) Assumptions
East Metro Pipeline Replacement Project	49 CFR 192, Subpart O	11615874, 11676981, 11706370, 11819647, 12013233	$ 15,041,804	The average cost per unit of the new pipeline for work in 2016 was $7.9 million per mile. The Company installed 1.9 miles of pipeline at a cost of $15 million.	$ 617,924	$ (17,923)	$ 600,000	These are carry-over costs related to the 2016 scope of work.	$ -	n/a
TIMP Assessments	49 CFR 192, Subpart O	11649521, 11649797, 34000342	$ 6,989,496	2016 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c).	$ 890,572	$ 61,344	$ 951,916	2017 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c)	$ 300,000	2018 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c).
ASV/RCV Valve Replacements	49 CFR Part 192.935	11503515	$ 195,802	Unit cost is $49K/RCV for actuator installations on four different valve locations: Inver Hills, Rosemount TBS, Lake Elmo 1B, and Maplewood Plant.	$ 148,122	$ 101,878	$ 250,000	Unit cost is $63K/RCV for installation of electronic controls to actuate and confirm operations on valves installed in 2016: Inver Hills, Rosemount TBS, Lake Elmo 1B, and Maplewood Plant.	$ 1,000,000	Unit cost is $333K/RCV to install valves and actuating equipment on three valves (includes contingency).
Programmatic Main Replacement/MAOP Validation	49 CFR 192.921(a); ADB-12-06, Docket No. PMHSA-2012-0068	11651650, 11810375	$ -	n/a	$ 595,679	$ 7,433,463	$ 8,029,142	*See* Subpart 1(e)	$ 8,000,000	*See* Subpart 1(e)
TOTAL TIMP CAPITAL			**$ 22,227,103**		**$ 2,252,296**	**$ 7,578,762**	**$ 9,831,057**		**$ 9,300,000**	

*Costs and CPU Assumptions include non-GUIC recoverable internal labor.

O&M

Program	Regulation	Parent Number	2016 Actuals	Cost Per Unit (CPU) Assumptions	2017 Actuals [1]	2017 Forecast	2017 Total	Cost Per Unit (CPU) Assumptions	2018 Plan	Cost Per Unit (CPU) Assumptions
East Metro Pipeline Replacement Project	49 CFR 192, Subpart O	11984262	$ -	n/a	$ -	$ -	$ -	n/a	$ -	n/a
TIMP Assessments	49 CFR 192, Subpart O	11984286	$ 39,977	2016 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c).	$ 20,000	$ 478,117	$ 498,117	2017 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c)	$ 1,509,000	2018 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs. See Subpart 1(c).
TOTAL TIMP O&M			**$ 39,977**		**$ 20,000**	**$ 478,117**	**$ 498,117**		**$ 1,509,000**	

[1] Actual costs through August 2017.

Northern States Power Company

Docket No. G002/M-17-___
Gas Utility Infrastructure Cost Rider - 2018 Factors
Attachment C1(b)

East Metro Pipeline Replacement Project, Project Detail

2016

Prt Proj Num	Prt Proj Desc	Jan Act	Feb Act	Mar Act	Apr Act	May Act	Jun Act	Jul Act	Aug Act	Sep Act	Oct Act	Nov Act	Dec Act	Total
11615874	East Metro Pipe Replacement Proj HP Gas	$545	$202	$0	$0	$0	$3,023	($40)	$0	$18,698	$1,829,797	($1,339,554)	$2,735	$515,406
11676981	East Metro Pipe Replacement Proj Distr	$234,278	$379,084	$804,335	$1,995,781	$422,434	$3,706,023	($1,623,344)	$5,463,082	$2,053,805	($2,229,302)	$2,625,178	$183,707	$14,015,061
11706370	Install Rice & Co Rd 8 Regulator (East Metro)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11819647	RTU's - East Metro Pipe Replacement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12013233	East Metro Pipeline Replacement - Reg Installation	$0	$172	$200,321	$13,465	($26,992)	$491	($1)	$7,126	$0	$863	$0	$0	$195,445
	Total	**$234,822**	**$379,459**	**$1,004,656**	**$2,009,245**	**$395,442**	**$3,709,537**	**($1,623,386)**	**$5,470,208**	**$2,072,503**	**($398,642)**	**$1,285,624**	**$186,443**	**$14,725,912**

*Excludes non-GUIC recoverable costs associated with internal labor.

2017

Prt Proj Num	Prt Proj Desc	Jan Act	Feb Act	Mar Act	Apr Act	May Act	Jun Act	Jul Act	Aug Act	Sep Fcst	Oct Fcst	Nov Fcst	Dec Fcst	Total
11615874	East Metro Pipe Replacement Proj HP Gas	$3,056	$766	$0	$0	$0	$0	$0	$0	($1,000)	($1,000)	($1,000)	($1,000)	($178)
11676981	East Metro Pipe Replacement Proj Distr	$47,378	$15,283	$1,916	$260,823	$125,380	$134,644	$13,591	$1,486	($135)	($135)	($135)	($135)	$599,961
11706370	Install Rice & Co Rd 8 Regulator (East Metro)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11819647	RTU's - East Metro Pipe Replacement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12013233	East Metro Pipeline Replacement - Reg Installation	$0	($260)	$0	$0	$0	$0	$0	$0	$100	$100	$100	$100	$140
	Total	**$50,434**	**$15,790**	**$1,916**	**$260,823**	**$125,380**	**$134,644**	**$13,591**	**$1,486**	**($1,035)**	**($1,035)**	**($1,035)**	**($1,035)**	**$599,924**

*Excludes non-GUIC recoverable costs associated with internal labor.

2016-2018 Project Detail - TIMP Assessments

2016

Line/Loop	Project Description	Actual	O&M or Capital
Granite City	**In-Line Inspection**	**$ 19,457**	
Task 1	Install Launchers & Receivers	$ 19,457	Capital
East County Line Casing	**Pipe Replacement**	**$ 1,529,077**	
Task 1	ENVIRONMENTAL/RESTORATION	$ 5,431	Capital
Task 2	INSTALL LABOR & EQUIPMENT	$ 1,145,917	
Task 3	INTERNAL LABOR	$ 36,568	
Task 4	MATERIALS	$ 222,737	
Task 5	OUTSIDE SERVICES	$ 40,179	
Task 6	PERMITS	$ 71,769	
Task 7	TAPPERS	$ 6,476	
East County Line Casing	**Pressure Test**	**$ 39,977**	
Task 1	Prepare Pipe for Pressure test	$ 17,000	O&M
Task 2	Pressure Test	$ 5,977	
Task 3	Place Pipeline in Service	$ 17,000	
Rosemount Line - Inverhills Lateral ILI	**In-Line Inspection**	**$ 524,523**	
Task 1	INSTALL LABOR & EQUIPMENT	$ 345,889	Capital
Task 2	MATERIALS	$ 175,759	
Task 3	INTERNAL LABOR	$ 2,876	
Lake Elmo Line ILI	**In-Line Inspection**	**$ 974,923**	
Task 1	ENVIRONMENTAL/RESTORATION	$ 4,571	Capital
Task 2	INSTALL LABOR & EQUIPMENT	$ 621,934	
Task 3	INTERNAL LABOR	$ 37,058	
Task 4	MATERIALS	$ 311,359	
Island Line (South of River)	**ILI & Replacement**	**$ 3,163,645**	
Task 1	ENVIRONMENTAL/RESTORATION	$ (5)	Capital
Task 2	INSTALL LABOR & EQUIPMENT	$ 2,072,586	
Task 3	MISC	$ 36,107	
Task 4	MATERIALS	$ 925,962	
Task 5	DIRECT EXAMINATION COSTS	$ 63,848	
Task 6	PERMITS	$ 8,408	
Task 7	OUTSIDE SERVICES	$ 56,739	
High Bridge Lateral Replacement	**ILI & Replacement**	**$ 777,871**	
Task 1	Distribution	$ 255,342	Capital
Task 2	Transmission	$ 522,529	
Capital Total		**$ 6,989,496**	
O&M Total		**$ 39,977**	

*Amounts above include non-GUIC recoverable costs associated with internal labor and internal labor-related Engineering and Supervision (E&S) overhead charges.

2017

Line/Loop	Project Description	Estimates	O&M or Capital
Island Line (South of River)	**ILI Assessable (Launcher & Receiver Installation)**	**$ 300,000**	
Task 1	Pigging Runs	$ 300,000	Capital
Inver Hills Lateral	**ILI Assessable (Launcher & Receiver Installation)**	**$ 550,000**	
Task 1	Pigging Runs	$ 350,000	Capital
Task 2	Validation Digs	$ 200,000	O&M
Lake Elmo Line ILI	**ILI Assessable (Launcher & Receiver Installation)**	**$ 650,000**	
Task 1	Pigging Runs	$ 350,000	Capital
Task 2	Validation Digs	$ 300,000	O&M
Capital Total		**$ 1,000,000**	
O&M Total		**$ 500,000**	

*Amounts above include non-GUIC recoverable costs associated with internal labor and internal labor-related Engineering and Supervision (E&S) overhead charges.

2018

Line/Loop	Project Description	Estimates	O&M or Capital
Rosemount Line	**2nd ILI**	**$ 430,000**	
Task 1	Pigging Runs	$ 230,000	O&M
Task 2	Validation Digs	$ 200,000	
Blue Lake Line	**2nd ILI**	**$ 539,000**	
Task 1	Pigging Runs	$ 339,000	O&M
Task 2	Validation Digs	$ 200,000	
Island Line (South of River)	**ILI Assessable (Launcher & Receiver Installation)**	**$ 400,000**	
Task 1	Pigging Runs	$ 150,000	Capital
Task 2	Validation Digs	$ 150,000	
Task 3	O&M Repairs	$ 100,000	O&M
Montreal Line North	**Hydrostatic Pressure Test**	**$ 440,000**	
Task 1	Montreal Station to Shepard Road - 20"	$ 240,000	O&M
Task 2	Shepard Road crossing - 24"	$ 100,000	
Task 3	Shepard Road to north valve header - 20"	$ 100,000	
Capital Total		**$ 300,000**	
O&M Total		**$ 1,509,000**	

*Amounts above include non-GUIC recoverable costs associated with internal labor and internal labor-related Engineering and Supervision (E&S) overhead charges.

2016-2018 TIMP Project Detail - ASV/RCV

2016			
Subproject	**Size**	**Description**	**Actual Cost**
RCV at the Cedar TBS	26”	The capital expenditures associated with the RCV project include a new 26" valve, actuator, and connections to a Remote Terminal Unit.	$19,960
Rosemount Line Take-off	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off	$44,825
Rosemount TBS (St. Paul 1P)	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS	$19,523
Lake Elmo 1B TBS	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS	$30,554
Maplewood palnt	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Maplewood Plant	$80,941
Total			**$195,802**

*Amounts above include internal company labor that is not recoverable through the GUIC rider.

2017			
Subproject	**Size**	**Description**	**Estimated Cost**
Rosemount Line Take-off	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off	$63,500
Rosemount TBS (St. Paul 1P)	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS	$65,500
Lake Elmo 1B TBS	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS	$60,500
Maplewood palnt	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Maplewood Plant	$60,500
Total			**$250,000**

*Amounts above include internal company labor that is not recoverable through the GUIC rider.

2018			
Subproject	**Size**	**Description**	**Estimated Cost**
Rich Valley Station Inlet	16”	Install new valve and actuator on the Rosemount line at the Rich Valley Station Inlet	$550,000
Hwy 55 and Babcock	16”	Install new actuator on the Rosemount line at Hwy 55 and Babcock Rd	$100,000
South St. Paul Station Inlet	16”	Install new actuator on the Rosemount line at the South St. Paul Station Inlet	$150,000
All	n/a	Contingency	$200,000
Total			**$1,000,000**

*Amounts above include internal company labor that is not recoverable through the GUIC rider.

2017 TIMP Project Detail - Programmatic Replacement/MAOP Validation

2017		
Individual Project Name	**Description**	**Assumptions**
Montreal Line South Renewal	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace 1,300' of 20" Grade B pipe installed in 1948 by Northern Natural Gas and sold to Northern States Power with 1,300' of new 20" Grade X-52 pipe. · Location: Lillydale: From Mendota Station to the Montreal River Crossing. · Construction Period: August – November 2017	· Mileage: o Installation: 2,100' – 20" Pipe o Retirement: 1,800' – 20" Pipe · Cost Per Unit: $1,230/ft · Asset Information (valves, reg. stations, etc): Initial planning calls for reuse of valves at Mendota Station and at the river crossing. A launcher and receiver would need to be installed with piping. · Constraints: Limited space for construction, potential conflicts with railroad and park lands.
Island Line South Renewal	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace 7,900' of 20" Grade B pipe installed in 1952 by Northern Natural Gas and sold to Northern States Power with 7,900' of new 20" Grade X-52 pipe. · Location: Lillydale: From Mendota Station to the Pickerel Lake. · Construction Period: August – November 2017	· Mileage: o Installation: 2,100' – 20" Pipe o Retirement: 1,800' – 20" Pipe · Cost Per Unit: $1,160/ft · Asset Information (valves, reg. stations, etc): Initial planning calls for reuse of valves at Mendota Station. · Constraints: Limited space for construction, potential conflicts with railroad and park lands. · Notes: In Line Inspection scheduled for early 2017. Extent and timing of renewal work pending in line inspection results
Total Estimated Costs: $7.7M	- $4.5M Construction - $2.5M Construction - $500K for Damages - $229K Risk Contingencies	· Risk Contingencies: UPRR trestle reconstruction, completing project before heating season, environmental impact, impact to nursery, Pool and Yacht Club, other utility work in same area.
East County Line Renewal – S.St. Paul Station to RR Tracks	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1957 pipeline of 2,820" of 30" with standarized 24" · Location: South Saint Paul regulator station near Concorde Street in South Saint Paul · 2018 Construction Period: May – October 2018	Benefits: Make ILI assessable, MAOP established through uprate Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $5.3 million or $1,879/ft.
2017 Estimated Costs:	- $100K Design, Engineering, Easement Acquisition	
2018 Estimated Costs:	- $5.2M Construction	
Total Estimated Capital Costs:	- $5.3M	
Crossover Line - Repl 12in Upper 55 to S. St Paul Reg Station	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1946 pipeline of 5,244" of 12" with standarized 12" · Location: Carmen and 65th to Upper 55th Street and 9th Ave South in Inver Grove Heights, MN · 2018 Construction Period: May – October 2018	Benefits: Encroachment, poor accessibility. Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $2.2 million or $420/ft.
2017 Estimated Costs:	- $200K Design, Engineering, Easement Acquisition	
2018 Estimated Costs:	- $2.0M Construction	
Total Estimated Capital Costs:	- $2.2M	

2018 TIMP Project Detail - Programmatic Replacement/MAOP Validation

2018		
Individual Project Name	**Description***	**Assumptions***
County Road B (NSP to Rice)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1950s pipeline of 34,331" of 30", 24" and 20" with standarized 20" · Location: County Road B in North Saint Paul and Maplewood, MN. · 2018 Construction Period: May – October 2018 · Total Construction Period: 2018-2020	Benefits: Couplings, valves, service tees, MAOP established through uprate, make ILI assessable Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $36 million or $1,048/ft.
2018 Estimated Costs:	- $500K Design, Engineering, Easement Acquisition	
2019-2020 Estimated Costs:	- $35.5M Construction	
Total Estimated Capital Costs:	- $36M	
East County Line (30"Maplewoood Propane to North Saint Paul)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1957 pipelineof 7,323" of 30" with standarized 20" · Location: Century Avenue from Maplewood Propane facility to North Saint Paul Station in the communities of Maplewood, Oakdale and North Saint Paul, MN · 2018 Construction Period: May – October 2018 · Total Construction Period: 2018-2019	Benefits: Make ILI assessable Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $10.9 million or $1,488/ft.
2018 Estimated Costs:	- $300K Design, Engineering, Easement Acquisition	
2019 Estimated Costs:	- $10.6M Construction	
Total Estimated Capital Costs:	- $10.9M	
East County Line Renewal – S.St. Paul Station to RR Tracks	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1957 pipeline of 2,820" of 30" with standarized 24" · Location: South Saint Paul regulator station near Concorde Street in South Saint Paul · 2018 Construction Period: May – October 2018	Benefits: Make ILI assessable, MAOP established through uprate Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $5.3 million or $1,879/ft.
2017 Estimated Costs:	- $100K Design, Engineering, Easement Acquisition	
2018 Estimated Costs:	- $5.2M Construction	
Total Estimated Capital Costs:	- $5.3M	
Crossover Line - Repl 12in Upper 55 to S. St Paul Reg Station	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace original 1946 pipeline of 5,244" of 12" with standarized 12" · Location: Carmen and 65th to Upper 55th Street and 9th Ave South in Inver Grove Heights, MN · 2018 Construction Period: May – October 2018	Benefits: Encroachment, poor accessibility. Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $2.2 million or $420/ft.
2017 Estimated Costs:	- $200K Design, Engineering, Easement Acquisition	
2018 Estimated Costs:	- $2.0M Construction	
Total Estimated Capital Costs:	- $2.2M	

Quantitative Risk Assessment for 2018 GUIC Programs and Initiatives

TIMP

Methodology

Xcel Energy's risk assessment methodology is a process to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. The goal of the Company's integrity programs is to protect the public, property and the environment from pipeline failures.

The purpose of this risk assessment methodology is to develop a quantitative risk score and assign a risk category (high, medium, low) for identified projects that are funded through the Company's GUIC rider.

These quantitative risk assessment methodologies assign numeric values to likelihood and consequences by using available data and quantifying assessments. In some cases, subject matter expert (SME) input is utilized.

TIMP Transmission Pipeline Assessments

Replacement Project Risk

2018 Projects by Risk Category
NONE

Data Inputs: Findings from completed pipeline assessments and pipeline patrols. Data and information is gathered and integrated for the pipeline segment that could be relevant. In some cases replacement may be required due to the inability to assess for an applicable threat as required by Subpart O of 49 CFR 192.

Risk = Σ (Likelihood x Consequence) for all threats

Likelihood of Failure Lookup Table

Likelihood of Failure Score (L) = 0 if there are no known defects or situations of concern for the threat category. When known issues exist the following table is utilized.

Threat Category	L = 5	L = 3	L = 0.25
External Corrosion	An immediate repair condition as per 192.933(d)(1) Any metal-loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location. Predicted metal loss greater than 50% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Internal Corrosion	An immediate repair condition as per 192.933(d)(1) Any metal-loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding.	A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
	Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Predicted metal loss greater than 50% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	
Stress Corrosion Cracking (SCC) or other crack like defects	An immediate repair condition as per 192.933(d)(1) A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. Any indication of significant SCC or significant selective seam weld corrosion (SSWC). A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Evidence of cracks or crack-like defects in the pipe body, longitudinal seam, circumferential or branch-connection welds that are not an immediate condition. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	The pipeline meets the SCC threat criteria per ASME B31.8S Appendix A but no indications of SCC have been found as a result of assessments. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Manufacturing	An immediate repair condition as per 192.933(d)(1) A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Tooling marks, rolling scabs, or other imperfections from the original pipe fabrication > 10% of the nominal wall thickness An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	Tooling marks, rolling scabs, or other imperfections from the original pipe fabrication ≤ 10% of the nominal wall thickness An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Welding/Fabrication/Construction	An immediate repair condition as per 192.933(d)(1) or a one-year condition as per 192.933(d)(2) A leaking defect. A dent that has any indication of metal loss, cracking or a stress riser. An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A dent that exceeds the criteria established in 192.933 (d) (3) but is not an immediate repair condition or a one-year condition as per 192.933(d)(2) Presence of legacy construction techniques (e.g. miter bends, wrinkle bends, dresser couplings, acetylene welds, puddle welds, or a crease in a field bend). An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	A dent that meets the criteria established in 192.933 (d) (3) An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Equipment	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii). A leaking defect.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
3rd Party Mechanical Damage	An immediate repair condition as per 192.933(d)(1) or a one-year condition as per 192.933(d)(2) Any metal-loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. A dent that has any indication of metal loss, cracking or a stress riser. Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A plain dent that exceeds the criteria established in 192.933(d)(3) but in not an immediate repair condition or a one-year condition. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location. A gouge or groove greater than 12.5% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	A plain dent that meets the criteria established in 192.933(d(3) Tooling marks, rolling scabs or other imperfections from the original pipe fabrication ≤ 10% of the nominal wall thickness in conjunction with a dent whose depth is > 4% of the nominal pipe diameter. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Weather/Outside Force	An immediate repair condition as per 192.933(d)(1) A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	An active land slide zone. Line exposed due to erosion and subject to abnormal stresses. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Other	Pipeline cannot be assessed for a specific threat or threats with currently available assessment techniques. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Replacement is more economical than the cost of conducting ongoing assessments. Line must be taken out of service for the pipeline assessment but it is not possible to take the pipeline out of service or provide a temporary supply to serve the load.	NA

Consequence of Failure Lookup Table

Class Location	Score
4	1.15
3	1.10
2	1.05
1	1

Risk Matrix

For a segment of pipeline in the same Class Location, the following table may be used.

			Consequence			
			Class 1	Class 2	Class 3	Class 4
			1	**1.05**	**1.1**	**1.15**
Likelihood of Failure	Sum of Likelihood of Failure Scores	**≥ 5**	≥ 5	≥ 5.25	≥ 5.5	≥ 5.75
	Sum of Likelihood of Failure Scores	**4**	4	4.2	4.4	4.6
	Sum of Likelihood of Failure Scores	**3**	3	3.15	3.3	3.45
	Sum of Likelihood of Failure Scores	**≤ 2**	≤ 2	≤ 2.1	≤ 2.2	≤ 2.3
	Sum of Likelihood of Failure Scores	**≤ 1**	≤ 1	≤ 1.05	≤ 1.1	≤ 1.15

(dark)	High Risk: Risk Score ≥ 5
(medium)	Medium Risk: 3 ≤ Risk Score < 5
(light)	Low Risk: Risk Score < 3

TIMP Transmission Pipeline Assessments

Integrity Assessments Project Risk

2018 Projects by Risk Category

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Score	Risk Level (High, Medium, Low)
Blue Lake Line	Western	16	2005	6	Yes	4	High
Rosemount Line ILI	Newport	16	1990	5	Yes	4	High
Island Line S ILI	Newport	20	1952	2	Yes	2	Medium
Inver Hills Lateral ILI	Newport	16	1998	6	No	2	Medium
Montreal Line N	St. Paul	20	1962	4	Yes	2	Medium

Data Inputs:

- Years since last integrity assessment
- Presence of High Consequence Areas on the line.

Used for decisions on prioritizing integrity assessments

Risk Score = Likelihood of Failure x Consequence of Failure

			Consequence	
			Non-HCA	HCA
			1	**2**
Likelihood of Failure	Last Assessment > 20 years prior or no previous assessment	**4**	4	8
	15 years ≤ Last Assessment < 20 years prior	**3**	3	6
	5 years ≤ Last Assessment < 15 years prior	**2**	2	4
	Last Assessment < 5 years prior	**1**	1	2

High Risk, Risk Score ≥ 4
Medium Risk, 2 ≤ Risk Score < 4
Low Risk, Risk < 1

TIMP Automatic Shutdown Valve (ASV) /Remote Control Valve (RCV) Project Risk

Line Name	Regulation	Proposed RCV Location	Nearest Service Center	Likelihood of Failure	COF	ASV/RCV Location Risk, R_V	Risk Level
Rosemount Line	49 CFR Part 192.935	Rich Valley Station Inlet	Newport	2	3	6	Medium
Rosemount Line	49 CFR Part 192.935	Hwy 55 and Babcock	Newport	2	3	6	Medium
Rosemount Line	49 CFR Part 192.935	South St. Paul Station Inlet	Newport	4	2	8	Medium

Data inputs:

- Travel Time from Nearest Service Center to valve location (minutes), T_t
- High Consequence Area (HCA) area downstream (feet), A_H
- Risk of Failure (ROF) from TIMP risk model, from maximum of segments downstream of valve

Risk Score (R_V) = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = ROF

Consequence of Failure = Location Factor + Protection Factor

$T_{t,max}$ is the longest minimum travel time for any line in the NSPM transmission system

$A_{H,max}$ is the maximum HCA area protected by any valve in the NSPM system.

Location Factor (F_L) = $T_t / T_{t,max}$

Protection Factor (F_P) = $A_H / A_{H,max}$

Likelihood of Failure Lookup Table

Condition	Score
Risk of Failure (ROF) Score from TIMP Risk ≥ 0.3	4
Risk of Failure (ROF) Score from TIMP Risk; 0. 2 ≤ F < 0.3	3
Risk of Failure (ROF) Score from TIMP Risk; 0. 1 ≤ F < 0.2	2
Risk of Failure (ROF) Score from TIMP Risk < 0.1	0.9

<u>Consequence of Failure Lookup Table</u>

Condition	**Score**
Location Factor + Protection Factor ≥ 0.5	4
Location Factor + Protection Factor; 0.3 ≤ F < 0.5	3
Location Factor + Protection Factor; 0.1 ≤ F < 0.3	2
Location Factor + Protection Factor < 0.1	0.9

			Consequence			
			Location Factor + Protection Factor < 0.1	Location Factor + Protection Factor 0.1 ≤ F < 0.3	Location Factor + Protection Factor 0.3 ≤ F < 0.5	Location Factor + Protection Factor 0.5 ≤ F < 1.5
			0.9	**2**	**3**	**4**
Likelihood of Failure	Risk of Failure (ROF) Score from TIMP Risk ≥ 0.3	**4**	3.6	8	**12**	**16**
	Risk of Failure (ROF) Score from TIMP Risk; 0. 2 ≤ F < 0.3	**3**	2.7	6	**9**	**12**
	Risk of Failure (ROF) Score from TIMP Risk; 0. 1 ≤ F < 0.2	**2**	1.8	4	6	8
	Risk of Failure (ROF) Score from TIMP Risk < 0.1	**0.9**	0.8	1.8	2.7	3.6

High Risk: Risk Score ≥ 9
Medium Risk: Medium Risk, 4 ≤ Risk Score < 9
Low Risk: Risk Score <4

TIMP MAOP Project Risk

Project	Regulation	Project Location (Service Area)	Current Classification	Prior Test	Materia l	Consequen ce	Risk Score	Project Classificatio n
County Road B (NSP to Rice)	49 CFR 192.921(a)	White Bear Lake	Transmission	3	0.4	4	13.6	High
East County Line (30"Maplewoood Propane to North Saint Paul)	49 CFR 192.921(a)	St. Paul	Transmission	3	0.4	4	13.6	High
East County Line (30" SSP to RR Tracks)	49 CFR 192.921(a)	Newport	Transmission	3	0.4	4	13.6	High
Crossover Line - Repl 12in Upper 55 to S. St Paul Reg Station	49 CFR 192.921(a)	Newport	Transmission	2	0.4	4	9.6	High

Data inputs:

- Legacy Pipe (pre 1970 ERW (e.g. LFERW), SSAW, Flash Weld (AOSmith) or joint factor <1)
- Modern Pipe (pipe that is not Legacy Pipe)
- Test Pressure (validated as traceable, verifiable and complete)
- Material Records (validated as traceable, verifiable and complete)
- Class Location
- Presence of High Consequence Area (HCA) or Moderate Consequence Area (MCA)
- Grandfathered Pipeline as per 49CFR 192.619(c)

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Prior Test Score + Material Score

Prior Test Lookup Table

Condition	Prior Test Score
Legacy Pipe with Test Pressure < specified in 619(a)(2) or 1.25 x MAOP, whichever is greater	3
Modern Pipe with Test Pressure < specified in 619(a)(2)	2
Test Pressure records are satisfactory	0

Material Lookup Table

Condition	Material Score
Pipeline contains material not validated	0.4
Pipeline material is validated	0

Consequence Lookup Table

Condition	Consequence Score
Contains HCA	4
No HCA but Class 3 or Class 4	3
Grandfathered Pipeline in Class 1 or 2 with MCA	2
Class 1 or 2, not grandfathered, no HCA	1

			Consequence			
			Class 1 or 2, not grandfathered, no HCA	Grandfathered Pipeline Class 1 or 2 with MCA	No HCA but Class 3 or Class 4	Contains HCA
			1	**2**	**3**	**4**
Likelihood of Failure	Legacy Pipe with Test Pressure < specified in 619(a)(2) or 1.25 x MAOP, whichever is greater; Material not validated	**3.4**	3.4	6.8	10.2	13.6
	Legacy Pipe with Test Pressure < specified in 619(a)(2) or 1.25 x MAOP, whichever is greater; Pipe Material validated	**3**	3	6	9	12
	Modern Pipe with Test Pressure < specified in 619(a)(2); Pipe Material NOT validated	**2.4**	2.4	4.8	7.2	9.6
	Modern Pipe with Test Pressure < specified in 619(a)(2); Pipe Material validated	**2**	2	4	6	8
	Test Pressure Records Satisfactory; Pipe Material NOT Validated	**0.4**	0.4	0.8	1.2	1.6
	Test Pressure Records Satisfactory; Pipe Material Validated	**0**	0	0	0	0

High Risk: Risk Score ≥ 7
Medium Risk: 4 ≤ Risk Score < 7
Low Risk: Risk Score <4
No Risk: Risk Score = 0

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 process. At its core, the DIMP can be summarized in three steps: 1) understand your assets, 2) risk evaluation, and 3) and 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 information becomes available about the Company's natural gas assets. 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 or changes to state or federal codes. Using the processes identified below, Xcel Energy is continually updating its DIMP plans and projects to address the on-going obligation to ensure the safe and reliable operation of its gas distribution system.

1) Understand Your Assets

The overall goal of the Company's integrity programs is to provide safe and reliable service to its customers. For the DIMP to be successful, the Company needs to gather information about gas distribution assets and their operating environments. Xcel Energy collects specific data and information from Company records, including paper documents, electronic databases, and the experience of subject matter experts (SMEs).

2) Risk Evaluation

Using the knowledge of our gas distribution assets, Xcel Energy evaluates relative risk based on variables including pipe material, pipe size, prior failures, 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. The Company employs a risk assessment methodology to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. A calculated "relative risk" value is assigned and is used as guidance by Company SMEs, enabling stratification or ranking of projects based on asset characterization and probability of a forecasted pipe failure. This risk assessment methodology leads to a quantitative risk score and a risk category —either high, medium, or low.

The Company evaluates our gas transmission pipelines for the following threats:

- Corrosion;
- Natural forces;
- Excavation damage;
- Other outside force;
- Materials, weld, or joint failure;
- Equipment Failure;
- Incorrect operation; and
- Other Threats.

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

3) Risk Mitigation

We integrate the results from the risk evaluation process into determining planned risk mitigation activities. 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 measure is the targeted replacement of pipe segments that are considered to be poor performing or problematic. Specific programs identified as appropriate measures to reduce risk include:

- Replacement of poor performing coated steel pipelines to address corrosion;
- Renewal of mechanical or compression coupled mains and services to address material and welds concerns and corrosion;
- Renewal of a poor performing type of polyethylene pipe material installed called Aldyl-A (PEA) pipelines to address material and welds concerns and equipment issues;
- Replacement of copper loop risers to address corrosion;
- Inspecting intermediate pressure (IP) pipelines, defined generally as lines operating above 60 pounds per square inch gage (PSIG) and below

transmission pressure, repairing or replacing as needed to address corrosion and material and welds concerns;
- Replacement of intermediate pressure pipelines to address corrosion and material and welds concerns.

Risk mitigation is not solely focused on pipe replacement programs, but can also include preventative measures, performing inspections utilizing specialized technology, or more frequent inspections of equipment and 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. 2018 DIMP PROJECTS

The Company requests recovery of the following O&M and capital expenditures associated with six 2018 DIMP programs:

2018 Estimated DIMP Project Costs
($ Millions)

Program	2018 Capital	2018 O&M
Poor Performing Main Replacements	$11.05	$0.00
Poor Performing Service Replacements	$6.91	$0.00
IP Line Assessments and Replacements	$19.82	$1.03
Distribution Valve Replacement Project	$0.50	$0.00
Sewer and Gas Line Conflict Investigation	$0.00	$2.31
Federal Code Mitigation	$0.00	$0.20
TOTAL 2018 DIMP Capital Expenditures and O&M	**$38.27***	**$3.53**
TOTAL 2018 MN DIMP Revenue Requirement	**$7.96****	**$3.53**

** 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.*

All of these projects were included in the Company's 2015, 2016, and 2017 GUIC Rider petitions.[1] The capital-related cost estimates for 2018 exclude internal labor and include only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2018 project detail for each project is presented in Attachment D1(a-m) and the risk assessment scores for 2018 projects are presented in Attachment D2(a-b).

1) Poor Performing Main Replacements
Parent Projects: 11649522 & 12173831 (Capital); 11984265 (O&M)

2018 Estimated Project Costs
$11.05 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
The Company's approach for the systematic renewal of poor performing mains allows for optimized resource use and coordination with local communities, reducing the inconvenience of street construction for our customers. The Company is continually evaluating threats on the pipeline system and identifying distribution main segments that pose a risk due to pipe material deterioration or leaks. The selection and prioritization of pipe segments and/or areas targeted for replacement is based on leak history, relative ranking from the risk modeling, deficiencies in coating or cathodic protection, and construction methods, particularly those joined using mechanical couplings. Additional reviews and input from engineering and SMEs were incorporated into the replacement decisions. Replacing main pipeline segments 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[2] 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 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 (i.e. excavation

[1] Docket Nos. G002/M-14-336, G002/M-15-808, and G002/M-16-891.
[2] *See* PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02.

damage) or natural forces (i.e. frost heave). Once disturbed, the mechanical couplings can begin to leak, resulting in property damage, outages, and other consequences. The systematic removal of these pipe segments will reduce operating risk and reduce the likelihood of incidents.

As previously described, the Company utilizes a risk assessment process to perform the initial relative ranking of poor performing mains. This list is then reviewed by SMEs, who may adjust the project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees.

To minimize costs to customers, main and service renewal projects are designed with consideration of adjacent facilities, municipal requirements, customer safety and reliability, and distribution system operational needs. This includes the viability of dual main installations, which eliminates directional boring associated with installing gas services under the road. The Company may also convert segments from low-pressure to high-pressure distribution, eliminating the need for additional capital and on-going operating expenses for regulator stations. Additionally, to the extent possible, main and service replacements will be coordinated with city rehabilitation and resurfacing projects to further reduce overall costs and minimize construction impacts on neighborhoods. Both main and service replacements are considered for simultaneous construction to minimize overall costs.

Planned replacement activity in 2018 spans the key areas of:

Geographic Area (by Division)	Mains (Miles)
St. Paul	8.4
White Bear Lake	28.5
Wyoming	3.8
Newport	11.5
St. Cloud	0.3
Red Wing	2.3
Winona	10.4
Faribault	1.3
Total	**66.5**

**Estimates as of August 31, 2017. A majority of the 2018 projects are in the process of being identified and scoped.*

The Company utilizes a sourcing process that results in multi-year, unit cost agreements. Materials are sourced through the Company's standard procurement contracts. Engineering and design is completed in-house using Xcel Energy employees and contractor staff. Internal labor costs are excluded from the GUIC Rider.

For 2018, the poor performing mains materials set to be replaced include PEA and additional material types, based on their overall relative risk. A majority of the 2018 projects are in the process of being identified and scoped. Based on preliminary estimates, the Company expects to replace around 66.5 miles of distribution pipeline in 2018. The project cost estimates are based on 2016 average installation cost by operating area—main costs are per linear foot, service costs are a unit cost per service. On average, it is estimated that the total capital cost per mile of main replaced is $197,578. This is roughly a 24% increase compared to the cost per mile of main replaced based on 2015 average installation cost by operating area identified in last year's filing. This increase results from a new four-year extension signed in 2016 that carries a higher cost per unit. Additional unit cost increases were caused by construction issues associated with four individual projects that negatively impacted overall productivity.

Main projects are generally planned six months to one year in advance. 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, 2018 project identification occurs in the 3rd and 4th quarters of 2017, construction will commence during the 2nd quarter of 2018, and in-servicing will occur during the 3rd and 4th quarters of 2018.

2) Poor Performing Service Replacements
Parent Projects: 11649766 & 12173830 (Capital); 11984268 (O&M)

2018 Estimated Project Costs
$6.91 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
Replacing poor performing or problematic services in a reasonable timeframe is a practical way to ensure public safety.

As with the analysis of poor performing mains, the Company uses the aforementioned risk assessment methodology to provide a relative ranking of problematic service segments. These problematic segments are then reviewed by SMEs, who may adjust project priorities based on their knowledge. 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 the appropriate order. Where pertinent, service replacements are considered for simultaneous construction along with main replacements to minimize construction costs.

Planned replacement activity in 2018 spans the key areas of:

Geographic Area (by Division)	Services (Number)*
St. Paul	838
White Bear Lake	1,237
Wyoming	286
Newport	703
St. Cloud	33
Red Wing	266
Winona	854
Faribault	92
Total	**4,309**

** Estimates as of August 31, 2017. A majority of the 2018 projects are in the process of being identified and scoped.*

Based on preliminary estimates, the Company estimates the replacement of 4,309 service lines in 2018. Project costs are estimated on 2016 average installation cost by operating area, and service costs are a unit cost per service. On average, it is estimated that the total capital cost per service replaced is $1,108. This is roughly a 10% increase compared to the cost per service replaced based on 2015 average installation cost by operating area identified in last year’s filing. Similar to main replacement, the increase results from a new four-year extension signed in 2016 that carries a higher cost per unit.

Service replacement projects are generally planned six months to one year in advance. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be in-service during the 3rd and 4th quarters. For example, 2018 project identification occurs in the 3rd and 4th quarters of 2017, construction will commence during the 2nd quarter of 2018, and in-service will occur during the 3rd and 4th quarters of 2018.

3) Intermediate Pressure (IP) Line Assessments
Parent Projects: 11980562 (Capital); 11984278 (O&M)

2018 Estimated Project Costs
$19.82 million Capital expenditure
$1.03 million O&M expenditure

Project Summary and Scope
This is an ongoing project to assess and renew IP lines or distribution pipelines in excess of 60 PSIG. Selection of pipeline segments for inspection is based on an evaluation of all the critical IP lines in the distribution system, and an evaluation of elements of specific DIMP threats. The IP system is comprised of steel pipe susceptible to the threats of corrosion, manufacturing defects (material defects, long seam defects), construction methods (compression couplings and welds), and third-party damage. The consequences associated with a failure of these pipelines is heightened due to the higher operating pressures and the location of many of these lines in heavily developed areas.

In Minnesota, the general range of operating pressures on the Company's IP system is between 125-350 PSIG.[3] As a result of the lower pressures as compared to transmission pipelines, certain evaluation techniques, such as In-Line Inspections (ILI), can be difficult or impracticable. At present, the number of products on the market that perform ILI of distribution lines while a pipeline is in service is extremely limited, but under development. The Company models the assessment of their IP under the principles of 49 CFR 192 subpart O to ensure safe and reliable gas service in Minnesota service territories.

[3] Xcel Energy does have High Density Polyethylene (HDPE)-100 systems that operate at 95 PSIG.

In 2018, the Company will begin construction activities on three replacement projects that support the integrity management of the Company's high pressure distribution pipelines. These lines will be removed and replaced with distribution pipeline in 2018.[4] In addition, the Company will conduct an integrity assessment, known as an external corrosion direct assessment (ECDA) on two pipelines to identify any potential threats of corrosion and repair any corrosion defects. Lastly, there will also be a hydrostatic pressure test on the Montreal Line North. The IP Line Assessment work in 2018 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Langdon Line (TBS to Ashland)	Replacement	6.0	Capital
Colby Lake Lateral - Woodlane to Colby Lake	Replacement	2.5	Capital
H005 - Lexington to Snelling	Replacement	3.0	Capital
H08 – Lake Elmo 1A TBS	ECDA	3.4	O&M
T009 – Cottage Grove TBS	ECDA	1.6	O&M
Montreal Line North – River Crossings/Headers	Hydrostatic Pressure Test	2.4	O&M

- **<u>Langdon Line (Town Border Station to Ashland):</u>** This project parallels Highway 61 from 100 Street South in Cottage Grove to 1st Street in Saint Paul Park, MN. It replaces 6.0 miles of 12-inch, 8-inch and 6-inch pipe installed in 1958 with a standardized 12-inch pipe. Design and construction will be completed in 2018 and 2019.

  This pipeline has been offset and moved numerous times to accommodate realignment and growth along Highway 61. Age and construction techniques used during original installation and throughout the life of the pipe do not make it suitable for conducting in-line inspection. Replacement with a single diameter line will support an in-line inspection. Replacement of the 6-inch and 8-inch pipe supports additional reliability of the Metro area bulk system and

[4] The Langdon Line has additional replacement work planned beyond 2018.

improves redundancy in the southeast metro area. Potential risks for this project include permitting issues, rerouting the line along Highway 61, and project coordination with other projects to ensure integrity of overall distribution systems.

- **<u>Colby Lake Lateral - Woodlane to Colby Lake:</u>** This is a 2.5-mile replacement project located in Woodbury, MN. In 2017, the Company began the design, engineering, and easement acquisition. 2018 construction activities will focus on replacing the existing pipeline.

  The pipeline was constructed in 1964-1965 using vintage materials and construction methods which, while acceptable at the time, are now associated with threats that contribute to the probability of failures in the pipelines. Because of the age of this pipeline and the record keeping requirements at the time, this pipeline has incomplete strength testing documentation which would require conducting a hydrostatic test of the pipeline.

  The existing pipe has been offset multiple times with fittings that will not allow for use of internal inspection devices. The new pipeline will make ILI possible for this critical pipeline. The existing pipeline is located under a major roadway making it difficult to inspect and repair, and will add risk to the construction of this pipeline in a congested corridor. Conducting a health assessment via ECDA is not a viable option capable of identifying manufacturing or construction defects.

  The existing line is at capacity. Replacement with a larger single diameter pipe will allow for continued growth in Washington County and will allow for future integrity inspections using ILI tools. The incremental cost of installing a 12-inch single diameter pipeline instead of replacing the pipeline in kind is $1,143,000. The incremental cost associated with upsizing the pipeline has been removed from our requested revenue requirement. The Company has additionally included a summary highlighting the incremental cost allocation for this project as part of Attachment D1(f).

- **<u>H005 - Lexington to Snelling:</u>** This is a 3.0-mile replacement project located in Arden Hills beginning at the intersection of Snelling and Hamline and continuing north to Lexington and I-694.

The pipeline was constructed in 1964 using vintage materials and construction methods; resulting in threats associated with material and construction defects. The pipeline has mechanical couplings which are a known threat. The pipeline has a history of leak repairs, most notably caused by material failure, mechanical leaks, third party damage, and corrosion.

The existing pipeline has been offset multiple times with fittings that do not allow use of internal inspection devices and is also located under a major roadway making it difficult to otherwise inspect. The new pipeline will be accessible to ILI tools. A health assessment performed by ECDA is not capable of identifying manufacturing or construction defects, which are key threats for pipelines of this vintage. This pipeline has a threat of unknown third party damage due to a history of extensive road work around the line. Risks for the project are related to timing of other projects and permitting in a congested corridor. The pipeline has numerous services served directly off of the high pressure system. The project includes extending a nearby 60 psi system to facilitate transfer of these services from the high pressure system to the distribution pressure system.

- **H08 – Lake Elmo 1A TBS and T009 – Cottage Grove TBS:** These are 3.4-mile and 1.6-mile long IP systems located near Lake Elmo, MN, and Cottage Grove, MN, respectively. These lines will be assessed using ECDA methodology. Conducting ECDA on these lines will give us a baseline assessment of the health of these IP systems.

- **Montreal Line North – River Crossings/Header:** This project includes several high pressure distribution pipe segments crossing the Mississippi River and entails hydrostatic pressure testing 2.4 miles of 12-inch pipe. These sections cross the Mississippi River and extend from Shepard Road in St Paul to Lilydale Road in Lilydale.

  These pipes are considered high pressure distribution lines and were originally installed in 1948. A portion of each segment was rerouted in 1962 for the I35E construction. The final section of pipe is a valve header on the south side of the river that is considered high pressure distribution and was installed in 1977. The project will perform strength tests on the pipe segments to establish a required baseline pressure strength test.

4) Distribution Valve Replacement Project
Parent Projects: 11649520 & 12173704 (Capital); N/A (O&M)

2018 Estimated Project Costs
$0.50 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
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 during these events, the public can be better protected and customer impacts can be minimized.

The Company has identified a need to add, replace, or otherwise rehabilitate existing distribution valves. As a result of DIMP regulations, the Company is focusing directly on valve conditions and locations when determining valves that should be replaced or installed. This work is in response to the Company's obligation under Code 49 CFR Part 192.1007(d).

In addition to new valve installations, the program will replace existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life. Valves which are identified and considered in this program serve an important system isolation function and currently require maintenance or repair, which is infeasible. Most replacement valves will be installed within the existing vault. In some cases, the replacement valve will be installed adjacent to the existing valve by rerouting main around the existing valve location. The new valve would be direct-buried and accessed via a valve box, and the existing valve and vault are removed or abandoned in place.

The Company's prioritization of valve replacements is based on an evaluation of the health and condition of existing valves, and the need for the valve to protect the public and reduce the number of customers impacted in the event sections of the gas distribution system needed to be isolated. Critical isolation valves have a higher prioritization and were replaced early in the program. Valve criticality and prioritization has been determined by the Company's engineering department.

Many of the valves identified for replacement within this program are located within busy road right-of-ways. These intersections are controlled by multiple interests and permitting can have significant lead times. Additionally, many of these valves are located on critical distribution lines which have seasonal construction constraints. If permitting cannot be attained in a timely manner or if construction cannot be done because of operational constraints, a specific project may be deferred into a future year.

In total, the Company currently estimates a total of 32 existing distribution valves will be replaced in the Twin Cities Metro and Southeast areas. These valves, range in size from 2-inch to 12-inch. Of these valves, 18 are expected to be replaced in 2017 with the remaining 14 valves being replaced in 2018.

5) Sewer and Gas Line Conflict Investigation
Parent Projects: N/A (Capital); 11984282 (O&M)

<u>2018 Estimated Project Costs</u>
$0.00 million Capital expenditure
$2.31 million O&M expenditure

<u>Project Summary and Scope</u>
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 bores. In particular, PHMSA's Gas Distribution Pipeline Integrity Management Enforcement Guidance[5] 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."

The Company has been inspecting sewer laterals and mains since 2010 and has found 149 incidences of conflicts between sewer and gas lines. In recent years, there has been a downward trend in the number of conflicts found. Through August, the Company has not discovered any conflicts in 2017, leading to a

[5] http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_61354CFDB0D1A9033931723B931E3EEF668A0700/filename/DIMP_Enforcement_Guidance (1_29_2014).pdf.

determination that a reduction of inspections is reasonable in 2018 and 2019. The current plan estimates approximately 11,500 services will be inspected for conflicts in 2018, the 9th year of legacy inspections. The inspection program is anticipated to be a 10-year program that began in 2010. However, the Company will continue to monitor circumstances and will accelerate or scale back inspections if conditions warrant.

6) Federal Code Mitigation
Parent Projects: 12173398 (Capital); 12173409 (O&M)

2018 Estimated Project Costs
$0.00 million Capital expenditure
$0.20 million O&M expenditure

This project began in 2016. Over time, as the Federal code[6] governing the operation and maintenance of the gas system has changed, the Company's standards and compliance manual has also evolved. The changes in code have resulted in incremental field work related to repairs or changes on legacy assets to maintain compliance. Some of these items are relatively minor, such as ice shield installation, while others are more significant. The Company will initially focus corrective action activities on the highest risk items. The remaining items will be reassessed after more data is collected from inspections.

Field employees log the necessary repairs or exceptions as they perform routine three-year leak surveys and other work on the system. Based on the work expected to be completed in 2017, the Company anticipates roughly 400 items of varying criticality in 2018 with an average cost of $550 per exception.[7] These are initial estimates since only a portion of the system has been surveyed and documented. Examples of 2018 projects include modifying risers, installing guard posts, and relocating meter sets.

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[6] Inclusive of Title 49 of the Code of Federal Regulations (CFR) Part 192 Subparts A through P, PHMSA Advisory Bulletins, and other guidance provided by Federal institutions.
[7] Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line.

III. 2017 DIMP PROJECTS

There are six projects under the DIMP in 2017. Following are the DIMP project costs originally included in the Company's 2017 GUIC Rider Petition,[8] as compared to revised 2017 cost estimates[9] based on current year project developments and actual construction activity:

2017 Estimated DIMP Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Estimates	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Estimates	Variance	% O&M Variance
Poor Performing Main Replacements	$11.03	$9.33	($1.70)	(15.41%)	$0.24	$0.00	($0.24)	(100.00 %)
Poor Performing Service Replacements	$6.90	$5.52	($1.38)	(20.00%)	$0.04	$0.00	($0.04)	(100.00 %)
IP Line Assessments	$0.67	$0.43	($0.24)	(35.82%)	$0.30	$0.30	$0.00	0.00%
Distribution Valve Replacement Project	$0.72	$0.31	($0.41)	(56.94%)	$0.00	$0.00	$0.00	0.00%
Federal Code Mitigation	$0.18	$0.00	$(0.18)	(100.00 %)	$0.47	$0.47	$0.00	0.00%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	n/a	$3.50	$3.43	($0.07)	(2.00%)
TOTAL 2017 DIMP Capital Expenditures and O&M	**$19.50***	**$15.60***	**($3.90)**	**(20.05%)**	**$4.55**	**$4.20**	**($0.35)**	**(6.15%)**
TOTAL 2017 MN DIMP Revenue Requirement	**$4.14****	**$4.81****	**$0.67**	**16.18%**	**$4.55**	**$4.20**	**($0.35)**	**(7.69%)**

[8] Docket No. G002/M-16-891.
[9] Based on actual costs as of 8/31/2017 and estimates from 9/1/2017 through 12/31/2017.

** 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.*

The capital-related cost estimates for 2017 exclude internal labor and include only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2017 project detail for each project is presented in Attachment D1(a-m).

1) Poor Performing Main Replacements
Parent Projects: 11649522 & 12173831 & 34000462 (Capital); 11984265 (O&M)

Project Summary and Scope
For 2017, the poor performing mains materials include PEA and vintage coated steel, but additional material types may be included based on their high or medium risk assessment classifications. In addition, some costs are the result of work initially scheduled in 2016 for the Sartell Bridge Replacement project being delayed until 2017.

In total, the Company expects to replace around 54.68 miles of distribution main pipeline in 2017. Actual and remaining replacement activity in 2017 spans the key areas of:

Geographic Area (by Division)	Main (Miles)
St. Paul	5.99
White Bear Lake	22.98
Wyoming	8.93
Newport	7.02
St. Cloud	2.50
Southeast	6.07
Moorhead	1.19
Total	**54.68**

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, 2017 project identification occurred in the 3rd and 4th quarters of 2016, construction commenced during the 2nd quarter of 2017, and in-service has occurred throughout the 3rd and 4th quarters of 2017.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$11.03	$8.07	$1.26	$9.33	($1.70)	(15.41%)
O&M Expenditure	$0.24	$0.00	$0.00	$0.00	($0.24)	(100.00%)

Variance Explanation

Capital: The main driver for the reduced capital expenditures is the decrease in the number of miles of problematic pipeline replaced based on a revised relative risk assessment among GUIC projects. The projects consist of coupled steel and PEA mains and services and copper loop risers. The construction resources and projects identified for 2017 have been prioritized based on relative risk and SME input.

O&M: The reduction in O&M expenditures is the result of a change in the Company's capitalization policy related to service transfers. Service transfers are now considered a capital costs to be capitalized as a part of the renewal, and will no longer be considered O&M.

2) Poor Performing Service Replacements
Parent Projects: 11649766 & 12173830 (Capital); 11984268 (O&M)

Project Summary and Scope

For 2017, the primary service-related material types addressed include PEA, vintage coated steel, and copper risers. Additional material types are included as necessary based on their overall risks. In total, the Company estimates the replacement of approximately 3,420 service lines in 2017. Actual and remaining replacement activity in 2017 spans the key areas of:

Geographic Area (by Division)	Services (Number)
St. Paul	638
White Bear Lake	1,068
Wyoming	572
Newport	422
St. Cloud	167
Southeast	435
Moorhead	118
Total	**3,420**

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, 2017 project identification occurred in the 3rd and 4th quarter of 2016, construction commenced during the 2nd quarter of 2017, and in-service has occurred in the 3rd and 4th quarters of 2017.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$6.90	$1.45	$4.07	$5.52	($1.38)	(20.00%)
O&M Expenditure	$0.04	$0.00	$0.00	$0.00	($0.04)	(100.00%)

Variance Explanation

Capital: The main driver for the reduced capital expenditures is a decrease in the number of miles of high-risk pipe and associated services, based on a revised relative risk assessment among GUIC projects.

O&M: The reduction in O&M expenditures is the result of a change in the Company's capitalization policy related to service transfers. Service transfers are now considered a capital costs to be capitalized as a part of the renewal, and will no longer be considered O&M.

3) IP Line Assessments
Parent Projects: 11980562 (Capital); 11984278 (O&M)

Project Summary and Scope
This project performs health and condition assessments on IP lines. The IP system is comprised of steel pipe susceptible to the threats of corrosion, construction methods (compression couplings, materials and welds), and third-party damage.

In 2017, the Company is performing an ECDA test for one line and completing design and engineering activities for two future line replacement projects. The scope of 2017 work includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Hugo Line	ECDA	11.1	O&M
Colby Lake Lateral Renewal	Replacement	2.5	Capital
H005 System Renewal – Lexington to Snelling	Replacement	3.0	Capital

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$0.67	$0.01	$0.42	$0.43	($0.24)	(35.82%)
O&M Expenditure	$0.30	$0.00	$0.30	$0.30	$0.00	0.00%

Variance Explanation

Capital: Engineering costs and the cost of field services needed (survey, soil bore, etc.) to support engineering are projected to be lower than initially expected. Further, no capital repairs are necessary due to results from the previously completed Hugo IP line ECDA project.

O&M: None.

4) Distribution Valve Replacement Project
Parent Projects: 11649520 (Capital); N/A (O&M)

Project Summary and Scope
In total, by the end of 2017 the Company estimates that a total of 18 inoperable emergency distribution valves will have been replaced, ranging in size from 2-inch to 12-inch. These valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections during these events, the public can be better protected and customer impacts can be minimized. A majority of the new valve installations have been performed by internal resources.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	**2017 Actuals (Jan-Aug)**	**2017 Forecast (Sep-Dec)**	**2017 Total Estimates**	**Variance**	**Variance %**
Capital Expenditure	$0.72	$0.18	$0.13	$0.31	($0.41)	(56.94%)
O&M Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the reduction in capital expenditures is the removal of capitalized internal labor costs. In addition, four of the planned valve replacements in 2017 have been rescheduled to 2018 to coordinate with a county road project.

O&M: None.

5) Sewer and Gas Line Conflict Investigation
Parent Projects: N/A (Capital); 11984282 (O&M)

Project Summary and Scope
The sewer and gas line conflict inspection program is anticipated to be a 10-year program that began in 2010. The Company will continue to monitor risk circumstances and will accelerate or scale back inspections if conditions warrant.

Consistent with the level of effort for 2010-2016, the current 2017 plan estimates that approximately 18,800 services will be inspected. Through August, the Company has not discovered any conflicts in 2017.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	**2017 Actuals (Jan-Aug)**	**2017 Forecast (Sep-Dec)**	**2017 Total Estimates**	**Variance**	**Variance %**
Capital Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	n/a
O&M Expenditure	$3.50	$1.90	$1.53	$3.43	($0.07)	(2.00%)

Variance Explanation

Capital: N/A.

O&M: The main driver for the reduction in O&M expenditures is the removal of non-GUIC recoverable internal labor costs.

6) Federal Code Mitigation
Parent Projects: 12173398 (Capital); 12173409 (O&M)

Project Summary and Scope
Work began in 2017 and will progress in a planned fashion until all issues are mitigated or risk no longer exists. Nearly all of the work planned in 2017 relates to the sleeving of risers in the St. Cloud area.

The cost per exception included in current budgets is estimated at $800. Based on actual results, it appears the cost per exception will be closer to $550. These are initial estimates since only a portion of the system has been surveyed and documented.

2017 Estimated Project Costs
($ Millions)

	2017 As Filed, 16-891	2017 Actuals (Jan-Aug)	2017 Forecast (Sep-Dec)	2017 Total Estimates	Variance	Variance %
Capital Expenditure	$0.18	$0.00	$0.00	$0.00	$(0.18)	(100.00%)
O&M Expenditure	$0.47	$0.08	$0.39	$0.47	$0.00	0.00%

Variance Explanation

Capital: Based on a revised program evaluation, it was discovered that internal company labor had been included in previous capital estimates. As a result, the Company is not requesting recovery of capital projects related to Federal Code Mitigation through the GUIC rider.

O&M: None.

IV. 2016 DIMP PROJECTS

There were six projects under the DIMP in 2016. Following are the DIMP project costs originally included in the Company's 2017 GUIC Rider Petition[10], as compared to actual 2016 costs.

**2016 Actual DIMP Project Costs
($ Millions)**

	2016 Capital, As Filed	2016 Capital Actuals	Variance	% Capital Variance	2016 O&M, As Filed	2016 O&M Actuals	Variance	% O&M Variance
Poor Performing Main Replacements	$6.51	$12.74	$6.23	95.70%	$0.14	$0.00	($0.14)	(100.00%)
Poor Performing Service Replacements	$4.01	$3.31	($0.70)	(17.46%)	$0.00	$0.00	$0.00	0.00%
IP Line Assessments	$0.00	$0.00	$0.00	0.00%	$0.55	$0.75	$0.20	36.36%
Distribution Valve Replacement Project	$0.20	$0.26	$0.06	30.00%	$0.00	$0.00	$0.00	0.00%
Pipeline Data Project - Distribution	$0.17	$0.17	$0.00	0.00%	$ 0.00	$0.00	$0.00	0.00%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	0.00%	$3.28	$3.52	$0.24	7.39%
Federal Code Mitigation	$0.18	$0.00	($0.18)	(100.00%)	$0.47	$0.23	($0.24)	(51.06%)
TOTAL 2016 DIMP Capital Expenditures and O&M	**$11.07***	**$16.48***	**$5.41**	**48.87%**	**$4.44**	**$4.50**	**$0.06**	**1.35%**
TOTAL 2016 MN DIMP Incremental Revenue Requirement	**$2.24****	**$2.34****	**$0.10**	**4.46%**	**$4.44**	**$4.50**	**$0.06**	**1.35%**

[10] Docket No. G002/M-16-891.

** 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.*

The capital-related cost estimates for 2016 exclude internal labor and include only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2016 project detail for each project is presented in Attachment D1(a-m).

**1) Poor Performing Main Replacements
Parent Projects: 11649522, 12173831 & 34000462 (Capital); 11984265 (O&M)**

Project Summary and Scope

For 2016, the poor performing mains materials primarily included PEA and vintage coated steel. The Company replaced 50.95 miles of distribution main pipeline in 2016. Actual replacement activity in 2016 spans the key areas of:

Geographic Area (by Division)	Main (Miles)
St. Paul	16.66
White Bear Lake	17.42
Wyoming	2.09
Newport	3.94
St. Cloud	4.54
Southeast	4.32
Moorhead	1.98
Total	50.95

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$6.51	$12.74	$6.23	95.70%
O&M Expenditure	$0.14	$0.00	($0.14)	(100.00%)

Variance Explanation

Capital: The increase in capital expenditures resulted from five projects incurring significantly higher costs than anticipated. While difficult excavating conditions were considered in original estimates, four of the projects, three completed by contractors and one by internal resources, experienced additional unforeseen issues accessing townhome areas with full-sized excavating equipment. These projects required extensive unexpected activities such as hand-digging, mechanical rock breaking, spoil hauling and bringing in fresh sand fill. Main and service replacement activities in urban environments can have greater costs due to the unpredictable nature of performing the work in confined spaces.

The Sartell Pedestrian Bridge Crossing Replacement project in Sartell, Minnesota also experienced cost-overruns due to contracting crews unexpectedly needing to drill a river bore through granite which delayed project completion significantly.

O&M: The reduction in O&M expenditures is the result of a change in the Company's capitalization policy related to service transfers. Service transfers are now considered a capital costs to be capitalized as a part of the renewal, and will no longer be considered O&M.

2) Poor Performing Service Replacements
Parent Projects: 11649766 & 12173830 (Capital); 11984268 (O&M)

Project Summary and Scope

For 2016, the primary service-related material types addressed were PEA, vintage coated steel, and copper risers. In total, the Company replaced approximately 3,039 service lines in 2016. Actual replacement activity in 2016 spans the key areas of:

Geographic Area (by Division)	Services (Number)
St. Paul	1,117
White Bear Lake	898
Wyoming	118
Newport	260
St. Cloud	182
Southeast	268
Moorhead	196
Total	**3,039**

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$4.01	$3.31	($0.70)	(17.46%)
O&M Expenditure	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The main driver for the decrease in capital expenditures on services is the difficulty in forecasting service costs in relation to main costs. Mains and services are forecasted together based on previous main mileage to services ratios. Home densities can vary greatly between urban, suburban, and rural areas. When home densities where actual installations are taking place differ from our experience in previous years, we end up with variances in service costs from our forecast to actuals. In this case, due to home density for installation areas being lower than initially forecasted, dollars originally forecasted for services were actually spent on main replacement activities instead.

O&M: None.

3) IP Line Assessments
Parent Projects: 11980562 (Capital); 11984278 (O&M)

Project Summary and Scope

This project performed health and condition assessments on IP lines. Two planned IP assessments were completed in 2016; the 12.3 mile Anoka IP line and the 19-mile Shoreview IP line. The Company performed verification digs of the Anoka IP. Work was also performed on the Shoreview IP line, specifically to complete inspection and verification digs as part of the ECDA project.

In addition to the ECDA projects, during an underwater inspection of the Island Line Mississippi River crossing, a section of exposed pipeline was discovered and unplanned mitigation actions were needed to eliminate the exposed pipeline.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	0.00%
O&M Expenditure	$0.55	$0.75	$0.07	12.32%

Variance Explanation

Capital: None.

O&M: Underwater inspection activities and mitigation on the Island Line, to address exposed river crossing, resulted in higher than expected contract labor costs. This was partially offset by results from the indirect assessment of the Anoka and Shoreview IP lines. The assessments resulted in no areas under the "immediate" repair criteria and only five meeting the "scheduled" repair criteria. This was fewer than initially anticipated, reducing the number of validation digs and repairs. The final number of digs selected for this project was six. In addition to the lowered number of digs, the excavation work performed utilized internal labor not included for recovery through the GUIC rider.

4) Distribution Valve Replacement Project
Parent Projects: 11649520 (Capital); N/A (O&M)

Project Summary and Scope
Approximately 114 emergency valves ranging in size from 2-inch to 12-inch were installed in 2016. With the exception of minor restoration work completed in 2017 related to 2016 valve projects, 2016 was the final year new emergency valve work was performed.

In 2016, one new valve was installed near the intersection of Mankato Avenue and Lake Boulevard, in Winona, with the remainder of the new valves scattered throughout the Twin Cities Metro area. The work for this project was performed by internal resources. Costs associated with internal labor are not included for recovery through the GUIC rider.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$0.20	$0.26	$0.06	30.00%
O&M Expenditure	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: The main driver for the slight increase in capital expenditures resulted from six new valves being installed. Restoration costs were greater than expected since several of the valves were located in major roadways.

O&M: None.

5) Pipeline Data Project - Distribution
Parent Projects: 11813698 (Capital); N/A (O&M)

Project Summary and Scope

This project focused on remediation of legacy records for the gas distribution mains and services into the Company's Geographic Information System. The project concluded in 2015 as planned. However, invoices totaling $171,000 were not received and paid until January 2016.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$0.17	$0.17	$0.00	0.00%
O&M Expenditure	$0.00	$0.00	$0.00	n/a

Variance Explanation

Capital: None.

O&M: N/A.

6) Sewer and Gas Line Conflict Investigation
Parent Projects: N/A (Capital); 11984282 (O&M)

Project Summary and Scope
The sewer and gas line conflict inspection program is anticipated to be a 10-year program that began in 2010. The Company will continue to monitor risk circumstances and will accelerate or scale back inspections if conditions warrant.

Consistent with the level of effort for 2010-2015, approximately 18,581 services inspected for conflicts in 2016. The Company discovered three conflicts during the year.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	n/a
O&M Expenditure	$3.28	$3.52	$0.24	7.39%

Variance Explanation

Capital: N/A.

O&M: Slight overspend resulted from unanticipated excavation activities on certain projects.

7) Federal Code Mitigation
Parent Projects: 12173398 (Capital); 12173409 (O&M)

Project Summary and Scope
Work was originally planned in 2016 to mitigate risks associated with 860 exceptions based on updated information taken from continued field surveys and other mechanisms to obtain the data. The work in 2016 related to the sleeving of risers in the St. Cloud area.

2016 Actual Project Costs
($ Millions)

	2016 As Filed, 16-891	2016 Actual	Variance	Variance %
Capital Expenditure	$0.18	$0.00	($0.18)	(100.00%)
O&M Expenditure	$0.47	$0.23	($0.24)	(51.06%)

Variance Explanation

Capital: Based on a revised program evaluation, it was discovered that internal company labor had been included in previous capital estimates. As a result, the Company is not requesting recovery of capital projects related to Federal Code Mitigation through the GUIC rider.

O&M: Work for this program was reprioritized and a number of O&M activities for sleeving risers in the St. Cloud area, initially planned in 2016, are now taking place in 2017.

V. DIMP MULTI-YEAR PLAN

As mentioned above, many of the DIMP projects are initiatives that will span multiple years. As such, the Company has formulated a five-year plan for those projects that will extend beyond 2018. As the Company continues to execute its risk-based strategy, replacement projects planned for 2019 and beyond will target pipe segments displaying the highest level of relative risk. Therefore, it is anticipated that there will be an increase in the number of overall projects.

The information provided in the table below depicts the current 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. Additionally, coordination with local government entities, securing rights-of-way and permits, resource and equipment availability and unforeseen circumstances all can have an impact on final construction estimates.

DIMP 2019-2022 Plan
($ Millions)

	2019 Estimates		2020 Estimates		2021 Estimates		2022 Estimates	
Sub-Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$11.20	$0.00	$11.20	$0.00	$11.20	$0.00	$11.20	$0.00
Poor Performing Services	$7.00	$0.00	$7.00	$0.00	$7.00	$0.00	$7.00	$0.00
IP Line Assessments	$15.08	$0.48	$8.88	$0.58	$0.00	$0.58	$0.00	$0.58
Distribution Valve Replacement	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pipeline Data Project - Distribution	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sewer & Gas Line Conflict Remediation	$0.00	$2.30	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Federal Code Mitigation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$33.28**	**$2.78**	**$27.08**	**$0.58**	**$18.20**	**$0.58**	**$18.20**	**$0.58**

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

DIMP 2016-2018 Project Detail

CAPITAL

Program	Regulation	Parent Number	2016 Actuals	Cost Per Unit (CPU) Assumptions	2017 Actuals [1]	2017 Forecast	2017 Total	Cost Per Unit (CPU) Assumptions	2018 Plan	Cost Per Unit (CPU) Assumptions
Distribution Valve Replacement	Code 49 CFR Part 192.1007(d).	11649520, 12173704	$ 533,029	2016 forecasted costs are $4,814/valve for 97 valves.	$ 211,469	$ 407,699	$ 619,168	2017 estimated cost per valve is $36K/valve for 22 valves.	$ 800,000	2018 estimated cost per valve is $57K/valve for 14 valves.
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02	11649522, 12173831, 34000462	$ 13,253,352	Based on 2015 YTD actuals: $28.07/ft. for contractor-performed work and internal/local projects. This does not take into account Capitalization Policy change at end of June, 2015, nor that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to main projects from Capitalization change (air tests and tie-overs) = 2.5% or $0.70/ft., resulting in revised target of $28.77/ft. - Anticipated increase to contracts that will impact DIMP work = 5% or $1.44/ft., resulting in revised target of $30.21/ft. - 2016 Final CPU Target is $30.21/ft.	$ 8,176,546	$ 1,530,558	$ 9,707,104	Based on 2015 YTD actuals: $28.07/ft. for contractor-performed work and internal/local projects. This does not take into account Capitalization Policy change at end of June, 2015, nor that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016, currently a 2-yr extension is being negotiated, with no net impact to cost anticipated. - Anticipated increase to main projects from Capitalization change (air tests and tie-overs) = 2.5% or $0.70/ft., resulting in revised target of $28.77/ft. - Anticipated increase to contracts that will impact DIMP work = 5% or $1.44/ft., resulting in revised target of $30.21/ft. - 2017 CPU Target is $30.21/ft. - 2-1-17 updated forecast based on 2016 actual cost of $37.42/ft, reduced footage for plan. This increase was largely due to 2 projects with higher than anticipated costs and an increase of roughly 10% annually to Engineering and Supervision overheads. These overheads are not identified before the work, instead as costs are realized and distributed against all active and ongoing work.	$ 11,440,526	2018 forecast is based on 2016 actual cost, considered the best available information. - Forecast based on 2016 actual cost of $37.42/ft - Predict that increased costs due to increased SWPPP costs to manage erosion control and sedimentation protection - Q3 Contracting agreement calls for 2% increase to all unit rates in 2018, revised forecast for mains without 2017 data is $38.17/ft
Poor Performing Services		11649766, 12173830	$ 3,366,544	Based on 2015 YTD actuals: $584.73/service. The Capitalization Policy change at end of June does not impact this. This does not take into account that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to contracts that will impact DIMP work = 5% or $29.24/service, resulting in revised target of $613.97/service - 2016 Final CPU Target is $613.97/service	$ 1,494,569	$ 4,136,363	$ 5,630,932	Based on 2015 YTD actuals: $584.73/service. The Capitalization Policy change at end of June does not impact this. This does not take into account that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016. Currently, a 2-year extension is being negotiated, with no net impact to cost anticipated. - Anticipated increase to contracts that will impact DIMP work = 5% or $29.24/service, resulting in revised target of $613.97/service - 2017 CPU Target is $613.97/service - 2-1-17 updated forecast based on 2016 actual cost of $1107.78/service. This increase is driven by sewer mitigation and SWPPP/restoration costs higher than anticipated costs and an increase of roughly 10% annually to Engineering and Supervision overheads. These overheads are not identified before the work, instead as costs are realized and distributed against all active and ongoing work.	$ 7,156,396	2018 forecast is based on 2016 actual cost, considered the best available information. - Forecast based on 2016 actual cost of $1,107.78/service - Predict that increased costs due to increased SWPPP costs to manage erosion control and sedimentation protection will be consistent - Q3 Contracting agreement calls for 2% increase to all unit rates in 2018, revised forecast for mains without 2017 data is $1,129.94/svc
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).	11980562	$ -	N/A	$ 23,008	$ 476,992	$ 500,000	● Engineering, Design and Easement Acquisition for Colby Lake Lateral Renewal- 2.5 miles - Total Cost Per Unit: $5 million or $379/ft. ● Engineering, Design and Easement Acquisition for H005 System Renewal - Lexington to Snelling- 3.0 miles -Total Cost Per Unit: $5.2 million or $328/ft.	$ 22,200,000	● Construction of Colby Lake Lateral Renewal- 2.5 miles - Total Cost Per Unit: $5 million or $379/ft. ● Construction of H005 System Renewal - Lexington to Snelling- 3.0 miles - Total Cost Per Unit: $5.2 million or $328/ft. ● Construction of Langdon Line (TBS to Ashland)- 6.0 miles - Total Cost Per Unit: $21.1 million or $663/ft.
Pipeline Data Project (PDP)	Code 49 CFR Part 192.1007(a)	11813698	$ 170,898	These are carry-over costs from 2015.	$ -	$ -	$ -	N/A	$ -	N/A
TOTAL DIMP CAPITAL			**$ 17,323,823**		**$ 9,905,591**	**$ 6,551,612**	**$ 16,457,203**		**$ 41,596,922**	

*Costs and CPU Assumptions include non-GUIC recoverable internal labor and betterment that are not reflected in Attachment C.

DIMP 2016-2018 Project Detail

O&M

Program	Regulation	Parent Number	2016 Actuals	Cost Per Unit (CPU) Assumptions	2017 Actuals [1]	2017 Forecast	2017 Total	Cost Per Unit (CPU) Assumptions	2018 Plan	Cost Per Unit (CPU) Assumptions
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02	11984265	$ -	None.	$ -	$ -	$ -	None.	$ -	None.
Poor Performing Services		11984268	$ -	None.	$ -	$ -	$ -	None.	$ -	None.
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(a)	11984278	$ 617,744	● Shoreview IP ECDA - 10 miles - See Attachment C1(e) for project detail. ● River Crossing Inspections - See Attachment C1(e) for project detail.	$ 1,913	$ 298,086	$ 299,999	● Hugo Line - 11.1 miles - see Attachment C1€ for details - Survey costs $40,000 and digs cost $250,000 - Also included are additional minor costs (permitting, new CP test leads, etc.)	$ 1,025,000	● External Corrosion Direct Assessment (ECDA) of H08 - Lake Elmo 1A TBS ($200K)-3.4 miles - Survey $10K; Digs, 3@$60K; additionally included are minor costs (permitting, new CP test leads, etc.) ● External Corrosion Direct Assessment (ECDA) of HT009 - Cottage Grove- 1.6 miles - Survey $10K; Digs, 3@$60K; additionally included are minor costs (permitting, new CP test leads, etc.) ● Hydrostatic Pressure Test of Montreal Line North- 2.4 miles - See Attachment C1(e) for project scope.
Federal Code Mitigation	Code 49 CFR Part 192: (192.365/192.357) ; (192.745/192.747) ; (192.707/192.327/192.361) ; (192.365/192.487) ; (192.479/192.461) ; (192.357/192.353) ; (PHMSA Advisory Bulletin 08-03) ; (192.321) ; (192.455/192.457)	12173409	$ 223,057	• $550 per exception is an average, high-level estimate for all exception types, based on the type of repair as well as historical costs. Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line. • The primary focus in 2016 is mitigating risk posed by corrosion to meter sets and meter risers. The Company has identified roughly 400 exceptions where the risers are buried in concrete that require corrective action.	$ 83,503	$ 388,497	$ 472,000	• $550 per exception is an average, high-level estimate for all exception types, based on the type of repair as well as historical costs. Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line. • The primary focus in 2017 is mitigating risk posed by corrosion to meter sets and meter risers. The Company has identified roughly 800 exceptions where the risers are buried in concrete that require corrective action.	$ 200,000	• $550 per exception is an average, high-level estimate for all exception types, based on the type of repair as well as historical costs. Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line. • The final 2018 O&M project list in-process of scope development.
Sewer Conflict Investigation	Dockets Nos. G002/M-12-248 and G002/M-10-422	11984282	$ 3,519,807	Based on 2015 YTD actuals: $182.18/inspection. This does not take into account that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to contracts that will impact Sewer Mitigation work = 4% or $7.29/inspection, resulting in revised target of $189.47/inspection - 2016 Final CPU Target is $189.47/inspection -2016 volume of inspections is estimated at 17,300. Projects are not tracked at the individual inspection level. - List of communities in 2016: Arden Hills, Baxter, Becker, Chisago, Cottage Grove, Delano, East Grand Forks, Falcon Heights, Faribault, Forest Lake, Glyndon, Hugo, Inver Grove Heights, Lake City, Lindstrom, Little Canada, Mahtomedi, Maplewood, Mendota Heights, Moorehead, Moorhead, Mounds View, New Brighton, New London, Newport, Nisswa, Northfield, Oak Park Heights, Oakdale, Red Wing, Roseville, Sartell, Sauk Rapids, Shoreview, St Cloud, St Joseph, St Paul Park, Stillwater, Stillwater Twp, Vadnais Heights, Wabasha, Waite Park, White Bear Lake, White Bear Lake Twp, Winona, Woodbury, Wyoming	$ 1,899,027	$ 1,529,219	$ 3,428,246	Based on 2015 YTD actuals: $182.18/inspection. This does not take into account that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016 through 2019. - Anticipated increase to contracts that will impact Sewer Mitigation work = 4% or $7.29/inspection, resulting in revised target of $189.47/inspection - 2016 Final CPU Target is $189.47/inspection -2017 volume of inspections is estimated at 17,300. Projects are not tracked at the individual inspection level. List of projects is being developed, not yet available. - August 2016, in leiu of bidding work, we negotiated a cost reduction for inspections resulting in more inspections in 2017, and adjusted forecast for 2017. - We allowed for increases on lower volume work where contractor's costs were higher and received a lower inspection rate, resulting in a 2.4% decrease in forecast costs	$ 2,308,000	Utilizing best information available, we anticipate roughly 12,000 inspections in 2018 with a slightly lower budget. Additionally, we seek to reinvigorate efforts to communicate in partnership with other industry partners, as we have seen a decrease in customer calls to inspect as part of Call Before You Clear program. We anticipate this could reduce inspections by roughly 1,000 for legacy inspections and increase premise visits by 250 annually.
TOTAL DIMP O&M			**$ 4,360,607**		**$ 1,984,443**	**$ 2,215,802**	**$ 4,200,245**		**$ 3,533,000**	

*Non-GUIC recoverable internal labor are included in these amounts.

[1] Actual costs through August 2017.

Northern States Power Company | Docket No. G002/M-17-____

Gas Utility Infrastructure Cost Rider - 2018 Factors

DIMP Replacement Project Detail for 2016 | Attachment D1(b)

				Main Footage				Service			Service Cost
	Project	**WO**	**Actual Cost for Mains**	**Estimate**	**Actual Replaced**	**Actual Installed from Passport**	**Main CPU**	**Estimate**	**Replaced**	**Transferred**	**Actual Cost for Services**
St Paul	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	12092489	$257,014	8,600	6,800	8,804	$29.19	31	28	2	$25,572
	ST PAUL - ARMSTRONG AVE	12328949	$390,059	7,506	4,530	7,704	$50.63	150	146	6	$127,360
	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	12381180	$295,480	8,900	7,150	9,006	$32.81	157	140	18	$133,607
	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	12294860	$126,996	7,810	6,680	6,850	$18.54	81	74	6	$101,332
	LAUDERDALE - EUSTIS ST	12398688	$57,202	1,100	848	1,188	$48.15	17	15	2	$15,714
	ROSEVILLE - WEWERS RD	12380740	$71,035	1,400	940	1,388	$51.18	15	14	2	$18,450
	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	12344852	$1,538,468	23,400	18,950	23,645	$65.07	305	282	20	$261,305
	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	12404989	$417,774	1,200	920	1,270	$328.96	6	3	3	$5,846
	ST PAUL - JUNO (CONTRACTOR PORTION)	12361662	$389,647	4,750	3,150	4,880	$79.85	77	69	11	$60,520
	ST PAUL - JUNO (INTERNAL PORTION)	12358730	$88,284	1,260	940	1,288	$68.54	20	17	2	$17,645
	ST PAUL - AURORA (INTERNAL PORTION)	12364882	$78,567	960	920	971	$80.91	36	23	13	$26,444
	ST PAUL - AURORA (CONTRACTOR PORTION)	12369728	$189,102	3,875	2,800	3,740	$50.56	100	85	15	$85,728
	ST PAUL - BERKELY-STANFORD-WELLESLY	12317526	$247,703	10,440	9,170	10,566	$23.44	195	192	4	$196,107
	ROSEVILLE - SKILLMAN-ELDRIDGE	12294862	$141,177	6,700	4,650	6,648	$21.24	79	61	18	$79,596
White Bear Lake	LAKE ELMO - 32ND ST	12344860	$257,014	8,600	6,380	8,702	$29.54	48	41	7	$55,727
	LAKE ELMO - LAKE ELMO AVE	12293638	$191,687	6,800	5,450	6,766	$28.33	51	36	11	$49,095
	NORTH ST PAUL - 19TH AVE	12334697	$184,690	7,000	6,850	7,102	$26.01	85	81	8	$65,311
	BAYTOWN TWP/ 13606 30TH ST N	12371725	$24,351	320	320	308	$79.06	5	1	3	$1,218
	OAKDALE - GROSPOINT AVE	12320156	$479,969	16,200	12,180	16,470	$29.14	178	169	11	$157,716
	WHITE BEAR LAKE - FLORENCE ST	12317855	$577,920	16,600	14,000	16,720	$34.56	128	117	10	$128,407
	MAPLEWOOD - ROSELAWN AVE	12320058	$597,768	12,900	8,950	12,860	$46.48	179	131	50	$128,603
	OAKDALE - GERSHWIN AVE	12320143	$50,431	2,150	1,820	2,170	$23.24	70	55	18	$73,113
	SHOREVIEW - DEBRA LN	12320392	$366,570	11,200	9,180	11,194	$32.75	105	101	5	$118,626
	OAKDALE - GREENE AVE	12275730	$50,431	2,150	1,980	2,134	$23.63	22	21	1	$25,012
	SHOREVIEW - NANCY PL	12317856	$181,770	7,600	4,950	7,554	$24.06	85	81	4	$71,967
Wyoming	FOREST LAKE - 2ND ST SE	12334677	$402,423	10,900	10,850	11,102	$36.25	118	88	29	$101,351
Newport	MENDOTA HTS - HWY 13 - WACHTER AVE	12346357	$8,927	911	855	844	$10.58	5	1	-	$1,254
	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	12346387	$102,882	1,680	1,475	1,704	$60.38	28	16	12	$28,802
	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	12352620	$92,540	1,900	1,780	1,941	$47.68	22	14	7	$21,644
	ST PAUL PARK - 13TH-14TH-CHICAGO	12352631	$199,174	8,815	6,450	8,794	$22.65	100	26	75	$30,139
	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	12346491	$200,936	7,530	6,400	7,496	$26.81	120	106	16	$105,969
St Cloud	DELANO	12249351	$427,255	14,800	9,800	14,868	$28.74	127	123	5	$210,085
	ST CLOUD - 6TH AVE BTW 12TH&14TH ST N	12415619	$45,078	770	1,200	892	$50.54	48	34	14	$31,344
	SARETLL - RIVER CROSSING AND MAIN REINFORCEMENT	12403875	$1,165,743	2,600	2,564	2,957	$394.23	8	2	6	$0
	ST JOSEPH - 1ST AVE NE - CTY RD 75	12342575	$337,745	9,150	8,450	9,088	$37.16	85	82	3	$85,111
Southeast	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	12385504	$273,141	8,100	6,930	8,066	$33.86	127	106	20	$119,531
	NORTHFIELD - FLORELLAS CT	12354151	$37,725	1,550	1,380	1,542	$24.46	22	17	4	$17,734
	FARIBAULT - 8TH ST SW	12328936	$158,253	5,320	5,240	5,308	$29.81	48	45	4	$42,603
	FARIBAULT - 7TH ST NW	12345274	$157,378	4,900	4,680	4,884	$32.22	43	14	31	$15,543
	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	12350531	$141,662	3,000	2,650	2,996	$47.28	49	38	22	$48,742
Fargo	MOORHEAD - REGAL ESTATES	12359542	$275,250	10,500	9,950	10,427	$26.40	242	224	22	$341,021
			$11,277,221	**271,847**	**221,162**	**272,837**	**$41.33**	**3,417**	**2,919**	**520**	**$3,230,894**

*Project detail amounts vary from costs presented in Attachment D, due to extracting the data from different systems (PowerPlan vs. Passport) and non-GUIC recoverable costs associated with internal labor.

NSP-MN Main & Services DIMP Replacement Projects 2017							
Area	Work Order Number	Description	Total Design FT.	Tot. Svc	Design Estimate Main	Anticipated Service Cost	GL Main Cost (2017 YTD September)
St Paul	12494722	ST PAUL - WESTMINSTER	5,876	79	$283,935	$87,532	$304,811
	12294045	ROSEVILLE - FERNWOOD ST DIMP	3,761	40	$92,034	$40,000	$94,200
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL DIMP 2017	9,600	141	$488,249	$141,000	$535,404
	12508317	ST PAUL- KELLOGG (DOWNTOWN)	409	1	$38,325	$1,000	$36,474
	12480505	ST PAULWANDA ST - DIMP	800	12	$41,543	$12,000	$44,989
	12438126	ST PAUL - BURNS-RUTH DIMP 2017	11,665	147	$553,778	$147,000	$498,216
	12511782	ROSEVILLE - OAKCREST	8,980	90	$341,227	$90,000	$281,308
	12510283	ST PAUL - WHITALL ST	8,235	91	$472,016	$91,000	$392,387
	12511776	ROSEVILLE - SHELDON	2,316	24	$89,694	$24,000	$3,046
White Bear Lake	12499044	MAHTOMEDI - HALLMAN-KENWOOD-WILLIAMS	5,680	47	$176,359	$52,076	$195,442
	12501049	STILLWATER - BIRCHWOOD DR	4,406	40	$159,274	$44,320	$163,595
	12317857	ARDEN HILLS - ARDEN VIEW DR	2,276	34	$46,411	$37,672	$38,180
	12479407	NORTH ST PAUL - 16TH AVE	2,747	36	$81,833	$39,888	$78,196
	12481969	NORTH ST PAUL - INDIAN WAY	1,916	25	$56,872	$27,700	$41,972
	12490131	MAPLEWOOD - WINTHROP DR.	2,886	32	$109,196	$35,456	$120,191
	12453189	MAPLEWOOD - KOHLMAN/VAN DYKE	2,151	18	$60,897	$19,944	$92,826
	12480668	MAPLEWOOD - BEAVER LAKE ESTATES	13,282	225	$377,077	$249,300	$326,350
	12466988	MAPLEWOOD - MCKNIGHT	2,100	61	$224,967	$67,588	$248,184
	12484866	MAHTOMEDI - OAKRIDGE DR	4,354	37	$127,002	$40,996	$133,549
	12488109	NORTH OAKS - HAYCAMP RD	19,313	80	$392,378	$88,640	$442,998
	12319969	MAHTOMEDI - GRIFFIN AVE	3,200	40	$95,828	$44,320	$93,563
	12509562	NORTH ST PAUL 17TH AVE	950	8	$62,173	$8,864	$91,617
	12511999	NO ST PAUL 17TH AVE, MARGARET, HENRY & 18TH AVE	51	0	$7,792	$0	$8,921
	12482131	NORTH ST PAUL - MARGERET ST/12TH AVE	1,850	12	$128,641	$13,296	$142,392
	12486720	MOUNDS VIEW - WOODALE DR	7,621	52	$198,758	$57,616	$10,065
	12521893	NORTH ST PAUL - 15TH AVE/16TH AVE	3,600	52	$123,487	$57,616	$76,935
	12481995	NORTH ST PAUL - BURKE AVE	2,948	41	$80,481	$45,428	$85,398
	12478879	NORTH ST PAUL - HILLTOP CT	2,591	29	$92,808	$32,132	$5,959
	12490150	NEW BRIGHTON - WINDSOR CT	6,436	100	$192,233	$110,800	$38,984
	100391006	NORTH ST PAUL - COWERN PL/NORTHWOOD DR	8,765	124	$269,737	$137,392	
	12509429	CENTER CITY - CRESCENT RD	1,944	12	$48,369	$13,296	$2,137
	100382714	NORTH ST PAUL - 18TH AVE	5,423	65	$168,452	$72,020	
	100412219	ARDEN HILLS - GLENPAUL AVE DIMP	4,620	58	$105,991	$64,264	
	100441817	LITTLE CANADA - LABORE RD	5,423	39	$114,201	$43,212	
	100441854	FOREST LAKE - 208TH/209TH	4,002	32	$113,188	$35,456	
	100441816	LITTLE CANADA - EDGERTON ST	5,007	50	$101,045	$55,400	
	12494720	LITTLE CANADA/ JACKSON ST	2,100	21	$44,863	$23,268	$40,348
	100412206	MAPLEWOOD - EDGERTON ST	4,144	22	$107,618	$24,376	
	100439829	NORTH ST PAUL - 2ND AVE	3,789	51	$145,277	$56,508	
Wyoming	12586221	FOREST LAKE - 216/IMPERIAL/INWOOD	3,333	25	$85,189	$27,700	$8,117
	12490080	LINDSTROM- ANDREWS AVE	2,218	25	$51,580	$27,700	$30,267
	100441814	LINDSTROM/ LAKE SHORE TERRACE	4,200	37	$172,132	$40,996	
	12511766	FOREST LAKE - 3RD-6TH NW	1,228	101	$340,249	$111,908	$385,477
	12505525	FOREST LAKE - BAY DR	10,693	107	$361,075	$118,556	$348,405
	100441815	WYOMING - FINELY AVE	3,123	21	$63,147	$23,268	$1,611
	12586414	FOREST LAKE - IVERSON AVE DIMP	3,701	53	$113,706	$58,724	$64,231
	100442027	FOREST LAKE - LAKE ST/11TH AVE	2,123	22	$62,500	$24,376	
	100441850	FOREST LAKE - 215TH/INWOOD AVE	4,291	33	$113,418	$36,564	
Newport	12352434	COTTAGE GROVE - IRONWOOD DIMP	3,227	100	$157,371	$110,800	$145,253
	12510007	WEST ST PAUL - OAKDALE	5,406	55	$325,364	$60,940	$392,548
St Cloud	12533323	ST CLOUD - 44TH AVE N, VA	2,200	7	$98,449	$7,756	$104,899
	12527212	ST. CLOUD-44TH AVE. & VETERANS DR.-DIMP-2400' 4" PE	2,400	12	$82,506	$13,296	$124,023
	12467823	ST CLOUD - 16TH AVE - 2ND ST N TO BRECKENRIDGE	8,136	118	$412,958	$130,744	$446,403
	12466583	ST CLOUD - 16TH AVE - 2ND ST N TO GERMAIN	2,799	41	$139,265	$45,428	$118,456
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1,700	-	$740,000	$0	$734,000
Southeast	12505914	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST DIMP	11,070	160	$1,367,236	$177,280	$1,583,306
	100349421	WINONA 3RD STREET DIMP - RAILROAD WORK	300	0	$33,226	$0	
	12551116	WINONA 98049 - CLARKS LN	8,160	79	$122,507	$87,532	$159,320
	12360394	RED WING - SPRUCE/SOUTHWOOD DIMP	6,000	86	$189,040	$95,288	$249,150
	12356426	LAKE CITY - LAKEWOOD AVE DIMP	4,110	79	$133,903	$87,532	$56,994
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE.	1,268	38	$54,983	$42,104	$39,501
	12422040	DILWORTH - 1ST AVE SE DIMP	4,989	80	$52,327	$88,640	$87,378
2017 DIMP-related Main Replacement Total			**283,892**	**3,347**	**$11,686,143**	**$3,649,508**	**$9,747,976**

*Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

DIMP Replacement Project Detail for 2017

NSP-MN Main & Service Replacement Projects 2018				
Area	Description	Total Design FT.	Tot. Svc	Anticipated Cost
St Paul	ST PAUL - ST PETER, FORD 4TH DIMP (2018)	3850	25	$ 680,850
	ST PAUL - FALCON/EDGEBROOK/WINTHROP	16450	232	$ 872,564
	ST PAUL - MCKNIHGT/WINTHROP/POWERS	9215	125.0	$ 483,298
	ROSEVILLE - OXFORD	1200	5.0	$ 50,443
White Bear Lake	NORTH ST PAUL - 1ST AVE	6311	82.0	$ 284,837
	NORHT ST PAUL - LAKE BLVD	8462	70.0	$ 274,511
	MAPLEWOOD - COPE AVE	3531	38.0	$ 119,800
	MAPLEWOOD - JACKSON ST	4795	45.0	$ 172,702
	MAPLEWOOD - CRAIG PL	5454	53.0	$ 177,204
	NORTH ST PAUL - 17TH AVE	1046	8.0	$ 71,112
	BAYPORT - 7TH ST DIMP	980	11.0	$ 40,000
	MAPLEWOOD-MAYHILL	3771	40.0	$ 156,188
	WHITE BEAR LAKE - STILLWATER ST-BALD-GARDEN	14049	124.0	$ 584,937
	LAKE ELMO - 31ST/JAMLEY/JANERO	6880	43.0	$ 241,955
Wyoming	FOREST LAKE - 1ST-7TH AVE & 3RD-7TH ST	12000	98.0	$ 557,602
Newport	COTTAGE GROVE - 85TH ST	5420	63.0	$ 272,607
	ST PAUL PARK- SUMMIT AVE	3900	38.0	$ 188,034
	COTTAGE GROVE - IDEAL-85TH ST	8200	94.0	$ 410,975
	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	4735	40.0	$ 221,495
	COTTAGE GROVE - HYDE AVE	3710	41.0	$ 184,247
	MENDOTA HEIGHTS - BACHELOR-STANWICH	10570	100.0	$ 506,307
	MENDOTA HEIGHTS - OVERLOOK RD	5700	45.0	$ 263,144
Southeast	RED WING - 9TH ST	850	8.0	$ 40,699
	RED WING - WRIGHT/FINRUD DIMP	10400	130.0	$ 533,179
	WINONA - 44TH AVE	4300	99.0	$ 270,576
	RED WING - MAPLE ST	7600	161.0	$ 477,146
	WINONA - E 10TH ST	3000	108.0	$ 231,900
	WINONA - E 7TH ST	3500	64.0	$ 201,868
	WINONA - E 9TH ST	1400	35.0	$ 91,160
	WINONA - COLLEGEVIEW ST	2000	54.0	$ 1,346,660
	WINONA - W 9TH ST	3400	64.0	$ 198,126
	WINONA - 7TH ST W	5800	138.0	$ 369,910
	RED WING - WOODLAND DR	4200	48.0	$ 210,337
	RED WING - REDING AVE	4830	48.0	$ 233,912
	WINONA - CONRAD DR	6600	133.0	$ 394,307
2018 Designed DIMP-related Main Replacement Total		198,109	2,510	$ 11,414,592

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2017 and the first two quarters of 2018.

Project detail amounts vary from costs presented in Attachment D, due to extracting the data from different systems (PowerPlan vs. Passport) and non-GUIC recoverable costs associated with internal labor.

2016-2018 Project Detail - DIMP Assessments/Replacements

2016			
Line/Loop	**Project Description**	**Actual**	**O&M or Capital**
Anoka IP ECDA (12.3 Miles)	**ECDA**	**$ 19,000**	
	1 Validation Dig	19,000	O&M
Shoreview 175# IP Line (10 Miles)	**ECDA**	**$ 70,000**	
	4 Validation Digs	70,000	O&M
River Crossing Inspections	**Underwater Inspections/Mitigation**	**$ 529,000**	
	River Crossing Inspections	68,000	O&M
	Mobilization/Demobilization	16,000	
	Grout Bag Stabilization	445,000	
Capital Total		**$ -**	
O&M Total		**$ 618,000**	

2017			
Line/Loop	**Project Description**	**Estimates**	**O&M or Capital**
Hugo IP Line (11.1 miles)	**ECDA**	**$ 300,000**	
	ISFS Survey	40,000	O&M
	Traffic Control	9,000	
	Permitting	1,000	
	Test Leads	-	
	Validation Digs	250,000	
Colby Lake Lateral Renewal	**Replacement**	**$ 250,000**	
Engineering, Design, Easement Acquisition		250,000	Capital
H005 System Renewal - Lexington to Snelling	**Replacement**	**$ 250,000**	
Engineering, Design, Easement Acquisition		250,000	Capital
Capital Total		**$ 500,000**	
O&M Total		**$ 300,000**	

2018		
Project	**Description**	**Assumptions**
Langdon Line (TBS to Ashland) Capital Project (no O&M) 2018 Estimated Costs: 2019 Estimated Costs: Total Estimated Capital Costs:	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace 6.0 miles of 12-inch, 8-inch and 6-inch pipe installed in 1958 with a standardized 12-inch pipe. Design and construction will be completed in 2018 and 2019. · Location: This project parallels Highway 61 from 100 Street South in Cottage Grove to 1st Street in Saint Paul Park, MN. · 2018 Construction Period: May – October 2018 · Total Construction Period: 2018-2019 - $12.5M Design, Engineering, Construction - $8.6M Construction - $21.1M	Benefits: Eliminate poor performance, unknown construction specifics, ILI assessable, establish MAOP Current Classification: High Pressure Distribution Future Classification: Distribution · Total Cost Per Unit: $21.1 million or $663/ft.
Colby Lake Lateral - Woodlane to Colby Lake Capital Project (no O&M) 2017 Estimated Costs: 2018 Estimated Costs: Total Estimated Capital Costs:	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: 2.5-mile replacement project; The pipeline was constructed in 1964-1965 using vintage materials and construction methods which, while acceptable at the time, are now associated with threats that contribute to the probability of failures in the pipelines. · Location: Woodbury, MN. · 2018 Construction Period: May – October 2018 - $250K Design, Engineering, Easement Acquisition - $4.75M Construction - $5M	Benefits: ILI assessable Current Classification: High Pressure Distribution Future Classification: Distribution · Total Cost Per Unit: $5 million or $379/ft.
H005 - Lexington to Snelling Capital Project (no O&M) 2017 Estimated Costs: 2018 Estimated Costs: Total Estimated Capital Costs:	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: This is a 3.0 mile replacement project; the pipeline was constructed in 1964 using vintage materials and construction methods; resulting in threats associated with material and construction defects. The pipeline has known mechanical couplings which are a known threat. · Location: Arden Hills beginning at the intersection of Snelling and Hamline and continuing north to Lexington and I-694. · 2018 Construction Period: May – October 2018 - $250K Design, Engineering, Easement Acquisition - $4.95M Construction - $5.2M	Benefits: Eliminate poor performance, unknown Current Classification: High Pressure Distribution Future Classification: Distribution · Total Cost Per Unit: $5.2 million or $328/ft.
H08 – Lake Elmo 1A TBS O&M Project 2018 Estimated O&M Costs:	· Project Type: ECDA · Regulation: 49 CFR 192.921(a) · Overview: Conducting ECDA to provide baseline assessment. · Location: Lake Elmo, MN. · 2018 Assessment Period: May – October 2018 - $200K ECDA	· Survey: $10K · 3 digs at $60K each · Minor costs (permitting, new CP test leads, etc.)
T009 – Cottage Grove TBS O&M Project 2018 Estimated O&M Costs:	· Project Type: ECDA · Regulation: 49 CFR 192.921(a) · Overview: Conducting ECDA to provide baseline assessment. · Location: Cottage Grove, MN. · 2018 Assessment Period: May – October 2018 - $200K ECDA	· Survey: $10K · 3 digs at $60K each · Minor costs (permitting, new CP test leads, etc.)
Montreal Line North – River Crossings/Headers O&M Project Crossing 1 Crossing 2 Crossing 3 Crossing 4 South Header Total Estimated O&M Costs:	· Project Type: Hydrostatic Pressure Test · Regulation: 49 CFR 192.921(a) · Overview: High pressure distribution pipe segments crossing the Mississippi River and entails hydrostatic pressure testing 2.4 miles of 12-inch pipe. Provide baseline assessment. · Location: Sections cross the Mississippi River and extend from Shepard Road in St Paul to Lilydale Road in Lilydale. · 2018 Assessment Period: May – October 2018 $130K North header to south header - 12" $120K North header to south header - 12" $120K North header to south header - 12" $120K North header to south header - 12" $134K $625K	

Colby Lake Lateral Upsize

Xcel Energy
RESPONSIBLE BY NATURE

6" (12") to Colby Lake Lateral Upsize - Project Summary

Capacity Need

- Approximately 2.3 miles of the 6" on the Colby Lake Lateral will be replaced as part of GUIC.
- The existing 6" HP line is only capable of delivering the minimum inlet pressure of 58 psig down to a morning low of -24°F, which occurs approximately once per year. This causes the regulator outlet pressures to droop and create tail end pressures below minimum.
- Upsizing the 2.3 miles of 6" pipe to 12" will serve the current and future demand through 2036 planning term during a -32°F design day, which is a 1-in-30 year occurrence.
- Upsizing to 12" was chosen to accommodate future pigging requirements on the line.

Project Alternatives

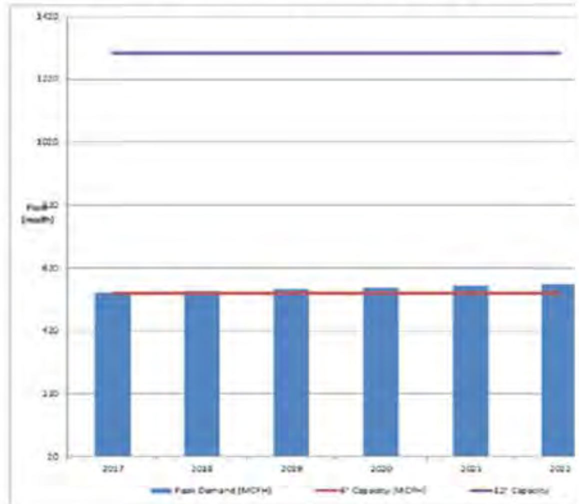
- **Install like for like 6" HP pipe.** This would require the installation of a parallel 6" HP pipeline in 2018 to meet design day requirements.
- The option cost would be $4.4M, exceeding the incremental cost of upsizing the 2.3 miles of 6" to be replaced.

Incremental Cost & Allocation

- The estimated cost for a like-for-like replacement of the 6" pipe is $4,338,000. The approximate incremental cost for project upsize to 12" is $1,143,000 for the 2.3 miles of pipe for a total project costs of $5,481,000.
- The costs associated with the like-for-like replacement or 79.1% ($4,338,000 /$5,481,000) will be funded by the GUIC. The costs associated with the upsize or 20.9% ($1,143,000/ $5,481,000) will be funded by base rates.

	Pipeline Size	Estimated Cost	Allocation
GUIC	6"	$ 4,338,000	79.1%
Non-GUIC Recoverable	All 12"	$ 1,143,000	20.9%
	Total:	$ 5,481,000	100%

Pipeline Capacity vs. Peak Demand



DIMP Distribution Valve Project Detail for 2016

NSP-MN New Distribution Valve Installation DIMP Projects 2016

Division	Size (in)	Material	Location	WO #	Estimated Cost	Actual Cost	Completed
NPT	2	PE	Linwood & Century	11762634	$3,000	$3,329	3/22/2016
NPT	2	PEYP	6th & 7th	11794426	$3,000	$2,586	3/28/2016
NPT	3	PES	Rich Valley & Alverno	11800143	$4,000	$3,462	2/29/2016
NPT	4	PEYU	Upper Afton & Oakwood	11759132	$5,000	$3,049	2/23/2016
NPT	4	PEYU	Oakwood & Century	11760021	$5,000	$3,635	2/26/2016
NPT	4	PEYU	Mcknight & Burlington	12344074	$5,000	$3,345	3/4/2016
NPT	4	PET	Cliff & Akron	11775030	$5,000	$4,765	2/25/2016
NPT	4	PEA	Cahill & Buckley	11797338	$5,000	$5,231	4/4/2016
NPT	4	PEYP	Cahill & 80th	11785263	$5,000	$4,315	3/3/2016
NPT	4	PEYU	Concord & Concord Path	11797699	$5,000	$3,184	2/26/2016
NPT	4	PE	Ruth & Burns	11760816	$5,000	$5,537	7/14/2016
NPT	8	PEYU	Cypress & Pacific	11778091	$10,000	$11,494	3/14/2016
NPT	4	SC	9th Ave & Pleasant Ave	11766140	$0	$12,481	3/22/2016
SE	4	C	Mankato Ave & Lake Blvd	12398435	$9,000	$2,804	2017
STC	12	SC	3130 2nd St S (Carry over from 2015)	12190722	$0	$4,591	10/28/2015
STP	2	PEYU	Armstrong & View	11713907	$4,043	$2,501	7/6/2016
STP	2	PEYU	Case & Forest	11777324	$3,000	$3,061	4/4/2016
STP	4	PEYP	Palace & View	12394529	$3,925	$2,188	6/3/2016
STP	4	PEYP	Forest & Hawthorne	11777092	$5,000	$4,397	6/20/2016
STP	4	PEYP	3rd Street E.	12452200	$0	$3,491	10/24/2016
STP	4	PEYP	County Rd "C" & Victoria	12395715	$5,000	$244	Cancelled
WBL	2	PET	County Rd E & Auger Ave	11774994	$2,500	$6,510	10/11/2016
WBL	2	PEYD	Hallam Ave & Stillwater Rd	11799929	$2,500	$2,895	10/24/2016
WBL	2	PEYP	Forest Blvd & 159th St	11803546	$2,500	$2,410	2/25/2016
WBL	2	PEA	W Pleasant Lake Rd & Red Fox Rd	11786256	$2,500	$1,767	2/23/2016
WBL	2	PET	Heron Ave & 19th St N	11781532	$2,500	$2,168	3/4/2016
WBL	2	PEYP	Myrtle St W & William St N	11824591	$2,500	$5,442	10/7/2016
WBL	2	PET	Pine St W & 3rd St S	11819422	$2,500	$208	Cancelled
WBL	2	PE	Olinda Blvd N & Omaha Ave N	11799609	$2,500	$5,112	10/5/2016
WBL	2	PET	30th St N & Oakgreen Ave N	11799089	$2,500	$2,098	3/14/2016
WBL	2	PEYP	20th St N & Neal Ave N	11794772	$2,500	$1,940	3/8/2016
WBL	2	PEYP	111th Ave NE & Club West Pkwy	11804844	$2,500	$1,381	3/7/2016
WBL	2	PEYP	Baltimore St & 12th Ave NE	11800149	$2,500	$1,840	3/7/2016
WBL	2	PEYU	113th Ave NE & Club West Pkwy	11800011	$2,500	$1,848	8/25/2016
WBL	2	PEYP	7th St NW & Glenbrook Ave N	11820751	$2,500	$5,217	9/28/2016
WBL	2	PEYP	Grand Ave & 4th St N	11801917	$2,500	$8,206	3/3/2016
WBL	2	PEYP	Grovner Ave & 5th St N	11802649	$2,500	$2,065	3/2/2016
WBL	3	PET	Little Canada Rd & Centerville Rd	12453548	$3,000	$4,091	10/28/2016
WBL	3	PEA	McMenemy St & McMenemy Circle	11803601	$3,000	$4,214	10/17/2016
WBL	3	PEA	Robb Farm Rd & E Gilfillan Rd	11784200	$3,000	$3,637	2/24/2016
WBL	3	PE	Division St N & South Ave E	11797883	$3,000	$4,493	10/18/2016
WBL	3	PE	Stillwater Blvd & Hale Ave N	11805856	$3,000	$5,692	10/3/2016
WBL	3	PE	Scandia N & Jewel Ln	11895527	$3,000	$3,197	3/22/2016
WBL	3	PE	Scandia N & Forest Blvd N	11896580	$3,000	$2,094	10/23/2016
WBL	3	PE	Forest Blvd N & Thurnbeck Dr	11899087	$3,000	$3,144	3/23/2016
WBL	4	PEA	Otter Lake Rd & Hammond Rd	12405340	$4,000	$4,764	6/1/2016
WBL	4	PEYD	Hwy 96 E & White Bear Pkwy	11759043	$4,000	$3,720	11/10/2016
WBL	4	C	Birch Lake Blvd & Otter Lake Rd	11760184	$9,000	($2,013)	deferred
WBL	4	C	4th St & Bald Eagle Ave	11761163	$9,000	$17,787	10/12/2016
WBL	4	PEYP	117th St & Portland Ave	11770029	$4,000	$6,281	9/9/2016
WBL	4	PET	129th St N & Elmcrest Ave	11774429	$4,000	$3,305	8/2/2016

DIMP Distribution Valve Project Detail for 2016

NSP-MN New Distribution Valve Installation DIMP Projects 2016

Division	Size (in)	Material	Location	WO #	Estimated Cost	Actual Cost	Completed
WBL	4	C	County Rd F & Bellaire Ave	11765476	$9,000	$9,526	9/23/2016
WBL	4	PEYD	Arcade St & Berwood Ave	11779412	$4,000	$2,562	8/13/2016
WBL	4	PEYP	Edgerton St & Centerville Rd	11790811	$4,000	$3,375	11/1/2016
WBL	4	PEYU	Farnham Ave N & Oneka Pkwy	11803572	$4,000	$3,679	3/1/2016
WBL	4	PEYU	Heritage Pkwy & Education Dr	11803585	$4,000	$2,836	2/26/2016
WBL	4	PEYP	County Rd D & White Bear Ave	11797366	$4,000	$6,525	10/27/2016
WBL	4	PEYU	White Bear Ave & Beam Ave	11798542	$4,000	$12,641	11/2/2016
WBL	4	PE	McKnight Rd & Lydia Ave	11798614	$4,000	$3,795	8/27/2016
WBL	4	PEYP	County Rd J & Pheasant Dr	11786563	$4,000	$4,619	10/24/2016
WBL	4	PET	50th St & Hadley Ave	11798029	$4,000	$5,017	10/5/2016
WBL	4	PEYP	Hadley Ave & 34th St N	11805498	$4,000	$4,402	6/1/2016
WBL	4	PEYP	15th St N & 15th St Ct N	11780159	$4,000	$2,850	9/14/2016
WBL	4	PEYP	15th St N & Hwy 694 N	11780218	$4,000	$10,142	10/7/2016
WBL	4	PET	Norell Ave N & Dellwood Rd	11800020	$4,000	$2,035	3/9/2016
WBL	4	PEYU	Stillwater Blvd & Oakridge Rd	11823047	$4,000	$5,168	3/17/2016
WBL	4	PEYD	Stonebridge N & Penfield Ave N	11800054	$4,000	$3,554	3/18/2016
WBL	4	PEYD	30th St N & Manning Ave N	11798215	$4,000	$3,022	3/11/2016
WBL	4	PEYP	Stillwater Blvd N & 40th St N	11796603	$4,000	$3,347	9/26/2016
WBL	4	PEYP	Stillwater Blvd N & 58th St N	11795996	$4,000	$15,935	3/10/2016
WBL	4	PET	Northbrook Blvd N & 51st St N	11799730	$4,000	$3,401	3/14/2016
WBL	4	PET	10th St N & Neal Ave N	11829021	$4,000	$3,868	10/6/2016
WBL	4	PEYD	10th St N & Oakgreen Ave N	11795073	$4,000	$6,427	5/4/2016
WBL	4	C	County Rd E & 20th Ave SW	11784983	$9,000	$10,096	9/8/2016
WBL	4	PEYP	Greenway Ave & 5th St N	11802222	$4,000	$2,087	6/1/2016
WBL	4	PEYU	Roselawn Ave & Edgerton St	11790765	$4,000	$5,734	10/27/2016
WBL	4	PET	Lexington Ave & Ingerson Rd	11794394	$4,000	$5,103	10/28/2016
WBL	4	PEYP	60th Street N.	12447964	$0	$1,316	10/25/2016
WBL	6	C	Cedar Ave & Keri Ann Ln	11764478	$15,000	$20,728	10/31/2016
WBL	6	C	White Bear Ave & Hwy 694	11764950	$15,000	$25,656	10/19/2016
WBL	6	C	Flandreau St & Kennard St	11798472	$15,000	$16,877	10/27/2016
WBL	6	PEYU	Hodgson Rd & Hwy 96 W	11791524	$6,000	$8,105	8/18/2016
WBL	6	C	Larpenteur Ave E & English St	11791740	$15,000	$13,192	10/13/2016
WBL	6	C	Hillview Rd & Long Lake Rd	11792760	$15,000	$12,103	11/10/2016
WBL	6	C	Hadley Ave & 7th St N	11821649	$15,000	$23,876	10/6/2016
WBL	8	C	Larpenteur Ave & Mcknight Rd	11780179	$20,000	$14,422	11/11/2016
WBL	8	C	Larpenteur Ave E & Kennard St	11791892	$20,000	$22,681	11/4/2016
WBL	2	PET	South Oaks & Clover Ave.	11779311	$2,500	$1,381	3/7/2016
WBL	6	PEYP	Lincoln Rd & Lake Ln (Carryover cost from 2015)	11898941	$0	$511	12/11/2015
WBL	4	PEYP	Conway Avenue	12457540	$0	$5,681	11/23/2016
WYO	2	PEYP	Europa N & 132nd St	11771874	$2,500	$467	3/1/2016
WYO	4	PEYP	Itasca Ave N & Green Lake	11901363	$4,000	$3,354	3/21/2016
WYO	4	PEYP	Wyoming Trl N & Ironwood	11901106	$4,000	$2,977	3/22/2016
WYO	4	PEYP	Scandia N & Forest Blvd N	11896688	$4,000	$4,291	9/1/2016
WYO	4	PEYU	264th St N & Forest Blvd N	11902308	$4,000	$2,620	3/21/2016
WYO	4	PEYU	113th Ave NE & Club West Pkwy	11802970	$4,000	$3,231	8/13/2016
WYO	4	PEYU	Club West Pkwy & 114th Ave NE	11799971	$4,000	$2,610	8/13/2016
				Total	**$466,968**	**$533,028**	

*** This project list includes non-recoverable internal labor.**

Total Valves	97
Average Cost	$4,814

DIMP Distribution Valve Project Detail for 2017

NSP-MN Inoperable Distribution Valve Replacement DIMP Projects 2017

Project Name/Location	Valve #	Size/Mtl
Henry Ave & Fleming Field, SSTP	EV1245	12" SC
Algonquin & Iroquois, STP	EV1275	12" SC
7th & Dale, STP	EV1241	12" SC
Forest & Rose, STP	EV1202	12" SC
Cypress & 6th, STP	EV1218	6" SC
Victoria & St. Anthony, STP	EV1069	6" SC
Algonquin & Iroquois, STP	EV1276	6" SC
Robert & Page, STP	EV1178	8" SC
Cypress & Reaney, STP	EV1213	8" SC
Roselawn & McMenomie	DV6070	4" SC
Roselawn & McMenomie	DV6068	6" SC
Roselawn & McMenomie	EV6069	6" SC
McKnight & 3rd St E	EV1289	4" SC
McKnight & 3rd St E	EV1288	8" SC
McKnight & 3rd St E	EV1290	4" SC
Larpenter & Gary (Postponed to 2018)	EV1261	8" SC
Larpenter & Gary (Postponed to 2018)	EV1262	8" SC
Larpenter & Gary (Postponed to 2018)	EV1263	8" SC
McKnight & Hudson Rd	EV1291	8" SC
Larpenter & Gary (Postponed to 2018)	EV6132	8"SC
Hwy 19 W TBS	EV3512	8" SC
Hwy 19 W TBS	EV3513	6" SC

Total valves: 22
Project Cost $800,000 (includes non-recoverable internal labor)
Average Cost = $36K

** Known valves, subject to change.*

DIMP Distribution Valve Project Detail for 2018

NSP-MN Inoperable Distribution Valve Replacement DIMP Projects 2018

Project Name/Location	Valve #	Size/Mtl
Snelling & Englewood, STP	EV1020	12" SC
Fairview & Juno, STP	EV1030	16" SC
Fairview & Montreal, STP	EV1037	16" SC
Dayton Ave & Cretin Ave, STP	EV5199	2" PE
St. Albans & Alley South of Selby, STP	EV1373	4" SC
Hamline & County Road "B", RSV	R063 bypass	4" SC
St. Peter & 10th St., STP	R172 Block Valve	6" SC
7th & South, NSTP	EV0291	6" SC
Rich Valley Rd & 105th St, Eagan	R413W bypass	2" SC
Plato & Water, STP	R182 Block Valve	4" SC
Larpenter & Gary (Carry Over from 2017)	EV1261	8" SC
Larpenter & Gary (Carry Over from 2017)	EV1262	8" SC
Larpenter & Gary (Carry Over from 2017)	EV1263	8" SC
Larpenter & Gary (Carry Over from 2017)	EV6132	8"SC

Total valves: 14
Project Cost $800,000 (includes non-recoverable internal labor)
Average Cost = $57K

** Known valves, subject to change.*

Northern States Power Company

Docket No. G002/M-17-____
Gas Utility Infrastructure Cost Rider - 2018 Factors
Attachment D1(j)

DIMP Federal Code Mitigation 2016-2018

2016			Division					Total Items	Unit Cost	Actual Spend
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN			
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	0	0	0	506	0	506	$ 442	**$ 223,000**

*Does not include an additional 217 visited sites that required no substantive work but incurred minor costs.

2017			Division					Total Items	Unit Cost	Projected Spend
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN			
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	0	0	0	608	0	608	$ 550	$ 333,900
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	29	14	1		7	51	$ 550	$ 28,050
IS	O&M	MMIG RPTG ONLY- REMEDIATE IDLE RISER/NO METER	3	7	9	1	28	48	$ 800	$ 38,400
IE	O&M	MMIG RPTG ONLY- INSTALL GUARD POST - RESIDENTIAL	2	1	6	11	20	40	$ 1,000	$ 40,000
IF	O&M	MMIG RPTG ONLY- INSTALL GUARD POST - COMMERCIAL/INDUSTRIAL	3	2	2	2	9	18	$ 1,000	$ 18,000
IT	O&M	MMIG RPTG ONLY- RELOCATE INACCESSIBLE METER SET (IN TO OUT)	1	0	0	4	2	7	$ 1,600	$ 11,200
IC	O&M	MMIG RPTG ONLY- REPAIR RISER (ATMOS. CORR. - PITTING)	0	0	0	2	0	2	$ 1,000	$ 2,000
IH	O&M	MMIG RPTG ONLY- INSTALL ICE SHIELD - METER SET	0	0	0	1	0	1	$ 350	$ 350
Total	O&M	**Total Items**						**775**		**$ 471,900**

*Preliminary estimates; subject to change.

2018			Division					Total Items	Unit Cost	Projected Spend
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN			
IM	O&M	TBD								**$ 200,000**

* Final O&M project list in-process of scope development.

DIMP 2016 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2016 Projects

2016				
Polygon ID	City	State	Project	Estimated Service Count
312787367	Stacy	MN	Sunrise Estates Mobile Home Park	225
312787494	Landfall	MN	Landfall Terrace	274
312787518	Maplewood	MN	Rolling Hills Mobile Home Park	359
312787529	Maplewood	MN	Beaver Lake Estates	254
312787540	Shoreview	MN	Brookside	216
312787606	Arden Hills	MN	Arden Manor	287
312787661	Inver Grove Heights	MN	Emerald Hills Village	402
312787960	Rice	MN	Rockwood Estates	206
312788048	Sartell	MN	Evergreen Village	196
312788092	St Cloud	MN	Bel Clare Estates	293
312788103	St Cloud	MN	River View Park	70
312788114	St Cloud	MN	Shady Oak	18
312788136	St Cloud	MN	Sherwood Manor	72
312788147	St Cloud	MN	Cloverleaf MHP	169
317305364	Oakdale	MN	7th St & Gershwin	95
317305386	Oakdale	MN	9th St & Heron	86
317305971	Sartell	MN	Heritage & Anna	194
317305993	St Cloud	MN	33rd st s & Oregon	366
359596048	Forest Lake	MN	Shore and 4th	508
359596072	Forest Lake	MN	Broadway and Lake	570
359596139	Sauk Rapids	MN	5th Ave and 5th St	668
359596152	Nisswa	MN	Hwy 371 and Roy Lake	151
359596165	Nisswa	MN	Poplar and Cullen	204
359596178	Nisswa	MN	White Pine and Cnty Rd 13	184
359596230	Little Canada	MN	Cnty Rd C and Sylvan	447
359596243	Little Canada	MN	Allen and Payne	616
359596256	Hugo	MN	Falcon and 130th	1565
359596280	Grant	MN	Jasmine and 68th	430
359596307	Grant	MN	Jamaca and 105	130
359596320	Grant	MN	88th and Kimbro	185
359596333	Forest Lake	MN	216th and Scandia	618
359596347	Forest Lake	MN	15th and 9th	228
359596386	Cottage Grove	MN	70th St and Innsdale	2037
359596399	Woodbury	MN	Pheasant Run and Corral	1800
359596412	Woodbury	MN	Wynstone and Cnty Rd 19	1137
359596425	Becker	MN	Sherburn and Lee	541
359596438	Becker	MN	Jefferson and 14th	83
359596477	Baxter	MN	Highland Scenic & Chestnut	223
359596490	Moorhead	MN	Belsly & 12th St	402
359596530	White Bear Township	MN	Sandterra & Mallard	255
359596701	Oakdale	MN	22nd & Helmo Ave	1611
			Total	**18,375**

*Tables will exceed amounts of actual inspections completed due to inaccessible locations and customer service issues.

DIMP 2017 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2017 Projects

2017				
Polygon ID	**City**	**State**	**Project**	**Estimated Service Count**
312787299	Lindstrom	MN	Lake Shore Terrace Trailer Park	80
312787310	Lindstrom	MN	Blue Waters Leisure Park	63
312787321	Wyoming	MN	River Bend Trailer Park	53
312787332	Wyoming	MN	Birtchwood Terrace Trailer Parks	83
312787378	Lindstrom	MN	Lindstrom Mobile Home Park #1	25
312787389	Lindstrom	MN	Stone Gate Terrace	52
312787400	Shafer	MN	Shafer Mobile Home Park #1	25
312787411	Shafer	MN	Shafer Mobile Home Park #2	18
312787685	Inver Grove Heights	MN	52nd & Brent	65
312787740	Faribault	MN	Sunrise MHP	72
312787773	Lake City	MN	Maplewood Trailer Park	77
312787817	Cross Lake	MN	Sand Point	46
312787828	Cross Lake	MN	Peaceful Harbor	29
312787839	Brainerd	MN	Spencer Trailer Park	12
312787850	Cross Lake	MN	Chattum Park	43
312787861	Fifty Lakes	MN	Open Gate Resort	20
312787872	Pequot Lakes	MN	Pequot Terrace	39
312787883	Brainerd	MN	Lazy Acres MHP	23
312787894	Cosmos	MN	Cosmos MHP	19
312787905	Waverly	MN	12-HI MHP	11
312787916	Montrose	MN	Montrose Manor	11
312787927	Watertown	MN	Watertown	1
312787938	Watertown	MN	Riverside Terrace	10
312787949	Royalton	MN	East Trailer Park	33
312787971	Spicer	MN	Spicer MHP #2	2
312787982	Spicer	MN	Spicer MHP #1	5
312787993	New London	MN	New London MHP #1	45
312788004	Foley	MN	Foley Park #1	17
312788015	Foley	MN	Foley Park #2	24
312788026	Foley	MN	Foley MHP	29
312788114	St Cloud	MN	Shady Oak	18
312788125	Sauk Rapids	MN	Fischer's Garden MHP	81
312788158	Glyndon	MN	Praireview Estates	26
312788169	Glyndon	MN	Glyndon MHP	28
312788180	Dilworth	MN	Dilworth MHP	62
312788202	Dilworth	MN	Villa Del Sol	28
312787674	Maplewood	MN	Maplewood MHP	23
359596503	Moorhead	MN	34 St and 12 Ave	678
359596504	White Bear Township	MN	Park and Beaver	525
325047668	Marine On St Croix	MN	Marine On St Croix (174 septic)	266
372455208	Chisago	MN	Lake Blvd and Loft F637	480
372455214	Wyoming	MN	Forest and 264th	1372
372455218	Stillwater Twp	MN	Stoneridge and Norrell	359
372455222	Winona	MN	Hwy 61 and Gilmore	1554
372455226	Mahtomedi	MN	Maple and Mahtomedi	1155
372455230	Grant	MN	Dellwood and Jamaca	361
372455234	Vadnais Heights	MN	County Rd E and Centerville	1060
372455238	North Oaks	MN	E Oaks and North Oaks	930
372455242	New Brighton	MN	I35 and County Rd E2	1082
372455246	St Cloud	MN	Roosevelt Rd and 11th	1983
372455250	St Cloud	MN	2nd St and 7th Ave	1005
372455254	Nisswa	MN	Lazy Brook and Hwy 371	619
372455258	Woodbury	MN	Courtly Rd and Woodbury Dr	5833
			Total	**20,560**

DIMP 2018 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2018 Projects

2017				
Polygon ID	**City**	**State**	**Project**	**Estimated Service Count**
3.72E+08	Roseville	MN	County Rd C2 W and Western Ave	784
3.6E+08	Vadnais Heights	MN	Berwood and Arcade	1,168
3.72E+08	Faribault	MN	8th St and 4th Ave	969
3.72E+08	Sauk Rapids	MN	11th St N and 9th St N	869
3.72E+08	Cottage Grove	MN	80th St S and Hwy 61	3,619
			Total	**7,409**

Quantitative Risk Assessment for 2018 GUIC Programs and Initiatives

DIMP

Methodology

Xcel Energy's risk assessment methodology is a process to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. The goal of the Company's integrity programs is to protect the public, property and the environment from pipeline failures.

The purpose of this risk assessment methodology is to develop a quantitative risk score and assign a risk category (high, medium, low) for identified projects that are funded through the Company's GUIC rider.

These quantitative risk assessment methodologies assign numeric values to likelihood and consequences by using available data and quantifying assessments. In some cases, subject matter expert (SME) input is utilized.

DIMP Poor Performing Mains & Services

Problematic Steel Project Risk

SEE ATTACHMENT D2(b)

Uses Commercial Software: Optimain DS by Opvantek

Data Inputs include data such as Leak Date, Leak Class, Leak Cause, Pipe Length, Pipe Material, Pipe Pressure, Pipe Diameter, Pipe Coating, Year Installed, Cathodic Protection, Presence of Excess Flow Valve on Service, Building Class and proximity to pipeline, and Population Density.

A Project is comprised of mains and services with similar material, diameter and pressure and cathodic protection status. Typical projects consist of approximately 1500 feet of main and associated services.

Project Risk = Main Risk + Service Risk

Main Risk = ∑ (Risk Profile Score x EV Failure) for each failure type

Service Risk = ∑ (Risk Profile Score x EV Failure) for each service and failure type

> Failure Types include Corrosion Leaks & Other Leaks
>
> EV Failure = probability of future leaks using the number and type of prior leaks on the project
>
> Risk Profile = ∑ (Weight x Score) over all of the Risk Profile Factors
>
> Risk Profile Factors include factors such as Leak Class, Volume/Pressure, Inside Meters, Cover Type, Building Class, and Population Density

Projects may also be designated as high or medium risk via engineering judgment provided by subject matter experts (SMEs) who evaluate factors such as recent leakage which is not yet in the Optimain model, field observations that the pipe has significant corrosion, the presence of problematic material types such as bare steel or copper, or the presence of mechanical compression couplings. Lower risk pipe segments in the same block as higher risk segments may be done as part of the same project to minimize disruption to the local community.

Risk Category	Project Risk Scores Range	Number of Optimain Projects Currently Identified as of August 2016	Percentage
High	Score ≥ 36	1,476	2.51%
Medium	24 ≤ Score < 36	652	1.11%
Low	1 ≤ Score < 24	12,596	21.45%
None	Score < 1	43,985	74.92%
Total	**All**	**58,709**	

DIMP Poor Performing Mains & Services

Problematic Plastic Project Risk

SEE ATTACHMENT D2(b)

Data inputs:

- Material Risk Factor
- Pressure Leak Factor
- Population Density

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Material Risk Factor + Pressure Risk Factor

<u>Material Risk Factor Lookup Table</u>

Material Type and Year Installed	**Score**
Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; use installation dates prior to 1975 to account for depletion of inventory	4
Century Products Medium Density Polyethylene (MDPE) designated PE 2306 installed in any year	4
High-Density Polyethylene (HDPE) gas pipe designated PE 3306 installed in any year	4
Dylon	4
Aldyl-A installed in 1975 or later	0

<u>Pressure Risk Factor Lookup Table</u>

Pressure system	**Score**
Pounds High	1
Pounds Medium	0.75
Pounds Low	0.5

<u>Consequence of Failure Lookup Table</u>

Condition	**Score**
Business District[1]	1.75
Population Density from Census Block Data ≥ 2000 people per square mile	1.5
1000 < Population Density from Census Block Data < 2000	1.25
Population Density from Census Block Data < 1000 people per square mile	1

(1) Business Districts that have a high population during the workday will not be reflected on census data.

Risk Matrix

<table>
<tr><td colspan="3" rowspan="3"></td><td colspan="4">Consequence</td></tr>
<tr><td>Population Density from Census Block Data < 1000 people per square mile</td><td>1000 < Population Density from Census Block Data < 2000</td><td>Population Density from Census Block Data ≥ 2000 people per square mile</td><td>Business District</td></tr>
<tr><td>1</td><td>1.25</td><td>1.5</td><td>1.75</td></tr>
<tr><td rowspan="4">Likelihood of Failure</td><td>Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; or Century MDPE 2306 or HDPE 3306 or Dylon - Pounds High</td><td>5</td><td>5.0</td><td>6.3</td><td>7.5</td><td>8.8</td></tr>
<tr><td>Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; or Century MDPE 2306 or HDPE 3306 or Dylon - Pounds Medium</td><td>4.75</td><td>4.8</td><td>5.9</td><td>7.1</td><td>8.3</td></tr>
<tr><td>Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; or Century MDPE 2306 or HDPE 3306 or Dylon - Pounds Low</td><td>4.5</td><td>4.5</td><td>5.6</td><td>6.8</td><td>7.9</td></tr>
<tr><td>Aldyl-A installed in 1975 or later</td><td>≤ 1</td><td>≤ 1</td><td>≤ 1.25</td><td>≤ 1.5</td><td>≤ 1.75</td></tr>
</table>

High Risk, Risk Score ≥ 7
Medium Risk, 4 ≤ Risk Score < 7
Low Risk, Risk < 4

DIMP Intermediate Pressure (IP) Line Assessments
Line Replacements Project Risk

Project	Regulation	Current Classification	Mechanical Joint	Manufac-turing/ Construct-ion Defect	Corrosion	3rd Party Damage	Other Leak History	Conse-quence	Risk Score	Project Classificati-on
Colby Lake Lateral	49 CFR 192.921(a)	Distribution	0	2	1	1	1	3	15	High
H005 - Lexington to Snelling	49 CFR 192.921(a)	Distribution	2	2	1	1	1	3	21	High
Langdon Line (TBS to Ashland)	49 CFR 192.921(a)	Distribution	2	2	1	1	0	3	18	High

HP = distribution pipeline with MAOP > 60 psig

Used for decisions on replacement or other mitigation necessity

Data inputs:

- Construction Risk Factor - Presence of Mechanical Joint Joining Method
- Manufacturing/Construction Risk Factor – Post Construction Pressure Test
- History of Corrosion, 3rd Party Damage and other leakage
- Pipeline Class Location

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = (Mechanical Joint Risk Factor + Manufacturing/Construction Risk Factor + Maximum Score of (Corrosion Risk Factor, 3rd Party Damage Risk Factor, Other Leak History Factor)

Mechanical Joint Risk Factor Lookup Table

Condition	Score
Pipeline Segment Contains Mechanical Joints	2
Does Not Include Mechanical Joints	0

Manufacturing/Construction Defect Risk Factor Lookup Table

Condition	Score
Post Construction Pressure Test < (MAOP x class location test factor from 192.619(a)(2)) OR Documentation of Pressure Test is not Traceable, Verifiable and Complete (TVC)	2
Post Construction Pressure Test ≥ (MAOP x class location test factor from 192.619(a)(2))	0

Corrosion Risk Factor Lookup Table

Condition	Score
History of Corrosion Leakage	1
Presence of Corrosion Pitting	1
No history of Corrosion leakage or pitting	0

3rd Party Damage Risk Factor Lookup Table

Condition	Score
Presence of 3rd Party Damage	1
No Presence of 3rd Party Damage	0

Other Leak History Risk Factor Lookup Table

Condition	Score
History of Leakage due to Causes other than corrosion or 3rd Party Damage	1
No History of Other Leakage	0

Consequence of Failure Lookup Table

Class Location	Score
4	4
3	3
2	2
1	0.5

Projects may also be designated as high risk or medium risk via engineering judgment provided by subject matter experts (SMEs).

Risk Matrix

			Consequence			
			Class 1	Class 2	Class 3	Class 4
			0.5	**2**	**3**	**4**
Likelihood of Failure	Mechanical Coupled **AND** No TVC Test to criteria **AND** Corrosion/Leakage/3rd Party	**5**	2.5	10	15	20
	Mechanical Coupled **AND** No TVC Test to criteria **AND NOT** Corrosion/Leakage/3rd Party	**4**	2	8	12	16
	Mechanical Coupled **OR** No TVC Test to criteria **AND** Corrosion/Leakage/3rd Party	**3**	1.5	6	9	12
	Mechanical Coupled **OR** No TVC Test to criteria **AND NOT** Corrosion/Leakage/3rd Party	**2**	1	4	6	8
	Not Mechanically Coupled, Pressure Test is TVC and meets criteria, no Corrosion/Leakage/3rd Party	**0**	0	0	0	0

(dark)	High Risk, Risk Score ≥ 10
(medium)	Medium Risk, 4 ≤ Risk Score < 10
(light)	Low Risk, Risk < 4

DIMP Intermediate Pressure (IP) Line Assessments

Line Assessments Project Risk

Project	Years Since Assessment	Pipeline Class Location	Risk Score	Risk Level
H08 – Lake Elmo 1A TBS	32	Class 3	6	Medium
T009 – Cottage Grove TBS	14	Class 3	4.5	Medium
Montreal Line North	n/a	Class 3	9	High

HP = distribution pipeline with MAOP > 60 psig

Used for decisions on prioritizing integrity assessments

Data inputs:

- Years since last integrity assessment
- Pipeline Class Location

Risk Score = Likelihood of Failure x Consequence of Failure

			Consequence			
			Class 1	Class 2	Class 3	Class 4
			1	**2**	**3**	**4**
Likelihood of Failure	Last Assessment > 35 years prior or no previous assessment	**3**	3	6	9	12
	20 years ≤ Last Assessment < 35 years prior	**2**	2	4	6	8
	10 years ≤ Last Assessment < 20 years prior	**1.5**	1.5	3	4.5	6
	Last Assessment < 10 years prior	**0.5**	0.5	1	1.5	2

High Risk, Risk Score ≥ 8
Medium Risk, 4 ≤ Risk Score < 8
Low Risk, Risk < 4

DIMP Distribution Valve Replacement

Project Risk

Project Name/Location	Size/Mtl	Main Line Valve Operable? Y or N	Vault Condition? Good or Poor	Atmospheric Corrosion Status? Present or not Present	Likelihood of Failure Score	Consequence of Failure Score	Risk Score	Risk Category High Risk: Risk Score ≥ 12 Medium Risk: 9 ≤ Risk Score < 12 Low Risk: Risk Score < 9
Snelling & Englewood, STP	12" SC	N	Good	N	3	3	9	Medium Risk
Fairview & Juno, STP	16" SC	N	Good	N	3	4	12	High Risk
Fairview & Montreal, STP	16" SC	N	Good	N	3	4	12	High Risk
Dayton Ave & Cretin Ave, STP	2" PE	N	Good	N	3	4	12	High Risk
St. Albans & Alley South of Selby, STP	4" SC	N	Poor	N	3.75	4	15	High Risk
Hamline & County Road "B", RSV	4" SC	N	Good	N	3	1	3	Low Risk
St. Peter & 10th St., STP	6" SC	N	Good	N	3	1	3	Low Risk
7th & South, NSTP	6" SC	N	N/A	N	3	2	6	Medium Risk
Rich Valley Rd & 105th St, Eagan	2" SC	N	N/A	N	3	1	3	Low Risk
Plato & Water, STP	4" SC	N	Good	N	3	1	3	Low Risk
Larpenter & Gary (Carry Over from 2017)	8" SC	N	Good	Y	3.25	4	13	High Risk
Larpenter & Gary (Carry Over from 2017)	8" SC	N	Good	Y	3.25	4	13	High Risk
Larpenter & Gary (Carry Over from 2017)	8" SC	N	Good	Y	3.25	4	13	High Risk
Larpenter & Gary (Carry Over from 2017)	8"SC	N	Good	Y	3.25	4	13	High Risk

Data inputs:

- Number of Premises in Existing Emergency Area due to non-functional valve
- Valve Operability
- Atmospheric Corrosion History
- Vault Condition

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Valve Operability Risk Factor + Vault Condition Risk Factor + Atmospheric Corrosion Risk Factor

Valve Operability Risk Factor Lookup Table

Valve Operable	**Score**
No	3
Yes	0

Vault Condition Risk Factor Lookup Table

Vault Condition	**Score**
Vault Condition Poor (Inaccessible due to water intrusion)	0.75
Vault Condition Good	0

Atmospheric Corrosion Risk Factor Lookup Table

Atmospheric Corrosion Status	**Score**
Atmospheric Corrosion Present	0.25
Atmospheric Corrosion Not Present	0

Consequence of Failure Lookup Table

Premise Count of Existing Emergency Area if valve remains inoperable	**Score**
Premises in Existing Emergency Area > 4000	4
3000 < Premises in Existing Emergency Area ≤ 4000	3
2000 < Premises in Existing Emergency Area ≤ 3000	2
Premises in Existing Emergency Area ≤ 2000	1

Risk Matrix

			Consequence			
			Existing Emergency Area < 2000 services	2000 < Premises in Existing Emergency Area ≤ 3000	3000 < Premises in Existing Emergency Area ≤ 4000	Premises in Existing Emergency Area > 4000
			1	**2**	**3**	**4**
Likelihood of Failure	Valve Inoperable AND Vault Condition Poor AND Atmospheric Corrosion	**4**	4	8	12	16
	Valve Inoperable AND Vault Condition Poor	**3.75**	3.75	7.5	11.25	15
	Valve Inoperable AND Atmospheric Corrosion	**3.25**	3.25	6.5	9.75	13
	Valve Inoperable	**3**	3	6	9	12
	Valve Operable but Vault Condition Poor AND Atmospheric Corrosion	**1**	1	2	3	4

High Risk, Risk Score ≥ 12
Medium Risk, 6 ≤ Risk Score < 12
Low Risk, Risk < 6

DIMP Sewer & Gas Line Conflict

Project Risk

Polygon ID	City	State	Project	Estimated Service Count	Risk Score	Risk Level
372455262	Roseville	MN	County Rd C2 W and Western Ave	784	**6**	High
359596126	Vadnais Heights	MN	Berwood and Arcade	1168	**6**	High
372455266	Faribault	MN	8th St and 4th Ave	969	**6**	High
372455270	Sauk Rapids	MN	11th St N and 9th St N	869	**6**	High
372455278	Cottage Grove	MN	80th St S and Hwy 61	3619	**6**	High
Total Inspections				***7,408**		

*The current plan estimates that approximately 11,500 services will be inspected for conflicts in 2018, the 9th year of legacy inspections. Approximately 7,408 of the 11,500 planned inspections have been identified and scoped at this time.

Results from the previous year's inspections are reviewed and specific areas targeted that have been determined to have a higher probability of conflicts, as confirmed either through camera inspections or excavation of the service line and visual affirmation.

The Company will continue to monitor circumstances that may indicate a need to accelerate or scale back inspections.

Risk assessment methodology is subject to change as the Company monitors the results on ongoing inspections. The current risk assessment approach is summarized below:

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Community/Area with Prior Conflict	**3**	3	6	9
	Area known to have a lot of rock Area known to have high water table Terraced properties (high home elevation relative to road)	**2**	2	4	6
	Areas installed post 2003 Areas previously inspected PE services off of joint main trench PE services off of steel main Known Septic areas	**0.5**	0.5	1	1.5

High Risk: Risk Score ≥ 6
Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
Low Risk: Risk Score < 2

DIMP Federal Code Mitigation

Project Risk

2018 Projects by Risk Category
NONE *** Final O&M project list in-process of scope development.**

Risk Assessments are dependent upon Category of work. Other risk assessment methods will be developed as necessary as more classes of work are identified from inspections:

Install Guard Post

			Consequence				
			Residential Location Type – Rural Area	Residential Location Type – Urban Area	Commercial Location Type	Regulator Station Location Type – Rural Area	Regulator Station Location Type – Urban Area
			1	**2**	**3**	**4**	**5**
Likelihood of Failure	Near Vehicular Travel – No Current Protection	**5**	5	10	15	20	25
	Near Vehicular Travel – Protection Not to Standards	**4**	4	8	12	16	20
	SME Recommended	**3**	3	6	9	12	15
	Near Vehicular Travel – Protection Not to Standards	**2**	2	4	6	8	10
	Not Near Vehicular Travel – Protection to Standards	**0.8**	0.8	1.6	2.4	3.2	4

High Risk: Risk Score ≥ 15
Medium Risk: Medium Risk, 5 ≤ Risk Score < 15
Low Risk: Risk Score < 5

Install Ice Shield

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	2-story or higher roofline above meter	**3**	3	6	9
	single story roofline above meter	**2**	2	4	6
	no roofline above meter	**0.5**	0.5	1	1.5

(dark)	High Risk: Risk Score ≥ 6
(medium)	Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
(light)	Low Risk: Risk Score < 2

Riser in Concrete with no Sleeve

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Riser in concrete with no sleeve; installed prior to 1990	**3**	3	6	9
	Riser in concrete with no sleeve; installed 1990 or later	**2**	2	4	6
	Riser not in direct contact with concrete	**0.5**	0.5	1	1.5

High Risk: Risk Score ≥ 6
Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
Low Risk: Risk Score < 2

Riser Repair

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Riser has wall loss due to corrosion or other factor	**3**	3	6	9
	Riser bent and dented but no wall loss	**2**	2	4	6
	No damage to riser	**0.5**	0.5	1	1.5

High Risk: Risk Score ≥ 6
Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
Low Risk: Risk Score < 2

Idle Riser

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Years Inactive ≥ 10	**3**	3	**6**	**9**
	2 ≤ Years Inactive < 10	**2**	2	4	**6**
	Inactive < 2 years	**0.5**	0.5	1	1.5

High Risk: Risk Score ≥ 6
Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
Low Risk: Risk Score < 2

Inaccessible Meter

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Not able to access or in hazardous location	**3**	3	6	9
	Access requires entry into a living space or office space that is not a proper meter room or meter cabinet	**2**	2	4	6
	Readily Accessible	**0.5**	0.5	1	1.5

High Risk: Risk Score ≥ 6
Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
Low Risk: Risk Score < 2

Coated Steel

Priority	Optimain Total (RiskProject) Score	Priority Distribution
High	Score ≥ 36	25
Medium	24 ≤ Score < 36	2
Low	1 ≤ Score < 24	0
None	Score < 1	0
Total	**All**	**27**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	OPTIMAIN SCORE	QRA SCORE
	RED WING - 9TH ST	850	8.0	1955	Coated Steel	Medium	32	
	NORTH ST PAUL - 1ST AVE	6311	82.0	1958	Coated Steel	Low	38	
	NORHT ST PAUL - LAKE BLVD	8462	70.0	1959	Coated Steel	Low	103	
	MAPLEWOOD - COPE AVE	3531	38.0	1957	Coated Steel	Medium	53	
	MAPLEWOOD - JACKSON ST	4795	45.0	1956	Coated Steel	Low	332	
	MAPLEWOOD - CRAIG PL	5454	53.0	1959	Coated Steel	Low	123	
	NORTH ST PAUL - 17TH AVE	1046	8.0	1957	Coated Steel	Low	257	
	BAYPORT - 7TH ST DIMP	980	11.0	1958	Coated Steel	Low	159	
	MAPLEWOOD-MAYHILL	3771	40.0	1959	Coated Steel	Low	106	
	WHITE BEAR LAKE - STILLWATER ST-BALD-GARDEN	14049	124.0	1961	Coated Steel	Medium	52	
	COTTAGE GROVE - 85TH ST	5420	63.0	1962	Coated Steel	Medium	182	
	ST PAUL PARK- SUMMIT AVE	3900	38.0	1950	Coated Steel	Low	70	
	ST PAUL - ST PETER, FORD 4TH DIMP (2018)	3850	25.0	1963	Coated Steel	Low	84	
	ST PAUL - FALCON/EDGEBROOK/WINTHROP	16450	232.0	1960	Coated Steel	Low	40	
	RED WING - WRIGHT/FINRUD DIMP	10400	130.0	1975	Coated Steel	Medium	131	
	WINONA - 44TH AVE	4300	99.0	1961	Coated Steel	Low	242	
	RED WING - MAPLE ST	7600	161.0	1959	Coated Steel	Low	28	
	WINONA - E 10TH ST	3000	108.0	1965	Coated Steel	Low	198	
	WINONA - E 7TH ST	3500	64.0	1965	Coated Steel	Low	54	
	WINONA - E 9TH ST	1400	35.0	1961	Coated Steel	Low	90	
	WINONA - COLLEGEVIEW ST	2000	54.0	1960	Coated Steel	Medium	214	
	WINONA - W 9TH ST	3400	64.0	1960	Coated Steel	Medium	220	
	WINONA - 7TH ST W	5800	138.0	1966	Coated Steel	Low	56	
	COTTAGE GROVE - IDEAL-85TH ST	8200	94.0	1962	Coated Steel	Medium	182	
	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	4735	40.0	1961	Coated Steel	Medium	92	
	COTTAGE GROVE - HYDE AVE	3710	41.0	1961	Coated Steel	Medium	231	
	ST PAUL - MCKNIHGT/WINTHROP/POWERS	9215	125.0	1964	Coated Steel	Low	45	

*Scoring included for known 2018 projects with completed engineering and design.

Poor Performing Plastic - Aldyl-A

Priority	Quantitative Risk Assessment Score	Priority Distribution
High	Score ≥ 7	0
Medium	4 ≤ Score < 7	8
Low	0 ≤ Score < 4	0
Total	**All**	**8**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	OPTIMAIN SCORE	QRA SCORE
	LAKE ELMO - 31ST/JAMLEY/JANERO	6880	43.0	1967	Aldyl-A	Low		4.750
	MENDOTA HEIGHTS - BACHELOR-STANWICH	10570	100.0	1967	Aldyl-A	Medium		4.750
	ROSEVILLE - OXFORD	1200	5.0	1968	Aldyl-A	Medium		4.750
	FOREST LAKE - 1ST-7TH AVE & 3RD-7TH ST	12000	98.0	1968	Aldyl-A	Medium		4.750
	MENDOTA HEIGHTS - OVERLOOK RD	5700	45.0	1969	Aldyl-A	Medium		4.750
	RED WING - WOODLAND DR	4200	48.0	1969	Aldyl-A	Medium		4.750
	RED WING - REDING AVE	4830	48.0	1968	Aldyl-A	Medium		4.750
	WINONA - CONRAD DR	6600	133.0	1968	Aldyl-A	Medium		4.750

*Scoring included for known 2018 projects with completed engineering and design.

Capital Expenditures (CWIP Only excluding internal labor)

Project Name	Sub Project	Pre-2016	2016	2017	2018	2019	2020	2021	2022	Total by Subproject
TIMP	Transmission	1,209,118	4,556,068	8,213,943	8,715,280	28,780,870	21,105,270	30,940,660	30,786,800	134,308,009
TIMP	Distribution	39,086,442	14,195,598	711,617	-	-	-	-	-	53,993,656
Total TIMP		**40,295,560**	**18,751,666**	**8,925,560**	**8,715,280**	**28,780,870**	**21,105,270**	**30,940,660**	**30,786,800**	**188,301,666**
DIMP	Distribution	10,677,614	12,628,215	12,969,308	36,813,451	31,940,440	25,907,840	17,267,600	17,267,600	165,472,068
DIMP	Software	1,852,326	170,898	-	-	-	-	-	-	2,023,224
Total DIMP		**12,529,940**	**12,799,113**	**12,969,308**	**36,813,451**	**31,940,440**	**25,907,840**	**17,267,600**	**17,267,600**	**167,495,293**
Total GUIC		**52,825,500**	**31,550,779**	**21,894,868**	**45,528,731**	**60,721,310**	**47,013,110**	**48,208,260**	**48,054,400**	**355,796,958**

TIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	41,002,201	41,224,699	41,221,031	41,358,584	41,362,685	48,647,724	47,049,533	52,672,931	54,706,235	52,527,236	55,163,535	59,397,911	59,397,911
Less Accumulated Book Depreciation Reserve	(135,999)	(50,939)	34,589	120,256	206,070	296,627	396,067	493,430	605,136	716,688	828,720	946,473	946,473
Less Accumulated Deferred Taxes	3,463,723	3,642,527	3,821,330	4,000,134	4,178,937	4,357,740	4,536,544	4,715,347	4,894,151	5,072,954	5,251,757	5,430,561	5,430,561
End Of Month Rate Base	37,674,476	37,633,111	37,365,112	37,238,194	36,977,678	43,993,356	42,116,923	47,464,154	49,206,948	46,737,594	49,083,057	53,020,878	53,020,878
Average Rate Base (Prior Mo + Cur Month/2)	37,883,755	37,653,793	37,499,111	37,301,653	37,107,936	40,485,517	43,055,139	44,790,538	48,335,551	47,972,271	47,910,326	51,051,968	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	71,663	71,228	70,936	70,562	70,196	76,585	81,446	84,729	91,435	90,748	90,630	96,573	966,732
Equity Return (Avg RB * Wtd Cost of Equity)	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Total Return on Rate Base	231,407	230,002	229,057	227,851	226,668	247,299	262,995	273,596	295,250	293,031	292,652	311,842	3,121,649
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	699,538
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Gross Up for Income Tax (see below)	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)
Total Income Statement Expense	414,982	413,289	410,607	399,596	404,915	437,299	450,241	471,398	485,674	(804,259)	1,422,244	(1,107,293)	3,398,693
Total Revenue Requirement	**646,388**	**643,291**	**639,664**	**627,447**	**631,583**	**684,599**	**713,236**	**744,993**	**780,924**	**(511,228)**	**1,714,896**	**(795,451)**	**6,520,342**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.06%												
Required Rate of Return	7.33%												
Current Income Tax Calculation													
Equity Return	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Less Tax Depreciation	292,496	294,064	298,157	314,373	309,691	299,354	309,528	299,258	315,276	2,145,430	(1,005,281)	2,595,461	6,467,808
Plus CPI-Tax Interest (If Applicable)	-	-	392	1,499	4,817	7,635	10,877	13,057	14,929	18,877	22,690	11,471	106,244
Total	131,292	128,812	124,688	108,885	116,215	151,265	161,141	185,135	193,976	(1,633,915)	1,520,828	(2,072,165)	(883,843)
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)

TIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	59,405,130	59,491,425	59,499,445	59,770,146	60,147,335	60,459,921	60,762,999	60,956,906	62,773,002	64,337,448	65,967,643	68,222,346	68,222,346
Less Accumulated Book Depreciation Reserve	1,067,185	1,187,967	1,308,815	1,429,952	1,551,664	1,673,922	1,796,636	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,636,295)
Less Accumulated Deferred Taxes	5,540,657	5,650,753	5,760,850	5,870,946	5,981,042	6,091,138	6,201,235	6,311,331	6,421,427	6,531,523	6,641,620	6,751,716	6,751,716
End Of Month Rate Base	52,797,288	52,652,705	52,429,780	52,469,248	52,614,630	52,694,860	52,765,129	52,729,829	59,055,029	61,902,543	63,855,801	66,106,926	66,106,926
Average Rate Base (Prior Mo + Cur Month/2)	52,909,083	52,724,997	52,541,243	52,449,514	52,541,939	52,654,745	52,729,995	52,747,479	55,892,429	60,478,786	62,879,172	64,981,364	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	100,086	99,738	99,391	99,217	99,392	99,605	99,748	99,781	105,730	114,406	118,946	122,923	1,258,962
Equity Return (Avg RB * Wtd Cost of Equity)	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Total Return on Rate Base	320,100	318,986	317,875	317,320	317,879	318,561	319,016	319,122	338,149	365,897	380,419	393,137	4,026,461
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	1,009,577
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Gross Up for Income Tax (see below)	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189
Total Income Statement Expense	365,951	348,147	377,387	391,711	371,365	363,884	321,786	307,552	375,806	395,913	409,152	422,373	4,451,028
Total Revenue Requirement	**686,051**	**667,134**	**695,261**	**709,031**	**689,244**	**682,445**	**640,802**	**626,675**	**713,955**	**761,809**	**789,571**	**815,510**	**8,477,489**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.99%												
Required Rate of Return	7.26%												
Current Income Tax Calculation													
Equity Return	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Less Tax Depreciation	381,646	405,544	363,714	343,963	374,676	386,874	447,841	469,417	390,576	389,584	387,771	385,156	4,726,762
Plus CPI-Tax Interest (If Applicable)	3,115	2,382	2,594	2,826	2,932	2,735	2,629	3,179	3,692	4,943	5,439	4,648	41,113
Total	72,292	46,964	88,308	108,199	78,551	67,173	6,867	(13,764)	80,446	104,731	119,699	133,645	893,111
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189

TIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	68,723,162	69,018,830	69,246,855	69,526,617	69,832,343	70,330,018	70,969,160	71,964,909	75,047,409	76,017,765	76,810,635	77,452,797	77,452,797
Less Accumulated Book Depreciation Reserve	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)	(3,458,473)	(3,458,473)
Less Accumulated Deferred Taxes	6,869,006	6,986,297	7,103,588	7,220,878	7,338,169	7,455,459	7,572,750	7,690,041	7,807,331	7,924,622	8,041,912	8,159,203	8,159,203
End Of Month Rate Base	66,463,310	66,558,103	66,560,976	66,604,906	66,669,946	66,930,142	67,336,383	68,107,252	70,962,749	71,700,328	72,251,553	72,752,068	72,752,068
Average Rate Base (Prior Mo + Cur Month/2)	66,285,118	66,510,707	66,559,539	66,582,941	66,637,426	66,800,044	67,133,263	67,721,818	69,535,000	71,331,538	71,975,940	72,501,810	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	125,389	125,816	125,908	125,953	126,056	126,363	126,994	128,107	131,537	134,935	136,154	137,149	1,550,363
Equity Return (Avg RB * Wtd Cost of Equity)	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Total Return on Rate Base	415,387	416,800	417,106	417,253	417,595	418,614	420,702	424,390	435,753	447,011	451,049	454,345	5,136,004
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	1,159,565
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Gross Up for Income Tax (see below)	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908
Total Income Statement Expense	449,324	450,266	449,099	437,054	438,503	432,347	430,684	426,452	434,845	465,678	478,544	483,663	5,376,458
Total Revenue Requirement	**864,711**	**867,067**	**866,206**	**854,307**	**856,098**	**850,960**	**851,385**	**850,842**	**870,598**	**912,689**	**929,593**	**938,007**	**10,512,463**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Less Tax Depreciation	405,470	405,470	407,782	426,180	426,180	438,102	444,989	457,815	461,102	430,844	417,702	414,448	5,136,086
Plus CPI-Tax Interest (If Applicable)	2,612	1,731	1,366	1,806	2,718	3,963	5,280	7,009	5,923	3,204	2,754	2,238	40,605
Total	140,614	141,229	139,100	121,569	123,094	113,641	110,255	102,777	109,785	148,618	165,255	171,210	1,587,146
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908

TIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	77,943,161	78,357,327	78,891,953	79,891,266	81,123,838	83,184,433	85,707,214	89,809,399	94,030,698	98,019,039	101,406,402	104,217,957	104,217,957
Less Accumulated Book Depreciation Reserve	(3,323,462)	(3,186,112)	(3,052,130)	(2,928,230)	(2,808,434)	(2,707,265)	(2,617,083)	(2,559,876)	(2,500,830)	(2,430,454)	(2,337,160)	(2,224,397)	(2,224,397)
Less Accumulated Deferred Taxes	8,329,445	8,499,688	8,669,930	8,840,173	9,010,415	9,180,658	9,350,900	9,521,143	9,691,385	9,861,627	10,031,870	10,202,112	10,202,112
End Of Month Rate Base	72,937,178	73,043,752	73,274,152	73,979,322	74,921,857	76,711,041	78,973,397	82,848,132	86,840,143	90,587,865	93,711,692	96,240,242	96,240,242
Average Rate Base (Prior Mo + Cur Month/2)	72,844,623	72,990,465	73,158,952	73,626,737	74,450,590	75,816,449	77,842,219	80,910,765	84,844,138	88,714,004	92,149,778	94,975,967	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	137,798	138,074	138,392	139,277	140,836	143,419	147,252	153,056	160,497	167,817	174,317	179,663	1,820,398
Equity Return (Avg RB * Wtd Cost of Equity)	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Total Return on Rate Base	456,493	457,407	458,463	461,394	466,557	475,116	487,811	507,041	531,690	555,941	577,472	595,183	6,030,568
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	1,316,453
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Gross Up for Income Tax (see below)	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497
Total Income Statement Expense	508,778	509,969	504,807	495,962	501,688	485,663	493,312	470,232	514,251	545,904	584,788	607,893	6,223,247
Total Revenue Requirement	**965,271**	**967,376**	**963,270**	**957,357**	**968,245**	**960,779**	**981,123**	**977,273**	**1,045,941**	**1,101,845**	**1,162,260**	**1,203,076**	**12,253,815**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Less Tax Depreciation	528,241	528,241	537,947	556,097	556,097	592,027	599,127	659,627	629,377	613,727	583,401	570,591	6,954,501
Plus CPI-Tax Interest (If Applicable)	1,850	1,503	1,692	2,892	3,955	6,113	8,113	12,248	14,320	13,920	12,278	10,276	89,161
Total	112,205	113,074	104,900	90,976	97,069	71,377	78,068	39,360	94,209	131,634	180,062	207,195	1,320,128
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497

DIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	11,591,891	11,546,320	11,589,091	11,749,440	14,328,919	14,348,999	14,579,803	15,463,671	16,110,526	21,489,430	24,782,895	24,917,235	24,917,235
Less Accumulated Book Depreciation Reserve	114,394	104,450	33,015	14,442	17,596	55,317	116,027	160,076	167,682	9,801	(991,966)	(1,463,418)	(1,463,418)
Less Accumulated Deferred Taxes	510,188	668,335	826,481	984,628	1,142,774	1,300,921	1,459,068	1,617,214	1,775,361	1,933,508	2,091,654	2,249,801	2,249,801
End Of Month Rate Base	10,967,309	10,773,536	10,729,595	10,750,370	13,168,549	12,992,761	13,004,708	13,686,381	14,167,482	19,546,122	23,683,207	24,130,853	24,130,853
Average Rate Base (Prior Mo + Cur Month/2)	10,857,363	10,870,422	10,751,566	10,739,983	11,959,459	13,080,655	12,998,735	13,345,544	13,926,932	16,856,802	21,614,665	23,907,030	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	20,539	20,563	20,338	20,316	22,623	24,744	24,589	25,245	26,345	31,887	40,888	45,224	323,303
Equity Return (Avg RB * Wtd Cost of Equity)	45,782	45,837	45,336	45,287	50,429	55,157	54,811	56,274	58,725	71,080	91,142	100,808	720,667
Total Return on Rate Base	66,320	66,400	65,674	65,603	73,052	79,901	79,401	81,519	85,070	102,967	132,030	146,032	1,043,970
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	190,385
Book Depreciation	23,933	24,295	24,292	24,505	42,585	60,518	60,783	61,953	63,561	69,888	78,994	82,593	617,899
Deferred Taxes	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	1,897,760
Gross Up for Income Tax (see below)	69,307	28,580	64,656	11,056	53,604	64,514	10,772	8,817	(66,764)	(1,009,575)	(573,495)	(69,716)	(1,408,243)
Total Income Statement Expense	267,252	226,887	262,960	209,574	270,201	299,044	245,567	244,783	170,809	(765,675)	(320,489)	186,888	1,297,801
Total Revenue Requirement	**333,572**	**293,287**	**328,635**	**275,177**	**343,253**	**378,945**	**324,968**	**326,302**	**255,879**	**(662,709)**	**(188,459)**	**332,920**	**2,341,771**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.06%												
Required Rate of Return	7.33%												
Current Income Tax Calculation													
Equity Return	45,782	45,837	45,336	45,287	50,429	55,157	54,811	56,274	58,725	71,080	91,142	100,808	720,667
Book Depreciation	23,933	24,295	24,292	24,505	42,585	60,518	60,783	61,953	63,561	69,888	78,994	82,593	617,899
Deferred Taxes	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	158,147	1,897,760
Less Tax Depreciation	131,014	188,920	137,432	214,393	178,701	187,221	267,574	277,613	394,647	1,757,322	1,174,491	345,485	5,254,813
Plus CPI-Tax Interest (If Applicable)	1,376	1,146	1,288	2,123	3,510	4,829	9,099	13,735	19,596	27,427	33,446	(94,865)	22,711
Total	98,223	40,504	91,631	15,669	75,969	91,430	15,266	12,496	(94,618)	(1,430,781)	(812,762)	(98,803)	(1,995,777)
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	69,307	28,580	64,656	11,056	53,604	64,514	10,772	8,817	(66,764)	(1,009,575)	(573,495)	(69,716)	(1,408,243)

DIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	26,179,523	26,171,540	26,023,237	26,200,254	27,429,311	28,646,435	29,682,221	31,092,133	34,096,033	36,028,342	37,510,020	38,399,899	38,399,899
Less Accumulated Book Depreciation Reserve	(2,758,169)	(2,701,687)	(2,647,745)	(2,643,491)	(3,032,838)	(3,361,152)	(3,466,009)	(3,884,022)	(4,711,807)	(4,830,686)	(4,866,182)	(4,884,030)	(4,884,030)
Less Accumulated Deferred Taxes	2,394,576	2,539,352	2,684,127	2,828,903	2,973,679	3,118,454	3,263,230	3,408,005	3,552,781	3,697,556	3,842,332	3,987,108	3,987,108
End Of Month Rate Base	26,543,116	26,333,875	25,986,855	26,014,843	27,488,471	28,889,133	29,885,001	31,568,149	35,255,060	37,161,472	38,533,870	39,296,821	39,296,821
Average Rate Base (Prior Mo + Cur Month/2)	25,336,985	26,438,496	26,160,365	26,000,849	26,751,657	28,188,802	29,387,067	30,726,575	33,411,604	36,208,266	37,847,671	38,915,346	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	47,929	50,013	49,487	49,185	50,605	53,324	55,591	58,124	63,204	68,494	71,595	73,615	691,165
Equity Return (Avg RB * Wtd Cost of Equity)	105,360	109,940	108,784	108,120	111,242	117,218	122,201	127,771	138,937	150,566	157,383	161,823	1,519,346
Total Return on Rate Base	153,289	159,953	158,270	157,305	161,848	170,542	177,792	185,896	202,140	219,060	228,978	235,438	2,210,511
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	423,514
Book Depreciation	84,059	85,376	85,212	85,242	86,719	89,287	91,653	94,221	98,855	104,038	107,623	110,113	1,122,399
Deferred Taxes	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	1,737,307
Gross Up for Income Tax (see below)	89,812	43,186	37,351	(305,567)	(227,762)	(77,296)	(183,043)	(249,067)	11,343	29,793	55,363	90,292	(685,595)
Total Income Statement Expense	353,940	308,630	302,632	(40,256)	39,026	192,060	88,678	25,222	290,267	313,900	343,054	380,473	2,597,625
Total Revenue Requirement	**507,228**	**468,583**	**460,902**	**117,049**	**200,873**	**362,602**	**266,470**	**211,118**	**492,407**	**532,960**	**572,033**	**615,911**	**4,808,136**

	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
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.99%												
Required Rate of Return	7.26%												
Current Income Tax Calculation													
Equity Return	105,360	109,940	108,784	108,120	111,242	117,218	122,201	127,771	138,937	150,566	157,383	161,823	1,519,346
Book Depreciation	84,059	85,376	85,212	85,242	86,719	89,287	91,653	94,221	98,855	104,038	107,623	110,113	1,122,399
Deferred Taxes	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	144,776	1,737,307
Less Tax Depreciation	208,617	281,039	289,923	775,527	669,957	464,824	621,560	723,266	368,425	357,677	331,904	289,309	5,382,027
Plus CPI-Tax Interest (If Applicable)	1,705	2,150	4,086	4,336	4,435	3,998	3,520	3,518	1,933	520	583	559	31,344
Total	127,282	61,203	52,934	(433,053)	(322,786)	(109,545)	(259,410)	(352,980)	16,075	42,224	78,461	127,963	(971,632)
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	89,812	43,186	37,351	(305,567)	(227,762)	(77,296)	(183,043)	(249,067)	11,343	29,793	55,363	90,292	(685,595)

DIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	38,869,570	39,380,099	39,878,371	40,834,591	43,136,771	46,390,320	49,800,659	55,224,896	60,495,356	66,097,033	70,894,481	73,521,576	73,521,576
Less Accumulated Book Depreciation Reserve	(4,799,251)	(4,715,964)	(4,630,095)	(4,563,701)	(4,557,501)	(4,585,129)	(4,605,046)	(4,671,691)	(4,713,761)	(4,753,208)	(4,759,112)	(4,661,392)	(4,661,392)
Less Accumulated Deferred Taxes	4,130,591	4,274,074	4,417,558	4,561,041	4,704,525	4,848,008	4,991,492	5,134,975	5,278,458	5,421,942	5,565,425	5,708,909	5,708,909
End Of Month Rate Base	39,538,230	39,821,988	40,090,908	40,837,251	42,989,748	46,127,441	49,414,214	54,761,612	59,930,658	65,428,299	70,088,168	72,474,059	72,474,059
Average Rate Base (Prior Mo + Cur Month/2)	39,417,525	39,680,109	39,956,448	40,464,079	41,913,499	44,558,595	47,770,828	52,087,913	57,346,135	62,679,479	67,758,234	71,281,114	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	74,565	75,062	75,584	76,545	79,286	84,290	90,366	98,533	108,480	118,569	128,176	134,840	1,144,296
Equity Return (Avg RB * Wtd Cost of Equity)	172,452	173,600	174,809	177,030	183,372	194,944	208,997	227,885	250,889	274,223	296,442	311,855	2,646,499
Total Return on Rate Base	247,016	248,662	250,394	253,575	262,658	279,234	299,364	326,418	359,369	392,791	424,618	446,695	3,790,794
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	652,677
Book Depreciation	111,541	112,570	113,629	115,156	118,578	124,411	131,408	140,684	151,914	163,330	174,249	182,045	1,639,514
Deferred Taxes	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	1,721,801
Gross Up for Income Tax (see below)	27,584	24,788	26,481	9,027	(38,112)	(48,891)	(23,224)	(70,784)	(1,408)	11,665	69,353	164,802	151,283
Total Income Statement Expense	336,997	335,231	337,983	322,057	278,339	273,394	306,058	267,773	348,380	372,868	441,475	544,719	4,165,275
Total Revenue Requirement	**584,014**	**583,893**	**588,377**	**575,631**	**540,997**	**552,628**	**605,422**	**594,191**	**707,749**	**765,660**	**866,094**	**991,414**	**7,956,069**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	172,452	173,600	174,809	177,030	183,372	194,944	208,997	227,885	250,889	274,223	296,442	311,855	2,646,499
Book Depreciation	111,541	112,570	113,629	115,156	118,578	124,411	131,408	140,684	151,914	163,330	174,249	182,045	1,639,514
Deferred Taxes	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	143,483	1,721,801
Less Tax Depreciation	389,160	395,450	395,370	424,621	503,678	538,899	524,674	624,419	562,066	578,937	529,045	412,601	5,878,920
Plus CPI-Tax Interest (If Applicable)	776	927	977	1,744	4,233	6,772	7,872	12,050	13,785	14,434	13,159	8,777	85,506
Total	39,092	35,130	37,529	12,793	(54,012)	(69,288)	(32,913)	(100,316)	(1,995)	16,532	98,288	233,559	214,399
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	27,584	24,788	26,481	9,027	(38,112)	(48,891)	(23,224)	(70,784)	(1,408)	11,665	69,353	164,802	151,283

DIMP - Capital Revenue Requirements	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													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	74,924,097	75,853,063	76,530,690	77,495,003	79,495,603	82,423,406	85,435,615	90,139,805	94,716,866	99,557,393	103,685,740	105,869,552	105,869,552
Less Accumulated Book Depreciation Reserve	(4,522,216)	(4,372,437)	(4,214,197)	(4,071,326)	(3,984,349)	(3,928,377)	(3,863,886)	(3,839,375)	(3,791,232)	(3,740,455)	(3,660,501)	(3,483,814)	(3,483,814)
Less Accumulated Deferred Taxes	5,883,148	6,057,388	6,231,628	6,405,868	6,580,108	6,754,348	6,928,588	7,102,828	7,277,067	7,451,307	7,625,547	7,799,787	7,799,787
End Of Month Rate Base	73,563,165	74,168,112	74,513,259	75,160,460	76,899,844	79,597,435	82,370,912	86,876,353	91,231,030	95,846,540	99,720,694	101,553,580	101,553,580
Average Rate Base (Prior Mo + Cur Month/2)	73,018,612	73,865,638	74,340,685	74,836,860	76,030,152	78,248,640	80,984,174	84,623,633	89,053,692	93,538,785	97,783,617	100,637,137	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	138,127	139,729	140,628	141,566	143,824	148,020	153,195	160,080	168,460	176,944	184,974	190,372	1,885,919
Equity Return (Avg RB * Wtd Cost of Equity)	319,456	323,162	325,240	327,411	332,632	342,338	354,306	370,228	389,610	409,232	427,803	440,287	4,361,707
Total Return on Rate Base	457,583	462,891	465,868	468,978	476,456	490,358	507,501	530,308	558,070	586,176	612,777	630,659	6,247,626
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	104,136	104,136	104,136	104,136	104,136	104,136	104,136	104,136	104,136	104,136	104,136	104,136	1,249,635
Book Depreciation	186,276	188,724	190,411	192,135	195,248	200,423	206,660	214,762	224,507	234,396	243,813	250,441	2,527,793
Deferred Taxes	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	2,090,878
Gross Up for Income Tax (see below)	97,231	95,564	97,466	81,419	36,998	25,663	48,564	8,051	68,575	79,757	128,704	214,990	982,981
Total Income Statement Expense	561,883	562,664	566,252	551,930	510,622	504,462	533,600	501,189	571,458	592,529	650,893	743,806	6,851,288
Total Revenue Requirement	**1,019,466**	**1,025,556**	**1,032,121**	**1,020,908**	**987,078**	**994,820**	**1,041,100**	**1,031,497**	**1,129,528**	**1,178,705**	**1,263,670**	**1,374,466**	**13,098,914**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	319,456	323,162	325,240	327,411	332,632	342,338	354,306	370,228	389,610	409,232	427,803	440,287	4,361,707
Book Depreciation	186,276	188,724	190,411	192,135	195,248	200,423	206,660	214,762	224,507	234,396	243,813	250,441	2,527,793
Deferred Taxes	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	174,240	2,090,878
Less Tax Depreciation	547,376	553,676	553,676	580,468	653,746	686,837	673,441	758,588	703,415	717,606	675,032	567,868	7,671,730
Plus CPI-Tax Interest (If Applicable)	5,201	2,986	1,915	2,070	4,061	6,207	7,061	10,768	12,243	12,771	11,576	7,585	84,443
Total	137,797	135,435	138,129	115,388	52,435	36,370	68,825	11,410	97,185	113,032	182,400	304,686	1,393,091
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	97,231	95,564	97,466	81,419	36,998	25,663	48,564	8,051	68,575	79,757	128,704	214,990	982,981

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.

<u>Analysis Assumptions:</u> Cost Comparison of Using Contractor vs. In-House Workforce/Equipment for Sewer Inspection

1. Estimated annual O&M expense levels for sewer conflict inspections are included in the most recent plans and reflected in this filing.
2. Assume 5 mainline trucks at $300K, 5 premise out trucks/vans at $25K, 2 Emergency trucks/vans at $25K.
3. Assumed cost to replace specific equipment and vehicles associated with this work. Based the estimates on conversations with our current vendor performing this work and our assumed costs of ownership.
4. Maintenance of equipment, including specific mechanic personnel for unique equipment or equivalent outsourcing.
5. Assumed insurance costs of 12 dedicated vehicles and equipment to perform this work with Company-owned fleet.
6. Wash stations - assumed costs of $6,000 per station at 14 gas Service Centers, $1,000 annual maintenance and upkeep of each.
7. Purchase and updates of software system for tracking, monthly fees for electronic storage. Initial and ongoing hardware costs for dispatching and completing work.
8. Assume 2 operator employees per truck at $60 per hour rate for qualified labor (fully loaded). Also assume 2% annual wage increase. Emergency Inspection - Assume 2 (fully loaded) after hours premise out crews. Premise out 5 fully loaded employees.
9. Overtime and out of town costs are assumed at 10% of labor costs.
10. Assumed 2 (fully loaded) oversight positions to replicate vendor Management and Supervision.
11. Scheduling - In 2010 through 2012, we had a single contractor staff augmentation resource. Once the program expanded and became long-term, we needed to restructure to dispatch, complete and provide QA/QC assistance based on internal auditing results.
13. Plumber costs are assumed for a licensed plumber or an equivalent outsourcing.
14. WACC Assumptions are pulled from 2015 MN Gas Jurisdictional Filing.

Debt	4,349,580
Cost of Debt	5.78%
Equity	4,856,662
Cost of Equity	10.09%
Tax Rate	35.00%
WACC	**7.10%**

Cost Comparison of Using Contractor vs. In-House Workforce/Equipment for Sewer Inspection

		Actuals							Forecast		
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Ln.	**Current State**										
1	Annual O&M Expenses (est beyond 2016)	$4,175,186	$3,639,148	$3,462,587	$3,464,732	$3,447,300	$3,381,101	$3,519,807	3,500,000	2,300,000	2,000,000
2	Estimated Discount Factor using 2015 WACC	1	0.93	0.87	0.81	0.76	0.71	0.66	0.62	0.58	0.54
3	PV of Costs	4,175,186	3,397,964	3,018,830	2,820,503	2,620,324	2,399,679	2,332,560	2,165,714	1,328,862	1,078,949
4	Cumulative PV of Costs	4,175,186	7,573,150	10,591,980	13,412,483	16,032,808	18,432,487	20,765,047	22,930,760	24,259,622	25,338,571
	Owning the Equipment Comparison										
5	Trucks/Specialized Equipment	1,675,000	-	-	-	-	-	-	-	-	-
6	Equipment/Vehicle Replacement	50,000	100,000	150,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
7	Vehicle Maintenance	100,000	125,000	150,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
8	Insurance	28,800	28,800	28,800	28,800	28,800	28,800	28,800	28,800	28,800	28,800
9	Vehicle Fuel	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000
10	Wash Stations (1 per Gas Service Center, incl maint)	84,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
11	Software - MDTs and Korterra	120,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
12	Employees - fully loaded (17)	2,121,600	2,164,032	2,207,313	2,251,459	2,296,488	2,342,418	2,389,266	2,437,052	2,485,793	2,535,508
13	Overtime and Out of Town Costs (Per Diem, etc.)	212,160	216,403	220,731	225,146	229,649	234,242	238,927	243,705	248,579	253,551
14	Employee Training/Certification	100,000	25,000	25,000	50,000	25,000	25,000	50,000	25,000	25,000	50,000
15	Permits	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
16	Management and Supervision (2) fully loaded	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
17	Scheduling (1 in '10-12, 2 from 2013-2019) fully loaded	35,000	35,000	35,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
18	Plumber Costs	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
19	Dig Up, Inspection and Repair (DRR)	150,000	150,000	125,000	100,000	80,000	80,000	65,000	65,000	60,000	60,000
20	Total Costs	5,037,560	3,259,235	3,356,844	3,690,405	3,694,937	3,745,460	3,806,993	3,834,557	3,883,172	3,962,859
21	Estimated Discount Factor using 2015 WACC	1	0.93	0.87	0.81	0.76	0.71	0.66	0.62	0.58	0.54
22	PV of Costs	5,037,560	3,043,229	2,926,639	3,004,215	2,808,556	2,658,276	2,522,877	2,372,729	2,243,565	2,137,862
23	Cumulative PV of Costs	5,037,560	8,080,789	11,007,428	14,011,643	16,820,199	19,478,475	22,001,352	24,374,081	26,617,646	28,755,507
24	**In-house vs Contractor Favorable / (Unfavorable)**	**(862,374)**	**(507,640)**	**(415,449)**	**(599,160)**	**(787,391)**	**(1,045,988)**	**(1,236,305)**	**(1,443,321)**	**(2,358,023)**	**(3,416,936)**

DEFERRED ITEMS (Actual O&M Expense Only)	**2010**	**2011**	**2012**	**2013**	**2014**		**Total**	
11990774 - MN Rider Amortization								
TIMP	$ -	$ -	$ 580,929	$ 3,180,143	$ 340,062		$ 4,101,134	[A]
DIMP	$ 4,175,186	$ 3,639,148	$ 3,538,635	$ 3,630,020	$ 3,686,292		$ 18,669,281	[B]
	2015 YE Actuals	**2016 YE Actuals**	**2017 YE Budget**	**2018 YE Budget**	**2019 YE Budget**		**Total**	
5 Year Amortization								
TIMP (annual amt. equals [A]/5)	$ 820,227	$ 820,227	$ 820,227	$ 820,227	$ 820,227		$ 4,101,134	
DIMP (annual amt. equals [B]/5)	$ 3,733,856	$ 3,733,856	$ 3,733,856	$ 3,733,856	$ 3,733,856		$ 18,669,281	
Grand Total	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**		**$ 22,770,415**	

MN GUIC Incremental O&M	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
	Actual	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
TIMP O&M							
MN Transmission Pipeline Assessments	39,977	498,117	1,509,000	2,900,000	1,700,000	1,700,000	1,700,000
MN East Metro Pipeline Replacement	-	-	-	-	-	-	-
Total TIMP O&M	**39,977**	**498,117**	**1,509,000**	**2,900,000**	**1,700,000**	**1,700,000**	**1,700,000**
MN Allocator (G Load Dispatch)	88.8069%	88.2300%	87.8646%	87.8961%	87.4956%	87.3529%	87.2730%
MN Allocated TIMP O&M	**35,502**	**439,489**	**1,325,877**	**2,548,987**	**1,487,425**	**1,484,999**	**1,483,641**
DIMP O&M							
MN IP Line Assessments	617,744	299,999	1,025,000	479,000	579,000	579,000	579,000
MN Poor Performing Mains	-	-	-	-	-	-	-
MN Poor Performing Services	-	-	-	-	-	-	-
MN Federal Code Mitigation	223,057	472,000	200,000	-	-	-	-
MN Sewer Conflict Investigation	3,519,807	3,428,246	2,308,000	2,300,000	-	-	-
Total DIMP O&M	**4,360,607**	**4,200,245**	**3,533,000**	**2,779,000**	**579,000**	**579,000**	**579,000**
Total Operations & Maintenance Expenses	**4,396,110**	**4,639,734**	**4,858,877**	**5,327,987**	**2,066,425**	**2,063,999**	**2,062,641**

Universal Inputs

	2016	2017	2018	2019
Cap Structure (Last Authorized)				
Long Term Debt %	45.61%	45.61%	45.61%	45.61%
Long Term Debt Cost	4.94%	4.94%	4.94%	4.94%
Short Term Debt %	1.89%	1.89%	1.89%	1.89%
Short Term Debt Cost	1.12%	1.12%	1.12%	1.12%
Weighted Cost of Debt	2.27%	2.27%	2.27%	2.27%
Common Stock %	52.50%	52.50%	52.50%	52.50%
Common Stock Cost	9.64%	9.50%	10.00%	10.00%
Weighted Cost of Equity	5.06%	4.99%	5.25%	5.25%
Rate of Return	7.33%	7.26%	7.52%	7.52%
Tax Rates				
Income Tax Rates				
State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
Composite Income Tax Rate				
State Composite Income Tax Rate	41.3700%	41.3700%	41.3700%	41.3700%
Company Composite Income Tax Rate	40.8097%	40.8468%	40.8468%	40.8468%
Property Tax Rate	1.70%	1.70%	1.70%	1.70%
Book Depreciation Lives				
Transmission	75.00	75.00	75.00	75.00
Distribution	46.14	46.14	46.14	46.14
Software	5.00	5.00	5.00	5.00
Net Salvage %				
Transmission	-15.00%	-15.00%	-15.00%	-15.00%
Distribution	-16.39%	-16.39%	-16.39%	-16.39%
Software	0.00%	0.00%	0.00%	0.00%
Book Depreciation Rates				
Transmission	1.53%	1.53%	1.53%	1.53%
Distribution	2.52%	2.52%	2.52%	2.52%
Software	20.00%	20.00%	20.00%	20.00%
Carrying Charge Rate Calculation				
Rate of Return	7.33%	7.26%	7.52%	7.52%
Equity Tax Gross-up	3.57%	3.52%	3.70%	3.70%
Annual Carrying Charge Rate	10.90%	10.78%	11.22%	11.22%
Monthly Carrying Charge Rate	0.87%	0.86%	0.89%	0.89%

" 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)

	2010 TY	
Operating Revenues		
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)

	2016	2017	2018	2019	2020	2021	2022	
Revenue Collection Forecast	**12,696**	**5,814**	**36,138**	**32,382**	**34,297**	**38,088**	**44,193**	[C] Fn 2
% of GUIC Revenue as Compared to Base Revenue Approved in Docket G-002/GR-09-1153 (2010 TY)	7.98%	3.65%	22.71%	20.35%	21.56%	23.94%	27.78%	= [C] / [A]
Capital Expenditures Forecast	**31,551**	**21,895**	**45,529**	**60,721**	**47,013**	**48,208**	**48,054**	[D]
% of GUIC Capital Expenditures as Compared to Expenditures Approved in Docket G-002/GR-09-1153 (2010 TY)	105.56%	73.25%	152.32%	203.15%	157.29%	161.29%	160.77%	= [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. G002/M-12-248

	GUIC Rider			Base Rates & PGA			MN Gas 2016 Annual Report			
Amounts in $000's	Dec - 2015	Dec - 2016	BOY/EOY Avg	Dec - 2015	Dec - 2016	BOY/EOY Avg	Dec - 2015	Dec - 2016	BOY/EOY Avg	Annual Report Page Reference
Rate Base										
Plant Investment	$ 53,708	$ 84,315	$ 69,011	$ 1,107,621	$ 1,134,763	$ 1,121,192	$ 1,161,329	$ 1,219,078	$ 1,190,203	G-2; G-16 + G-16A; G-34A
Depreciation Reserve	1,087	(517)	285	544,083	557,433	550,758	545,170	556,916	551,043	G-2; G-19 + G-19A; G-34A
Net Utility Plant	52,620	84,832	68,726	563,538	577,329	570,434	616,159	662,161	639,160	
CWIP				14,701	24,107	19,404	14,701	24,107	19,404	G-2; G-34A
Accumulated Deferred Taxes	9,686	7,680	8,683	157,633	169,417	163,525	167,319	177,097	172,208	sum G-29A
DTA - NOL Average Balance			-	-	2,052	1,026	-	2,052	1,026	G-29A; G-34B
Total Accum Deferred Taxes	9,686	7,680	8,683	157,633	171,468	164,551	167,319	179,149	173,234	G-29A
Cash Working Capital										
Materials and Supplies				1,070	1,070	1,070	1,070	1,070	1,070	G-34A
Fuel Inventory				23,584	23,584	23,584	23,584	23,584	23,584	G-34A
Non-plant Assets and Liabilities				(1,860)	(8,460)	(5,160)	(1,860)	(8,460)	(5,160)	G-34A
Prepaids and Other				(281)	(281)	(281)	(281)	(281)	(281)	G-34A
Regulatory Amortizations										
Total Other Rate Base Items				22,513	15,913	19,213	22,513	15,913	19,213	
Total Rate Base	**$ 42,934**	**$ 77,152**	**$ 60,043**	**$ 443,119**	**$ 445,881**	**$ 444,500**	**$ 486,053**	**$ 523,033**	**$ 504,543**	**G-34; G-34A**
	8.83%	14.75%	11.90%	91.17%	85.25%	88.10%	100.00%	100.00%	100.00%	
Amounts in $000's		2016			2016			2016		
Revenues										
Operating Revenues		$ 15,288			$ 401,171			$ 416,460		G-2; G-30; G-34
Expenses										
Operating Expenses:										
Production					2,381			2,381		G-33
Purchased Gas					179,662			179,662		G-33
Natural Gas Storage					2,223			2,223		G-33
Gas Transmission		(444)			48,726			48,281		G-33
Gas Distribution		4,361			31,353			35,714		G-33
Customer Accounting					11,739			11,739		G-33
Customer Service & Information					20,118			20,118		G-33
Sales, Econ Dvlp & Other					5			5		G-33
Administrative & General					21,093			21,093		G-33
Total Operating Expenses		3,916			317,300			321,216		G-2; G-30
Book Depreciation		1,795			38,368			40,163		G-30
Amortization		3,369			(3,440)			(71)		G-30; G-30-1
Total Depreciation and Amortization		5,164			34,928			40,092		G-2
Taxes:										
Total Federal Income Taxes		(1,822)			1,822			(0)		G-30
Total State Income Taxes		(566)			566			(0)		G-30
Property Taxes		890			16,500			17,390		G-30
Deferred Income Tax & ITC		4,043			5,351			9,394		G-30
Payroll & Other Taxes					1,926			1,926		G-30
Total Taxes Other Than Income		4,933			23,777			28,710		G-30
Total Taxes		2,546			26,164			28,710		G-30
Total Expenses		11,626			378,392			390,019		G-2; G-30; G-34
Net Operating Income		3,662			22,779			26,441		G-30; G-34
AFUDC					1,341			1,341		G-2; G-32; G-34
Net Income		**$ 3,662**			**$ 24,120**			**$ 27,782**		**G-2; G-34**
		13.18%			86.82%			100.00%		
Revenue Requirements Calculation										
ROR		7.33%			7.53%			7.53%		
Average Rate Base		56,830	GUIC 13 Mo Ave		444,500			504,543		
Required Operating Income		4,166			33,471			37,992		
Net Income		3,662			24,120			27,782		
Income Deficiency		504			9,351			10,210		
Revenue Conversion Factor		1.705611			1.705611			1.705611		
Revenue Deficiency		859			15,949			17,415		
Revenue Requirements		**$ 16,147**			**$ 417,120**			**$ 430,156**		
		3.75%			96.97%			100.00%		

MN GUIC Rider - Annual Tracker Summary							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
	Actual	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Operations & Maintenance Expenses							
TIMP	35,502	439,489	1,325,877	2,548,987	1,487,425	1,484,999	1,483,641
DIMP	4,360,607	4,200,245	3,533,000	2,779,000	579,000	579,000	579,000
Total Operations & Maintenance Expenses	4,396,110	4,639,734	4,858,877	5,327,987	2,066,425	2,063,999	2,062,641
Capital-Related Revenue Requirements							
TIMP	6,520,342	8,477,489	10,512,463	12,253,815	15,685,557	18,591,604	22,803,000
DIMP	2,341,771	4,808,136	7,956,069	13,098,914	17,373,074	20,250,188	22,160,640
Total Capital-Related Revenue Requirements	8,862,113	13,285,625	18,468,532	25,352,729	33,058,631	38,841,792	44,963,640
Deferred Gas Infrastructure Costs							
TIMP	820,227	820,227	820,227	820,227	-	-	-
DIMP	3,733,856	3,733,856	3,733,856	3,733,856	-	-	-
Total Deferred Gas Infrastructure Costs	4,554,083	4,554,083	4,554,083	4,554,083	-	-	-
ADIT Prorate	-	6,725	76,920	101,611	121,624	144,000	167,438
Revenue Requirement in Base Rates	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)
Revenue Requirement Subtotal	**17,332,305**	**22,006,166**	**27,478,411**	**34,856,410**	**34,766,680**	**40,569,792**	**46,713,719**
Prior Year Carryover	(1,184,983)	859,175	-	-	-	-	-
Revenue Requirement (RR)	**16,147,322**	**22,865,341**	**27,478,411**	**34,856,410**	**34,766,680**	**40,569,792**	**46,713,719**
Revenue Collections (RC)	15,288,148	22,865,341	27,478,411	34,856,410	34,766,680	40,569,792	46,713,719
Carryover Balance (RR - RC)	859,175	-	-	-	-	-	-

2016 Tracker

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Annual Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
Operations & Maintenance Expenses													
TIMP	7,956	11,839	8,757	1,834	3,144	1,707	(158)	424	0	-	-	-	35,502
DIMP	(9,085)	24,617	11,073	18,187	345,187	221,367	636,329	625,508	593,576	458,013	631,593	804,240	4,360,607
Total Operations & Maintenance Expenses	(1,129)	36,456	19,830	20,021	348,332	223,075	636,171	625,932	593,576	458,013	631,593	804,240	4,396,110
Capital-Related Revenue Requirements													
TIMP	646,388	643,291	639,664	627,447	631,583	684,599	713,236	744,993	780,924	(511,228)	1,714,896	(795,451)	6,520,342
DIMP	333,572	293,287	328,635	275,177	343,253	378,945	324,968	326,302	255,879	(662,709)	(188,459)	332,920	2,341,771
Total Capital-Related Revenue Requirements	979,961	936,578	968,299	902,624	974,836	1,063,543	1,038,203	1,071,295	1,036,803	(1,173,937)	1,526,437	(462,530)	8,862,113
Deferred Gas Infrastructure Costs													
TIMP	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Total Deferred Gas Infrastructure Costs	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement in Base Rates	-	(270)	(267)	(12,219)	(46,850)	(48,208)	(69,327)	(38,264)	(66,149)	(66,149)	(66,149)	(66,147)	(480,000)
Revenue Requirement Subtotal	**1,358,339**	**1,352,271**	**1,367,369**	**1,289,933**	**1,655,825**	**1,617,916**	**1,984,554**	**2,038,470**	**1,943,737**	**(402,566)**	**2,471,388**	**655,070**	**17,332,305**

Prior Year Carryover Balance	(1,184,983)
Total Revenue Requirements	**16,147,322**
Revenue Collections (Jan '16-Mar '17)*	**15,288,148**
Current Year Carryover Balance	**859,175**

* Note - revenues related to the 2016 revenue requirements were approved to be collected over the 15-month period 1/1/16 through 3/31/17 in Docket No. G-002/M-15-808.

2017 Tracker													
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	
Operations & Maintenance Expenses													
TIMP	-	-	-	17,646	-	-	-	-	92,897	113,264	100,348	115,334	439,489
DIMP	45,587	46,451	96,088	141,495	387,299	369,829	447,098	450,596	675,746	823,286	528,173	188,597	4,200,245
Total Operations & Maintenance Expenses	45,587	46,451	96,088	159,141	387,299	369,829	447,098	450,596	768,643	936,550	628,521	303,931	4,639,734
Capital-Related Revenue Requirements													
TIMP	686,051	667,134	695,261	709,031	689,244	682,445	640,802	626,675	713,955	761,809	789,571	815,510	8,477,489
DIMP	507,228	468,583	460,902	117,049	200,873	362,602	266,470	211,118	492,407	532,960	572,033	615,911	4,808,136
Total Capital-Related Revenue Requirements	1,193,279	1,135,717	1,156,163	826,080	890,117	1,045,047	907,272	837,793	1,206,362	1,294,769	1,361,603	1,431,421	13,285,625
Deferred Gas Infrastructure Costs													
TIMP	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Total Deferred Gas Infrastructure Costs	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate	-	-	-	-	-	-	-	-	3,327	2,218	1,145	36	6,725
Revenue Requirement in Base Rates	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
Revenue Requirement Subtotal	**1,578,373**	**1,521,675**	**1,591,758**	**1,324,728**	**1,616,923**	**1,754,383**	**1,693,877**	**1,627,896**	**2,317,839**	**2,573,044**	**2,330,776**	**2,074,895**	**22,006,166**

Prior Year Carryover Balance	859,175
Total Revenue Requirements	**22,865,341**
Revenue Collections (Apr '17-Mar '18)*	**22,865,341**
Current Year Carryover Balance	**-**

* Note - The revenue collections of $22.9 million shown here assumes collection of the remaining 2017 revenue requirements with a new rate in place from January to March 2018.

2018 Tracker													
	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**	
Operations & Maintenance Expenses													
TIMP	-	-	-	-	-	127,488	152,986	191,232	254,976	382,464	25,498	191,232	1,325,877
DIMP	-	16,100	7,242	11,895	268,374	191,960	451,556	623,014	631,310	489,046	481,347	361,155	3,533,000
Total Operations & Maintenance Expenses	-	16,100	7,242	11,895	268,374	319,448	604,542	814,246	886,287	871,511	506,845	552,387	4,858,877
Capital-Related Revenue Requirements													
TIMP	864,711	867,067	866,206	854,307	856,098	850,960	851,385	850,842	870,598	912,689	929,593	938,007	10,512,463
DIMP	584,014	583,893	588,377	575,631	540,997	552,628	605,422	594,191	707,749	765,660	866,094	991,414	7,956,069
Total Capital-Related Revenue Requirements	1,448,724	1,450,960	1,454,582	1,429,938	1,397,095	1,403,588	1,456,807	1,445,033	1,578,346	1,678,349	1,795,687	1,929,422	18,468,532
Deferred Gas Infrastructure Costs													
TIMP	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Total Deferred Gas Infrastructure Costs	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate	12,700	11,638	10,463	9,326	8,151	7,013	5,838	4,663	3,526	2,350	1,213	38	76,920
Revenue Requirement in Base Rates	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
Revenue Requirement Subtotal	**1,800,931**	**1,818,206**	**1,811,795**	**1,790,666**	**2,013,126**	**2,069,556**	**2,406,694**	**2,603,449**	**2,807,665**	**2,891,717**	**2,643,252**	**2,821,354**	**27,478,411**

Prior Year Carryover Balance	-
Total Revenue Requirements	**27,478,411**
Revenue Collections (Apr '18 - Mar '19)	**27,478,411**
Current Year Carryover Balance	**-**

2019 Tracker

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
Operations & Maintenance Expenses													
TIMP	-	-	-	-	-	245,095	294,114	367,642	490,190	735,285	49,019	367,642	2,548,987
DIMP	-	16,045	7,217	11,854	229,935	153,941	421,923	500,387	479,575	328,116	350,533	279,475	2,779,000
Total Operations & Maintenance Expenses	-	16,045	7,217	11,854	229,935	399,036	716,036	868,029	969,764	1,063,401	399,552	647,117	5,327,987
Capital-Related Revenue Requirements													
TIMP	965,271	967,376	963,270	957,357	968,245	960,779	981,123	977,273	1,045,941	1,101,845	1,162,260	1,203,076	12,253,815
DIMP	1,019,466	1,025,556	1,032,121	1,020,908	987,078	994,820	1,041,100	1,031,497	1,129,528	1,178,705	1,263,670	1,374,466	13,098,914
Total Capital-Related Revenue Requirements	1,984,737	1,992,931	1,995,391	1,978,264	1,955,323	1,955,599	2,022,224	2,008,770	2,175,469	2,280,550	2,425,930	2,577,542	25,352,729
Deferred Gas Infrastructure Costs													
TIMP	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Total Deferred Gas Infrastructure Costs	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate	16,777	15,374	13,822	12,319	10,767	9,265	7,712	6,160	4,657	3,105	1,603	50	101,611
Revenue Requirement in Base Rates	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
Revenue Requirement Subtotal	**2,341,020**	**2,363,857**	**2,355,936**	**2,341,944**	**2,535,532**	**2,703,406**	**3,085,479**	**3,222,466**	**3,489,398**	**3,686,563**	**3,166,592**	**3,564,216**	**34,856,410**

Prior Year Carryover Balance	-
Total Revenue Requirements	**34,856,410**
Revenue Collections (Apr '19 - Mar '20)	**34,856,410**
Current Year Carryover Balance	**-**

Revenue Requirements Category Descriptions

Attachments F and G to this Petition respectively provide the TIMP and DIMP annual revenue requirements for 2016-2019. 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 2018 plant in service for gas utility infrastructure projects (GUIC), the $77,452,797 for TIMP (Attachment F) and $73,521,576 for DIMP (Attachment G) reflect the dollar-value portion of the project in service as of December 31, 2018, 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 2018 book depreciation reserve for GUIC projects, the ($3,458,473) for TIMP (Attachment F) and ($4,661,392) for DIMP (Attachment G) reflect the amount of the plant in service that has been recovered as of December 31, 2018, which results in an increase 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 2018 accumulated deferred taxes for GUIC projects, the $8,159,203 for TIMP (Attachment F) and $5,708,909 for DIMP (Attachment G) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2018, 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 2018 debt return for GUIC projects, the $1,550,363 for TIMP (Attachment F) and $1,144,296 for DIMP (Attachment G) reflect the amount of debt return the Company is allowed for January 2018 - December 2018 based on the cost of debt and ratios approved in the most recent electric rate filing (Docket No. E002/GR-13-868).

> **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 2018 equity return for GUIC projects, the $3,585,641 for TIMP (Attachment F) and $2,646,499 for DIMP (Attachment G) reflect the amount of return on equity the Company is allowed for January 2018 - December 2018 based on the equity ratio approved in the most recent electric rate filing (Docket No. E002/GR-13-868) and the return on equity proposed in the current docket.

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 four 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, and then paid the following year. In the specific case of the estimated annual 2018 property tax amount for GUIC projects, the $1,159,565 for TIMP (Attachment F) and $652,677 for DIMP (Attachment G) reflect property tax rates from the pay-2017 tax year using plant in service as of December 31, 2015 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 2018 book depreciation for GUIC projects, the $1,689,498 for TIMP (Attachment F) and $1,639,514 for DIMP (Attachment G) reflect the amount of plant in service that is being recovered through depreciation expense from January 2018-December 2018 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 2018 deferred taxes for GUIC projects, the $1,407,487 for TIMP (Attachment F) and $1,721,801 for DIMP (Attachment G) reflect the January 1, 2018 - December 31, 2018 tax timing difference when book expense differs from tax expense and results in an increase to revenue requirements.

Plus Gross Up for Income 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 2018 current taxes for GUIC projects, the $1,119,908 for TIMP (Attachment F) and $151,283 for DIMP (Attachment G) 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.

		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17
Revenue Requirement Subtotal		1,358,339	1,352,271	1,367,369	1,289,933	1,655,825	1,617,916	1,984,554	2,038,470	1,943,737	(402,566)	2,471,388	655,070	1,578,373	1,521,675	1,591,758
Revenue Collections (shaded = actuals)		3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733	298,324	496,841	953,420	1,126,556	717,341	748,292
														Revenue Collections (Jan '16-Mar '17)*		15,288,148
Carryover Rollforward:																
Carryover Beginning Balance		(1,184,983)	(2,990,304)	(4,280,661)	(4,758,073)	(4,689,519)	(3,639,978)	(2,453,955)	(891,574)	701,052	2,476,056	1,775,167	3,749,714	3,451,363	2,324,807	1,607,466
Activity (Under/(Over) Collection)		(1,805,321)	(1,290,357)	(477,412)	68,554	1,049,541	1,186,023	1,562,381	1,592,626	1,775,004	(700,889)	1,974,547	(298,351)	451,817	804,335	843,466
3-month deferral impact														(1,578,373)	(1,521,675)	(1,591,758)
Carrying Charge																
Carryover Ending Balance		(2,990,304)	(4,280,661)	(4,758,073)	(4,689,519)	(3,639,978)	(2,453,955)	(891,574)	701,052	2,476,056	1,775,167	3,749,714	3,451,363	2,324,807	1,607,466	859,175
Monthly Interest Rate																
Rate Calculation:																
Annual Revenue Requirements																
Carryover Balance																
Carrying Charge																
Total Revenue Requirement																
Total Sales																
Cost per Therm																
Rate by Class:																
Allocated Revenue Requirement	Weighting*															
Residential	67.2244%															
Commercial Firm	21.2597%															
Commercial Demand Billed	2.1010%															
Interruptible	5.6521%															
Transport	3.7628%															
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153																
Sales by Customer Group (Billed by total Usage)																
Residential		68,347,473	56,468,255	46,220,639	25,081,110	14,740,988	8,906,845	6,435,105	6,570,745	8,647,552	18,724,809	38,318,515	59,364,541	68,368,938	57,400,677	45,591,199
Commercial Firm		36,782,234	30,859,812	26,556,962	13,434,879	9,702,243	4,956,830	3,909,831	4,147,409	5,295,143	10,881,204	21,341,201	33,661,319	36,992,880	31,037,926	26,707,660
Commercial Demand Billed		3,572,710	3,117,804	3,487,429	1,980,169	1,776,409	1,514,922	1,662,088	1,488,900	1,613,067	2,102,566	2,645,160	2,703,575	3,297,774	3,543,830	2,778,197
Interruptible		12,635,578	12,082,408	10,789,546	8,672,081	6,454,790	5,409,278	5,984,729	5,487,738	5,554,440	7,437,646	10,020,443	12,289,865	12,743,223	11,344,338	10,915,849
Transport		18,946,134	11,075,216	15,456,105	15,504,081	20,908,639	19,168,001	28,596,563	20,747,736	12,759,486	18,154,881	12,067,675	18,018,070	13,400,291	8,920,664	15,037,356
Total Sales		140,284,128	113,603,495	102,510,681	64,672,321	53,583,069	39,955,875	46,588,316	38,442,529	33,869,688	57,301,107	84,392,993	126,037,370	134,803,106	112,247,435	101,030,260
Allocated Cost Per therm																
Residential		0.033941	0.033941	0.033941	0.033941	0.033941	0.033941	0.033941	0.033941	0.010922	0.010922	0.010922	0.010922	0.010922	0.010922	0.010922
Commercial Firm		0.019357	0.019357	0.019357	0.019357	0.019357	0.019357	0.019357	0.019357	0.006110	0.006110	0.006110	0.006110	0.006110	0.006110	0.006110
Commercial Demand Billed		0.012021	0.012021	0.012021	0.012021	0.012021	0.012021	0.012021	0.012021	0.005274	0.005274	0.005274	0.005274	0.005274	0.005274	0.005274
Interruptible		0.008369	0.008369	0.008369	0.008369	0.008369	0.008369	0.008369	0.008369	0.003860	0.003860	0.003860	0.003860	0.003860	0.003860	0.003860
Transport		0.002445	0.002445	0.002445	0.002445	0.002445	0.002445	0.002445	0.002445	0.001570	0.001570	0.001570	0.001570	0.001570	0.001570	0.001570

		Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18
Revenue Requirement Subtotal		1,324,728	1,616,923	1,754,383	1,693,877	1,627,896	2,317,839	2,573,044	2,330,776	2,074,895	1,800,931	1,818,206	1,811,795
Revenue Collections (shaded = actuals)		387,813	263,473	179,974	175,650	158,511	183,916	332,228	622,679	917,656	7,764,261	6,480,979	5,398,201
											Revenue Collections (Apr '17 - Mar '18)		22,865,341
Carryover Rollforward:													
Carryover Beginning Balance		859,175	6,487,896	7,841,345	9,415,754	10,933,982	12,403,366	14,537,289	16,778,105	18,486,201	19,643,441	11,879,180	5,398,201
Activity (Under/(Over) Collection)		936,915	1,353,449	1,574,409	1,518,227	1,469,384	2,133,923	2,240,816	1,708,096	1,157,239	(5,963,330)	(4,662,773)	(3,586,406)
3-month deferral impact		4,691,807									(1,800,931)	(1,818,206)	(1,811,795)
Carrying Charge													
Carryover Ending Balance		6,487,896	7,841,345	9,415,754	10,933,982	12,403,366	14,537,289	16,778,105	18,486,201	19,643,441	11,879,180	5,398,201	-
Monthly Interest Rate													
Rate Calculation:													
Annual Revenue Requirements											0		
Carryover Balance											19,643,441		
Carrying Charge											-		
Total Revenue Requirement											19,643,441		
Total Sales											355,841,030		
Cost per Therm											0.055203		
Rate by Class:													
Allocated Revenue Requirement	Weighting*												
Residential	67.2244%										4,401,728	4,401,728	4,401,728
Commercial Firm	21.2597%										1,392,046	1,392,046	1,392,046
Commercial Demand Billed	2.1010%										137,570	137,570	137,570
Interruptible	5.6521%										370,089	370,089	370,089
Transport	3.7628%										246,381	246,381	246,381
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153													
Sales by Customer Group (Billed by total Usage)													
Residential		25,622,491	14,105,793	8,074,948	6,480,071	6,547,950	8,485,676	18,827,870	38,289,787	57,992,449	68,607,836	57,589,726	46,038,468
Commercial Firm		13,511,076	9,757,419	4,172,031	3,932,713	4,171,695	5,326,020	10,399,748	20,383,255	31,323,471	36,389,043	30,911,244	26,262,453
Commercial Demand Billed		1,861,098	1,846,201	1,515,639	1,662,485	1,489,696	1,616,610	1,926,806	2,467,829	2,939,989	3,468,290	3,262,168	2,935,582
Interruptible		8,707,681	6,256,040	5,568,671	5,932,718	5,653,844	5,905,382	8,257,832	10,066,135	11,701,268	12,567,642	12,587,144	10,661,505
Transport		12,064,463	14,308,757	17,055,491	23,804,050	17,654,387	12,430,942	13,382,156	17,876,476	20,511,876	19,616,813	13,052,685	11,890,432
Total Sales		61,766,809	46,274,210	36,386,780	41,812,036	35,517,572	33,764,630	52,794,411	89,083,481	124,469,052	140,649,623	117,402,968	97,788,439
Allocated Cost Per therm													
Residential		0.010922	0.010922	0.010922	0.010922	0.010922	0.010922	0.010922	0.010922	0.010922	0.076669	0.076669	0.076669
Commercial Firm		0.006110	0.006110	0.006110	0.006110	0.006110	0.006110	0.006110	0.006110	0.006110	0.044635	0.044635	0.044635
Commercial Demand Billed		0.005274	0.005274	0.005274	0.005274	0.005274	0.005274	0.005274	0.005274	0.005274	0.042697	0.042697	0.042697
Interruptible		0.003860	0.003860	0.003860	0.003860	0.003860	0.003860	0.003860	0.003860	0.003860	0.030999	0.030999	0.030999
Transport		0.001570	0.001570	0.001570	0.001570	0.001570	0.001570	0.001570	0.001570	0.001570	0.016588	0.016588	0.016588

		Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19
Revenue Requirement Subtotal		1,790,666	2,013,126	2,069,556	2,406,694	2,603,449	2,807,665	2,891,717	2,643,252	2,821,354	2,341,020	2,363,857	2,355,936
Revenue Collections (shaded = actuals)		1,842,936	1,470,184	1,169,589	1,400,531	1,269,537	1,178,149	1,530,029	2,657,466	3,975,739	4,387,607	3,561,956	3,034,689
											Revenue Collections (Apr '18 - Mar '19)		27,478,411
Carryover Rollforward:													
Carryover Beginning Balance		-	5,378,662	5,921,604	6,821,572	7,827,735	9,161,646	10,791,163	12,152,851	12,138,637	10,984,252	6,596,645	3,034,689
Activity (Under/(Over) Collection)		(52,270)	542,942	899,967	1,006,163	1,333,912	1,629,517	1,361,688	(14,214)	(1,154,386)	(2,046,587)	(1,198,099)	(678,753)
3-month deferral impact		5,430,932									(2,341,020)	(2,363,857)	(2,355,936)
Carrying Charge		-	-	-	-	-	-	-	-	-	-	-	-
Carryover Ending Balance		5,378,662	5,921,604	6,821,572	7,827,735	9,161,646	10,791,163	12,152,851	12,138,637	10,984,252	6,596,645	3,034,689	(0)
Monthly Interest Rate		0.89%											
Rate Calculation:													
Annual Revenue Requirements		27,478,411											
Carryover Balance		-											
Carrying Charge		-											
Total Revenue Requirement		27,478,411											
Total Sales		895,120,348											
Cost per Therm		0.030698											
Rate by Class:													
Allocated Revenue Requirement	Weighting*												
Residential	67.2244%	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350	1,539,350
Commercial Firm	21.2597%	486,819	486,819	486,819	486,819	486,819	486,819	486,819	486,819	486,819	486,819	486,819	486,819
Commercial Demand Billed	2.1010%	48,110	48,110	48,110	48,110	48,110	48,110	48,110	48,110	48,110	48,110	48,110	48,110
Interruptible	5.6521%	129,426	129,426	129,426	129,426	129,426	129,426	129,426	129,426	129,426	129,426	129,426	129,426
Transport	3.7628%	86,163	86,163	86,163	86,163	86,163	86,163	86,163	86,163	86,163	86,163	86,163	86,163
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153													
Sales by Customer Group (Billed by total Usage)													
Residential		25,385,157	13,933,901	8,638,464	6,322,405	6,537,535	8,574,743	19,217,857	39,082,894	59,193,664	68,456,138	57,462,391	45,936,674
Commercial Firm		13,634,991	8,729,891	4,918,883	3,921,746	4,294,303	5,377,647	11,091,153	21,673,317	33,313,914	36,597,835	31,088,586	26,413,016
Commercial Demand Billed		2,057,402	1,828,361	1,432,877	1,433,288	1,486,671	1,524,808	2,013,588	2,579,200	3,072,284	3,472,869	3,266,431	2,939,460
Interruptible		7,712,053	5,556,247	5,042,474	4,771,851	5,253,261	5,065,571	8,232,254	10,007,805	11,649,128	12,320,047	12,367,753	10,483,849
Transport		11,244,778	17,843,436	18,067,142	29,173,564	23,783,914	17,835,901	9,286,452	13,224,808	22,282,321	22,081,183	11,846,992	13,083,222
Total Sales		60,034,380	47,891,836	38,099,839	45,622,854	41,355,683	38,378,671	49,841,304	86,568,025	129,511,310	142,928,072	116,032,154	98,856,220
Allocated Cost Per therm													
Residential		0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492	0.051492
Commercial Firm		0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056	0.029056
Commercial Demand Billed		0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298	0.021298
Interruptible		0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774	0.015774
Transport		0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929	0.004929

		Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20
Revenue Requirement Subtotal		2,341,944	2,535,532	2,703,406	3,085,479	3,222,466	3,489,398	3,686,563	3,166,592	3,564,216	2,635,899	2,646,743	2,643,733
Revenue Collections (shaded = actuals)		2,449,922	1,893,271	1,502,967	1,697,213	1,749,965	1,410,404	2,552,362	3,389,317	4,752,015	5,268,121	4,436,784	3,754,068
												Revenue Collections (Apr '19 - Mar '20)	34,856,410
Carryover Rollforward:													
Carryover Beginning Balance		(0)	6,952,836	7,595,097	8,795,536	10,183,802	11,656,303	13,735,297	14,869,498	14,646,772	13,458,973	8,190,852	3,754,068
Activity (Under/(Over) Collection)		(107,978)	642,261	1,200,439	1,388,266	1,472,501	2,078,994	1,134,201	(222,726)	(1,187,799)	(2,632,222)	(1,790,041)	(1,110,335)
3-month deferral impact		7,060,814									(2,635,899)	(2,646,743)	(2,643,733)
Carrying Charge		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Carryover Ending Balance		6,952,836	7,595,097	8,795,536	10,183,802	11,656,303	13,735,297	14,869,498	14,646,772	13,458,973	8,190,852	3,754,068	(0)
Monthly Interest Rate		0.89%											
Rate Calculation:													
Annual Revenue Requirements		34,856,410											
Carryover Balance		(0)											
Carrying Charge		(0)											
Total Revenue Requirement		34,856,410											
Total Sales		908,569,381											
Cost per Therm		0.038364											
Rate by Class:													
Allocated Revenue Requirement	Weighting*												
Residential	67.2244%	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668	1,952,668
Commercial Firm	21.2597%	617,531	617,531	617,531	617,531	617,531	617,531	617,531	617,531	617,531	617,531	617,531	617,531
Commercial Demand Billed	2.1010%	61,028	61,028	61,028	61,028	61,028	61,028	61,028	61,028	61,028	61,028	61,028	61,028
Interruptible	5.6521%	164,177	164,177	164,177	164,177	164,177	164,177	164,177	164,177	164,177	164,177	164,177	164,177
Transport	3.7628%	109,298	109,298	109,298	109,298	109,298	109,298	109,298	109,298	109,298	109,298	109,298	109,298
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153													
Sales by Customer Group (Billed by total Usage)													
Residential		25,329,029	13,903,092	8,619,363	6,308,425	6,523,080	8,555,784	19,175,365	38,996,479	59,062,782	68,540,312	58,306,076	45,971,679
Commercial Firm		13,713,064	8,779,929	4,947,046	3,944,208	4,318,887	5,408,431	11,154,679	21,797,581	33,504,894	37,032,123	31,897,380	26,715,926
Commercial Demand Billed		2,060,135	1,830,766	1,434,756	1,435,155	1,488,627	1,526,795	2,016,236	2,582,571	3,076,337	3,490,417	3,342,238	2,953,549
Interruptible		7,601,921	5,470,709	4,968,704	4,718,299	5,193,542	4,972,859	8,089,017	9,814,168	11,448,932	12,075,897	12,358,706	10,331,205
Transport		15,155,678	19,365,624	19,206,573	27,833,570	28,090,555	16,299,815	26,094,737	15,155,363	16,773,384	16,180,430	9,745,080	11,881,414
Total Sales		63,859,827	49,350,121	39,176,443	44,239,658	45,614,691	36,763,684	66,530,033	88,346,162	123,866,329	137,319,180	115,649,480	97,853,773
Allocated Cost Per therm													
Residential		0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217	0.065217
Commercial Firm		0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466	0.036466
Commercial Demand Billed		0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887	0.026887
Interruptible		0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301	0.020301
Transport		0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914	0.005914

Redline

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	~~$0.010922~~$0.051492 per therm	R
Commercial Firm	~~$0.006110~~$0.029056 per therm	R
Commercial Demand Billed	~~$0.005274~~$0.021298 per therm	R
Interruptible	~~$0.003860~~$0.015774 per therm	R
Transportation	~~$0.001570~~$0.004929 per therm	R

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.

(Continued on Sheet No. 5-65)

Clean

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.

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Residential	$0.051492 per therm	R
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Commercial Demand Billed	$0.021298 per therm	R
Interruptible	$0.015774 per therm	R
Transportation	$0.004929 per therm	R

<u>Recoverable GUIC Expenses</u>
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.

(Continued on Sheet No. 5-65)

REPORT:

COST OF EQUITY – GUIC RIDER

PREPARED FOR

NORTHERN STATES POWER COMPANY - MINNESOTA

BEFORE THE:

MINNESOTA PUBLIC UTILITIES COMMISSION

NOVEMBER 1, 2017

CONCENTRIC ENERGY ADVISORS

www.ceadvisors.com

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I. INTRODUCTION AND QUALIFICATIONS

My name is James M. Coyne. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy and water industries. Based in Marlborough, Massachusetts and Washington D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses.

I provide expert testimony before federal, state and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. I regularly advise utilities, generating companies, public bodies and private equity investors on business issues pertaining to the utility industry. This work includes calculating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to rate policy, valuation, capital costs, alternative regulation, fuels and power markets. I have authored numerous articles on the energy industry, lectured on utility regulation for regulatory commission staff, and provided testimony before the FERC as well as state and provincial jurisdictions in the U.S. and Canada. I have also testified before the Minnesota Public Utilities Commission ("Commission"). I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My educational and professional background is summarized more fully in Appendix 1.

I am submitting this report on behalf of Northern States Power Company, a Minnesota corporation ("NSPM" or the "Company"), a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

II. PURPOSE AND OVERVIEW

The purpose of this report is to present evidence and provide a recommendation regarding an appropriate return on equity ("ROE")[1] for NSPM's Gas Utility Infrastructure Cost ("GUIC") rider. Appendix 2 contains a description of the various models used to estimate the cost of equity and the assumptions underlying those models. My analyses and conclusions are supported by the data presented in Appendix 3, Schedules 1 through 5.2.

My ROE recommendation is based primarily on the range of results that I derive from the Discounted Cash Flow ("DCF") model, the Bond Yield Plus Risk Premium approach ("Risk Premium") and the Capital Asset Pricing Model ("CAPM"). In addition, I consider authorized returns in other jurisdictions for gas distribution companies in 2016 and 2017, and the Commission's prior precedents for setting GUIC ROEs.

My recommendation takes into consideration the general economic and capital market environment. I specifically consider the unusually low Treasury bond yields in the current market which, when combined with the unsustainable high valuations and low dividend yields of utility stocks, are causing the DCF model to under-estimate the cost of equity at this time. For that reason, I also give weight to the results of the Risk Premium approach and the CAPM analysis, both of which can be adjusted to reflect investor expectations for higher interest rates by using forward-looking data. This is especially important given the shift that has occurred in monetary policy as the Federal Reserve continues to move toward normalizing interest rates after an extended period of policy accommodation.

The ROE results presented in my Schedules indicate a wide range of results from 8.63 percent to 11.01 percent from a combination of models and alternative input assumptions. Based on the results of all three methods (i.e., DCF, Risk Premium, and CAPM), and taking into consideration

[1] I use the terms "ROE" and "cost of equity" interchangeably throughout my Direct Testimony.
[2] In the remainder of this report, all references to "Schedules" are to the schedules contained in Appendix 3.

my observations pertaining to capital market conditions, I recommend the Commission authorize an ROE for the GUIC of 10.0 percent.

The balance of this report is organized as follows: Section III provides background on the regulatory principles behind making an ROE determination in general. Section IV presents a review of current and projected capital market conditions and the implications for the utility cost of capital. Section V describes the criteria and approach for selecting proxy groups of comparable companies. Section VI discusses the market data and models used to estimate the cost of equity, as well as the results of the Constant Growth DCF, Risk Premium and CAPM analyses. Section VII summarizes my results, conclusions and recommendation.

III. REGULATORY PRINCIPLES

Utilities are entitled by law to receive a fair rate of return sufficient to attract needed capital at reasonable rates. The basic tenets of this regulatory doctrine originate from several bellwether decisions by the United States Supreme Court, and that doctrine is followed to the same degree across this country with respect to state-level rate-making, including in Minnesota.

Regulated utilities rely primarily on common stock and long-term debt to finance their permanent property, plant and equipment. The allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital, debt and equity, are weighted by their respective book values. The ROE represents the cost of raising and retaining equity capital, and is estimated through one or more analytical techniques that use market data to quantify investor expectations regarding equity returns.

However, the ROE cannot be derived solely through quantitative metrics and models. To properly estimate the ROE the financial, regulatory and economic context in which the analysis takes place must also be considered. The DCF, Risk Premium and CAPM approaches, while fundamental to the ROE determination, are still only models. One should not assume that the results of these models can be mechanistically applied without also considering informed judgment and the context of capital market conditions.

Also, it is important to note that the U.S. Supreme Court has held that under the statutory standard of "just and reasonable" it is the result reached, not the method employed, which is controlling.[3] Consequently, it is appropriate to consider a variety of approaches and data sources when arriving at a recommended ROE.

The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of invested capital, and the market-required return on that capital. Because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital on favorable terms. Such decisions balance the long-term interests of customers and shareholders. The financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which they operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. It is therefore important for the ROE authorized in this proceeding to take into consideration current and expected capital market conditions, as well as investors' expectations and requirements regarding both risks and returns.

Concentric recognizes that the Commission's determination of the appropriate rate of return looks to the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest.[4] In this instance, NSPM's last general gas rate case was decided in December, 2010, when the Company's ROE was set at 10.09 percent.[5] While the Commission may, based on its prior precedent, place some weight on this prior decision, Concentric presents an updated cost of equity analysis for the basis of its recommendation.

3 Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), at 602.
4 Minn. Statute 216B.1635, subd.6.
5 G0002/GR-09-1153, December 6, 2010.

IV. CAPITAL MARKET CONDITIONS AND IMPLICATIONS FOR ROE

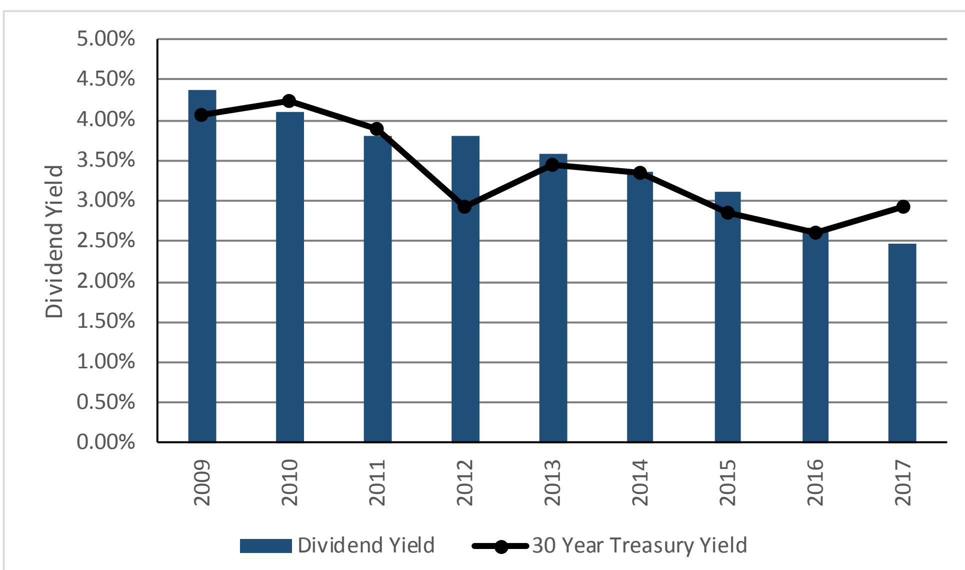
The required cost of capital, including the ROE, is a function of prevailing and expected conditions in the general economy and in financial markets. The standard ROE estimation tools, such as the DCF, CAPM and Risk Premium models, each reflect the state of the general economy and financial markets by incorporating specific economic and financial data. These inputs are, however, only samples of the various economic and market forces that may affect the ROE going forward. Consideration must be given to whether the assumptions relied on in the current or projected data are sustainable over the period that the recommended ROE will be in effect. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return. Therefore, an assessment of fluctuating market conditions is integral to any ROE recommendation.

In the current capital market environment, the cost of equity for regulated utility companies is being affected by two factors requiring special consideration: (a) low government bond yields, which have led to high valuations and low dividend yields on utility stocks relative to historical levels; and (b) the change in monetary policy and the market's expectation for higher interest rates. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

The Federal Open Market Committee ("FOMC") took extraordinary measures (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) over the past decade to stimulate the U.S. economy. The resulting very low or zero returns on short-term government bonds drove yield-seeking investors into longer-term instruments, bidding up prices and reducing yields on those investments. Furthermore, the Federal Reserve's purchases of longer-term bonds drove Treasury bond yields to historic lows, with the 10-year government bond yield reaching a low of 1.37 percent in July 2016. Continued economic expansion and "normalization" of Federal Reserve policy have relieved some of this downward pressure on the 10-year Treasury yield, which has since rebounded to 2.33 percent as of September 29, 2017.

The Federal Reserve's accommodative monetary policy caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. As a result of this search for higher yield, the share prices for many common stocks, especially dividend-paying stocks such as utilities, have been driven higher while the dividend yields (which are computed by dividing the dividend payment by the stock price) have decreased to levels well below the historical average. As shown in Figure 1, since the Federal Reserve intervened to stabilize financial markets and support the economic recovery after the Great Recession of 2008-09, Treasury bond yields and utility dividend yields have both declined. Specifically, 30-year Treasury bond yields have fallen by approximately 115 basis points since 2009, and natural gas utility dividend yields have decreased by about 190 basis points over this same period.

Figure 1: Dividend Yields for Natural Gas Utility Stocks



Similarly, Xcel Energy's average dividend yield has declined from 5.15 percent in 2009 to an average of 3.17 percent in 2017.

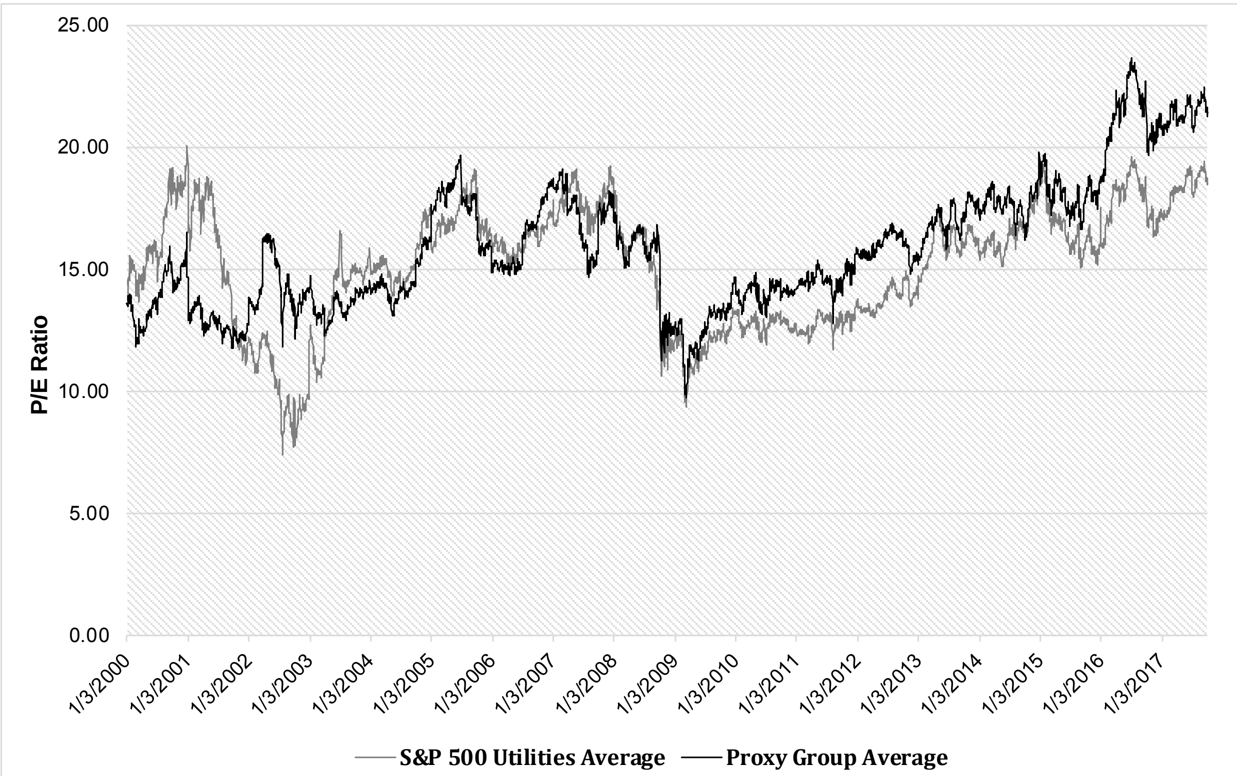
The DCF model is generally a reliable model to estimate the cost of equity and adequately reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility stocks. Value Line recently commented on the industry's low dividend yields and high valuations:

> The high valuation of stocks in the Electric Utility Industry is evident by a few ways of measuring this. The group's average dividend yield, at 3.3%, is comfortably above the median of all stocks under our coverage. However, this yield is low, by historical standards. In addition, for many years electric utility equities had a price-earnings ratio well below that of the market. Thus, the relative price-earnings ratio shown on our pages was below 1.00. Last year, this figure was right around 1.00 for many electric utility stocks. Today, many issues have a price-earnings ratio above 20. We also note that the majority of electric utility equities are trading within their 3- to 5-year Target Price Range. A few, such as ALLETE and CMS Energy, have recent prices above their 2020-2022 Target Price Range. As a result, the long-term total return potential of this group is just 3%, despite the likelihood of annual dividend growth from most of these companies. Income-oriented investors should keep this in mind.[6]

As shown in Figure 2, the average price/earnings ("P/E") ratio for the proxy companies and utilities in general has been steadily climbing since the end of the financial crisis in 2009, and today is near the highest level since 2000. These high current valuations are important because the DCF model utilizes current dividend yields based on unsustainable stock prices. Value Line projects that P/E ratios for the proxy group companies will contract in the next few years. All else equal, if the P/E ratios for utility stocks decline consistent with Value Line's projections, the DCF model will produce higher ROE estimates. Therefore, the DCF model is likely understating the forward-looking cost of equity for the proxy group companies under these circumstances.

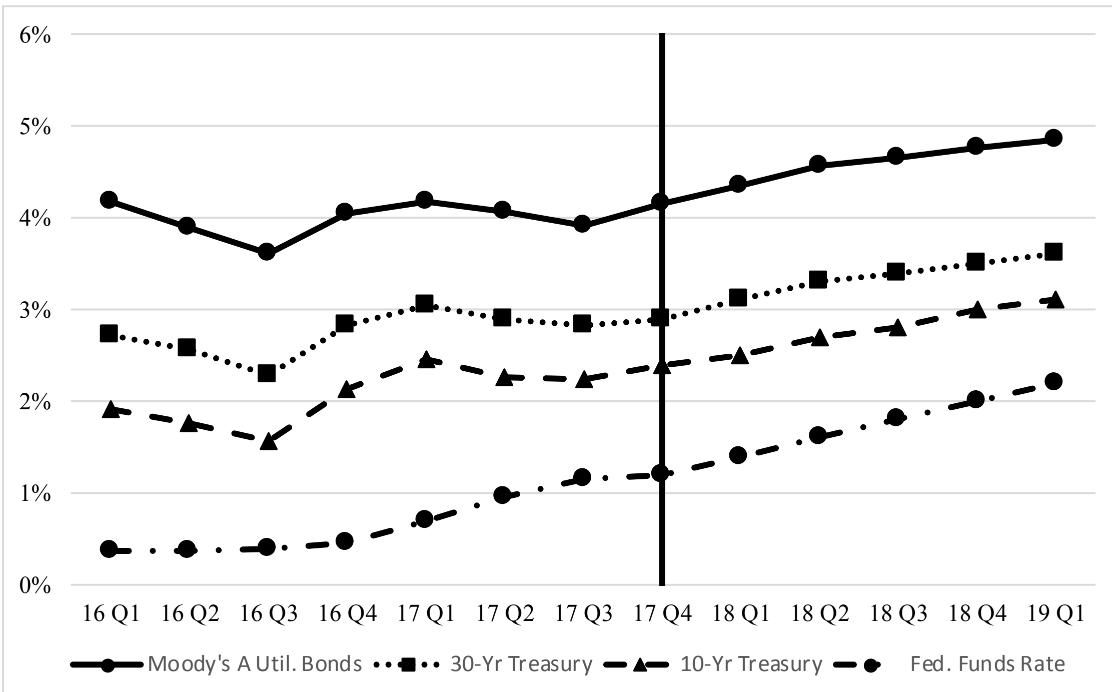
[6] Value Line Investment Survey, Electric Utility (Central) Industry, June 16, 2017, at 901.

Figure 2: Utility P/E Ratios vs. Proxy Group 2000 to September 2017



Since the process of estimating the cost of equity is a forward-looking analysis, it is not appropriate to base the ROE estimate on the low interest rate environment of the past few years, especially when interest rates are increasing and are expected to be significantly higher in the next several years. As shown in Figure 3, the interest rate environment is changing, as the Federal Reserve has begun tightening monetary policy, raising the federal funds rate in 25 basis point increments four times since December 2015. Yields on 10-year and 30-year Treasury bonds have increased substantially from the low point in July 2016. In addition, investor expectations are for higher interest rates on Treasury bonds and utility bonds over the next few years.[7]

Figure 3: Interest Rate Conditions[8]



The Federal Reserve has announced its intention to raise short-term interest rates in 25 basis point increments once more in 2017 and three times in 2018.[9]

According to the October 2017 issue of Blue Chip Financial Forecasts, almost 96 percent of those surveyed expect the Federal Reserve will raise short-term interest rates again at the December 2017 meeting.[10] In response to the question regarding expected increases in interest

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7 These investor expectations are reported by Blue Chip Financial Forecasts, which conducts a monthly survey of 45 economists employed by some of America's largest and most respected manufacturers, banks, insurance companies and brokerage firms in order to develop their consensus view.

8 Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume 36, No. 10, October 1, 2017, at 2.

9 FOMC, Federal Reserve press release, December 14, 2016.

10 Blue Chip Financial Forecasts, Vol. 36, Issue No. 10, October 1, 2017, at 14.

rates in 2018 by the Federal Reserve, 29 percent of those surveyed expect an increase of 50 basis points, 38 percent expect an increase of 75 basis points, and 24 percent expect an increase of 100 basis points.[11] These responses are aligned with the FOMC target rate projections noted above.

Furthermore, in Janet Yellen's testimony to Congress in July 2017, the Chair discussed the Federal Reserve's intention to begin reducing the size of its balance sheet. In response to the Great Recession, the Federal Reserve pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it has continued to reinvest the proceeds from the bonds it holds. The FOMC announced that it plans to start reducing the size of the Federal Reserve's $4.5 trillion bond portfolio in October 2017 by no longer reinvesting the proceeds of the bonds it holds.[12] The Federal Reserve's announced unwinding plan provides additional support for investors' view that long-term interest rates will increase, as the Federal Reserve gradually reverses the Quantitative Easing program that reduced those long-term rates.

Currently, NSPM has a GUIC rider petition pending before the Commission, which includes a requested 9.50 percent ROE. This petition was filed in November 2016 based on market data through September 2016. At the time of this pending petition, interest rates on 10-year Treasury bonds in the third quarter of 2016 averaged 1.56 percent, as compared with 2.24 percent in the third quarter of 2017.

It is necessary to consider the effects of capital market conditions on the inputs and assumptions used in the ROE estimation models and to consider whether current market conditions are

[11] *Ibid.*
[12] Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting September 20, 2017.

sustainable on a forward-looking basis. The Federal Reserve's accommodative monetary policy in recent years has resulted in high utility valuations and low dividend yields. As the Federal Reserve continues to normalize monetary policy, these high valuations and low dividend yields for utility stocks are not sustainable. Therefore, it is not appropriate to rely solely on the results of the DCF model because that model is based on historical stock prices, which are used to calculate the dividend yield. Rather, I also give weight to the Risk Premium model and the CAPM, both of which can be adjusted to use a forward-looking risk-free rate that is consistent with market expectations for higher Treasury yields. Specifically, I have used a forecasted 30-year Treasury bond yield in both the CAPM and Risk Premium analyses in order to take into consideration the market's expectation for higher interest rates. As the DCF model relies on "unrepresentative" inputs in the current market environment, I place less weight on these results.

V. PROXY GROUP SELECTION

Since the ROE is a market-based concept and given the fact that NSPM is not publicly-traded, it is necessary to establish a group of companies that is both publicly-traded and comparable to certain NSPM business and financial characteristics to serve as a "proxy" for purposes of the ROE estimation process. Even if NSPM's regulated utility operations in Minnesota made up the entirety of a publicly-traded entity, it is possible that transitory events could bias the Company's market value in one way or another over a given period of time. A significant benefit of using a proxy group is the ability to mitigate the effects of company-specific events that may not be representative of the industry or long-term trends. As a result of the screening criteria used to select my proxy groups, the companies in my ROE analyses have similar business and operating characteristics to NSPM's regulated utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

NSPM, a wholly-owned subsidiary of Xcel Energy, Inc. ("Xcel"), provides electric and natural gas service to approximately 1.27 million electric customers and 452,000 gas customers in Minnesota.[13] In addition, I note that NSPM's regulated gas distribution operations accounted for approximately 10 percent of operating revenue, with the remaining 90 percent coming from the regulated electric utility business.[14] NSPM's long-term issuer ratings are A- from Standard & Poor's ("S&P") and A2 from Moody's Investor Services ("Moody's").[15]

In previous GUIC rider decisions, the Commission relied on a weighted average of the cost of equity results for both a natural gas proxy group and a combined gas/electric utility proxy group. For example, in Docket No. G-002/GR-09-1153, the Administrative Law Judge recommended weighting those results 79 percent for the natural gas proxy group and 21 percent for the combined gas/electric utility proxy group. Consistent with prior decisions, I have developed two proxy groups to estimate the authorized ROE for the GUIC rider investments, a natural gas proxy group and a combined gas/electric proxy group.

A. Natural Gas Proxy Group

To develop the natural gas proxy group, I began with the 11 companies that Value Line classifies as "Natural Gas Utilities" and then screened companies according to the following criteria:

1) Consistently pays quarterly cash dividends;
2) Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3) Is covered by more than one equity analyst;
4) Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), Thomson First Call (as reported by Yahoo! Finance), and Zacks Investment Research ("Zacks");

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13 Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 304; Gas Jurisdictional Annual Report, Northern States Power – Minnesota, 2016.
14 Northern States Power – Minnesota FERC Form 1, December 31, 2016, at 115.
15 Source: SNL Financial.

5) Regulated net operating income makes up more than 60 percent of the consolidated company's net operating income;
6) Regulated net operating income from gas distribution service makes up more than 60 percent of the consolidated company's regulated operations; and
7) Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

B. Combination Proxy Group

To develop the combination proxy group, I began with the 40 domestic companies that Value Line classifies as "Electric Utilities" and then screened companies according to the following criteria:

1) Consistently pays quarterly cash dividends;
2) Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3) Is covered by more than one equity analyst;
4) Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), Thomson First Call (as reported by Yahoo! Finance), and Zacks Investment Research ("Zacks");
5) Owns generation assets that are included in rate base;
6) Regulated net operating income makes up more than 60 percent of the consolidated company's net operating income;
7) Regulated electric net operating income makes up more than 50 percent of the consolidated company's regulated operations;
8) Regulated net operating income from gas distribution makes up more than 10 percent of the consolidated company's regulated operations; and
9) Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

I did not include Xcel Energy in my proxy groups because it is my general practice to exclude the subject company, or its parent holding company, from the proxy group due to the circular logic that would occur by including those results.

Based on the screening criteria discussed above, I developed a gas distribution proxy group and a combination gas/electric utility proxy group consisting of the companies shown in Figure 4 and Figure 5.

Figure 4: Gas Distribution Company Proxy Group

Company	**Ticker**
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Corporation	SWX
Spire, Inc.	SR

Figure 5: Combination Gas/Electric Proxy Group

Company	Ticker
Ameren Corporation	AEE
Black Hills Corporation	BKH
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
DTE Energy Company	DTE
NorthWestern Corporation	NWE
PG&E Corporation	PCG
SCANA Corporation	SCG
Vectren Corporation	VVC
Wisconsin Energy Corporation	WEC

Please refer to Schedules 1.1 and 1.2 for my proxy group screening data and results.

I have selected the above proxy groups to best align with the financial and operational characteristics of NSPM. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like NSPM, are generally in sound financial condition. Additionally, I have screened on the percent of net operating income from regulated operations to differentiate utilities that derive the large majority of their operating income from regulated operations from those with substantial merchant or market-related risks. Also, I have screened on the percent contribution of the gas and electric segments to overall financial results in order to differentiate utilities that, like NSPM, derive the predominant share of their operating income from their gas and electric segments. Further, the generation screen for the combined utility proxy group identifies utilities that, like NSPM, own regulated generation in rate base and bear the risk of generation in their asset mix. These screens collectively reflect the risk factors that investors consider in making their investment decisions in utility companies.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

I have considered the results of several ROE estimation models, including the Constant Growth DCF, Risk Premium, and CAPM models. The formulas used to derive the results of each model and the assumptions underlying each approach are described in detail in Appendix 2.

All of the traditional ROE estimation methods are being distorted toward unreasonably low ROE estimates by current market conditions. As discussed previously, economic conditions are causing the results of the DCF model to be unreliable. As prices for utility stocks have increased, the dividend yield declines, resulting in a lower ROE estimate using the DCF model. With respect to the CAPM and Risk Premium models, yields on Treasury bonds directly affect the calculation of the ROE under both models. Generally, low Treasury bond yields result in lower ROE estimates in the CAPM and Risk Premium models, unless there has been an offsetting increase in the risk premium.

A. Constant Growth DCF Model

I calculated DCF results for each of the proxy group companies using the following inputs:

1) Average stock prices for the historical period, over 30, 90 and 180 trading days through September 29, 2017;
2) Annualized dividend per share as of September 29, 2017; and
3) Company-specific earnings growth forecasts.

It is important to use an average of recent trading days to calculate the subject company's stock price in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, it is important to reflect the conditions that have defined the financial markets over the recent past. In my view, consideration of these three averaging periods reasonably balances those concerns.

Utility companies tend to increase their quarterly dividends at different times throughout the year, so it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth for purposes of calculating this component of the DCF model. Accordingly, the DCF estimates reflect one-half of the expected growth in the dividend yield.

I have used the consensus analyst five-year growth estimates in earnings per share ("EPS") from Thomson First Call and Zacks, as well as EPS growth rates published by Value Line.

I relied on earnings per share growth rates because the Constant Growth DCF model assumes that dividends grow at a single growth rate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that EPS, dividends per share and book value per share will all grow at the same constant rate. It is therefore important to focus on measures of long-term earnings growth from credible sources as an appropriate measure of long-term growth in the DCF model.

I calculated the Mean High DCF result using the maximum growth rate (i.e., the maximum of the Value Line, Zacks and First Call EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies. I used a similar approach to calculate the Mean Low DCF results, using the minimum growth rate for each company. The Mean DCF results reflect the average growth rate for each company in combination with the expected dividend yield.

The results of my Constant Growth DCF analysis are provided in Schedules 2.1 and 2.2, and summarized in Figure 6 and Figure 7.

Figure 6: Constant Growth DCF Results – Natural Gas Proxy Group

	Mean Low	Mean	Mean High
30-day average	7.31%	8.57%	10.18%
90-day average	7.37%	8.63%	10.24%
180-day average	7.46%	8.73%	10.34%

Figure 7: Constant Growth DCF Results – Combination Proxy Group

	Mean Low	Mean	Mean High
30-day average	7.51%	8.70%	9.83%
90-day average	7.52%	8.71%	9.83%
180-day average	7.59%	8.78%	9.90%

As discussed in Section IV of this report, the prolonged period of low interest rates has distorted the results of the DCF model. In particular, dividend yields for utility companies are well below historical levels, which reduces the Constant Growth DCF results. It is particularly important that the ROE in this proceeding be based on forward-looking expectations for interest rates. It would not be appropriate to base the ROE determination on models that only take into consideration historical data which is from a period when the interest rate environment was much different than investors are expecting in the near future. In this economic environment, it is not reasonable to conclude that current stock valuations and dividend yields are sustainable, especially in the face of higher interest rates. As such, my conclusion is that the Constant Growth DCF model does not produce reliable results because one of the fundamental assumptions of the Constant Growth DCF method is that the P/E ratio will remain constant.

Other regulators have recognized that anomalous capital market conditions are having an effect on the results of the DCF model. For example, the Federal Energy Regulatory Commission

("FERC") has determined that anomalous capital market conditions have caused the DCF model to understate equity costs for regulated utilities at this time:

> Though the Commission noted certain economic conditions in Opinion No. 531, the principle argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above…[16]
>
> ****
>
> Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with Hope and Bluefield.[17]
>
> ****
>
> As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of the zone of reasonableness in this proceeding accurately reflects the equity returns necessary to meet the Hope and Bluefield capital attraction standards. We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies…[18]

Following the FERC's logic in Opinion No. 551, yields on 10-year Treasury bonds remain well below 3.0 percent,[19] which is the level that the FERC determined represents "anomalous" capital market conditions. The results of the DCF model are understating the cost of equity under current market conditions due to the low interest rate environment that has reduced dividend yields and raised valuations on utility shares to unsustainable levels. Consequently, it is necessary to consider the results of Risk Premium models, such as the Risk Premium and CAPM analyses in order to determine where to set the appropriate return.

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16 FERC Docket No. EL14-12-002, Opinion No. 551, at para 121. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court, the DC court did not question the finding by the FERC that capital market conditions were anomalous.

17 *Ibid.*, at para 122.

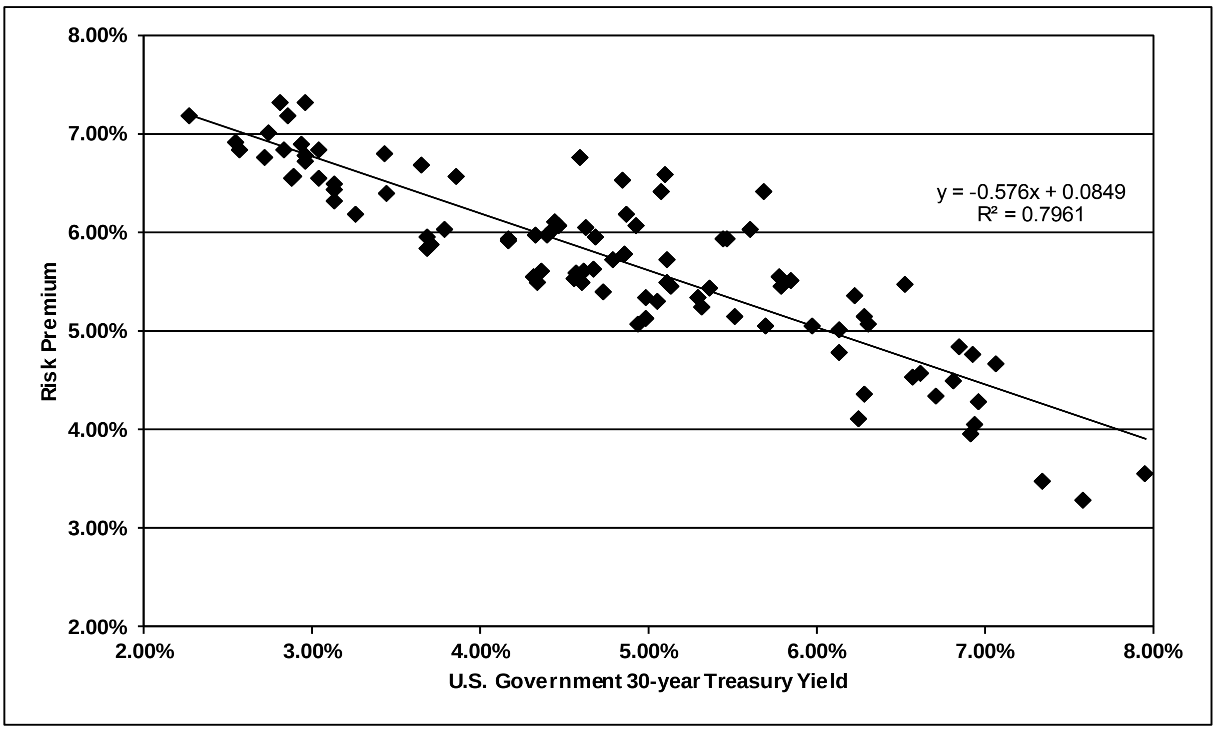
18 *Ibid.*

19 10-year Treasury bond yield was 2.33% on September 29, 2017.

B. Risk Premium Analysis

I conducted two Risk Premium analyses. My first risk premium analysis examines the relationship between quarterly average allowed ROEs for natural gas distribution companies and the respective 30-year Treasury yield from the relevant quarter. Data regarding allowed ROEs were provided by Regulatory Research Associates. The data includes 564 gas distribution rate cases from 1993 through September 29, 2017. The results of that regression are detailed in Figure 8.

Figure 4: Risk Premium Regression Results vs. 30-Year Treasury Yield



As illustrated by the chart, the risk premium varies with the level of the bond yield, and generally increases as bond yields decrease, and vice versa. My analysis considers three estimates of the 30-year Treasury yield, including the current 30-day average, a "Near-Term" Blue Chip consensus forecast for Q4 2017-Q1 2019, and a "Long-Term" Blue Chip consensus forecast for 2019-2023. I find this "Long-Term" result to be most applicable because investors typically have a multi-year view of their required returns on equity. As shown in Schedule 3.1, page 2, from 1993 through September 29, 2017, the average implied risk premium over these historic Treasury yields is 5.73 percent. Based on the regression coefficients in Schedule 3.1, page 2, which allow for the estimation of the risk premium at varying bond yields, the results of my analysis are shown in Figure 9.

Figure 5: Risk Premium Results Using 30-Year Treasury Yield

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Near-Term Forecast for Yield on 30-Year Treasury Bond[20]	Using Long-Term Forecast for Yield 30-Year Treasury Bond[21]
Yield	2.77%	3.30%	4.30%
Risk Premium	6.90%	6.59%	6.02%
Resulting ROE	9.67%	9.89%	10.32%

As an alternative to the Treasury Yield Risk Premium analyses described above, I have performed a similar analysis using historical A-rated utility bond yields to calculate the risk premium against authorized ROEs for gas distributors. A Blue Chip forecast, which I included in the Treasury yield version of the model, is not available for the A-rated utility bond yield. I therefore derived a forecast for the A-rated utility bond yield using average historical spreads from January 1, 2015 through September 29, 2017. The average spread between the 30-year Treasury bond yield and the A-rated utility bond yield during this period was 1.26 percent. I added this spread to the Blue Chip consensus forecasts referenced above to arrive at a Near-Term forecast of 4.56 percent and a Long-Term forecast of 5.56 percent. Inserting these forecasts for the A-rated utility bond yield into the regression equation provides the results shown in Figure 10. My calculations are shown in Schedule 3.2. The results of this analysis reasonably track the Risk Premium results using the 30-Year Treasury Yield.

[20] Blue Chip consensus forecast for 4Q 2017 – 1Q 2019, as of October 1, 2017.
[21] Blue Chip consensus forecast for 2019 – 2023, as of June 1, 2017.

Figure 6: Risk Premium Results vs. A-rated Utility Bond Yield

	Using 30-Day Average Yield on A-Rated Utility Bond	Using Near Term Forecast for A-Rated Utility Bond	Using Long-Term Forecast for A-Rated Utility Bond
Yield	3.86%	4.56%	5.56%
Risk Premium	5.71%	5.30%	4.71%
ROEs	9.56%	9.86%	10.27%

As noted earlier, I find that the Risk Premium results based on the 5-year forecast for the 30-year Treasury bond are applicable since they are forward-looking, and investors typically have a multi-year forward view of their estimates of the cost of equity. For purposes of my final range of analytical results, I draw from my Risk Premium model the results of 10.32 percent (based on Treasury yields) and 10.27 percent (based on Moody's A-rated utility bond yields).

C. CAPM Analysis

I also conducted a CAPM analysis for the two proxy groups.

Since both the DCF model and the CAPM assume long-term investment horizons, I used the Blue Chip forecast of the yield on 30-year Treasury bonds for 2019-2023 of 4.30 percent as my estimate of the risk-free rate.[22] Using the 5-year forecast of Treasury bond yields as the risk-free rate in the CAPM formula appropriately reflects the market's expectation for forward-looking interest rates.

I considered two measures of Beta for the proxy group companies: (1) the reported Beta from Bloomberg (which is calculated using 24 months of weekly data); and (2) the reported Beta from Value Line (which is calculated using 60 months of weekly data). My calculations for Beta are provided on Schedules 4.1 and 4.2.

22 Blue Chip Financial Forecasts, June 1, 2017, at 14.

To derive the Market Risk Premium ("MRP"), I conducted a Constant Growth DCF analysis on each of the S&P 500 companies and calculated the expected total market return, weighted by market capitalization. This total market return is based on current dividend yields and projected earnings growth for each company in the S&P 500 Index. A forward-looking MRP is calculated by subtracting the risk-free rate (based on the 5-year forecast of the 30-year Treasury bond) from the total market return. This analysis results in a 9.25 percent MRP, as shown on Schedule 4.3.

The CAPM is inherently a forward-looking model since it is designed to estimate investors' required equity return expectations. The MRP should, therefore, reflect investors' expected equity market returns relative to expected returns on Treasury securities, not historical return data. This is also consistent with the approach used by the FERC in developing a forward-looking MRP in Opinion No. 531.[23]

The CAPM results are shown in Schedules 4.4 and 4.5 and summarized in Figure 11 and Figure 12.

Figure 7: Forward-Looking CAPM Results – Natural Gas Proxy Group

Using Value Line Betas	11.01%
Using Bloomberg Betas	10.03%
Mean Result	10.52%

[23] FERC Opinion No. 531, at para. 108.

Figure 8: Forward-Looking CAPM Results – Combination Proxy Group

Using Value Line Betas	10.54%
Using Bloomberg Betas	9.13%
Mean Result	9.84%

These forward-looking CAPM results for the natural gas proxy group are consistent with the Risk Premium results and the Mean High DCF results but well above the Mean DCF results.

D. Flotation Costs

Flotation costs are the costs associated with the sale of new issues of common stock. Those costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's allowed return. To appropriately reflect flotation costs, the DCF calculation should be modified to provide a dividend yield that would reimburse investors for issuance costs. My flotation cost calculation is based on the costs of issuing equity that were incurred by Xcel in the common equity issuances shown in Schedules 5.1 and 5.2. Those issuance costs were applied to my natural gas and combination proxy groups. Based on the issuance costs provided in Schedule 5.1, flotation costs for NSPM are approximately 0.08 percent (i.e., 8 basis points) for the natural gas proxy group and 0.10 percent (i.e., 10 basis points) for the combination proxy group.

The need to reimburse investors for equity issuance costs has been recognized by the Commission in many, although not all, previous decisions.[24] I did not make an explicit

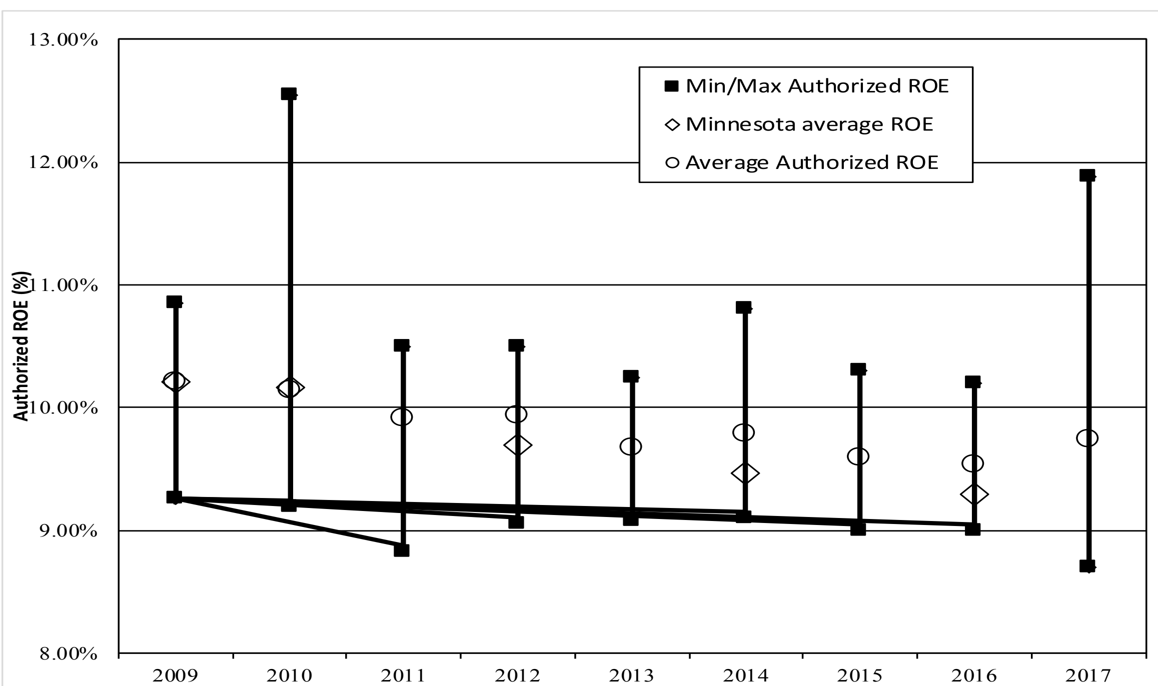
[24] Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order, at 9; Docket No. E002/GR-10-971, Findings of Fact, Conclusions, and Order, at 8; Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order, at 10-11; Docket No. E017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order, at 57-58; Docket No. G004/GR-04-1487, Findings of Fact, Conclusions of Law and Order, at 11.

adjustment for flotation costs. Rather, I took into consideration flotation costs in establishing my recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, and Risk Premium analyses.

E. Authorized Returns in Other Jurisdictions

In additional to the results of the traditional models used to estimate the cost of equity, I also considered authorized returns for gas distribution companies in other jurisdictions. Figure 13 shows the range of authorized returns for natural gas utilities in other jurisdictions since January 2009, and the returns authorized in Minnesota for natural gas companies over this same period. The average authorized ROE for gas distribution companies in 2016 and 2017 has been 9.62 percent.

Figure 9: Comparison of Minnesota and U.S. Authorized Returns[25]



[25] Source: SNL Financial.

As shown in Figure 13, the authorized returns for gas distribution companies in Minnesota have steadily declined from 2009 to 2016 and are currently near the bottom of the range produced by the authorized ROEs from other state jurisdictions. This is the result of the Commission's primary reliance on the results of the DCF analysis to determine a company's authorized ROE, rather than also considering whether the results of the DCF model are reasonable by reference to other models such as the CAPM and the Risk Premium model.

This should concern the Commission for two reasons. First, Minnesota utility subsidiaries must compete for capital within their own corporate structure, which must in turn compete for capital with other utilities and businesses. Placing NSPM at the low end of authorized ROEs outside Minnesota over the longer term can negatively impact NSPM's access to capital.

Second, as noted in Sections IV and VI, the historically low interest rates on Treasury bonds have resulted in high valuations of utility stocks, which has reduced dividend yields and therefore the results produced by the DCF model. Given that interest rates are expected to increase over the period during which the Company's cost of equity for the GUIC rider will be in effect, the results of the DCF model will underestimate an investor's expected ROE. As a result, it is important that the Commission consider the results of alternative methods such as the forward-looking CAPM and Bond Yield Plus Risk Premium analyses.

VII. SUMMARY AND CONCLUSIONS

Figure 14 summarizes the mean results of my DCF, Risk Premium and CAPM analyses for the natural gas and combination proxy groups.

Figure 10: Summary of ROE Model Results

	Natural Gas Proxy Group	**Combination Proxy Group**
DCF – 90-day average		
Constant Growth	8.63%	8.71%
Risk Premium – 30 Yr. U.S. Treasury		
30 Yr. U.S. Treasury	10.32%	10.32%
Moody's A-rated Utility Index	10.27%	10.27%
CAPM		
Value Line Beta	11.01%	10.54%
Bloomberg Beta	10.03%	9.13%
Mean of All Methods	10.05%	9.79%
Proxy Group Weight	79%	21%
Weighted Average ROE	10.00%	

The results range from a low of 8.63 percent for the Constant Growth DCF analysis to a high of 11.01 percent for the CAPM analysis (for the natural gas proxy group). The mean of all methods for the gas distribution and combined gas/electric proxy groups is 10.05 percent and 9.79 percent, respectively. As discussed previously, the Commission has in prior decisions applied a weighting of 79 percent to the results of the natural gas proxy group and 21 percent to the results of the combined gas/electric proxy group. Using that same weighting, I derive an ROE estimate of 10.0 percent. That is my recommendation for the GUIC rider. My recommendation is based on the following conclusions:

1) The results of the DCF model are under-estimating the cost of equity at this time given the current low dividend yields and high stock valuations for utility companies,

which are not considered to be sustainable over the longer-term in the face of higher interest rates;

2) Risk Premium and CAPM methods that rely on forward-looking inputs for the risk-free rate should be given greater weight during a period when the DCF model is being distorted by anomalous conditions in capital markets and interest rates are projected to increase substantially from current levels.

3) Authorized returns for regulated natural gas utilities in other U.S. jurisdictions have averaged 9.62 percent over the January 2016 – September 2017 period. Given the increase in Treasury yields that has already occurred, this trailing average sets a lower boundary on a forward-looking equity return.

4) Average yields on 10-year Treasury bonds have risen by 68 basis points from the third quarter of 2016 to the third quarter of 2017. This supports a return above NSPM's requested 9.50 percent ROE in the pending GUIC rider petition that was filed in November 2016, and the trailing average for allowed ROEs in other jurisdictions.

On balance, I believe that an authorized ROE of 10.0 percent represents a fair determination of the Company's cost of equity for the GUIC rider. The Commission may wish to consider the previously allowed ROE for the Company in its last general rate case, but due to the passage of time, I believe this updated cost of equity analysis better serves the Commission's reliance for this purpose.

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

Areas of Expertise

- **Energy Regulation**
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- **Management and Business Strategy**
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- **Financial and Economic Advisory**
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- Ontario Power Generation Inc.: Before the Ontario Energy Board, provided expert testimony on the appropriate common equity ratio for the company's regulated nuclear and hydroelectric generation assets, with Daniel Dane. (EB-2016-0152)
- Atco Electric Yukon: Before the Yukon Utilities Board, provided expert testimony on the appropriate risk premium to be applied to Atco Electric Yukon's return on equity in relation to utilities in other jurisdictions. (Docket 2016-2017 GRA)
- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, provided expert testimony on the cost of capital and business risk for the Company's gas distribution operations. (Docket No. 8698/8710)

- Northern States Power Co.: Before the Minnesota Public Utilities Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. E002/GR-15-826)
- Maritime Electric: Before the Island Regulatory and Appeals Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. UE20942)
- Newfoundland Power Inc.: Before the Newfoundland and Labrador Board of Commissioners of Public Utilities, provided expert testimony on the cost of capital and business risk for the Company's electric distribution operations. (2016/2017 General Rate Application)
- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No. 3698852)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on performance based regulation recommendations for the Company's Québec electric transmission and distribution businesses, with Robert Yardley. (R-3897-2014)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)

- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors

in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)

- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Provided consulting services to Hydro One Networks for the Company's 2015 – 2019 Custom Distribution Rate Application to the OEB. Assisted the Company in developing its proposal for specific performance metrics for the Plan; reviewed the comments of stakeholders on performance metrics; reviewed the Company's existing performance metrics; reviewed the fastest growing areas of budgeted expenditures for their performance metric potential; developed a set of recommended metrics for review with the Company; and assisted the Company with drafting its submission to the OEB. (2014)

- Advised the Ontario Power Authority (OPA) on appropriate efficiency metrics to utilize in measuring the effectiveness of the organization in response to a directive by the Ontario Energy Board. Conducted research and analysis to examine efficiency metrics used in the industry to measure the effectiveness of organizations with similar responsibilities to those of the OPA. This analysis was designed to help facilitate the OPA's recommended metrics to the OEB. (2013)
- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

PUBLICATIONS AND RESEARCH

- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May, 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.
- "Rate of Return: Where the Regulatory Rubber Meets the Road", CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.
- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	Project 3698852	Cost of Capital (Gas Distribution)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startran IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Maine Public Utility Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2015 2016	Newfoundland Power	2016/2017 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015 2016	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017	Northern States Power Company	PSCW Docket No. 4220-UR-123	Return on Equity (Gas & Electric)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

Description of Models and Associated Methodology Used to Estimate Return on Equity

Constant Growth DCF Model

The DCF approach, which is widely used in regulatory proceedings, is based on the theory that a stock's price represents the present value of all future expected cash flows. In its simplest form, the DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate, as reflected in the following formula, where "k" equals the required return, "D" is the current dividend, "g" is the expected growth rate, and "P" is the subject company's stock price:

$$k = \frac{D(1+g)}{P} + g$$

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE accordingly, as shown in the following formula:

$$r = \frac{D}{P} + \mathrm{g}$$

Stated in this manner, the cost of common equity is equal to the dividend yield plus the dividend growth rate. The Constant Growth DCF model is based on the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Risk Premium Approach

In general terms, this approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (*i.e.*, a premium) than a bondholder would. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds, as reflected in the following formula, in which *RP* = Risk Premium (difference between allowed ROE and the respective bond yield); and Y = Applicable bond yield:

$$ROE = RP + Y$$

Since the equity risk premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking estimates of the cost of equity, and others that consider historical, or ex-post, estimates. This Commission has previously recognized an approach that uses actual authorized returns for utilities as the measure of the Equity Risk Premium. The analysis therefore relies on authorized returns from a large sample of U.S. electric utilities, and separately on authorized returns for Wisconsin utilities only.

To estimate the relationship between interest rates and the cost of equity using the risk premium approach, a regression is conducted using the following equation, where a = intercept term and b = slope term:

$$RP = a + (b \times Y)$$

CAPM Analysis

The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[1] As shown in the following equation, the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f)$$

where:

[1] Systematic risks are fundamental market risks that reflect aggregate economic measures and therefore cannot be mitigated through diversification. Unsystematic risks reflect company-specific risks that can be mitigated and ultimately eliminated through investments in a portfolio of companies and/or market sectors.

K_e = the required ROE for a given security;

r_f = the risk-free rate of return;

β = the Beta of an individual security; and

r_m = the required return for the market as a whole.

The term (r_m – r_f) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in the above equation, is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

PROXY GROUP SCREENING DATA AND RESULTS - NATURAL GAS PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Postive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 60%	% Regulated Natural Gas Operating Income > 60%	Announced Merger within 180 days from 9/29/2017
Atmos Energy Corporation	ATO	Yes	A	Yes	Yes	94%	69%	No
New Jersey Resources Corporation	NJR	Yes	A	Yes	Yes	65%	100%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	102%	67%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	100%	96%	No
ONE Gas, Inc.	OGS	Yes	A	Yes	Yes	100%	100%	No
Southwest Gas Corporation	SWX	Yes	BBB+	Yes	Yes	82%	100%	No
Spire, Inc.	SR	Yes	A-	Yes	Yes	99%	100%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] to [6] Source: Form 10-Ks for 2016, 2015 & 2014
[7] SNL Financial News Releases

PROXY GROUP SCREENING DATA AND RESULTS - COMBINED UTILITY PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Company Owns Generation Assets in Rate Base	% Regulated Operating Income > 60%	% Regulated Electric Oper Income > 50%	% Regulated Gas Operating Income > 10%	Announced Merger within 180 days from 9/29/2017
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	101%	89%	11%	No
Black Hills Corporation	BKH	Yes	BBB	Yes	Yes	Yes	87%	60%	40%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	96%	73%	27%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	Yes	104%	69%	31%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	98%	80%	20%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	100%	84%	16%	No
PG&E Corporation	PCG	Yes	A-	Yes	Yes	Yes	100%	89%	11%	No
SCANA Corporation	SCG	Yes	BBB	Yes	Yes	Yes	89%	85%	15%	No
Vectren Corporation	VVC	Yes	A-	Yes	Yes	Yes	85%	50%	45%	No
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	Yes	Yes	75%	63%	36%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: SNL Financial (pulled from FERC Form 1)
[6] - [8] Source: Form 10-Ks for 2016, 2015 & 2014, three-year average
[9] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF - NATURAL GAS PROXY GROUP

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Atmos Energy Corporation	ATO	$1.80	$86.73	2.08%	2.15%	6.00%	7.60%	6.70%	6.77%	8.14%	8.91%	9.75%
New Jersey Resources Corporation	NJR	$1.09	$43.01	2.53%	2.60%	3.00%	6.00%	6.00%	5.00%	5.57%	7.60%	8.61%
NiSource Inc.	NI	$0.70	$26.60	2.63%	2.71%	5.50%	7.40%	6.10%	6.33%	8.20%	9.05%	10.13%
Northwest Natural Gas Company	NWN	$1.88	$65.92	2.85%	2.92%	7.00%	4.00%	4.30%	5.10%	6.91%	8.02%	9.95%
ONE Gas, Inc.	OGS	$1.68	$74.77	2.25%	2.33%	9.50%	6.00%	6.00%	7.17%	8.31%	9.49%	11.85%
Southwest Gas Corporation	SWX	$1.98	$79.26	2.50%	2.57%	7.50%	4.00%	5.60%	5.70%	6.55%	8.27%	10.09%
Spire, Inc.	SR	$2.10	$76.02	2.76%	2.84%	8.00%	4.64%	4.80%	5.81%	7.47%	8.66%	10.87%
MEAN				2.51%	2.59%	6.64%	5.66%	5.64%	5.98%	7.31%	8.57%	10.18%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF - NATURAL GAS PROXY GROUP

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Atmos Energy Corporation	ATO	$1.80	$85.53	2.10%	2.18%	6.00%	7.60%	6.70%	6.77%	8.17%	8.94%	9.78%
New Jersey Resources Corporation	NJR	$1.09	$42.20	2.58%	2.65%	3.00%	6.00%	6.00%	5.00%	5.62%	7.65%	8.66%
NiSource Inc.	NI	$0.70	$26.18	2.67%	2.76%	5.50%	7.40%	6.10%	6.33%	8.25%	9.09%	10.17%
Northwest Natural Gas Company	NWN	$1.88	$63.41	2.96%	3.04%	7.00%	4.00%	4.30%	5.10%	7.02%	8.14%	10.07%
ONE Gas, Inc.	OGS	$1.68	$72.68	2.31%	2.39%	9.50%	6.00%	6.00%	7.17%	8.38%	9.56%	11.92%
Southwest Gas Corporation	SWX	$1.98	$78.44	2.52%	2.60%	7.50%	4.00%	5.60%	5.70%	6.57%	8.30%	10.12%
Spire, Inc.	SR	$2.10	$73.23	2.87%	2.95%	8.00%	4.64%	4.80%	5.81%	7.57%	8.76%	10.98%
MEAN				2.58%	2.65%	6.64%	5.66%	5.64%	5.98%	7.37%	8.63%	10.24%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF - NATURAL GAS PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Mean Low ROE	Overall Mean ROE	Mean High ROE
Atmos Energy Corporation	ATO	$1.80	$82.03	2.19%	2.27%	6.00%	7.60%	6.70%	6.77%	8.26%	9.04%	9.88%
New Jersey Resources Corporation	NJR	$1.09	$40.60	2.68%	2.75%	3.00%	6.00%	6.00%	5.00%	5.72%	7.75%	8.77%
NiSource Inc.	NI	$0.70	$24.82	2.82%	2.91%	5.50%	7.40%	6.10%	6.33%	8.40%	9.24%	10.32%
Northwest Natural Gas Company	NWN	$1.88	$61.32	3.07%	3.14%	7.00%	4.00%	4.30%	5.10%	7.13%	8.24%	10.17%
ONE Gas, Inc.	OGS	$1.68	$69.60	2.41%	2.50%	9.50%	6.00%	6.00%	7.17%	8.49%	9.67%	12.03%
Southwest Gas Corporation	SWX	$1.98	$80.34	2.46%	2.53%	7.50%	4.00%	5.60%	5.70%	6.51%	8.23%	10.06%
Spire, Inc.	SR	$2.10	$69.95	3.00%	3.09%	8.00%	4.64%	4.80%	5.81%	7.71%	8.90%	11.12%
MEAN				2.66%	2.74%	6.64%	5.66%	5.64%	5.98%	7.46%	8.73%	10.34%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

30-DAY CONSTANT GROWTH DCF - COMBINED UTILITY PROXY GROUP

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Ameren Corporation	AEE	$1.76	$59.52	2.96%	3.05%	6.00%	6.10%	6.50%	6.20%	9.05%	9.25%	9.55%
Black Hills Corporation	BKH	$1.78	$69.64	2.56%	2.64%	7.50%	7.65%	5.00%	6.72%	7.62%	9.36%	10.30%
CMS Energy Corporation	CMS	$1.33	$47.86	2.78%	2.87%	6.50%	7.44%	6.00%	6.65%	8.86%	9.52%	10.32%
Dominion Resources, Inc.	D	$3.02	$78.53	3.85%	3.94%	5.50%	3.46%	6.00%	4.99%	7.37%	8.93%	9.96%
DTE Energy Company	DTE	$3.30	$110.81	2.98%	3.06%	6.00%	4.59%	5.90%	5.50%	7.64%	8.56%	9.07%
NorthWestern Corporation	NWE	$2.10	$59.29	3.54%	3.60%	4.50%	3.05%	1.60%	3.05%	5.17%	6.65%	8.12%
PG&E Corporation	PCG	$2.12	$69.65	3.04%	3.13%	9.50%	2.08%	5.00%	5.53%	5.16%	8.65%	12.69%
SCANA Corporation	SCG	$2.45	$58.28	4.20%	4.29%	4.00%	5.50%	3.30%	4.27%	7.57%	8.56%	9.82%
Vectren Corporation	VVC	$1.68	$65.90	2.55%	2.63%	6.50%	6.00%	5.50%	6.00%	8.12%	8.63%	9.13%
Wisconsin Energy Corporation	WEC	$2.08	$64.96	3.20%	3.29%	6.00%	5.61%	5.30%	5.64%	8.59%	8.93%	9.30%
MEAN				3.17%	3.25%	6.20%	5.15%	5.01%	5.45%	7.51%	8.70%	9.83%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF - COMBINED UTILITY PROXY GROUP

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Ameren Corporation	AEE	$1.76	$57.35	3.07%	3.16%	6.00%	6.10%	6.50%	6.20%	9.16%	9.36%	9.67%
Black Hills Corporation	BKH	$1.78	$69.61	2.56%	2.64%	7.50%	7.65%	5.00%	6.72%	7.62%	9.36%	10.31%
CMS Energy Corporation	CMS	$1.33	$47.24	2.82%	2.91%	6.50%	7.44%	6.00%	6.65%	8.90%	9.56%	10.36%
Dominion Resources, Inc.	D	$3.02	$78.34	3.86%	3.95%	5.50%	3.46%	6.00%	4.99%	7.38%	8.94%	9.97%
DTE Energy Company	DTE	$3.30	$109.00	3.03%	3.11%	6.00%	4.59%	5.90%	5.50%	7.69%	8.61%	9.12%
NorthWestern Corporation	NWE	$2.10	$60.48	3.47%	3.53%	4.50%	3.05%	1.60%	3.05%	5.10%	6.58%	8.05%
PG&E Corporation	PCG	$2.12	$68.39	3.10%	3.19%	9.50%	2.08%	5.00%	5.53%	5.21%	8.71%	12.75%
SCANA Corporation	SCG	$2.45	$63.58	3.85%	3.94%	4.00%	5.50%	3.30%	4.27%	7.22%	8.20%	9.46%
Vectren Corporation	VVC	$1.68	$62.10	2.71%	2.79%	6.50%	6.00%	5.50%	6.00%	8.28%	8.79%	9.29%
Wisconsin Energy Corporation	WEC	$2.08	$63.58	3.27%	3.36%	6.00%	5.61%	5.30%	5.64%	8.66%	9.00%	9.37%
MEAN				3.17%	3.26%	6.20%	5.15%	5.01%	5.45%	7.52%	8.71%	9.83%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF - COMBINED UTILITY PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Mean Low ROE	Overall Mean ROE	Mean High ROE
Ameren Corporation	AEE	$1.76	$55.77	3.16%	3.25%	6.00%	6.10%	6.50%	6.20%	9.25%	9.45%	9.76%
Black Hills Corporation	BKH	$1.78	$67.46	2.64%	2.73%	7.50%	7.65%	5.00%	6.72%	7.70%	9.44%	10.39%
CMS Energy Corporation	CMS	$1.33	$45.76	2.91%	3.00%	6.50%	7.44%	6.00%	6.65%	8.99%	9.65%	10.45%
Dominion Resources, Inc.	D	$3.02	$77.41	3.90%	4.00%	5.50%	3.46%	6.00%	4.99%	7.43%	8.99%	10.02%
DTE Energy Company	DTE	$3.30	$105.27	3.13%	3.22%	6.00%	4.59%	5.90%	5.50%	7.80%	8.72%	9.23%
NorthWestern Corporation	NWE	$2.10	$59.48	3.53%	3.58%	4.50%	3.05%	1.60%	3.05%	5.16%	6.63%	8.11%
PG&E Corporation	PCG	$2.12	$66.83	3.17%	3.26%	9.50%	2.08%	5.00%	5.53%	5.29%	8.79%	12.82%
SCANA Corporation	SCG	$2.45	$65.53	3.74%	3.82%	4.00%	5.50%	3.30%	4.27%	7.10%	8.08%	9.34%
Vectren Corporation	VVC	$1.68	$59.67	2.82%	2.90%	6.50%	6.00%	5.50%	6.00%	8.39%	8.90%	9.41%
Wisconsin Energy Corporation	WEC	$2.08	$61.65	3.37%	3.47%	6.00%	5.61%	5.30%	5.64%	8.76%	9.11%	9.48%
MEAN				3.24%	3.32%	6.20%	5.15%	5.01%	5.45%	7.59%	8.78%	9.90%

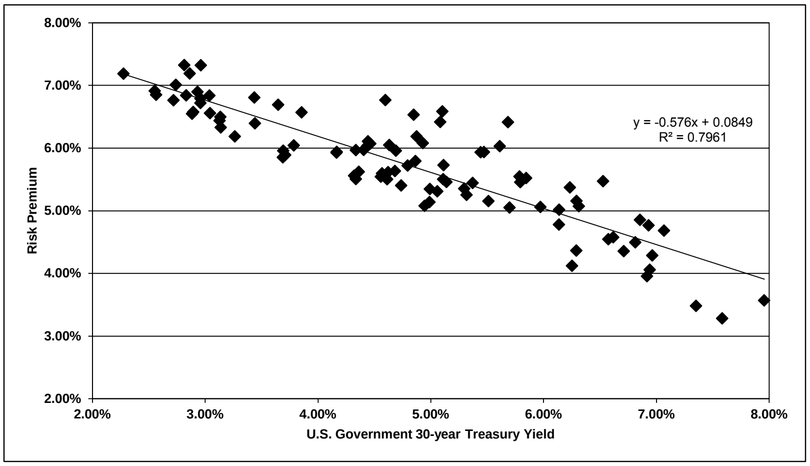
Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

TREASURY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%

TREASURY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
AVERAGE	10.53%	4.80%	5.73%
MEDIAN	10.52%	4.80%	5.79%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.892259
R Square	0.796126
Adjusted R Square	0.793934
Standard Error	0.004061
Observations	95

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005989	0.005989	363.165040	0.000000
Residual	93	0.001534	0.000016		
Total	94	0.007523			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0849	0.001510	56.23	0.000000	0.081933	0.087932	0.081933	0.087932
U.S. Govt. 30-year Treasury	(0.5760)	0.030227	(19.06)	0.000000	(0.636055)	(0.516006)	(0.636055)	(0.516006)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	2.77%	6.90%	9.67%
Blue Chip Consensus Forecast (Q4 2017-Q1 2019) [5]	3.30%	6.59%	9.89%
Blue Chip Consensus Forecast (2019-2023) [6]	4.30%	6.02%	10.32%
AVERAGE			9.96%

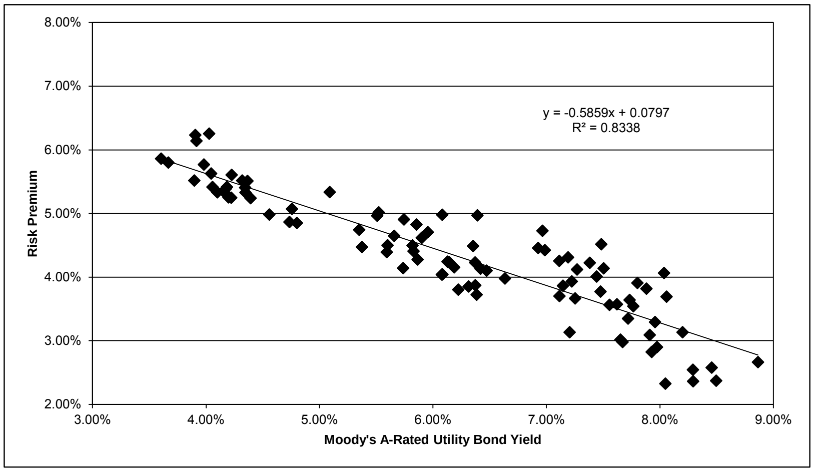
Notes:
[1] Source: Regulatory Research Associates, accessed October 5, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 36, No. 10, October 1, 2017, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.084932 + (-0.576030 x Column [7])
[9] Equals Column [7] + Column [8]

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Natural Gas ROE	Moody's A-Rated Utility Bond	Risk Premium
1993.1	11.75%	8.06%	3.69%
1993.2	11.71%	7.80%	3.91%
1993.3	11.39%	7.27%	4.12%
1993.4	11.16%	7.22%	3.93%
1994.1	11.12%	7.56%	3.56%
1994.2	10.84%	8.29%	2.54%
1994.3	10.87%	8.50%	2.37%
1994.4	11.53%	8.86%	2.66%
1995.2	11.00%	7.91%	3.09%
1995.3	11.07%	7.72%	3.35%
1995.4	11.61%	7.38%	4.22%
1996.1	11.45%	7.44%	4.01%
1996.2	10.88%	7.97%	2.90%
1996.3	11.25%	7.96%	3.29%
1996.4	11.19%	7.62%	3.57%
1997.1	11.31%	7.77%	3.54%
1997.2	11.70%	7.88%	3.82%
1997.3	12.00%	7.48%	4.52%
1997.4	10.92%	7.25%	3.66%
1998.2	11.37%	7.11%	4.25%
1998.3	11.41%	6.99%	4.42%
1998.4	11.69%	6.97%	4.73%
1999.1	10.82%	7.12%	3.70%
1999.2	11.25%	7.48%	3.77%
1999.4	10.38%	8.05%	2.33%
2000.1	10.66%	8.29%	2.36%
2000.2	11.03%	8.46%	2.58%
2000.3	11.33%	8.20%	3.13%
2000.4	12.10%	8.04%	4.06%
2001.1	11.38%	7.73%	3.64%
2001.2	10.75%	7.93%	2.82%
2001.4	10.65%	7.67%	2.98%
2002.1	10.67%	7.65%	3.01%
2002.2	11.64%	7.50%	4.14%
2002.3	11.50%	7.19%	4.31%
2002.4	11.01%	7.15%	3.86%
2003.1	11.38%	6.93%	4.45%
2003.2	11.36%	6.39%	4.97%
2003.3	10.61%	6.64%	3.98%
2003.4	10.84%	6.35%	4.49%
2004.1	11.06%	6.08%	4.98%
2004.2	10.57%	6.47%	4.10%
2004.3	10.37%	6.13%	4.24%
2004.4	10.66%	5.95%	4.70%
2005.1	10.65%	5.75%	4.90%
2005.2	10.54%	5.52%	5.01%
2005.3	10.47%	5.51%	4.96%
2005.4	10.32%	5.82%	4.50%
2006.1	10.68%	5.86%	4.82%
2006.2	10.60%	6.37%	4.23%
2006.3	10.34%	6.19%	4.15%
2006.4	10.14%	5.87%	4.28%
2007.1	10.52%	5.90%	4.62%
2007.2	10.13%	6.08%	4.04%
2007.3	10.03%	6.22%	3.80%
2007.4	10.12%	6.08%	4.04%
2008.1	10.38%	6.14%	4.23%
2008.2	10.17%	6.31%	3.85%
2008.3	10.55%	6.42%	4.13%
2008.4	10.34%	7.21%	3.13%
2009.1	10.24%	6.37%	3.87%
2009.2	10.11%	6.39%	3.72%
2009.3	9.88%	5.74%	4.14%
2009.4	10.31%	5.66%	4.65%
2010.1	10.24%	5.83%	4.41%
2010.2	9.99%	5.59%	4.39%
2010.3	10.43%	5.09%	5.33%
2010.4	10.09%	5.35%	4.74%
2011.1	10.10%	5.60%	4.50%
2011.2	9.85%	5.37%	4.47%
2011.3	9.65%	4.80%	4.85%
2011.4	9.88%	4.37%	5.51%
2012.1	9.63%	4.39%	5.24%
2012.2	9.83%	4.23%	5.60%
2012.3	9.75%	3.98%	5.77%
2012.4	10.06%	3.92%	6.14%
2013.1	9.57%	4.18%	5.39%
2013.2	9.47%	4.22%	5.24%
2013.3	9.60%	4.74%	4.86%
2013.4	9.83%	4.76%	5.07%
2014.1	9.54%	4.56%	4.98%

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Natural Gas ROE	Moody's A-Rated Utility Bond	Risk Premium
2014.2	9.84%	4.32%	5.52%
2014.3	9.45%	4.20%	5.25%
2014.4	10.28%	4.03%	6.25%
2015.1	9.47%	3.67%	5.80%
2015.2	9.43%	4.10%	5.33%
2015.3	9.75%	4.34%	5.41%
2015.4	9.68%	4.35%	5.33%
2016.1	9.48%	4.18%	5.31%
2016.2	9.42%	3.90%	5.52%
2016.3	9.47%	3.61%	5.86%
2016.4	9.67%	4.04%	5.63%
2017.1	9.60%	4.18%	5.42%
2017.2	9.47%	4.06%	5.41%
2017.3	10.14%	3.91%	6.23%
AVERAGE	10.53%	6.19%	4.34%
MEDIAN	10.52%	6.22%	4.28%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.913119
R Square	0.833787
Adjusted R Square	0.832000
Standard Error	0.003828
Observations	95

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006835	0.006835	466.523652	0.000000
Residual	93	0.001362	0.000015		
Total	94	0.008197			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0797	0.001723	46.23	0.000000	0.076254	0.083098	0.076254	0.083098
Moody's A-Rated Utility Bond	(0.5859)	0.027124	(21.60)	0.000000	(0.639714)	(0.531989)	(0.639714)	(0.531989)

	[7]	[8]	[9]
	Moody's A-Rated Utility Bond	Risk Premium	ROE
Current 30-Day Average [4]	3.86%	5.71%	9.56%
Near-Term Consensus Forecast (Q4 2017-Q1 2019) [5]	4.56%	5.30%	9.86%
Long-Term Consensus Forecast (2019-2023) [6]	5.56%	4.71%	10.27%
AVERAGE			9.90%

Notes:

[1] Source: Regulatory Research Associates, accessed October 5, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are an average of the trading days in each quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional
[5] Equals Blue Chip Financial Forecasts near-term 30-year Treasury bond yield (Q4 2017-Q1 2019 Average: 3.30%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through September 29, 2017 (1.26%)
[6] Equals Blue Chip Financial Forecasts long-term 30-year Treasury bond yield (2019 - 2023 Forecast: 4.30%) plus average daily spread between Treasury and utility bond yields from January 1, 2015 through September 29, 2017 (1.26%)
[7] *See notes [4], [5] & [6]*
[8] Equals 0.079676 + (-0.585851 x Column [7])
[9] Equals Column [7] + Column [8]

BETA - NATURAL GAS PROXY GROUP
AS OF SEPTEMBER 29, 2017

		[1] Bloomberg	[2] Value Line
Atmos Energy Corporation	ATO	0.578	0.700
New Jersey Resources Corporation	NJR	0.709	0.800
NiSource Inc.	NI	0.602	NMF
Northwest Natural Gas Company	NWN	0.523	0.700
ONE Gas, Inc.	OGS	0.677	0.700
Southwest Gas Corporation	SWX	0.628	0.750
Spire, Inc.	SR	0.616	0.700
Average		0.619	0.725

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

BETA - COMBINED UTILITY PROXY GROUP
AS OF SEPTEMBER 29, 2017

		[1] Bloomberg	[2] Value Line
Ameren Corporation	AEE	0.483	0.650
Black Hills Corporation	BKH	0.518	0.850
CMS Energy Corporation	CMS	0.466	0.650
Dominion Resources, Inc.	D	0.505	0.650
DTE Energy Company	DTE	0.533	0.650
NorthWestern Corporation	NWE	0.593	0.650
PG&E Corporation	PCG	0.546	0.650
SCANA Corporation	SCG	0.489	0.650
Vectren Corporation	VVC	0.632	0.750
Wisconsin Energy Corporation	WEC	0.456	0.600
Average		0.522	0.675

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	0.18%	3.63%	0.01%	6.50%	0.01%
American Express Co	AXP	0.36%	1.55%	0.01%	9.70%	0.03%
Verizon Communications Inc	VZ	0.90%	4.77%	0.04%	1.92%	0.02%
Broadcom Ltd	AVGO	0.44%	1.68%	0.01%	15.32%	0.07%
Boeing Co/The	BA	0.67%	2.23%	0.01%	15.20%	0.10%
Caterpillar Inc	CAT	0.33%	2.50%	0.01%	10.00%	0.03%
JPMorgan Chase & Co	JPM	1.50%	2.35%	0.04%	3.00%	0.05%
Chevron Corp	CVX	0.99%	3.68%	0.04%	42.57%	0.42%
Coca-Cola Co/The	KO	0.86%	3.29%	0.03%	5.61%	0.05%
AbbVie Inc	ABBV	0.63%	2.88%	0.02%	8.60%	0.05%
Walt Disney Co/The	DIS	0.68%	1.58%	0.01%	7.19%	0.05%
Extra Space Storage Inc	EXR	0.04%	3.90%	0.00%	6.57%	0.00%
Exxon Mobil Corp	XOM	1.55%	3.76%	0.06%	19.49%	0.30%
Phillips 66	PSX	0.21%	3.06%	0.01%	-3.74%	-0.01%
General Electric Co	GE	0.94%	3.97%	0.04%	11.23%	0.11%
HP Inc	HPQ	0.15%	2.66%	0.00%	4.09%	0.01%
Home Depot Inc/The	HD	0.86%	2.18%	0.02%	13.69%	0.12%
International Business Machines Corp	IBM	0.60%	4.14%	0.02%	2.38%	0.01%
Concho Resources Inc	CXO	0.09%	n/a	n/a	20.00%	0.02%
Johnson & Johnson	JNJ	1.56%	2.58%	0.04%	6.03%	0.09%
McDonald's Corp	MCD	0.57%	2.58%	0.01%	10.09%	0.06%
Merck & Co Inc	MRK	0.78%	2.94%	0.02%	6.07%	0.05%
3M Co	MMM	0.56%	2.24%	0.01%	8.80%	0.05%
American Water Works Co Inc	AWK	0.06%	2.05%	0.00%	7.95%	0.01%
Bank of America Corp	BAC	1.19%	1.89%	0.02%	10.47%	0.13%
CSRA Inc	CSRA	0.02%	1.24%	0.00%	7.55%	0.00%
Brighthouse Financial Inc	BHF	0.03%	n/a	n/a	8.00%	0.00%
Baker Hughes a GE Co	BHGE	0.07%	1.86%	0.00%	6.50%	0.00%
Pfizer Inc	PFE	0.95%	3.59%	0.03%	8.43%	0.08%
Procter & Gamble Co/The	PG	1.04%	3.03%	0.03%	7.18%	0.07%
AT&T Inc	T	1.07%	5.00%	0.05%	5.25%	0.06%
Travelers Cos Inc/The	TRV	0.15%	2.35%	0.00%	11.58%	0.02%
United Technologies Corp	UTX	0.41%	2.41%	0.01%	8.72%	0.04%
Analog Devices Inc	ADI	0.14%	2.09%	0.00%	11.55%	0.02%
Wal-Mart Stores Inc	WMT	1.04%	2.61%	0.03%	5.12%	0.05%
Cisco Systems Inc	CSCO	0.74%	3.45%	0.03%	6.43%	0.05%
Intel Corp	INTC	0.80%	2.86%	0.02%	8.14%	0.07%
General Motors Co	GM	0.26%	3.76%	0.01%	9.04%	0.02%
Microsoft Corp	MSFT	2.56%	2.26%	0.06%	10.54%	0.27%
Dollar General Corp	DG	0.10%	1.28%	0.00%	8.55%	0.01%
Kinder Morgan Inc/DE	KMI	0.19%	2.61%	0.00%	20.00%	0.04%
Citigroup Inc	C	0.89%	1.76%	0.02%	12.97%	0.11%
American International Group Inc	AIG	0.25%	2.09%	0.01%	11.00%	0.03%
Honeywell International Inc	HON	0.48%	2.10%	0.01%	9.95%	0.05%
Altria Group Inc	MO	0.54%	4.16%	0.02%	0.61%	0.00%
HCA Healthcare Inc	HCA	0.13%	n/a	n/a	12.07%	0.02%
Under Armour Inc	UAA	0.01%	n/a	n/a	13.17%	0.00%
International Paper Co	IP	0.10%	3.26%	0.00%	7.23%	0.01%
Hewlett Packard Enterprise Co	HPE	0.11%	1.77%	0.00%	-3.56%	0.00%
Abbott Laboratories	ABT	0.41%	1.99%	0.01%	11.77%	0.05%
Aflac Inc	AFL	0.14%	2.11%	0.00%	2.85%	0.00%
Air Products & Chemicals Inc	APD	0.15%	2.51%	0.00%	9.29%	0.01%
Royal Caribbean Cruises Ltd	RCL	0.11%	2.02%	0.00%	19.10%	0.02%
American Electric Power Co Inc	AEP	0.15%	3.36%	0.01%	5.00%	0.01%
Hess Corp	HES	0.07%	2.13%	0.00%	-14.74%	-0.01%
Anadarko Petroleum Corp	APC	0.12%	0.41%	0.00%	-10.30%	-0.01%
Aon PLC	AON	0.17%	0.99%	0.00%	11.86%	0.02%
Apache Corp	APA	0.08%	2.18%	0.00%	-20.64%	-0.02%
Archer-Daniels-Midland Co	ADM	0.11%	3.01%	0.00%	9.80%	0.01%
Automatic Data Processing Inc	ADP	0.22%	2.09%	0.00%	11.48%	0.02%
Verisk Analytics Inc	VRSK	0.06%	n/a	n/a	7.96%	0.00%
AutoZone Inc	AZO	0.07%	n/a	n/a	13.07%	0.01%
Avery Dennison Corp	AVY	0.04%	1.83%	0.00%	7.65%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Ball Corp	BLL	0.06%	0.97%	0.00%	7.23%	0.00%
Bank of New York Mellon Corp/The	BK	0.24%	1.81%	0.00%	13.24%	0.03%
CR Bard Inc	BCR	0.10%	0.32%	0.00%	11.00%	0.01%
Baxter International Inc	BAX	0.15%	1.02%	0.00%	13.56%	0.02%
Becton Dickinson and Co	BDX	0.20%	1.49%	0.00%	12.53%	0.02%
Berkshire Hathaway Inc	BRK/B	1.09%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	0.08%	2.39%	0.00%	12.68%	0.01%
H&R Block Inc	HRB	0.02%	3.63%	0.00%	11.00%	0.00%
Boston Scientific Corp	BSX	0.18%	n/a	n/a	10.33%	0.02%
Bristol-Myers Squibb Co	BMY	0.47%	2.45%	0.01%	8.00%	0.04%
Fortune Brands Home & Security Inc	FBHS	0.05%	1.07%	0.00%	12.12%	0.01%
Brown-Forman Corp	BF/B	0.05%	1.34%	0.00%	9.72%	0.01%
Cabot Oil & Gas Corp	COG	0.06%	0.75%	0.00%	31.95%	0.02%
Campbell Soup Co	CPB	0.06%	2.99%	0.00%	4.46%	0.00%
Kansas City Southern	KSU	0.05%	1.33%	0.00%	14.00%	0.01%
Advanced Micro Devices Inc	AMD	0.05%	n/a	n/a	5.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	0.10%	0.86%	0.00%	15.76%	0.02%
Carnival Corp	CCL	0.15%	2.48%	0.00%	13.28%	0.02%
Qorvo Inc	QRVO	0.04%	n/a	n/a	13.18%	0.01%
CenturyLink Inc	CTL	0.05%	11.43%	0.01%	-2.86%	0.00%
Cigna Corp	CI	0.21%	0.02%	0.00%	12.91%	0.03%
UDR Inc	UDR	0.05%	3.26%	0.00%	6.13%	0.00%
Clorox Co/The	CLX	0.08%	2.55%	0.00%	6.72%	0.01%
CMS Energy Corp	CMS	0.06%	2.87%	0.00%	5.00%	0.00%
Colgate-Palmolive Co	CL	0.29%	2.20%	0.01%	9.47%	0.03%
Comerica Inc	CMA	0.06%	1.57%	0.00%	8.00%	0.00%
CA Inc	CA	0.06%	3.06%	0.00%	2.97%	0.00%
Conagra Brands Inc	CAG	0.06%	2.52%	0.00%	7.00%	0.00%
Consolidated Edison Inc	ED	0.11%	3.42%	0.00%	n/a	n/a
SL Green Realty Corp	SLG	0.04%	3.06%	0.00%	0.64%	0.00%
Corning Inc	GLW	0.12%	2.07%	0.00%	8.58%	0.01%
Cummins Inc	CMI	0.13%	2.57%	0.00%	10.23%	0.01%
Danaher Corp	DHR	0.27%	0.65%	0.00%	7.57%	0.02%
Target Corp	TGT	0.14%	4.20%	0.01%	-0.78%	0.00%
Deere & Co	DE	0.18%	1.91%	0.00%	4.50%	0.01%
Dominion Energy Inc	D	0.22%	3.93%	0.01%	5.60%	0.01%
Dover Corp	DOV	0.06%	2.06%	0.00%	15.47%	0.01%
CBOE Holdings Inc	CBOE	0.05%	1.00%	0.00%	22.39%	0.01%
Duke Energy Corp	DUK	0.26%	4.24%	0.01%	2.00%	0.01%
Eaton Corp PLC	ETN	0.15%	3.13%	0.00%	10.22%	0.02%
Ecolab Inc	ECL	0.17%	1.15%	0.00%	12.86%	0.02%
PerkinElmer Inc	PKI	0.03%	0.41%	0.00%	10.42%	0.00%
Emerson Electric Co	EMR	0.18%	3.06%	0.01%	7.45%	0.01%
EOG Resources Inc	EOG	0.25%	0.69%	0.00%	-18.26%	-0.05%
Entergy Corp	ETR	0.06%	4.56%	0.00%	-3.83%	0.00%
Equifax Inc	EFX	0.06%	1.47%	0.00%	11.03%	0.01%
EQT Corp	EQT	0.05%	0.18%	0.00%	15.00%	0.01%
Quintiles IMS Holdings Inc	Q	0.09%	n/a	n/a	14.33%	0.01%
XL Group Ltd	XL	0.05%	2.23%	0.00%	9.00%	0.00%
Gartner Inc	IT	0.05%	n/a	n/a	17.50%	0.01%
FedEx Corp	FDX	0.27%	0.89%	0.00%	12.50%	0.03%
Macy's Inc	M	0.03%	6.92%	0.00%	-0.48%	0.00%
FMC Corp	FMC	0.05%	0.74%	0.00%	12.60%	0.01%
Ford Motor Co	F	0.21%	5.01%	0.01%	-2.07%	0.00%
NextEra Energy Inc	NEE	0.31%	2.68%	0.01%	6.67%	0.02%
Franklin Resources Inc	BEN	0.11%	1.80%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.09%	n/a	n/a	24.46%	0.02%
Gap Inc/The	GPS	0.05%	3.12%	0.00%	7.00%	0.00%
General Dynamics Corp	GD	0.28%	1.63%	0.00%	8.51%	0.02%
General Mills Inc	GIS	0.13%	3.79%	0.00%	9.57%	0.01%
Genuine Parts Co	GPC	0.06%	2.82%	0.00%	8.92%	0.01%
WW Grainger Inc	GWW	0.05%	2.85%	0.00%	9.55%	0.00%
Halliburton Co	HAL	0.18%	1.56%	0.00%	74.00%	0.13%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Harley-Davidson Inc	HOG	0.04%	3.03%	0.00%	7.85%	0.00%
Harris Corp	HRS	0.07%	1.73%	0.00%	n/a	n/a
HCP Inc	HCP	0.06%	5.32%	0.00%	3.11%	0.00%
Helmerich & Payne Inc	HP	0.03%	5.37%	0.00%	n/a	n/a
Fortive Corp	FTV	0.11%	0.40%	0.00%	9.37%	0.01%
Hershey Co/The	HSY	0.07%	2.40%	0.00%	9.53%	0.01%
Synchrony Financial	SYF	0.11%	1.93%	0.00%	8.09%	0.01%
Hormel Foods Corp	HRL	0.08%	2.12%	0.00%	6.15%	0.00%
Arthur J Gallagher & Co	AJG	0.05%	2.53%	0.00%	10.83%	0.01%
Mondelez International Inc	MDLZ	0.27%	2.16%	0.01%	11.64%	0.03%
CenterPoint Energy Inc	CNP	0.06%	3.66%	0.00%	6.00%	0.00%
Humana Inc	HUM	0.16%	0.66%	0.00%	12.93%	0.02%
Willis Towers Watson PLC	WLTW	0.09%	1.37%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.23%	2.11%	0.00%	9.20%	0.02%
Ingersoll-Rand PLC	IR	0.10%	2.02%	0.00%	10.71%	0.01%
Foot Locker Inc	FL	0.02%	3.52%	0.00%	3.40%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	3.46%	0.00%	8.64%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.93%	0.00%	4.00%	0.00%
Jacobs Engineering Group Inc	JEC	0.03%	1.03%	0.00%	8.73%	0.00%
Hanesbrands Inc	HBI	0.04%	2.44%	0.00%	10.45%	0.00%
Kellogg Co	K	0.10%	3.46%	0.00%	6.23%	0.01%
Perrigo Co PLC	PRGO	0.05%	0.76%	0.00%	5.97%	0.00%
Kimberly-Clark Corp	KMB	0.19%	3.30%	0.01%	6.22%	0.01%
Kimco Realty Corp	KIM	0.04%	5.52%	0.00%	19.96%	0.01%
Kohl's Corp	KSS	0.03%	4.82%	0.00%	5.45%	0.00%
Oracle Corp	ORCL	0.90%	1.57%	0.01%	8.77%	0.08%
Kroger Co/The	KR	0.08%	2.49%	0.00%	5.57%	0.00%
Leggett & Platt Inc	LEG	0.03%	3.02%	0.00%	19.00%	0.01%
Lennar Corp	LEN	0.05%	0.30%	0.00%	11.29%	0.01%
Leucadia National Corp	LUK	0.04%	1.58%	0.00%	18.00%	0.01%
Eli Lilly & Co	LLY	0.42%	2.43%	0.01%	8.50%	0.04%
L Brands Inc	LB	0.05%	5.77%	0.00%	6.81%	0.00%
Charter Communications Inc	CHTR	0.42%	n/a	n/a	23.96%	0.10%
Lincoln National Corp	LNC	0.07%	1.58%	0.00%	9.25%	0.01%
Loews Corp	L	0.07%	0.52%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.30%	2.05%	0.01%	14.38%	0.04%
Host Hotels & Resorts Inc	HST	0.06%	4.33%	0.00%	4.10%	0.00%
Marsh & McLennan Cos Inc	MMC	0.19%	1.79%	0.00%	12.86%	0.02%
Masco Corp	MAS	0.06%	1.08%	0.00%	14.33%	0.01%
Mattel Inc	MAT	0.02%	3.88%	0.00%	11.30%	0.00%
S&P Global Inc	SPGI	0.18%	1.05%	0.00%	10.00%	0.02%
Medtronic PLC	MDT	0.47%	2.37%	0.01%	6.43%	0.03%
CVS Health Corp	CVS	0.37%	2.46%	0.01%	13.33%	0.05%
DowDuPont Inc	DWDP	0.72%	2.66%	0.02%	7.83%	0.06%
Micron Technology Inc	MU	0.20%	n/a	n/a	0.83%	0.00%
Motorola Solutions Inc	MSI	0.06%	2.22%	0.00%	4.10%	0.00%
Mylan NV	MYL	0.08%	n/a	n/a	3.20%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	11.35%	0.01%
Newell Brands Inc	NWL	0.09%	2.16%	0.00%	11.32%	0.01%
Newmont Mining Corp	NEM	0.09%	0.80%	0.00%	-11.65%	-0.01%
Twenty-First Century Fox Inc	FOXA	0.12%	1.36%	0.00%	9.23%	0.01%
NIKE Inc	NKE	0.30%	1.39%	0.00%	8.50%	0.03%
NiSource Inc	NI	0.04%	2.74%	0.00%	6.10%	0.00%
Noble Energy Inc	NBL	0.06%	1.41%	0.00%	3.72%	0.00%
Norfolk Southern Corp	NSC	0.17%	1.85%	0.00%	13.57%	0.02%
Eversource Energy	ES	0.09%	3.14%	0.00%	6.10%	0.01%
Northrop Grumman Corp	NOC	0.22%	1.39%	0.00%	7.67%	0.02%
Wells Fargo & Co	WFC	1.22%	2.83%	0.03%	11.46%	0.14%
Nucor Corp	NUE	0.08%	2.69%	0.00%	12.00%	0.01%
PVH Corp	PVH	0.04%	0.12%	0.00%	10.96%	0.00%
Occidental Petroleum Corp	OXY	0.22%	4.80%	0.01%	-3.39%	-0.01%
Omnicom Group Inc	OMC	0.08%	2.97%	0.00%	4.95%	0.00%
ONEOK Inc	OKE	0.09%	5.38%	0.01%	13.25%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

		[6]	[7]	[8]	[9]	[10]
Name	Ticker	Weight In Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Long-Term Growth Estimate	Cap. Weighted Long-Term Growth
Raymond James Financial Inc	RJF	0.05%	1.04%	0.00%	15.45%	0.01%
PG&E Corp	PCG	0.16%	3.11%	0.00%	n/a	n/a
Parker-Hannifin Corp	PH	0.10%	1.51%	0.00%	11.88%	0.01%
PPL Corp	PPL	0.12%	4.16%	0.00%	n/a	n/a
PepsiCo Inc	PEP	0.71%	2.89%	0.02%	6.06%	0.04%
Exelon Corp	EXC	0.16%	3.48%	0.01%	3.57%	0.01%
ConocoPhillips	COP	0.27%	2.12%	0.01%	7.00%	0.02%
PulteGroup Inc	PHM	0.04%	1.32%	0.00%	18.40%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.10%	0.00%	5.50%	0.00%
PNC Financial Services Group Inc/The	PNC	0.29%	2.23%	0.01%	10.12%	0.03%
PPG Industries Inc	PPG	0.12%	1.66%	0.00%	8.09%	0.01%
Praxair Inc	PX	0.18%	2.25%	0.00%	10.35%	0.02%
Progressive Corp/The	PGR	0.13%	1.41%	0.00%	11.83%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.72%	0.00%	2.90%	0.00%
Raytheon Co	RTN	0.24%	1.71%	0.00%	8.41%	0.02%
Robert Half International Inc	RHI	0.03%	1.91%	0.00%	8.30%	0.00%
SCANA Corp	SCG	0.03%	5.05%	0.00%	3.25%	0.00%
Edison International	EIX	0.11%	2.81%	0.00%	6.23%	0.01%
Schlumberger Ltd	SLB	0.43%	2.87%	0.01%	41.71%	0.18%
Charles Schwab Corp/The	SCHW	0.26%	0.73%	0.00%	19.46%	0.05%
Sherwin-Williams Co/The	SHW	0.15%	0.95%	0.00%	10.99%	0.02%
JM Smucker Co/The	SJM	0.05%	2.97%	0.00%	3.96%	0.00%
Snap-on Inc	SNA	0.04%	1.91%	0.00%	10.85%	0.00%
AMETEK Inc	AME	0.07%	0.55%	0.00%	11.62%	0.01%
Southern Co/The	SO	0.22%	4.72%	0.01%	2.00%	0.00%
BB&T Corp	BBT	0.17%	2.81%	0.00%	9.75%	0.02%
Southwest Airlines Co	LUV	0.15%	0.89%	0.00%	6.43%	0.01%
Stanley Black & Decker Inc	SWK	0.10%	1.67%	0.00%	11.00%	0.01%
Public Storage	PSA	0.17%	3.74%	0.01%	5.45%	0.01%
SunTrust Banks Inc	STI	0.13%	2.68%	0.00%	9.42%	0.01%
Sysco Corp	SYY	0.13%	2.45%	0.00%	10.04%	0.01%
Andeavor	ANDV	0.07%	2.29%	0.00%	18.94%	0.01%
Texas Instruments Inc	TXN	0.40%	2.77%	0.01%	10.53%	0.04%
Textron Inc	TXT	0.06%	0.15%	0.00%	8.78%	0.01%
Thermo Fisher Scientific Inc	TMO	0.34%	0.32%	0.00%	13.00%	0.04%
Tiffany & Co	TIF	0.05%	2.18%	0.00%	10.10%	0.01%
TJX Cos Inc/The	TJX	0.21%	1.70%	0.00%	10.65%	0.02%
Torchmark Corp	TMK	0.04%	0.75%	0.00%	8.00%	0.00%
Total System Services Inc	TSS	0.05%	0.79%	0.00%	11.14%	0.01%
Johnson Controls International plc	JCI	0.17%	2.48%	0.00%	8.47%	0.01%
Ulta Beauty Inc	ULTA	0.06%	n/a	n/a	21.60%	0.01%
Union Pacific Corp	UNP	0.41%	2.09%	0.01%	11.63%	0.05%
UnitedHealth Group Inc	UNH	0.85%	1.53%	0.01%	12.15%	0.10%
Unum Group	UNM	0.05%	1.80%	0.00%	5.00%	0.00%
Marathon Oil Corp	MRO	0.05%	1.47%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	7.20%	0.00%
Ventas Inc	VTR	0.10%	4.76%	0.00%	3.03%	0.00%
VF Corp	VFC	0.11%	2.64%	0.00%	7.96%	0.01%
Vornado Realty Trust	VNO	0.07%	3.12%	0.00%	-0.83%	0.00%
Vulcan Materials Co	VMC	0.07%	0.84%	0.00%	21.82%	0.02%
Weyerhaeuser Co	WY	0.11%	3.64%	0.00%	7.40%	0.01%
Whirlpool Corp	WHR	0.06%	2.39%	0.00%	14.19%	0.01%
Williams Cos Inc/The	WMB	0.11%	4.00%	0.00%	n/a	n/a
WEC Energy Group Inc	WEC	0.09%	3.31%	0.00%	5.55%	0.00%
Xerox Corp	XRX	0.04%	3.00%	0.00%	2.90%	0.00%
Adobe Systems Inc	ADBE	0.33%	n/a	n/a	19.82%	0.07%
AES Corp/VA	AES	0.03%	4.36%	0.00%	8.00%	0.00%
Amgen Inc	AMGN	0.61%	2.47%	0.01%	4.67%	0.03%
Apple Inc	AAPL	3.56%	1.64%	0.06%	10.98%	0.39%
Autodesk Inc	ADSK	0.11%	n/a	n/a	26.00%	0.03%
Cintas Corp	CTAS	0.07%	0.92%	0.00%	11.58%	0.01%
Comcast Corp	CMCSA	0.81%	1.64%	0.01%	9.13%	0.07%
Molson Coors Brewing Co	TAP	0.07%	2.01%	0.00%	7.32%	0.01%

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
KLA-Tencor Corp	KLAC	0.07%	2.23%	0.00%	7.90%	0.01%
Marriott International Inc/MD	MAR	0.18%	1.20%	0.00%	14.94%	0.03%
McCormick & Co Inc/MD	MKC	0.05%	1.83%	0.00%	9.60%	0.01%
Nordstrom Inc	JWN	0.04%	3.14%	0.00%	6.00%	0.00%
PACCAR Inc	PCAR	0.11%	1.38%	0.00%	6.73%	0.01%
Costco Wholesale Corp	COST	0.32%	1.22%	0.00%	10.18%	0.03%
Stryker Corp	SYK	0.24%	1.20%	0.00%	9.23%	0.02%
Tyson Foods Inc	TSN	0.09%	1.28%	0.00%	8.60%	0.01%
Applied Materials Inc	AMAT	0.25%	0.77%	0.00%	16.71%	0.04%
Time Warner Inc	TWX	0.36%	1.57%	0.01%	8.30%	0.03%
American Airlines Group Inc	AAL	0.10%	0.84%	0.00%	-3.18%	0.00%
Cardinal Health Inc	CAH	0.09%	2.76%	0.00%	12.37%	0.01%
Celgene Corp	CELG	0.51%	n/a	n/a	19.46%	0.10%
Cerner Corp	CERN	0.11%	n/a	n/a	12.00%	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.61%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.07%	1.00%	0.00%	12.66%	0.01%
Flowserve Corp	FLS	0.02%	1.78%	0.00%	12.68%	0.00%
Electronic Arts Inc	EA	0.16%	n/a	n/a	14.17%	0.02%
Express Scripts Holding Co	ESRX	0.16%	n/a	n/a	13.28%	0.02%
Expeditors International of Washington Inc	EXPD	0.05%	1.40%	0.00%	8.40%	0.00%
Fastenal Co	FAST	0.06%	2.81%	0.00%	15.40%	0.01%
M&T Bank Corp	MTB	0.11%	1.86%	0.00%	10.19%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	10.80%	0.01%
Fifth Third Bancorp	FITB	0.09%	2.29%	0.00%	4.20%	0.00%
Gilead Sciences Inc	GILD	0.47%	2.57%	0.01%	-7.44%	-0.04%
Hasbro Inc	HAS	0.05%	2.33%	0.00%	9.70%	0.01%
Huntington Bancshares Inc/OH	HBAN	0.07%	2.29%	0.00%	10.71%	0.01%
Welltower Inc	HCN	0.12%	4.95%	0.01%	2.61%	0.00%
Biogen Inc	BIIB	0.30%	n/a	n/a	6.48%	0.02%
Range Resources Corp	RRC	0.02%	0.41%	0.00%	-19.59%	0.00%
Northern Trust Corp	NTRS	0.09%	1.83%	0.00%	12.14%	0.01%
Packaging Corp of America	PKG	0.05%	2.20%	0.00%	8.25%	0.00%
Paychex Inc	PAYX	0.10%	3.34%	0.00%	7.70%	0.01%
People's United Financial Inc	PBCT	0.03%	3.80%	0.00%	2.00%	0.00%
Patterson Cos Inc	PDCO	0.02%	2.69%	0.00%	10.63%	0.00%
QUALCOMM Inc	QCOM	0.34%	4.40%	0.02%	8.75%	0.03%
Roper Technologies Inc	ROP	0.11%	0.58%	0.00%	12.93%	0.01%
Ross Stores Inc	ROST	0.11%	0.99%	0.00%	13.60%	0.02%
IDEXX Laboratories Inc	IDXX	0.06%	n/a	n/a	10.81%	0.01%
Starbucks Corp	SBUX	0.35%	1.86%	0.01%	16.52%	0.06%
KeyCorp	KEY	0.09%	2.02%	0.00%	10.90%	0.01%
State Street Corp	STT	0.16%	1.76%	0.00%	11.80%	0.02%
US Bancorp	USB	0.40%	2.24%	0.01%	12.13%	0.05%
AO Smith Corp	AOS	0.04%	0.94%	0.00%	15.00%	0.01%
Symantec Corp	SYMC	0.09%	0.91%	0.00%	13.14%	0.01%
T Rowe Price Group Inc	TROW	0.10%	2.52%	0.00%	12.85%	0.01%
Waste Management Inc	WM	0.15%	2.17%	0.00%	10.22%	0.02%
CBS Corp	CBS	0.09%	1.24%	0.00%	13.37%	0.01%
Allergan PLC	AGN	0.31%	1.37%	0.00%	12.33%	0.04%
Constellation Brands Inc	STZ	0.15%	1.04%	0.00%	16.36%	0.03%
Xilinx Inc	XLNX	0.08%	1.98%	0.00%	8.37%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.06%	0.59%	0.00%	9.80%	0.01%
Zions Bancorporation	ZION	0.04%	1.02%	0.00%	9.00%	0.00%
Alaska Air Group Inc	ALK	0.04%	1.57%	0.00%	6.33%	0.00%
Invesco Ltd	IVZ	0.06%	3.31%	0.00%	12.29%	0.01%
Intuit Inc	INTU	0.16%	1.10%	0.00%	14.88%	0.02%
Morgan Stanley	MS	0.40%	2.08%	0.01%	16.72%	0.07%
Microchip Technology Inc	MCHP	0.09%	1.61%	0.00%	17.06%	0.02%
Chubb Ltd	CB	0.30%	1.99%	0.01%	10.60%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	9.18%	0.00%
Chesapeake Energy Corp	CHK	0.02%	n/a	n/a	-13.02%	0.00%
Citizens Financial Group Inc	CFG	0.08%	1.90%	0.00%	21.44%	0.02%
O'Reilly Automotive Inc	ORLY	0.08%	n/a	n/a	15.32%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Allstate Corp/The	ALL	0.15%	1.61%	0.00%	16.27%	0.02%
FLIR Systems Inc	FLIR	0.02%	1.54%	0.00%	n/a	n/a
Equity Residential	EQR	0.11%	3.06%	0.00%	5.87%	0.01%
BorgWarner Inc	BWA	0.05%	1.09%	0.00%	5.09%	0.00%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	12.19%	0.00%
Incyte Corp	INCY	0.11%	n/a	n/a	44.05%	0.05%
Simon Property Group Inc	SPG	0.22%	4.47%	0.01%	7.06%	0.02%
Eastman Chemical Co	EMN	0.06%	2.25%	0.00%	7.53%	0.00%
AvalonBay Communities Inc	AVB	0.11%	3.18%	0.00%	6.42%	0.01%
Prudential Financial Inc	PRU	0.20%	2.82%	0.01%	8.00%	0.02%
United Parcel Service Inc	UPS	0.37%	2.76%	0.01%	11.90%	0.04%
Apartment Investment & Management Co	AIV	0.03%	3.28%	0.00%	19.07%	0.01%
Walgreens Boots Alliance Inc	WBA	0.37%	2.07%	0.01%	9.03%	0.03%
McKesson Corp	MCK	0.14%	0.89%	0.00%	5.30%	0.01%
Lockheed Martin Corp	LMT	0.40%	2.58%	0.01%	9.42%	0.04%
AmerisourceBergen Corp	ABC	0.08%	1.76%	0.00%	6.76%	0.01%
Capital One Financial Corp	COF	0.18%	1.89%	0.00%	5.97%	0.01%
Waters Corp	WAT	0.06%	n/a	n/a	8.28%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	12.88%	0.01%
Darden Restaurants Inc	DRI	0.04%	3.20%	0.00%	9.57%	0.00%
NetApp Inc	NTAP	0.05%	1.83%	0.00%	9.90%	0.01%
Citrix Systems Inc	CTXS	0.05%	n/a	n/a	13.10%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.04%	1.20%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.11%	0.84%	0.00%	15.25%	0.02%
DaVita Inc	DVA	0.05%	n/a	n/a	3.75%	0.00%
Hartford Financial Services Group Inc/The	HIG	0.09%	1.66%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.05%	5.66%	0.00%	14.60%	0.01%
Estee Lauder Cos Inc/The	EL	0.11%	1.26%	0.00%	11.49%	0.01%
Cadence Design Systems Inc	CDNS	0.05%	n/a	n/a	11.45%	0.01%
Principal Financial Group Inc	PFG	0.08%	2.92%	0.00%	10.40%	0.01%
Stericycle Inc	SRCL	0.03%	n/a	n/a	7.68%	0.00%
Universal Health Services Inc	UHS	0.04%	0.36%	0.00%	8.69%	0.00%
E*TRADE Financial Corp	ETFC	0.05%	n/a	n/a	15.37%	0.01%
Skyworks Solutions Inc	SWKS	0.08%	1.26%	0.00%	13.59%	0.01%
National Oilwell Varco Inc	NOV	0.06%	0.56%	0.00%	n/a	n/a
Quest Diagnostics Inc	DGX	0.06%	1.92%	0.00%	6.95%	0.00%
Activision Blizzard Inc	ATVI	0.22%	0.47%	0.00%	13.63%	0.03%
Rockwell Automation Inc	ROK	0.10%	1.71%	0.00%	11.84%	0.01%
Kraft Heinz Co/The	KHC	0.42%	3.22%	0.01%	8.39%	0.04%
American Tower Corp	AMT	0.26%	1.93%	0.01%	20.68%	0.05%
Regeneron Pharmaceuticals Inc	REGN	0.21%	n/a	n/a	18.00%	0.04%
Amazon.com Inc	AMZN	2.06%	n/a	n/a	27.82%	0.57%
Ralph Lauren Corp	RL	0.02%	2.27%	0.00%	0.29%	0.00%
Boston Properties Inc	BXP	0.08%	2.44%	0.00%	4.46%	0.00%
Amphenol Corp	APH	0.12%	0.90%	0.00%	11.23%	0.01%
Arconic Inc	ARNC	0.05%	0.96%	0.00%	16.90%	0.01%
Pioneer Natural Resources Co	PXD	0.11%	0.05%	0.00%	20.00%	0.02%
Valero Energy Corp	VLO	0.15%	3.64%	0.01%	10.45%	0.02%
Synopsys Inc	SNPS	0.05%	n/a	n/a	9.12%	0.00%
L3 Technologies Inc	LLL	0.07%	1.59%	0.00%	6.90%	0.00%
Western Union Co/The	WU	0.04%	3.65%	0.00%	8.00%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.37%	0.00%	9.20%	0.00%
Accenture PLC	ACN	0.37%	1.97%	0.01%	10.63%	0.04%
TransDigm Group Inc	TDG	0.06%	n/a	n/a	10.21%	0.01%
Yum! Brands Inc	YUM	0.11%	1.63%	0.00%	12.74%	0.01%
Prologis Inc	PLD	0.15%	2.77%	0.00%	6.21%	0.01%
FirstEnergy Corp	FE	0.06%	4.67%	0.00%	n/a	n/a
VeriSign Inc	VRSN	0.05%	n/a	n/a	10.20%	0.00%
Quanta Services Inc	PWR	0.03%	n/a	n/a	8.00%	0.00%
Henry Schein Inc	HSIC	0.06%	n/a	n/a	10.25%	0.01%
Ameren Corp	AEE	0.06%	3.04%	0.00%	n/a	n/a
ANSYS Inc	ANSS	0.05%	n/a	n/a	12.40%	0.01%
NVIDIA Corp	NVDA	0.48%	0.31%	0.00%	12.52%	0.06%

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Scripps Networks Interactive Inc	SNI	0.04%	1.40%	0.00%	8.53%	0.00%
Sealed Air Corp	SEE	0.04%	1.50%	0.00%	8.12%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.19%	0.83%	0.00%	14.35%	0.03%
Intuitive Surgical Inc	ISRG	0.17%	n/a	n/a	10.05%	0.02%
Aetna Inc	AET	0.24%	1.26%	0.00%	11.46%	0.03%
Affiliated Managers Group Inc	AMG	0.05%	0.42%	0.00%	15.79%	0.01%
Republic Services Inc	RSG	0.10%	2.09%	0.00%	11.46%	0.01%
eBay Inc	EBAY	0.18%	n/a	n/a	8.54%	0.02%
Goldman Sachs Group Inc/The	GS	0.41%	1.26%	0.01%	11.19%	0.05%
Sempra Energy	SRE	0.13%	2.88%	0.00%	14.25%	0.02%
SBA Communications Corp	SBAC	0.08%	n/a	n/a	23.05%	0.02%
Moody's Corp	MCO	0.12%	1.09%	0.00%	8.00%	0.01%
Priceline Group Inc/The	PCLN	0.40%	n/a	n/a	17.26%	0.07%
F5 Networks Inc	FFIV	0.03%	n/a	n/a	11.85%	0.00%
Akamai Technologies Inc	AKAM	0.04%	n/a	n/a	13.40%	0.00%
Devon Energy Corp	DVN	0.09%	0.65%	0.00%	18.42%	0.02%
Alphabet Inc	GOOGL	1.30%	n/a	n/a	16.64%	0.22%
Red Hat Inc	RHT	0.09%	n/a	n/a	17.00%	0.01%
Allegion PLC	ALLE	0.04%	0.74%	0.00%	13.09%	0.00%
Netflix Inc	NFLX	0.35%	n/a	n/a	40.60%	0.14%
Agilent Technologies Inc	A	0.09%	0.82%	0.00%	9.53%	0.01%
Anthem Inc	ANTM	0.22%	1.47%	0.00%	9.78%	0.02%
CME Group Inc	CME	0.21%	1.95%	0.00%	10.47%	0.02%
Juniper Networks Inc	JNPR	0.05%	1.44%	0.00%	8.62%	0.00%
BlackRock Inc	BLK	0.32%	2.24%	0.01%	13.60%	0.04%
DTE Energy Co	DTE	0.09%	3.07%	0.00%	5.35%	0.00%
Nasdaq Inc	NDAQ	0.06%	1.96%	0.00%	9.08%	0.01%
Philip Morris International Inc	PM	0.77%	3.86%	0.03%	9.61%	0.07%
salesforce.com Inc	CRM	0.30%	n/a	n/a	28.05%	0.08%
MetLife Inc	MET	0.25%	3.08%	0.01%	35.90%	0.09%
Under Armour Inc	UA	0.01%	n/a	n/a	9.68%	0.00%
Monsanto Co	MON	0.24%	1.80%	0.00%	7.47%	0.02%
Coach Inc	COH	0.05%	3.35%	0.00%	11.57%	0.01%
Fluor Corp	FLR	0.03%	2.00%	0.00%	11.89%	0.00%
CSX Corp	CSX	0.22%	1.47%	0.00%	11.33%	0.03%
Edwards Lifesciences Corp	EW	0.10%	n/a	n/a	16.60%	0.02%
Ameriprise Financial Inc	AMP	0.10%	2.24%	0.00%	10.40%	0.01%
Xcel Energy Inc	XEL	0.11%	3.04%	0.00%	6.05%	0.01%
Rockwell Collins Inc	COL	0.09%	1.01%	0.00%	10.73%	0.01%
TechnipFMC PLC	FTI	0.06%	n/a	n/a	8.59%	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.82%	0.00%	8.38%	0.01%
CBRE Group Inc	CBG	0.06%	n/a	n/a	9.35%	0.01%
Mastercard Inc	MA	0.66%	0.62%	0.00%	16.63%	0.11%
Signet Jewelers Ltd	SIG	0.02%	1.86%	0.00%	3.40%	0.00%
CarMax Inc	KMX	0.06%	n/a	n/a	13.79%	0.01%
Intercontinental Exchange Inc	ICE	0.18%	1.16%	0.00%	10.98%	0.02%
Fidelity National Information Services Inc	FIS	0.14%	1.24%	0.00%	8.23%	0.01%
Chipotle Mexican Grill Inc	CMG	0.04%	n/a	n/a	50.05%	0.02%
Wynn Resorts Ltd	WYNN	0.07%	1.34%	0.00%	31.90%	0.02%
Assurant Inc	AIZ	0.02%	2.22%	0.00%	19.35%	0.00%
NRG Energy Inc	NRG	0.04%	0.47%	0.00%	n/a	n/a
Monster Beverage Corp	MNST	0.14%	n/a	n/a	20.30%	0.03%
Regions Financial Corp	RF	0.08%	2.36%	0.00%	13.86%	0.01%
Mosaic Co/The	MOS	0.03%	2.78%	0.00%	11.70%	0.00%
Expedia Inc	EXPE	0.09%	0.83%	0.00%	17.98%	0.02%
Discovery Communications Inc	DISCA	0.01%	n/a	n/a	9.70%	0.00%
CF Industries Holdings Inc	CF	0.04%	3.41%	0.00%	6.00%	0.00%
Viacom Inc	VIAB	0.04%	2.87%	0.00%	2.96%	0.00%
Wyndham Worldwide Corp	WYN	0.05%	2.20%	0.00%	14.25%	0.01%
Alphabet Inc	GOOG	1.49%	n/a	n/a	16.64%	0.25%
TE Connectivity Ltd	TEL	0.13%	1.93%	0.00%	6.87%	0.01%
Cooper Cos Inc/The	COO	0.05%	0.03%	0.00%	9.75%	0.01%
Discover Financial Services	DFS	0.11%	2.17%	0.00%	3.98%	0.00%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
TripAdvisor Inc	TRIP	0.02%	n/a	n/a	14.50%	0.00%
Dr Pepper Snapple Group Inc	DPS	0.07%	2.62%	0.00%	8.58%	0.01%
Visa Inc	V	0.86%	0.63%	0.01%	16.76%	0.14%
Mid-America Apartment Communities Inc	MAA	0.05%	3.26%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.05%	1.15%	0.00%	15.00%	0.01%
Marathon Petroleum Corp	MPC	0.13%	2.85%	0.00%	12.68%	0.02%
Level 3 Communications Inc	LVLT	0.09%	n/a	n/a	5.00%	0.00%
Tractor Supply Co	TSCO	0.04%	1.71%	0.00%	13.65%	0.00%
ResMed Inc	RMD	0.05%	1.82%	0.00%	11.56%	0.01%
Mettler-Toledo International Inc	MTD	0.07%	n/a	n/a	12.08%	0.01%
Albemarle Corp	ALB	0.07%	0.94%	0.00%	12.17%	0.01%
Essex Property Trust Inc	ESS	0.07%	2.76%	0.00%	5.99%	0.00%
GGP Inc	GGP	0.08%	4.24%	0.00%	4.65%	0.00%
Realty Income Corp	O	0.07%	4.45%	0.00%	4.42%	0.00%
Seagate Technology PLC	STX	0.04%	7.60%	0.00%	8.73%	0.00%
WestRock Co	WRK	0.06%	2.82%	0.00%	9.67%	0.01%
IHS Markit Ltd	INFO	0.08%	n/a	n/a	13.51%	0.01%
Western Digital Corp	WDC	0.11%	2.31%	0.00%	11.74%	0.01%
Church & Dwight Co Inc	CHD	0.05%	1.57%	0.00%	9.14%	0.00%
Duke Realty Corp	DRE	0.05%	2.64%	0.00%	4.52%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.22%	0.00%	4.67%	0.00%
MGM Resorts International	MGM	0.08%	1.35%	0.00%	17.46%	0.01%
Twenty-First Century Fox Inc	FOX	0.09%	1.40%	0.00%	9.23%	0.01%
Alliant Energy Corp	LNT	0.04%	3.03%	0.00%	5.50%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.83%	0.00%	13.35%	0.01%
Lam Research Corp	LRCX	0.13%	0.97%	0.00%	7.70%	0.01%
Mohawk Industries Inc	MHK	0.08%	n/a	n/a	8.48%	0.01%
Pentair PLC	PNR	0.06%	2.03%	0.00%	8.04%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	72.50%	0.12%
Facebook Inc	FB	1.81%	n/a	n/a	26.79%	0.48%
United Rentals Inc	URI	0.05%	n/a	n/a	14.17%	0.01%
Alexandria Real Estate Equities Inc	ARE	0.05%	2.89%	0.00%	6.80%	0.00%
United Continental Holdings Inc	UAL	0.08%	n/a	n/a	-0.23%	0.00%
Navient Corp	NAVI	0.02%	4.26%	0.00%	8.00%	0.00%
Delta Air Lines Inc	DAL	0.16%	2.53%	0.00%	5.57%	0.01%
News Corp	NWS	0.01%	1.47%	0.00%	12.59%	0.00%
Centene Corp	CNC	0.07%	n/a	n/a	12.48%	0.01%
Regency Centers Corp	REG	0.05%	3.42%	0.00%	9.26%	0.00%
Macerich Co/The	MAC	0.03%	5.17%	0.00%	7.66%	0.00%
Martin Marietta Materials Inc	MLM	0.06%	0.85%	0.00%	21.24%	0.01%
Envision Healthcare Corp	EVHC	0.02%	n/a	n/a	8.03%	0.00%
PayPal Holdings Inc	PYPL	0.34%	n/a	n/a	19.83%	0.07%
Coty Inc	COTY	0.06%	3.02%	0.00%	17.00%	0.01%
DISH Network Corp	DISH	0.06%	n/a	n/a	-7.33%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.14%	n/a	n/a	20.50%	0.03%
Everest Re Group Ltd	RE	0.04%	2.19%	0.00%	10.00%	0.00%
News Corp	NWSA	0.02%	1.51%	0.00%	12.59%	0.00%
Global Payments Inc	GPN	0.06%	0.04%	0.00%	14.50%	0.01%
Crown Castle International Corp	CCI	0.18%	3.80%	0.01%	21.60%	0.04%
Delphi Automotive PLC	DLPH	0.12%	1.18%	0.00%	12.18%	0.01%
Advance Auto Parts Inc	AAP	0.03%	0.24%	0.00%	8.96%	0.00%
Michael Kors Holdings Ltd	KORS	0.03%	n/a	n/a	7.00%	0.00%
Align Technology Inc	ALGN	0.07%	n/a	n/a	30.00%	0.02%
Illumina Inc	ILMN	0.13%	n/a	n/a	15.48%	0.02%
Acuity Brands Inc	AYI	0.03%	0.30%	0.00%	17.67%	0.01%
Alliance Data Systems Corp	ADS	0.05%	0.94%	0.00%	14.00%	0.01%
LKQ Corp	LKQ	0.05%	n/a	n/a	12.50%	0.01%
Nielsen Holdings PLC	NLSN	0.07%	3.28%	0.00%	10.00%	0.01%
Garmin Ltd	GRMN	0.05%	3.78%	0.00%	5.68%	0.00%
Cimarex Energy Co	XEC	0.05%	0.28%	0.00%	63.66%	0.03%
Zoetis Inc	ZTS	0.14%	0.66%	0.00%	14.75%	0.02%
Digital Realty Trust Inc	DLR	0.11%	3.14%	0.00%	5.58%	0.01%
Equinix Inc	EQIX	0.16%	1.79%	0.00%	29.25%	0.05%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.98%	
[2] Estimated Weighted Average Long-Term Growth Rate		11.46%	
[3] S&P 500 Estimated Required Market Return		13.55%	
[4] Risk-Free Rate	2.77%	3.30%	4.30%
[5] Implied Market Risk Premium	10.78%	10.25%	9.25%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] Weight In Index	[7] Estimated Dividend Yield	[8] Cap-Weighted Dividend Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth
Discovery Communications Inc	DISCK	0.02%	n/a	n/a	9.70%	0.00%

Notes:
[1] Equals sum of col. [8]
[2] Equals sum of col. [10]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional and Blue Chip Financial Forecasts
[5] Equals [3] - [4]
[6] Equals weight in S&P 500 based on market capitalization
[7] Source: Bloomberg Professional
[8] Equals [6] x [7]
[9] Source: Bloomberg Professional
[10] Equals [6] x [9]

CAPITAL ASSET PRICING MODEL - NATURAL GAS PROXY GROUP

$$K = Rf + \beta\ (Rm - Rf)$$

	[4]	[5]	[6]	[7]	[8]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Bloomberg Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.619	13.55%	10.78%	9.44%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.619	13.55%	10.25%	9.65%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.619	13.55%	9.25%	10.03%
				Average:	**9.71%**
				Median:	**9.65%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.725	13.55%	10.78%	10.59%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.725	13.55%	10.25%	10.73%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.725	13.55%	9.25%	11.01%
				Average:	**10.78%**
				Median:	**10.73%**

Notes:
[1] Source: Bloomberg Professional, 30-day average as of September 29, 2017
[2] Source: Blue Chip Financial Forecasts, Vol. 36, No. 10, October 1, 2017, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Bloomberg Professional and Value Line
[6] Source: Bloomberg Professional
[7] Equals [6] − [4]
[8] Equals [4] + [5] x [7]

CAPITAL ASSET PRICING MODEL - COMBINED UTILITY PROXY GROUP

K = Rf + β (Rm − Rf)

	[4]	[5]	[6]	[7]	[8]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Bloomberg Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.522	13.55%	10.78%	8.40%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.522	13.55%	10.25%	8.65%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.522	13.55%	9.25%	9.13%
				Average:	**8.73%**
				Median:	**8.65%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	2.77%	0.675	13.55%	10.78%	10.05%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2017 - Q1 2019) [2]	3.30%	0.675	13.55%	10.25%	10.22%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [3]	4.30%	0.675	13.55%	9.25%	10.54%
				Average:	**10.27%**
				Median:	**10.22%**

Notes:

[1] Source: Bloomberg Professional, 30-day average as of September 29, 2017
[2] Source: Blue Chip Financial Forecasts, Vol. 36, No. 10, October 1, 2017, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Bloomberg Professional and Value Line
[6] Source: Bloomberg Professional
[7] Equals [6] − [4]
[8] Equals [4] + [5] x [7]

FLOTATION COST ADJUSTMENT - NATURAL GAS PROXY GROUP

Flotation Costs from Inception to Date

Date	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage	
11/16/1949	1,584,238	$10.750	$10.250	$0.124	$0.137	$9.989	$1,205,605	$17,030,559	$15,824,953	7.079%	
6/4/1952	1,108,966	$10.500	$10.500	$0.098	$0.162	$10.240	$288,331	$11,644,143	$11,355,812	2.476%	
4/14/1954	1,219,856	$15.250	$14.000	$0.060	$0.124	$13.816	$1,749,274	$18,602,804	$16,853,530	9.403%	
2/29/1956	670,920	$17.825	$16.750	$0.050	$0.221	$16.479	$903,058	$11,959,149	$11,056,091	7.551%	
7/22/1959	952,033	$23.375	$22.000	$0.069	$0.191	$21.740	$1,556,574	$22,253,771	$20,697,197	6.995%	
7/28/1965	772,008	$35.250	$33.000	$0.092	$0.225	$32.683	$1,981,745	$27,213,282	$25,231,537	7.282%	
1/22/1969	1,080,811	$29.000	$27.000	$0.119	$0.187	$26.694	$2,492,350	$31,343,519	$28,851,169	7.952%	
10/21/1970	1,729,298	$23.125	$21.500	$0.175	$0.149	$21.176	$3,370,402	$39,990,016	$36,619,614	8.428%	
7/26/1972	1,902,228	$25.000	$23.500	$0.129	$0.166	$23.205	$3,414,499	$47,555,700	$44,141,201	7.180%	
10/10/1973	2,092,451	$25.825	$24.500	$0.128	$0.153	$24.219	$3,360,476	$54,037,547	$50,677,071	6.219%	
11/20/1974	2,300,000	$17.625	$17.500	$0.910	$0.069	$16.521	$2,539,200	$40,537,500	$37,998,300	6.264%	
8/14/1975	1,750,000	$23.000	$23.000	$0.740	$0.077	$22.183	$1,429,750	$40,250,000	$38,820,250	3.552%	
6/3/1976	2,000,000	$24.000	$24.000	$0.720	$0.064	$23.216	$1,568,000	$48,000,000	$46,432,000	3.267%	
5/31/1993	3,041,955	$44.125	$43.625	$1.200	$0.048	$42.377	$5,317,337	$134,226,264	$128,908,927	3.961%	
9/23/1997	4,500,000	$49.938	$49.563	$1.230	$0.133	$48.200	$7,821,000	$224,721,000	$216,900,000	3.480%	
9/29/1997	400,000	$50.500	$49.563	$1.230	$0.133	$48.200	$920,000	$20,200,000	$19,280,000	4.554%	
2/25/2002	20,000,000	$22.950	$22.500	$0.730	$0.015	$21.755	$23,900,000	$459,000,000	$435,100,000	5.207%	
9/9/2008	17,250,000	$20.860	$20.200	$0.100	$0.006	$20.094	$13,218,352	$359,835,000	$346,616,648	3.673%	
8/3/2010	21,850,000	$22.100	$21.500	$0.645	$0.013	$20.571	$33,407,927	$482,885,000	$449,477,073	6.918%	[1]
March 2013	7,757,449	$29.057	$29.057	$0.291	$0.052	$28.714	$2,657,558	$225,407,642	$222,750,085	1.179%	
June 2014	5,693,946	$30.663	$30.663	$0.307	$0.030	$30.326	$1,915,210	$174,592,340	$172,677,130	1.097%	
Total Public Issuances							$115,016,648	$2,491,285,237	$2,376,268,590	4.617%	
Total Non-Public Issuances							$0	$1,548,782,000	$1,548,782,000	0.000%	
Total Weighted Flotation Costs							$115,016,648	$4,040,067,237	$3,925,050,590	2.847%	

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9715, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + .5g)}{P \times (1 - F)} + g$$

Source: Company data.

[1] This issuance was structured as a forward equity sale. The spread between the initial forward sale price (*i.e.* , $20.855) and the actual forward settle price (*i.e.* , $20.584) is reflected in the net proceeds.

FLOTATION COST ADJUSTMENT - NATURAL GAS PROXY GROUP

		[1] Stock Price	[2] Annualized Dividend	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Dividend Yield Adjusted for Flotation Costs	[6] Value Line Earnings Growth	[7] Yahoo! Finance Earnings Growth	[8] Zacks Earnings Growth	[9] Average Growth Estimate	[10] DCF k(e)	[11] Flotation Adjusted DCF k(e)
Atmos Energy Corporation	ATO	$86.73	$1.80	2.08%	2.15%	2.21%	6.00%	7.60%	6.70%	6.77%	8.91%	8.98%
New Jersey Resources Corporation	NJR	$43.01	$1.09	2.53%	2.60%	2.67%	3.00%	6.00%	6.00%	5.00%	7.60%	7.67%
NiSource Inc.	NI	$26.60	$0.70	2.63%	2.71%	2.79%	5.50%	7.40%	6.10%	6.33%	9.05%	9.13%
Northwest Natural Gas Company	NWN	$65.92	$1.88	2.85%	2.92%	3.01%	7.00%	4.00%	4.30%	5.10%	8.02%	8.11%
ONE Gas, Inc.	OGS	$74.77	$1.68	2.25%	2.33%	2.40%	9.50%	6.00%	6.00%	7.17%	9.49%	9.56%
Southwest Gas Corporation	SWX	$79.26	$1.98	2.50%	2.57%	2.64%	7.50%	4.00%	5.60%	5.70%	8.27%	8.34%
Spire, Inc.	SR	$76.02	$2.10	2.76%	2.84%	2.93%	8.00%	4.64%	4.80%	5.81%	8.66%	8.74%
		PROXY GROUP MEAN		2.51%	2.59%	2.66%	6.64%	5.66%	5.64%	5.98%	8.57%	8.65%

MEAN		8.65%
UNADJUSTED CONSTANT GROWTH DCF MEAN		8.57%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.08%

[1] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [9])
[5] Equals [4] /(1- [Flotation Cost Percentage])
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals [11] - [10]

FLOTATION COST ADJUSTMENT - COMBINED UTILITY PROXY GROUP

Flotation Costs from Inception to Date

Date	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage	
11/16/1949	1,584,238	$10.750	$10.250	$0.124	$0.137	$9.989	$1,205,605	$17,030,559	$15,824,953	7.079%	
6/4/1952	1,108,966	$10.500	$10.500	$0.098	$0.162	$10.240	$288,331	$11,644,143	$11,355,812	2.476%	
4/14/1954	1,219,856	$15.250	$14.000	$0.060	$0.124	$13.816	$1,749,274	$18,602,804	$16,853,530	9.403%	
2/29/1956	670,920	$17.825	$16.750	$0.050	$0.221	$16.479	$903,058	$11,959,149	$11,056,091	7.551%	
7/22/1959	952,033	$23.375	$22.000	$0.069	$0.191	$21.740	$1,556,574	$22,253,771	$20,697,197	6.995%	
7/28/1965	772,008	$35.250	$33.000	$0.092	$0.225	$32.683	$1,981,745	$27,213,282	$25,231,537	7.282%	
1/22/1969	1,080,811	$29.000	$27.000	$0.119	$0.187	$26.694	$2,492,350	$31,343,519	$28,851,169	7.952%	
10/21/1970	1,729,298	$23.125	$21.500	$0.175	$0.149	$21.176	$3,370,402	$39,990,016	$36,619,614	8.428%	
7/26/1972	1,902,228	$25.000	$23.500	$0.129	$0.166	$23.205	$3,414,499	$47,555,700	$44,141,201	7.180%	
10/10/1973	2,092,451	$25.825	$24.500	$0.128	$0.153	$24.219	$3,360,476	$54,037,547	$50,677,071	6.219%	
11/20/1974	2,300,000	$17.625	$17.500	$0.910	$0.069	$16.521	$2,539,200	$40,537,500	$37,998,300	6.264%	
8/14/1975	1,750,000	$23.000	$23.000	$0.740	$0.077	$22.183	$1,429,750	$40,250,000	$38,820,250	3.552%	
6/3/1976	2,000,000	$24.000	$24.000	$0.720	$0.064	$23.216	$1,568,000	$48,000,000	$46,432,000	3.267%	
5/31/1993	3,041,955	$44.125	$43.625	$1.200	$0.048	$42.377	$5,317,337	$134,226,264	$128,908,927	3.961%	
9/23/1997	4,500,000	$49.938	$49.563	$1.230	$0.133	$48.200	$7,821,000	$224,721,000	$216,900,000	3.480%	
9/29/1997	400,000	$50.500	$49.563	$1.230	$0.133	$48.200	$920,000	$20,200,000	$19,280,000	4.554%	
2/25/2002	20,000,000	$22.950	$22.500	$0.730	$0.015	$21.755	$23,900,000	$459,000,000	$435,100,000	5.207%	
9/9/2008	17,250,000	$20.860	$20.200	$0.100	$0.006	$20.094	$13,218,352	$359,835,000	$346,616,648	3.673%	
8/3/2010	21,850,000	$22.100	$21.500	$0.645	$0.013	$20.571	$33,407,927	$482,885,000	$449,477,073	6.918%	[1]
March 2013	7,757,449	$29.057	$29.057	$0.291	$0.052	$28.714	$2,657,558	$225,407,642	$222,750,085	1.179%	
June 2014	5,693,946	$30.663	$30.663	$0.307	$0.030	$30.326	$1,915,210	$174,592,340	$172,677,130	1.097%	
Total Public Issuances							$115,016,648	$2,491,285,237	$2,376,268,590	4.617%	
Total Non-Public Issuances							$0	$1,548,782,000	$1,548,782,000	0.000%	
Total Weighted Flotation Costs							$115,016,648	$4,040,067,237	$3,925,050,590	2.847%	

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9715, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + .5g)}{P \times (1 - F)} + g$$

Source: Company data.

[1] This issuance was structured as a forward equity sale. The spread between the initial forward sale price (*i.e.* , $20.855) and the actual forward settle price (*i.e.* , $20.584) is reflected in the net proceeds.

FLOTATION COST ADJUSTMENT - COMBINED UTILITY PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Stock Price	Annualized Dividend	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Estimate	DCF k(e)	Flotation Adjusted DCF k(e)
Ameren Corporation	AEE	$59.52	$1.76	2.96%	3.05%	3.14%	6.00%	6.10%	6.50%	6.20%	9.25%	9.34%
Black Hills Corporation	BKH	$69.64	$1.78	2.56%	2.64%	2.72%	7.50%	7.65%	5.00%	6.72%	9.36%	9.44%
CMS Energy Corporation	CMS	$47.86	$1.33	2.78%	2.87%	2.96%	6.50%	7.44%	6.00%	6.65%	9.52%	9.60%
Dominion Resources, Inc.	D	$78.53	$3.02	3.85%	3.94%	4.06%	5.50%	3.46%	6.00%	4.99%	8.93%	9.04%
DTE Energy Company	DTE	$110.81	$3.30	2.98%	3.06%	3.15%	6.00%	4.59%	5.90%	5.50%	8.56%	8.65%
NorthWestern Corporation	NWE	$59.29	$2.10	3.54%	3.60%	3.70%	4.50%	3.05%	1.60%	3.05%	6.65%	6.75%
PG&E Corporation	PCG	$69.65	$2.12	3.04%	3.13%	3.22%	9.50%	2.08%	5.00%	5.53%	8.65%	8.75%
SCANA Corporation	SCG	$58.28	$2.45	4.20%	4.29%	4.42%	4.00%	5.50%	3.30%	4.27%	8.56%	8.69%
Vectren Corporation	VVC	$65.90	$1.68	2.55%	2.63%	2.70%	6.50%	6.00%	5.50%	6.00%	8.63%	8.70%
Wisconsin Energy Corporation	WEC	$64.96	$2.08	3.20%	3.29%	3.39%	6.00%	5.61%	5.30%	5.64%	8.93%	9.03%
		PROXY GROUP MEAN		3.17%	3.25%	3.35%	6.20%	5.15%	5.01%	5.45%	8.70%	8.80%

MEAN		8.80%
UNADJUSTED CONSTANT GROWTH DCF MEAN		8.70%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.10%

[1] Source: Bloomberg Professional, equals 30-day average as of September 29, 2017
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [9])
[5] Equals [4] /(1- [Flotation Cost Percentage])
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals [11] - [10]

Xcel Energy	**Gas Utility Infrastructure Cost (GUIC) Rider Performance Metrics**

Introduction

This attachment discusses our proposal for metrics to measure the appropriateness of GUIC expenditures and is provided pursuant to Order Point 2 of the Commission's August 18, 2016 Order in Docket No. G002/M-15-808.

In its Order approving our previous GUIC Petition, the Commission required Xcel Energy to develop, with stakeholder involvement, metrics to measure the appropriateness of GUIC expenditures. Each metric should include reconciliation to the pertinent Transmission Integrity Management Program (TIMP) or Distribution Integrity Management Program (DIMP) rules that it addresses, or other goals, benefits, or requirements. The Company proposed metrics in a petition supplement filed January 13, 2017 in Docket No. G002/M-16-891. We provide an update on our metrics results in the following sections.

A. Summary of Program Expenditures, Relevant Rules and Guidelines, and Program Goals

Following is a summary of the metrics proposed by the Company as well as a discussion of associated rules, goals and benefits. The GUIC programs of work proposed for 2018 are summarized below in Table 1.

Table 1
Summary of 2018 GUIC Project Expenditures

Program	Project	Capital ($ Millions)	O&M ($ Millions)
TIMP	Transmission Pipeline Assessments	$0.29	$1.51
	ASV/RCV	$0.97	$0.00
	Programmatic Replacement/MAOP Remediation	$7.77	$0.00
DIMP	Poor Performing Main Replacement	$11.05	$0.00
	Poor Performing Service Replacement	$6.91	$0.00
	Intermediate Pressure (IP) Line Assessments	$19.82	$1.03
	Distribution Valve Replacement	$0.50	$0.00
	Sewer & Gas Line Conflict Investigation	$0.00	$2.31
	Federal Code Mitigation	$0.00	$0.20
TOTAL		$47.3	$5.05

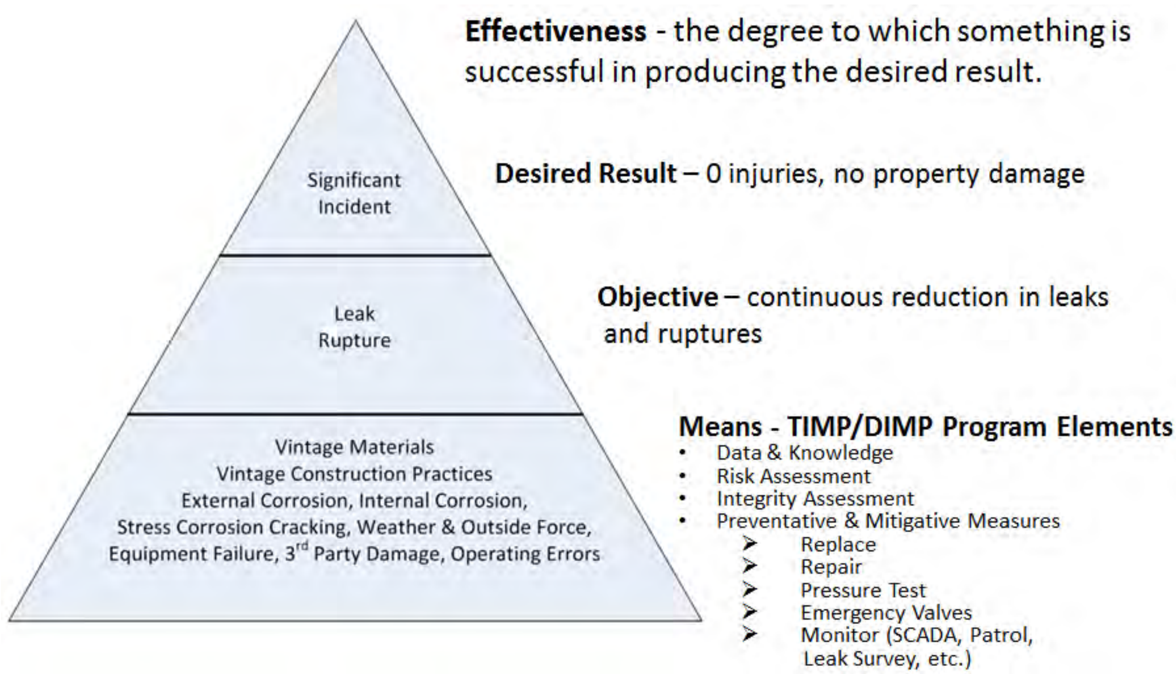
The GUIC projects proposed for 2018 fall into two broad categories, TIMP and DIMP. The related rules associated with each project are summarized below in Table 2 and discussed in more detail in our November 1, 2017 Petition.

Table 2
Summary of TIMP/DIMP Rules and Regulatory Guidance

Program	Project	49 CFR Part	PHMSA Advisory Bulletin or Other
TIMP	Transmission Pipeline Assessments	192.937	Gas Transmission & Gathering Notice of Proposed Rulemaking 192.710
	ASV/RCV	192.935(c)	NTSB PAR-11/01
	Programmatic Replacement/MAOP Remediation		PHMSA ADB-11-01 NTSB PAR-11/01 Gas Transmission & Gathering Notice of Proposed Rulemaking 192.624
DIMP	Poor Performing Main Replacement	192.1007(d)	PHMSA ADB-99-02 PHMSA ADB-08-02
	Poor Performing Service Replacement	192.1007(d)	PHMSA ADB-99-02 PHMSA ADB-08-02
	Intermediate Pressure (IP) Line Assessments	192.1007(d)	
	Distribution Valve Replacement	192.1007(d)	
	Sewer & Gas Line Conflict Investigation	192.1007(d)	
	Federal Code Mitigation	192.1007(d)	

The goals of the TIMP and DIMP are illustrated below in Figure 1.

Figure 1
TIMP and DIMP Goals



TIMP and DIMP are undertaken to reduce the likelihood of a significant gas incident that may result in injury to the public or damage to property. To achieve this objective, TIMP and DIMP projects enact preventative and mitigative measures to reduce the likelihood or severity of gas leaks and pipeline ruptures.

The Company's proposed Metrics are summarized in Table 3 below.

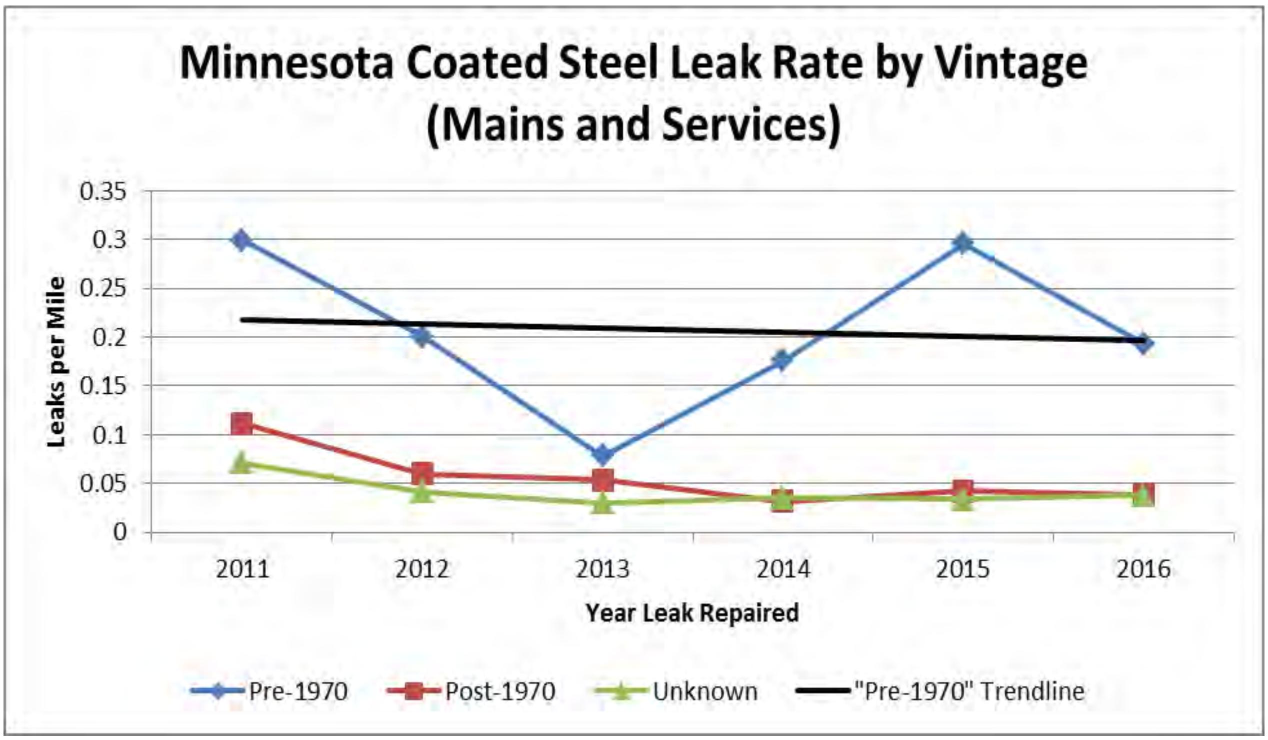
Table 3
Proposed GUIC Metrics

Program	Metric	Benefit
DIMP	Leak Rate by Vintage and Pipe Type	Monitor the impact of renewal efforts on the leakage rates. Selection of higher-risk pipe segments will lower leakage rates over time.
	Poor Performing Main Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.
	Poor Performing Service Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.
TIMP	Gas Transmission Anomalies Repaired	Monitor the impact of pipeline assessment, repair and renewal efforts on the number of anomalies that require repair. Appropriate repairs and renewal efforts will lower anomalies over time.
	Actual vs. Estimated Cost Variance Explanations for Capital Projects	Monitor cost variances to ensure variances are understood and reasonable.

B. DIMP Metrics

49 CFR Part 192.1007(e) currently requires performance metrics for DIMP, including the total number of leaks either eliminated or repaired, categorized by cause. The Company proposes that the DIMP metrics include a similar metric focused on the leak rates over time as illustrated below in Figure 2.

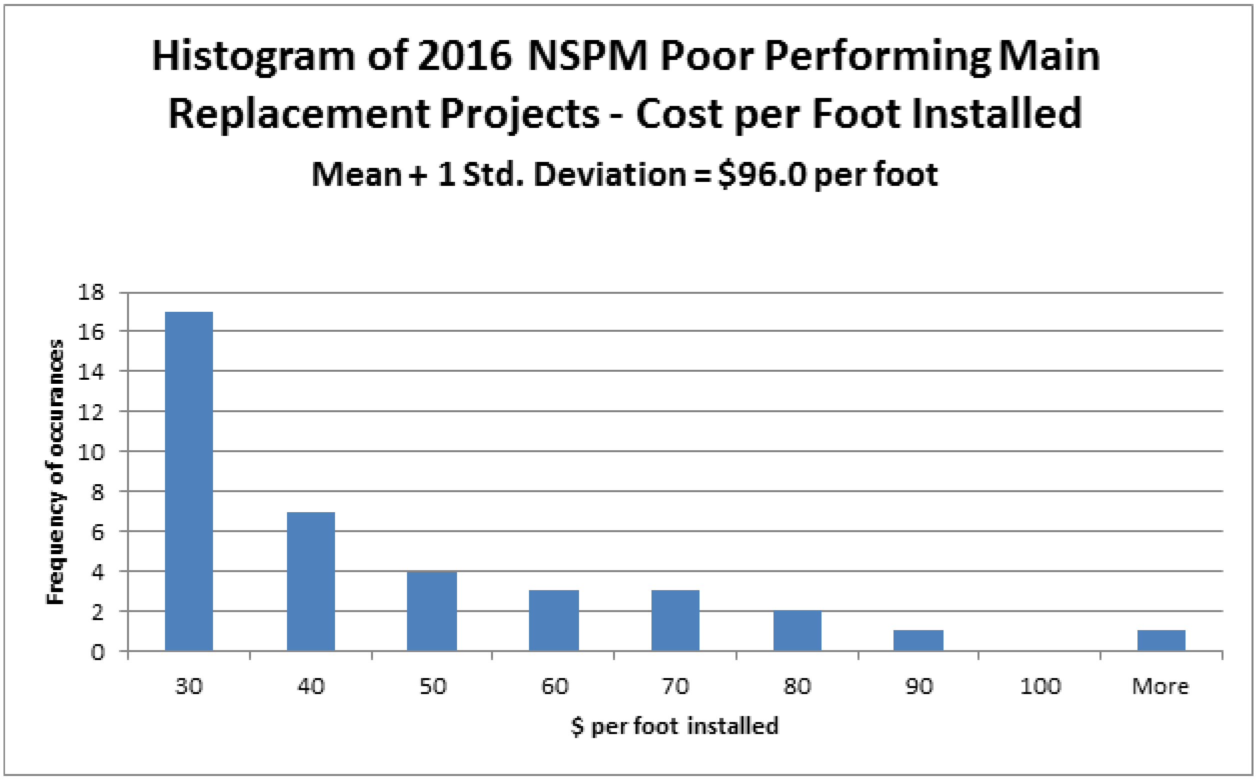
Figure 2
Number of Leaks Per Mile



The metric shown in Figure 2 is Leaks per Mile (mains and services) for Coated Steel, by year and by pipe vintage. Only underground leakage not associated with excavation damage is included to evaluate the impact of GUIC distribution pipe replacement efforts. We expect that the leak rates for the pre-1970 coated steel pipe will continue to decrease over time as problematic pipe is replaced. Because most of the Company's distribution system is on a three-year leak survey cycle and different parts of the system are being surveyed each year, some variation of leak rates from year to year is expected.

The other DIMP metrics proposed by the Company are associated with monitoring costs for problematic main and service replacements, evaluating significant variances (those greater than one standard deviation above the mean unit cost). Unit costs may vary for many reasons including differences in soil conditions, paving requirements, traffic control requirements and permit restrictions.

Figure 3
Unit Costs for Poor Performing Main Replacement Projects

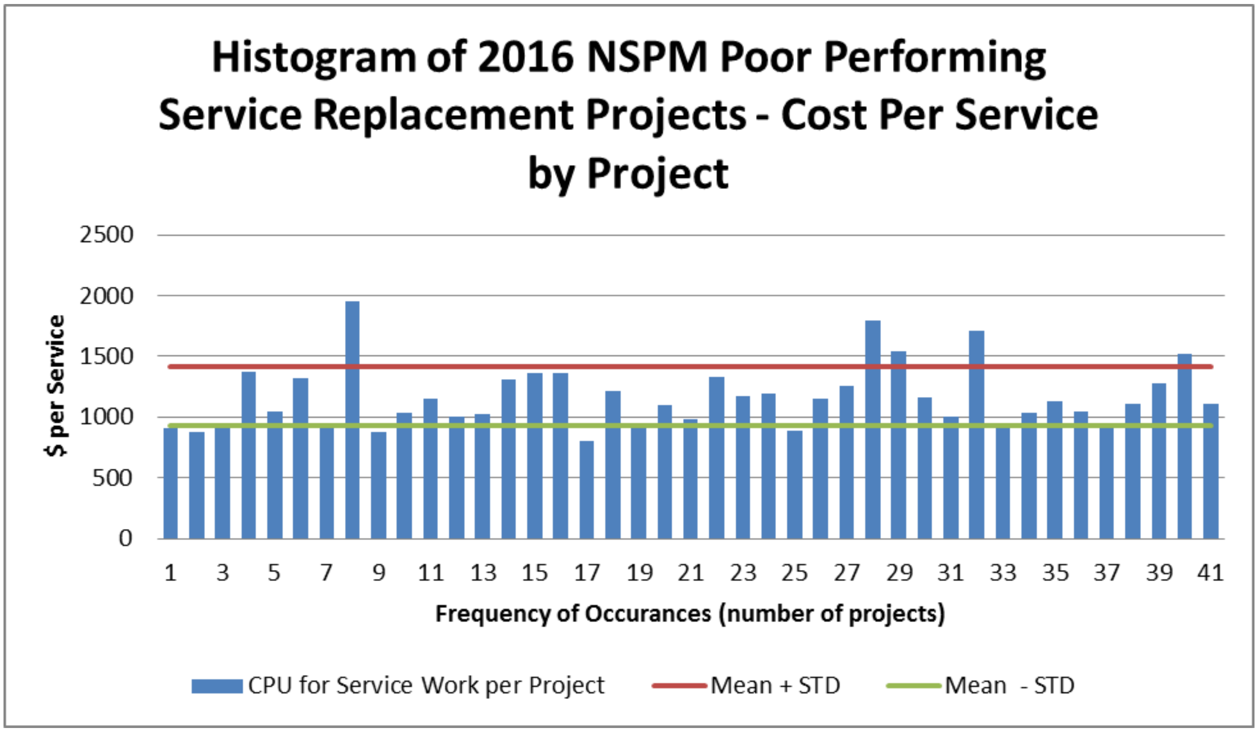


The illustrative cost metric shown in Figure 3 depicts the average cost per foot plus one standard deviation of $96.0 per foot. There was one project in 2016 that exceeded this amount:

This project replaced 4" and 2" main in downtown St. Paul, through dense urban area with significant concrete and asphalt. Open trench was used for the entire project. The following are items created significant cost pressure, resulting in the $329.96 cost per foot. The Company worked with the City of St. Paul extensively in the planning phases to find the most reasonable and cost-effective solutions.

- Permit costs exceeded $50,000, partly to offset meter revenue lost by the City of St. Paul.
- The Company was required to use sound and vibration monitoring equipment to ensure no damage to the historic buildings in the downtown area.
- Significant rock was encountered in the project, which required breaking and removal. The Company also had to haul in clean sand fill to replace the rock it removed. This accounted for approximately one third of the cost for the project.
- Significant asphalt and concrete restoration costs due to the nature of the area.

Figure 4
Unit Costs for Poor Performing Service Replacement Projects



As shown in Figure 4, the average cost per gas service plus and minus one standard deviation is $1,411 and $925 per service, respectively. In total, nine projects fell above or below this range. Cost variance explanations are as follows:

- **Below $925: Mean minus (-) STD**
  - **ST PAUL - ARMSTRONG AVE - $872 Cost per Service**
    - Both phases of this project had lower than average cost, due to average length of service from new main.
    - Work was coordinated with City of St Paul reconstruction, and we avoided some restoration cost due to this.
  - **ST PAUL - JUNO (CONTRACTOR PORTION)- $877 Cost per Service**
    - Juno St was in the area of City of St Paul reconstruction work, and both internal and contractor portions benefitted from coordination with city reconstruction efforts, reducing the restoration costs where the city had the road base removed.
  - **NORTH ST PAUL - 19TH AVE - $806 Cost per Service**
    - Length of service in a residential neighborhood contributed to lower cost, as well as little to no hard surface restoration was needed due to location of existing and new main in the boulevard.

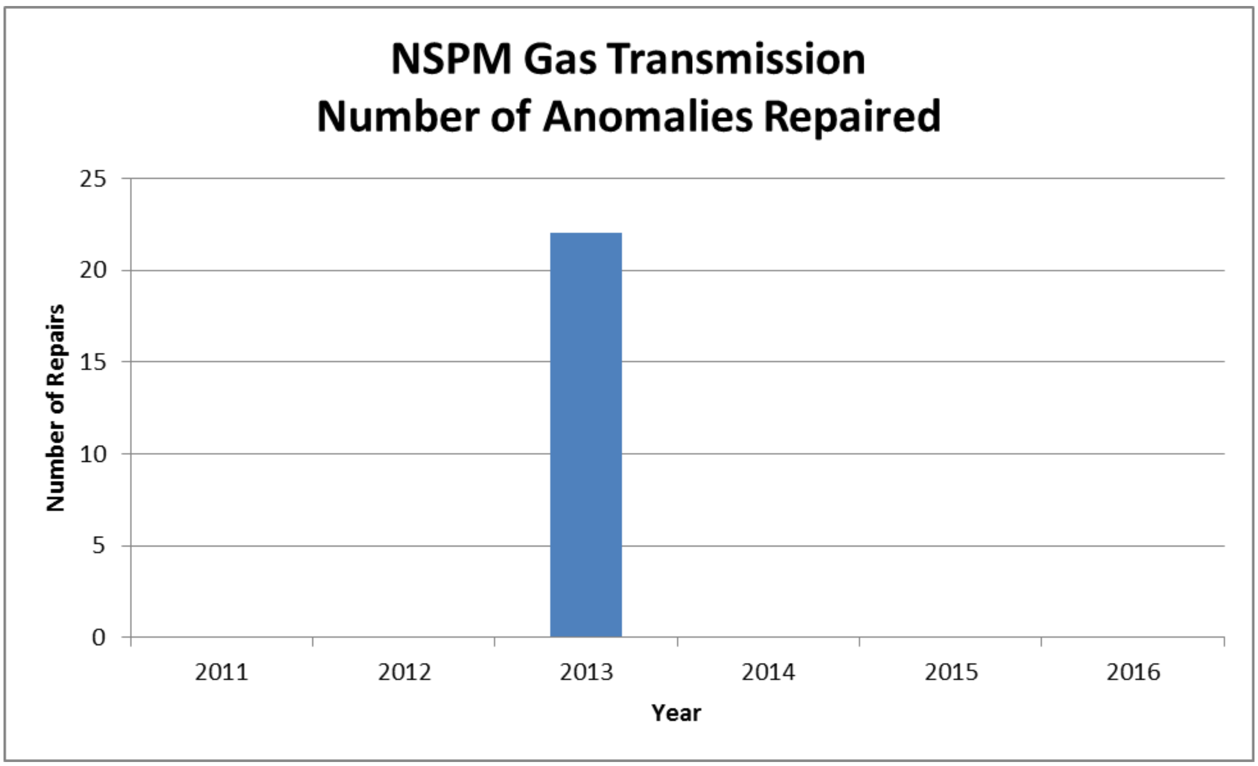
- **ST PAUL - ARMSTRONG AVE - $872 Cost per Service**
  - Lower restoration costs than planned due to coordination with the City of St Paul on reconstruction projects.

- **Above $1,411: Mean plus (+) STD**
  - **ST PAUL - DOWNTOWN - 10TH-MINNESOTA- $1,949 Cost per Service**
    - Commercial services in dense urban setting and concrete base to road made for challenging conditions and most costly main and service CPU for 2016.
  - **SOUTH ST PAUL - 3RD AVE S - 6TH ST S - $1,800 Cost per Service**
    - Main in this area was located in the street, and not related to any city efforts. Additionally, we had higher than normal Stormwater Pollution Prevention Plan (SWPPP) costs as we worked with the City of South St Paul in managing storm water on the project.
  - **MENDOTA HTS - 3RD ST-VANDALL-SOMERSET - $1,546 Cost per Service**
    - Similar to South St Paul, we had additional SWPPP costs in this area to manage the storm water, each hole required protection to ensure runoff would not enter city water inlets nearby.
  - **DELANO - $1,708 Cost per Service**
    - Higher average length of service contributed to roughly 25% higher average cost in this relatively rural area. The City had specific criteria that needed to be met. Sod restoration (specified in the permit) negatively impacted restoration costs.
  - **MOORHEAD - REGAL ESTATES – $1,522 Cost per Service**
    - Several delays coordinating sewer mitigation and construction issues pertaining to getting access to homes. To facilitate work, the Company had to locate private streetlight facilities or be 100% responsible for any damages.

C. TIMP Metrics

The goal of projects under the Company's TIMP is to detect and repair pipe anomalies and to mitigate the consequence of a failure. The detection and repair of anomalies is achieved primarily through Pipeline Assessments, Replacement, and MAOP remediation. The potential consequences of a pipe failure are mitigated primarily by the installation of Remote Control Valves (RCVs). The Company's metric for TIMP is focused on the number of anomalies repaired as illustrated below in Figure 5.

Figure 5
Number of Anomalies Repaired



Anomaly repairs are expected to vary from year to year as different pipelines are inspected or assessed each year. However, as assessments continue and anomalies are repaired, the Company anticipates the number of repairs to ultimately reduce.

The Company has also proposed a TIMP metric that monitors actual versus estimated costs for capital replacement projects as illustrated below in Table 4.

Table 4
TIMP Replacement Project Cost Monitoring

Project	Cost Estimate at Issue for Construction ($ Millions)	Actual Cost ($ Millions)	Variance Explanation
East County Line Casing Removal, replace 0.1 miles of 16 inch, cased pipeline underneath Stillwater Avenue in St. Paul.	$1.1	$1.2	Construction schedule delays associated with non-locatable fiber optic cable added costs; site security, material orders, and technical issues related to underground utility coordination.
Island Line (South of River), replace 1.9 miles of 16 inch pipeline.[1]	$3.8	$3.2	Construction costs associated with contract labor for this project were less than anticipated.
High Bridge Lateral Replacement, replace 0.8 miles of 18 inch pipeline.[2]	$0.7	$0.7	None.

[1] The cost estimate submitted in the 2017 GUIC Filing for this project of $1.7 million was inaccurate and was ultimately managed at $3.8 million to account for additional construction and engineering costs associated with the daily dewatering of the jobsite.

[2] The original cost estimate for this project was $900K but included $200K of work that was part of the East Metro Pipeline Replacement Project. With these costs excluded, there was no variance for this project.

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served copies or summaries of the foregoing documents 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-16-891
Docket No. G002/GR-09-1153
Xcel Energy Miscellaneous Gas Service List

Dated this 1st day of November 2017

/s/

____
Carl Cronin

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