414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2018

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 2018, REVENUE REQUIREMENTS FOR 2019,
AND REVISED ADJUSTMENT FACTORS
DOCKET NO. G002/M-18-____

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 2019.

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 Brandon Kirschner at (612) 215-5361 or brandon.m.kirschner@xcelenergy.com or Mary Martinka at (612) 330-6737 or mary.a.martinka@xcelenergy.com.

SINCERELY,

/s/

LISA R. PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Vice-Chair
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 2018, REVENUE REQUIREMENTS FOR 2019, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-18-____

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 2019 Gas Utility Infrastructure Cost (GUIC) revenue requirement.

In order to continue to promote the safety of our natural gas system, we are requesting recovery of a 2019 revenue requirement of approximately $28.9 million. The costs included in this request are consistent with the eligibility requirements set forth in the GUIC statute.[1] This includes the final year of amortized costs for the previously approved deferral. We also have included a revenue requirement adjustment to remove the impact of assets retired during GUIC work that were also included in our currently approved base rates.

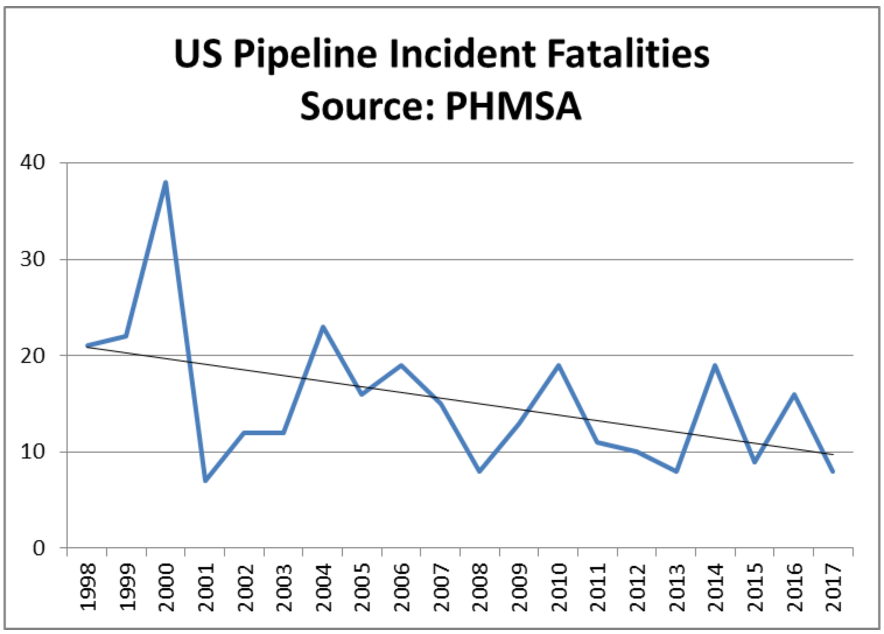
GUIC programs continue to play an important role in pipeline safety. Since the GUIC Rider was established in 2015, significant progress has been made identifying pipeline risks and taking necessary corrective action to repair, rehabilitate, and replace the highest risk infrastructure. The Company is 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

[1] Minn. Stat. § 216B.1635.

repairing and replacing problematic equipment. GUIC projects are aimed at updating our gas infrastructure to have greater structural integrity, facilitating efficient assessments going forward, and ensuring 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. This trend reflects the kind of infrastructure work discussed in this Petition and recovered through the GUIC Rider. Still, while the overall trend in fatalities has been decreasing, continued infrastructure work is critically needed to bring that number down further.

Figure 1



From the inception of the GUIC Rider in 2015 to the close of 2018, the Company expects to have completed the replacement of over 200 miles of high- and medium-risk, aging, corroded, and otherwise damaged gas distribution pipeline as well as the replacement of over 12,000 aging distribution service lines. The Company will continue working proactively to identify high- and medium-risk areas in order to help ensure the safety of our distribution system and reduce the number distribution pipeline leaks. In addition to main and service replacements, by the end of 2018 the Company expects to have performed almost 188,000 sewer line inspections since the inception of the program in 2010.[2] Through August 2018, a total of 153 known sewer and gas line conflicts have been identified and cleared as a result of these inspections. As with our other Transmission and Integrity Management Programs (TIMP) and Distribution Integrity

[2] Number of sewer line conflicts in previous filings included new construction inspections. Those have been excluded from this year's count as new construction work is not within the scope of GUIC.

Management Programs (DIMP) projects, the end result of these projects is a gas infrastructure system that is safer and more reliable.

There have also been a number of major projects completed under the GUIC programs that are providing enhanced system safety. 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. Likewise, the replacement of 1.7 miles of the leak-prone Montreal Line South and Island Line South has been completed as a part of the GUIC. These lines are critical as they provide the bulk of gas service to the City of St. Paul and north suburbs. The upgrades to these lines will also allow for more efficient assessments of the lines—helping to ensure future integrity and reliability.

In 2018, the Company began work on two important high pressure distribution reconstruction projects: the Colby Lake Lateral Replacement Project and the Arden Hills/System H05 Renewal Project. In total, these projects will replace roughly five miles of natural gas pipeline systems originally constructed in the 1960s. These replacement projects address several risk factors including, external corrosion, legacy manufacturing and construction techniques, and third party damage.

Beyond major renewal and replacement projects, 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. Upcoming DIMP work will include poor performing main and service replacements, sewer line conflict remediation, and pipeline inspections.

There are several new topics and pieces of information included in this year's GUIC Rider petition. This petition includes a revenue requirement adjustment to remove the impact of assets retired during GUIC work that were also included in our currently approved base rates. We include a discussion of refinements in our contract and invoice review processes to increase accuracy in our GUIC cost oversight process. Within our revenue requirement schedules, we have added a new schedule that includes monthly revenue requirements tracking, estimated revenues, and monthly rates. We have included this information in response to a request for more revenue requirement clarity made by the Department in our 2018 GUIC Rider filing. Finally, we include a brief discussion of additional requirements related to excess flow valves (EFV) ordered by the Commission earlier this year.

We submit this request acknowledging the pendency of our 2018 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 need to continue critical systemic safety improvements. Accordingly, we file this petition looking ahead to 2019 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 return on equity (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

Ryan J. Long
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
(612) 215-4659
ryan.j.long@xcelenergy.com

C. Date of Filing and Proposed Effective Date

The date of this filing is November 1, 2018. The proposed effective date for the 2019 GUIC Rider factors is January 1, 2020. 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 the Company'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

Lisa R. Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall (401-7th Floor)
Minneapolis, MN 55401
(612) 330-7681
lisa.r.peterson@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:

Ryan J. Long
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
ryan.j.long@xcelenergy.com

Lynnette Sweet
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. Organization and Attachments

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

B. Background

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 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 […] 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.*[3]

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. *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 E. 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.

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[3] *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.

2. *TIMP Projects*

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 74 miles 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.[4] 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 gas transmission line assessments, the Company conducts ILI wherever practicable. There are advantages to using ILI compared to alternative assessment methods. First, the pipelines need not be taken out of service while the inspection is in process. Second, ILI provides the most comprehensive profile of the integrity of a pipeline, including the assessment for multiple threats. Third, ILI technology allows for assessment of longer distances with one inspection run. Other approved assessment methodologies (pressure testing or direct assessment) only assess for limited threats and are usually performed on relatively short segments at a time. After an initial capital investment to prepare a pipeline for an ILI tool, subsequent assessments will be performed on the same line 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 and remote controlled valves.

In 2017, the Company began work on the Programmatic Replacement and MAOP Remediation Program. The MAOP initiative strives to meet the requirement to have traceable, verifiable, and complete records of a pipeline's MAOP and targets necessary repairs or replacement efforts on transmission pipelines that have been assessed for asset health and condition in prior years. The revised federal guidance[5] requiring operators to re-establish MAOP are highly prescriptive and go well beyond the standards operators previously employed to maintain their transmission systems.[6]

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

[5] 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.

[6] 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.

Through the initiative, the Company is gathering and validating existing MAOP records for the Company's transmission pipelines, and remediating any gaps in such records. [7] 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 missing information regarding 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 comprehensive asset knowledge was not necessarily passed on to future owners. However, incomplete or partial records are not an adequate basis for establishing MAOP. If records are unknown or unknowable, a more conservative approach is warranted. 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 PHMSA.[8]

The installation of automatic shutoff valves and remote controlled valves provides the Company with a mechanism to more expediently shut off the flow of gas. These valves can be useful tools to prevent negative impacts to public safety in the event of an incident.

Project descriptions, scopes of work, estimated costs and in-service dates for specific TIMP projects are provided as Attachment C. Attachment F reports the capital expenditure costs and forecasted costs for incremental TIMP activities between March 2012 and December 2023. Attachment G shows the development of 2017-2020 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment F.

3. DIMP Projects

The Company's DIMP is grounded in federal rules issued by PHMSA with a goal to ensure safe and reliable gas delivery to our customers.[9] 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

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[7] 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.

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

[9] *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.

consequence. Over time, the Company has seen the conflict rate decrease from 0.20 percent in 2010 down to a 0.02 percent in 2017. 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.[10]

DIMP work also includes assessing and potentially remediating high- and medium-risk mains.[11] 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 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 proactive approach. This benefits customers in that work undertaken systematically and planfully reduces costs compared to work undertaken in a reactionary or immediate threat mode. 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 further in Attachment D.

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided in Attachment D. Attachment F reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2023. Attachment H shows the development of 2017-2020 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment F.

4. *Deferral Orders*

The Commission previously approved deferred accounting treatment for the sewer line conflict remediation activities and other safety-related work initiated before the implementation of the GUIC Rider.[12] 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 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.[13] The Company has been amortizing these costs over five years of

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[10] *See* https://www.xcelenergy.com/energy_portfolio/natural_gas/projects/sewer-and-septic-line-investigation-project.

[11] Medium risk for mains is a new risk standard established in our proposed performance metrics.

[12] *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).

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

GUIC Rider recovery. Our 2019 request represents the fifth and final installment of deferred cost amortization.

C. Standard of Review

The legal standard of review for the Company's petition for its GUIC Rider is:

> *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.*[14]

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:

> *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.*[15]

As the Commission has already recognized, the Company'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 to allow us to continue the recovery of our projected TIMP and DIMP expenses for 2019, including the costs for which the Commission previously granted deferred accounting through the GUIC Rider.[16] The Company's revenue requirement reflects the impact of ongoing GUIC projects already approved by the Commission.

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[14] Minn. Stat. § 216B.1635 Subd. 5.

[15] Minn. Stat. § 216B.1635 Subd. 6.

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

The 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.*[17]

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 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 work for our customers. Additionally, we can leverage economies of scale by obtaining the requisite project equipment 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, regardless of the recovery mechanism used. The primary advantages of a rider mechanism are the added flexibility, frequency of 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.

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

B. The Public Interest Supports Ongoing GUIC Investments

The public and customer benefits of increased safety and reliability that are delivered through the GUIC Rider are significant and ongoing, but continued efforts are needed. 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, which raises the risks of major catastrophes in the event of a failure. We were reminded once again of the safety risks gas systems can pose with the recent gas distribution system accident in Massachusetts which resulted in a series of explosions and fires.[18]

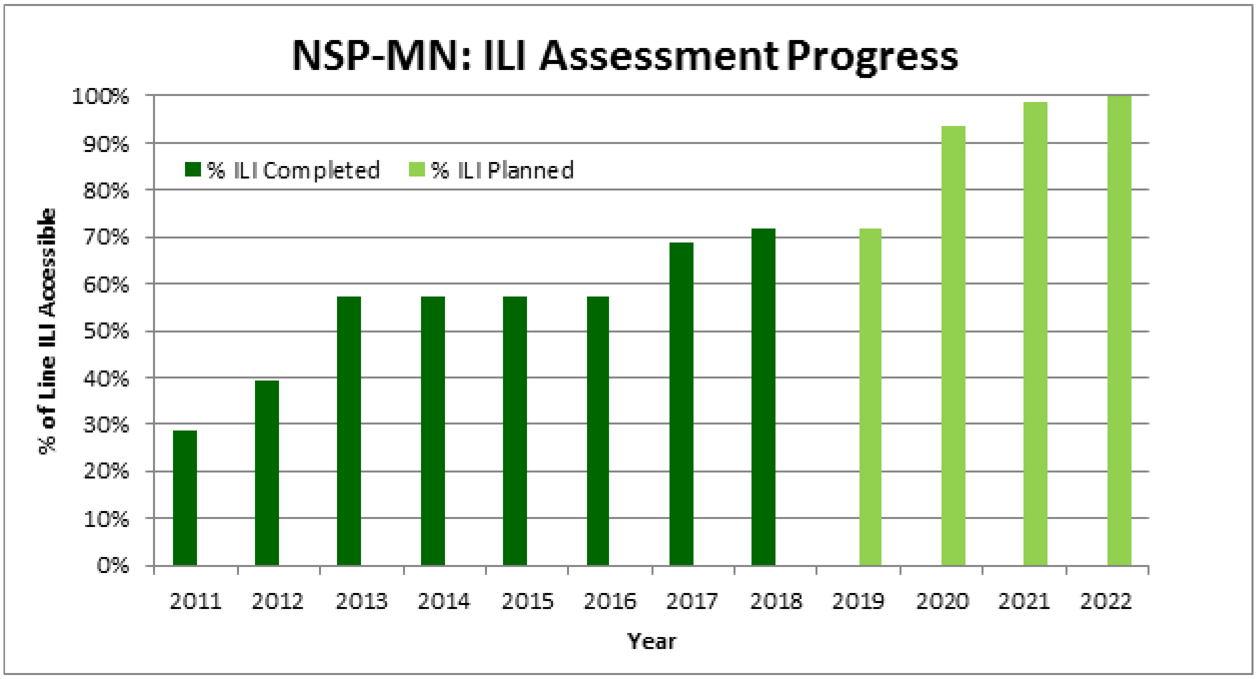
1. Addressing Aging Assets

Federal regulation requires pipeline operators to assess the integrity of their pipelines based on the threats to which the pipeline is susceptible. The characteristics of the Company's gas utility assets, including material types and construction methods used at the time of installation, introduce 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 have a higher risk of failure. Older assets also have a higher risk of material or construction flaws. While age alone does not indicate an imminent risk of failure, it is a predictive factor and we must address risks posed by legacy construction techniques and materials.

In order to assess these aging gas transmission assets, the Company primarily utilizes ILI due to its superior ability to provide detailed information regarding the current pipeline condition without having to remove the line from service. Not all pipelines can be assessed by ILI due to limitations in availability of ILI tools. As shown in Figure 2 below, approximately 72 percent of the Company's gas transmission system that will be assessable using ILI tools has been assessed. The Company's current TIMP assessment plan projects 100 percent ILI accessibility of transmission pipelines by 2022.

[18] https://www.ntsb.gov/investigations/AccidentReports/Pages/PLD18MR003-preliminary-report.aspx.

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. 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.[19]

3. *Conferring Public Benefits*

Through GUIC activities, the Company confers immediate safety and reliability benefits to customers and the public, 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.

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

C. GUIC Activities Are Reasonable and Prudent

The GUIC statute requires that our annual filing include information regarding the reasonableness and prudency of our GUIC costs incurred.[20] Through stringent oversight processes and a contract and charge review process, the Company is able to ensure that costs are tracked and are reasonable in comparison to the forecasted amounts. The Company looks for many opportunities to control costs, and one way is through the prudent use of outsourcing when the situation calls for expertise outside our normal core competencies as a gas utility. The following discussion will highlight these efforts undertaken by the Company to ensure the reasonableness and prudency of our GUIC costs.

1. Cost Controls

Expenditures for GUIC projects must successfully pass through the Company's capital and operations and maintenance (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 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 Gas Engineering and Operations business unit monitors capital expenditures 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.[22] In the limited circumstances where a competitive process is not required, written justification and director level authorization from the business area and Supply Chain is required.[23]

Furthermore, where practical, the Company establishes bid-unit contracts for activities that are reproducible and are awarded to the vendors that provide the best

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[20] Minn. Stat. § 216B.1635 Subd. 4(2)(iv).
[21] Including cumulative amounts in multi-year agreements.
[22] The bid process also ensures compliance with Company policies regarding the use of diverse contractors and suppliers as specified within the Company's corporate policy on Supplier Diversity.
[23] Some examples of situations where a competitive bid would not be used include emergency work and the absence of competitive firms.

overall value, resource availability, and proven safety performance. When bid-unit contracts cannot be used, 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.[24]

Aging infrastructure across the country has resulted in a large number of gas operators responding to the Call to Action issued by the United States Department of Transportation (DOT) and PHMSA in 2011 with multi-year replacement programs, which has resulted in heavy competition to secure specialized equipment, engineers, and construction crews required for renewal work. 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 also in human resources, including engineers and construction crews.

2. *Oversight Methods*

In addition to using a competitive bid process to secure needed resources, we also employ significant and ongoing cost 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 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 Code of Federal 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

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[24] 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.

Company's Pipeline and Compliance Standards Manual. The Company primarily uses contract inspectors for oversight work, as these inspectors can provide specialized experience and equipment to support this type of work. Also, utilizing outside resources for oversight work allows for an independent approach to inspections that is completed in a standard manner consistent with our Pipeline Compliance and 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 21 planned inspections and evaluated 13 unplanned events in 2017. Inspections included a review of field locations and records, operations and maintenance procedures, safety-related concerns, and outages.

GUIC activities have internal personnel identified that oversee those activities. Those personnel work closely with gas engineering, design, and our contractors before, during, and after construction to plan and schedule the work, discuss efficiency opportunities and communicate challenges that may impact the work as well as its cost. 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 of progress and findings to MNOPS.

3. Contract and Charge Review Process

To ensure capital and O&M costs are appropriately reflected in our GUIC request, the Company recently established additional review processes to more closely evaluate the contracts, work orders, and invoices associated with its GUIC work programs. These process improvements were developed in response to the GUIC Rider Audit Report, published by the Company's Audit Services department on May 31, 2018. The report completed an overall assessment of the business practices associated with the GUIC's capital and O&M cost settlement activities since the Rider's inception in 2015. The Report also identified recommendations and opportunities to confirm the proper posting of expenditures to the correct jurisdiction and business unit/project.

As part of the new process, all capital and O&M transactions posting to GUIC cost structures are now individually reviewed on a monthly basis and require management approval. The Company believes this enhanced examination of individual transactions and subsequent validation that each transaction relates to a Master

Service Agreement involving Minnesota-specific work will help prevent instances of inadvertent incorrect jurisdictional assignments moving forward.

4. Outsourcing

While the Company seeks to minimize its outsourcing of TIMP and DIMP work, 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 most 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. Outsourcing this small amount of administrative work is reasonable as the work is not within our core business and can only completed when temperatures are consistently above freezing. As such the work is only needed for a part of the year, and outsourcing allows us to hire lower-cost administrative staff for only the months in which work is performed. 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 saves customers the cost of purchasing expensive, specialized equipment, and ensures investigations are conducted by experienced resources.

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 Company and customer facilities, and customer outages are reported accurately 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 the Company 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 2019, 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.

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.[25] 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. As we have discussed previously, the Commission has agreed that these costs are new and outside of what was requested in our last rate case.[26] 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.[27] 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.

While the projects being completed as a part of the GUIC programs are incremental to costs proposed in our last gas general rate case, these projects are replacing gas assets that were included in the rate base approved in that case and as such are being

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[25] 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.
[26] *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.
[27] *See* 49 C.F.R. 192, Subpart P.

recovered in our current base rates. As we mentioned in our Reply Comments filed in the 2018 GUIC Rider Filing, capital plant has increased annually since our last gas rate case and the amount of non-GUIC assets added are far larger than the net book value of assets in base rates that have been retired during the GUIC projects.[28]

Due to the method of accounting used for our capital assets, the Company cannot directly identify the value of the specific assets replaced during GUIC work. However, based on our analysis, we estimate that approximately $10.1 million in assets that are included in our current base rates have been retired as of the result of GUIC work. We further estimate that these retired assets had a remaining net book value of approximately $3.1 million[29] at the start of the 2010 test year utilized in our last gas general rate case. When ADIT on the retired assets is also accounted for, the net impact to rate base is a decrease of $2.4 million.

Attachment J includes the calculation of our estimate of annual GUIC related retirements from 2012 through 2019. In conjunction with the information contained in Table 3 in Section IV.H. below, this attachment contains the information required in Minn. Stat. § 216B.1635 Subd. 4(iii). Our calculation is primarily based on an analysis of retirement information from 2012 through 2017. For retirements in 2018 and 2019, complete actual data was not yet available. As such, our estimates are based on averages of annual retirements in previous years. We will redo this analysis when actual retirement information for 2018 and 2019 is available, and the final 2019 revenue requirement for GUIC will reflect the impact of these actual retirements.

Given that the GUIC Rider represents a somewhat unique set of circumstances, insofar as it is the only Rider primarily involving the replacement of assets, we have removed the impact of these estimated retired assets from our 2019 GUIC Rider revenue requirement request.[30] Doing so is an effective way to recognize the impact of asset replacements in base rates that have accumulated since we began GUIC work in earnest. The revenue requirement of these assets has become significant primarily due to the passage of time since our last rate case. However, we make this adjustment while also noting that the increased depreciation, and other revenue requirement impacts, from non-GUIC assets added since our last rate case has been greater than the revenue requirement impact of assets retired due to GUIC work.

Removing the impact of these retired assets results in adjustments to the return on the rate base, estimated book depreciation, annual deferred tax, and the estimated property tax included in our requested 2019 GUIC Rider revenue requirement.

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[28] *See* the Company's Reply Comments, Docket No. G002/M-17-787 (July 27, 2018) at page 6.

[29] Our estimate is that the assets, in aggregate, were approximately 69 percent depreciated at the start of the 2010 test year.

[30] This adjustment was included in our revenue requirement for the first time in our 2018 GUIC Rider Filing Reply Comments, in response to Comments from the Department.

Table 1 below shows the derivation of the estimated revenue requirement impact.

Table 1
Revenue Requirement Impact – GUIC Replaced Assets ($ Millions)

Net Book Value of Retired Assets	$3.09
Less: ADIT on Retired Assets	(0.70)
Rate Base	$2.39
Rate of Return on Rate Base	$0.31
Estimated Book Depreciation on Retired Assets	0.30
Annual Deferred Tax Impact	(0.02)
Estimated Property Tax on Retired Assets	0.17
Revenue Requirement Impact	**$0.76**

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 previous GUIC Rider filings.

The Company provides actual and estimated TIMP and DIMP cost data for 2017-2023 in Attachment K. 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 Energy the ability to implement multi-year pipeline-replacement programs, adjusting the rates annually to correct for over- or under-recovery."[31]

F. Deferred Accounting Projects

This rider request includes $4.6 million in previously deferred TIMP and DIMP costs. The Commission previously approved a five-year amortization schedule[32] and 2019 will represent the fifth and final year of amortization. A description of the projects approved for deferred accounting is available in our Annual Reports filed in the deferred accounting dockets.[33] The deferred amounts and five-year amortization are presented in Attachment K.

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[31] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 7.
[32] *Ibid.* at page 8.
[33] *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.

G. Estimated Revenue Requirement for TIMP- and DIMP-Related Activities

Table 2 below presents Xcel Energy's 2019 total estimated revenue requirement of $28.9 million for TIMP and DIMP activities. Capital-related revenue requirements and O&M expenses total $20.2 million and $5.3 million, respectively. Costs associated with the amortization of deferred costs total $4.6 million.[34] O&M totaling $0.5 million of TIMP costs already being recovered in base rates is removed from this rider request. Approximately $0.8 million is also being removed to account for the impact of GUIC-related retirements.

Table 2
2018-2019 Gas Utility Infrastructure Revenue Requirements ($ Millions)

	2018 Original Forecast[35]	2018 Current Forecast	2019 Forecast
Capital-Related Revenue Requirements			
TIMP	10.51	8.47	9.49
DIMP	7.96	5.60	10.76
Total	**18.47**	**14.07**	**20.25**
O&M Expenses			
TIMP	1.33	0.94	2.56
DIMP	3.53	2.91	2.78
Total	**4.86**	**3.85**	**5.34**
5-Year Amortization of Deferred Costs (Years 4 and 5)			
TIMP	0.82	0.82	0.82
DIMP	3.73	3.73	3.73
Total	**4.55**	**4.55**	**4.55**
ADIT Prorate / GUIC Retirement Revenue Credits	0.08	(0.48)	(0.76)
O&M Recovery in Base Rates	(0.48)	(0.48)	(0.48)
Revenue Requirement Subtotal	**27.48**	**21.50**	**28.91**
True-up Carryover	0	(1.63)	0.00
Total GUIC Revenue Requirement	**27.48**	**19.87**	**28.91**

[34] As approved in Docket Nos. G002/M-10-422 and G002/M-12-248.
[35] Forecast shown in Attachment B of the Company's Reply Comments regarding the 2018 GUIC Rider Petition in Docket No. G002/M-17-787.

The Company's 2019 request includes $43 million in capital expenditures, down $4 million from 2018. The increase in DIMP capital-related revenue requirement from 2018 to 2019 is primarily driven by large projects placed in-service late in 2018, which only have a partial year of revenue requirement in 2018 and a full year of revenue requirement in 2019. These large projects include Poor Performing Main Replacements ($1.5 million revenue requirement increase), Poor Performing Service Replacements ($1.0 million), and IP Line Assessments ($2.0 million).

Similarly, the increase in TIMP capital related revenue requirement from 2018 to 2019 is also driven by additions placed in-service late in 2018. The large projects include the Programmatic Replacement/MAOP Remediation project ($0.4 million revenue requirement increase), Transmission Pipeline Assessments project ($0.2 million), and East Metro Replacement Project ($0.1 million).

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 3 below.

Capital expenditure estimates from 2012 through 2023 total $159.3 million for TIMP and $227.9 million for DIMP, reflecting an estimated total of $387.1 million. Distribution mains and services are depreciated using a composite depreciation rate of 2.28 percent and transmission mains are depreciated using a depreciation rate of 1.31 percent. The Company's depreciation calculations assume an average remaining life of 36.79 years[36] and a net salvage rate of negative 22.85 percent for distribution mains and services and average remaining life of 60.44 years[37] and net salvage rate of negative 15.00 percent for transmission mains.

[36] Average service life for distribution mains and services is 50.38 years

[37] Average service life for transmission mains is 75 years.

Table 3
GUIC Capital Expenditures (CWIP only) and Net Salvage: 2012-2023
(In Thousands - $000)

	TIMP			DIMP			Total
Year	Transmission	Distribution[38]	**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	0[39]	10,011	29,021
2016	4,556	14,196	18,752	12,782	445	13,227	31,979
2017	6,191	600	6,791	13,444		13,444	20,235
2018	8,801	(033)	8,768	38,546	-	38,546	47,313
2019	26,763	-	26,763	16,301	-	16,301	43,064
2020	34,347	-	34,347	16,886		16,886	51,233
2021	2,677	-	2,677	42,881	0	42,881	45,558
2022	5,456	-	5,456	43,469		43,469	48,925
2023	15,403	0	15,403	32,427	0	32,427	47,830
Total	**105,404**	**53,849**	**159,253**	**227,413**	**445**	**227,859**	**387,112**
Salvage Rate[40]	(15.00%)	(22.85%)		(22.85%)	0.00%		
Net Salvage	**(15,811)**	**(12,304)**	**(28,115)**	**(51,964)**	**-**	**(51,964)**	**(80,079)**

I. Gas Utility Projects

1. TIMP

TIMP is an ongoing program and will continue in 2019 and beyond. Further, PHMSA is currently working to address a number of Congressional mandates and National Transportation Safety Board (NTSB) recommendations that will likely

[38] 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 installed is considered distribution plant from a regulatory accounting perspective.
[39] 2015 amount has been adjusted from what was reported in our 2017 GUIC Rider Petition (Docket No. G002/M-16-891). Expenditures of $49,945 that should have been assigned to another affiliated Operating Company were inadvertently included in the numbers for NSPM.
[40] Depreciation lives and salvage rates approved in Docket No. E,G002/D-17-581. These percentages can be found in Attachment L.

increase and clarify compliance standards for pipeline operators beyond the current TIMP rules. A number of new regulatory requirements are forthcoming that impact the Company's obligations and required work activities to safely maintain and operate the gas system. These include:

- Safety of Gas Transmission and Gathering Pipelines[41] - This set of new regulatory requirements 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 2016, with an estimated final rule publication date in 2019;
- Operator Qualification, Cost Recovery and other Pipeline Safety Proposed Changes Plastic Pipe Rupture Detection and Valve Rule[42] - The final rule publications occurred 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 automatic shutoff valves or remote controlled valves 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[43] 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. 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.

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41 https://www.phmsa.dot.gov/regulations-fr/rulemaking/2016-11240.

42 https://www.phmsa.dot.gov/regulations-fr/rulemaking/2016-31461.

43 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.

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

We expect to continue spending related to compliance activities in the following areas 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 $2.5 million and $7.1 million depending on the specific segments being assessed. The costs incurred will likely be a combination of capital expenditures and O&M expenses, depending on the type of work being performed.

The forecasted capital and O&M costs for assessments included in our last four GUIC are shown in Table 4 below.

Table 4
GUIC Transmission Pipeline Assessments[44]
(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 (17-787)	20.9	$0.3	$1.5
2019 (18-___)	15.8	$1.0	$2.9

As shown in Figure 3 below, the Company expects to complete three second-run ILI projects, one hydrostatic pressure test project, and one derate project in 2019. [45] Hydrostatic pressure tests utilize liquid to aid in visual leak detection. This is the first instance in which a hydrostatic pressure test has been selected as an IP Assessment method for a DIMP project as part of the Company's GUIC. Other assessment methods are not practical for this project since this line is located under the Mississippi River. Based on the current assessment plan, the Company expects to complete between three to five projects each year through 2022.

Figure 3

Transmission Integrity Assessments						
NSPMN: 2015-2019 Number of Projects						
	2015	2016	2017	2018	2019	Total
ILI	0	0	2	3	3	8
Pressure Test	2	1	0	0	1	4
Derate	0	0	0	0	1	1
Direct Assessment	1	0	0	0	0	1
Total	3	1	2	3	5	14
NSPMN: 2015-2019 Mileage						
	2015	2016	2017	2018	2019	Total
ILI	0	0	7.8	20.6	9.7	38.1
Pressure Test	3.1	0.1	0	0	0.3	3.5
Derate	0	0	0	0	5.8	5.8
Direct Assessment	6.5	0	0	0	0	6.5
Total	9.6	0.1	7.8	20.6	15.8	53.9

44 Assessment methods include ILI, pressure testing, and direct assessments. The Company's costs and mileage amounts included in the 2016, 2017, and 2018 GUIC Filings differ from actual and forecasted amounts as a result from program modifications approved through the RRC.
45 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.

a. Automatic Shutoff Valves and Remote Controlled Shutoff Valves

The automatic shutoff valve and remote controlled shutoff valve installation project began in 2015 and we expect it to continue through 2021. We anticipate the associated capital expenditures for installations to range from $0.5 - $1.0 million per year. The Company continues to evaluate 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[46] 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 assessment will drive the overall scope and timing of these capital expenditures. In 2017, the Company entered the pre-work phase of the initiative for several transmission line replacement projects with the highest risk factors and completed the design and engineering work as well as right-of-way and easement acquisitions. Construction activities began on several projects in 2018, after the pre-work for the projects was completed. For other projects pre-work is taking place during 2018, with construction starting in 2019. These schedules are subject to change based on results from transmission pipeline assessment activities. Annual expenditures for this program will span from a low of $15 million[47] to a high of $32 million, based on the respective construction schedules for these projects.[48]

c. TIMP Summary

The Company has made significant progress in improving the safety and reliability of its pipeline system, but work is still needed. 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 Attachments C and C1, TIMP Overview and Project Detail.

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[46] MAOP verification and testing for transmission pipelines were initially defined in the Pipeline Safety Act of 2011.
[47] Expected to take place in 2023.
[48] This program does not have capital expenditures planned in 2021 and 2022.

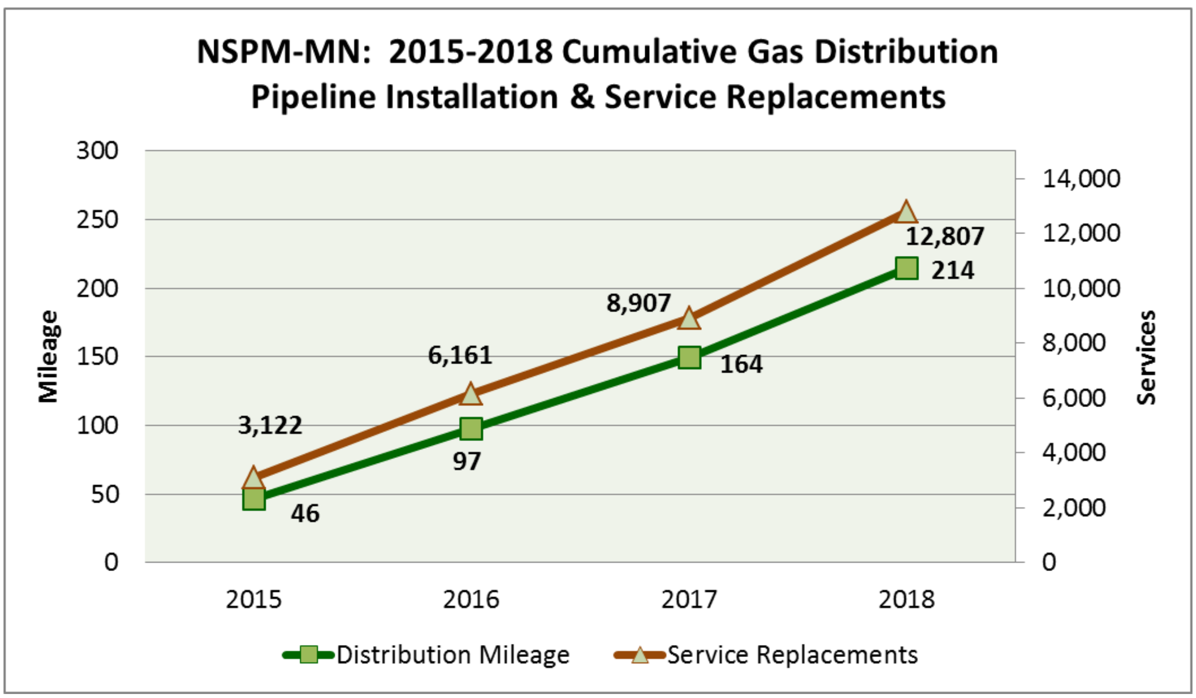
2. *DIMP*

a. Poor Performing Main and Service Replacement

Under 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. 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.

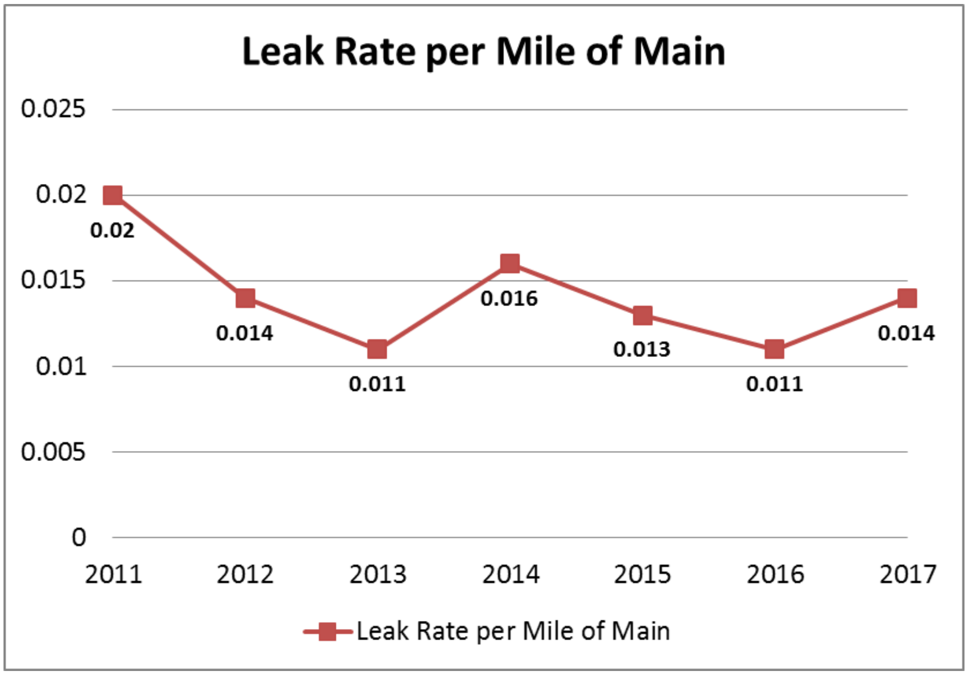
The poor performing main and service replacement projects are multi-year initiatives. Future capital expenditures associated with poor performing mains are estimated at $11 million annually, while the poor performing services investment is estimated at $7 million annually. Both projects will require design and construction resource procurement and deployment. The Company does not expect to incur significant O&M costs for the project as the costs of service transfers are a capital cost when the transfer is completed as the result of, and in conjunction with, another capital project. Figure 4 illustrates the extent of the Company's integrity-related main and service distribution replacement work:

Figure 4



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 5 reflects leak data submitted to the DOT for the years 2011-2017:

Figure 5
Distribution Mains Leak Rate



As evidenced in Figure 5, the performance of the Company's distribution system has gradually improved, as measured by an overall declining leak rate per mile of main from 2011 to 2017. 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

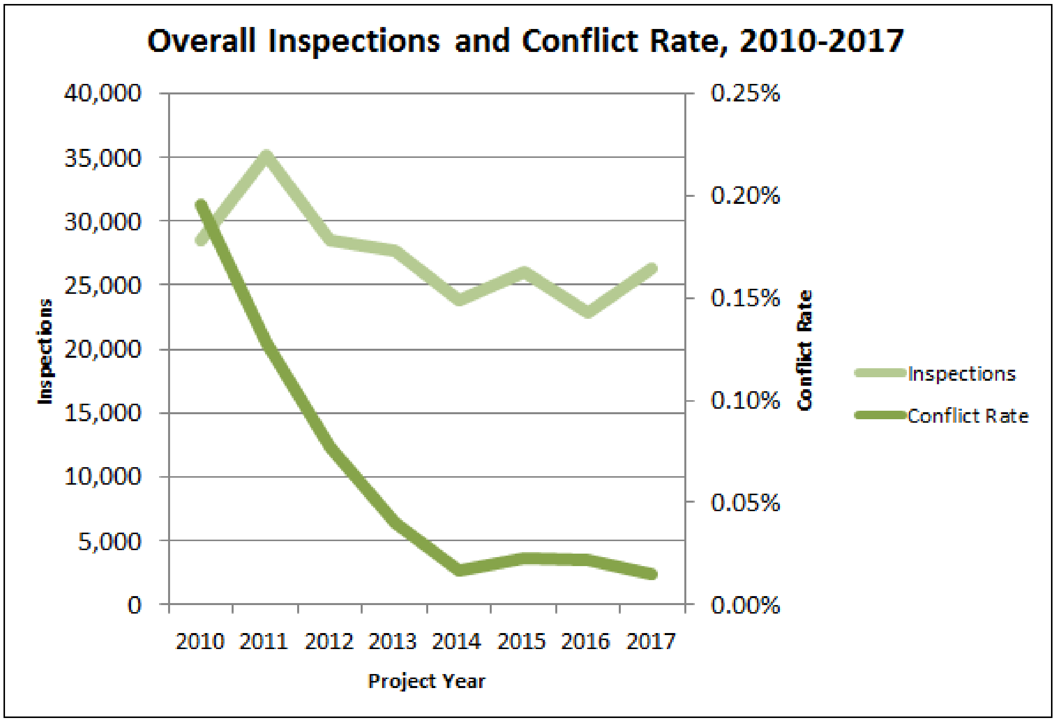
DIMP projects focused on distribution valves and pipeline data are reaching the end of their planned duration. The Company completed the pipeline data project in 2015 and installation of new valves in 2016. Some replacement valve work has continued, but is expected to conclude in 2018

c. Sewer and Gas Line Conflict Remediation

This program was developed in response to a 2010 incident when a sewer cleaning contractor working in Saint Paul perforated a natural gas main that intersected the sewer line, resulting in a fire, property damage, and injury. The risk associated with a sewer conflict is considered to be a low probability but a high consequence. Pursuant to this program, the Company has inspected sewer lines and remediated instances of gas line conflicts since 2010. Based on the number of conflicts found during the initial three years of inspections 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 2018, the Company expects to have performed roughly 188,000 sewer line inspections. Through August 2018, a total of 153 conflicts have been identified and cleared. Figure 6 illustrates the progress of the Company's Sewer and Gas Line Inspection Program between 2010 and 2017.

Figure 6



As shown in Figure 6, the conflict rate has decreased steadily from 0.20 percent in 2010 down to 0.02 percent in 2017. The Company reviews the results of the program every year to determine whether the program should continue. Due to the decrease in conflicts discovered, the Company has reduced the annual scope of this program from \$3.5 million for 18,880 inspections in 2017, down to \$2.3 million for 12,000 inspections in 2018, a \$1.2 million annual reduction. In 2019, the final year of planned legacy inspections, the Company will inspect 12,000 services. The Company continues to believe conflict threats exist with sewer laterals and will monitor the program and re-evaluate the potential conclusion of the program as additional conflict information is assessed.

d. Distribution Pipeline Inspection and Replacement

Distribution pipeline inspections, or IP line assessment is an ongoing program, that involves the regular inspection and replacement of high- and medium-risk segments of pipeline to satisfy the federal pipeline safety regulations set forth by PHMSA rules.[49] The asset health data collected from these inspections will be used to develop plans for additional mitigation actions as needed to protect public safety.

As shown in Figure 7, the Company expects to complete two Direct Assessment projects with validation digs and a hydrostatic pressure test project in 2019. Since the GUIC was established in 2015, the Company has assessed a total of 58.6 miles. Based on the current plan, the Company expects to complete between three and five projects annually through 2022.

Figure 7

Distribution Integrity Assessments						
NSPMN: 2015-2019 Number of Projects						
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
ILI	0	0	0	0	0	0
Pressure Test	0	0	0	0	1	1
Direct Assessment	0	2	1	2	2	7
Total	0	2	1	2	3	8
NSPMN: 2015-2019 Mileage						
	2015	**2016**	**2017**	**2018**	**2019**	**Total**
ILI	0	0	0	0	0	0
Pressure Test	0	0	0	0	2.4	2.4
Direct Assessment	0	30.7	11.1	5	9.4	56.2
Total	0	30.7	11.1	5	11.8	58.6

Future costs associated with distribution pipeline inspections and replacement could vary between $1 million and $28 million annually, depending on the specific pipeline segments being assessed and/or replaced. In years where the Company is focusing large-scale replacement efforts in its TIMP Programmatic Replacement/MAOP Remediation Program, capital investments in IP Line Assessment and Replacements could be minimal.

e. Federal Code Mitigation

Federal code mitigation began in 2016. Over time, as the federal code[50] governing the operation and maintenance of the gas system has changed the Company's standards

[49] *See* 49 CFR Part 192.921 (a). The rule requires an operator to 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.

and compliance manual has 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. This project is expected to conclude in 2018.

f. Excess Flow Valves

PHMSA rules[51] require all gas utilities to install excess flow valves on new or replaced gas service lines.[52] Further, the rules also require utilities to install an excess flow valve on existing gas service lines in the event that a customer requests one. In compliance with these rules, the Company has installed excess flow valves on all new and replaced lines since the implementation of these rules. For services that have been replaced as a part of the programmatic service replacement GUIC project, the costs of installing excess flow valves on these services have been recovered through our GUIC Rider revenue requirement.

Earlier this year, the Commission opened an investigative docket to gather information as to how each gas utility in Minnesota was responding to the PHMSA requirements. After gathering this information, the Commission ordered each utility to develop a plan to have face-to-face meetings with decision-makers at schools, universities, hospitals, apartment buildings, and other large public facilities to notify them of the purpose of excess flow valves and manual service line shutoff valves and the Company's installation installation policy and costs.[53]

The Company is currently in the process of developing its meeting plan and will submit this to the Commission in December 2018. We do not have any costs for this meeting plan reflected in our 2019 GUIC Rider filing, but as acknowledged by the Commission's Order, the Company may request recovery of these costs through a future GUIC Rider filing.

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50 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.

51 49 CFR Part 192.383

52 An EFV is a safety device installed inside a natural gas service line near its connection with the gas main that will shut off the flow of gas automatically in the event of a gas line break or other damage that severs a service line.

53 *See* Order Finding that Excess Flow Valves Comply with Federal Regulations and Taking Other Actions, Order Point 7, Docket No. G999/CI-18-41 (August 20, 2018).

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

On December 6, 2010, the Company's most recent gas general rate case was approved by the Commission.[54] 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 unadjusted sales forecast based on a proposed 2019 GUIC rate generates $28.9 million of GUIC-related revenues in 2020. The GUIC revenue estimates reflect 18.2 percent of the base revenues of $159.10 million approved in the previous general rate case. For more details on the expected 2019 revenues, please reference Attachment M. In addition, Attachment N shows our 2017 GUIC Rider recovery, gas base rate recovery, and purchased gas adjustment (PGA) in comparison to amounts reported in our 2017 Minnesota Jurisdictional Gas Annual Report.[55]

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

A. Calculations for Revenue Requirements and Proposed 2018 GUIC Rate Adjustment Factors

In this section, we provide the 2019 revenue requirement and 2019 rate adjustments factor calculations for the proposed GUIC.

1. Revenue Requirements

The projected GUIC revenue requirements for 2017 through 2023 are summarized in Attachment O to this filing. The projected 2019 revenue requirements proposed for recovery through the 2019 GUIC adjustment factors from Minnesota gas customers are approximately $28.9 million. The supporting revenue requirements and projected 2017-2023 GUIC Tracker activity are provided in Attachment P. In addition, the eligible revenue requirements also include property taxes, current and deferred taxes, and book depreciation. Attachments G and H summarize the projected revenue requirements for the TIMP and DIMP projects respectively. Attachment Q provides descriptions of the rate base and return calculation categories included in Attachments G and H.

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[54] See Docket No. G002/GR-09-1153.

[55] Filed in Docket No. E,G999-PR-18-4.

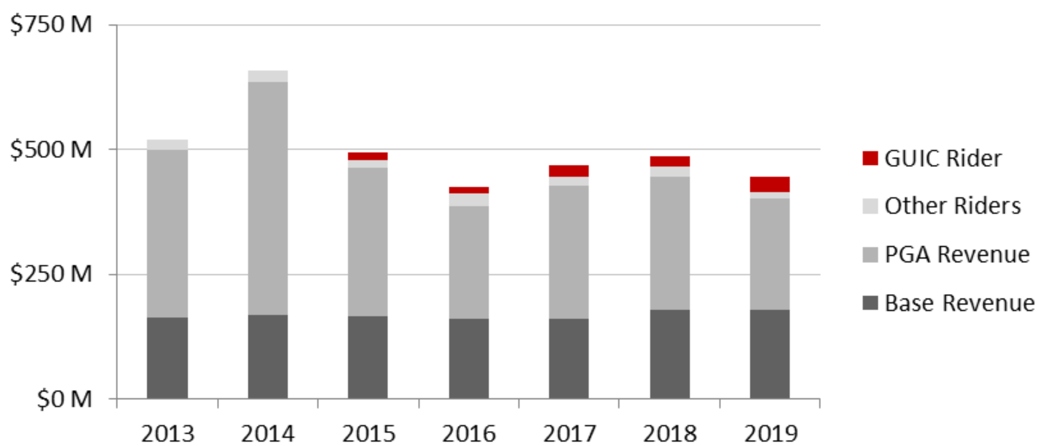
2. GUIC as a Part of Overall Gas Utility Recovery

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,
- PGA revenues, and
- GUIC Rider annual revenue requirement,

To provide context as to how the GUIC Rider fits into the Company's total gas utility recovery, Figure 8 below shows the total gas utility revenue collections by recovery mechanism, split among Base Rates, PGA, and GUIC.

Figure 8
Annual Revenue Collections by Recovery Mechanism



GUIC % of Total	0.0%	0.0%	2.8%	3.0%	4.6%	4.3%	6.5%
Earned ROE	9.76%	9.08%	9.71%	8.12%	9.16%		

GUIC represents 6.5 percent of total bill collections forecasted in 2019. We also provide the earned ROE as reported in our jurisdictional annual reports. The reported earned ROEs include 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 and we have continued to not earn our authorized gas rate of return on equity.[56]

3. Proposed 2018 Rate and Carryover Balance

As of the filing date in this docket, the Company's 2018 GUIC Rider Petition[57] is still open in front of the Commission. The factors currently in place are collecting the 2017 revenue requirement, per the Commission's Order in the 2017 GUIC Rider Petition.[58] We recognize that the Commission's decision on our 2018 GUIC Rider Petition will inform us on the level and timing of possible recovery for our 2018 request. For illustrative purposes in this docket, we have assumed a rate that will collect the 2017 carryover balance and 2018 revenue requirements from March 2019 through December 2019 (see rate factors below), in order to mitigate the impact of a large carryover balance in 2019 rates.

4. Accumulated Deferred Income Tax (ADIT) Prorate

For the purposes of this filing, the Company presents actual ADIT for the historic calculations in 2017 and the actual months of 2018. The Company calculated the forecasted portions of 2018 and 2019 revenue requirements utilizing the new methodology for the proration of ADIT that was initially proposed in our Reply Comments in the 2018 GUIC Rider filing.[59] This new methodology is in accordance with our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6).[60] Implementing this new methodology results in an ADIT prorate adjustment that has very little impact to customer rates, but still meets IRS regulations for deferred tax benefits.

The Company took steps to evaluate this topic in significant depth and explore what alternative treatments could be applied across all of the Company's open rider proceedings so as to minimize the customer impact while still maintaining the significant deferred tax benefits provided to customers. The Company engaged Deloitte Tax to evaluate rider calculations and propose any further optimizations that could be applied. Based on recent IRS guidance, Deloitte Tax along with our tax experts developed the following proposal:

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[56] Please reference Page 35 of our 2017 Minnesota Jurisdictional Gas Annual Report. Our earned return on equity for 2017 was nearly 1 percent lower than the authorized return on equity of 10.09 percent.
[57] Docket No. G002/M-17-787.
[59] *See* Reply Comments, Pages 22-23, Docket No. G002/M-17-787 (July 27, 2018).
[59] *See* Reply Comments, Pages 22-23, Docket No. G002/M-17-787 (July 27, 2018).
[60] A technical description of this issue can be found in Docket No. E002/GR-15-826, Exhibit___(LHP-1), pages 53-56.

1. Apply a mid-month convention for the proration factors in each of the monthly revenue requirement calculations.
2. Remove ADIT from the beginning-of-month and end-of-month rate base average, since the proration is itself a form of averaging.

The impact of the new ADIT prorate methodology on TIMP projects is $86, and the impact on DIMP projects is $102. The calculation of these impacts can be found in Attachment R to this petition. Application of this new ADIT prorate methodology has also been proposed by the Company in its Transmission Cost Recovery, Renewable Energy Standard, and State Energy Policy Rider dockets, with similar de minimis impacts on customer revenue requirements.

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 2019 revenue requirement is allocated to class in the same manner as revenues were apportioned in our most recent natural gas rate case,[61] consistent with the Commission's 2015, 2016, and 2017 GUIC Rider orders.

Proposed class factors are calculated by dividing the class revenue responsibility by the forecasted Minnesota unadjusted sales for the recovery period and include the GUIC Rider adjustment factor as part of the Resource Adjustment line on customer bills. The 2019 GUIC adjustment factor calculation is shown in Attachment S. Table 5 below shows the currently approved GUIC adjustment factors, 2018 pending factors assumed in this docket, and proposed 2019 factors.

Table 5
Proposed 2019 GUIC Adjustment Factors
(Dollars per therm)

	Current Factors	2018 Factors*	2019 Proposed Factors**
Residential	$0.027634	$0.055641	$0.051938
Commercial Firm	$0.015080	$0.029202	$0.027807
Commercial Demand Billed	$0.011332	$0.018960	$0.020294
Interruptible	$0.008114	$0.013980	$0.015563
Transportation	$0.003287	$0.002646	$0.003889

* Assumes the 2018 revenue requirement is recovered March 1, 2019 through Dec. 31, 2019.
**Assumes 2019 proposed revenue requirement is recovered January 1, 2020 through Dec. 31, 2020.

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

The residential bill impacts under each factor are listed in Table 6:

Table 6
Monthly Residential Bill Impacts

	Current Factors	2018 Factors	2019 Proposed Factors
Current Monthly Bill Impact / Change In Impact	$2.00[62]	$2.03	$(0.27)
Bill Impact Change as % of Total Bill		4.0%	(0.5)%

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 Rider filing, 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."[63] The Commission also approved the same methodology for the Company's customer class allocation in its 2016 and 2017 GUIC Rider filings.

B. Timing of 2019 GUIC Factor Implementation

We request approval to implement GUIC Rider factors in this annual report, effective January 1, 2020, pending review and approval by the Commission. The factor calculations assume that the 2018 costs are recovered using the 2018 factors shown above starting March 1, 2019 through December 31, 2019, and the proposed 2019 factors effective January 1, 2020 through December 31, 2020.

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.

The current forecast test period of the GUIC Rider has been beneficial in providing current recovery for timely safety investments. However, the length of regulatory review of our past two GUIC Rider filings has caused a delay in recovery. As this filing continues to grow larger and more complex, it stands to reason that the need for a lengthy review process will continue. While this is understandable, protracted filings

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[62] Based on current Residential bill factor.
[63] *Ibid.* at page 12.

and delayed recovery puts financial pressure on the Company when making these important GUIC investments. As such, the Company has proposed a January 2020 start to our 2019 GUIC Rider recovery in order to allow for regulatory review and potential recovery of our 2018 request, but in conjunction with this voluntary delay, the Company is asking to include a carrying charge in our revenue requirement calculation. Our proposal is to use the Company's current weighted average cost of capital on our monthly unrecovered GUIC Rider recovery tracker balance starting in January 2020.

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. Differences in revenue requirements from forecast to actual amounts are also recorded in the tracker. 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 2018 are shown on Attachment S within the carryover rollforward section.

In the Department's July 2, 2018 Comments in our 2018 GUIC Rider filing, the Department recommended that Xcel present a GUIC Rider tracker that combines information presented in Attachments O and Q of our past rider filings. In response to the Department's request, we provide Attachment T, a tracker that presents revenue requirement, rates, and recoveries within the same page in order to provide stakeholders and the Commission a better understanding of how the GUIC revenue requirement is recovered via the rider.

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 U.

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."[64]

In this Petition, the Company supports the capital structure and cost of debt agreed to in the settlement of our 2016 Minnesota Electric General Rate Case.[65] For 2019, the settlement parties agreed that the capital structure should be represented by:

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[64] Minn. Stat. § 216B.1635, Subd. 6. The Commission authorized a return on equity of 10.09 percent in our last general rate case.

[65] *See* Findings of Fact, Conclusions, and Order, Docket No. E002/GR-15-826 (June 21, 2017) at page 11.

1. a cost of long-term debt of 4.75 percent;
2. a cost of short-term debt of 4.31percent; and
3. an overall ROR of 7.08 percent.[66]

The Company retained an independent expert, Concentric Energy Advisors (Concentric), to assess the appropriateness of our proposed use of a 10.25 percent ROE in the calculation of ROR for the 2019 GUIC revenue requirement. Concentric prepared a report of their assessment, which can be found as Attachment V to our Petition. The use of a 10.25 percent ROE results in an overall ROR of 7.63 percent.

Concentric considered three commonly-used ROE estimation models to assess the reasonableness of our proposed 10.25 percent ROE:

1. Constant Growth Discount Cash Flow (DCF) model,
2. Capital Asset Pricing Model (CAPM), and
3. Risk Premium model.

Utilizing the results of multiple analysis methods to assess a proposed ROE is a proper way to mitigate potential anomalous market conditions that may skew the results of any single ROE calculation and result in incongruous ROE results. The Commission has recognized the need to use multiple analysis methods when assessing ROE proposals. In their most recent Orders for both Minnesota Power and Otter Tail Power Company, the Commission relied on the results of multiple methods[67] to check the reasonableness of the results of the DCF model.

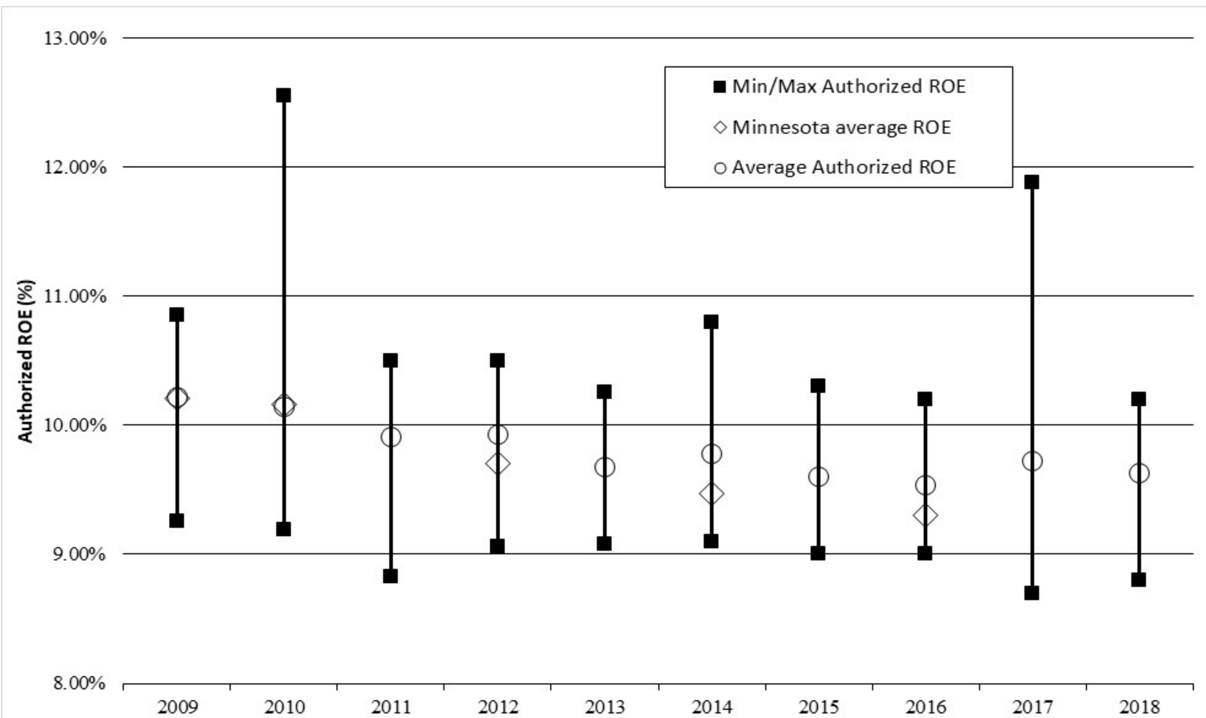
The need for multiple analysis methods is crucial at this time as traditional ROE estimation methods are currently being distorted toward unreasonably low ROE estimates. Current dividend yields for utility companies are well below historical levels. That, in turn, results in a DCF model that produces depressed ROE results. In addition, it is expected that interest rates will increase over the time the GUIC Rider will be in effect, which will result in an underestimation of the expected ROE using the DCF model. 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 impact on future results, especially in a period where interest rates are expected to increase in the long term future.

In addition to using multiple analysis methods to assess our proposed ROE, Concentric also considered authorized ROEs for gas distribution companies in other

[66] Overall ROR was based on a common equity cost (i.e. ROE) of 9.20 percent.
[67] Risk Premium and CAPM.

jurisdictions. In order to maintain investments in Minnesota as an attractive option, it is important for Minnesota Gas investments to avoid being placed at the low end of authorized ROEs, both within Xcel Energy and the market as a whole. Figure 9 below shows a comparison of the average authorized ROEs in the state of Minnesota in comparison to those in other markets. Overall, authorized ROEs in Minnesota have been trending downward since 2009. Authorized ROEs in Minnesota tend to be lower than the authorized ROEs in the United States utility market. In addition ROEs authorized in Minnesota tend to be significantly lower than the maximum authorized ROEs.

Figure 9
Comparison of Minnesota and United States Authorized Gas Utility ROEs



The Company's gas utility completes for capital both within Xcel Energy's overall capital structure and in the utility investment market as a whole. Xcel Energy will naturally focus capital investments in the jurisdictions that offer the most advantageous return opportunities. Being at the low end of investment opportunities with our corporate structure and the utility market will hamper the Company's ability to access capital for necessary construction and raise the cost of project financing.

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 7.63 percent ROR is:

1. expressly authorized by statute,
2. consistent with comparable utility proxy groups, and
3. 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.

VII. PROPOSED GUIC METRICS

In its August 18, 2016 Order,[68] 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.*

In compliance with that Order, the Company submitted a supplemental filing in our 2017 GUIC Rider filing, which included a proposal for GUIC metrics.[69] Before submitting this proposal, the Company engaged with stakeholders to gather input on the proposed metrics. The same proposed metrics were included in our 2018 GUIC Rider request.[70]

In its February 8, 2018 Order,[71] the Commission declined to adopt our proposed metrics. They went on to state that:

> *Xcel shall continue to discuss with other parties, including the Department and the [Minnesota Office of Attorney General] OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GUIC proceedings.*

[68] Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808.
[69] *See* Supplement and Compliance Metrics Proposal, Docket No. G002/M-16-891 (January 13, 2017)
[70] *See* Petition, Compliance Filing, and Annual Report, Page 42, Docket No. G002/M-17-787 (November 1, 2017).
[71] *See* Order Approving Rider with Modifications, Docket No. G002/M-16-891 (February 8, 2018).

The Company met on September 26, 2018 with stakeholders from the Commission, the Department, MNOPS, and OAG, to continue the discussion of metric to gauge GUIC operations. While we did not reach a consensus as to what metrics should be used to measure the GUIC, it was a fruitful meeting.

Based on dialogue with stakeholders, the Company modified the presentation of our proposed metrics to include additional information about gas transmission anomalies, broken down by type of anomaly repair. In addition, we have agreed to share additional metrics related information and data with the stakeholders to help them better understand our metrics proposals. Please reference Attachment W for a full review of the TIMP and DIMP objectives and the current results of the performance.

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 2018 investment that has not yet been recovered and outline our proposal to recover the 2019 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 2018 GUIC Rider factors and proposed 2019 GUIC Rider factors.

Dated: November 1, 2018

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Vice-Chair
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 2018, REVENUE REQUIREMENTS FOR 2019, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-18-____

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 2019 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 2018 GUIC adjustment factors, 2019 GUIC adjustment factors, and its proposed capital structure and ROE for 2019.

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.	**Filing Date** November 1, 2018 **Proposed Implementation Date (Petition, Section II.C.)** January 1, 2020 **Number of Days in Advance** 426 **Forecast Period** January 1, 2019 – December 2019
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.	**TIMP** – Attachments C,C1 **DIMP** – Attachments D,D1
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:	**Filing Date** November 1, 2018 **Previous Filing Date** November 1, 2017

Compliance Matrix

Petition Requirements	Reference
(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;	**TIMP** – Attachments C,C1 **DIMP** – Attachments D,D1
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	**TIMP** – Attachment C1 **DIMP** – Attachment D1
(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 J
(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;	**TIMP** – Attachment C **DIMP** – Attachment D
(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;	Section IV.A. Section V.A. Attachments F,G,H,K,O,P,Q,R,S
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	**TIMP** – Attachment C1(a) and Attachment F **DIMP** – Attachment D1(a) and Attachment F
(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 M
(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 M
(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.B. Sections IV.A.,D.,J. Sections V.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, unless the commission determines that a different rate of return is in the public interest.	Section III.C. Section VI. Attachment V

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 No. 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.	Section IV.C.4. 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 Sections 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
E. Discussion, analysis, and documentation demonstrating that plan costs were prudent.	Sections III.B.4., IV.C.4 Attachment I
F. Analysis of what it would have cost to conduct the plan over a ten-year period beginning in 2003.	Sections III.B.4., IV.C.4 Attachment I

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company for Approval of Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs **Minnesota Public Utilities Commission** ORDER **January 28, 2013 Docket No. G002/M-12-248**	
1.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.	Section III.B.4. No gas general rate case since Order was issued
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 No. G002/M-15-808**	
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 Section VII. Attachment W

Compliance Matrix

<table>
<tr><th>Petition Requirements</th><th>Reference</th></tr>
<tr><td>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.</td><td>Current Petition
Section IV.I.2.e.
Attachment D</td></tr>
<tr><td>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.</td><td>Compliance Submitted
August 29, 2016
Docket No. G002/M-15-808

Current Petition
Section V.D.2.</td></tr>
<tr><td>**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 2016, Forecasted 2017 GUIC Revenue Requirement, and Revised GUIC Adjustment Factors**

Minnesota Public Utilities Commission
ORDER APPROVING RIDER RECOVERY WITH MODIFICATIONS

February 8, 2018 Docket No. G002/M-16-891</td><td></td></tr>
<tr><td>1. The Commission approves Xcel's proposed GUIC-rider tariff sheets, modified to reflect the decisions made in this order.</td><td>Compliance Submitted
February 20, 2018
Docket No. G002/M-16-891</td></tr>
<tr><td>2. The Commission approves a revised capital structure with a return on equity of 9.04% and an overall rate of return of 7.02%:

<table><tr><th></th><th>Capital Structure</th><th>Cost</th><th>Weighted Cost</th></tr><tr><td>Long-term Debt</td><td>45.61%</td><td>4.94%</td><td>2.25%</td></tr><tr><td>Short-term Debt</td><td>1.89%</td><td>1.12%</td><td>0.02%</td></tr><tr><td>Common Equity</td><td>52.50%</td><td>9.04%</td><td>4.75%</td></tr><tr><td>Total</td><td>100.00%</td><td></td><td>7.02%</td></tr></table></td><td>Compliance Submitted
February 20, 2018
Docket No. G002/M-16-891</td></tr>
</table>

Compliance Matrix

Petition Requirements	Reference
3. The Commission approves $444,543 in DIMP software costs for recovery in the GUIC rider and disallows rider recovery of QA/QC-related costs as duplicative services.	Compliance Submitted February 20, 2018 Docket No. G002/M-16-891
4. The Commission accepts Xcel's cost/revenue study as complying with ordering paragraph 11 of the Commission's August 2016 order.	Section IV.J. Attachment N
5. Xcel shall continue to discuss with other parties, including the Department and the OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GIUC proceedings.	Meeting with Stakeholders hosted by Department of Commerce on September 26, 2018 Section VII. Attachment U
6. Xcel shall continue to provide, in future GUIC filings, 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., IV. Attachments C,C1,D,D1
7. The Commission denies Xcel's proposed accumulated deferred income tax (ADIT) proration for the forecasted year in the instant petition, and instead determines that the Company's 2017 GUIC rider must not be effective prior to January 1, 2018.	Compliance Submitted February 20, 2018 Docket No. G002/M-16-891 Current Petition Section V.A.4. Attachment R
8. The Commission approves a revised sales forecast based on the Company's regression model results before monthly sales and demand-side management (DSM) adjustments as set forth by the Company in Attachment F of its reply comments for the 2017 GUIC rider.	Section V.A.5. Attachment S
9. The Commission approves recovery of sewer conflict inspection program costs in the 2017 GUIC rider.	Sections III.B.4., IV.C.4 Attachment I
10. Xcel shall provide a cost/benefit analysis in its initial petition in future GUIC rider filings if the Company wishes to receive accelerated recovery of sewer lines costs on a going forward basis.	Sections III.B.4., IV.C.4 Attachment I

Compliance Matrix

Petition Requirements	Reference
12. Xcel is authorized to recover the 2017 revenue requirements over the 12 months following the effective date of this order.	Compliance Submitted February 20, 2018 Docket No. G002/M-16-891
13. Within ten days, Xcel shall make a compliance filing showing the final rate adjustment factors, effective dates, and all related tariff changes.	Compliance Submitted February 20, 2018 Docket No. G002/M-16-891

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Attachment	Item
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B	Index of Attachments
C	TIMP Project Overview
C1	TIMP Project Detail
C2	TIMP Quantitative Risk Assessment Scores
D	DIMP Project Overview
D1	DIMP Project Detail
D2(a)	DIMP Quantitative Risk Assessment Scores
D2(b)	DIMP Replacements Risk Assessment Scores
E	Minnesota Statute § 216B.1635
F	Capital TIMP and DIMP Expenditures Actual and Forecast Through 2023
G	TIMP Capital Revenue Requirements for 2017-2020
H	DIMP Capital Revenue Requirements for 2017-2020
I	Cost Comparison of Using Contractor vs. In-House Workforce and Equipment for Sewer Inspection
J	Calculation of Estimated Annual GUIC Related Retirements for 2010-2019
K	TIMP and DIMP O&M Budget Estimates for 2017-2023 and Cost Data for Previous Years
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Attachment	Item
M	Magnitude of GUIC in Relation to Most Recent Natural Gas Rate Case Docket No. G002/GR-09-1153
N	Cost/Revenue Reconciliation to 2017 Jurisdictional Annual Report
O	Annual Revenue Requirements Tracker Summary for 2017-2020
P	Revenue Requirements Monthly Tracker for 2017-2020
Q	TIMP and DIMP Revenue Requirements Category Descriptions
R	Accumulated Deferred Income Tax (ADIT) Prorate Calculation
S	GUIC Rate Factor Calculation for 2017-2020
T	Carryover Rollforward
U	Proposed Tariff Sheet No. 5-64 Revisions: Redline and Clean
V	Return on Equity (ROE) Analysis
W	Performance Metrics

Transmission Integrity Management Program
Overview and Project Detail

I. TIMP OVERVIEW

Our Transmission Integrity Management Program (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, we 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:

1) understand your assets,
2) risk evaluation, and
3) risk mitigation.

Our 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 and ongoing integrity 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 installation location of the gas transmission assets is also important, including class location, geotechnical data and structures in the area.

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 population density, 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[1] receiving the highest priority. Pipeline asset information from existing records, operating data, and input from subject matter experts (SMEs) is initially used 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 condition and physical characteristics of its gas assets, along with industry guidance and directives, are incorporated into risk evaluations 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

The Pipeline Safety Action Plan[2] issued by the DOT in 2011 called for gas system operators to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of natural gas facilities. We integrate the results from our risk

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[1] Known as high consequence areas (HCA).
[2] http://opsweb.phmsa.dot.gov/Pipelineforum/dot-action/index.html.

evaluation processes into determining planned risk mitigation activities. Typical risk mitigation measures include excavation of the pipeline, repair or complete removal of the anomaly, and reducing the operating pressure of the system.

In direct support of the DOT's call to action, the Company evaluated both the the Montreal South and Island South pipelines. After the health assessment of the lines, the decision was made 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. Replacement also 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 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 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 become effective until mid to late 2019.

The potential specific IM requirement changes include:

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

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 IM program, the Company has identified different risk mitigation strategies intended to reduce the likelihood of consequences posed by threats.

The 2017-2019 TIMP project detail is presented in Attachment C1and the risk assessment scores for 2019 TIMP projects are presented in Attachment C2.

II. 2019 TIMP PROJECTS

In this filing, the Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with three 2019 TIMP programs:

2019 Estimated TIMP Project Costs
($ Millions)

Program	2019 Capital[3]	2019 O&M
Transmission Pipeline Assessments	$1.01	$2.90
ASV/RCV	$0.75	$0.00
Programmatic Replacement / MAOP Remediation	$26.36	$0.00
TOTAL 2019 TIMP Capital Expenditures and O&M	**$28.12**	**$2.90**
TOTAL 2019 Minnesota TIMP Revenue Requirements	**$9.49**[4]	**$2.56**[5]

3 Estimated capital costs include estimated removal costs.
4 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.
5 $480,000 of O&M amount is recovered through base rates and is removed from our GUIC revenue requirement.

These projects were included in the Company's 2015 through 2018 Gas Utility Infrastructure Cost (GUIC) Rider petitions.[6] Projects planned for completion in 2019 and outlined below will begin during the 2nd and 3rd quarters of 2019 and will be placed in service during the 3rd and 4th quarters of 2019.

1) Transmission Pipeline Assessments
Work Breakdown Structure (WBS):[7] E.0000018.052, E.000004.019, E.000009.018 (Capital); A.0008610.004.002.002 (O&M)

2019 Estimated Project Costs
$1.01 million Capital expenditure
$2.90 million O&M expenditure

Project Summary and Scope
This project is an ongoing program, beginning in 2002, of health and condition assessments on gas transmission lines. Federal regulations require assessment of gas transmission pipelines using In Line Inspection (ILI), pressure testing or direct assessment.[8] 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,[9] 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.[10]

The Company has selected ILI as the primary 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

[6] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, and G002/M-17-787.
[7] WBS has replaced the parent project number given for projects in previous versions of our GUIC filing. This switch in numbering has been due to a change in our work and asset management system. The previously-used parent projects generally correspond with one WBS.
[8] The requirements are further defined in the Company's TIMP manual.
[9] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012.
[10] This standard is incorporated by reference into 49 C.F.R. § 192, Subpart O.

methodologies, the Company may choose to utilize direct assessment and pressure testing as complementary assessment methodologies.

ILI 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 ensures 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 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.

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 remediations. A typical remediation may include excavation and repair, 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 2019 includes five projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Crossover Line 16-inch	ILI	0.4	O&M
Crossover Line 12-inch	ILI	6.7	O&M
High Bridge Line	ILI	2.6	O&M
Eagan Line	Derate	5.8	Capital
Montreal Line North - Transmission	Hydrostatic Pressure Test	0.3	O&M

- **<u>Crossover Line 16-inch</u>:** This project is an ILI of a 16-inch pipeline, installed in 1964, that connects Mendota Station to the 12-inch portion of the Crossover line as well as the Eagan Line. This is the second ILI assessment of this line and will cover 0.35 miles using smart tool technology. We do not expect any issues will prevent the use of ILI. Running a second ILI allows the Company to compare the results with the first ILI in 2012 and identify any new anomalies or growth of existing anomalies.

  After the ILI is run, validation digs will be completed on the line. 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 defined by federal code requirements[11] and pipeline conditions.

- **<u>Crossover Line 12-inch</u>:** This project is an ILI of a 12-inch pipeline, installed as early as 1948, that connects the Rosemount Line to the 16-inch portion of the Crossover line as well as the Eagan Line. This is the second ILI assessment

[11] Code 49 CFR Parts 192.927, 192.929, and 192.933.

of this line and will cover 6.7 miles of 12-inch pipeline using smart tool technology. We do not expect any issues will prevent the use of ILI. Running a second ILI allows the Company to compare the results with the first ILI in 2012 and identify any new anomalies or growth of existing anomalies. After the ILI is run, validation digs will be completed on the line.

- **<u>High Bridge Line</u>:** This project is an ILI of a 20-inch pipeline, installed in 2007, that connects Mendota Station to the High Bridge electric production facility. This is the second ILI assessment of this line and will cover 2.6 miles of 20-inch pipeline using smart tool technology. We do not expect any issues will prevent the use of ILI. Running a second ILI allows the Company to compare the results with the first ILI in 2013 and identify any new anomalies or growth of existing anomalies. After the ILI is run, validation digs will be completed on the line.

- **<u>Eagan Line</u>:** Installed in 1941, the Eagan Line is a 5.8-mile long 12-inch diameter pipeline that connects the Crossover line to a gas delivery point from Northern Natural Gas (NNG). Due to changes in the system in recent years, the Company plans to lower the line's pressure to reduce risk and reclassify the pipeline as a distribution pipeline rather than conducting ILI. The scope of the project will be to disconnect or install regulation between the Eagan Line, Crossover Line, and NNG delivery point. This line was previously assessed using direct assessment in 2006 and pressure testing in 2013.

- **<u>Montreal Line North – Transmission</u>:** 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 considered transmission piping and is a combination of 20-inch and 24-inch diameter pipe that was originally installed in 1962 during construction of Interstate 35E. The original pipeline is three miles long and had an external corrosion direct assessment conducted in 2012. Most of the line assessed in 2012 was replaced during the East Metro Replacement Project. The final 0.3 miles is being pressure tested pursuant to the seven year CFR assessment rule. Performing a hydrostatic pressure test allows the Company to complete required baseline testing for the Montreal Line.

Costs for direct assessment are classified as O&M costs 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 initial ILI runs are capital costs per the Company's capitalization policy. This includes vendor costs associated with the use of 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. The costs for assessment by pressure test including test equipment, test medium, and disposal of medium will be classified as O&M in all cases.

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
WBS: E.0000018.041 (Capital)

2019 Estimated Project Costs
$0.75 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
This project is for the installation of mainline isolation valves or adding 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 in 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 NPRM addressing ASVs and RCVs and seeking comments on several broad areas for potentially expanding the TIMP rules. PHMSA has completed its study[12] on ASVs and RCVs, but has not yet issued a ruling.

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 system protection in a HCA 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 lower-risk location prior to one at a higher-risk location, if the latter is on a pipeline scheduled for a near-term 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 2021. The number of valves, valve sizes, and activity occurring at each of the locations listed below was determined by the risk analysis. Per the Company's capitalization policy, the cost of these installations is a capital cost. O&M expenses are not expected in future years.

The 2019 scope of work includes the following valves:

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[12] https://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Final%20Valve_Study.pdf.

Valve Location	Size	Description
Mendota Station Inlet	16-inch	Install new actuator on Cedar Line
Mendota Station Outlet	20-inch	Install new actuator on Island Line South
Mendota Station Inlet	16-inch	Install new actuator on Crossover Line
Mendota Station Outlet	20-inch	Install new actuator on Montreal Line
Mendota Station Outlet	20-inch	Install new actuator on High Bridge Line

The locations proposed for installation in 2019 and beyond are based on a revised risk analysis of work completed in 2018. After 2019, in total, the Company expects to install another six valves, in total, during 2020 and 2021 as part of this GUIC program.

3) Programmatic Replacement/MAOP Remediation
WBS: E.0000018.055, E.0000004.048, E.0000042.001, and E.0000044.001 (Capital)

2019 Estimated Project Costs
$26.36 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
The MAOP Remediation Advisory Bulletin[13] 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 acknowledges there are gaps in data regarding our facilities that need to be closed to meet the

[13] ADB-12-06, Docket No. PMHSA-2012-0068.

Federal standards. 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.

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 hiring contract engineering and research analysts. The Company's internal engineering department will assist in 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 delivery schedules.

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.

In 2019 we will conduct replacement work on two 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-inch Maplewoood Propane to North Saint Paul)	Replacement	1.5	Capital

- **<u>County Road B (NSP to Rice)</u>:** This project is along County Road B in North Saint Paul, Maplewood, Roseville, and Little Canada, MN and entails replacing 6.5 miles of 30-inch, 24-inch and 20-inch pipe with a standardized 20-inch pipe. This pipeline was originally installed in the 1950s with service lines directly connected to it, multi diameter piping and mechanical couplings. 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. Design and construction are anticipated to be completed over a three-year span from 2018 through 2020.

- **<u>East County Line (30-inch Maplewood Propane to North Saint Paul)</u>:** This project extends from our Maplewood Propane facility to North Saint Paul Station in the communities of Maplewood, Oakdale and North Saint Paul, MN. 1.5 miles of 30-inch pipe will be replaced with 20-inch pipe. This pipeline was originally installed in 1957. Replacement with standardized piping will make the line accessible to ILI tools. Design and construction occurs in 2018 and 2019.

III. 2018 TIMP PROJECTS

In 2018, there are four projects under the TIMP:

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

The TIMP project costs included in the Company's 2018 GUIC Rider Petition,[14] as compared to updated 2018 cost estimates[15] based on emerging project developments and actual construction activity, are provided below:

2018 Estimated TIMP Project Costs
($ Millions)

Program	2018 Capital, As Filed[16]	2018 Capital Estimates	Capital Variance	Capital Variance %	2018 O&M, As Filed	2018 O&M Estimates	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$0.00	($0.03)	($0.03)	-100.00%	$0.00	$0.00	$0.00	0.00%
Transmission Pipeline Assessments	$0.29	$0.48	$0.19	65.23%	$1.51	$1.07	($0.44)	-29.16%
ASV/RCV	$0.97	$0.78	($0.19)	-20.06%	$0.00	$0.00	$0.00	0.00%
Programmatic Replacements/ MAOP Remediation	$7.77	$7.03	($0.73)	-9.45%	$0.00	$0.00	$0.00	0.00%
TOTAL 2018 TIMP Capital Expenditures and O&M	**$9.03**	**$8.26**	**($0.77)**	**-8.5%**	**$1.51**	**$1.07**	**($0.44)**	**-29.2%**
TOTAL 2018 MN TIMP Revenue Requirements[17] [18]	**$10.51**	**$8.47**	**($2.04)**	**-19.44%**	**$1.33**	**$0.94**	**($0.39)**	**-29.3%**

[14] Docket No. G002/M-17-787.
[15] Based on actual costs as of 6/30/2018 and estimates from 7/1/2018 through 12/31/2018.
[16] Estimated capital costs include estimated removal costs.
[17] Capital Costs represents the eligible calculated revenue requirements, which include: debt and equity return on rate base, property taxes, current and deferred taxes, and book depreciation.
[18] $480,000 of O&M amount is recovered through base rates, and is removed from our GUIC revenue requirement.

TIMP projects planned for completion in 2018, and outlined below generally began during the 2nd and 3rd quarters of 2018 and will begin service during the 3rd and 4th quarters of 2018.

1) East Metro Replacement Project
WBS: E.0000030.002, E.0000030.009 (Capital)

Project Summary and Scope
The East Metro Replacement Project was completed in 2017. However, minor credits associated with constructing the Highland regulator station and restoration activities were not processed until 2018.

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Capital Variance	Capital Variance %	2018 O&M, As Filed	2018 O&M Estimates	O&M Variance
Capital / O&M Expenditure	$0.00	($0.03)	($0.03)	-100.00%	$0.00	$0.00	$0.00

Variance Explanation

Capital: Credits associated with constructing the Highland regulator station and restoration activities in 2017 were not processed until 2018.

O&M: None.

2) Transmission Pipeline Assessments
WBS: E.0000018.052, E.000004.019, E.000009.018 (Capital); A.0008410.163.002 (O&M)

Project Summary and Scope
The scope of assessments in 2018 includes three 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

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Capital Variance	Capital Variance %	2018 O&M, As Filed	2018 O&M Estimates	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$0.29	$0.48	$0.19	65.23%	$1.51	$1.07	($0.44)	-29.16%

Variance Explanation

Capital: The Island Line (South of River) project had an ILI to assess the health of pipe from original construction in 1952 to reduce risk on the NSPM bulk system. The line is located under a lake and is inaccessible by standard methods. There are additional costs related to the need for specialized ILI equipment that were not included in the original budget. The rental cost for the required tool was $190,000, but was budgeted for $70,000. In addition, costs to hook-up launcher and receiver facilities took slightly more time than anticipated which added to the overall cost.

O&M: The previously planned 2018 integrity assessment via hydrostatic pressure tests of the Montreal Line North has been moved into spring 2019 as a result of a further defined six-week project timeline that will not allow completion in 2018.

3) ASVs and RCVs
WBS: E.0000018.041 (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 locations proposed for installation in 2018 were originally based on discovery work completed in January 2016.

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

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

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Capital Variance	Capital Variance %	2018 O&M, As Filed	2018 O&M Estimates	O&M Variance
Capital / O&M Expenditure	$0.97	$0.78	($0.19)	-20.06%	$0.00	$0.00	$0.00

Variance Explanation

Capital: Material costs associated with 2018 valves were incurred in 2017. In addition, we were able to utilize more internal labor than originally anticipated. The cost of internal labor is not recovered through the GUIC Rider.

O&M: None.

4) Programmatic Replacement/MAOP Remediation WBS: E.0000018.055 and E.0000004.048 (Capital)

Project Summary and Scope

In 2018, the Company is completing construction activities associated with the East County Line – South Saint Paul Station to Railroad Tracks. This project replaces 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. The original pipeline was installed in 1957 and is not capable of being inspected using ILI. Replacement with standardized 24-inch pipe will provide the opportunity to utilize ILI on not only the replaced pipe but also piping to the Mississippi River Crossing.

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Capital Variance	Capital Variance %	2018 O&M, As Filed	2018 O&M Estimates	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$7.77	$7.03	($0.73)	-9.45%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the decrease in capital expenditures results from the removal of $5.7 million related to the Crossover Project from the Company's GUIC Program due to revised risk scoring. This decrease was partially offset by additional costs related to 2017 carryover charges for the Montreal/Island Line Replacement project prompted by several invoices that were not processed until 2018. Additionally, there were also cost increases related to the East County Line Renewal project. Oil contamination was found in the existing pipe causing additional expenses to clean the pipe before removal and grouting. Also, the City required curb-to-curb paving instead of only restoring the area impacted by the trench.

O&M: None.

IV. 2017 TIMP PROJECTS

In 2017, there were 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 2018 GUIC Rider Petition,[19] as compared to actual 2017 costs.[20]

2017 Actual TIMP Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals[21]	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Actuals	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$0.60	$0.61	$0.01	1.01%	$0.00	$0.00	$0.00	n/a
Transmission Pipeline Assessments	$0.90	$0.92	$0.02	2.55%	$0.50	$0.02	($0.48)	-96.00%
ASV/RCV	$0.17	$0.24	$0.07	42.51%	$0.00	$0.00	$0.00	n/a
Programmatic Replacements/ MAOP Remediation	$7.63	$6.04	($1.60)	-20.92%	$0.00	$0.00	$0.00	n/a
TOTAL 2017 TIMP Capital Expenditures and O&M	**$9.31**	**$7.81**	**($1.50)**	**-16.1%**	**$0.50**	**$0.02**	**($0.48)**	**-96.00%**
TOTAL 2017 MN TIMP Revenue Requirements[22] [23]	**$8.48**	**$7.92**	**($0.55)**	**-6.53%**	**$0.44**	**$0.02**	**($0.42)**	**-95.45%**

[19] Docket No. G002/M-17-787.
[20] Based on actual costs as of 12/31/2017.
[21] Includes removal costs (RWIP).
[22] 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.
[23] $480,000 of O&M amount is recovered through base rates, and is removed from our GUIC revenue requirement

TIMP projects completed in 2017 and outlined below generally began during the 2nd and 3rd quarters of 2017 and were placed into service during the 3rd and 4th quarters of 2017.

1) East Metro Replacement Project
Work Breakdown Structure (WBS): E.0000030.001, E.0000030.002 (Capital)

Project Summary and Scope
The scope of work in 2017 for the East Metro Replacement Project included construction of the Highland regulator station and completion of certain restoration activities.

2017 Actual Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Actuals	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$0.60	$0.61	$0.01	1.01%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: Not significant.

O&M: None.

2) Transmission Pipeline Assessments
WBS: E.0000018.052 (Capital); A.0008410.163.002.002 (O&M)

Project Summary and Scope
The project scope in 2017 included work on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Island Line (South of River)[24]	ILI	1.9	Capital
Inver Hills Lateral	ILI	2.0	Capital / O&M
Lake Elmo Line	ILI	5.8	Capital / O&M
High Bridge Lateral Replacement	Replacement	0.8	Capital

2017 Actual Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Actuals	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$0.90	$0.92	$0.02	2.55%	$0.50	$0.02	($0.48)	-96.00%

Variance Explanation

Capital: Not significant.

O&M: The Company was able to utilize more internal labor than expected for the validation digs for the Inver Hills Lateral and Lake Elmo Line ILI. Internal labor is not recovered through the GUIC Rider. In addition, several invoices related to 2017 work were not processed until 2018.

3) ASVs and RCVs
WBS: E.0000018.041 (Capital)

Project Summary and Scope
In 2017, the Company installed valves at four different locations:

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

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

2017 Actual Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Actuals	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$0.17	$0.24	$0.07	42.51%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance was due to lead materials received in 2017 for planned installations in 2018.

O&M: None.

4) Programmatic Replacement/MAOP Remediation
WBS: E.0000018.055 and E.0000004.048 (Capital)

Project Summary and Scope

The scope of work in 2017 included three projects on the following lines:

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 Railroad Tracks	Replacement	0.5	Capital

The primary scope of work in 2017 related to construction activities to replace both the Montreal Line South and the Island Line South from the Mendota Station to the Mississippi River bottom. Environmental concerns with constructing in the easement altered the alignment of the pipeline and required the closing and eventual full restoration of an entire segment of road not included in original plans. The project incurred significant costs as a result of a new alignment, difficult construction requirements, and significant hard surface restoration. The alignment and location of the new pipelines changed to reduce the risk of third-party damage by nearby railroad reconstruction work.

2017 Actual TIMP Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Capital Variance	Capital Variance %	2017 O&M, As Filed	2017 O&M Actuals	O&M Variance	O&M Variance %
Capital / O&M Expenditure	$7.63	$6.04	($1.60)	-20.92%	$0.00	$0.00	$0.00	0.00%

Capital: A primary driver for the decrease in capital expenditures results from 2017 invoices that were not processed until 2018 related to the Montreal/Island Line Replacement project.

O&M: None.

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 2019.

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.

TIMP 2020-2023 Plan[25]
($ Millions)

	2020 Estimates		2021 Estimates		2022 Estimates		2023 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Transmission Pipeline Assessments	$3.52	$1.70	$2.21	$1.70	$5.29	$1.70	$0.83	$1.70
ASV/RCV	$0.75	$0.00	$0.75	$0.00	$0.75	$0.00	$0.75	$0.00
Programmatic Replacement / MAOP Remediation	$31.75	$0.00	$0.00	$0.00	$0.00	$0.00	$14.70	$0.00
TOTAL	**$36.02**	**$1.70**	**$2.96**	**$1.70**	**$6.04**	**$1.70**	**$16.28**	**$1.70**

[25] Capital figures denoted represent total estimated capital expenditures, including removal costs.

TIMP 2017-2019 Project Detail

CAPITAL

Program	Regulation	WBS Structure	2017 Actuals	Cost Per Unit (CPU) Assumptions	2018 Actuals [1]	2018 Forecast	2018 Total	Cost Per Unit (CPU) Assumptions	2019 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments	49 CFR 192, Subpart O	E.0000018.052; E.0000004.019; E.0000009.018	$ 971,440	2017 Assessment Projects; costs are 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 C1(a) for actual cost details by individual project.	$ 114,231	$ 385,769	$ 500,000	2018 Assessment Projects; costs are 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 C1(a) for actual cost details by individual project.	$ 1,030,000	2019 Assessment Projects; costs are 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 C1(a) for actual cost details by individual project.
ASV/RCV Valve Replacements	49 CFR Part 192.935	E.0000018.041	$ 264,714	Costs are based on common activities associated with installing valves and actuating equipment at different valve locations. See Subpart C1(b) for actual cost details by individual project.	$ (20,053)	$ 815,054	$ 795,000	Costs are based on common activities associated with installing valves and actuating equipment at different valve locations. See Subpart C1(b) for actual cost details by individual project.	$ 1,000,000	Costs are based on common activities associated with installing valves and actuating equipment at different valve locations. See Subpart C1(b) for actual cost details by individual project.
East Metro Pipeline Replacement Project	49 CFR 192, Subpart O	11615874, 11676981, 11706370, 11819647, 12013233	$ 622,472	Project concluded in 2016; 2017 costs are for final restoration activities and the building of the Highland Regulator station.	$ (32,830)	$ -	$ (32,830)	Project concluded in 2016; 2018 credits associated with final settlement activities.	$ -	n/a
Programmatic Main Replacement/MAOP Validation	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.	E.0000018.055; E.0000004.048; E.0000042.001; E.0000044.001; E.0000042.001; E.0000044.001.	$ 5,825,337	Based on 2017/2018 actual costs for Montreal/Island Line Renewal Project: Montreal Line, CPU $2,045/ft; Island Line, CPU $1,711/ft.	$ 3,429,570	$ 3,973,580	$ 7,403,150	*See* Subpart C1 c	$ 26,900,000	*See Subpart C1 c*
TOTAL TIMP CAPITAL			**$ 7,683,964**		**$ 3,490,918**	**$ 5,174,402**	**$ 8,665,320**		**$ 28,930,000**	

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

O&M

Program	Regulation	WBS Structure	2017 Actuals	Cost Per Unit (CPU) Assumptions	2018 Actuals [1]	2018 Forecast	2018 Total	Cost Per Unit (CPU) Assumptions	2019 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments	49 CFR 192, Subpart O	A.0008410.163.002	$ 20,000	rkel	$ 422,746	$ 646,254	$ 1,069,000	2018 Assessment Projects; costs are 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 C1(a) for actual cost details by individual project.	$ 2,900,000	2019 Assessment Projects; costs are 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 C1(a) for actual cost details by individual project.
TOTAL TIMP O&M			**$ 20,000**		**$ 422,746**	**$ 646,254**	**$ 1,069,000**		**$ 2,900,000**	

[1] Actual costs through June 2018.

2017-2019 Project Detail - TIMP Assessments

2017

Line/Loop	Project Description	Estimates	O&M or Capital
Island Line (South of River)	**ILI Assessable (Launcher & Receiver Installation)**	**$ 628,063**	
Task 1	Pigging Runs	$ 628,063	Capital
Inver Hills Lateral	**ILI Assessable (Launcher & Receiver Installation)**	**$ 292,392**	
Task 1	Pigging Runs	$ 282,392	Capital
Task 2	Validation Digs	$ 10,000	O&M
Lake Elmo Line ILI	**ILI Assessable (Launcher & Receiver Installation)**	**$ 157,938**	
Task 1	Pigging Runs	$ 147,938	Capital
Task 2	Validation Digs	$ 10,000	O&M
High Bridge Lateral Replacement	**ILI & Replacement**	**$ (48,085)**	
	Material Returns	$ (48,085)	Capital
East County Line Casing	**Pipe Replacement**	**$ (38,868)**	
Task 1	Material Returns	$ (38,868)	Capital
Capital Total		**$ 971,440**	
O&M Total		**$ 20,000**	

*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
Capital Total		**$ 300,000**	
O&M Total		**$ 1,069,000**	

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

2019

Line/Loop	Project Description	Estimates	O&M or Capital
Eagan Line	**ILI Assessable (Launcher & Receiver Installation)**	**$ 1,030,000**	
Task 1	Cut & Cap Crossover Interconnect	$ 65,000	Capital
	Cut & Cap Eagan TBS	$ 65,000	
	Retire/Remove R490	$ 300,000	
Task 2	Retire/Remove R499	$ 300,000	
	Retire Remove R505	$ 300,000	
Crossover 16"	**2nd ILI**	**$ 800,000**	
Task 1	Pigging Runs	$ 500,000	O&M
Task 2	Validation Digs	$ 200,000	
Task 3	Contingency	$ 100,000	
Crossover 12"	**2nd ILI**	**$ 800,000**	
Task 1	Pigging Runs	$ 500,000	O&M
Task 2	Validation Digs	$ 200,000	
Task 3	Contingency	$ 100,000	
High Bridge Line	**ILI Assessable (Launcher & Receiver Installation)**	**$ 800,000**	
Task 1	Pigging Runs	$ 500,000	O&M
Task 2	Validation Digs	$ 200,000	
Task 3	Contingency	$ 100,000	
Montreal Line North	**Hydrostatic Pressure Test**	**$ 500,000**	
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	
Task 4	Contingency	$ 60,000	
Capital Total		**$ 1,030,000**	
O&M Total		**$ 2,900,000**	

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

2017-2019 TIMP Project Detail - ASV/RCV

2017

Subproject	Size	Description	Actual Cost
Rosemount Line Take-off	16"	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off	$41,086
Rosemount TBS (St. Paul 1P)	16"	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS	$8,620
Lake Elmo 1B TBS	12"	Add a valve and remote controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS	($16,365)
Maplewood plant	12"	Add a valve and remote controlled actuator on the Lake Elmo Line at the Maplewood Plant	$12,737
Hwy 55 and Babcock	16"	Install new actuator on the Rosemount line at Hwy 55 and Babcock Rd	$119,869
Rich Valley Station Inlet	16"	Install new valve and actuator on the Rosemount line at the Rich Valley Station Inlet	$80,437
South St. Paul Station Inlet	16"	Install new actuator on the Rosemount line at the South St. Paul Station Inlet	$18,328
Total			**$264,714**

*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	$300,000
Hwy 55 and Babcock	16"	Install new actuator on the Rosemount line at Hwy 55 and Babcock Rd	$420,000
South St. Paul Station Inlet	16"	Install new actuator on the Rosemount line at the South St. Paul Station Inlet	$75,000
Total			**$795,000**

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

2019

Subproject	Size	Description	Estimated Cost
Mendota Station Inlet	16"	Install new actuator on Cedar Line TL0203 Inlet EV0460	$175,000
Mendota Station Outlet	20"	Install new actuator on Island Line S. TL0206 Outlet EV0444	$216,667
Mendota Station Inlet	16"	Install new actuator on Crossover Line TL0207 Inlet EV421	$175,000
Mendota Station Outlet	20"	Install new actuator on Montreal Line Outlet EV0443	$216,667
Mendota Station Outlet	20"	Install new actuator on High Bridge Line EV0461	$216,666
Total			**$1,000,000**

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

2017-2019 TIMP Project Detail - Programmatic Replacement/MAOP Validation

2017

Project Name	Project Description	Actual Cost
Montreal Line South Renewal	Montreal Line S Renewal - Construction	$ 2,727,795
	Materials	$ 251,467
	Permitting	$ 8,346
	Engineering	$ 328,667
	Total	**$ 3,316,274**
Island Line South Renewal	Island Line S Renewal - Construction	$ 2,254,402
	Engineering	$ 58
	Materials	$ 249,419
	Permitting	$ 5,184
	Total	**$ 2,509,063**
	Grand Total	**$ 5,825,337**

2018 and 2019

Individual Project Name	Description*	Assumptions*
Montreal Line South Renewal	· Project Type: Pipeline Replacement · Regulation: May 7, 2012 PHMSA MAOP Advisory Bulletin · 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: Lilydale: From Mendota Station to the Montreal River Crossing.	· Mileage: o Installation: 2,100' – 20" Pipe o Retirement: 1,800' – 20" Pipe Benefits: MAOP established by Traceable, Verifiable and Complete Records.
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: Lilydale: From Mendota Station to the Pickerel Lake.	· Mileage: o Installation: 2,100' – 20" Pipe o Retirement: 1,800' – 20" Pipe Benefits: MAOP established by Traceable, Verifiable and Complete Records.
***Carry Over Costs from 2017 Project Scope**		
2018 Estimated Costs:	Montreal Line S Renewal - Construction	$ 977,448
	Island Line S Renewal - Construction	$ 1,083,637
	Total	**$ 2,061,085**
East County Line Renewal – S.St. Paul Station to RR Tracks	· Project Type: Pipeline Replacement · Regulation: May 7, 2012 PHMSA MAOP Advisory Bulletin · Overview: Replace original 1957 pipeline of 2,820" of 30" with standardized 24" · Location: South Saint Paul regulator station near Concorde Street in South Saint Paul · 2018 Construction Period: May – October 2018	Benefits: MAOP established by Traceable, Verifiable and Complete Records. Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $4.5 million or $1,595/ft.
2018 Estimated Costs:	- $4.5M Design, Engineering, Easement Acquisition and Construction	
Total Estimated Capital Costs:	- $4.5M	
County Road B (NSP to Rice)	· Project Type: Pipeline Replacement · Regulation: May 7, 2012 PHMSA MAOP Advisory Bulletin · Overview: Replace original 1950s pipeline of 34,331" of 30", 24" and 20" with standardized 20" · Location: County Road B in North Saint Paul and Maplewood, MN. · 2018 Construction Period: May – October 2018 · Total Construction Period: 2018-2020	Benefits: MAOP established by Traceable, Verifiable and Complete Records. Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $49.9 million or $1,456/ft.
2018 Estimated Costs:	- $500K Design, Engineering, Easement Acquisition	
2019 Estimated Costs:	- $17.0M Construction - Phase 1	
2020 Estimated Costs:	- $32.4M Construction - Phase 2	
Total Estimated Capital Costs:	- $49.9M	
East County Line (30"Maplewoood Propane to North Saint Paul)	· Project Type: Pipeline Replacement · Regulation: May 7, 2012 PHMSA MAOP Advisory Bulletin · Overview: Replace original 1957 pipeline of 7,323" of 30" with standardized 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: MAOP established by Traceable, Verifiable and Complete Records. Current Classification: Transmission Future Classification: Distribution · Total Cost Per Unit: $10.2 million or $1,393/ft.
2018 Estimated Costs:	- $318K Design, Engineering, Easement Acquisition	
2019 Estimated Costs:	- $9.9M Construction	
Total Estimated Capital Costs:	- $10.2M	

Quantitative Risk Assessment for 2019 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

2019 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

High Risk: Risk Score ≥ 5
Medium Risk: 3 ≤ Risk Score < 5
Low Risk: Risk Score < 3

TIMP Transmission Pipeline Assessments

Integrity Assessments Project Risk

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Score	Risk Level (High, Medium, Low)
Crossover 16”	Rice Street	16	1964	6	Yes	4	High
Crossover 12”	Rice Street	16	1948	6	Yes	4	High
Highbridge Line	Rice Street	20	1952	6	Yes	4	High
Montreal Line North	Rice Street	20/24	1962	7	Yes	4	High

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
Cedar Line	49 CFR Part 192.935	Mendota Station Inlet	Newport	4	4	16	High
Island Line	49 CFR Part 192.935	Mendota Station Outlet	Rice Street	4	2	8	Medium
Crossover Line	49 CFR Part 192.935	Mendota Station Inlet	Rice Street	4	3	12	High
Montreal Line	49 CFR Part 192.935	Mendota Station Outlet	Rice Street	4	2	8	Medium
High Bridge Line	49 CFR Part 192.935	Mendota Station Outlet	Rice Street	4	3	12	High

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

Consequence of Failure Lookup Table

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

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

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	Material	Consequence	Risk Score	Project Classification
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

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

(dark)	High Risk: Risk Score ≥ 7
(medium)	Medium Risk: 4 ≤ Risk Score < 7
(light)	Low Risk: Risk Score <4
(white)	No Risk: Risk Score = 0

Distribution Integrity Management Program
Overview and Project Detail

I. DIMP OVERVIEW

Managing the integrity and safe operation of our gas systems is a continuous process. At its core, the Distribution Integrity Management Program (DIMP) can be summarized in three steps:

1) understand your assets,
2) risk evaluation, and
3) risk mitigation.

Our 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, we are continually updating our DIMP plans and projects to address the on-going obligation to ensure the safe and reliable operation of our gas distribution system.

1) Understand Your Assets

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

2) Risk Evaluation

Using the knowledge of our gas distribution assets, we evaluate 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 SMEs, enabling stratification or ranking of projects based on asset characterization and probability of 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 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 poor performing Aldyl-A (PEA) pipelines, a type of polyethylene pipe material to address material and welds concerns and equipment issues;
- Replacement of copper loop risers to address corrosion;

- Inspecting intermediate pressure (IP) pipelines[1] and repairing or replacing as needed to address corrosion and joint, material, and weld concerns;
- Replacement of IP pipelines to address corrosion and joint, 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. 2019 DIMP PROJECTS

The Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with four 2019 DIMP programs:

2019 Estimated DIMP Project Costs
($ Millions)

Program	2019 Capital[2]	2019 O&M
Poor Performing Main Replacements	$10.08	$0.00
Poor Performing Service Replacements	$6.30	$0.00
IP Line Assessments and Replacements	$0.00	$0.63
Sewer and Gas Line Conflict Investigation	$0.00	$2.15
TOTAL 2019 DIMP Capital Expenditures and O&M	**$16.38**	**$2.78**
TOTAL 2019 Minnesota DIMP Revenue Requirement	**$10.76**[3]	**$2.78**

[1] Generally defined as lines operating above 60 pounds per square inch gauge and below transmission.
[2] Estimated capital costs include estimated removal costs.
[3] 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 through 2018 GUIC Rider petitions.[4] The capital-related cost estimates for 2019 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads. The 2019 project detail for each project is presented in Attachment D1 and the risk assessment scores for 2019 projects are presented in Attachments D2(a) and D2(b).

Main and service 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, 2019 project identification occurs in the 3rd and 4th quarters of 2018, construction will commence during the 2nd quarter of 2019, and in-servicing will occur during the 3rd and 4th quarters of 2019.

1) Poor Performing Main Replacements
Work Breakdown Structure (WBS):[5] E.0000007.002, E.0000007.045, E.0000007.060, E.0000007.067, E.0010011.003 (Capital)

2019 Estimated Project Costs
$10.08 million Capital 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 engineers and SMEs are incorporated into the replacement decisions. Replacing main pipeline segments is a multi-year

[4] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, and G002/M-17-787.
[5] WBS has replaced the parent project number given for projects in previous versions of our GUIC filing. This switch in numbering has been due to a change in our work and asset management system. The previously-used parent projects generally correspond with one WBS.

project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

Materials and construction methods are a major contributing factor in poor main performance. For example, mains made from PEA[6] can become brittle over time and are 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 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 and ensure customer safety and system reliability, main and service renewal projects are designed with consideration of adjacent facilities, municipal requirements, and distribution system operational needs. This includes the viability of dual main installations, which eliminates directional boring associated with installing gas services under roadways. 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.

[6] PHMSA has issued several advisory bulletins about PEA mains, including PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02.

For 2019, 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 2019 projects are in the process of being identified and scoped. Planned replacement activity in 2019 includes:

Geographic Area (by Division)	Mains (Miles)[7]
St. Paul	5
White Bear Lake	16
Wyoming	4
Newport	6
St. Cloud	10
Red Wing	5
Winona	9
Faribault	4
Total	**59**

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

2) Poor Performing Service Replacements
WBS: E.0000002.005, E.0000002.043, E.0000002.053, E.0000002.056, E.0010011.004 (Capital)

2019 Estimated Project Costs
$6.30 million Capital expenditure

Project Summary and Scope
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

[7] Estimates as of August 31, 2018. A majority of the 2019 are in the process of being identified and scoped.

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 2019 includes:

Geographic Area (by Division)	Services (Number)[8]
St. Paul	650
White Bear Lake	1,350
Wyoming	250
Newport	650
St. Cloud	450
Red Wing	275
Winona	500
Faribault	175
Total	**4,300**

3) IP Line Assessments
WBS: A.0008610.004.001.005 (O&M)

2019 Estimated Project Costs
$0.63 million O&M expenditure

Project Summary and Scope
This is an ongoing project to assess and renew IP lines. Selection of assessment methodologies and pipeline segments for inspection is based on an evaluation of 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

[8] Estimates as of August 31, 2018. A majority of the 2019 projects are in the process of being identified and scoped.

threats from corrosion, manufacturing defects,[9] construction methods,[10] and third-party damage. The consequences associated with a failure of these pipelines are heightened due to the higher operating pressures and the location of many of these lines in heavily developed areas. For IP lines, direct assessment is the primary assessment methodology. However, pressure testing may also be utilized based on the applicable threats and the ability to take the pipeline out of service.

The Company plans on conducting between one and five IP line assessments per year. The Company maintains a prioritized list of anomalies identified through external corrosion direct assessment (ECDA) surveys, and verification digs will be completed on these anomalies, as applicable. O&M budgets for this program are volatile depending on the condition of the pipelines assessed and the number of anomalies identified for excavation and repair.

For 2019, the Company has a single IP Line Assessment project planned, the hydrostatic pressure test of the river crossings associated with the Montreal Line North.

Line/Loop	Type	Project Length (mi)	Project Type
Montreal Line North River Crossings/Headers	Hydrostatic Pressure Test	2.4	O&M

- **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. This is the first instance in which a hydrostatic pressure test has been selected as an IP Assessment method for a DIMP project as part of the Company's GUIC. ECDA is not practical for this project since this line is located under the Mississippi River.

  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 Interstate 35E construction. The final section of pipe is a valve header on the

[9] Material defects, long seam defects.
[10] Compression couplings and welds.

south side of the Mississippi River that is considered high pressure distribution and was installed in 1977. The pipe segments will be assessed by means of pressure strength test.

4) Sewer and Gas Line Conflict Investigation
WBS: A.0008410.163.001.004, A.0008510.114.001.002, A.0008610.004.001.002 (O&M)

2019 Estimated Project Costs
$2.15 million O&M expenditure

Project Summary and Scope
Both the Commission and PHMSA have asked the Company 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 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.* [11]

The Company has been inspecting sewer laterals and mains since 2010 and has found 153 incidences of conflicts between sewer and gas lines. Through the annual conflict investigation work, there has been a downward trend in the number of conflicts found each year. Through August, the Company has discovered three conflicts in 2018, leading to a determination that a continuance of inspections is reasonable in 2018 and 2019. The current plan estimates approximately 13,040 services will be inspected for conflicts in 2019, the tenth and final year of legacy inspections. The inspection program was initially designed and executed as a three-year program and extended to a 10-year program that began in 2010 and will conclude in 2019. The Company will continue to monitor circumstances and accelerate or scale back inspections if conditions warrant.

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

III. 2018 DIMP PROJECTS

There are six projects under the DIMP in 2018. Following are the DIMP project costs originally included in the Company's 2018 GUIC Rider Petition,[12] as compared to revised 2018 cost estimates[13] based on current year project developments and actual construction activity:

2018 Estimated DIMP Project Costs
($ Millions)

	2018 Capital, As Filed[14]	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Poor Performing Main Replacements	$11.05	$11.56	$0.52	4.66%	$0.00	$0.00	$0.00	0.00%
Poor Performing Service Replacements	$6.91	$7.22	$0.31	4.45%	$0.00	$0.00	$0.00	0.00%
IP Line Assessments	$19.82	$19.76	($0.05)	-0.27%	$1.03	$0.40	($0.63)	-60.98%
Distribution Valve Replacement Project	$0.50	$0.50	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Federal Code Mitigation	$0.00	$0.00	$0.00	0.00%	$0.20	$0.20	$0.00	0.00%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	0.00%	$2.31	$2.31	$0.00	0.00%
TOTAL 2018 DIMP Capital Expenditures and O&M	**$38.27**	**$39.04**	**$0.77**	**2.01%**	**$3.53**	**$2.91**	**($0.63)**	**-17.69%**
TOTAL 2018 MN DIMP Revenue Requirement[15]	**$7.96**	**$5.60**	**($2.36)**	**-29.62%**	**$3.53**	**$2.91**	**($0.63)**	**-17.69%**

[12] Docket No. G002/M-17-787.
[13] Based on actual costs as of 6/30/2018 and estimates from 7/1/2018 through 12/31/2018.
[14] Estimated capital costs include estimated removal costs.
[15] Capital Costs 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 2018 exclude internal labor and include 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.

1) Poor Performing Main Replacements
WBS: E.0000007.002, E.0000007.045, E.0000007.060, E.0000007.067, E.0010011.003 (Capital)

Project Summary and Scope

For 2018, 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. Actual and remaining replacement activity in 2018 includes:

Geographic Area (by Division)	Main (Miles)
St. Paul	9
White Bear Lake	32
Wyoming	3
Newport	13
St. Cloud	0.5
Southeast	6.5
Moorhead	1
Total	**65**

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditure	$11.05	$11.56	$0.52	4.66%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the increase in capital expenditures is an increase in problematic pipeline replaced based on a revised relative risk assessment among GUIC projects. The projects consist of coupled steel and PEA mains. The construction resources and projects identified for 2018 have been prioritized based on relative risk and SME input.

2) Poor Performing Service Replacements
WBS: E.0000002.005, E.0000002.043, E.0000002.053, E.0000002.056, E.0010011.004 (Capital)

Project Summary and Scope
For 2018, 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. Actual and remaining replacement activity in 2018 includes:

Geographic Area (by Division)	Services (Number)
St. Paul	550
White Bear Lake	1650
Wyoming	125
Newport	775
St. Cloud	25
Southeast	625
Moorhead	150
Total	**3,900**

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditure	$6.91	$7.22	$0.31	4.45%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the slight increase in capital expenditures is an increase in service and copper loop riser projects replaced based on a revised relative risk assessment among GUIC projects. The construction resources and projects identified for 2018 have been prioritized based on relative risk and SME input.

3) IP Line Assessments
WBS: E.0000007.053, E.0000051.001, E.0000052.001 (Capital); A.0008610.004.001.005 (O&M)

Project Summary and Scope
This project includes health and condition assessments on IP lines. In 2018, the Company began construction activities on two replacement projects that support the integrity management of the Company's intermediate pressure (IP) distribution pipelines. In addition, the Company conducted ECDA on three pipelines to identify and address the threat of corrosion, and repair any corrosion defects. The IP Line Assessment work in 2018 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Colby Lake Lateral - Woodlane to Colby Lake	Replacement	2.5	Capital
H005 - Lexington to Snelling	Replacement	3.0	Capital
H08 – Lake Elmo 1A Town Border Station (TBS)	ECDA	3.4	O&M
T009 – Cottage Grove Town Border Station (TBS)	ECDA	1.6	O&M
Green Lake	ECDA	23	O&M

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditure	$19.82	$19.76	($0.05)	-0.27%	$1.03	$0.40	($0.63)	-60.98%

Variance Explanation

Capital: In 2018, there was a $12 million decrease related to rescheduling of the Langdon Line Replacement Project into 2021. This rescheduling was offset by additional costs related to final project designs for the Colby Lake Lateral and H005 - Lexington to Snelling projects. The delay of Langdon Line construction resulted from contract labor resource pressures from other projects with higher risk factors. Additional costs for Colby Lake and H05 System Renewal include increased costs for traffic control, wetlands and ground water mitigation, impact to local businesses, final bore designs, and utility obstructions.

O&M: The previously planned 2018 hydrostatic pressure tests integrity assessment of the Montreal Line North's associated river crossings has been moved into 2019 as a result of a further defined six-week project timeline that will not allow completion this year. The project has been rescheduled in the spring of 2019.

4) Distribution Valve Replacement Project
WBS: E.0010011.005 (Capital)

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. 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.

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).

Many of the valves identified for replacement within this program are located within busy road rights-of-way. These locations 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.

The Company identified a total of 32 existing distribution valves to be replaced in the Twin Cities Metro and Southeast areas. These valves range in size from 2-inch to 16-inch. Of these valves, 18 were originally planned to be replaced in 2017 with the remaining 14 valves planned to be replaced in 2018. Due to operational constraints and material availability six valves were deferred from 2017 into 2018. By the end of 2018, the Company estimates that a total of 16 inoperable emergency distribution valves will have been replaced throughout the year, ranging in size from 4-inch to 16-inch. Replacing these valves will allow the Company more options to isolating sections to address an emergency or system incident, while impacting the smallest number of customers.

The Company expects this project will conclude in 2018. However, expenses related to final restoration activities may potentially carry over into 2019 based on emerging work prioritization.

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditure	$0.50	$0.50	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: No variance expected.

5) Sewer and Gas Line Conflict Investigation
WBS: A.0008410.163.001.004, A.0008510.114.001.002, A.0008610.004.001.002 (O&M)

Project Summary and Scope
The sewer and gas line conflict inspection program began in 2010. The Company will continue to monitor risk circumstances and accelerate or scale back inspections if conditions warrant.

Consistent with the level of effort from 2010 through 2017, the current 2018 plan estimates that approximately 12,000 services will be inspected. Through August of this year, the Company has discovered three conflicts in 2018.

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital Expenditure	$0.00	$0.00	$0.00	0.00%	$2.31	$2.31	$0.00	0.00%

Variance Explanation

O&M: No variance expected.

6) Federal Code Mitigation
WBS: A.0008510.114.001.003, A.0008610.004.001.003 (O&M)

Project Summary and Scope
This project began in 2016. Over time, as the Federal Code[16] governing the operation and maintenance of the gas system has changed, the Company's

[16] 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.

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 initially focuses 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 2018, the Company anticipates roughly 400-500 items of varying criticality with an average cost of $550 per exception.[17] 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. Based on the status of current surveys, this program is expected to conclude in 2018.

2018 Estimated Project Costs
($ Millions)

	2018 Capital, As Filed	2018 Capital Estimates	Variance	% Capital Variance	2018 O&M, As Filed	2018 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditure	$0.00	$0.00	$0.00	0.00%	$0.20	$0.20	$0.00	0.00%

<u>Variance Explanation</u>

O&M: No variance expected.

[17] Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or service line.

IV. 2017 DIMP PROJECTS

There were six projects under the DIMP in 2017. Following are the DIMP project costs originally included in the Company's 2018 GUIC Rider Petition,[18] as compared to actual 2017 costs.[19]

2017 Actual DIMP Project Costs
($ Millions)

DIMP Program	2017 Capital, As Filed	2017 Capital Actuals[20]	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Poor Performing Main Replacements	$9.33	$13.29	$3.96	42.43%	$0.00	$0.00	$0.00	0.00%
Poor Performing Service Replacements	$5.52	$3.47	($2.05)	-37.07%	$0.00	$0.00	$0.00	0.00%
Intermediate Pressure (IP) Line Assessments	$0.43	$0.15	($0.28)	-64.75%	$0.30	$0.00	($0.30)	-99.36%
Distribution Valve Replacement Project	$0.31	$0.34	$0.02	7.12%	$0.00	$0.00	$0.00	0.00%
Federal Code Mitigation	$0.00	$0.00	$0.00	0.00%	$0.47	$0.16	($0.31)	-66.62%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	0.00%	$3.43	$3.28	($0.15)	-4.37%
TOTAL 2017 DIMP Capital Expenditures and O&M	**$15.60**	**$17.25**	**$1.65**	**10.61%**	**$4.20**	**$3.44**	**($0.76)**	**-18.10%**
TOTAL 2017 MN DIMP Incremental Revenue Requirement[21]	**$4.81**	**$3.96**	**($0.85)**	**-17.70%**	**$4.20**	**$3.44**	**($0.83)**	**-19.38%**

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18 Docket No. G002/M-17-787.
19 Based on actual costs as of 12/31/2017.
20 Includes removal costs (RWIP).
21 Capital Costs 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.

1) Poor Performing Main Replacements
WBS: E.0000007.002, E.0000007.045, E.0000007.060, E.0000007.067, E.0010011.003 (Capital)

Project Summary and Scope
For 2017, the poor performing mains materials primarily included PEA and vintage coated steel. Actual replacement activity in 2017 included:

Geographic Area (by Division)	Main (Miles)
St. Paul	10
White Bear Lake	23
Wyoming	7
Newport	1.5
St. Cloud	3
Southeast	5.5
Moorhead	1
Total	**51**

2017 Actual Project Costs
($ Millions)

DIMP Program	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital /O&M Expenditure	$9.33	$13.29	$3.96	42.43%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the increase in capital expenditures is related to imprecise assumptions related to planned service costs relative to main costs. More main costs relative to service costs occurred as a result of home density differences between urban, suburban, and rural settings. As a result, dollars originally budgeted as part of service costs were actually spent on main replacement activities.

The scope of final work varied significantly from original plans. This was the result of issues such as instances of construction under asphalt and concrete, larger diameter steel main, or a bore crossing the Mississippi River.

O&M: None.

2) Poor Performing Service Replacements
WBS: E.0000002.005, E.0000002.043, E.0000002.053, E.0000002.056, E.0010011.004 (Capital)

Project Summary and Scope
For 2017, the primary service-related material types addressed were PEA, vintage coated steel, and copper risers. Actual replacement activity in 2017 included:

Geographic Area (by Division)	Services (Number)
St. Paul	520
White Bear Lake	1,120
Wyoming	320
Newport	120
St. Cloud	160
Southeast	410
Moorhead	100
Total	**2,750**

2017 Actual Project Costs
($ Millions)

DIMP Program	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditure	$5.52	$3.47	($2.05)	-37.07%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the decrease in capital expenditures is related to incorrect assumptions related to planned service costs relative to main costs. More main costs relative to service costs occurred as a result of home density differences between urban, suburban, and rural settings. As a result, dollars originally budgeted as part of service costs were actually spent on main replacement activities. These differences are often not captured accurately in budgeted amounts.

3) IP Line Assessments
WBS: E.0000007.053 (Capital); A.0008610.004.001.005 (O&M)

Project Summary and Scope
This project includes health and condition assessments on IP lines. In 2017, the Company performed an ECDA test and completed the design and engineering activities for two replacement projects being constructed in 2018. 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 Actual Project Costs
($ Millions)

Program	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditure	$0.43	$0.15	($0.28)	-64.75%	$0.30	$0.00	($0.30)	-99.36%

Variance Explanation

Capital: Engineering costs were lower than anticipated for the Colby Lake Lateral Renewal and H005 System Renewal – Lexington to Snelling projects.

O&M: The Company was able to utilize more internal labor than was initially anticipated. Internal labor is not recovered through the GUIC Rider. In addition, certain costs performed in 2017 were not processed until 2018.

4) Distribution Valve Replacement Project
WBS: E.0000004.075, E.0000004.054, E.0010011.005, E.0000008.050, E.0000008.002 (Capital)

Project Summary and Scope
In 2017, the Company replaced a total of twelve inoperable emergency distribution valves, ranging in size from 4-inch to 12-inch. In addition, the Company incurred minor carry-over costs related to fourteen valves that were originally replaced in 2016.

2017 Actual Project Costs
($ Millions)

Program	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital Expenditure	$0.31	$0.34	$0.02	7.12%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: Not significant.

5) Sewer and Gas Line Conflict Investigation
WBS: A.0008410.163.001.004, A.0008510.114.001.002, A.0008610.004.001.002 (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 accelerate or scale back inspections if conditions warrant.

Consistent with the level of effort for 2010 through 2016, approximately 22,293 services were inspected for conflicts in 2017. The Company discovered four conflicts during the year.

2017 Actual Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditure	$0.00	$0.00	$0.00	n/a	$3.43	$3.28	($0.15)	-4.37%

Variance Explanation

O&M: The decrease in O&M expenditures from our previous estimate results from the Company being able to utilize internal labor for a portion of the 2017 work. Internal labor is not recovered through GUIC.

6) Federal Code Mitigation
WBS: A.0008510.114.001.003, A.0008610.004.001.003 (O&M)

Project Summary and Scope
The work in 2017 related to the sleeving of risers and raising meter sets in the St. Cloud and Moorhead areas, as well as some meter relocation throughout the state.

2017 Actual Project Costs
($ Millions)

	2017 Capital, As Filed	2017 Capital Actuals	Variance	% Capital Variance	2017 O&M, As Filed	2017 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditure	$0.00	$0.00	$0.00	0.00%	$0.47	$0.16	($0.31)	-66.62%

Variance Explanation

O&M: Work for this program was reprioritized and a number of O&M activities, initially planned in 2017, are now taking place in 2018.

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 2019. As the Company continues to execute its risk-based strategy and replacement projects planned in advance of 2020 and beyond, pipe segments displaying the highest level of relative risk will be targeted. 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 for future years, broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates. More detailed annual estimates will be developed in the future. 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 2020-2023 Plan[22]
($ Millions)

	2020 Estimates		2021 Estimates		2022 Estimates		2023 Estimates	
Sub-Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$10.08	$0.00	$10.08	$0.00	$10.08	$0.00	$10.08	$0.00
Poor Performing Services	$6.30	$0.00	$6.30	$0.00	$6.30	$0.00	$6.54	$0.00
IP Line Assessments	$0.48	$0.58	$23.50	$0.58	$28.45	$0.58	$17.48	$0.58
TOTAL	**$16.86**	**$0.58**	**$39.88**	**$0.58**	**$44.83**	**$0.58**	**$34.10**	**$0.58**

[22] Capital figures denoted represent total estimated capital expenditures, including removal costs.

Northern States Power Company

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Gas Utility Infrastructure Cost Rider - 2019 Factors
Attachment D1 - Page 1 of 1

DIMP 2017-2019 Project Detail

CAPITAL

Program	Regulation	WBS Structure	2017 Actuals	Cost Per Unit (CPU) Assumptions	2018 Actuals [1]	2018 Forecast	2018 Total	Cost Per Unit (CPU) Assumptions	2019 Plan	Cost Per Unit (CPU) Assumptions
Distribution Valve Replacement	Code 49 CFR Part 192.1007(d).		$ 507,262	See Attachment D1(f) for actual cost results.	$ 75,962	$ 419,038	$ 495,000	2018 estimated cost per valve is $31K/valve for 16 valves.	$ -	N/A
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02		$ 13,494,952	Based on 2017 actuals: $46.72/ft. for contractor-performed work and internal/local projects.	$ 909,316	$ 10,654,452	$ 11,563,768	2018 forecast is $41.5/ft. for contractor-performed work and internal/local projects. Considered the best available information.	$ 10,080,000	2019 forecast is $56.2/ft. for contractor-performed work and internal/local projects. Considered the best available information.
Poor Performing Services			$ 3,522,523	Based on 2017 actuals: $1,283/service.	$ 162,856	$ 7,056,435	$ 7,219,292	2018 forecast is $1,283/service for contractor-performed work and internal/local projects. Considered the best available information.	$ 6,300,000	2019 forecast is $1,765/service for contractor-performed work and internal/local projects. Considered the best available information.
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).		$ 166,550	See Attachment D1(e) for actual cost results.	$ 3,106,180	$ 16,658,570	$ 19,764,750	See Attachment D1(e) for CPU estimates by project.	$ -	See Attachment D1(e) for CPU estimates by project.
TOTAL DIMP CAPITAL			**$ 17,691,287**		**$ 4,254,314**	**$ 34,788,496**	**$ 39,042,810**		**$ 16,380,000**	

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

O&M

Program	Regulation	WBS Structure	2017 Actuals	Cost Per Unit (CPU) Assumptions	2018 Actuals [1]	2018 Forecast	2018 Total	Cost Per Unit (CPU) Assumptions	2019 Plan	Cost Per Unit (CPU) Assumptions
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).		$ 1,913	See Attachment D1(e) for actual cost results.	$ 8,217	$ 391,783	$ 400,000	See Attachment D1(e) for CPU estimates by project.	$ 625,000	See Attachment D1(e) for CPU estimates by project.
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)		$ 157,562	• $606 per exception is an average.	$ (40,071)	$ 240,071	$ 200,000	• $600 per exception is an average.	$ -	N/A
Sewer Conflict Investigation	Dockets Nos. G002/M-12-248 and G002/M-10-422		$ 3,284,612	Based on 2017 actuals: $159.8/inspection; 20,560 inspections	$ 765,597	$ 1,542,403	$ 2,308,000	$200.70/inspection; 11,500 inspections	$ 2,154,000	$165.18/inspection; 13,040 inspections
TOTAL DIMP O&M			**$ 3,444,087**		**$ 733,743**	**$ 2,174,257**	**$ 2,908,000**		**$ 2,779,000**	

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

[1] Actual costs through June 2018.

DIMP Replacement Project Detail for 2017

NSP-MN Main & Services DIMP Replacement Projects 2017

Area	Work Order Number	Description	Installed Footage	Services Replaced	Service CPU	Total Service Cost	Main Cost ($/ft installed)	Cost Per Unit ($/Ft Installed)
St Paul	12494722	ST PAUL - WESTMINSTER	5,876	57	$1,494	$85,142	$311,836	$53.07
	12294045	ROSEVILLE - FERNWOOD ST DIMP	3,761	40	$1,339	$53,570	$94,996	$25.26
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL DIMP 2017	9,600	137	$978	$134,044	$504,065	$52.51
	12508317	ST PAUL- KELLOGG (DOWNTOWN)	409	1	$1,403	$1,403	$36,496	$89.23
	12480505	ST PAULWANDA ST - DIMP	800	12	$1,105	$13,254	$44,997	$56.25
	12438126	ST PAUL - BURNS-RUTH DIMP 2017	11,665	145	$1,291	$187,291	$641,775	$55.02
	12511782	ROSEVILLE - OAKCREST	8,980	63	$967	$61,004	$428,887	$47.76
	12510283	ST PAUL - WHITALL ST	8,235	40	$1,082	$43,304	$682,412	$82.87
	12511776	ROSEVILLE - SHELDON	2,316	24	$1,374	$32,976	$76,391	$32.98
White Bear Lake	12499044	MAHTOMEDI - HALLMAN-KENWOOD-WILLIAMS	5,680	47	$1,203	$56,541	$195,641	$34.44
	12501049	STILLWATER - BIRCHWOOD DR	4,406	40	$976	$39,040	$163,897	$37.20
	12317857	ARDEN HILLS - ARDEN VIEW DR	2,276	33	$1,129	$37,266	$38,952	$17.11
	12479407	NORTH ST PAUL - 16TH AVE	2,747	23	$1,291	$29,704	$79,329	$28.88
	12481969	NORTH ST PAUL - INDIAN WAY	1,916	25	$1,033	$25,829	$41,770	$21.80
	12490131	MAPLEWOOD - WINTHROP DR.	2,886	33	$1,127	$37,202	$125,069	$43.34
	12453189	MAPLEWOOD - KOHLMAN/VAN DYKE	2,151	18	$1,311	$23,598	$65,552	$30.48
	12480668	MAPLEWOOD - BEAVER LAKE ESTATES	13,282	164	$1,361	$223,212	$531,283	$40.00
	12466988	MAPLEWOOD - MCKNIGHT	2,100	43	$1,218	$52,377	$214,163	$101.98
	12484866	MAHTOMEDI - OAKRIDGE DR	4,354	35	$1,200	$42,016	$140,837	$32.35
	12488109	NORTH OAKS - HAYCAMP RD	19,313	19	$2,743	$52,125	$506,384	$26.22
	12319969	MAHTOMEDI - GRIFFIN AVE	3,200	36	$1,282	$46,139	$95,928	$29.98
	12509562	NORTH ST PAUL 17TH AVE	950	8	$1,334	$10,672	$91,894	$96.73
	12482131	NORTH ST PAUL - MARGERET ST/12TH AVE	1,850	12	$1,192	$14,311	$221,012	$119.47
	12486720	MOUNDS VIEW - WOODALE DR	7,621	26	$1,159	$30,137	$196,472	$25.78
	12521893	NORTH ST PAUL - 15TH AVE/16TH AVE	3,600	52	$1,315	$68,380	$116,067	$32.24
	12481995	NORTH ST PAUL - BURKE AVE	2,948	35	$1,134	$39,705	$87,472	$29.67
	12585338	NEW BRIGHTON - WINDSOR CT	6,436	100	$1,164	$116,406	$297,506	$46.23
	100391006	NORTH ST PAUL - COWERN PL/NORTHWOOD DR	8,765	122	$1,277	$155,789	$240,222	$27.41
	12509429	CENTER CITY - CRESCENT RD	1,944	12	$1,299	$15,592	$44,006	$22.64
	100382714	NORTH ST PAUL - 18TH AVE	5,423	65	$1,367	$88,860	$138,119	$25.47
	100412219	ARDEN HILLS - GLENPAUL AVE DIMP	4,620	58	$1,244	$72,148	$67,584	$14.63
	100441854	FOREST LAKE - 208TH/209TH	4,002	32	$1,348	$43,139	$90,602	$22.64
	12494720	LITTLE CANADA/ JACKSON ST	2,100	10	$1,445	$14,454	$34,191	$16.28
	100412206	MAPLEWOOD - EDGERTON ST	4,144	22	$1,297	$28,541	$177,753	$42.89
	100439829	NORTH ST PAUL - 2ND AVE	3,789	51	$1,303	$66,449	$70,705	$18.66
Wyoming	12586221	FOREST LAKE - 216/IMPERIAL/INWOOD	3,333	25	$1,178	$29,457	$81,193	$24.36
	12490080	LINDSTROM- ANDREWS AVE	2,218	25	$1,520	$37,979	$87,225	$39.33
	12511766	FOREST LAKE - 3RD-6TH NW	10,797	84	$1,485	$124,794	$395,066	$36.59
	12505525	FOREST LAKE - BAY DR	10,693	77	$1,346	$103,649	$402,666	$37.66
	100441815	WYOMING - FINELY AVE	3,123	21	$1,279	$26,862	$60,166	$19.27
	12586414	FOREST LAKE - IVERSON AVE DIMP	3,701	53	$1,283	$68,004	$111,938	$30.25
	100441850	FOREST LAKE - 215TH/INWOOD AVE	4,291	33	$1,253	$41,355	$101,330	$23.61
Newport	12352434	COTTAGE GROVE - IRONWOOD DIMP	3,227	99	$1,314	$130,090	$144,482	$44.77
	12510007	WEST ST PAUL - OAKDALE	5,406	24	$1,365	$32,766	$493,706	$91.33
St Cloud	12533323	ST CLOUD - 44TH AVE N, VA	2,200	7	$1,640	$11,466	$105,081	$47.76
	12527212	ST. CLOUD-44TH AVE. & VETERANS DR.-DIMP-2400' 4" PE	2,400	12	$1,410	$16,925	$122,742	$51.14
	12467823	ST CLOUD - 16TH AVE - 2ND ST N TO BRECKENRIDGE	8,136	106	$1,328	$140,772	$452,598	$55.63
	12466583	ST CLOUD - 16TH AVE - 2ND ST N TO GERMAIN	2,799	38	$1,314	$49,922	$120,546	$43.07
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1,700	-	$0	$0	$748,060	$440.04
Southeast	12505914	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST DIMP	11,070	160	$1,599	$256,002	$1,624,373	$146.74
	100349421	WINONA 3RD STREET DIMP - RAILROAD WORK	300	0	$0	$0	$52,540	$175.13
	12551116	WINONA 98049 - CLARKS LN	8,160	79	$1,304	$103,002	$160,121	$19.62
	12360394	RED WING - SPRUCE/SOUTHWOOD DIMP	6,000	86	$1,314	$113,010	$285,165	$47.53
	12356426	LAKE CITY - LAKEWOOD AVE DIMP	4,110	79	$983	$77,701	$207,910	$50.59
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE.	1,268	38	$1,166	$44,311	$59,635	$47.03
	12422040	DILWORTH - 1ST AVE SE DIMP	4,989	60	$1,214	$72,838	$94,049	$18.85
2017 DIMP-related Main Replacement Total			**274,066**	**2,746**	**$1,282.8**	**$3,522,525**	**$12,804,857**	**$46.72**

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

DIMP Replacement Project Detail for 2018

NSP-MN Main & Services DIMP Replacement Projects 2018

Area	Notification	Description	Estimated Footage	Services Replaced	Service CPU	Estimated Service Cost	Estimated Main Cost	Cost Per Unit ($/Ft Installed)
St Paul		ROSEVILLE - CO RD 2/LAKEVIEW AVE	14,150	142	$1,283	$182,186	$586,942	$41.5
		ROSEVILLE - OXFORD	1,350	5	$1,283	$6,415	$55,998	$41.5
		ST PAUL - WANDA ST	900	12	$1,283	$15,396	$37,332	$41.5
		ST PAUL - UPPER/AFTON	9,215	125	$1,283	$160,375	$382,238	$41.5
		ST PAUL - FALCON/EDGEBROOK/WINTHROP	16,450	232	$1,283	$297,656	$682,346	$41.5
		ST PAUL - EDGERTON ST	1,100	12	$1,283	$15,396	$45,628	$41.5
		ST PAUL - DOROTHY DAY PL	2,150	7	$1,283	$8,981	$89,182	$41.5
		ST PAUL - 10616177 CAPITAL BLVD	150	0	$1,283	$0	$6,222	$41.5
		ST PAUL - 11076457 VIEW ST	150	2	$1,283	$2,566	$6,222	$41.5
		ST PAUL - 10447282 2ND ST S	350	0	$1,283	$0	$14,518	$41.5
		ST PAUL - 11338101 FAIRMOUNT	100	0	$1,283	$0	$4,148	$41.5
		ST PAUL - RICE ST	500	5	$1,283	$6,415	$20,740	$41.5
White Bear Lake		SHOREVIEW - JANSA	7,000	57	$1,283	$73,131	$290,360	$41.5
		LITTLE CANADA - LABORE RD	5,423	39	$1,283	$50,037	$224,946	$41.5
		LITTLE CANADA - EDGERTON ST	5,007	50	$1,283	$64,150	$207,690	$41.5
		LITTLE CANADA - EDGERTON ST N	8,500	74	$1,283	$94,942	$352,580	$41.5
		LITTLE CANADA - GREENBRIER	2,500	25	$1,283	$32,075	$103,700	$41.5
		LITTLE CANADA - WESTWIND DR	3,000	28	$1,283	$35,924	$124,440	$41.5
		MAPLEWOOD - ELM	1,400	10	$1,283	$12,830	$58,072	$41.5
		NEW BRIGHTON - 10TH	3,500	37	$1,283	$47,471	$145,180	$41.5
		NEW BRIGHTON - WINDSOR CT PH 3	1,850	45	$1,283	$57,735	$76,738	$41.5
		NORTH ST PAUL - IVY	2,000	30	$1,283	$38,490	$82,960	$41.5
		OAKDALE - GERSHWIN	1,200	14	$1,283	$17,962	$49,776	$41.5
		OAKDALE - GRAFTON	1,400	12	$1,283	$15,396	$58,072	$41.5
		SHOREVIEW - NICHOLS	2,000	25	$1,283	$32,075	$82,960	$41.5
		SHOREVIEW - BRIGADOON	2,500	45	$1,283	$57,735	$103,700	$41.5
		SHOREVIEW - MERCURY	4,000	24	$1,283	$30,792	$165,920	$41.5
		BIRCHWOOD VILLAGE - BIRCHWOOD	3,500	22	$1,283	$28,226	$145,180	$41.5
		MAPLEWOOD - MARY JO LN	4,739	36	$1,283	$46,188	$196,574	$41.5
		MAPLEWOOD - COPE AVE	3,531	38	$1,283	$48,754	$146,466	$41.5
		MAPLEWOOD - JACKSON ST	4,795	45	$1,283	$57,735	$198,897	$41.5
		MAPLEWOOD - CRAIG PL	5,454	53	$1,283	$67,999	$226,232	$41.5
		MAPLEWOOD - MARYLAND	2,700	21	$1,283	$26,943	$111,996	$41.5
		MAPLEWOOD - PROSERITY	1,250	8	$1,283	$10,264	$51,850	$41.5
		MAPLEWOOD - ARCADE	4,000	37	$1,283	$47,471	$165,920	$41.5
		MAPLEWOOD - ROSELAWN	2,400	8	$1,283	$10,264	$99,552	$41.5
		MAPLEWOOD - RADITZ	3,800	30	$1,283	$38,490	$157,624	$41.5
		MAPLEWOOD - HOLLOWAY	3,500	27	$1,283	$34,641	$145,180	$41.5
		MAPLEWOOD - MAYHILL/MINNEHAHA	5,000	56	$1,283	$71,848	$207,400	$41.5
		NORTH ST PAUL - HILLTOP CT	2,591	29	$1,283	$37,207	$107,475	$41.5
		NORTH ST PAUL - COWERN	2,300	28	$1,283	$35,924	$95,404	$41.5
		NORTH ST PAUL - 1ST AVE	6,311	82	$1,283	$105,206	$261,780	$41.5
		NORTH ST PAUL - SHOSHONE	2,500	27	$1,283	$34,641	$103,700	$41.5
		NORTH ST PAUL - 325618 1ST AVE	2,000	19	$1,283	$24,377	$82,960	$41.5
		NORTH ST PAUL - SKILLMAN	7,000	73	$1,283	$93,659	$290,360	$41.5
		NORTH ST PAUL - 7TH	1,400	4	$1,283	$5,132	$58,072	$41.5
		NORTH ST PAUL - NAVAJO	2,300	28	$1,283	$35,924	$95,404	$41.5
		NORTH ST PAUL - 1ST AVE E	3,400	46	$1,283	$59,018	$141,032	$41.5
		NORTH ST PAUL - 4TH & MARGARET	4,500	54	$1,283	$69,282	$186,660	$41.5
		OAKDALE - 341993 49TH ST	180	0	$1,283	$0	$7,466	$41.5
		SHOREVIEW - HODGSON	4,600	19	$1,283	$24,377	$190,808	$41.5
		STILLWATER - SYCAMORE	4,700	45	$1,283	$57,735	$194,956	$41.5
		STILLWATER - OLIVE ST	2,350	25	$1,283	$32,075	$97,478	$41.5
		WHITE BEAR LAKE - CLARENCE	4,000	44	$1,283	$56,452	$165,920	$41.5
		WHITE BEAR LAKE - STILLWATER ST-BALD-GARDEN	14,049	124	$1,283	$159,092	$582,753	$41.5
		WHITE BEAR LAKE - SOUTHWOOD	2,500	34	$1,283	$43,622	$103,700	$41.5
		WHITE BEAR LAKE - E COUTNY LN	2,250	18	$1,283	$23,094	$93,330	$41.5
		WHITE BEAR LAKE - 10800339 CO RD E E	250	1	$1,283	$1,283	$10,370	$41.5
		WHITE BEAR TOWNSHIP - BELLAIRE	7,000	57	$1,283	$73,131	$290,360	$41.5
Wyoming		FOREST LAKE - FONDANT	5,000	48	$1,283	$61,584	$207,400	$41.5
		FOREST LAKE - HARROW	2,000	15	$1,283	$19,245	$82,960	$41.5
		FOREST LAKE - 210TH	6,352	41	$1,283	$52,603	$263,481	$41.5
		FOREST LAKE - LAKE ST/11TH AVE	2,123	22	$1,283	$28,226	$88,062	$41.5
Newport		INVER GROVE HTS - CONROY CT DIMP	5,370	130	$1,283	$166,790	$222,748	$41.5
		INVER GROVE HTS - DAWN-UPPER 75TH-77TH	5,160	93	$1,283	$119,319	$214,037	$41.5
		MAPLEWOOD- MARNIE & HIGHWOOD	13,500	88	$1,283	$112,904	$559,980	$41.5
		ST PAUL - VALLEY VIEW ST	3,750	38	$1,283	$48,754	$155,550	$41.5
		WEST ST PAUL - MENDOTA RD	3,040	18	$1,283	$23,094	$126,099	$41.5
		COTTAGE GROVE - HEARTHSIDE RD	4,160	94	$1,283	$120,602	$172,557	$41.5
		COTTAGE GROVE - IDEAL-85TH ST DIMP	2,000	18	$1,283	$23,094	$82,960	$41.5
		COTTAGE GROVE - HAMLET	6,950	89	$1,283	$114,187	$288,286	$41.5
		MAPLEWOOD-MAYHILL	3,771	40	$1,283	$51,320	$156,421	$41.5
		MENDOTA HEIGHTS - OVERLOOK RD	5,700	45	$1,283	$57,735	$236,436	$41.5
		MENDOTA HEIGHTS - WINSTON CT	4,600	38	$1,283	$48,754	$190,808	$41.5
		ST PAUL - CONGRESS	4,700	38	$1,283	$48,754	$194,956	$41.5
		ST PAUL PARK- SUMMIT AVE	3,900	38	$1,283	$48,754	$161,772	$41.5
St Cloud		ST CLOUD - 6TH ST N, 11TH ST 10TH ST	1,600	19	$1,283	$24,377	$66,368	$41.5
Southeast		WINONA - KNOLLWOOD LN	2,100	8	$1,283	$10,264	$87,108	$41.5
		RED WING - WRIGHT/FINRUD DIMP	10,400	130	$1,283	$166,790	$431,392	$41.5
		RED WING - 21ST ST	1,500	17	$1,283	$21,811	$62,220	$41.5
		RED WING - CENTRAL PARK ST	1,600	18	$1,283	$23,094	$66,368	$41.5
		WINONA 98058 - COLLEGEVIEW ST	2,000	54	$1,283	$69,282	$82,960	$41.5
		WINONA 107558 - E 7TH ST	3,500	64	$1,283	$82,112	$145,180	$41.5
		WINONA 107542 - E 10TH ST	3,000	108	$1,283	$138,564	$124,440	$41.5
		WINONA 107603 - 7TH ST W	5,800	138	$1,283	$177,054	$240,584	$41.5
		WINONA 106932 - 44TH AVE	4,300	99	$1,283	$127,017	$178,364	$41.5
Moorhead		MOORHEAD - BIRCH, CEDAR, & OAK	8,000	130	$1,283	$166,790	$331,840	$41.5
2017 DIMP-related Main Replacement Total			**344,571**	**3,873**	**$1,283**	**$4,969,059**	**$14,292,805**	**$41.5**

*Project detail amounts vary from costs presented in Attachment D1(a), due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

DIMP Replacement Project Detail for 2019

NSP-MN Main & Service Replacement Projects 2019					
City	Description	Total Design FT.	Tot. Svc	Anticipated Cost	Cost Per Unit ($/Ft Installed)
Cottage Grove	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE DIMP	7000	40	$ 394,463	$ 56.4
	COTTAGE GROVE - HYDE AVE DIMP	3600	41	$ 234,268	$ 65.1
Faribault	FARIBAULT 109442 - IRVING AVE	4600	81	$ 287,923	$ 62.6
Forest Lake	FOREST LAKE - 210TH	6352	41	$ 306,683	$ 48.3
	FOREST LAKE - HARROW	2000	15	$ 99,245	$ 49.6
	FOREST LAKE - LAKE ST/11TH AVE	2123	22	$ 113,146	$ 53.3
Lake City	LAKE CITY 117574 - S 10TH ST	2100	43	$ 139,169	$ 66.3
Lake Elmo	LAKE ELMO - 31ST/JAMLEY/JANERO	6882	43	$ 330,449	$ 48.0
Mahtomedi	MAHTOMEDI - NEPTUNE	2350	14	$ 111,962	$ 47.6
Maplewood	MAPLEWOOD - BEAUMONT	1300	16	$ 72,528	$ 55.8
	MAPLEWOOD - PROSERITY	1100	8	$ 54,264	$ 49.3
Mendota Heights	MENDOTA HEIGHTS - BACHELOR-STANWICH	10570	100	$ 551,100	$ 52.1
	MENDOTA HEIGHTS - OVERLOOK RD	5700	45.0	$ 285,735	$ 50.1
North St Paul	NORTH ST PAUL - HILLTOP CT	2591	29.0	$ 140,847	$ 54.4
	NORTH ST PAUL - COWERN	2300	28.0	$ 127,924	$ 55.6
Northfield	NORTHFIELD - 321 ST W	3950	35.0	$ 202,905	$ 51.4
Red Wing	RED WING 189784 - 9TH ST	850	8.0	$ 44,264	$ 52.1
	RED WING 189276 - WOODLAND DR	4200	48.0	$ 229,584	$ 54.7
	RED WING 189336 - REDING AVE	4830	48.0	$ 254,784	$ 52.8
	RED WING 195249 - MAPLE ST	7600	174.0	$ 527,242	$ 69.4
Roseville	ROSEVILLE - OXFORD	1200	5.0	$ 54,415	$ 45.3
Sartell	SARTELL - RIVERSIDE AVE	4300		$ 172,000	$ 40.0
St Cloud	ST CLOUD - VETRANS DR & ANDERSON AVE	3500	7.0	$ 168,481	$ 48.1
	ST CLOUD - CLOVERFIELD TRAILER PARK	6900		$ 276,000	$ 40.0
	ST CLOUD - 4TH AVE N	4600		$ 184,000	$ 40.0
	ST CLOUD - KINGS WAY	1550	19.0	$ 86,377	$ 55.7
St Paul	ST PAUL - BATTLE CREEK 1	4300	58.0	$ 246,414	$ 57.3
Wabasha	WABASHA - INDUSTRIAL PARK	4200	11.0	$ 182,113	$ 43.4
Waite Park	WAITE PARK - PROSPER DR	2600		$ 104,000	$ 40.0
White Bear Lake	WHITE BEAR LAKE - CLARENCE	3900	44.0	$ 212,452	$ 54.5
	WHITE BEAR TOWNSHIP - SOUTH SHORE BLVD	9500	95.0	$ 501,885	$ 52.8
Winona	WINONA 107542 - E 10TH ST	3000	108.0	$ 258,564	$ 86.2
	WINONA 107558 - E 7TH ST	3500	64.0	$ 222,112	$ 63.5
	WINONA 107587 - E 9TH ST	1400	35.0	$ 100,905	$ 72.1
	WINONA 98058 - COLLEGEVIEW ST	2000	54.0	$ 149,282	$ 74.6
	WINONA 98162 - W 9TH ST	3400	64.0	$ 218,112	$ 64.2
	WINONA 98341 - E 8TH ST	4000	66.0	$ 274,678	$ 68.7
	WINONA 107603 - 7TH ST W	5800	138.0	$ 409,054	$ 70.5
	WINONA - EDGEWOOD RD	3950	49.0	$ 220,867	$ 55.9
	WINONA - LAIRD ST	475	6.0	$ 26,698	$ 56.2
	WINONA - HILBERT ST	6850	66.0	$ 391,678	$ 57.2
	WINONA - 11TH ST/SUNSET DR	15050	194.0	$ 850,902	$ 56.5
	WINONA - W 6TH ST	2700	25.0	$ 167,825	$ 62.2
	WINONA 98082 -CONRAD DR	5300	133.0	$ 382,639	$ 72.2
2019 Designed DIMP-related Main Replacement Total		147,666	1,764	$ 10,369,938	$ 56.2

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2018 and the first two quarters of 2019.

2017-2019 Project Detail - DIMP Assessments/Replacements

2017

Line/Loop	Project Description	Estimates	O&M or Capital
Hugo IP Line (11.1 miles)	**ECDA**	**$ 1,913**	
	Permitting	1,913	O&M
Colby Lake Lateral Renewal	**Replacement**	**$ 131,191**	
	Engineering, Design, Easement Acquisition	131,191	Capital
H005 System Renewal - Lexington to Snelling	**Replacement**	**$ 35,359**	
	Engineering, Design, Easement Acquisition	35,359	Capital
Capital Total		**$ 166,550**	
O&M Total		**$ 1,913**	

2018

Project	Description	Assumptions
Colby Lake Lateral - Woodlane to Colby Lake Capital Project (no O&M) 2017 Actual Costs: $ 131,191 2018 Estimated Costs: - $11.6M Construction	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · 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	Benefits: ILI assessable Current Classification: High Pressure Distribution Future Classification: Distribution · Total Cost Per Unit: $4.6 million per mile.
H005 - Lexington to Snelling Capital Project (no O&M) 2017 Actual Costs: $ 35,359 2018 Estimated Costs: - $10.6M Construction	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · 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	Benefits: Eliminate poor performance, unknown Current Classification: High Pressure Distribution Future Classification: Distribution · Total Cost Per Unit: $3.5 million per mile.
H08 – Lake Elmo 1A TBS O&M Project 2018 Estimated O&M Costs: - $200K ECDA	· Project Type: ECDA · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Lake Elmo, MN. · 2018 Assessment Period: May – October 2018	· 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: - $200K ECDA	· Project Type: ECDA · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Cottage Grove, MN. · 2018 Assessment Period: May – October 2018	· Survey: $10K · 3 digs at $60K each · Minor costs (permitting, new CP test leads, etc.)

2019

Line/Loop	Project Description	
Montreal Line North – River Crossings/Headers	· Project Type: Hydrostatic Pressure Test	
	· Regulation: 49 CFR 192.1007(d)	
	· Overview: High pressure distribution pipe segments crossing the	
	· Location: Sections cross the Mississippi River and extend from Shepard	
O&M Project	· 2018 Assessment Period: May – October 2018	
Crossing 1	$130K	North header to south header - 12"
Crossing 2	$120K	North header to south header - 12"
Crossing 3	$120K	North header to south header - 12"
Crossing 4	$120K	North header to south header - 12"
South Header	$134K	
Total Estimated O&M Costs:	$625K	

DIMP Distribution Valve Project Detail for 2017

NSP-MN Inoperable Distribution Valve Replacement DIMP Projects 2017

Project Name/Location	Valve #	Size/Mtl	Actual Cost
7th & Dale, STP	EV1241	12" SC	$ 59,446
Cypress & 6th, STP	EV1218	6" SC	$ 33,499
Roselawn & McMenemy, MPLWD	DV6070	4" SC	$ 97,293
McKnight & 3rd St E, STP	EV1289	4" SC	$ 53,480
McKnight & Hudson Rd, STP	EV1291	8" SC	$ 60,454
Chippewa & Wyoming, STP	EV1121	12" SC	$ 46,186
Sugar Loaf Rd & Lake Blvd, WIN	EV3237	4" SC	$ 15,311
Victoria & St. Anthony, STP	EV1069	6" SC	$ 5,895
Forest & Rose, STP	EV1202	12" SC	$ 60,172
Cypress & Reaney, STP	EV1213	8" SC	$ 10,504
Henry Ave & Fleming Field, SSTP	EV1245	12" SC	$ 25,561
Algonquin & Iroquois, STP	EV1275	12" SC	$ 31,137
Conway, Maplewood	EV5555	4" PE	$ 692
7th St N & Glenbrook Ave, Oakdale	EV6803	2" PE	$ 7
60th St N, Stillwater	EV5542	4" PE	$ (119)
Stillwater & Hale, Oakdale	EV5386	4" PE	$ 23
Koehler & Oak Creek, Vadnais Heights	EV5344	4" PE	$ 11
Olinda & Omaha, Baytown	EV5454	2" PE	$ 25
White Bear Ave & Beam, Maplewood	EV5360	4" PE	$ 31
White Bear Ave & Co Rd D, Maplewood	EV5359	4" PE	$ 29
Lexington & Ingerson, Shoreview	EV6819	4" PE	$ 11
Hillview & Quincy, Moundsview	EV6841	6" PE	$ 1,178
Larpenteur & English, Maplewood	EV6786	6" SC	$ 249
Larpenteur & Kennard, Maplewood	EV6787	8" SC	$ 6,115
White Bear Ave & I-694, White Bear Lake	EV5255	6" SC	$ 16
Cedar & Linden, White Bear Lake	EV5252	6" SC	$ 55
		Total	**$ 507,261**

Total Valves: 26

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
Fairview & Montreal, STP	EV1038	16" SC
Fairview & Montreal, STP	EV1316	16" SC
St. Albans & Alley South of Selby, STP	EV1373	4" SC
Victoria & St. Anthony, STP	EV1069	6" SC
Henry Ave & Fleming Field, SSTP	EV1245	12" SC
7th & South, NSTP	EV0291	6" SC
Algonquin & Iroquois, STP	EV1275	12" SC
Algonquin & Iroquois, STP	EV1276	12" SC
Forest & Rose, STP	EV1202	12" SC
Robert & Page, STP	EV1178	8" SC
Cypress & Reaney, STP	EV1213	8" SC
Hwy 19 W TBS, Northfield	EV3512	8"SC
Hwy 19 W TBS, Northfield	EV3513	6"SC

Total valves: 16

** Known valves, subject to change.*

DIMP Federal Code Mitigation 2017-2018

2017			Division							
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN	Total Items	Unit Cost	Actual Spend
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	48	34	8	170	0	260	$ 606	**$157,562**

2018			Division							
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN	Total Items	Unit Cost	Projected Spend
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	79	64	0	191	0	334	$ 600	**$200,400**

DIMP 2017 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2017 Projects

2017				
Polygon ID	**City**	**State**	**Project**	**Actual 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	Prairieview 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**
372455262	Roseville	MN	County Rd C2 W and Western Ave	784
359596126	Vadnais Heights	MN	Berwood and Arcade	1,168
372455266	Faribault	MN	8th St and 4th Ave	969
372455270	Sauk Rapids	MN	11th St N and 9th St N	869
372455278	Cottage Grove	MN	80th St S and Hwy 61	3,619
Not yet scoped				4,091
			Total	**11,500** *

*The current plan estimates that approximately 11,500 services will be inspected for conflicts in 2018, the 9th year of legacy inspections. Approximately 7,409 of the 11,500 planned inspections have been identified and scoped at this time.

DIMP 2019 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2019 Projects

2019			
Polygon ID	**City**	**State**	**Estimated Service Count**
372500010	Lindstrom	MN	500
372500011	Lino Lakes	MN	200
372500019	Oak Park Heights	MN	350
372500014	Marine Saint Croix	MN	250
372500015	Mendota Heights	MN	450
372500040	New Brighton	MN	3,390
372500018	Northfield	MN	1,000
372500020	Oakdale	MN	2,200
372500021	Red Wing	MN	1,100
372500028	Shoreview	MN	1,700
372500032	Vadnais Heights	MN	400
372500036	White Bear Lake	MN	1,500
		Total	**13,040**

Quantitative Risk Assessment for 2019 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 2018	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

Material Risk Factor Lookup Table

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

Pressure Risk Factor Lookup Table

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

Consequence of Failure Lookup Table

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

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

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 Classification
None										

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
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
Fairview & Montreal, STP	16" SC	N	Good	N	3	4	12	High Risk
Fairview & Montreal, STP	16" SC	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
Victoria & St. Anthony, STP	6" SC	N	Good	Y	3.25	4	13	High Risk
Henry Ave & Fleming Field, SSTP	12" SC	N	Good	N	3	3	9	Medium Risk
7th & South, NSTP	6" SC	N	N/A	N	3	2	6	Medium Risk
Algonquin & Iroquois, STP	12" SC	N	Good	N	3	4	12	High Risk
Algonquin & Iroquois, STP	12" SC	N	Good	N	3	4	12	High Risk
Forest & Rose, STP	12" SC	N	Good	N	3	4	12	High Risk
Robert & Page, STP	8" SC	N	Good	N	3	4	12	High Risk
Cypress & Reaney, STP	8" SC	N	Good	N	3	4	12	High Risk
Hwy 19 W TBS, Northfield	8"SC	N	Poor	N	3.75	4	15	High Risk
Hwy 19 W TBS, Northfield	6"SC	N	Poor	N	3.75	4	15	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 2019, the 10th 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
Likelihood of Failure	Area known to have a lot of rock Area known to have high water table Terraced properties (high home elevation relative to road) Services installed between 1991 and 2001 with trenchless or unknown installation method Services installed with trenchless installation method between 1991 and 2001 or with unknown installation date	**2**	2	4	6
Likelihood of Failure	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

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

DIMP Federal Code Mitigation

Project Risk

2019 Projects by Risk Category
NONE

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

High Risk: Risk Score ≥ 6

Medium Risk: Medium Risk, 2 ≤ Risk Score < 6

Low Risk: Risk Score < 2

<u>Riser in Concrete with no Sleeve</u>

			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

(dark)	High Risk: Risk Score ≥ 6
(medium)	Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
(light)	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	16
Medium	24 ≤ Score < 36	8
Low	1 ≤ Score < 24	0
None	Score < 1	0
Total	**All**	**24**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	OPTIMAIN SCORE	QRA SCORE
TBD	WINONA 107542 - E 10TH ST	3,000	108	1965	Coated Steel	MEDIUM	198	
TBD	WINONA 107558 - E 7TH ST	3,500	64	1965	Coated Steel	MEDIUM	54	
TBD	WINONA 107587 - E 9TH ST	1,400	35	1961	Coated Steel	MEDIUM	90	
TBD	WINONA 98058 - COLLEGEVIEW ST	2,000	54	1960	Coated Steel	HIGH	214	
TBD	WINONA 98162 - W 9TH ST	3,400	64	1960	Coated Steel	HIGH	220	
TBD	WINONA 98341 - E 8TH ST	4,000	66	1960	Coated Steel	HIGH	43	
TBD	WINONA 107603 - 7TH ST W	5,800	138	1966 Unknown	Coated Steel	MEDIUM	56	
TBD	WINONA - EDGEWOOD RD	3,950	49	1965	Coated Steel	HIGH	80.33	
TBD	WINONA - LAIRD ST	475	6	1960	Coated Steel	HIGH	52	
TBD	WINONA - HILBERT ST	6,850	66	1948	Coated Steel	HIGH	88	
TBD	WINONA - 11TH ST/SUNSET DR	15,050	194	1960	Coated Steel	HIGH	87	
TBD	WINONA - W 6TH ST	2,700	25	1963	Coated Steel	HIGH	67	
TBD	MAHTOMEDI - NEPTUNE	2,350	14	Unknown	Coated Steel	HIGH	33	
TBD	MAPLEWOOD - BEAUMONT	1,300	16	1955	Coated Steel	MEDIUM	28	
TBD	MAPLEWOOD - PROSERITY	1,100	8	1963	Coated Steel	MEDIUM	24	
TBD	RED WING 189784 - 9TH ST	850	8	1955	Coated Steel	HIGH	32	
TBD	RED WING 195249 - MAPLE ST	7,600	174	1959	Coated Steel	MEDIUM	28	
TBD	ROSEVILLE - OXFORD	1,200	5	Unknown	Coated Steel	HIGH	278	
TBD	ST CLOUD - KINGS WAY	1,550	19	Unknown	Coated Steel	HIGH	30	
TBD	ST PAUL - BATTLE CREEK 1	4,300	58	1960	Coated Steel	MEDIUM	30	
TBD	WHITE BEAR TOWNSHIP - SOUTH SHORE BLVD	9,500	95	Unknown	Coated Steel	HIGH	33	
TBD	WINONA 98082 -CONRAD DR	5,300	133	1968	Coated Steel	HIGH	224	
TBD	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE DIMP	7,000	40	1961	Coated Steel	HIGH	92	
TBD	COTTAGE GROVE - HYDE AVE DIMP	3,600	41	1961	Coated Steel	HIGH	231	

*Scoring included for known 2019 projects with completed engineering and design.

Poor Performing Plastic - Aldyl-A

Priority	Quantitative Risk Assessment Score	Priority Distribution
High	Score ≥ 7	1
Medium	4 ≤ Score < 7	18
Low	0 ≤ Score < 4	0
Total	**All**	**19**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	OPTIMAIN SCORE	QRA SCORE
TBD	FARIBAULT 109442 - IRVING AVE	4,600	81	1971	PE (Aldyl A)	HIGH	N/A	4.75
TBD	FOREST LAKE - 210TH	6,352	41	1967	PE (Aldyl A)	HIGH	N/A	4.75
TBD	FOREST LAKE - HARROW	2,000	15	1969	PE (Aldyl A)	HIGH	N/A	4.75
TBD	FOREST LAKE - LAKE ST/11TH AVE	2,123	22	Unknown	PE (Aldyl A)	HIGH	N/A	5.00
TBD	LAKE CITY 117574 - S 10TH ST	2,100	43	Unknown	PE (Aldyl A)	HIGH	N/A	5.00
TBD	LAKE ELMO - 31ST/JAMLEY/JANERO	6,882	43	1967	PE (Aldyl A)	MEDIUM	N/A	4.75
TBD	MENDOTA HEIGHTS - BACHELOR-STANWICH	10,570	100	1967	PE (Aldyl A)	HIGH	N/A	4.75
TBD	MENDOTA HEIGHTS - OVERLOOK RD	5,700	45	1969	PE (Aldyl A)	HIGH	N/A	4.75
TBD	NORTH ST PAUL - HILLTOP CT	2,591	29	1969	PE (Aldyl A)	HIGH	N/A	7.13
TBD	NORTH ST PAUL - COWERN	2,300	28	1968	PE (Aldyl A)	MEDIUM	N/A	6.75
TBD	NORTHFIELD - 321 ST W	3,950	35	1967	PE (Aldyl A)	HIGH	N/A	4.75
TBD	RED WING 189276 - WOODLAND DR	4,200	48	1969	PE (Aldyl A)	HIGH	N/A	4.75
TBD	RED WING 189336 - REDING AVE	4,830	48	1968	PE (Aldyl A)	HIGH	N/A	4.75
TBD	ST CLOUD - VETRANS DR & ANDERSON AVE	3,500	7	Unknown	PE (Aldyl A)	HIGH	N/A	5.00
TBD	ST CLOUD - CLOVERFIELD TRAILER PARK	6,900		Unknown	PE (Aldyl A)	HIGH	N/A	4.75
TBD	ST CLOUD - 4TH AVE N	4,600		Unknown	PE (Aldyl A)	HIGH	N/A	4.75
TBD	WABASHA - INDUSTRIAL PARK	4,200	11	Unknown	PE (Aldyl A)	HIGH	N/A	4.75
TBD	WAITE PARK - PROSPER DR	2,600		Unknown	PE (Aldyl A)	HIGH	N/A	4.75
TBD	WHITE BEAR LAKE - CLARENCE	3,900	44	1968	PE (Aldyl A)	HIGH	N/A	5.94

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

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.

Capital Expenditures
Actual and Forecast through 2023

Capital Expenditures (CWIP Only excluding internal labor)

Project Name	Sub Project	Pre-2017	2017	2018	2019	2020	2021	2022	2023	Total by Subproject
TIMP	Transmission	5,765,186	6,191,157	8,800,711	26,763,278	34,346,541	2,677,359	5,455,853	15,403,485	105,403,572
TIMP	Distribution	53,282,040	600,218	(32,830)	-	-	-	-	-	53,849,428
Total TIMP		**59,047,226**	**6,791,375**	**8,767,881**	**26,763,278**	**34,346,541**	**2,677,359**	**5,455,853**	**15,403,485**	**159,253,000**
DIMP	Distribution	23,459,665	13,444,043	38,545,588	16,300,802	16,886,009	42,880,964	43,469,459	32,426,777	227,413,305
DIMP	Software	444,543	-	-	-	-	-	-	-	444,543
Total DIMP		**23,904,208**	**13,444,043**	**38,545,588**	**16,300,802**	**16,886,009**	**42,880,964**	**43,469,459**	**32,426,777**	**227,857,848**
Total GUIC		**82,951,434**	**20,235,417**	**47,313,469**	**43,064,080**	**51,232,550**	**45,558,323**	**48,925,313**	**47,830,262**	**387,110,848**

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	59,405,917	59,493,185	59,504,067	59,782,253	60,173,422	60,494,532	60,806,937	61,029,357	61,012,569	61,028,374	66,480,475	66,781,746	66,781,746
Less Accumulated Book Depreciation Reserve	1,067,186	1,187,970	1,308,824	1,429,974	1,551,713	1,674,017	1,796,789	1,915,984	2,006,684	2,129,945	2,250,693	2,379,149	2,379,149
Less Accumulated Deferred Taxes	5,645,038	5,863,906	6,082,775	6,301,643	6,520,512	6,739,380	6,958,249	7,177,117	7,395,986	7,614,854	7,833,723	8,052,591	8,052,591
End Of Month Rate Base	52,693,693	52,441,308	52,112,469	52,050,636	52,101,197	52,081,135	52,051,899	51,936,255	51,609,899	51,283,575	56,396,059	56,350,007	56,350,007
Average Rate Base (Prior Mo + Cur Month/2)	52,859,481	52,567,500	52,276,889	52,081,552	52,075,916	52,091,166	52,066,517	51,994,077	51,773,077	51,446,737	53,839,817	56,373,033	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	99,993	99,440	98,890	98,521	98,510	98,539	98,492	98,355	97,937	97,320	101,847	106,639	1,194,485
Equity Return (Avg RB * Wtd Cost of Equity)	209,235	208,080	206,929	206,156	206,134	206,194	206,097	205,810	204,935	203,643	213,116	223,143	2,499,473
Total Return on Rate Base	309,228	307,520	305,820	304,677	304,644	304,733	304,589	304,165	302,873	300,963	314,963	329,782	3,693,958
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	120,714	120,784	120,854	121,150	121,739	122,304	122,772	123,122	123,256	123,261	128,870	134,783	1,483,608
Deferred Taxes	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	2,626,422
Gross Up for Income Tax (see below)	(69,108)	(87,254)	(58,343)	(44,079)	(65,836)	(74,023)	(116,718)	(131,016)	(106,578)	(33,000)	(42,669)	(61,194)	(889,818)
Total Income Statement Expense	354,606	336,530	365,511	380,071	358,903	351,280	309,054	295,106	319,678	393,261	389,201	376,589	4,229,790
Total Revenue Requirement	**663,834**	**644,050**	**671,331**	**684,748**	**663,547**	**656,014**	**613,643**	**599,271**	**622,550**	**694,224**	**704,164**	**706,372**	**7,923,747**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.75%												
Required Rate of Return	7.02%												
Current Income Tax Calculation													
Equity Return	209,235	208,080	206,929	206,156	206,134	206,194	206,097	205,810	204,935	203,643	213,116	223,143	2,499,473
Book Depreciation	120,714	120,784	120,854	121,150	121,739	122,304	122,772	123,122	123,256	123,261	128,870	134,783	1,483,608
Deferred Taxes	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	218,869	2,626,422
Less Tax Depreciation	649,873	673,771	631,929	611,439	642,917	654,948	715,711	736,539	702,160	601,377	629,877	665,034	7,915,576
Plus CPI-Tax Interest (If Applicable)	3,115	2,382	2,593	2,795	2,872	2,676	2,560	3,062	4,056	8,837	8,551	1,515	45,014
Total	(97,941)	(123,657)	(82,684)	(62,469)	(93,303)	(104,906)	(165,414)	(185,677)	(151,044)	(46,768)	(60,472)	(86,724)	(1,261,059)
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	(69,108)	(87,254)	(58,343)	(44,079)	(65,836)	(74,023)	(116,718)	(131,016)	(106,578)	(33,000)	(42,669)	(61,194)	(889,818)

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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	66,961,891	67,017,881	68,871,363	70,688,202	70,688,599	70,668,590	71,431,497	72,214,816	72,895,998	73,525,908	74,076,611	74,551,685	74,551,685
Less Accumulated Book Depreciation Reserve	2,489,604	2,600,257	2,711,971	2,826,207	2,941,954	3,086,838	(1,572,397)	(1,623,238)	(1,597,174)	(1,532,236)	(1,447,130)	(1,345,805)	(1,345,805)
Less Accumulated Deferred Taxes	8,082,276	8,111,961	8,141,646	8,171,331	8,201,016	8,230,701	8,245,065	8,274,750	8,304,913	8,334,120	8,364,283	8,393,489	8,393,489
End Of Month Rate Base	56,390,011	56,305,663	58,017,747	59,690,664	59,545,629	59,351,051	64,758,829	65,563,304	66,188,259	66,724,024	67,159,458	67,504,000	67,504,000
Average Rate Base (Prior Mo + Cur Month/2)	56,370,009	56,347,837	57,161,705	58,854,205	59,618,146	59,448,340	62,047,758	65,146,224	65,860,700	66,441,538	66,926,659	67,317,126	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	105,694	105,652	107,178	110,352	111,784	111,466	116,340	122,149	123,489	124,578	125,487	126,220	1,390,388
Equity Return (Avg RB * Wtd Cost of Equity)	246,619	246,522	250,082	257,487	260,829	260,086	271,459	285,015	288,141	290,682	292,804	294,512	3,244,239
Total Return on Rate Base	352,313	352,174	357,261	367,839	372,613	371,552	387,798	407,164	411,629	415,260	418,292	420,732	4,634,627
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	94,590	94,590	94,590	94,590	94,590	94,590	94,590	94,590	94,590	94,590	94,590	94,590	1,135,079
Book Depreciation	110,456	110,653	111,713	114,237	115,747	115,737	116,123	117,022	117,986	118,891	119,722	120,465	1,388,751
Deferred Taxes	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	356,219
Gross Up for Income Tax (see below)	6,925	7,198	773,404	9,606	11,222	13,792	14,444	18,927	21,019	22,531	24,423	30,634	954,124
Total Income Statement Expense	241,656	242,125	1,009,392	248,118	251,244	253,803	254,842	260,224	263,280	265,697	268,419	275,373	3,834,174
Total Revenue Requirement	**593,968**	**594,299**	**1,366,653**	**615,957**	**623,858**	**625,355**	**642,640**	**667,388**	**674,909**	**680,956**	**686,711**	**696,105**	**8,468,800**

Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.50%												
Current Income Tax Calculation													
Equity Return	246,619	246,522	250,082	257,487	260,829	260,086	271,459	285,015	288,141	290,682	292,804	294,512	3,244,239
Book Depreciation	110,456	110,653	111,713	114,237	115,747	115,737	116,123	117,022	117,986	118,891	119,722	120,465	1,388,751
Deferred Taxes	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	29,685	356,219
Less Tax Depreciation	370,092	369,126	(1,525,792)	378,405	381,147	375,541	385,934	388,686	387,688	387,688	386,179	372,471	2,657,167
Plus CPI-Tax Interest (If Applicable)	502	111	173	813	2,708	4,225	4,477	3,888	3,987	4,292	4,517	3,757	33,449
Total	17,169	17,844	1,917,445	23,817	27,822	34,192	35,810	46,923	52,110	55,861	60,549	75,948	2,365,491
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	6,925	7,198	773,404	9,606	11,222	13,792	14,444	18,927	21,019	22,531	24,423	30,634	954,124

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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	74,653,577	74,734,328	74,827,289	74,926,380	75,028,547	75,159,400	75,338,580	75,542,016	75,757,628	75,962,388	85,727,506	85,825,266	85,825,266
Less Accumulated Book Depreciation Reserve	(1,236,824)	(1,124,120)	(1,011,300)	(898,366)	(785,316)	(674,267)	(566,775)	(460,937)	(355,802)	(249,572)	(132,481)	(7,032)	(7,032)
Less Accumulated Deferred Taxes	8,453,549	8,547,499	8,638,467	8,732,417	8,823,385	8,917,335	9,008,303	9,100,762	9,194,713	9,285,680	9,379,631	9,470,598	9,470,598
End Of Month Rate Base	67,436,851	67,310,948	67,200,122	67,092,328	66,990,478	66,916,332	66,897,051	66,902,191	66,918,718	66,926,279	76,480,357	76,361,699	76,361,699
Average Rate Base (Prior Mo + Cur Month/2)	67,440,396	67,326,925	67,210,051	67,099,250	66,995,919	66,906,430	66,861,208	66,853,392	66,863,479	66,877,015	71,656,343	76,375,544	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	126,451	126,238	126,019	125,811	125,617	125,450	125,365	125,350	125,369	125,394	134,356	143,204	1,534,624
Equity Return (Avg RB * Wtd Cost of Equity)	302,358	301,849	301,325	300,828	300,365	299,964	299,761	299,726	299,771	299,832	321,259	342,417	3,669,456
Total Return on Rate Base	428,809	428,087	427,344	426,639	425,982	425,413	425,126	425,076	425,140	425,226	455,615	485,621	5,204,079
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	105,595	105,595	105,595	105,595	105,595	105,595	105,595	105,595	105,595	105,595	105,595	105,595	1,267,144
Book Depreciation	120,874	120,974	121,069	121,174	121,284	121,411	121,580	121,789	122,017	122,247	127,689	133,072	1,475,179
Deferred Taxes	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	1,109,508
Gross Up for Income Tax (see below)	38,544	38,465	36,979	28,013	25,495	21,454	24,941	14,136	30,827	42,268	57,255	77,943	436,319
Total Income Statement Expense	357,472	357,494	356,103	347,241	344,833	340,919	344,575	333,979	350,899	362,569	382,999	409,070	4,288,150
Total Revenue Requirement	**786,281**	**785,581**	**783,446**	**773,880**	**770,815**	**766,332**	**769,701**	**759,055**	**776,039**	**787,795**	**838,613**	**894,691**	**9,492,230**
Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.38%												
Required Rate of Return	7.63%												
Current Income Tax Calculation													
Equity Return	302,358	301,849	301,325	300,828	300,365	299,964	299,761	299,726	299,771	299,832	321,259	342,417	3,669,456
Book Depreciation	120,874	120,974	121,069	121,174	121,284	121,411	121,580	121,789	122,017	122,247	127,689	133,072	1,475,179
Deferred Taxes	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	1,109,508
Less Tax Depreciation	423,289	423,289	426,871	452,102	465,199	484,694	487,400	528,830	503,117	485,702	467,871	430,665	5,579,029
Plus CPI-Tax Interest (If Applicable)	3,156	3,371	3,698	7,091	14,299	24,050	35,434	49,903	65,296	75,955	68,413	55,955	406,620
Total	95,558	95,364	91,680	69,451	63,207	53,189	61,834	35,046	76,427	104,791	141,949	193,238	1,081,735
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	38,544	38,465	36,979	28,013	25,495	21,454	24,941	14,136	30,827	42,268	57,255	77,943	436,319

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TIMP - Capital Revenue Requirements	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	85,960,694	86,115,031	86,358,431	86,646,537	86,957,082	87,306,034	87,708,192	88,137,056	88,579,327	89,034,498	89,341,109	138,826,768	138,826,768
Less Accumulated Book Depreciation Reserve	115,580	(33,250)	81,268	192,583	302,479	409,731	513,229	615,099	716,403	819,007	931,873	1,077,105	1,077,105
Less Accumulated Deferred Taxes	9,590,811	9,743,045	9,890,446	10,042,679	10,190,080	10,342,313	10,489,714	10,639,531	10,791,764	10,939,165	11,091,399	11,238,799	11,238,799
End Of Month Rate Base	76,254,303	76,405,236	76,386,717	76,411,274	76,464,524	76,553,990	76,705,249	76,882,427	77,071,159	77,276,326	77,317,838	126,510,864	126,510,864
Average Rate Base (Prior Mo + Cur Month/2)	76,247,894	76,253,653	76,322,276	76,322,879	76,364,199	76,433,140	76,555,919	76,718,929	76,900,676	77,100,042	77,220,965	101,840,651	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	142,965	142,976	143,104	143,105	143,183	143,312	143,542	143,848	144,189	144,563	144,789	190,951	1,770,527
Equity Return (Avg RB * Wtd Cost of Equity)	341,845	341,871	342,178	342,181	342,366	342,675	343,226	343,957	344,771	345,665	346,207	456,586	4,233,527
Total Return on Rate Base	484,810	484,846	485,282	485,286	485,549	485,987	486,768	487,805	488,960	490,228	490,997	647,537	6,004,055
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	121,563	121,563	121,563	121,563	121,563	121,563	121,563	121,563	121,563	121,563	121,563	121,563	1,458,759
Book Depreciation	133,200	133,358	133,575	133,865	134,192	134,552	134,962	135,415	135,891	136,381	136,796	163,975	1,646,160
Deferred Taxes	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	1,797,805
Gross Up for Income Tax (see below)	8,560	8,749	4,100	(8,915)	(4,442)	(8,255)	(3,620)	(3,396)	12,238	33,559	43,697	69,295	151,570
Total Income Statement Expense	413,140	413,487	409,055	396,331	401,130	397,677	402,722	403,400	419,509	441,320	451,874	504,650	5,054,294
Total Revenue Requirement	**897,949**	**898,333**	**894,338**	**881,617**	**886,679**	**883,665**	**889,490**	**891,204**	**908,469**	**931,547**	**942,871**	**1,152,187**	**11,058,349**
Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.38%												
Required Rate of Return	7.63%												
Current Income Tax Calculation													
Equity Return	341,845	341,871	342,178	342,181	342,366	342,675	343,226	343,957	344,771	345,665	346,207	456,586	4,233,527
Book Depreciation	133,200	133,358	133,575	133,865	134,192	134,552	134,962	135,415	135,891	136,381	136,796	163,975	1,646,160
Deferred Taxes	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	1,797,805
Less Tax Depreciation	660,467	660,467	672,956	711,059	711,059	734,370	739,695	758,746	739,695	698,930	680,051	679,518	8,447,012
Plus CPI-Tax Interest (If Applicable)	56,828	57,112	57,551	63,094	73,672	86,861	102,715	121,138	139,556	150,267	155,566	80,938	1,145,296
Total	21,222	21,691	10,165	(22,101)	(11,012)	(20,465)	(8,975)	(8,419)	30,340	83,200	108,336	171,797	375,777
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	8,560	8,749	4,100	(8,915)	(4,442)	(8,255)	(3,620)	(3,396)	12,238	33,559	43,697	69,295	151,570

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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	24,536,584	24,531,083	24,387,313	24,564,804	25,809,184	27,069,459	28,128,413	29,572,813	30,572,801	32,717,247	33,685,075	35,605,770	35,605,770
Less Accumulated Book Depreciation Reserve	(2,990,916)	(2,961,827)	(2,935,257)	(2,958,380)	(3,375,078)	(3,766,387)	(3,898,463)	(4,343,813)	(4,462,379)	(5,407,497)	(5,665,799)	(5,709,218)	(5,709,218)
Less Accumulated Deferred Taxes	2,554,389	2,906,147	3,257,905	3,609,662	3,961,420	4,313,178	4,664,935	5,016,693	5,368,450	5,720,208	6,071,966	6,423,723	6,423,723
End Of Month Rate Base	24,973,110	24,586,762	24,064,665	23,913,522	25,222,842	26,522,669	27,361,941	28,899,933	29,666,729	32,404,536	33,278,908	34,891,265	34,891,265
Average Rate Base (Prior Mo + Cur Month/2)	23,856,778	24,779,936	24,325,714	23,989,094	24,568,182	25,872,755	26,942,305	28,130,937	29,283,331	31,035,632	32,841,722	34,085,086	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	45,129	46,875	46,016	45,379	46,475	48,943	50,966	53,214	55,394	58,709	62,126	64,478	623,704
Equity Return (Avg RB * Wtd Cost of Equity)	94,433	98,087	96,289	94,957	97,249	102,413	106,647	111,352	115,913	122,849	129,998	134,920	1,305,108
Total Return on Rate Base	139,562	144,963	142,305	140,336	143,724	151,356	157,612	164,566	171,307	181,558	192,124	199,398	1,928,812
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	32,966	32,966	32,966	32,966	32,966	32,966	32,966	32,966	32,966	32,966	32,966	32,966	395,590
Book Depreciation	56,677	57,997	57,840	57,875	59,368	61,998	64,433	67,062	69,628	72,930	76,198	79,231	781,237
Deferred Taxes	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	4,221,091
Gross Up for Income Tax (see below)	(86,671)	(142,008)	(142,492)	(460,631)	(408,565)	(258,403)	(365,006)	(431,602)	(430,055)	(323,975)	(184,747)	(135,507)	(3,369,664)
Total Income Statement Expense	354,729	300,712	300,071	(18,033)	35,526	188,318	84,150	20,183	24,297	133,678	276,174	328,447	2,028,254
Total Revenue Requirement	**494,291**	**445,674**	**442,376**	**122,304**	**179,250**	**339,674**	**241,763**	**184,749**	**195,605**	**315,237**	**468,298**	**527,845**	**3,957,066**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.75%												
Required Rate of Return	7.02%												
Current Income Tax Calculation													
Equity Return	94,433	98,087	96,289	94,957	97,249	102,413	106,647	111,352	115,913	122,849	129,998	134,920	1,305,108
Book Depreciation	56,677	57,997	57,840	57,875	59,368	61,998	64,433	67,062	69,628	72,930	76,198	79,231	781,237
Deferred Taxes	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	351,758	4,221,091
Less Tax Depreciation	627,762	711,703	712,791	1,162,663	1,092,782	887,228	1,044,387	1,146,087	1,151,195	1,011,601	825,655	761,293	11,135,147
Plus CPI-Tax Interest (If Applicable)	2,063	2,606	4,962	5,262	5,384	4,847	4,259	4,245	4,418	4,923	5,875	3,342	52,186
Total	(122,832)	(201,255)	(201,942)	(652,812)	(579,023)	(366,212)	(517,291)	(611,671)	(609,478)	(459,141)	(261,826)	(192,042)	(4,775,524)
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	(86,671)	(142,008)	(142,492)	(460,631)	(408,565)	(258,403)	(365,006)	(431,602)	(430,055)	(323,975)	(184,747)	(135,507)	(3,369,664)

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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	35,219,317	35,955,134	36,100,797	37,240,702	38,781,550	39,273,714	40,968,748	44,752,463	48,796,615	52,898,205	56,215,748	74,190,519	74,190,519
Less Accumulated Book Depreciation Reserve	(5,608,057)	(5,551,986)	(5,489,114)	(5,335,022)	(5,259,675)	(5,181,040)	(5,501,813)	(5,650,681)	(5,790,981)	(5,926,881)	(6,004,998)	(5,960,180)	(5,960,180)
Less Accumulated Deferred Taxes	6,525,473	6,627,222	6,728,972	6,830,721	6,932,470	7,034,220	7,083,453	7,185,203	7,288,593	7,388,702	7,492,092	7,592,200	7,592,200
End Of Month Rate Base	34,301,900	34,879,899	34,860,939	35,745,003	37,108,755	37,420,534	39,387,107	43,217,941	47,299,003	51,436,385	54,728,655	72,558,498	72,558,498
Average Rate Base (Prior Mo + Cur Month/2)	34,596,583	34,590,900	34,870,419	35,302,971	36,426,879	37,264,644	38,379,204	41,251,650	45,206,777	49,317,640	53,030,824	63,593,522	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	64,869	64,858	65,382	66,193	68,300	69,871	71,961	77,347	84,763	92,471	99,433	119,238	944,685
Equity Return (Avg RB * Wtd Cost of Equity)	151,360	151,335	152,558	154,450	159,368	163,033	167,909	180,476	197,780	215,765	232,010	278,222	2,204,265
Total Return on Rate Base	216,229	216,193	217,940	220,644	227,668	232,904	239,870	257,823	282,542	308,235	331,443	397,460	3,148,950
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	50,432	50,432	50,432	50,432	50,432	50,432	50,432	50,432	50,432	50,432	50,432	50,432	605,186
Book Depreciation	65,299	65,589	66,322	67,390	69,619	71,308	73,126	77,680	84,187	90,958	97,125	114,823	943,426
Deferred Taxes	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	1,220,993
Gross Up for Income Tax (see below)	14,149	3,751	2,066	3,128	(7,112)	(29,470)	(68,298)	(104,659)	(84,559)	(70,784)	(25,237)	47,905	(319,119)
Total Income Statement Expense	231,629	221,521	220,569	222,700	214,688	194,020	157,010	125,203	151,810	172,355	224,070	314,909	2,450,486
Total Revenue Requirement	**447,858**	**437,714**	**438,510**	**443,343**	**442,356**	**426,924**	**396,880**	**383,026**	**434,352**	**480,590**	**555,512**	**712,369**	**5,599,436**

Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.50%												
Current Income Tax Calculation													
Equity Return	151,360	151,335	152,558	154,450	159,368	163,033	167,909	180,476	197,780	215,765	232,010	278,222	2,204,265
Book Depreciation	65,299	65,589	66,322	67,390	69,619	71,308	73,126	77,680	84,187	90,958	97,125	114,823	943,426
Deferred Taxes	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	101,749	1,220,993
Less Tax Depreciation	288,554	313,534	320,298	320,886	353,577	416,193	524,318	639,534	623,067	623,067	540,780	405,799	5,369,609
Plus CPI-Tax Interest (If Applicable)	5,225	4,159	4,791	5,051	5,208	7,040	12,208	20,156	29,711	39,105	47,329	29,772	209,755
Total	35,079	9,299	5,122	7,755	(17,633)	(73,062)	(169,325)	(259,473)	(209,640)	(175,490)	(62,567)	118,767	(791,169)
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	14,149	3,751	2,066	3,128	(7,112)	(29,470)	(68,298)	(104,659)	(84,559)	(70,784)	(25,237)	47,905	(319,119)

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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	75,521,782	76,340,173	76,879,415	77,590,916	78,903,983	80,698,639	82,565,481	85,083,665	87,353,991	89,659,144	91,548,806	92,415,881	92,415,881
Less Accumulated Book Depreciation Reserve	(5,872,337)	(5,773,932)	(6,165,671)	(6,071,644)	(6,019,031)	(5,990,338)	(5,955,484)	(5,937,815)	(5,900,875)	(5,861,490)	(5,806,583)	(5,685,658)	(5,685,658)
Less Accumulated Deferred Taxes	7,698,060	7,810,083	7,918,550	8,030,573	8,139,039	8,251,062	8,359,529	8,469,774	8,581,797	8,690,263	8,802,286	8,910,753	8,910,753
End Of Month Rate Base	73,696,058	74,304,023	75,126,536	75,631,987	76,783,974	78,437,915	80,161,436	82,551,707	84,673,069	86,830,371	88,553,103	89,190,786	89,190,786
Average Rate Base (Prior Mo + Cur Month/2)	73,074,348	73,944,029	74,661,046	75,323,250	76,153,747	77,554,933	79,245,442	81,301,449	83,556,377	85,697,487	87,635,726	88,817,712	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	137,014	138,645	139,989	141,231	142,788	145,415	148,585	152,440	156,668	160,683	164,317	166,533	1,794,310
Equity Return (Avg RB * Wtd Cost of Equity)	327,617	331,516	334,730	337,699	341,423	347,705	355,284	364,501	374,611	384,210	392,900	398,199	4,290,396
Total Return on Rate Base	464,631	470,161	474,720	478,930	484,211	493,120	503,869	516,942	531,279	544,893	557,217	564,733	6,084,706
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	105,084	105,084	105,084	105,084	105,084	105,084	105,084	105,084	105,084	105,084	105,084	105,084	1,261,005
Book Depreciation	130,870	132,657	133,786	134,825	136,508	139,091	142,135	145,780	149,760	153,563	157,050	159,341	1,715,366
Deferred Taxes	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	1,322,937
Gross Up for Income Tax (see below)	39,850	39,023	40,315	32,700	15,666	7,973	15,777	7,866	26,960	30,058	43,703	73,673	373,563
Total Income Statement Expense	386,049	387,009	389,430	382,854	367,502	362,393	373,240	368,974	392,049	398,949	416,081	448,342	4,672,871
Total Revenue Requirement	**850,680**	**857,169**	**864,149**	**861,784**	**851,713**	**855,513**	**877,109**	**885,916**	**923,328**	**943,842**	**973,298**	**1,013,075**	**10,757,577**
Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.38%												
Required Rate of Return	7.63%												
Current Income Tax Calculation													
Equity Return	327,617	331,516	334,730	337,699	341,423	347,705	355,284	364,501	374,611	384,210	392,900	398,199	4,290,396
Book Depreciation	130,870	132,657	133,786	134,825	136,508	139,091	142,135	145,780	149,760	153,563	157,050	159,341	1,715,366
Deferred Taxes	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	1,322,937
Less Tax Depreciation	474,539	480,209	480,209	502,776	550,404	578,641	570,250	602,909	569,456	574,899	552,785	485,653	6,422,732
Plus CPI-Tax Interest (If Applicable)	4,604	2,539	1,400	1,077	1,068	1,368	1,701	1,885	1,681	1,400	940	519	20,181
Total	98,797	96,747	99,951	81,070	38,839	19,767	39,114	19,502	66,841	74,520	108,350	182,651	926,148
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	39,850	39,023	40,315	32,700	15,666	7,973	15,777	7,866	26,960	30,058	43,703	73,673	373,563

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DIMP - Capital Revenue Requirements	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	92,870,514	93,226,333	93,457,261	94,043,104	95,295,459	97,071,809	98,895,511	101,431,118	103,718,448	106,040,352	107,939,274	108,811,467	108,811,467
Less Accumulated Book Depreciation Reserve	(5,547,082)	(5,409,002)	(5,268,552)	(5,144,018)	(5,062,636)	(5,006,278)	(4,944,375)	(4,899,986)	(4,836,281)	(4,770,097)	(4,688,180)	(4,540,128)	(4,540,128)
Less Accumulated Deferred Taxes	9,032,982	9,170,172	9,303,007	9,440,198	9,573,033	9,710,223	9,843,058	9,978,071	10,115,261	10,248,096	10,385,286	10,518,121	10,518,121
End Of Month Rate Base	89,384,614	89,465,162	89,422,805	89,746,925	90,785,063	92,367,865	93,996,828	96,353,034	98,439,469	100,562,353	102,242,167	102,833,474	102,833,474
Average Rate Base (Prior Mo + Cur Month/2)	89,226,586	89,356,293	89,377,566	89,516,270	90,199,576	91,507,869	93,115,929	95,107,425	97,327,656	99,434,493	101,333,665	102,471,403	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	167,300	167,543	167,583	167,843	169,124	171,577	174,592	178,326	182,489	186,440	190,001	192,134	2,114,953
Equity Return (Avg RB * Wtd Cost of Equity)	400,033	400,614	400,709	401,331	404,395	410,260	417,470	426,398	436,352	445,798	454,313	459,413	5,057,087
Total Return on Rate Base	567,332	568,157	568,292	569,174	573,519	581,838	592,062	604,725	618,842	632,238	644,313	651,547	7,172,039
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	130,898	130,898	130,898	130,898	130,898	130,898	130,898	130,898	130,898	130,898	130,898	130,898	1,570,779
Book Depreciation	160,440	161,113	161,601	162,280	163,808	166,326	169,318	172,941	176,950	180,782	184,290	186,593	2,046,442
Deferred Taxes	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	1,620,152
Gross Up for Income Tax (see below)	61,143	59,311	59,518	50,690	33,423	25,541	33,312	25,290	44,721	48,058	61,829	91,847	594,683
Total Income Statement Expense	487,494	486,336	487,030	478,881	463,141	457,778	468,541	464,142	487,583	494,750	512,030	544,351	5,832,056
Total Revenue Requirement	**1,054,826**	**1,054,493**	**1,055,323**	**1,048,055**	**1,036,660**	**1,039,615**	**1,060,603**	**1,068,867**	**1,106,424**	**1,126,988**	**1,156,343**	**1,195,898**	**13,004,095**
Capital Structure													
Weighted Cost of Debt	2.25%												
Weighted Cost of Equity	5.38%												
Required Rate of Return	7.63%												
Current Income Tax Calculation													
Equity Return	400,033	400,614	400,709	401,331	404,395	410,260	417,470	426,398	436,352	445,798	454,313	459,413	5,057,087
Book Depreciation	160,440	161,113	161,601	162,280	163,808	166,326	169,318	172,941	176,950	180,782	184,290	186,593	2,046,442
Deferred Taxes	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	1,620,152
Less Tax Depreciation	544,180	549,850	549,850	573,394	621,307	649,951	641,559	674,503	640,358	645,231	622,711	555,293	7,268,184
Plus CPI-Tax Interest (If Applicable)	282	156	86	441	953	1,674	2,346	2,849	2,917	2,784	2,383	1,983	18,857
Total	151,588	147,046	147,560	125,672	82,862	63,322	82,588	62,699	110,875	119,146	153,288	227,710	1,474,354
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	61,143	59,311	59,518	50,690	33,423	25,541	33,312	25,290	44,721	48,058	61,829	91,847	594,683

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Analysis Assumptions: 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 pulled from the most recent filed petitions (16-0891 & 17-0787).
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. Weighted Average Cost of Capital (WACC) Assumptions are pulled from 2018 MN Gas Jurisdictional Filing.

Debt	4,932,439
Cost of Debt	4.64%
Equity	5,459,858
Cost of Equity	10.09%
Tax Rate	35.00%
WACC	**6.73%**

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 2017)	$4,175,186	$3,639,148	$3,462,587	$3,464,732	$3,447,300	$3,381,101	$3,519,807	3,284,612	2,308,000	2,154,000
2	Estimated Discount Factor using 2018 WACC	1	0.94	0.88	0.82	0.77	0.72	0.68	0.63	0.59	0.56
3	PV of Costs	4,175,186	3,409,597	3,039,536	2,849,571	2,656,393	2,441,038	2,380,886	2,081,647	1,370,447	1,198,327
4	Cumulative PV of Costs	4,175,186	7,584,783	10,624,319	13,473,890	16,130,282	18,571,321	20,952,207	23,033,854	24,404,301	25,602,628
	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 in 2010-2017, 12 in 2018, 11 in 2019)	2,121,600	2,164,032	2,207,313	2,251,459	2,296,488	2,342,418	2,389,266	2,437,052	1,640,623	1,455,889
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	164,062	145,589
14	Employee Training/Certification	100,000	25,000	25,000	50,000	25,000	25,000	50,000	25,000	16,500	14,000
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; 1 from 2018-2019) fully loaded	35,000	35,000	35,000	70,000	70,000	70,000	70,000	70,000	35,000	35,000
18	Plumber costs	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	16,500	15,500
19	Dig up, inspection and repair (DRR)	150,000	150,000	125,000	100,000	80,000	80,000	65,000	65,000	40,000	35,000
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	2,881,485	2,669,778
21	Estimated Discount Factor using 2015 WACC	1	0.94	0.88	0.82	0.77	0.72	0.68	0.63	0.59	0.56
22	PV of Costs	5,037,560	3,053,648	2,946,712	3,035,176	2,847,215	2,704,093	2,575,146	2,430,179	1,710,971	1,485,268
23	Cumulative PV of Costs	5,037,560	8,091,208	11,037,920	14,073,096	16,920,311	19,624,404	22,199,550	24,629,728	26,340,700	27,825,967
24	**In-house vs Contractor Favorable / (Unfavorable)**	**(862,374)**	**(506,425)**	**(413,602)**	**(599,207)**	**(790,029)**	**(1,053,083)**	**(1,247,343)**	**(1,595,874)**	**(1,936,399)**	**(2,223,340)**

Estimated Retirements, Rate Base, and Depreciation Expense for GUIC Replaced Assets

	Annual Retirements	Estimate of 2010 Rate Base for Replaced Assets	Depreciation Expense
2012	$ 47	$ 14	$ 1
2013	1,053	322	31
2014	537,681	164,566	16,007
2015	1,801,071	551,247	53,619
2016	1,269,324	388,497	37,788
2017	2,669,862	817,154	79,483
2018	1,913,419	585,633	56,963
2019	1,913,419	585,633	56,963
Total	$ 10,105,876	$ 3,093,065	$ 300,856

3-Yr Average Retirements 2015-2017	% of Remaining NBV for replaced assets	Composite Depreciation Rate
1,913,419	30.61%	2.98%

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4584498	1,138,112.99	727,159.33	410,953.66	(588,410.60)	52%	212,465.28	2.89%	16,998.53	20367000-Transmission Mains
4584499	118,508.05	71,833.85	46,674.20	(58,294.67)	49%	22,959.26	2.89%	1,684.07	20367000-Transmission Mains
4584500	160,030.19	91,759.19	68,271.00	(79,213.34)	49%	33,793.46	2.89%	2,288.39	20367000-Transmission Mains
4584501	667,967.18	339,231.68	328,735.50	(596,455.35)	89%	293,541.44	2.89%	17,230.93	20367000-Transmission Mains
4584502	13,644.50	6,482.39	7,162.11	(5,780.96)	42%	3,034.47	2.89%	167.01	20367000-Transmission Mains
4584544	25,152.80	32,698.64	(7,545.84)	(22,031.24)	88%	(6,609.37)	2.89%	636.46	20367000-Transmission Mains
4584545	137,819.26	179,165.04	(41,345.78)	(7,115.48)	5%	(2,134.64)	2.89%	205.56	20367000-Transmission Mains
4584659	379,108.30	436,123.78	(57,015.48)	(1,764.00)	0%	(265.29)	2.89%	50.96	20376010-Distribution Mains-Steel
4584661	27,934.20	30,782.26	(2,848.06)	(486.00)	2%	(49.55)	2.89%	14.04	20376010-Distribution Mains-Steel
4584698	104,514.88	120,233.26	(15,718.38)	(192.67)	0%	(28.98)	2.89%	5.57	20376010-Distribution Mains-Steel
4584720	(2,751.06)	(3,576.38)	825.32	340.44	12%	102.13	2.89%	(9.83)	20376010-Distribution Mains-Steel
4584724	669.30	870.09	(200.79)	(276.00)	41%	(82.80)	2.89%	7.97	20376010-Distribution Mains-Steel
4584725	3,005.77	3,907.50	(901.73)	(680.92)	23%	(204.28)	2.89%	19.67	20376010-Distribution Mains-Steel
4584727	2,993.36	3,891.36	(898.00)	(882.70)	29%	(264.81)	2.89%	25.50	20376010-Distribution Mains-Steel
4584729	2,674.78	3,477.21	(802.43)	(856.89)	32%	(257.07)	2.89%	24.75	20376010-Distribution Mains-Steel
4584731	842.47	1,095.20	(252.73)	(359.46)	43%	(107.83)	2.89%	10.38	20376010-Distribution Mains-Steel
4584733	2,816.53	3,649.38	(832.85)	(711.69)	25%	(210.45)	2.89%	20.56	20376010-Distribution Mains-Steel
4584735	2,170.31	2,759.53	(589.22)	(537.00)	25%	(145.79)	2.89%	15.51	20376010-Distribution Mains-Steel
4584736	11,111.00	13,858.40	(2,747.40)	(2,996.23)	27%	(740.87)	2.89%	86.56	20376010-Distribution Mains-Steel
4584737	13,504.12	16,516.22	(3,012.10)	(2,803.64)	21%	(625.35)	2.89%	80.99	20376010-Distribution Mains-Steel
4584738	11,996.42	14,381.69	(2,385.27)	(2,317.82)	19%	(460.86)	2.89%	66.96	20376010-Distribution Mains-Steel
4584739	3,938.25	4,625.90	(687.65)	(873.20)	22%	(152.47)	2.89%	25.23	20376010-Distribution Mains-Steel
4584740	17,797.83	20,474.53	(2,676.70)	(3,521.73)	20%	(529.65)	2.89%	101.74	20376010-Distribution Mains-Steel
4584742	10,211.46	11,499.89	(1,288.43)	(1,638.36)	16%	(206.72)	2.89%	47.33	20376010-Distribution Mains-Steel
4584743	13,021.75	14,349.39	(1,327.64)	(2,665.52)	20%	(271.76)	2.89%	77.00	20376010-Distribution Mains-Steel
4584744	12,955.20	13,962.31	(1,007.11)	(2,784.87)	21%	(216.49)	2.89%	80.45	20376010-Distribution Mains-Steel
4584746	7,606.12	8,013.18	(407.06)	(1,693.29)	22%	(90.62)	2.89%	48.92	20376010-Distribution Mains-Steel
4584749	6,101.44	6,280.20	(178.76)	(1,021.67)	17%	(29.93)	2.89%	29.51	20376010-Distribution Mains-Steel
4584751	2,309.61	2,321.34	(11.73)	(332.56)	14%	(1.69)	2.89%	9.61	20376010-Distribution Mains-Steel
4584819	43,766.76	56,896.79	(13,130.03)	(794.39)	2%	(238.32)	2.89%	22.95	20376010-Distribution Mains-Steel
4584825	15,415.14	20,039.68	(4,624.54)	(1,169.28)	8%	(350.78)	2.89%	33.78	20376010-Distribution Mains-Steel
4584827	50,957.13	66,244.26	(15,287.13)	(972.53)	2%	(291.76)	2.89%	28.10	20376010-Distribution Mains-Steel
4584833	8,193.59	10,219.61	(2,026.02)	(1,396.28)	17%	(345.26)	2.89%	40.34	20376010-Distribution Mains-Steel
4584835	12,412.94	15,181.66	(2,768.72)	(1,291.55)	10%	(288.08)	2.89%	37.31	20376010-Distribution Mains-Steel
4584841	28,491.58	31,396.47	(2,904.89)	(988.65)	3%	(100.80)	2.89%	28.56	20376010-Distribution Mains-Steel
4584854	89,162.40	42,108.45	47,053.95	(284.22)	0%	149.99	2.89%	8.21	20376010-Distribution Mains-Steel
4584877	852.66	1,108.46	(255.80)	(108.39)	13%	(32.52)	2.89%	3.13	20376010-Distribution Mains-Steel
4584879	712.52	926.28	(213.76)	(7,031.42)	987%	(2,109.47)	2.89%	203.13	20376010-Distribution Mains-Steel
4584880	216.78	275.63	(58.85)	(10,245.95)	4726%	(2,781.50)	2.89%	295.99	20376010-Distribution Mains-Steel
4584883	14,062.83	11,409.60	2,653.23	(2,224.71)	16%	419.74	2.89%	64.27	20376010-Distribution Mains-Steel
4584885	20,491.89	9,677.64	10,814.25	(303.71)	1%	160.28	2.89%	8.77	20376010-Distribution Mains-Steel

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4584955	302,384.84	355,185.02	(52,800.18)	(430.55)	0%	(75.18)	2.89%	12.44	20376010-Distribution Mains-Steel
4584956	38,056.62	43,780.12	(5,723.50)	(424.18)	1%	(63.79)	2.89%	12.25	20376010-Distribution Mains-Steel
4584957	37,595.99	42,339.68	(4,743.69)	(451.37)	1%	(56.95)	2.89%	13.04	20376010-Distribution Mains-Steel
4584960	52,659.64	58,028.63	(5,368.99)	(549.28)	1%	(56.00)	2.89%	15.87	20376010-Distribution Mains-Steel
4584966	63,882.11	67,300.98	(3,418.87)	(182.56)	0%	(9.77)	2.89%	5.27	20376010-Distribution Mains-Steel
4584969	52,181.30	53,710.21	(1,528.91)	(23.95)	0%	(0.70)	2.89%	0.69	20376010-Distribution Mains-Steel
4584972	39,899.99	40,102.77	(202.78)	(667.44)	2%	(3.39)	2.89%	19.28	20376010-Distribution Mains-Steel
4585002	3,388.54	4,405.11	(1,016.57)	(1,142.05)	34%	(342.62)	2.89%	32.99	20376010-Distribution Mains-Steel
4585008	187,076.41	219,742.29	(32,665.88)	(1,171.48)	1%	(204.56)	2.89%	33.84	20376010-Distribution Mains-Steel
4585051	1,325,900.97	305,061.62	1,020,839.35	(3,541.38)	0%	2,726.58	2.89%	102.31	20376010-Distribution Mains-Steel
4585145	2,342.97	2,808.83	(465.86)	(2,336.83)	100%	(464.64)	2.89%	67.51	20376010-Distribution Mains-Steel
4585148	7,082.75	5,746.45	1,336.30	(791.52)	11%	149.34	2.89%	22.87	20376010-Distribution Mains-Steel
4585153	14,870.88	19,332.09	(4,461.21)	(1,585.32)	11%	(475.59)	2.89%	45.80	20376010-Distribution Mains-Steel
4585154	15,077.93	19,536.56	(4,458.63)	(4,447.68)	29%	(1,315.20)	2.89%	128.49	20376010-Distribution Mains-Steel
4585155	47,246.76	60,073.55	(12,826.79)	(3,566.82)	8%	(968.34)	2.89%	103.04	20376010-Distribution Mains-Steel
4585156	35,695.31	44,521.76	(8,826.45)	(19,234.80)	54%	(4,756.23)	2.89%	555.67	20376010-Distribution Mains-Steel
4585158	208,589.04	255,114.85	(46,525.81)	(13,020.89)	6%	(2,904.31)	2.89%	376.16	20376010-Distribution Mains-Steel
4585159	132,735.07	159,127.01	(26,391.94)	(22,755.89)	17%	(4,524.59)	2.89%	657.39	20376010-Distribution Mains-Steel
4585160	250,174.96	293,858.57	(43,683.61)	(25,126.20)	10%	(4,387.34)	2.89%	725.87	20376010-Distribution Mains-Steel
4585161	286,264.45	329,316.77	(43,052.32)	(20,170.48)	7%	(3,033.51)	2.89%	582.70	20376010-Distribution Mains-Steel
4585163	238,246.16	268,306.88	(30,060.72)	(21,253.86)	9%	(2,681.71)	2.89%	614.00	20376010-Distribution Mains-Steel
4585166	257,626.53	283,893.00	(26,266.47)	(25,289.49)	10%	(2,578.41)	2.89%	730.59	20376010-Distribution Mains-Steel
4585169	312,008.57	336,263.29	(24,254.72)	(22,961.63)	7%	(1,784.98)	2.89%	663.34	20376010-Distribution Mains-Steel
4585172	314,643.38	331,482.71	(16,839.33)	(22,110.89)	7%	(1,183.35)	2.89%	638.76	20376010-Distribution Mains-Steel
4585175	298,012.72	306,744.39	(8,731.67)	(7,592.28)	3%	(222.45)	2.89%	219.33	20376010-Distribution Mains-Steel
4585178	96,237.78	96,726.78	(489.00)	(3,470.76)	4%	(17.64)	2.89%	100.27	20376010-Distribution Mains-Steel
4585181	63,144.61	61,935.96	1,208.65	(3,846.12)	6%	73.62	2.89%	111.11	20376010-Distribution Mains-Steel
4585184	53,722.38	51,393.18	2,329.20	(839.25)	2%	36.39	2.89%	24.25	20376010-Distribution Mains-Steel
4585188	24,608.92	22,350.05	2,258.87	(1,027.25)	4%	94.29	2.89%	29.68	20376010-Distribution Mains-Steel
4585190	27,016.80	23,882.34	3,134.46	(1,593.61)	6%	184.89	2.89%	46.04	20376010-Distribution Mains-Steel
4585192	20,762.58	17,851.10	2,911.48	(8,737.93)	42%	1,225.30	2.89%	252.43	20376010-Distribution Mains-Steel
4585195	163,961.48	136,998.01	26,963.47	(11,010.23)	7%	1,810.63	2.89%	318.07	20376010-Distribution Mains-Steel
4585240	210,543.07	273,705.98	(63,162.91)	(20,712.28)	10%	(6,213.68)	2.89%	598.35	20376010-Distribution Mains-Steel
4585242	348,345.70	452,849.53	(104,503.83)	(10,165.59)	3%	(3,049.68)	2.89%	293.67	20376010-Distribution Mains-Steel
4585245	173,790.70	225,927.99	(52,137.29)	(14,559.14)	8%	(4,367.75)	2.89%	420.60	20376010-Distribution Mains-Steel
4585248	258,232.52	334,593.60	(76,361.08)	(15,483.58)	6%	(4,578.60)	2.89%	447.30	20376010-Distribution Mains-Steel
4585251	280,415.40	356,544.76	(76,129.36)	(13,257.27)	5%	(3,599.19)	2.89%	382.99	20376010-Distribution Mains-Steel
4585254	257,326.23	320,955.00	(63,628.77)	(21,092.42)	8%	(5,215.50)	2.89%	609.34	20376010-Distribution Mains-Steel
4585256	422,598.47	516,859.12	(94,260.65)	(20,073.71)	5%	(4,477.44)	2.89%	579.91	20376010-Distribution Mains-Steel
4585259	405,083.09	485,626.26	(80,543.17)	(17,470.61)	4%	(3,473.70)	2.89%	504.71	20376010-Distribution Mains-Steel
4585261	377,894.55	443,879.65	(65,985.10)	(22,673.27)	6%	(3,959.04)	2.89%	655.01	20376010-Distribution Mains-Steel

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4585263	499,763.46	574,924.76	(75,161.30)	(17,369.87)	3%	(2,612.32)	2.89%	501.80	20376010-Distribution Mains-Steel
4585265	403,327.83	454,217.66	(50,889.83)	(15,911.65)	4%	(2,007.65)	2.89%	459.67	20376010-Distribution Mains-Steel
4585267	367,523.47	404,994.60	(37,471.13)	(18,687.19)	5%	(1,905.27)	2.89%	539.85	20376010-Distribution Mains-Steel
4585269	460,817.13	496,639.71	(35,822.58)	(13,004.21)	3%	(1,010.91)	2.89%	375.68	20376010-Distribution Mains-Steel
4585271	334,787.45	352,704.72	(17,917.27)	(11,997.69)	4%	(642.10)	2.89%	346.60	20376010-Distribution Mains-Steel
4585273	320,021.65	329,398.20	(9,376.55)	(8,090.88)	3%	(237.06)	2.89%	233.74	20376010-Distribution Mains-Steel
4585275	157,171.58	157,970.08	(798.50)	(7,857.05)	5%	(39.92)	2.89%	226.98	20376010-Distribution Mains-Steel
4585277	269,924.87	264,759.12	5,165.75	(4,450.23)	2%	85.17	2.89%	128.56	20376010-Distribution Mains-Steel
4585279	114,655.66	109,684.27	4,971.39	(2,224.27)	2%	96.44	2.89%	64.26	20376010-Distribution Mains-Steel
4585281	80,780.64	75,321.79	5,458.85	(1,900.59)	2%	128.43	2.89%	54.91	20376010-Distribution Mains-Steel
4585287	53,929.22	46,366.81	7,562.41	(5,498.68)	10%	771.07	2.89%	158.85	20376010-Distribution Mains-Steel
4585289	190,640.19	159,289.17	31,351.02	(3,587.58)	2%	589.98	2.89%	103.64	20376010-Distribution Mains-Steel
4585341	124,088.65	161,315.19	(37,226.54)	(7,463.47)	6%	(2,239.04)	2.89%	215.61	20376010-Distribution Mains-Steel
4585343	280,108.56	364,141.09	(84,032.53)	(1,786.78)	1%	(536.03)	2.89%	51.62	20376010-Distribution Mains-Steel
4585345	94,431.45	122,760.92	(28,329.47)	(6,684.96)	7%	(2,005.49)	2.89%	193.12	20376010-Distribution Mains-Steel
4585347	283,533.65	367,376.44	(83,842.79)	(5,503.60)	2%	(1,627.45)	2.89%	158.99	20376010-Distribution Mains-Steel
4585349	253,363.89	322,149.11	(68,785.22)	(4,503.59)	2%	(1,222.67)	2.89%	130.10	20376010-Distribution Mains-Steel
4585351	216,259.04	269,733.21	(53,474.17)	(12,495.82)	6%	(3,089.83)	2.89%	360.99	20376010-Distribution Mains-Steel
4585353	558,715.01	683,336.41	(124,621.40)	(4,355.48)	1%	(971.49)	2.89%	125.82	20376010-Distribution Mains-Steel
4585355	153,670.58	184,225.10	(30,554.52)	(11,690.62)	8%	(2,324.46)	2.89%	337.73	20376010-Distribution Mains-Steel
4585357	619,299.81	727,437.26	(108,137.45)	(5,039.22)	1%	(879.91)	2.89%	145.58	20376010-Distribution Mains-Steel
4585359	292,741.15	336,767.55	(44,026.40)	(6,344.00)	2%	(954.10)	2.89%	183.27	20376010-Distribution Mains-Steel
4585361	368,412.11	414,896.49	(46,484.38)	(4,501.00)	1%	(567.91)	2.89%	130.03	20376010-Distribution Mains-Steel
4585363	184,373.70	203,171.71	(18,798.01)	(4,030.41)	2%	(410.92)	2.89%	116.43	20376010-Distribution Mains-Steel
4585365	155,033.96	167,085.85	(12,051.89)	(1,448.28)	1%	(112.59)	2.89%	41.84	20376010-Distribution Mains-Steel
4585368	91,212.68	96,094.18	(4,881.50)	(3,449.06)	4%	(184.59)	2.89%	99.64	20376010-Distribution Mains-Steel
4585370	207,642.18	213,725.92	(6,083.74)	(1,989.49)	1%	(58.29)	2.89%	57.47	20376010-Distribution Mains-Steel
4585372	138,051.48	138,752.92	(701.44)	(2,358.29)	2%	(11.98)	2.89%	68.13	20376010-Distribution Mains-Steel
4585374	188,993.73	185,376.77	3,616.96	(13.83)	0%	0.26	2.89%	0.40	20376010-Distribution Mains-Steel
4585376	126,593.24	121,104.50	5,488.74	(3,582.84)	3%	155.34	2.89%	103.50	20376010-Distribution Mains-Steel
4585380	115,170.28	104,598.21	10,572.07	(1,445.09)	1%	132.65	2.89%	41.75	20376010-Distribution Mains-Steel
4585386	144,877.61	121,052.39	23,825.22	(2,195.40)	2%	361.04	2.89%	63.42	20376010-Distribution Mains-Steel
4585390	114,713.49	90,292.36	24,421.13	(5,813.20)	5%	1,237.56	2.89%	167.94	20376010-Distribution Mains-Steel
4585392	381,704.44	291,199.57	90,504.87	(7,230.67)	2%	1,714.44	2.89%	208.89	20376010-Distribution Mains-Steel
4585394	487,708.47	360,257.52	127,450.95	(13,686.36)	3%	3,576.60	2.89%	395.38	20376010-Distribution Mains-Steel
4585396	774,716.16	553,499.78	221,216.38	(10,285.85)	1%	2,937.07	2.89%	297.15	20376010-Distribution Mains-Steel
4585402	588,453.65	377,668.66	210,784.99	(10,945.92)	2%	3,920.85	2.89%	316.22	20376010-Distribution Mains-Steel
4585408	585,017.46	332,958.12	252,059.34	(8,381.08)	1%	3,611.05	2.89%	242.12	20376010-Distribution Mains-Steel
4585410	653,891.94	356,321.03	297,570.91	(2,821.78)	0%	1,284.13	2.89%	81.52	20376010-Distribution Mains-Steel
4585414	446,011.52	221,438.34	224,573.18	(14,116.13)	3%	7,107.67	2.89%	407.80	20376010-Distribution Mains-Steel
4585416	1,303,765.12	615,725.01	688,040.11	(26,023.19)	2%	13,733.30	2.89%	751.78	20376010-Distribution Mains-Steel

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4585437	43,400.65	56,420.84	(13,020.19)	(345.11)	1%	(103.53)	2.89%	9.97	20376010-Distribution Mains-Steel
4585439	635.00	825.50	(190.50)	(167.97)	26%	(50.39)	2.89%	4.85	20376010-Distribution Mains-Steel
4585440	223.97	291.16	(67.19)	(51.06)	23%	(15.32)	2.89%	1.48	20376010-Distribution Mains-Steel
4585441	59.57	77.44	(17.87)	(38.62)	65%	(11.59)	2.89%	1.12	20376010-Distribution Mains-Steel
4585443	69.50	86.69	(17.19)	(51.08)	73%	(12.63)	2.89%	1.48	20376010-Distribution Mains-Steel
4585444	59.59	72.88	(13.29)	(28.69)	48%	(6.40)	2.89%	0.83	20376010-Distribution Mains-Steel
4585445	57.37	67.39	(10.02)	(75.05)	131%	(13.11)	2.89%	2.17	20376010-Distribution Mains-Steel
4585446	140.71	161.87	(21.16)	(3,653.08)	2596%	(549.35)	2.89%	105.53	20376010-Distribution Mains-Steel
4585450	233,140.06	303,082.06	(69,942.00)	(4,066.83)	2%	(1,220.05)	2.89%	117.49	20376010-Distribution Mains-Steel
4585451	299,261.62	389,040.11	(89,778.49)	(3,991.84)	1%	(1,197.55)	2.89%	115.32	20376010-Distribution Mains-Steel
4585453	118,347.84	153,344.07	(34,996.23)	(4,112.50)	3%	(1,216.09)	2.89%	118.81	20376010-Distribution Mains-Steel
4585454	101,373.13	128,894.68	(27,521.55)	(1,366.50)	1%	(370.99)	2.89%	39.48	20376010-Distribution Mains-Steel
4585456	106,815.06	130,640.17	(23,825.11)	(4,602.08)	4%	(1,026.49)	2.89%	132.95	20376010-Distribution Mains-Steel
4585458	188,604.75	221,537.51	(32,932.76)	(3,852.59)	2%	(672.71)	2.89%	111.30	20376010-Distribution Mains-Steel
4585783	69,496.84	83,314.99	(13,818.15)	(1,208.27)	2%	(240.24)	2.89%	34.91	20376010-Distribution Mains-Steel
4585784	118,211.20	138,852.36	(20,641.16)	(10,946.20)	9%	(1,911.34)	2.89%	316.22	20376010-Distribution Mains-Steel
4585785	45,213.78	52,013.64	(6,799.86)	(1,984.69)	4%	(298.48)	2.89%	57.34	20376010-Distribution Mains-Steel
4585787	11,050.68	12,444.99	(1,394.31)	(1,439.52)	13%	(181.63)	2.89%	41.59	20376010-Distribution Mains-Steel
4585788	25,727.82	28,350.94	(2,623.12)	(629.12)	2%	(64.14)	2.89%	18.17	20376010-Distribution Mains-Steel
4585791	251,980.39	271,568.65	(19,588.26)	(7,826.03)	3%	(608.37)	2.89%	226.09	20376010-Distribution Mains-Steel
4585794	46,638.68	49,134.71	(2,496.03)	(14,000.35)	30%	(749.28)	2.89%	404.45	20376010-Distribution Mains-Steel
4585797	34,999.59	36,025.05	(1,025.46)	(11,630.80)	33%	(340.77)	2.89%	336.00	20376010-Distribution Mains-Steel
4585800	16,033.24	16,114.71	(81.47)	(2,473.57)	15%	(12.57)	2.89%	71.46	20376010-Distribution Mains-Steel
4585830	102,934.63	123,401.28	(20,466.65)	(3,001.66)	3%	(596.82)	2.89%	86.71	20376010-Distribution Mains-Steel
4585834	191,654.94	225,120.28	(33,465.34)	(8,094.53)	4%	(1,413.41)	2.89%	233.84	20376010-Distribution Mains-Steel
4585836	165,548.11	190,445.52	(24,897.41)	(958.47)	1%	(144.15)	2.89%	27.69	20376010-Distribution Mains-Steel
4585838	36,767.56	41,406.70	(4,639.14)	(2,481.97)	7%	(313.16)	2.89%	71.70	20376010-Distribution Mains-Steel
4585840	46,692.09	51,452.63	(4,760.54)	(1,210.40)	3%	(123.41)	2.89%	34.97	20376010-Distribution Mains-Steel
4585842	130,183.34	140,303.44	(10,120.10)	(500.68)	0%	(38.92)	2.89%	14.46	20376010-Distribution Mains-Steel
4585844	17,172.69	18,091.73	(919.04)	(128.33)	1%	(6.87)	2.89%	3.71	20376010-Distribution Mains-Steel
4585846	43,287.43	44,555.73	(1,268.30)	-	0%	-	2.89%	-	20376010-Distribution Mains-Steel
4585850	10,377.40	10,178.77	198.63	(531.24)	5%	10.17	2.89%	15.35	20376010-Distribution Mains-Steel
4585853	13,595.48	12,676.78	918.70	(2,770.73)	20%	187.23	2.89%	80.04	20376010-Distribution Mains-Steel
4585878	125,502.61	150,456.47	(24,953.86)	(2,224.99)	2%	(442.40)	2.89%	64.28	20376010-Distribution Mains-Steel
4586209	(2,096.76)	(2,332.58)	235.82	(6,959.14)	332%	782.69	2.56%	177.84	20376020-Distribution Mains-Plastic
4586210	3,972.88	4,216.49	(243.61)	(1,475.03)	37%	(90.45)	2.56%	37.70	20376020-Distribution Mains-Plastic
4586213	25,867.06	26,130.11	(263.05)	(488.76)	2%	(4.97)	2.56%	12.49	20376020-Distribution Mains-Plastic
4586216	19,565.14	19,263.75	301.39	(851.11)	4%	13.11	2.56%	21.75	20376020-Distribution Mains-Plastic
4586218	66,864.29	64,124.32	2,739.97	(595.42)	1%	24.40	2.56%	15.22	20376020-Distribution Mains-Plastic
4586221	10,624.82	9,917.71	707.11	(4,037.36)	38%	268.70	2.56%	103.18	20376020-Distribution Mains-Plastic
4586224	5,618.30	5,100.67	517.63	(814.00)	14%	75.00	2.56%	20.80	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586226	14,242.73	12,566.33	1,676.40	(1,205.90)	8%	141.94	2.56%	30.82	20376020-Distribution Mains-Plastic
4586229	9,101.02	7,797.09	1,303.93	(7,345.26)	81%	1,052.38	2.56%	187.71	20376020-Distribution Mains-Plastic
4586231	42,929.91	35,681.28	7,248.63	(5,521.60)	13%	932.31	2.56%	141.11	20376020-Distribution Mains-Plastic
4586233	15,498.56	12,485.32	3,013.24	(1,424.00)	9%	276.85	2.56%	36.39	20376020-Distribution Mains-Plastic
4586234	26,627.05	20,769.20	5,857.85	(1,826.00)	7%	401.71	2.56%	46.66	20376020-Distribution Mains-Plastic
4586235	147,883.45	111,567.77	36,315.68	(1,892.00)	1%	464.62	2.56%	48.35	20376020-Distribution Mains-Plastic
4586236	95,363.20	69,506.08	25,857.12	(1,518.00)	2%	411.60	2.56%	38.79	20376020-Distribution Mains-Plastic
4586237	16,475.68	11,587.09	4,888.59	(834.00)	5%	247.46	2.56%	21.31	20376020-Distribution Mains-Plastic
4586238	31,452.85	21,315.89	10,136.96	(676.00)	2%	217.87	2.56%	17.28	20376020-Distribution Mains-Plastic
4586239	32,069.40	20,913.56	11,155.84	(1,046.92)	3%	364.19	2.56%	26.75	20376020-Distribution Mains-Plastic
4586240	38,283.96	23,987.20	14,296.76	(2,018.40)	5%	753.75	2.56%	51.58	20376020-Distribution Mains-Plastic
4586241	19,111.11	11,485.53	7,625.58	(715.23)	4%	285.39	2.56%	18.28	20376020-Distribution Mains-Plastic
4586242	14,425.84	8,300.85	6,124.99	(773.18)	5%	328.28	2.56%	19.76	20376020-Distribution Mains-Plastic
4586243	45,612.65	25,079.62	20,533.03	(2,805.57)	6%	1,262.96	2.56%	71.70	20376020-Distribution Mains-Plastic
4586244	94,354.40	49,466.72	44,887.68	(624.79)	1%	297.23	2.56%	15.97	20376020-Distribution Mains-Plastic
4586245	36,279.06	18,092.04	18,187.02	(1,323.05)	4%	663.26	2.56%	33.81	20376020-Distribution Mains-Plastic
4586246	23,686.16	11,206.34	12,479.82	(750.50)	3%	395.43	2.56%	19.18	20376020-Distribution Mains-Plastic
4586247	111,618.54	49,954.15	61,664.39	(2,788.30)	2%	1,540.41	2.56%	71.26	20376020-Distribution Mains-Plastic
4586248	28,677.75	12,101.14	16,576.61	(1,639.04)	6%	947.41	2.56%	41.89	20376020-Distribution Mains-Plastic
4586249	66,602.27	26,400.85	40,201.42	(2,729.45)	4%	1,647.51	2.56%	69.75	20376020-Distribution Mains-Plastic
4586250	55,513.58	20,585.63	34,927.95	(2,434.10)	4%	1,531.48	2.56%	62.20	20376020-Distribution Mains-Plastic
4586251	149,003.61	51,443.16	97,560.45	(1,634.16)	1%	1,069.97	2.56%	41.76	20376020-Distribution Mains-Plastic
4586252	102,415.78	32,739.63	69,676.15	(708.04)	1%	481.70	2.56%	18.09	20376020-Distribution Mains-Plastic
4586253	102,654.81	30,190.80	72,464.01	(895.20)	1%	631.92	2.56%	22.88	20376020-Distribution Mains-Plastic
4586254	91,509.68	24,572.71	66,936.97	(576.77)	1%	421.89	2.56%	14.74	20376020-Distribution Mains-Plastic
4586284	16,350.08	18,188.89	(1,838.81)	(2,115.14)	13%	(237.88)	2.56%	54.05	20376020-Distribution Mains-Plastic
4586286	12,526.86	13,294.95	(768.09)	(894.81)	7%	(54.87)	2.56%	22.87	20376020-Distribution Mains-Plastic
4586288	18,673.12	19,340.58	(667.46)	(1,539.38)	8%	(55.02)	2.56%	39.34	20376020-Distribution Mains-Plastic
4586290	14,218.98	14,363.54	(144.56)	(303.85)	2%	(3.09)	2.56%	7.77	20376020-Distribution Mains-Plastic
4586293	22,678.29	22,328.91	349.38	(216.00)	1%	3.33	2.56%	5.52	20376020-Distribution Mains-Plastic
4586296	21,018.26	20,156.94	861.32	(983.06)	5%	40.29	2.56%	25.12	20376020-Distribution Mains-Plastic
4586298	5,395.71	5,036.60	359.11	(1,628.00)	30%	108.35	2.56%	41.60	20376020-Distribution Mains-Plastic
4586307	22,847.28	18,989.53	3,857.75	(2,917.17)	13%	492.56	2.56%	74.55	20376020-Distribution Mains-Plastic
4586309	66,728.64	53,755.13	12,973.51	(2,910.03)	4%	565.77	2.56%	74.37	20376020-Distribution Mains-Plastic
4586311	60,334.81	47,061.41	13,273.40	(11.61)	0%	2.55	2.56%	0.30	20376020-Distribution Mains-Plastic
4586312	111,092.29	83,811.39	27,280.90	(871.51)	1%	214.02	2.56%	22.27	20376020-Distribution Mains-Plastic
4586314	88,809.12	64,729.10	24,080.02	(1,376.16)	2%	373.14	2.56%	35.17	20376020-Distribution Mains-Plastic
4586315	38,153.57	26,832.74	11,320.83	(1,800.32)	5%	534.19	2.56%	46.01	20376020-Distribution Mains-Plastic
4586316	10,949.42	7,420.59	3,528.83	(1,980.42)	18%	638.26	2.56%	50.61	20376020-Distribution Mains-Plastic
4586317	26,230.50	15,764.17	10,466.33	(2,707.44)	10%	1,080.31	2.56%	69.19	20376020-Distribution Mains-Plastic
4586318	42,989.30	24,736.68	18,252.62	(1,059.20)	2%	449.72	2.56%	27.07	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586319	72,437.86	39,829.18	32,608.68	(3,202.32)	4%	1,441.56	2.56%	81.84	20376020-Distribution Mains-Plastic
4586320	110,407.27	57,882.65	52,524.62	(2,612.74)	2%	1,242.97	2.56%	66.77	20376020-Distribution Mains-Plastic
4586321	258,758.24	129,040.44	129,717.80	(10.10)	0%	5.06	2.56%	0.26	20376020-Distribution Mains-Plastic
4586322	99,509.17	47,079.51	52,429.66	(304.04)	0%	160.19	2.56%	7.77	20376020-Distribution Mains-Plastic
4586323	177,505.48	79,441.48	98,064.00	(733.10)	0%	405.01	2.56%	18.73	20376020-Distribution Mains-Plastic
4586325	101,997.95	40,431.57	61,566.38	(811.94)	1%	490.09	2.56%	20.75	20376020-Distribution Mains-Plastic
4586326	155,250.49	57,570.32	97,680.17	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
4586327	165,181.25	57,028.41	108,152.84	(1,843.56)	1%	1,207.08	2.56%	47.11	20376020-Distribution Mains-Plastic
4586328	379,000.46	121,156.61	257,843.85	(515.12)	0%	350.45	2.56%	13.16	20376020-Distribution Mains-Plastic
4586329	327,721.26	96,382.82	231,338.44	(1,322.84)	0%	933.79	2.56%	33.81	20376020-Distribution Mains-Plastic
4586330	279,664.16	75,097.08	204,567.08	(507.54)	0%	371.25	2.56%	12.97	20376020-Distribution Mains-Plastic
4586332	322,464.54	78,343.48	244,121.06	(418.56)	0%	316.87	2.56%	10.70	20376020-Distribution Mains-Plastic
4586334	11,327.95	11,443.14	(115.19)	(925.20)	8%	(9.41)	2.56%	23.64	20376020-Distribution Mains-Plastic
4586336	17,629.57	17,358.01	271.56	(1,059.46)	6%	16.32	2.56%	27.08	20376020-Distribution Mains-Plastic
4586348	153,133.44	115,528.51	37,604.93	(1,121.48)	1%	275.40	2.56%	28.66	20376020-Distribution Mains-Plastic
4586368	529,807.66	169,365.65	360,442.01	(2,285.69)	0%	1,555.01	2.56%	58.41	20376020-Distribution Mains-Plastic
4586455	(3,468.24)	(3,858.30)	390.06	(2,243.56)	65%	252.32	2.56%	57.34	20376020-Distribution Mains-Plastic
4586457	87,413.63	95,009.12	(7,595.49)	(2,324.36)	3%	(201.97)	2.56%	59.40	20376020-Distribution Mains-Plastic
4586459	27,449.10	29,132.17	(1,683.07)	(476.06)	2%	(29.19)	2.56%	12.17	20376020-Distribution Mains-Plastic
4586461	64,638.69	66,949.03	(2,310.34)	(1,698.90)	3%	(60.72)	2.56%	43.42	20376020-Distribution Mains-Plastic
4586463	28,385.54	28,674.34	(288.80)	(937.25)	3%	(9.54)	2.56%	23.95	20376020-Distribution Mains-Plastic
4586465	20,232.47	19,920.75	311.72	(1,569.32)	8%	24.18	2.56%	40.10	20376020-Distribution Mains-Plastic
4586469	32,708.92	30,532.01	2,176.91	(2,108.51)	6%	140.33	2.56%	53.88	20376020-Distribution Mains-Plastic
4586474	21,640.45	19,093.34	2,547.11	(1,681.11)	8%	197.87	2.56%	42.96	20376020-Distribution Mains-Plastic
4586476	68,667.14	58,828.97	9,838.17	(3,710.43)	5%	531.61	2.56%	94.82	20376020-Distribution Mains-Plastic
4586478	46,782.57	38,883.34	7,899.23	(3,761.52)	8%	635.13	2.56%	96.13	20376020-Distribution Mains-Plastic
4586480	71,182.12	57,342.73	13,839.39	(1,392.31)	2%	270.70	2.56%	35.58	20376020-Distribution Mains-Plastic
4586481	97,992.71	76,434.61	21,558.10	(1,428.09)	1%	314.18	2.56%	36.50	20376020-Distribution Mains-Plastic
4586482	201,128.31	151,737.39	49,390.92	(710.93)	0%	174.58	2.56%	18.17	20376020-Distribution Mains-Plastic
4586484	310,304.27	226,167.14	84,137.13	(3,219.86)	1%	873.05	2.56%	82.29	20376020-Distribution Mains-Plastic
4586485	334,392.76	235,172.53	99,220.23	(2,114.86)	1%	627.52	2.56%	54.05	20376020-Distribution Mains-Plastic
4586486	145,519.11	98,619.60	46,899.51	(2,552.98)	2%	822.80	2.56%	65.24	20376020-Distribution Mains-Plastic
4586487	252,210.31	164,475.06	87,735.25	(3,234.07)	1%	1,125.02	2.56%	82.65	20376020-Distribution Mains-Plastic
4586488	288,569.59	180,806.35	107,763.24	(3,382.83)	1%	1,263.28	2.56%	86.45	20376020-Distribution Mains-Plastic
4586489	276,831.78	166,372.31	110,459.47	(3,639.72)	1%	1,452.30	2.56%	93.02	20376020-Distribution Mains-Plastic
4586490	467,079.78	268,763.74	198,316.04	(4,157.79)	1%	1,765.34	2.56%	106.25	20376020-Distribution Mains-Plastic
4586491	402,491.57	221,305.57	181,186.00	(219.12)	0%	98.64	2.56%	5.60	20376020-Distribution Mains-Plastic
4586492	860,192.89	450,969.18	409,223.71	(508.18)	0%	241.76	2.56%	12.99	20376020-Distribution Mains-Plastic
4586493	847,137.25	422,459.97	424,677.28	(998.00)	0%	500.31	2.56%	25.50	20376020-Distribution Mains-Plastic
4586494	412,741.79	195,275.31	217,466.48	(3,031.72)	1%	1,597.36	2.56%	77.48	20376020-Distribution Mains-Plastic
4586495	452,368.18	202,454.41	249,913.77	(1,401.29)	0%	774.15	2.56%	35.81	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586496	210,956.77	89,017.38	121,939.39	(1,664.48)	1%	962.12	2.56%	42.54	20376020-Distribution Mains-Plastic
4586497	1,042,403.88	413,204.31	629,199.57	(2,339.25)	0%	1,411.98	2.56%	59.78	20376020-Distribution Mains-Plastic
4586498	737,520.30	273,488.64	464,031.66	(3,230.20)	0%	2,032.37	2.56%	82.55	20376020-Distribution Mains-Plastic
4586499	1,051,280.05	362,952.10	688,327.95	(1,824.16)	0%	1,194.37	2.56%	46.62	20376020-Distribution Mains-Plastic
4586500	1,583,487.39	506,199.59	1,077,287.80	(1,861.68)	0%	1,266.55	2.56%	47.58	20376020-Distribution Mains-Plastic
4586501	1,468,532.48	431,895.32	1,036,637.16	(870.88)	0%	614.75	2.56%	22.26	20376020-Distribution Mains-Plastic
4586502	1,729,585.95	464,438.86	1,265,147.09	(3,126.54)	0%	2,286.98	2.56%	79.90	20376020-Distribution Mains-Plastic
4586503	2,503,772.28	608,296.81	1,895,475.47	(1,974.24)	0%	1,494.59	2.56%	50.45	20376020-Distribution Mains-Plastic
4586506	1,538.82	1,554.41	(15.59)	(3,965.38)	258%	(40.17)	2.56%	101.34	20376020-Distribution Mains-Plastic
4586507	20,639.88	19,266.25	1,373.63	(4,164.68)	20%	277.17	2.56%	106.43	20376020-Distribution Mains-Plastic
4586511	25,743.41	21,396.71	4,346.70	(11,425.79)	44%	1,929.21	2.56%	291.99	20376020-Distribution Mains-Plastic
4586517	287,604.48	209,622.37	77,982.11	(12,376.64)	4%	3,355.85	2.56%	316.29	20376020-Distribution Mains-Plastic
4586519	113,301.25	79,682.78	33,618.47	(9,437.66)	8%	2,800.32	2.56%	241.18	20376020-Distribution Mains-Plastic
4586525	265,617.84	166,425.76	99,192.08	(9,834.55)	4%	3,672.61	2.56%	251.33	20376020-Distribution Mains-Plastic
4586531	152,073.13	83,615.74	68,457.39	(14,567.60)	10%	6,557.77	2.56%	372.28	20376020-Distribution Mains-Plastic
4586533	811,013.58	425,186.17	385,827.41	(10,129.61)	1%	4,819.01	2.56%	258.87	20376020-Distribution Mains-Plastic
4586535	234,048.73	116,718.02	117,330.71	(16,565.81)	7%	8,304.59	2.56%	423.35	20376020-Distribution Mains-Plastic
4586537	289,957.39	137,183.87	152,773.52	(14,437.47)	5%	7,606.85	2.56%	368.96	20376020-Distribution Mains-Plastic
4586541	224,217.42	94,612.92	129,604.50	(9,524.23)	4%	5,505.30	2.56%	243.40	20376020-Distribution Mains-Plastic
4586543	814,548.26	322,883.33	491,664.93	(11,439.53)	1%	6,904.95	2.56%	292.34	20376020-Distribution Mains-Plastic
4586545	673,729.22	249,833.39	423,895.83	(20,738.76)	3%	13,048.38	2.56%	529.99	20376020-Distribution Mains-Plastic
4586546	610,056.70	210,620.72	399,435.98	(60,383.28)	10%	39,536.09	2.56%	1,543.13	20376020-Distribution Mains-Plastic
4586548	739,919.98	236,533.07	503,386.91	(62,470.44)	8%	42,500.27	2.56%	1,596.47	20376020-Distribution Mains-Plastic
4586549	1,090,415.97	320,691.29	769,724.68	(28,710.89)	3%	20,267.02	2.56%	733.72	20376020-Distribution Mains-Plastic
4586550	1,656,455.92	444,801.61	1,211,654.31	(19,757.48)	1%	14,452.08	2.56%	504.91	20376020-Distribution Mains-Plastic
4586551	757,110.08	183,941.51	573,168.57	(19,040.96)	3%	14,414.92	2.56%	486.60	20376020-Distribution Mains-Plastic
4586553	19,790.03	9,869.13	9,920.90	(19,428.40)	98%	9,739.61	2.56%	496.50	20376020-Distribution Mains-Plastic
4586566	(29,470.12)	(33,890.64)	4,420.52	(9,579.67)	33%	1,436.95	2.56%	244.81	20376020-Distribution Mains-Plastic
4586571	78,555.97	85,381.58	(6,825.61)	(16,117.00)	21%	(1,400.38)	2.56%	411.88	20376020-Distribution Mains-Plastic
4586573	80,196.81	85,114.12	(4,917.31)	(36,206.83)	45%	(2,220.04)	2.56%	925.29	20376020-Distribution Mains-Plastic
4586575	255,511.38	264,644.32	(9,132.94)	(15,479.41)	6%	(553.29)	2.56%	395.58	20376020-Distribution Mains-Plastic
4586578	292,376.85	295,350.12	(2,973.27)	(16,181.39)	6%	(164.55)	2.56%	413.52	20376020-Distribution Mains-Plastic
4586581	222,221.04	218,797.63	3,423.41	(14,785.93)	7%	227.78	2.56%	377.86	20376020-Distribution Mains-Plastic
4586583	268,203.55	257,213.24	10,990.31	(19,952.26)	7%	817.59	2.56%	509.89	20376020-Distribution Mains-Plastic
4586585	386,161.96	360,462.17	25,699.79	(20,843.54)	5%	1,387.18	2.56%	532.67	20376020-Distribution Mains-Plastic
4586587	283,454.34	257,340.37	26,113.97	(30,640.76)	11%	2,822.86	2.56%	783.04	20376020-Distribution Mains-Plastic
4586589	508,729.67	448,851.65	59,878.02	(36,427.02)	7%	4,287.50	2.56%	930.91	20376020-Distribution Mains-Plastic
4586591	497,404.36	426,139.33	71,265.03	(35,738.74)	7%	5,120.43	2.56%	913.32	20376020-Distribution Mains-Plastic
4586593	342,207.45	284,425.84	57,781.61	(25,507.44)	7%	4,306.92	2.56%	651.86	20376020-Distribution Mains-Plastic
4586595	453,464.09	365,301.06	88,163.03	(27,362.48)	6%	5,319.85	2.56%	699.26	20376020-Distribution Mains-Plastic
4586597	999,885.24	779,914.92	219,970.32	(1,744.53)	0%	383.79	2.56%	44.58	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586599	2,950,300.45	2,225,796.23	724,504.22	(1,338.90)	0%	328.79	2.56%	34.22	20376020-Distribution Mains-Plastic
4586601	3,195,908.02	2,329,358.14	866,549.88	(1,568.73)	0%	425.35	2.56%	40.09	20376020-Distribution Mains-Plastic
4586602	1,687,144.21	1,186,539.01	500,605.20	(2,114.12)	0%	627.30	2.56%	54.03	20376020-Distribution Mains-Plastic
4586604	1,125,930.45	763,052.78	362,877.67	(3,919.09)	0%	1,263.09	2.56%	100.15	20376020-Distribution Mains-Plastic
4586606	1,157,667.76	754,955.46	402,712.30	(4,299.31)	0%	1,495.58	2.56%	109.87	20376020-Distribution Mains-Plastic
4586607	1,539,411.47	964,535.00	574,876.47	(2,102.52)	0%	785.16	2.56%	53.73	20376020-Distribution Mains-Plastic
4586609	1,049,859.00	630,951.40	418,907.60	(3,585.15)	0%	1,430.52	2.56%	91.62	20376020-Distribution Mains-Plastic
4586610	1,485,315.55	854,669.97	630,645.58	(3,790.30)	0%	1,609.31	2.56%	96.86	20376020-Distribution Mains-Plastic
4586612	847,317.54	465,888.23	381,429.31	(1,550.37)	0%	697.92	2.56%	39.62	20376020-Distribution Mains-Plastic
4586613	1,476,062.15	773,847.71	702,214.44	(971.15)	0%	462.01	2.56%	24.82	20376020-Distribution Mains-Plastic
4586614	3,822,588.28	1,906,291.42	1,916,296.86	(4,645.76)	0%	2,328.96	2.56%	118.72	20376020-Distribution Mains-Plastic
4586615	1,699,832.83	804,220.56	895,612.27	(7,438.54)	0%	3,919.24	2.56%	190.10	20376020-Distribution Mains-Plastic
4586616	2,031,799.85	909,318.52	1,122,481.33	(13,787.77)	1%	7,617.15	2.56%	352.35	20376020-Distribution Mains-Plastic
4586617	1,916,218.60	808,585.93	1,107,632.67	(11,672.39)	1%	6,747.00	2.56%	298.29	20376020-Distribution Mains-Plastic
4586618	3,052,458.37	1,209,980.71	1,842,477.66	(14,410.07)	0%	8,697.98	2.56%	368.26	20376020-Distribution Mains-Plastic
4586619	3,062,603.22	1,135,679.76	1,926,923.46	(11,449.35)	0%	7,203.68	2.56%	292.59	20376020-Distribution Mains-Plastic
4586621	5,234,772.40	1,807,293.52	3,427,478.88	(8,029.29)	0%	5,257.20	2.56%	205.19	20376020-Distribution Mains-Plastic
4586624	6,207,667.53	1,984,428.99	4,223,238.54	(11,235.51)	0%	7,643.81	2.56%	287.13	20376020-Distribution Mains-Plastic
4586625	6,865,746.50	2,019,215.88	4,846,530.62	(9,415.20)	0%	6,646.19	2.56%	240.61	20376020-Distribution Mains-Plastic
4586628	5,201,249.92	1,396,671.03	3,804,578.89	(6,256.35)	0%	4,576.36	2.56%	159.88	20376020-Distribution Mains-Plastic
4586629	6,158,563.51	1,496,236.23	4,662,327.28	(11,975.12)	0%	9,065.74	2.56%	306.03	20376020-Distribution Mains-Plastic
4586631	79,928.65	86,873.78	(6,945.13)	(2,161.83)	3%	(187.84)	2.56%	55.25	20376020-Distribution Mains-Plastic
4586633	45,797.73	48,605.84	(2,808.11)	(46.02)	0%	(2.82)	2.56%	1.18	20376020-Distribution Mains-Plastic
4586635	28,786.30	29,815.14	(1,028.84)	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
4586637	87,872.28	88,765.82	(893.54)	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
4586639	163,710.56	161,188.50	2,522.06	(3,816.61)	2%	58.80	2.56%	97.54	20376020-Distribution Mains-Plastic
4586641	149,775.19	143,637.59	6,137.60	(9,841.23)	7%	403.28	2.56%	251.50	20376020-Distribution Mains-Plastic
4586643	136,532.55	127,445.94	9,086.61	(11,925.54)	9%	793.68	2.56%	304.76	20376020-Distribution Mains-Plastic
4586645	184,395.69	167,407.92	16,987.77	(3,870.28)	2%	356.56	2.56%	98.91	20376020-Distribution Mains-Plastic
4586647	179,122.05	158,039.56	21,082.49	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
4586649	91,399.74	78,304.34	13,095.40	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
4586651	115,839.69	96,280.62	19,559.07	(4,209.48)	4%	710.75	2.56%	107.58	20376020-Distribution Mains-Plastic
4586653	371,659.83	299,400.92	72,258.91	(285.64)	0%	55.53	2.56%	7.30	20376020-Distribution Mains-Plastic
4586655	587,123.55	457,958.78	129,164.77	(295.57)	0%	65.02	2.56%	7.55	20376020-Distribution Mains-Plastic
4586657	1,353,997.06	1,021,496.45	332,500.61	(971.04)	0%	238.46	2.56%	24.82	20376020-Distribution Mains-Plastic
4586659	1,494,804.53	1,089,497.78	405,306.75	(639.46)	0%	173.39	2.56%	16.34	20376020-Distribution Mains-Plastic
4586661	1,276,232.38	897,551.86	378,680.52	(818.64)	0%	242.90	2.56%	20.92	20376020-Distribution Mains-Plastic
4586663	718,057.22	486,633.44	231,423.78	(836.34)	0%	269.55	2.56%	21.37	20376020-Distribution Mains-Plastic
4586665	731,485.26	477,026.89	254,458.37	(979.05)	0%	340.58	2.56%	25.02	20376020-Distribution Mains-Plastic
4586667	1,293,262.70	810,307.59	482,955.11	(581.89)	0%	217.30	2.56%	14.87	20376020-Distribution Mains-Plastic
4586669	1,195,203.12	718,301.51	476,901.61	(1,525.72)	0%	608.78	2.56%	38.99	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586671	1,101,424.38	633,773.68	467,650.70	(1,525.99)	0%	647.92	2.56%	39.00	20376020-Distribution Mains-Plastic
4586673	2,552,656.25	1,403,550.41	1,149,105.84	(1,066.08)	0%	479.91	2.56%	27.24	20376020-Distribution Mains-Plastic
4586675	1,504,770.78	788,898.90	715,871.88	(1,402.06)	0%	667.01	2.56%	35.83	20376020-Distribution Mains-Plastic
4586677	3,684,634.99	1,837,495.30	1,847,139.69	(2,246.88)	0%	1,126.38	2.56%	57.42	20376020-Distribution Mains-Plastic
4586679	3,994,045.69	1,889,652.43	2,104,393.26	(3,943.32)	0%	2,077.67	2.56%	100.77	20376020-Distribution Mains-Plastic
4586681	2,751,839.40	1,231,567.81	1,520,271.59	(2,661.48)	0%	1,470.35	2.56%	68.02	20376020-Distribution Mains-Plastic
4586683	3,394,331.87	1,432,304.77	1,962,027.10	(1,057.97)	0%	611.54	2.56%	27.04	20376020-Distribution Mains-Plastic
4586685	3,758,173.48	1,489,723.39	2,268,450.09	(1,621.78)	0%	978.91	2.56%	41.45	20376020-Distribution Mains-Plastic
4586687	4,144,530.76	1,536,881.73	2,607,649.03	(675.78)	0%	425.19	2.56%	17.27	20376020-Distribution Mains-Plastic
4586689	1,914,494.16	660,974.75	1,253,519.41	(1,470.45)	0%	962.78	2.56%	37.58	20376020-Distribution Mains-Plastic
4586691	2,590,183.73	828,014.07	1,762,169.66	(1,128.00)	0%	767.41	2.56%	28.83	20376020-Distribution Mains-Plastic
4586693	2,342,366.08	688,889.77	1,653,476.31	(651.44)	0%	459.85	2.56%	16.65	20376020-Distribution Mains-Plastic
4586695	1,680,122.31	451,156.54	1,228,965.77	(419.67)	0%	306.98	2.56%	10.72	20376020-Distribution Mains-Plastic
4586697	1,722,774.76	418,551.73	1,304,223.03	(366.27)	0%	277.28	2.56%	9.36	20376020-Distribution Mains-Plastic
4586700	6,971.34	5,437.67	1,533.67	(1,779.28)	26%	391.44	2.56%	45.47	20376020-Distribution Mains-Plastic
4586704	386,116.82	202,427.59	183,689.23	(5,147.63)	1%	2,448.91	2.56%	131.55	20376020-Distribution Mains-Plastic
4586705	1,132,668.40	564,851.79	567,816.61	(8,323.63)	1%	4,172.71	2.56%	212.71	20376020-Distribution Mains-Plastic
4586707	1,553,901.45	695,438.35	858,463.10	(12,767.04)	1%	7,053.24	2.56%	326.27	20376020-Distribution Mains-Plastic
4586709	1,269,469.79	503,212.23	766,257.56	(14,819.40)	1%	8,945.06	2.56%	378.72	20376020-Distribution Mains-Plastic
4586710	2,292,746.28	850,200.05	1,442,546.23	(8,713.13)	0%	5,482.11	2.56%	222.67	20376020-Distribution Mains-Plastic
4586714	714,645.90	228,453.62	486,192.28	(10,222.38)	1%	6,954.55	2.56%	261.24	20376020-Distribution Mains-Plastic
4586716	1,085,880.13	319,357.31	766,522.82	(15,647.94)	1%	11,045.88	2.56%	399.89	20376020-Distribution Mains-Plastic
4586718	713,539.98	191,604.07	521,935.91	(17,770.26)	2%	12,998.48	2.56%	454.13	20376020-Distribution Mains-Plastic
4586720	1,285,358.06	312,280.51	973,077.55	(18,379.48)	1%	13,914.15	2.56%	469.70	20376020-Distribution Mains-Plastic
4586731	9,558.86	10,144.94	(586.08)	(3,507.84)	37%	(215.08)	2.56%	89.64	20376020-Distribution Mains-Plastic
4586733	8,367.62	8,666.69	(299.07)	(4,455.00)	53%	(159.23)	2.56%	113.85	20376020-Distribution Mains-Plastic
4586735	31,858.28	32,182.26	(323.98)	(2,344.80)	7%	(23.85)	2.56%	59.92	20376020-Distribution Mains-Plastic
4586737	21,999.16	21,660.28	338.88	(516.21)	2%	7.95	2.56%	13.19	20376020-Distribution Mains-Plastic
4586740	29,368.60	28,165.06	1,203.54	(1,735.68)	6%	71.13	2.56%	44.36	20376020-Distribution Mains-Plastic
4586743	33,562.55	31,328.85	2,233.70	(1,989.42)	6%	132.40	2.56%	50.84	20376020-Distribution Mains-Plastic
4586745	38,279.94	34,753.26	3,526.68	(1,475.54)	4%	135.94	2.56%	37.71	20376020-Distribution Mains-Plastic
4586748	23,208.84	20,477.21	2,731.63	(2,082.22)	9%	245.07	2.56%	53.21	20376020-Distribution Mains-Plastic
4586750	77,389.78	66,301.84	11,087.94	(1,716.80)	2%	245.97	2.56%	43.87	20376020-Distribution Mains-Plastic
4586752	77,899.29	64,746.16	13,153.13	(1,032.85)	1%	174.39	2.56%	26.40	20376020-Distribution Mains-Plastic
4586754	54,772.91	44,123.88	10,649.03	(3,199.35)	6%	622.02	2.56%	81.76	20376020-Distribution Mains-Plastic
4586756	89,846.89	70,080.90	19,765.99	(530.08)	1%	116.62	2.56%	13.55	20376020-Distribution Mains-Plastic
4586757	154,776.80	116,768.31	38,008.49	(600.89)	0%	147.56	2.56%	15.36	20376020-Distribution Mains-Plastic
4586758	233,263.24	170,015.39	63,247.85	(3,732.30)	2%	1,011.99	2.56%	95.38	20376020-Distribution Mains-Plastic
4586759	171,427.21	120,561.78	50,865.43	(3,134.40)	2%	930.03	2.56%	80.10	20376020-Distribution Mains-Plastic
4586760	78,046.39	52,892.65	25,153.74	(1,794.60)	2%	578.39	2.56%	45.86	20376020-Distribution Mains-Plastic
4586762	146,925.22	92,057.59	54,867.63	(983.16)	1%	367.15	2.56%	25.13	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4586763	101,853.44	61,212.55	40,640.89	(396.16)	0%	158.07	2.56%	10.12	20376020-Distribution Mains-Plastic
4586764	181,250.92	104,294.13	76,956.79	(237.60)	0%	100.88	2.56%	6.07	20376020-Distribution Mains-Plastic
4586766	123,067.62	64,520.06	58,547.56	(267.10)	0%	127.07	2.56%	6.83	20376020-Distribution Mains-Plastic
4586767	84,784.98	42,281.56	42,503.42	(586.08)	1%	293.81	2.56%	14.98	20376020-Distribution Mains-Plastic
4586769	68,733.37	30,761.24	37,972.13	(480.45)	1%	265.43	2.56%	12.28	20376020-Distribution Mains-Plastic
4586770	77,477.08	32,693.01	44,784.07	(1,974.56)	3%	1,141.35	2.56%	50.46	20376020-Distribution Mains-Plastic
4586780	340,507.23	82,726.86	257,780.37	(312.85)	0%	236.84	2.56%	8.00	20376020-Distribution Mains-Plastic
4586815	206,303.32	118,709.62	87,593.70	(1,805.92)	1%	766.77	2.56%	46.15	20376020-Distribution Mains-Plastic
4586834	407,920.47	182,562.12	225,358.35	(1,857.17)	0%	1,026.01	2.56%	47.46	20376020-Distribution Mains-Plastic
4587204	174,123.27	226,360.22	(52,236.95)	(159.98)	0%	(47.99)	3.25%	5.20	20380010-Distribution Service-Steel
4587209	226,946.93	295,031.02	(68,084.09)	(1,124.15)	0%	(337.25)	3.25%	36.53	20380010-Distribution Service-Steel
4587213	349,927.68	454,906.08	(104,978.40)	(1,732.30)	0%	(519.69)	3.25%	56.30	20380010-Distribution Service-Steel
4587219	421,363.94	547,773.15	(126,409.21)	(1,646.76)	0%	(494.03)	3.25%	53.52	20380010-Distribution Service-Steel
4587225	251,034.06	326,344.34	(75,310.28)	(1,258.78)	1%	(377.63)	3.25%	40.91	20380010-Distribution Service-Steel
4587229	571,319.26	742,715.14	(171,395.88)	(948.85)	0%	(284.66)	3.25%	30.84	20380010-Distribution Service-Steel
4587240	549,571.19	714,442.47	(164,871.28)	(4,383.04)	1%	(1,314.91)	3.25%	142.45	20380010-Distribution Service-Steel
4587246	626,844.72	814,898.04	(188,053.32)	(1,310.96)	0%	(393.29)	3.25%	42.61	20380010-Distribution Service-Steel
4587251	717,463.01	932,701.86	(215,238.85)	(3,035.55)	0%	(910.66)	3.25%	98.66	20380010-Distribution Service-Steel
4587255	424,371.10	551,682.36	(127,311.26)	(3,917.52)	1%	(1,175.26)	3.25%	127.32	20380010-Distribution Service-Steel
4587263	306,329.88	398,228.86	(91,898.98)	(3,740.85)	1%	(1,122.26)	3.25%	121.58	20380010-Distribution Service-Steel
4587270	262,838.80	341,690.44	(78,851.64)	(3,757.68)	1%	(1,127.30)	3.25%	122.12	20380010-Distribution Service-Steel
4587278	137,245.55	178,419.18	(41,173.63)	(3,985.85)	3%	(1,195.75)	3.25%	129.54	20380010-Distribution Service-Steel
4587283	153,697.60	199,806.93	(46,109.33)	(366.62)	0%	(109.99)	3.25%	11.92	20380010-Distribution Service-Steel
4587288	74,251.94	96,527.49	(22,275.55)	(1,085.46)	1%	(325.64)	3.25%	35.28	20380010-Distribution Service-Steel
4587294	40,780.56	53,014.73	(12,234.17)	(1,444.05)	4%	(433.22)	3.25%	46.93	20380010-Distribution Service-Steel
4587298	70,294.95	91,383.46	(21,088.51)	(1,570.71)	2%	(471.21)	3.25%	51.05	20380010-Distribution Service-Steel
4587301	201,597.45	262,076.71	(60,479.26)	(1,044.24)	1%	(313.27)	3.25%	33.94	20380010-Distribution Service-Steel
4587304	110,665.68	143,001.12	(32,335.44)	(1,804.48)	2%	(527.25)	3.25%	58.65	20380010-Distribution Service-Steel
4587308	116,604.16	148,292.62	(31,688.46)	(2,794.54)	2%	(759.45)	3.25%	90.82	20380010-Distribution Service-Steel
4587319	145,927.19	181,112.77	(35,185.58)	(2,934.26)	2%	(707.50)	3.25%	95.36	20380010-Distribution Service-Steel
4587371	29,541.04	38,403.35	(8,862.31)	(2,600.24)	9%	(780.07)	3.25%	84.51	20380010-Distribution Service-Steel
4587373	87,875.82	114,238.54	(26,362.72)	(8,336.37)	9%	(2,500.91)	3.25%	270.93	20380010-Distribution Service-Steel
4587377	66,083.80	85,909.01	(19,825.21)	(2,864.25)	4%	(859.28)	3.25%	93.09	20380010-Distribution Service-Steel
4587381	57,885.19	75,250.74	(17,365.55)	(4,286.88)	7%	(1,286.06)	3.25%	139.32	20380010-Distribution Service-Steel
4587383	107,665.16	139,964.69	(32,299.53)	(3,046.54)	3%	(913.96)	3.25%	99.01	20380010-Distribution Service-Steel
4587386	88,545.10	115,108.62	(26,563.52)	(4,738.08)	5%	(1,421.42)	3.25%	153.99	20380010-Distribution Service-Steel
4587388	55,631.65	72,321.15	(16,689.50)	(3,909.06)	7%	(1,172.72)	3.25%	127.04	20380010-Distribution Service-Steel
4587392	31,461.65	40,900.13	(9,438.48)	(3,744.93)	12%	(1,123.48)	3.25%	121.71	20380010-Distribution Service-Steel
4587393	11,884.95	15,450.44	(3,565.49)	(3,685.36)	31%	(1,105.61)	3.25%	119.77	20380010-Distribution Service-Steel
4587394	4,514.47	5,868.81	(1,354.34)	(2,216.36)	49%	(664.91)	3.25%	72.03	20380010-Distribution Service-Steel
4587400	5,074.91	6,597.38	(1,522.47)	(3,130.86)	62%	(939.26)	3.25%	101.75	20380010-Distribution Service-Steel

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4587557	16,996.75	22,095.77	(5,099.02)	(108.84)	1%	(32.65)	3.25%	3.54	20380020-Distribut Service-Plastic
4587558	8,007.64	10,262.07	(2,254.43)	(647.68)	8%	(182.34)	3.25%	21.05	20380020-Distribut Service-Plastic
4587561	26,039.91	32,547.08	(6,507.17)	(490.11)	2%	(122.47)	3.25%	15.93	20380020-Distribut Service-Plastic
4587566	47,865.46	58,312.05	(10,446.59)	(228.08)	0%	(49.78)	3.25%	7.41	20380020-Distribut Service-Plastic
4587568	26,927.71	31,952.59	(5,024.88)	(1,054.41)	4%	(196.76)	3.25%	34.27	20380020-Distribut Service-Plastic
4587570	32,506.19	37,543.46	(5,037.27)	(748.16)	2%	(115.94)	3.25%	24.32	20380020-Distribut Service-Plastic
4587575	34,224.88	38,445.52	(4,220.64)	(1,012.60)	3%	(124.87)	3.25%	32.91	20380020-Distribut Service-Plastic
4587577	27,160.31	29,650.32	(2,490.01)	(1,268.45)	5%	(116.29)	3.25%	41.22	20380020-Distribut Service-Plastic
4587580	27,698.92	29,361.82	(1,662.90)	(1,331.40)	5%	(79.93)	3.25%	43.27	20380020-Distribut Service-Plastic
4587584	50,206.63	51,632.11	(1,425.48)	(2,745.30)	5%	(77.95)	3.25%	89.22	20380020-Distribut Service-Plastic
4587587	29,068.74	28,974.24	94.50	(1,996.50)	7%	6.49	3.25%	64.89	20380020-Distribut Service-Plastic
4587590	20,454.21	19,740.50	713.71	(1,969.74)	10%	68.73	3.25%	64.02	20380020-Distribut Service-Plastic
4587593	69,914.43	65,262.58	4,651.85	(1,787.90)	3%	118.96	3.25%	58.11	20380020-Distribut Service-Plastic
4587595	129,365.70	116,664.68	12,701.02	(5,615.68)	4%	551.34	3.25%	182.51	20380020-Distribut Service-Plastic
4587598	48,918.73	42,568.01	6,350.72	(7,617.12)	16%	988.87	3.25%	247.56	20380020-Distribut Service-Plastic
4587601	47,565.72	39,885.53	7,680.19	(4,375.03)	9%	706.41	3.25%	142.19	20380020-Distribut Service-Plastic
4587603	65,607.50	52,938.18	12,669.32	(2,505.55)	4%	483.84	3.25%	81.43	20380020-Distribut Service-Plastic
4587605	81,429.30	63,128.02	18,301.28	(3,316.14)	4%	745.30	3.25%	107.77	20380020-Distribut Service-Plastic
4587607	95,387.20	70,930.56	24,456.64	(3,796.66)	4%	973.44	3.25%	123.39	20380020-Distribut Service-Plastic
4587609	82,099.76	58,452.06	23,647.70	(2,784.30)	3%	801.98	3.25%	90.49	20380020-Distribut Service-Plastic
4587612	101,633.24	69,143.22	32,490.02	(3,515.12)	3%	1,123.71	3.25%	114.24	20380020-Distribut Service-Plastic
4587614	67,792.80	43,975.70	23,817.10	(5,106.31)	8%	1,793.96	3.25%	165.96	20380020-Distribut Service-Plastic
4587616	122,557.42	75,622.26	46,935.16	(6,897.80)	6%	2,641.61	3.25%	224.18	20380020-Distribut Service-Plastic
4587619	95,017.62	55,622.59	39,395.03	(6,293.70)	7%	2,609.42	3.25%	204.55	20380020-Distribut Service-Plastic
4587622	151,357.27	83,814.03	67,543.24	(3,683.78)	2%	1,643.89	3.25%	119.72	20380020-Distribut Service-Plastic
4587626	157,410.23	82,184.94	75,225.29	(4,330.62)	3%	2,069.57	3.25%	140.75	20380020-Distribut Service-Plastic
4587630	133,968.39	65,706.67	68,261.72	(5,935.39)	4%	3,024.29	3.25%	192.90	20380020-Distribut Service-Plastic
4587633	153,841.99	70,585.95	83,256.04	(6,500.76)	4%	3,518.07	3.25%	211.27	20380020-Distribut Service-Plastic
4587636	221,142.33	94,467.20	126,675.13	(3,831.29)	2%	2,194.65	3.25%	124.52	20380020-Distribut Service-Plastic
4587639	172,669.70	68,296.99	104,372.71	(4,664.31)	3%	2,819.41	3.25%	151.59	20380020-Distribut Service-Plastic
4587642	205,638.29	74,830.26	130,808.03	(6,605.91)	3%	4,202.07	3.25%	214.69	20380020-Distribut Service-Plastic
4587645	177,692.70	59,038.36	118,654.34	(5,843.07)	3%	3,901.71	3.25%	189.90	20380020-Distribut Service-Plastic
4587649	183,996.31	55,310.56	128,685.75	(5,552.54)	3%	3,883.41	3.25%	180.46	20380020-Distribut Service-Plastic
4587651	639.93	831.93	(192.00)	(10,971.61)	1715%	(3,291.84)	3.25%	356.58	20380020-Distribut Service-Plastic
4587657	13,264.98	16,579.79	(3,314.81)	(1,700.40)	13%	(424.92)	3.25%	55.26	20380020-Distribut Service-Plastic
4587659	20,960.30	25,534.87	(4,574.57)	(2,615.80)	12%	(570.90)	3.25%	85.01	20380020-Distribut Service-Plastic
4587661	21,544.64	25,565.01	(4,020.37)	(6,347.32)	29%	(1,184.45)	3.25%	206.29	20380020-Distribut Service-Plastic
4587663	17,802.67	20,561.43	(2,758.76)	(10,050.21)	56%	(1,557.41)	3.25%	326.63	20380020-Distribut Service-Plastic
4587665	14,639.46	16,444.81	(1,805.35)	(17,888.45)	122%	(2,206.02)	3.25%	581.37	20380020-Distribut Service-Plastic
4587667	75,333.33	82,239.70	(6,906.37)	(23,028.58)	31%	(2,111.20)	3.25%	748.43	20380020-Distribut Service-Plastic
4587669	23,925.39	25,361.72	(1,436.33)	(24,660.09)	103%	(1,480.44)	3.25%	801.45	20380020-Distribut Service-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4587671	63,139.57	64,932.23	(1,792.66)	(33,597.65)	53%	(953.91)	3.25%	1,091.92	20380020-Distribut Service-Plastic
4587673	85,095.70	84,819.06	276.64	(31,307.85)	37%	101.78	3.25%	1,017.51	20380020-Distribut Service-Plastic
4587676	88,898.39	85,796.41	3,101.98	(44,436.25)	50%	1,550.54	3.25%	1,444.18	20380020-Distribut Service-Plastic
4587679	101,145.21	94,415.37	6,729.84	(74,983.26)	74%	4,989.12	3.25%	2,436.96	20380020-Distribut Service-Plastic
4587682	110,408.04	99,567.92	10,840.12	(88,915.19)	81%	8,729.90	3.25%	2,889.74	20380020-Distribut Service-Plastic
4587685	54,259.57	47,215.49	7,044.08	(138,014.47)	254%	17,917.30	3.25%	4,485.47	20380020-Distribut Service-Plastic
4587688	41,247.82	34,587.74	6,660.08	(137,935.60)	334%	22,271.77	3.25%	4,482.91	20380020-Distribut Service-Plastic
4587691	52,948.46	42,723.71	10,224.75	(64,710.33)	122%	12,496.06	3.25%	2,103.09	20380020-Distribut Service-Plastic
4587694	58,115.76	45,054.21	13,061.55	(54,972.90)	95%	12,355.19	3.25%	1,786.62	20380020-Distribut Service-Plastic
4587697	50,819.06	37,789.39	13,029.67	(59,350.27)	117%	15,217.02	3.25%	1,928.88	20380020-Distribut Service-Plastic
4587699	82,554.95	58,776.14	23,778.81	(69,957.24)	85%	20,150.21	3.25%	2,273.61	20380020-Distribut Service-Plastic
4587702	117,769.30	80,120.92	37,648.38	(69,216.36)	59%	22,127.02	3.25%	2,249.53	20380020-Distribut Service-Plastic
4587705	171,861.17	111,482.58	60,378.59	(66,895.98)	39%	23,502.02	3.25%	2,174.12	20380020-Distribut Service-Plastic
4587708	134,888.50	83,230.95	51,657.55	(76,929.61)	57%	29,461.33	3.25%	2,500.21	20380020-Distribut Service-Plastic
4587711	523,597.64	306,510.11	217,087.53	(64,996.02)	12%	26,947.84	3.25%	2,112.37	20380020-Distribut Service-Plastic
4587714	210,619.00	116,630.16	93,988.84	(86,615.28)	41%	38,652.11	3.25%	2,815.00	20380020-Distribut Service-Plastic
4587717	316,275.82	165,129.75	151,146.07	(78,577.92)	25%	37,551.86	3.25%	2,553.78	20380020-Distribut Service-Plastic
4587720	227,619.48	111,639.15	115,980.33	(97,275.83)	43%	49,565.54	3.25%	3,161.46	20380020-Distribut Service-Plastic
4587723	370,163.16	169,838.67	200,324.49	(62,758.56)	17%	33,963.61	3.25%	2,039.65	20380020-Distribut Service-Plastic
4587727	340,738.53	145,556.09	195,182.44	(68,859.86)	20%	39,444.43	3.25%	2,237.95	20380020-Distribut Service-Plastic
4587731	348,276.95	137,755.87	210,521.08	(63,122.08)	18%	38,155.06	3.25%	2,051.47	20380020-Distribut Service-Plastic
4587734	360,635.90	131,232.75	229,403.15	(59,321.36)	16%	37,734.75	3.25%	1,927.94	20380020-Distribut Service-Plastic
4587738	284,802.53	94,625.57	190,176.96	(49,291.52)	17%	32,914.42	3.25%	1,601.97	20380020-Distribut Service-Plastic
4587741	409,098.24	122,977.78	286,120.46	(51,384.00)	13%	35,937.61	3.25%	1,669.98	20380020-Distribut Service-Plastic
4587829	4,462.56	5,801.36	(1,338.80)	(5,463.70)	122%	(1,639.15)	3.25%	177.57	20380020-Distribut Service-Plastic
4587830	31,250.56	40,625.73	(9,375.17)	(5,829.58)	19%	(1,748.87)	3.25%	189.46	20380020-Distribut Service-Plastic
4587831	24,994.93	32,031.87	(7,036.94)	(5,783.52)	23%	(1,628.26)	3.25%	187.96	20380020-Distribut Service-Plastic
4587834	32,615.34	40,765.67	(8,150.33)	(9,618.99)	29%	(2,403.71)	3.25%	312.62	20380020-Distribut Service-Plastic
4587837	48,200.16	58,719.79	(10,519.63)	(12,085.15)	25%	(2,637.57)	3.25%	392.77	20380020-Distribut Service-Plastic
4587839	40,213.02	47,717.03	(7,504.01)	(15,256.24)	38%	(2,846.91)	3.25%	495.83	20380020-Distribut Service-Plastic
4587842	59,945.27	69,234.62	(9,289.35)	(8,917.18)	15%	(1,381.84)	3.25%	289.81	20380020-Distribut Service-Plastic
4587844	71,286.03	80,077.07	(8,791.04)	(4,477.77)	6%	(552.20)	3.25%	145.53	20380020-Distribut Service-Plastic
4587846	59,468.56	64,920.50	(5,451.94)	(4,379.92)	7%	(401.54)	3.25%	142.35	20380020-Distribut Service-Plastic
4587848	183,936.20	194,978.80	(11,042.60)	(5,695.36)	3%	(341.92)	3.25%	185.10	20380020-Distribut Service-Plastic
4587850	165,376.39	170,071.78	(4,695.39)	(4,125.76)	2%	(117.14)	3.25%	134.09	20380020-Distribut Service-Plastic
4587853	120,481.44	120,089.80	391.64	(6,017.52)	5%	19.56	3.25%	195.57	20380020-Distribut Service-Plastic
4587856	257,455.05	248,471.55	8,983.50	(5,213.51)	2%	181.92	3.25%	169.44	20380020-Distribut Service-Plastic
4587858	356,993.08	333,240.07	23,753.01	(4,786.80)	1%	318.50	3.25%	155.57	20380020-Distribut Service-Plastic
4587862	524,491.04	472,996.93	51,494.11	(3,327.77)	1%	326.72	3.25%	108.15	20380020-Distribut Service-Plastic
4587866	311,419.77	270,990.54	40,429.23	(3,415.51)	1%	443.41	3.25%	111.00	20380020-Distribut Service-Plastic
4587869	216,477.46	181,523.95	34,953.51	(4,582.48)	2%	739.91	3.25%	148.93	20380020-Distribut Service-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4587872	310,612.12	250,630.53	59,981.59	(3,495.86)	1%	675.08	3.25%	113.62	20380020-Distribut Service-Plastic
4587876	417,633.07	323,769.79	93,863.28	(2,908.98)	1%	653.79	3.25%	94.54	20380020-Distribut Service-Plastic
4587881	403,723.71	300,211.67	103,512.04	(3,961.20)	1%	1,015.62	3.25%	128.74	20380020-Distribut Service-Plastic
4587888	629,711.08	448,331.48	181,379.60	(2,930.00)	0%	843.95	3.25%	95.23	20380020-Distribut Service-Plastic
4587892	541,737.96	368,555.70	173,182.26	(3,234.06)	1%	1,033.86	3.25%	105.11	20380020-Distribut Service-Plastic
4587896	965,683.57	626,417.82	339,265.75	(2,524.64)	0%	886.96	3.25%	82.05	20380020-Distribut Service-Plastic
4587901	871,231.87	537,580.82	333,651.05	(2,827.80)	0%	1,082.95	3.25%	91.90	20380020-Distribut Service-Plastic
4587905	598,161.35	350,159.11	248,002.24	(4,706.03)	1%	1,951.16	3.25%	152.95	20380020-Distribut Service-Plastic
4587909	810,314.60	448,711.40	361,603.20	(1,334.18)	0%	595.38	3.25%	43.36	20380020-Distribut Service-Plastic
4587913	1,005,461.23	524,958.13	480,503.10	(2,568.28)	0%	1,227.36	3.25%	83.47	20380020-Distribut Service-Plastic
4587921	1,118,680.19	548,672.31	570,007.88	(3,965.30)	0%	2,020.46	3.25%	128.87	20380020-Distribut Service-Plastic
4587925	908,008.70	416,613.53	491,395.17	(3,703.96)	0%	2,004.51	3.25%	120.38	20380020-Distribut Service-Plastic
4587928	1,094,114.95	467,382.14	626,732.81	(242.82)	0%	139.09	3.25%	7.89	20380020-Distribut Service-Plastic
4587931	1,633,119.51	645,956.65	987,162.86	(1,541.90)	0%	932.02	3.25%	50.11	20380020-Distribut Service-Plastic
4587935	1,552,318.53	564,877.22	987,441.31	(4,958.11)	0%	3,153.89	3.25%	161.14	20380020-Distribut Service-Plastic
4587940	2,242,430.83	745,047.12	1,497,383.71	(4,300.00)	0%	2,871.33	3.25%	139.75	20380020-Distribut Service-Plastic
4587946	3,414,707.87	1,026,484.85	2,388,223.02	(2,840.71)	0%	1,986.77	3.25%	92.32	20380020-Distribut Service-Plastic
4587951	370,050.04	481,065.19	(111,015.15)	(325.53)	0%	(97.66)	3.25%	10.58	20380020-Distribut Service-Plastic
4587952	83,466.80	106,965.59	(23,498.79)	(12,832.42)	15%	(3,612.77)	3.25%	417.05	20380020-Distribut Service-Plastic
4587956	228,506.74	285,608.70	(57,101.96)	(3,163.82)	1%	(790.61)	3.25%	102.82	20380020-Distribut Service-Plastic
4587960	369,207.64	449,786.84	(80,579.20)	(3,122.23)	1%	(681.42)	3.25%	101.47	20380020-Distribut Service-Plastic
4587965	477,196.66	566,244.52	(89,047.86)	(2,839.68)	1%	(529.90)	3.25%	92.29	20380020-Distribut Service-Plastic
4587969	587,441.48	678,473.46	(91,031.98)	(2,484.00)	0%	(384.93)	3.25%	80.73	20380020-Distribut Service-Plastic
4587973	656,745.95	737,736.30	(80,990.35)	(3,056.82)	0%	(376.97)	3.25%	99.35	20380020-Distribut Service-Plastic
4587978	920,452.91	1,004,838.00	(84,385.09)	(3,605.26)	0%	(330.52)	3.25%	117.17	20380020-Distribut Service-Plastic
4587985	884,086.19	937,162.28	(53,076.09)	(3,074.91)	0%	(184.60)	3.25%	99.93	20380020-Distribut Service-Plastic
4587990	1,382,161.63	1,421,404.25	(39,242.62)	(973.19)	0%	(27.63)	3.25%	31.63	20380020-Distribut Service-Plastic
4587994	2,352,153.86	2,344,507.75	7,646.11	(10,238.34)	0%	33.28	3.25%	332.75	20380020-Distribut Service-Plastic
4587999	2,924,814.33	2,822,757.32	102,057.01	(357.54)	0%	12.48	3.25%	11.62	20380020-Distribut Service-Plastic
4588004	4,876,869.87	4,552,380.72	324,489.15	(1,359.28)	0%	90.44	3.25%	44.18	20380020-Distribut Service-Plastic
4588009	5,254,128.89	4,738,281.68	515,847.21	(21,505.46)	0%	2,111.39	3.25%	698.93	20380020-Distribut Service-Plastic
4588013	3,621,692.24	3,151,516.48	470,175.76	(5,180.10)	0%	672.49	3.25%	168.35	20380020-Distribut Service-Plastic
4588017	2,453,003.99	2,056,930.02	396,073.97	(5,989.80)	0%	967.14	3.25%	194.67	20380020-Distribut Service-Plastic
4588021	2,972,749.98	2,398,689.07	574,060.91	(178.51)	0%	34.47	3.25%	5.80	20380020-Distribut Service-Plastic
4588027	3,515,634.63	2,725,493.80	790,140.83	(1,093.70)	0%	245.81	3.25%	35.55	20380020-Distribut Service-Plastic
4588032	3,692,236.29	2,745,571.29	946,665.00	(6,566.29)	0%	1,683.55	3.25%	213.40	20380020-Distribut Service-Plastic
4588037	3,878,946.84	2,761,669.62	1,117,277.22	(25,119.22)	1%	7,235.25	3.25%	816.37	20380020-Distribut Service-Plastic
4588041	4,864,964.41	3,309,737.26	1,555,227.15	(47,814.92)	1%	15,285.43	3.25%	1,553.98	20380020-Distribut Service-Plastic
4588046	4,398,026.97	2,852,903.77	1,545,123.20	(376.01)	0%	132.10	3.25%	12.22	20380020-Distribut Service-Plastic
4588052	6,318,714.43	3,898,869.70	2,419,844.73	(5,729.46)	0%	2,194.18	3.25%	186.21	20380020-Distribut Service-Plastic
4588058	6,278,899.01	3,675,620.04	2,603,278.97	(3,071.15)	0%	1,273.32	3.25%	99.81	20380020-Distribut Service-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4588063	8,209,086.21	4,545,778.35	3,663,307.86	(5,110.48)	0%	2,280.55	3.25%	166.09	20380020-Distribut Service-Plastic
4588067	5,848,228.23	3,053,399.60	2,794,828.63	(3,084.42)	0%	1,474.02	3.25%	100.24	20380020-Distribut Service-Plastic
4588072	6,820,222.41	3,345,073.16	3,475,149.25	(149.12)	0%	75.98	3.25%	4.85	20380020-Distribut Service-Plastic
4588077	6,690,418.08	3,069,705.08	3,620,713.00	(15,568.53)	0%	8,425.36	3.25%	505.98	20380020-Distribut Service-Plastic
4588082	6,947,859.77	2,967,974.74	3,979,885.03	(2,917.00)	0%	1,670.92	3.25%	94.80	20380020-Distribut Service-Plastic
4588087	6,471,056.01	2,559,531.97	3,911,524.04	(858.44)	0%	518.90	3.25%	27.90	20380020-Distribut Service-Plastic
4588093	6,961,238.25	2,533,143.08	4,428,095.17	(5,807.40)	0%	3,694.13	3.25%	188.74	20380020-Distribut Service-Plastic
4588098	6,791,744.83	2,256,555.69	4,535,189.14	(2,436.23)	0%	1,626.79	3.25%	79.18	20380020-Distribut Service-Plastic
4588103	7,047,640.53	2,118,569.55	4,929,070.98	(1,617.10)	0%	1,130.99	3.25%	52.56	20380020-Distribut Service-Plastic
4588124	3,281.56	4,205.44	(923.88)	(2,691.88)	82%	(757.86)	3.25%	87.49	20380020-Distribut Service-Plastic
4588126	4,249.56	5,311.49	(1,061.93)	(200.46)	5%	(50.09)	3.25%	6.51	20380020-Distribut Service-Plastic
4588128	24,342.25	29,654.92	(5,312.67)	(2,477.00)	10%	(540.60)	3.25%	80.50	20380020-Distribut Service-Plastic
4588130	39,645.28	47,043.34	(7,398.06)	(1,338.89)	3%	(249.85)	3.25%	43.51	20380020-Distribut Service-Plastic
4588133	30,406.69	35,118.62	(4,711.93)	(2,679.32)	9%	(415.20)	3.25%	87.08	20380020-Distribut Service-Plastic
4588136	61,091.71	68,625.58	(7,533.87)	(2,014.33)	3%	(248.41)	3.25%	65.47	20380020-Distribut Service-Plastic
4588140	66,892.15	73,024.66	(6,132.51)	(14,401.33)	22%	(1,320.28)	3.25%	468.04	20380020-Distribut Service-Plastic
4588144	99,340.85	105,304.78	(5,963.93)	(3,940.64)	4%	(236.58)	3.25%	128.07	20380020-Distribut Service-Plastic
4588146	116,337.77	119,640.86	(3,303.09)	(4,756.16)	4%	(135.04)	3.25%	154.58	20380020-Distribut Service-Plastic
4588149	126,513.29	126,102.04	411.25	(1,774.87)	1%	5.77	3.25%	57.68	20380020-Distribut Service-Plastic
4588152	218,754.71	211,121.57	7,633.14	(22,206.96)	10%	774.88	3.25%	721.73	20380020-Distribut Service-Plastic
4588155	414,004.60	386,457.92	27,546.68	(5,615.24)	1%	373.62	3.25%	182.50	20380020-Distribut Service-Plastic
4588158	411,517.66	371,115.19	40,402.47	(5,298.70)	1%	520.22	3.25%	172.21	20380020-Distribut Service-Plastic
4588161	257,814.83	224,344.77	33,470.06	(16,638.30)	6%	2,160.02	3.25%	540.74	20380020-Distribut Service-Plastic
4588164	155,501.94	130,393.84	25,108.10	(19,573.14)	13%	3,160.37	3.25%	636.13	20380020-Distribut Service-Plastic
4588167	141,252.65	113,975.68	27,276.97	(1,261.42)	1%	243.59	3.25%	41.00	20380020-Distribut Service-Plastic
4588169	225,225.72	174,606.12	50,619.60	(2,774.48)	1%	623.57	3.25%	90.17	20380020-Distribut Service-Plastic
4588172	169,156.99	125,786.26	43,370.73	(12,989.36)	8%	3,330.39	3.25%	422.15	20380020-Distribut Service-Plastic
4588175	297,365.70	211,713.61	85,652.09	(2,702.98)	1%	778.56	3.25%	87.85	20380020-Distribut Service-Plastic
4588177	218,447.69	148,614.53	69,833.16	(3,256.92)	1%	1,041.17	3.25%	105.85	20380020-Distribut Service-Plastic
4588179	252,265.30	163,638.98	88,626.32	(1,939.14)	1%	681.26	3.25%	63.02	20380020-Distribut Service-Plastic
4588182	177,851.97	109,740.94	68,111.03	(703.94)	0%	269.58	3.25%	22.88	20380020-Distribut Service-Plastic
4588185	212,736.06	124,534.08	88,201.98	(3,831.60)	2%	1,588.61	3.25%	124.53	20380020-Distribut Service-Plastic
4588188	295,568.33	163,670.85	131,897.48	(1,899.30)	1%	847.56	3.25%	61.73	20380020-Distribut Service-Plastic
4588191	240,215.00	125,417.88	114,797.12	(6,490.45)	3%	3,101.74	3.25%	210.94	20380020-Distribut Service-Plastic
4588195	246,296.09	120,799.36	125,496.73	(966.77)	0%	492.60	3.25%	31.42	20380020-Distribut Service-Plastic
4588199	311,615.06	142,975.58	168,639.48	(4,166.78)	1%	2,254.97	3.25%	135.42	20380020-Distribut Service-Plastic
4588202	263,700.99	112,647.33	151,053.66	(1,118.88)	0%	640.92	3.25%	36.36	20380020-Distribut Service-Plastic
4588204	296,994.04	117,471.68	179,522.36	(1,015.84)	0%	614.04	3.25%	33.01	20380020-Distribut Service-Plastic
4588207	289,704.32	105,421.26	184,283.06	(1,076.19)	0%	684.57	3.25%	34.98	20380020-Distribut Service-Plastic
4588210	323,782.68	107,576.73	216,205.95	(3,885.99)	1%	2,594.87	3.25%	126.29	20380020-Distribut Service-Plastic
4588213	598,335.63	179,863.84	418,471.79	(815.41)	0%	570.29	3.25%	26.50	20380020-Distribut Service-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
4790078	1,334.18	819.92	514.26	(1,366.82)	102%	526.84	4.03%	55.11	20378000-Dist Meas & Reg Sta Eq-Gen
4790079	2,568.28	1,578.33	989.95	(3,329.27)	130%	1,283.28	4.03%	134.24	20378000-Dist Meas & Reg Sta Eq-Gen
4790080	3,965.30	2,436.86	1,528.44	(545.07)	14%	210.10	4.03%	21.98	20378000-Dist Meas & Reg Sta Eq-Gen
4790081	3,703.96	2,276.25	1,427.71	(1,164.74)	31%	448.95	4.03%	46.97	20378000-Dist Meas & Reg Sta Eq-Gen
4790082	242.82	149.22	93.60	(1,530.96)	630%	590.14	4.03%	61.73	20378000-Dist Meas & Reg Sta Eq-Gen
4790091	1,541.90	947.57	594.33	(887.63)	58%	342.14	4.03%	35.79	20378000-Dist Meas & Reg Sta Eq-Gen
4790092	4,958.11	3,046.99	1,911.12	(2,031.64)	41%	783.10	4.03%	81.92	20378000-Dist Meas & Reg Sta Eq-Gen
4790093	4,300.00	2,642.55	1,657.45	(1,027.22)	24%	395.95	4.03%	41.42	20378000-Dist Meas & Reg Sta Eq-Gen
4790094	2,840.71	1,745.75	1,094.96	(706.18)	25%	272.20	4.03%	28.48	20378000-Dist Meas & Reg Sta Eq-Gen
4790095	4,958.11	3,046.99	1,911.12	(1,553.40)	31%	598.76	4.03%	62.64	20378000-Dist Meas & Reg Sta Eq-Gen
4790096	2,397.78	1,473.55	924.23	(1,634.11)	68%	629.87	4.03%	65.89	20378000-Dist Meas & Reg Sta Eq-Gen
4790097	221.29	135.99	85.30	(536.60)	242%	206.84	4.03%	21.64	20378000-Dist Meas & Reg Sta Eq-Gen
4790694	3,876.70	2,633.19	1,243.51	(1,124.64)	29%	360.75	4.03%	45.35	20378000-Dist Meas & Reg Sta Eq-Gen
4790695	4,305.90	2,924.72	1,381.18	(770.18)	18%	247.05	4.03%	31.06	20378000-Dist Meas & Reg Sta Eq-Gen
4790696	3,581.67	2,432.80	1,148.87	(943.82)	26%	302.74	4.03%	38.06	20378000-Dist Meas & Reg Sta Eq-Gen
4790697	3,876.71	2,633.20	1,243.51	(1,033.70)	27%	331.57	4.03%	41.68	20378000-Dist Meas & Reg Sta Eq-Gen
4790698	3,852.09	2,616.48	1,235.61	(1,745.87)	45%	560.01	4.03%	70.40	20378000-Dist Meas & Reg Sta Eq-Gen
4790699	325.53	221.11	104.42	(1,080.40)	332%	346.56	4.03%	43.56	20378000-Dist Meas & Reg Sta Eq-Gen
4791503	12,832.42	5,119.06	7,713.36	(936.57)	7%	562.96	4.03%	37.76	20378000-Dist Meas & Reg Sta Eq-Gen
4791504	3,163.82	1,262.10	1,901.72	(1,424.30)	45%	856.12	4.03%	57.43	20378000-Dist Meas & Reg Sta Eq-Gen
4791505	3,122.23	1,245.51	1,876.72	(867.72)	28%	521.57	4.03%	34.99	20378000-Dist Meas & Reg Sta Eq-Gen
4791506	2,839.68	1,132.79	1,706.89	(705.30)	25%	423.95	4.03%	28.44	20378000-Dist Meas & Reg Sta Eq-Gen
4791507	2,484.00	990.91	1,493.09	(1,244.88)	50%	748.28	4.03%	50.20	20378000-Dist Meas & Reg Sta Eq-Gen
4791549	3,056.82	1,812.64	1,244.18	(1,188.74)	39%	483.84	4.03%	47.93	20378000-Dist Meas & Reg Sta Eq-Gen
4791949	3,605.26	971.75	2,633.51	(1,003.90)	28%	733.31	4.03%	40.48	20378000-Dist Meas & Reg Sta Eq-Gen
4791975	3,074.91	828.80	2,246.11	(660.63)	21%	482.57	4.03%	26.64	20378000-Dist Meas & Reg Sta Eq-Gen
4795404	235,491.78	48,478.32	187,013.46	(1,368.47)	1%	1,086.76	2.89%	39.53	20376010-Distribution Mains-Steel
4795418	2,289,980.19	497,791.55	1,792,188.64	(7,964.75)	0%	6,233.39	2.56%	203.54	20376020-Distribution Mains-Plastic
4795421	958,468.23	208,350.03	750,118.20	(1,547.84)	0%	1,211.37	2.56%	39.56	20376020-Distribution Mains-Plastic
4795440	163,113.15	43,871.58	119,241.57	(45,544.56)	28%	33,294.71	3.25%	1,480.20	20380020-Distribut Service-Plastic
4795442	3,679,824.36	989,740.46	2,690,083.90	(16,530.11)	0%	12,084.10	3.25%	537.23	20380020-Distribut Service-Plastic
4795443	629,901.49	169,420.88	460,480.61	(9,203.04)	1%	6,727.75	3.25%	299.10	20380020-Distribut Service-Plastic
4795444	1,554,981.46	418,234.20	1,136,747.26	(4,958.11)	0%	3,624.56	3.25%	161.14	20380020-Distribut Service-Plastic
5287228	357,703.90	77,757.06	279,946.84	(22,022.67)	6%	17,235.42	2.56%	562.80	20376020-Distribution Mains-Plastic
6851764	383,503.56	83,365.33	300,138.23	(961.70)	0%	752.65	2.56%	24.58	20376020-Distribution Mains-Plastic
7391636	2,343,510.10	556,164.76	1,787,345.34	(2,397.78)	0%	1,828.74	3.25%	77.93	20380020-Distribut Service-Plastic
7391712	5,477,475.42	1,050,603.25	4,426,872.17	(17,675.07)	0%	14,284.92	2.56%	451.70	20376020-Distribution Mains-Plastic
7391717	9,049,917.15	2,147,737.76	6,902,179.39	(27,724.76)	0%	21,145.08	3.25%	901.05	20380020-Distribut Service-Plastic
7391893	99,347.28	23,577.22	75,770.06	(1,243.14)	1%	948.12	3.25%	40.40	20380020-Distribut Service-Plastic
7391922	1,060,308.48	203,371.70	856,936.78	(11,209.80)	1%	9,059.71	2.56%	286.47	20376020-Distribution Mains-Plastic
7391969	1,834,750.36	351,912.96	1,482,837.40	(1,120.62)	0%	905.68	2.56%	28.64	20376020-Distribution Mains-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
8500823	895,434.99	212,505.75	682,929.24	(43,938.45)	5%	33,510.92	3.25%	1,428.00	20380020-Distribut Service-Plastic
8500834	397,301.02	76,204.04	321,096.98	(257.28)	0%	207.93	2.56%	6.57	20376020-Distribution Mains-Plastic
11287563	48,416.60	9,286.54	39,130.06	(1,069.20)	2%	864.12	2.56%	27.32	20376020-Distribution Mains-Plastic
12435917	3,936,724.38	654,403.25	3,282,321.13	(15,390.73)	0%	12,832.32	2.56%	393.32	20376020-Distribution Mains-Plastic
13014594	1,989,768.50	330,760.10	1,659,008.40	(2,943.41)	0%	2,454.13	2.56%	75.22	20376020-Distribution Mains-Plastic
13819657	102,462.56	17,032.39	85,430.17	(1,000.34)	1%	834.05	2.56%	25.56	20376020-Distribution Mains-Plastic
14766146	170,969.78	26,914.43	144,055.35	(575.46)	0%	484.87	2.89%	16.62	20376010-Distribution Mains-Steel
16268507	437,882.47	61,591.00	376,291.47	(497.88)	0%	427.85	2.56%	12.72	20376020-Distribution Mains-Plastic
16276071	1,336,351.90	187,966.68	1,148,385.22	(3,503.28)	0%	3,010.52	2.56%	89.53	20376020-Distribution Mains-Plastic
16276709	5,215,361.12	733,574.43	4,481,786.69	(9,582.55)	0%	8,234.70	2.56%	244.89	20376020-Distribution Mains-Plastic
16638119	6,276,384.48	1,092,314.28	5,184,070.20	-	0%	-	3.25%	-	20380020-Distribut Service-Plastic
20290704	-	-	-	(1,279.43)	0%	-	2.56%	32.70	20376020-Distribution Mains-Plastic
20291152	-	-	-	(6,351.20)	0%	-	2.89%	183.48	20376010-Distribution Mains-Steel
23860823	1,641,033.39	188,854.28	1,452,179.11	(1,433.72)	0%	1,268.72	2.56%	36.64	20376020-Distribution Mains-Plastic
23860828	884,919.89	101,838.86	783,081.03	(7,414.88)	1%	6,561.56	2.56%	189.49	20376020-Distribution Mains-Plastic
23861345	3,160,746.45	363,747.03	2,796,999.42	(10,308.73)	0%	9,122.37	2.56%	263.45	20376020-Distribution Mains-Plastic
23861375	2,011,886.13	231,533.07	1,780,353.06	(1,618.74)	0%	1,432.45	2.56%	41.37	20376020-Distribution Mains-Plastic
23861380	851,684.87	98,014.10	753,670.77	(15,160.50)	2%	13,415.79	2.56%	387.44	20376020-Distribution Mains-Plastic
23863724	166,037.54	19,108.03	146,929.51	(421.62)	0%	373.10	2.56%	10.77	20376020-Distribution Mains-Plastic
32303665	388.21	42.31	345.90	(178.13)	46%	158.72	2.89%	5.15	20376010-Distribution Mains-Steel
33898552	6,532,609.87	584,725.33	5,947,884.54	(16,698.82)	0%	15,204.13	2.56%	426.75	20376020-Distribution Mains-Plastic
33898670	1,771,043.46	158,523.74	1,612,519.72	(503.13)	0%	458.10	2.56%	12.86	20376020-Distribution Mains-Plastic
34949551	993,906.53	88,963.27	904,943.26	(5,760.88)	1%	5,245.23	2.56%	147.22	20376020-Distribution Mains-Plastic
34949792	421,666.78	37,742.85	383,923.93	(1,027.46)	0%	935.49	2.56%	26.26	20376020-Distribution Mains-Plastic
36954016	143,348.09	12,830.90	130,517.19	(1,045.33)	1%	951.76	2.56%	26.71	20376020-Distribution Mains-Plastic
44260449	1,559,564.51	99,710.41	1,459,854.10	-	0%	-	2.56%	-	20376020-Distribution Mains-Plastic
44260798	174,410.76	11,150.91	163,259.85	(1,921.94)	1%	1,799.06	2.56%	49.12	20376020-Distribution Mains-Plastic
44261044	4,357,797.31	278,614.89	4,079,182.42	(14,337.22)	0%	13,420.57	2.56%	366.40	20376020-Distribution Mains-Plastic
45695733	1,773,947.58	113,416.89	1,660,530.69	(491.05)	0%	459.65	2.56%	12.55	20376020-Distribution Mains-Plastic
51432385	2,253,868.14	463,572.06	1,790,296.08	(221.29)	0%	175.78	3.25%	7.19	20380020-Distribut Service-Plastic
51432386	188,822.30	38,836.68	149,985.62	(1,951.54)	1%	1,550.15	3.25%	63.43	20380020-Distribut Service-Plastic
51432387	4,602,875.59	946,712.22	3,656,163.37	-	0%	-	3.25%	-	20380020-Distribut Service-Plastic
51432404	2,301,482.99	400,539.95	1,900,943.04	(3,876.70)	0%	3,202.02	3.25%	125.99	20380020-Distribut Service-Plastic
51432410	2,118,109.16	301,603.39	1,816,505.77	(4,305.90)	0%	3,692.77	3.25%	139.94	20380020-Distribut Service-Plastic
51432415	4,545,791.28	647,287.73	3,898,503.55	(4,826.85)	0%	4,139.54	3.25%	156.87	20380020-Distribut Service-Plastic
51432419	5,494,375.42	608,501.63	4,885,873.79	(589.14)	0%	523.89	3.25%	19.15	20380020-Distribut Service-Plastic
51432420	396,715.59	43,936.22	352,779.37	(2,930.29)	1%	2,605.76	3.25%	95.23	20380020-Distribut Service-Plastic
51432423	1,561,331.16	172,917.30	1,388,413.86	(3,581.67)	0%	3,185.00	3.25%	116.40	20380020-Distribut Service-Plastic
51432425	4,622,226.99	365,650.88	4,256,576.11	(9,518.78)	0%	8,765.78	3.25%	309.36	20380020-Distribut Service-Plastic
51432431	1,357,486.79	107,386.82	1,250,099.97	(3,876.71)	0%	3,570.03	3.25%	125.99	20380020-Distribut Service-Plastic
51432432	685,818.72	141,058.12	544,760.60	(364.62)	0%	289.63	3.25%	11.85	20380020-Distribut Service-Plastic

Estimated Net Book Value of Replaced Assets

Asset ID	Book Value	Estimated Reserve 1/1/2010	Net Book Value 1/1/2010	Estimated GUIC Retirement	% of Book Value Retired	Estimate of 2010 Rate Base for Replaced Asset	Approved Depreciation Rate	Depreciation Expense	Utility Account
51432433	504,177.96	71,791.27	432,386.69	(1,891.95)	0%	1,622.55	3.25%	61.49	20380020-Distribut Service-Plastic
51432437	87,382.16	6,912.54	80,469.62	(6,013.60)	7%	5,537.88	3.25%	195.44	20380020-Distribut Service-Plastic
51432447	910,775.06	158,507.28	752,267.78	(424.95)	0%	350.99	3.25%	13.81	20380020-Distribut Service-Plastic
51432448	515,587.65	40,786.63	474,801.02	(2,085.00)	0%	1,920.06	3.25%	67.76	20380020-Distribut Service-Plastic
52893431	1,911,909.16	73,342.55	1,838,566.61	(8,486.82)	0%	8,161.26	2.56%	216.89	20376020-Distribution Mains-Plastic
52896108	76,280.26	3,620.49	72,659.77	(3,781.00)	5%	3,601.54	3.25%	122.88	20380020-Distribut Service-Plastic
55410534	413.53	19.63	393.90	(2,571.88)	622%	2,449.79	3.25%	83.59	20380020-Distribut Service-Plastic
55673138	749,805.68	28,763.18	721,042.50	(8,086.22)	1%	7,776.03	2.56%	206.65	20376020-Distribution Mains-Plastic
55675327	51,807.83	2,459.00	49,348.83	(2,300.78)	4%	2,191.58	3.25%	74.78	20380020-Distribut Service-Plastic
56468336	714,396.23	27,404.86	686,991.37	(5,407.48)	1%	5,200.04	2.56%	138.19	20376020-Distribution Mains-Plastic
56760362	2,062,988.89	79,138.02	1,983,850.87	(2,709.57)	0%	2,605.63	2.56%	69.24	20376020-Distribution Mains-Plastic
56763759	35,877.92	1,702.95	34,174.97	(1,301.29)	4%	1,239.52	3.25%	42.29	20380020-Distribut Service-Plastic
58037637	3,866,537.96	183,522.34	3,683,015.62	(4.26)	0%	4.06	3.25%	0.14	20380020-Distribut Service-Plastic
58037665	985,826.78	46,791.53	939,035.25	(3,852.09)	0%	3,669.25	3.25%	125.19	20380020-Distribut Service-Plastic
58037827	578,538.81	27,459.91	551,078.90	(3,798.36)	1%	3,618.07	3.25%	123.45	20380020-Distribut Service-Plastic
58045438	360,166.62	5,698.32	354,468.30	(17,273.85)	5%	17,000.55	3.25%	561.40	20380020-Distribut Service-Plastic
	471,973,827.75	219,565,478.19	252,408,349.56	(6,402,254.26)	1%	1,959,512.54		190,597.42	

% of Remaining NBV for replaced assets	30.61%	Composite Depreciation Rate	2.98%

GUIC Rider Legacy Parents/WBS - Capital

Project No	PROJECT DESCRIPTION	Install Dates of Replaced Assets	GUIC Program
`			
11503515	ASV/REV Installation on High Pressure systems - MN Rider	No related retirements. New installations	GUIC TIMP
11615874	East Metro Pipe Replac. Proj HP Gas	1940s/1950s	GUIC TIMP
12013233	East Metro Pipeline Replacement - Reg Installation	1940s/1950s	GUIC TIMP
11676981	East Metro Pipe Replac. Proj Distr	1940s/1950s	GUIC TIMP
11706370	Install Rice & Co Rd Regulator	1940s/1950s	GUIC TIMP
11819647	RTUs - East Metro Pipe Replacement	1940s/1950s	GUIC TIMP
11649797	High Bridge Lateral Replacement	1948/but partial relocation in 1960	GUIC TIMP
11649797	High Bridge Lateral Replacement	1948/but partial relocation in 1960	GUIC TIMP
34000342	High Bridge Lat Replace Dist Reg	1948/but partial relocation in 1960	GUIC TIMP
11649521	NSPM TIMP Mitigation of ILI Results	Island Line 1950s / East County Line Casings 1960	GUIC TIMP
11651650	NSPM Pre 1950 Trans and IP Pipe	1950s	GUIC TIMP
34003261	NSPM Trans and IP Pipe - Distr	1950s	GUIC TIMP
50000704	MN/WBL/County Rd B Replacement-NSP to Rice	1950s	GUIC TIMP
50000709	MN/STP/ECL Replace-Maplewood to NSP	1957	GUIC TIMP
GUIC DIMP			
11649520	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations	GUIC DIMP
50000646	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations	GUIC DIMP
11649522	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
50000644	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
11649766	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
50000645	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
11813698	Pipeline Data Project Dist - NSPM	No related retirements. New installations	GUIC DIMP
11980562	Hugo Line ILI improvements	No related retirements. Assessment work only	GUIC DIMP
12173704	Replace Emr Vlvs in NSPM metro Dist Sys	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
12173830	NSPM Programmatic Service Reply	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
12173831	NSPM Programmatic Main Replace	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
34000462	Sartell Bridge Replacement	See Detail on Valve/Mains/Services Tabs	GUIC DIMP
50000705	MN/STP/County Rd B Replace-Rice to Hamline	1950s	GUIC DIMP
	MN/Colby Lake Lateral Replace	1964-1965	GUIC DIMP
	MN/Arden Hills/System H05 Replace	1964	GUIC DIMP
50000708	MN/NPT/Langdon Line Replacement	1958	GUIC DIMP

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Valve Replacements

Functional Class	Type of Asset Replaced	Project Description	Location	Year Retired Asset was Installed	Quantity Replaced	Year of Replacement	Valve #	Valve Size
Distribution	Valve	Inoperable Emergency Valve	Henry Ave & Fleming Field, SSTP	Uknown	1	2017	EV1245	12" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2017	EV1275	12" SC
Distribution	Valve	Inoperable Emergency Valve	7th & Dale, STP	Uknown	1	2017	EV1241	12" SC
Distribution	Valve	Inoperable Emergency Valve	Forest & Rose, STP	1974	1	2017	EV1202	12" SC
Distribution	Valve	Inoperable Emergency Valve	Cypress & 6th, STP	1974	1	2017	EV1218	6" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria & St. Anthony, STP	Uknown	1	2017	EV1069	6" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2017	EV1276	6" SC
Distribution	Valve	Inoperable Emergency Valve	Robert & Page, STP	1963	1	2017	EV1178	8" SC
Distribution	Valve	Inoperable Emergency Valve	Cypress & Reaney, STP	1974	1	2017	EV1213	8" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	DV6070	4" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	DV6068	6" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	EV6069	6" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1289	4" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1288	8" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1290	4" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Postponed to 2019)	1953	1	2017	EV1261	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Postponed to 2019)	1953	1	2017	EV1262	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Postponed to 2019)	1953	1	2017	EV1263	8" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & Hudson Rd	1954	1	2017	EV1291	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Postponed to 2019)	1953	1	2017	EV6132	8"SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2017	EV3512	8" SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2017	EV3513	6" SC
Distribution	Valve	Inoperable Emergency Valve	Snelling & Englewood, STP	Unknown	1	2018	EV1020	12" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Juno, STP	1974	1	2018	EV1030	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1976	1	2018	EV1037	16" SC
Distribution	Valve	Inoperable Emergency Valve	Dayton Ave & Cretin Ave, STP	N/A	1	2018	EV5199	2" PE
Distribution	Valve	Inoperable Emergency Valve	St. Albans & Alley South of Selby, STP	1974	1	2018	EV1373	4" SC
Distribution	Valve	Inoperable Emergency Valve	Hamline & County Road "B", RSV	N/A	1	2018	R063 bypass	4" SC
Distribution	Valve	Inoperable Emergency Valve	St. Peter & 10th St., STP	N/A	1	2018	R172 Block Valv	6" SC
Distribution	Valve	Inoperable Emergency Valve	7th & South, NSTP (Delayed to 2019)	1953	1	2018	EV0291	6" SC
Distribution	Valve	Inoperable Emergency Valve	Rich Valley Rd & 105th St, Eagan	N/A	1	2018	R413W bypass	2" SC
Distribution	Valve	Inoperable Emergency Valve	Plato & Water, STP	N/A	1	2018	R182 Block Valv	4" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Carry Over from 2017)	1953	1	2018	EV1261	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Carry Over from 2017)	1953	1	2018	EV1262	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Carry Over from 2017)	1953	1	2018	EV1263	8" SC
Distribution	Valve	Inoperable Emergency Valve	Larpenter & Gary (Carry Over from 2017)	1953	1	2018	EV6132	8"SC

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2015 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacements					Main Footage			Service		
Division	Project	WO	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred
St. Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	1977	12	12,760	7,100	12,760	230	223	4
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	1965	0	7,500	4,530	7,517	74	71	2
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	1967	2	2,600	1,300	1,300	48	46	4
	Barclay/Dieter	12185039	Unknown	-	3,750	2,675	3,925	60	58	4
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	1953	0	16,000	11,350	16,031	218	224	0
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	1972	7	2,326	4,660	2,326	24	21	4
	Idaho / Barclay / Clarence	12227467	1960	0	7,350	4,775	7,467	99	93	8
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	Unknown	-	4,400	2,405	4,560	49	48	0
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	1974	9	10,480	9,225	10,124	190	112	77
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	1970	5	15,000	15,234	15,234	250	228	0
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	1970	5	16,709	16,064	16,709	252	237	0
	WBL/OPH/Area D	12200298	1962	0	5,000	4,520	5,097	12	14	7
	Vad Heights - North Star Estates	12226824	1972	7	10,000	7,040	9,485	172	161	8
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	Unknown	-	2,900	2,000	3,845	43	16	23
	NO ST PAUL / 14th AVE E	11945105	1978	13	3,865	2,105	3,999	48	40	6
Wyoming	Forest Lake - Carry-over from 2014	12185020	1968	3	9,000	10,850	8,741	93	68	28
	Forest Lake - 11th Ave & 6th St	12233388	1968	3	4,100	3,310	3,310	36	41	6
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	Unknown	-	4,650	3,750	4,642	27	43	9
Newport	Cloman Way & Lower 67th St	12262781	1971	6	5,500	3,900	6,322	152	154	0
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	Unknown	-	2,204	950	2,224	26	26	0
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	Unknown	-	2,581	1,600	2,549	29	29	0
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	Unknown	-	9,274	5,050	9,274	110	110	0
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	1972	7	1,800	1,240	1,764	16	11	5
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	1974	9	2,224	2,980	2,224	20	15	3
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	1974	9	2,298	1,200	2,298	30	26	6
	Denton	12255539	1973	8	4,828	4,220	4,828	75	75	0
	Burns Ave	12170859	Unknown	-	6,901	3,900	6,902	85	73	11
St. Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	Unknown	-	250	256	270	2	0	0
	St Cloud - Lincoln Ave*	12223516	Unknown	-	7,750	5,990	6,273	36	18	11
	Watertown	12162124	Unknown	-	10,200	7,030	10,210	95	73	37
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	Unknown	-	286	250	250	3	3	0
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	1974	9	9,989	6,930	8,455	230	192	0
	Northfield Viking Ter	12241776	1970	5	10,550	8,525	7,677	180	180	0
	7th St S - Lake City	12205025	1971	6	1,400	-	1,256	6	0	0
	Hallstrom Dr & Burton St - Red Wing	12218584	1971	6	17,000	14,482	14,482	270	136	25
	Bluffview - Winona	12231997	1971	6	2,000	1,120	1,626	5	12	3
	Bush St & Langsford Ave - Red Wing	12212950	1972	7	5,950	5,100	6,337	85	69	7
	Hillsdale - Hidden Valley Mobile Home Park	12162836	1976	11	10,064	8,115	10,699	185	176	0
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	Unknown	-	975	-		1	0	0
	Moorehead Dale & 5th St S	12215099 & 12210767	Unknown	-	1,608	-	1,599	32	0	0
	Service Materials									
		Totals			254,022	195,731	244,591	3,598	3,122	298

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (Docket No. G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in Docket No. E,G002/D-07-1528)

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2016 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2016						
Area	**Work Order Number**	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot. Svc**
St. Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	25	1,350	28
	12328949	ST PAUL - ARMSTRONG AVE	1990	25	7,506	150
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	0	8,900	118
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	0	7,810	81
	12398688	LAUDERDALE - EUSTIS ST	Unknown	-	1,100	17
	12380740	ROSEVILLE - WEWERS RD	Unknown	-	1,400	15
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	0	1,200	5
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	0	23,400	305
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	0	150	-
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	15	4,750	56
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	15	1,260	20
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	15	960	36
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	15	3,875	100
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	15	10,440	195
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	1963	0	6,700	79
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	-	8,600	77
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	-	6,800	51
	12334697	NORTH ST PAUL - 19TH AVE	1956	0	7,000	85
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	-	320	5
	12320156	OAKDALE - GROSPOINT AVE	1960	0	16,200	178
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	11	16,600	109
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	0	12,900	179
	12320143	OAKDALE - GERSHWIN AVE	1967	2	9,500	70
	12320392	SHOREVIEW - DEBRA LN	1976	11	11,200	105
	12317856	SHOREVIEW - NANCY PL	1971	6	7,600	85
	12275730	OAKDALE - GREENE AVE	Unknown	-	2,150	22
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	7	10,900	128
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	-	1,680	28
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	3	1,900	22
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	-	8,815	100
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	-	7,530	120
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	-	911	5
St. Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	1	9,150	79
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	8	1,700	-
	12249351	DELANO	Unknown	-	14,800	127
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	9	8,100	127
	12354151	NORTHFIELD - FLORELLAS CT	1968	3	1,550	22
	12328936	FARIBAULT - 8TH ST SW	Unknown	-	5,320	48
	12345274	FARIBAULT - 7TH ST NW	1980	15	4,900	43
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	-	3,000	49
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	-	10,500	210
2016 DIMP-related Main Replacement Total					**270,427**	**3,279**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (Docket No. G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in Docket No. E,G002/D-07-1528)

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2017 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2017						
Area	**Work Order Number**	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot. Svc**
St. Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	0	3,760	44
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	14	11,300	177
	12328310	ST PAUL - HAGUE/SELBY	1978	13	6,745	128
	12326608	ST PAUL - EDMOND	Unknown	-	5,290	113
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	0	4,200	62
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	0	9,600	141
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	-	2,300	34
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	0	4,700	58
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3	3,200	39
	12092590	BAYPORT - 7TH ST	1964	0	1,000	11
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	-	2,100	25
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4	4,000	47
	12320027	FOREST LAKE - IVERSON AVE	1967	2	3,700	53
	N/A	FOREST LAKE - HEATH AVE	1968	3	3,600	34
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	6	3,338	100
	12438126	ST PAUL - BURNS-RUTH	1955	0	11,715	147
	DE 522036	COTTAGE GROVE - HYDE	1961	0	3,710	41
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	0	4,735	56
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	0	4,160	36
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	8	10,570	77
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	6	5,160	89
	DE 519457	INVER GROVE HTS - CONROY CT	1972	7	5,400	142
St. Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	7	4,100	26
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	7	2,500	10
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	3	8,500	154
	12320940	NORTHFIELD - WOODLEY ST E	1977	12	500	13
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	16	3,500	55
	12356426	LAKE CITY - LAKEWOOD AVE	1972	7	4,250	79
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	-	6,000	86
	12356414	WINONA - 9TH/52ND	1977	12	3,500	42
	N/A	NORTHFIELD - EDWARDS LN	1968	3	1,660	42
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	18	3,250	76
	N/A	RED WING - WRIGHT/FINRUD	1975	10	10,400	130
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	7	1,260	38
	12422040	DILWORTH - 1ST AVE SE	1972	7	5,000	48
2017 Designed DIMP-related Main Replacement Total					**168,703**	**2,453**

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Note: This page was initially included in Attachment A of our Reply Comments in Docket No. G002/M-17-178. Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

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
DIMP	$ 4,175,186	$ 3,639,148	$ 3,538,635	$ 3,630,020	$ 3,686,292		$ 18,669,281
	2015 YE Actuals	**2016 YE Actuals**	**2017 YE Actuals**	**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	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
TIMP O&M							
MN Transmission Pipeline Assessments	20,000	1,069,000	2,900,000	1,700,000	1,700,000	1,700,000	1,700,000
MN East Metro Pipeline Replacement	-	-	-	-	-	-	-
Total TIMP O&M	**20,000**	**1,069,000**	**2,900,000**	**1,700,000**	**1,700,000**	**1,700,000**	**1,700,000**
MN Allocator (G Load Dispatch)	88.2300%	87.8646%	88.3120%	87.9490%	87.6205%	87.4221%	87.4938%
MN Allocated TIMP O&M	**17,646**	**939,273**	**2,561,048**	**1,495,133**	**1,489,549**	**1,486,176**	**1,487,395**
DIMP O&M							
MN IP Line Assessments	1,913	400,000	479,000	579,000	579,000	579,000	579,000
MN Poor Performing Mains	-	-	-	-	-	-	-
MN Poor Performing Services	-	-	-	-	-	-	-
MN Federal Code Mitigation	157,562	200,000	-	-	-	-	-
MN Sewer Conflict Investigation	3,284,612	2,308,000	2,300,000	-	-	-	-
Total DIMP O&M	**3,444,087**	**2,908,000**	**2,779,000**	**579,000**	**579,000**	**579,000**	**579,000**
Total Operations & Maintenance Expenses	**3,461,733**	**3,847,273**	**5,340,048**	**2,074,133**	**2,068,549**	**2,065,176**	**2,066,395**

	2017	2018	2019	2020
Cap Structure (Last Authorized)				
Long Term Debt %	45.61%	45.81%	45.81%	45.81%
Long Term Debt Cost	4.94%	4.75%	4.75%	4.75%
Short Term Debt %	1.89%	1.69%	1.69%	1.69%
Short Term Debt Cost	1.12%	4.31%	4.31%	4.31%
Weighted Cost of Debt	2.27%	2.25%	2.25%	2.25%
Common Stock %	52.50%	52.50%	52.50%	52.50%
Common Stock Cost	9.04%	10.00%	10.25%	10.25%
Weighted Cost of Equity	4.75%	5.25%	5.38%	5.38%
Rate of Return	7.02%	7.50%	7.63%	7.63%
Tax Rates				
Income Tax Rates				
State Income Tax Rate	9.80%	9.80%	9.80%	9.80%
Federal Income Tax Rate	35.00%	21.00%	21.00%	21.00%
Composite Income Tax Rate				
State Composite Income Tax Rate	41.3700%	28.7420%	28.7420%	28.7420%
Company Composite Income Tax Rate	40.8468%	28.1344%	28.1344%	28.1344%
Property Tax Rate	1.70%	1.70%	1.70%	1.70%
Book Depreciation Lives				
Transmission	75.00	60.44	60.44	60.44
Distribution	46.14	36.79	36.79	36.79
Software	5.00	2.58	2.58	2.58
Net Salvage %				
Transmission	-15.00%	-15.00%	-15.00%	-15.00%
Distribution	-16.39%	-22.85%	-22.85%	-22.85%
Software	0.00%	0.00%	0.00%	0.00%
Book Depreciation Rates				
Transmission	1.53%	1.31%	1.31%	1.31%
Distribution	2.52%	2.28%	2.28%	2.28%
Software	20.00%	19.71%	19.71%	19.71%

*Note: 2018 Book Depreciation Rates reflect the depreciation change from Average Service Life to Average Remaining Life.

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

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

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

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

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

	2016	2017	2018	2019	2020	2021	2022	
Revenue Collection Forecast	**6,031**	**12,986**	**25,039**	**28,906**	**25,657**	**33,697**	**38,775**	[C] Fn 2
% of GUIC Revenue as Compared to Base Revenue Approved in Docket No. G002/GR-09-1153 (2010 TY)	3.79%	8.16%	15.74%	18.17%	16.13%	21.18%	24.37%	= [C] / [A]
Capital Expenditures Forecast	**20,235**	**47,313**	**43,064**	**51,233**	**45,558**	**48,925**	**47,830**	[D]
% of GUIC Capital Expenditures as Compared to Expenditures Approved in Docket No. G002/GR-09-1153 (2010 TY)	67.70%	158.29%	144.08%	171.41%	152.42%	163.69%	160.02%	= [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 No. 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 2017 Annual Report			
Amounts in $000's	Dec - 2016	Dec - 2017	BOY/EOY Avg	Dec - 2016	Dec - 2017	BOY/EOY Avg	Dec - 2016	Dec - 2017	BOY/EOY Avg	Annual Report Page Reference
Rate Base										
Plant Investment	$ 82,672	$ 102,388	$ 92,530	$ 1,116,277	$ 1,143,753	$ 1,130,015	$ 1,198,949	$ 1,246,141	$ 1,222,545	G-2; G-16 + G-16A; G-34A
Depreciation Reserve	(722)	(3,330)	(2,026)	544,784	561,985	553,385	544,062	558,655	$ 551,359	G-2; G-19 + G-19A; G-34A
Net Utility Plant	83,395	105,718	94,556	571,492	581,768	576,630	654,887	687,486	671,187	
CWIP				20,129	31,842	25,985	20,129	31,842	25,985	G-2; G-34A
Accumulated Deferred Taxes	7,629	14,476	11,053	167,368	169,495	168,431	174,997	183,971	179,484	sum G-29A
DTA - NOL Average Balance			-	-	-	-	-	-	-	G-29A; G-34B
Total Accum Deferred Taxes	7,629	14,476	11,053	167,368	169,495	168,431	174,997	183,971	179,484	G-29A
Cash Working Capital										
Materials and Supplies				1,084	1,084	1,084	1,084	1,084	1,084	G-34A
Fuel Inventory				23,652	23,652	23,652	23,652	23,652	23,652	G-34A
Non-plant Assets and Liabilities				(9,581)	(9,581)	(9,581)	(9,581)	(9,581)	(9,581)	G-34A
Prepaids and Other				422	422	422	422	422	422	G-34A
Regulatory Amortizations										
Total Other Rate Base Items				15,577	15,577	15,577	15,577	15,577	15,577	
Total Rate Base	**$ 75,766**	**$ 91,241**	**$ 83,503**	**$ 439,831**	**$ 459,692**	**$ 449,761**	**$ 515,597**	**$ 550,933**	**$ 533,264**	**G-34; G-34A**
	14.69%	16.56%	15.66%	85.31%	83.44%	84.34%	100.00%	100.00%	100.00%	

Amounts in $000's	GUIC Rider 2017	Base Rates & PGA 2017	MN Gas 2017 Annual Report 2017	Annual Report Page Reference
Revenues				
Operating Revenues	$ 21,593	$ 440,045	$ 461,638	G-2; G-30; G-34
Expenses				
Operating Expenses:				
Production		210	210	G-33
Purchased Gas		218,974	218,974	G-33
Natural Gas Storage		3,031	3,031	G-33
Gas Transmission	(462)	48,171	47,708	G-33
Gas Distribution	3,444	30,686	34,130	G-33
Customer Accounting		11,593	11,593	G-33
Customer Service & Information		24,402	24,402	G-33
Sales, Econ Dvlp & Other		(7)	(7)	G-33
Administrative & General		22,310	22,310	G-33
Total Operating Expenses	2,982	359,371	362,353	G-2; G-30
Book Depreciation	2,265	39,580	41,845	G-30
Amortization	5,093	(16,369)	(11,276)	G-30; G-30-1
Total Depreciation and Amortization	7,357	23,212	30,569	G-2
Taxes:				
Total Federal Income Taxes	(6,436)	6,436	(0)	G-30
Total State Income Taxes	(1,998)	1,998	(0)	G-30
Property Taxes	1,405	15,516	16,921	G-30
Deferred Income Tax & ITC	6,848	9,537	16,385	G-30
Payroll & Other Taxes		2,538	2,538	G-30
Total Taxes Other Than Income	8,253	27,591	35,844	G-30
Total Taxes	(181)	36,025	35,844	G-30
Total Expenses	10,158	418,608	428,765	G-2; G-30; G-34
Net Operating Income	11,435	21,438	32,873	G-30; G-34
AFUDC		1,316	1,316	G-2; G-32; G-34
Net Income	**$ 11,435**	**$ 22,754**	**$ 34,189**	**G-2; G-34**
	33.45%	66.55%	100.00%	
Revenue Requirements Calculation				
ROR	7.02%	7.50%	7.50%	
Average Rate Base	80,096 GUIC 13 Mo Ave	449,761	533,264	
Required Operating Income	5,623	33,732	39,995	
Net Income	11,435	22,754	34,189	
Income Deficiency	(5,812)	10,978	5,806	
Revenue Conversion Factor	1.705611	1.705611	1.705611	
Revenue Deficiency	(9,913)	18,725	9,903	
Revenue Requirements	**$ 11,680**	**$ 458,770**	**$ 468,112**	
	2.50%	98.00%	100.00%	

	2017	2018	2019	2020
	Actual	**Forecast**	**Forecast**	**Forecast**
Operations & Maintenance Expenses				
TIMP	17,646	939,273	2,561,048	1,495,133
DIMP	3,444,087	2,908,000	2,779,000	579,000
Total Operations & Maintenance Expenses	3,461,733	3,847,273	5,340,048	2,074,133
Capital-Related Revenue Requirements				
TIMP	7,923,747	8,468,800	9,492,230	11,058,349
DIMP	3,957,066	5,599,436	10,757,577	13,004,095
Total Capital-Related Revenue Requirements	11,880,813	14,068,236	20,249,806	24,062,444
Deferred Gas Infrastructure Costs				
TIMP	820,227	820,227	820,227	-
DIMP	3,733,856	3,733,856	3,733,856	-
Total Deferred Gas Infrastructure Costs	4,554,083	4,554,083	4,554,083	-
GUIC Retirement Revenue Credits	4,353	(484,635)	(757,540)	0
Revenue Requirement in Base Rates	(480,000)	(480,000)	(480,000)	(480,000)
Revenue Requirement Subtotal	**19,420,982**	**21,504,957**	**28,906,398**	**25,656,577**
Prior Year Carryover	538,473	(1,633,336)	-	-
Revenue Requirement (RR)	**19,959,455**	**19,871,621**	**28,906,398**	**25,656,577**
Revenue Collections (RC)*	21,592,791	19,871,621	28,906,398	25,656,577
Carryover Balance (RR - RC)	(1,633,336)	-	-	-

* Revenue Collections are collected over the following time periods: 2017 is collected from Apr '17-Feb '19. 2018 RR will be collected Mar '19-Dec '19. 2019 RR will be collected Jan '20-Dec '20. Remaining years will be collected from Jan-Dec of the following year.

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	Actual	Actual	Actual	Actual	
Operations & Maintenance Expenses													
TIMP	-	-	-	17,646	-	-	-	-	-	-	-	-	17,646
DIMP	45,587	46,451	96,088	141,495	387,299	369,829	447,098	450,596	391,436	556,069	469,300	42,838	3,444,087
Total Operations & Maintenance Expenses	45,587	46,451	96,088	159,141	387,299	369,829	447,098	450,596	391,436	556,069	469,300	42,838	3,461,733
Capital-Related Revenue Requirements													
TIMP*	663,834	644,050	671,331	684,748	663,547	656,014	613,643	599,271	622,550	694,224	704,164	706,372	7,923,747
DIMP*	494,291	445,674	442,376	122,304	179,250	339,674	241,763	184,749	195,605	315,237	468,298	527,845	3,957,066
Total Capital-Related Revenue Requirements	1,158,125	1,089,724	1,113,707	807,052	842,798	995,688	855,406	784,020	818,155	1,009,461	1,172,462	1,234,216	11,880,813
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
GUIC Retirement Revenue Credits	(71)	(74)	(86)	(589)	(31)	(130)	(249)	(747)	57	(528)	3,836	2,967	4,353
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	**1,543,148**	**1,475,609**	**1,549,216**	**1,305,111**	**1,569,572**	**1,704,893**	**1,641,761**	**1,573,376**	**1,549,155**	**1,904,510**	**1,985,104**	**1,619,528**	**19,420,982**

Prior Year Carryover Balance	538,473
Total Revenue Requirements	**19,959,455**
Revenue Collections at previous Do. 15-808 rate (Apr '17-Feb '18)	**5,638,892**
Revenue Collections at new Do. 16-891 rate (Mar '18-Feb '19)*	**15,953,899**
Current Year Carryover Balance	**(1,633,336)**

* Capital-Related Revenue Requirements changed from compliance filed in Docket 16-0891 on February 20, 2018 due to revised IRS guidance on Q4 2017 Bonus Tax Depreciation under the Tax Cuts and Jobs Act (TCJA). This clarifying information wasn't available at the time of the compliance filing.

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
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
Operations & Maintenance Expenses													
TIMP	(10,585)	11,430	63,383	52,742	199,797	54,678	31,980	122,482	122,482	122,482	94,912	73,489	939,273
DIMP	(22,859)	42,863	116,650	46,755	243,851	306,483	340,748	430,909	453,022	344,902	351,862	252,814	2,908,000
Total Operations & Maintenance Expenses	(33,445)	54,293	180,033	99,496	443,648	361,161	372,728	553,391	575,504	467,385	446,775	326,303	3,847,273
Capital-Related Revenue Requirements													
TIMP	593,968	594,299	1,366,653	615,957	623,858	625,355	642,640	667,388	674,909	680,956	686,711	696,105	8,468,800
DIMP	447,858	437,714	438,510	443,343	442,356	426,924	396,880	383,026	434,352	480,590	555,512	712,369	5,599,436
Total Capital-Related Revenue Requirements	1,041,826	1,032,014	1,805,162	1,059,300	1,066,213	1,052,279	1,039,521	1,050,414	1,109,261	1,161,547	1,242,223	1,408,474	14,068,236
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
GUIC Retirement Revenue Credits	(480,210)	74	86	589	31	130	249	747	(57)	528	(3,836)	(2,967)	(484,635)
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	**867,679**	**1,425,888**	**2,324,788**	**1,498,892**	**1,849,400**	**1,753,078**	**1,752,005**	**1,944,059**	**2,024,216**	**1,968,966**	**2,024,669**	**2,071,318**	**21,504,957**

Prior Year Carryover Balance	(1,633,336)
Total Revenue Requirements	**19,871,621**
Revenue Collections (Mar '19-Dec '19)*	**19,871,621**
Current Year Carryover Balance	**-**

* Note - The revenue collections of $20.8 million shown here assumes collection of the remaining 2018 revenue requirements with a new rate in place from Mar to Dec 2019.

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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	-	-	-	-	-	246,255	295,506	369,382	492,509	738,764	49,251	369,382	2,561,048
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	400,195	717,428	869,769	972,084	1,066,880	399,784	648,857	5,340,048
Capital-Related Revenue Requirements													
TIMP	786,281	785,581	783,446	773,880	770,815	766,332	769,701	759,055	776,039	787,795	838,613	894,691	9,492,230
DIMP	850,680	857,169	864,149	861,784	851,713	855,513	877,109	885,916	923,328	943,842	973,298	1,013,075	10,757,577
Total Capital-Related Revenue Requirements	1,636,960	1,642,750	1,647,596	1,635,664	1,622,528	1,621,845	1,646,810	1,644,971	1,699,367	1,731,638	1,811,912	1,907,766	20,249,806
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
GUIC Retirement Revenue Credits	(757,540)	0	0	0	0	0	0	0	0	0	0	0	(757,540)
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	**1,218,928**	**1,998,302**	**1,994,320**	**1,987,025**	**2,191,970**	**2,361,547**	**2,703,745**	**2,854,247**	**3,010,958**	**3,138,025**	**2,551,203**	**2,896,129**	**28,906,398**

Prior Year Carryover Balance	-
Total Revenue Requirements	**28,906,398**
Revenue Collections (Jan '20 - Dec '20)	**28,906,398**
Current Year Carryover Balance	**-**

2020 Tracker

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
Operations & Maintenance Expenses													
TIMP	-	-	-	-	-	143,763	172,515	215,644	287,526	431,288	28,753	215,644	1,495,133
DIMP	-	-	-	-	20,170	39,330	29,258	112,058	112,058	112,058	86,834	67,235	579,000
Total Operations & Maintenance Expenses	-	-	-	-	20,170	183,093	201,773	327,702	399,583	543,346	115,587	282,879	2,074,133
Capital-Related Revenue Requirements													
TIMP	897,949	898,333	894,338	881,617	886,679	883,665	889,490	891,204	908,469	931,547	942,871	1,152,187	11,058,349
DIMP	1,054,826	1,054,493	1,055,323	1,048,055	1,036,660	1,039,615	1,060,603	1,068,867	1,106,424	1,126,988	1,156,343	1,195,898	13,004,095
Total Capital-Related Revenue Requirements	1,952,776	1,952,826	1,949,660	1,929,672	1,923,340	1,923,280	1,950,093	1,960,071	2,014,893	2,058,535	2,099,214	2,348,085	24,062,444
Deferred Gas Infrastructure Costs													
TIMP	-	-	-	-	-	-	-	-	-	-	-	-	-
DIMP	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Deferred Gas Infrastructure Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
GUIC Retirement Revenue Credits	0	0	0	0	0	0	0	0	0	0	0	0	0
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	**1,912,776**	**1,912,826**	**1,909,660**	**1,889,672**	**1,903,510**	**2,066,373**	**2,111,866**	**2,247,773**	**2,374,476**	**2,561,881**	**2,174,800**	**2,590,964**	**25,656,577**

Prior Year Carryover Balance	-
Total Revenue Requirements	**25,656,577**
Revenue Collections (Jan '21 - Dec '21)	**25,656,577**
Current Year Carryover Balance	**-**

-
-

Revenue Requirements Category Descriptions

Attachments G and H to this Petition respectively provide the TIMP and DIMP annual revenue requirements for 2017-2020. 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 2019 plant in service for gas utility infrastructure projects (GUIC), the $85,825,266 for TIMP (Attachment G) and $92,415,881 for DIMP (Attachment H) reflect the dollar-value portion of the project in service as of December 31, 2019, 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 2019 book depreciation reserve for GUIC projects, the ($7,032) for TIMP (Attachment G) and ($5,685,658) for DIMP (Attachment H) reflect the amount of the plant in service that has been recovered as of December 31, 2019, 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 2019 accumulated deferred taxes for GUIC projects, the $9,470,598 for TIMP (Attachment G) and $8,910,753 for DIMP (Attachment H) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2019, 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 2019 debt return for GUIC return the Company is allowed in order to recover its weighted cost of debt for financing its capital projects, the $1,534,624 for TIMP (Attachment G) and $1,794,310 for DIMP (Attachment H) reflect the amount of debt return the Company is allowed for January 2019 - December 2019 based on the cost of debt and ratios approved in the most recent electric rate filing (Docket No. E002/GR-15-826).

> **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 2019 equity return for GUIC projects, the $3,669,456 for TIMP (Attachment G) and $4,290,396 for DIMP (Attachment H) reflect the amount of return on equity the Company is allowed for January 2019 - December 2019 based on the equity ratio approved in the most recent electric rate filing (Docket No. E002/GR-15-826) and the return on equity proposed in the present GUIC 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 2019 property tax amount for GUIC projects, the $1,267,144 for TIMP (Attachment G) and $1,261,005 for DIMP (Attachment H) reflect property tax rates from the pay-2018 tax year using plant in service as of December 31, 2016 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 2019 book depreciation for GUIC projects, the $1,475,179 for TIMP (Attachment G) and $1,715,366 for DIMP (Attachment H) reflect the amount of plant in service that is being recovered through depreciation expense from January 2019-December 2019 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 2019 deferred taxes for GUIC projects, the $1,109,508 for TIMP (Attachment G) and $1,322,937 for DIMP (Attachment H) reflect the January 1, 2019 - December 31, 2019 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 2019 current taxes for GUIC projects, the $436,319 for TIMP (Attachment G) and $373,563 for DIMP (Attachment H) 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.

Northern States Power Company

Accumulated Deferred Income Tax (ADIT) Prorate Calculation

2019

Line No.															
1	**TIMP**		**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**
2															
3	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
4	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.500000	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
5															
6	**Deferred Beg Bal**	C	8,408,811	8,501,270	8,593,729	8,686,188	8,778,647	8,871,106	8,963,565	9,056,024	9,148,483	9,240,942	9,333,401	9,425,860	
7	**Deferred Tax Exp Activity**	D	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	92,459	1,109,508
8	**Deferred Tax End Bal**	E=C+D	8,501,270	8,593,729	8,686,188	8,778,647	8,871,106	8,963,565	9,056,024	9,148,483	9,240,942	9,333,401	9,425,860	9,518,319	
9	**Average ADIT End Bal**	F=(C+E)/2	8,455,040	8,547,499	8,639,958	8,732,417	8,824,876	8,917,335	9,009,795	9,102,254	9,194,713	9,287,172	9,379,631	9,472,090	
10															
11	**Deferred Tax Exp Prorated Activity**	G=B*D	44,738	46,230	44,738	46,230	44,738	46,230	44,738	44,738	46,230	44,738	46,230	44,738	
12	**Deferred Tax End Bal Prorated**	H = C+G	8,453,549	8,547,499	8,638,467	8,732,417	8,823,385	8,917,335	9,008,303	9,100,762	9,194,713	9,285,680	9,379,631	9,470,598	
13															
14	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
15															
16	**RR of ADIT Pro-rate**	J = (F-H)*I	12	(0)	12	(0)	12	(0)	12	12	-	12	-	12	86
17															
18	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
19															
20	**MN Jur RR of ADIT Pro-rate**	L = J*K	**12**	**(0)**	**12**	**(0)**	**12**	**(0)**	**12**	**12**	**-**	**12**	**-**	**12**	**86**
21															
22															
23	**DIMP**		**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**
24															
25	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
26	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.500000	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
27															
28	**Deferred Beg Bal**	C	7,644,716	7,754,961	7,865,206	7,975,450	8,085,695	8,195,940	8,306,185	8,416,429	8,526,674	8,636,919	8,747,164	8,857,408	
29	**Deferred Tax Exp Activity**	D	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	110,245	1,322,937
30	**Deferred Tax End Bal**	E=C+D	7,754,961	7,865,206	7,975,450	8,085,695	8,195,940	8,306,185	8,416,429	8,526,674	8,636,919	8,747,164	8,857,408	8,967,653	
31	**Average ADIT End Bal**	F=(C+E)/2	7,699,839	7,810,083	7,920,328	8,030,573	8,140,818	8,251,062	8,361,307	8,471,552	8,581,797	8,692,041	8,802,286	8,912,531	
32															
33	**Deferred Tax Exp Prorated Activity**	G=B*D	53,344	55,122	53,344	55,122	53,344	55,122	53,344	53,344	55,122	53,344	55,122	53,344	
34	**Deferred Tax End Bal Prorated**	H = C+G	7,698,060	7,810,083	7,918,550	8,030,573	8,139,039	8,251,062	8,359,529	8,469,774	8,581,797	8,690,263	8,802,286	8,910,753	
35															
36	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
37															
38	**RR of ADIT Pro-rate**	J = (F-H)*I	15	(0)	15	(0)	15	(0)	15	15	-	15	-	15	102
39															
40	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
41															
42	**MN Jur RR of ADIT Pro-rate**	L = J*K	**15**	**(0)**	**15**	**(0)**	**15**	**(0)**	**15**	**15**	**-**	**15**	**-**	**15**	**102**
43															
44															

45	**Total**		**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**
46															
47	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
48	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.500000	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
49															
50	**Deferred Beg Bal**	C	16,053,527	16,256,231	16,458,935	16,661,638	16,864,342	17,067,046	17,269,750	17,472,454	17,675,157	17,877,861	18,080,565	18,283,269	
51	**Deferred Tax Exp Activity**	D	202,704	202,704	202,704	202,704	202,704	202,704	202,704	202,704	202,704	202,704	202,704	202,704	2,432,445
52	**Deferred Tax End Bal**	E=C+D	16,256,231	16,458,935	16,661,638	16,864,342	17,067,046	17,269,750	17,472,454	17,675,157	17,877,861	18,080,565	18,283,269	18,485,972	
53	**Average ADIT End Bal**	F=(C+E)/2	16,154,879	16,357,583	16,560,286	16,762,990	16,965,694	17,168,398	17,371,102	17,573,805	17,776,509	17,979,213	18,181,917	18,384,621	
54															
55	**Deferred Tax Exp Prorated Activity**	G=B*D	98,082	101,352	98,082	101,352	98,082	101,352	98,082	98,082	101,352	98,082	101,352	98,082	
56	**Deferred Tax End Bal Prorated**	H = C+G	16,151,609	16,357,583	16,557,017	16,762,990	16,962,425	17,168,398	17,367,832	17,570,536	17,776,509	17,975,944	18,181,917	18,381,351	
57															
58	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
59															
60	**RR of ADIT Pro-rate**	J = (F-H)*I	27	-	27	(0)	27	-	27	27	0	27	-	27	188
61															
62	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
63															
64	**MN Jur RR of ADIT Pro-rate**	L = J*K	**27**	**-**	**27**	**(0)**	**27**	**-**	**27**	**27**	**0**	**27**	**-**	**27**	**188**

2020

Line No.															
1	**TIMP**		**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
2															
3	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
4	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.482759	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
5															
6	**Deferred Beg Bal**	C	9,518,319	9,668,136	9,817,953	9,967,770	10,117,588	10,267,405	10,417,222	10,567,039	10,716,856	10,866,673	11,016,490	11,166,307	
7	**Deferred Tax Exp Activity**	D	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	149,817	1,797,805
8	**Deferred Tax End Bal**	E=C+D	9,668,136	9,817,953	9,967,770	10,117,588	10,267,405	10,417,222	10,567,039	10,716,856	10,866,673	11,016,490	11,166,307	11,316,124	
9	**Average ADIT End Bal**	F=(C+E)/2	9,593,228	9,743,045	9,892,862	10,042,679	10,192,496	10,342,313	10,492,130	10,641,947	10,791,764	10,941,582	11,091,399	11,241,216	
10															
11	**Deferred Tax Exp Prorated Activity**	G=B*D	72,492	72,325	72,492	74,909	72,492	74,909	72,492	72,492	74,909	72,492	74,909	72,492	
12	**Deferred Tax End Bal Prorated**	H = C+G	9,590,811	9,740,462	9,890,446	10,042,679	10,190,080	10,342,313	10,489,714	10,639,531	10,791,764	10,939,165	11,091,399	11,238,799	
13															
14	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
15															
16	**RR of ADIT Pro-rate**	J = (F-H)*I	20	21	20	-	20	-	20	20	-	20	-	20	160
17															
18	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
19															
20	**MN Jur RR of ADIT Pro-rate**	L = J*K	**20**	**21**	**20**	**-**	**20**	**-**	**20**	**20**	**-**	**20**	**-**	**20**	**160**
21															
22															

Line	DIMP		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
25	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
26	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.482759	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
28	**Deferred Beg Bal**	C	8,967,653	9,102,666	9,237,679	9,372,691	9,507,704	9,642,717	9,777,729	9,912,742	10,047,755	10,182,767	10,317,780	10,452,793	
29	**Deferred Tax Exp Activity**	D	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	135,013	1,620,152
30	**Deferred Tax End Bal**	E=C+D	9,102,666	9,237,679	9,372,691	9,507,704	9,642,717	9,777,729	9,912,742	10,047,755	10,182,767	10,317,780	10,452,793	10,587,805	
31	**Average ADIT End Bal**	F=(C+E)/2	9,035,160	9,170,172	9,305,185	9,440,198	9,575,210	9,710,223	9,845,236	9,980,248	10,115,261	10,250,274	10,385,286	10,520,299	
33	**Deferred Tax Exp Prorated Activity**	G=B*D	65,329	65,179	65,329	67,506	65,329	67,506	65,329	65,329	67,506	65,329	67,506	65,329	
34	**Deferred Tax End Bal Prorated**	H = C+G	9,032,982	9,167,844	9,303,007	9,440,198	9,573,033	9,710,223	9,843,058	9,978,071	10,115,261	10,248,096	10,385,286	10,518,121	
36	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
38	**RR of ADIT Pro-rate**	J = (F-H)*I	18	19	18	-	18	-	18	18	-	18	-	18	144
40	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
42	**MN Jur RR of ADIT Pro-rate**	L = J*K	**18**	**19**	**18**	**-**	**18**	**-**	**18**	**18**	**-**	**18**	**-**	**18**	**144**

Line	Total		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
47	**Pro-Rate Days**	A	15	14	15	15	15	15	15	15	15	15	15	15	
48	**Pro-Rate Factor**	B = A/Days in Month	0.483871	0.482759	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871	
50	**Deferred Beg Bal**	C	18,485,972	18,770,802	19,055,632	19,340,462	19,625,291	19,910,121	20,194,951	20,479,781	20,764,610	21,049,440	21,334,270	21,619,100	
51	**Deferred Tax Exp Activity**	D	284,830	284,830	284,830	284,830	284,830	284,830	284,830	284,830	284,830	284,830	284,830	284,830	3,417,957
52	**Deferred Tax End Bal**	E=C+D	18,770,802	19,055,632	19,340,462	19,625,291	19,910,121	20,194,951	20,479,781	20,764,610	21,049,440	21,334,270	21,619,100	21,903,929	
53	**Average ADIT End Bal**	F=(C+E)/2	18,628,387	18,913,217	19,198,047	19,482,877	19,767,706	20,052,536	20,337,366	20,622,196	20,907,025	21,191,855	21,476,685	21,761,515	
55	**Deferred Tax Exp Prorated Activity**	G=B*D	137,821	137,504	137,821	142,415	137,821	142,415	137,821	137,821	142,415	137,821	142,415	137,821	
56	**Deferred Tax End Bal Prorated**	H = C+G	18,623,793	18,908,306	19,193,453	19,482,877	19,763,112	20,052,536	20,332,772	20,617,602	20,907,025	21,187,261	21,476,685	21,756,921	
58	**Revenue Requirement Factor**	I= (WACC+(Equity Return*T/(1-T)))/12	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
60	**RR of ADIT Pro-rate**	J = (F-H)*I	38	40	38	(0)	38	(0)	38	38	(0)	38	(0)	38	304
62	**Jurisdictional Allocator**	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
64	**MN Jur RR of ADIT Pro-rate**	L = J*K	**38**	**40**	**38**	**(0)**	**38**	**(0)**	**38**	**38**	**(0)**	**38**	**(0)**	**38**	**304**

		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Revenue Requirement Subtotal		1,543,148	1,475,609	1,549,216	1,305,111	1,569,572	1,704,893	1,641,761	1,573,376	1,549,155	1,904,510	1,985,104	1,619,528
Revenue Collections (shaded = actuals)		1,126,556	717,341	748,292	387,813	263,473	179,974	175,650	158,511	183,916	321,225	703,628	1,064,416
													Revenue Collections (Apr '17
Carryover Rollforward:													
Carryover Beginning Balance					538,473	6,023,743	7,329,842	8,854,761	10,320,873	11,735,738	13,100,976	14,684,261	15,965,737
Activity (Under/(Over) Collection)					917,298	1,306,099	1,524,919	1,466,112	1,414,865	1,365,239	1,583,285	1,281,476	555,111
3-month deferral impact		(1,543,148)	(1,475,609)	(1,549,216)	4,567,972								
Carrying Charge													
Carryover Ending Balance					6,023,743	7,329,842	8,854,761	10,320,873	11,735,738	13,100,976	14,684,261	15,965,737	16,520,848
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													
Commercial Firm													
Commercial Demand Billed													
Interruptible													
Transport													
Total Sales		-	-	-	-	-	-	-	-	-	-	-	-
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
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
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
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
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

		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Revenue Requirement Subtotal		867,679	1,425,888	2,324,788	1,498,892	1,849,400	1,753,078	1,752,005	1,944,059	2,024,216	1,968,966	2,024,669	2,071,318
Revenue Collections (shaded = actuals)		1,168,573	1,031,712	1,954,223	1,534,546	596,436	455,180	455,986	462,696	483,300	851,343	1,536,354	2,455,997
		- Feb '18)	5,638,892										Revenue Collections (Mar '18
Carryover Rollforward:													
Carryover Beginning Balance		16,520,848	15,352,275	14,320,563	12,366,340	10,831,793	10,235,358	9,780,178	9,324,192	8,861,495	8,378,195	7,526,852	5,990,498
Activity (Under/(Over) Collection)		(300,895)	394,176	370,565	(35,654)	1,252,964	1,297,897	1,296,019	1,481,362	1,540,916	1,117,624	488,316	(384,679)
3-month deferral impact		(867,679)	(1,425,888)	(2,324,788)	(1,498,892)	(1,849,400)	(1,753,078)	(1,752,005)	(1,944,059)	(2,024,216)	(1,968,966)	(2,024,669)	(2,071,318)
Carrying Charge													
Carryover Ending Balance		15,352,275	14,320,563	12,366,340	10,831,793	10,235,358	9,780,178	9,324,192	8,861,495	8,378,195	7,526,852	5,990,498	3,534,502
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)										Forecast	Forecast	Forecast	Forecast
Residential										9,161,654	19,790,832	37,977,904	62,570,365
Commercial Firm										6,364,157	10,842,313	20,711,669	33,692,144
Commercial Demand Billed										1,835,924	1,975,129	2,663,903	3,292,674
Interruptible										5,775,535	7,049,965	10,809,894	12,797,315
Transport										20,227,564	18,666,092	17,232,049	23,638,559
Total Sales		-	-	-	-	-	-	-	-	43,364,833	58,324,332	89,395,419	135,991,057
Allocated Cost Per therm													
Residential		0.010922	0.010922	0.027634	0.027634	0.027634	0.027634	0.027634	0.027634	0.027634	0.027634	0.027634	0.027634
Commercial Firm		0.006110	0.006110	0.015080	0.015080	0.015080	0.015080	0.015080	0.015080	0.015080	0.015080	0.015080	0.015080
Commercial Demand Billed		0.005274	0.005274	0.011332	0.011332	0.011332	0.011332	0.011332	0.011332	0.011332	0.011332	0.011332	0.011332
Interruptible		0.003860	0.003860	0.008114	0.008114	0.008114	0.008114	0.008114	0.008114	0.008114	0.008114	0.008114	0.008114
Transport		0.001570	0.001570	0.003287	0.003287	0.003287	0.003287	0.003287	0.003287	0.003287	0.003287	0.003287	0.003287

		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Revenue Requirement Subtotal		1,218,928	1,998,302	1,994,320	1,987,025	2,191,970	2,361,547	2,703,745	2,854,247	3,010,958	3,138,025	2,551,203	2,896,129
Revenue Collections (shaded = actuals)		2,801,742	2,366,096	2,911,828	2,137,133	1,590,257	1,500,865	1,510,500	1,530,088	1,156,857	1,900,318	2,351,935	3,281,840
		- Feb '19)	15,953,899							Revenue Collections (Mar '19 - Dec '19)			19,871,621
Carryover Rollforward:													
Carryover Beginning Balance		3,534,502	732,759	(1,633,336)	22,171,342	14,822,660	13,232,403	11,731,538	10,221,038	8,690,950	7,534,093	5,633,775	3,281,840
Activity (Under/(Over) Collection)		(1,582,814)	(367,794)	(917,508)	(150,108)	601,714	860,682	1,193,245	1,324,159	1,854,101	1,237,707	199,268	(385,711)
3-month deferral impact		(1,218,928)	(1,998,302)	24,722,186	(7,198,574)	(2,191,970)	(2,361,547)	(2,703,745)	(2,854,247)	(3,010,958)	(3,138,025)	(2,551,203)	(2,896,129)
Carrying Charge													
Carryover Ending Balance		732,759	(1,633,336)	22,171,342	14,822,660	13,232,403	11,731,538	10,221,038	8,690,950	7,534,093	5,633,775	3,281,840	-
Monthly Interest Rate					0.00%								
Rate Calculation:													
Annual Revenue Requirements				21,504,957									
Carryover Balance				(1,633,336)									
Carrying Charge													
Total Revenue Requirement				19,871,621									
Total Sales				769,670,661									
Cost per Therm				0.025818									
Rate by Class:													
Allocated Revenue Requirement	Weighting*												
Residential	67.2244%			1,335,858	1,335,858	1,335,858	1,335,858	1,335,858	1,335,858	1,335,858	1,335,858	1,335,858	1,335,858
Commercial Firm	21.2597%			422,465	422,465	422,465	422,465	422,465	422,465	422,465	422,465	422,465	422,465
Commercial Demand Billed	2.1010%			41,750	41,750	41,750	41,750	41,750	41,750	41,750	41,750	41,750	41,750
Interruptible	5.6521%			112,316	112,316	112,316	112,316	112,316	112,316	112,316	112,316	112,316	112,316
Transport	3.7628%			74,773	74,773	74,773	74,773	74,773	74,773	74,773	74,773	74,773	74,773
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153													
Sales by Customer Group (Billed by total Usage)		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential		70,740,672	60,116,105	47,363,502	26,060,402	14,797,096	7,833,379	7,535,223	7,045,819	8,573,680	19,727,162	38,894,042	62,254,139
Commercial Firm		39,019,462	34,035,720	27,784,570	16,043,307	10,321,413	6,377,247	5,612,656	5,821,611	6,497,242	11,323,790	21,583,670	33,305,124
Commercial Demand Billed		4,028,918	3,744,711	3,264,273	2,435,454	2,008,198	1,765,936	1,469,119	1,570,222	1,653,225	1,851,532	2,849,836	3,152,140
Interruptible		12,944,787	12,665,051	11,213,052	9,008,840	7,208,297	5,960,853	5,489,710	5,658,997	5,476,296	6,979,864	11,014,624	12,330,151
Transport		32,793,191	14,112,948	23,155,975	29,227,760	27,259,058	36,194,329	38,398,203	39,166,939	22,607,119	33,721,058	16,753,349	16,071,178
Total Sales		159,527,030	124,674,534	112,781,372	82,775,764	61,594,062	58,131,744	58,504,910	59,263,588	44,807,562	73,603,407	91,095,520	127,112,733
Allocated Cost Per therm													
Residential		0.027634	0.027634	0.055641	0.055641	0.055641	0.055641	0.055641	0.055641	0.055641	0.055641	0.055641	0.055641
Commercial Firm		0.015080	0.015080	0.029202	0.029202	0.029202	0.029202	0.029202	0.029202	0.029202	0.029202	0.029202	0.029202
Commercial Demand Billed		0.011332	0.011332	0.018960	0.018960	0.018960	0.018960	0.018960	0.018960	0.018960	0.018960	0.018960	0.018960
Interruptible		0.008114	0.008114	0.013980	0.013980	0.013980	0.013980	0.013980	0.013980	0.013980	0.013980	0.013980	0.013980
Transport		0.003287	0.003287	0.002646	0.002646	0.002646	0.002646	0.002646	0.002646	0.002646	0.002646	0.002646	0.002646

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Revenue Requirement Subtotal		1,912,776	1,912,826	1,909,660	1,889,672	1,903,510	2,066,373	2,111,866	2,247,773	2,374,476	2,561,881	2,174,800	2,590,964
Revenue Collections (shaded = actuals)		4,238,545	3,599,088	3,005,788	2,015,873	1,509,251	1,512,667	1,681,912	1,801,893	1,239,601	1,923,394	2,611,144	3,767,241
												Revenue Collections (Jan '20 - Dec '20)	28,906,398
Carryover Rollforward:													
Carryover Beginning Balance		-	26,580,629	21,068,765	18,062,976	16,047,103	14,537,852	13,025,185	11,343,273	9,541,380	8,301,779	6,378,385	3,767,241
Activity (Under/(Over) Collection)		(2,325,769)	(1,686,262)	(1,096,128)	(126,201)	394,260	553,706	429,954	445,880	1,134,875	638,487	(436,343)	(1,176,278)
3-month deferral impact		28,906,398	(3,825,602)	(1,909,660)	(1,889,672)	(1,903,510)	(2,066,373)	(2,111,866)	(2,247,773)	(2,374,476)	(2,561,881)	(2,174,800)	(2,590,964)
Carrying Charge		-	-	-	-	-	-	-	-	-	-	-	-
Carryover Ending Balance		26,580,629	21,068,765	18,062,976	16,047,103	14,537,852	13,025,185	11,343,273	9,541,380	8,301,779	6,378,385	3,767,241	(0)
Monthly Interest Rate					0.00%								
Rate Calculation:													
Annual Revenue Requirements		28,906,398											
Carryover Balance		-											
Carrying Charge		-											
Total Revenue Requirement		28,906,398											
Total Sales		1,009,721,893											
Cost per Therm		0.028628											
Rate by Class:													
Allocated Revenue Requirement	Weighting*												
Residential	67.2244%	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346	1,619,346
Commercial Firm	21.2597%	512,118	512,118	512,118	512,118	512,118	512,118	512,118	512,118	512,118	512,118	512,118	512,118
Commercial Demand Billed	2.1010%	50,610	50,610	50,610	50,610	50,610	50,610	50,610	50,610	50,610	50,610	50,610	50,610
Interruptible	5.6521%	136,152	136,152	136,152	136,152	136,152	136,152	136,152	136,152	136,152	136,152	136,152	136,152
Transport	3.7628%	90,641	90,641	90,641	90,641	90,641	90,641	90,641	90,641	90,641	90,641	90,641	90,641
*Revenue Apportionment Allocations - Do. No. G002/GR-09-1153													
Sales by Customer Group (Billed by total Usage)		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential		71,055,724	61,884,494	47,298,984	26,176,931	15,528,182	7,185,871	7,508,093	7,328,179	8,235,769	20,140,032	39,053,712	62,743,589
Commercial Firm		38,706,652	35,095,307	27,436,753	16,483,524	10,695,103	5,980,577	5,862,711	6,384,168	6,564,251	11,946,696	21,989,316	33,858,211
Commercial Demand Billed		4,029,002	3,845,527	3,123,719	2,463,608	2,222,678	1,583,043	1,472,137	1,640,217	1,593,407	1,920,463	2,839,712	3,193,381
Interruptible		12,975,824	12,762,967	10,875,498	8,995,456	7,351,067	5,477,301	5,408,550	5,730,025	5,242,569	7,050,219	10,875,096	12,234,599
Transport		21,288,310	12,130,521	16,259,461	16,296,434	16,922,211	32,611,801	38,498,928	41,858,872	21,664,199	26,128,154	16,451,353	19,562,756
Total Sales		148,055,512	125,718,816	104,994,415	70,415,953	52,719,243	52,838,593	58,750,419	62,941,459	43,300,195	67,185,564	91,209,189	131,592,536
Allocated Cost Per therm													
Residential		0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938	0.051938
Commercial Firm		0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807	0.027807
Commercial Demand Billed		0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294	0.020294
Interruptible		0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563	0.015563
Transport		0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889	0.003889

Carryover Rollforward:	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Carryover Beginning Balance	538,473	6,023,743	7,329,842	8,854,761	10,320,873	11,735,738	13,100,976	14,684,261	15,965,737
Revenue Requirement	1,305,111	1,569,572	1,704,893	1,641,761	1,573,376	1,549,155	1,904,510	1,985,104	1,619,528
3 month deferral impact	4,567,972	-	-	-					
Cost Per Therm									
Revenue Collections	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Residential	229,980	138,176	88,606	69,278	73,306	88,769	189,411	469,534	713,375
Commercial Firm	77,048	52,944	29,427	25,725	27,183	31,813	62,559	145,470	227,299
Commercial Demand Billed	11,440	9,480	8,111	7,127	8,022	11,100	7,530	14,695	19,686
Interruptible	34,380	26,212	17,266	24,532	20,789	20,984	31,811	39,677	59,602
Transport	34,965	36,661	36,563	48,988	29,211	31,250	29,914	34,252	44,454
Total Revenue Collections	387,813	263,473	179,974	175,650	158,511	183,916	321,225	703,628	1,064,416
Carryover Ending Balance	**6,023,743**	**7,329,842**	**8,854,761**	**10,320,873**	**11,735,738**	**13,100,976**	**14,684,261**	**15,965,737**	**16,520,848**

Carryover Rollforward:	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
Carryover Beginning Balance	16,520,848	15,352,275	14,320,563	12,366,340	10,831,793	10,235,358	9,780,178	9,324,192	8,861,495	8,378,195	7,526,852	5,990,498
Revenue Requirement	867,679	1,425,888	2,324,788	1,498,892	1,849,400	1,753,078	1,752,005	1,944,059	2,024,216	1,968,966	2,024,669	2,071,318
3 month deferral impact	(867,679)	(1,425,888)	(2,324,788)	(1,498,892)	(1,849,400)	(1,753,078)	(1,752,005)	(1,944,059)	(2,024,216)	(1,968,966)	(2,024,669)	(2,071,318)
Cost Per Therm	0.055203	0.055203	0.055203	0.030698	0.030698	0.030698	0.030698	0.030698	-	-	-	-
Revenue Collections	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
Residential	801,959	704,935	1,308,440	1,027,011	269,626	207,058	174,299	186,024	253,173	546,900	1,049,481	1,729,069
Commercial Firm	251,703	217,226	428,500	304,489	115,688	72,269	62,471	69,549	95,971	163,502	312,332	508,078
Commercial Demand Billed	22,329	16,838	38,429	33,161	17,665	17,864	17,455	16,664	20,805	22,382	30,187	37,313
Interruptible	48,582	51,611	101,038	77,566	43,544	43,759	37,910	44,149	46,863	57,203	87,711	103,837
Transport	44,000	41,102	77,817	92,318	149,913	114,231	163,853	146,311	66,488	61,355	56,642	77,700
Total Revenue Collections	1,168,573	1,031,712	1,954,223	1,534,546	596,436	455,180	455,986	462,696	483,300	851,343	1,536,354	2,455,997
Carryover Ending Balance	**15,352,275**	**14,320,563**	**12,366,340**	**10,831,793**	**10,235,358**	**9,780,178**	**9,324,192**	**8,861,495**	**8,378,195**	**7,526,852**	**5,990,498**	**3,534,501**

Carryover Rollforward:	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Carryover Beginning Balance	3,534,501	732,759	(1,633,336)	22,171,342	14,822,660	13,232,403	11,731,538	10,221,038	8,690,950	7,534,093	5,633,775	3,281,840
Revenue Requirement	1,218,928	1,998,302	1,994,320	1,987,025	2,191,970	2,361,547	2,703,745	2,854,247	3,010,958	3,138,025	2,551,203	2,896,129
3 month deferral impact	(1,218,928)	(1,998,302)	24,722,186	(7,198,574)	(2,191,970)	(2,361,547)	(2,703,745)	(2,854,247)	(3,010,958)	(3,138,025)	(2,551,203)	(2,896,129)
Cost Per Therm	-	-	0.025818	0.025818	0.025818	0.025818	0.025818	0.025818	0.025818	0.025818	0.025818	0.025818
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	1,954,848	1,661,248	1,222,847	672,836	382,037	202,245	194,547	181,911	221,358	509,323	1,004,180	1,607,299
Commercial Firm	588,413	513,259	717,352	414,212	266,482	164,650	144,909	150,304	167,748	292,362	557,255	859,883
Commercial Demand Billed	45,656	42,435	84,278	62,879	51,848	45,594	37,930	40,541	42,684	47,803	73,578	81,383
Interruptible	105,034	102,764	289,502	232,593	186,106	153,899	141,735	146,106	141,389	180,209	284,379	318,344
Transport	107,791	46,389	597,849	754,612	703,784	934,478	991,378	1,011,225	583,678	870,622	432,544	414,931
Total Revenue Collections	2,801,742	2,366,096	2,911,828	2,137,133	1,590,257	1,500,865	1,510,500	1,530,088	1,156,857	1,900,318	2,351,935	3,281,840
Carryover Ending Balance	**732,759**	**(1,633,336)**	**22,171,342**	**14,822,660**	**13,232,403**	**11,731,538**	**10,221,038**	**8,690,950**	**7,534,093**	**5,633,775**	**3,281,840**	**(0)**

Carryover Rollforward:	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
Carryover Beginning Balance	(0)	26,580,628	21,068,765	18,062,976	16,047,103	14,537,852	13,025,185	11,343,273	9,541,380	8,301,779	6,378,385	3,767,241
Revenue Requirement	1,912,776	1,912,826	1,909,660	1,889,672	1,903,510	2,066,373	2,111,866	2,247,773	2,374,476	2,561,881	2,174,800	2,590,964
3 month deferral impact	28,906,398	(3,825,602)	(1,909,660)	(1,889,672)	(1,903,510)	(2,066,373)	(2,111,866)	(2,247,773)	(2,374,476)	(2,561,881)	(2,174,800)	(2,590,964)
Cost Per Therm	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628	0.028628
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	2,034,189	1,771,634	1,354,079	749,395	444,542	205,718	214,942	209,792	235,774	576,570	1,118,033	1,796,228
Commercial Firm	1,108,097	1,004,711	785,462	471,892	306,180	171,212	167,838	182,766	187,922	342,011	629,512	969,296
Commercial Demand Billed	115,343	110,090	89,426	70,528	63,631	45,319	42,144	46,956	45,616	54,979	81,295	91,420
Interruptible	371,473	365,379	311,345	257,523	210,447	156,805	154,836	164,040	150,085	201,834	311,333	350,253
Transport	609,443	347,274	465,477	466,536	484,450	933,613	1,102,150	1,198,339	620,204	747,999	470,971	560,044
Total Revenue Collections	4,238,545	3,599,088	3,005,788	2,015,873	1,509,251	1,512,667	1,681,912	1,801,893	1,239,601	1,923,394	2,611,144	3,767,241
Carryover Ending Balance	**26,580,628**	**21,068,765**	**18,062,976**	**16,047,103**	**14,537,852**	**13,025,185**	**11,343,273**	**9,541,380**	**8,301,779**	**6,378,385**	**3,767,241**	**(0)**

Carryover Rollforward:	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Carryover Beginning Balance	(0)	24,249,142	18,397,838	15,709,516	13,890,841	12,504,127	11,274,219	9,827,893	8,450,253	7,443,680	5,815,348	3,467,676
Revenue Requirement	2,593,859	2,592,028	2,591,111	2,578,175	2,582,267	2,744,181	2,788,057	2,916,717	3,061,123	3,238,215	2,876,702	3,134,281
3 month deferral impact	25,656,577	(5,185,886)	(2,591,111)	(2,578,175)	(2,582,267)	(2,744,181)	(2,788,057)	(2,916,717)	(3,061,123)	(3,238,215)	(2,876,702)	(3,134,281)
Cost Per Therm	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444	0.026444
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	1,894,787	1,603,715	1,250,524	695,747	413,193	189,679	208,634	184,520	217,018	547,423	1,024,198	1,668,590
Commercial Firm	1,041,936	914,785	728,100	443,500	291,683	163,650	169,349	167,347	179,566	333,580	579,101	905,435
Commercial Demand Billed	111,582	98,366	78,178	65,418	59,293	41,748	40,836	41,267	42,032	53,278	71,323	84,873
Interruptible	342,933	327,557	278,800	234,606	193,019	141,937	145,542	144,099	136,647	190,678	277,187	320,868
Transport	610,056	313,022	352,719	379,403	429,525	692,896	881,963	840,407	431,309	503,373	395,862	487,910
Total Revenue Collections	4,001,293	3,257,446	2,688,322	1,818,675	1,386,714	1,229,909	1,446,325	1,377,640	1,006,573	1,628,332	2,347,671	3,467,677
Carryover Ending Balance	**24,249,142**	**18,397,838**	**15,709,516**	**13,890,841**	**12,504,127**	**11,274,219**	**9,827,893**	**8,450,253**	**7,443,680**	**5,815,348**	**3,467,676**	**(0)**

Carryover Rollforward:	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**
Carryover Beginning Balance	(0)	31,496,598	24,125,890	20,450,241	18,022,750	16,370,691	14,764,888	12,947,300	11,123,434	9,785,115	7,781,560	4,639,123
Revenue Requirement	2,985,169	2,985,946	2,982,390	2,974,791	2,982,214	3,153,717	3,211,063	3,347,359	3,500,157	3,691,098	3,345,814	3,614,850
3 month deferral impact	33,696,715	(5,971,115)	(2,982,390)	(2,974,791)	(2,982,214)	(3,153,717)	(3,211,063)	(3,347,359)	(3,500,157)	(3,691,098)	(3,345,814)	(3,614,850)
Cost Per Therm	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234	0.035234
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	2,527,961	2,149,378	1,684,373	939,066	525,934	264,830	276,347	236,733	317,595	703,271	1,358,928	2,246,975
Commercial Firm	1,389,187	1,231,791	989,165	609,272	375,486	237,132	233,217	223,447	271,858	429,816	775,331	1,230,157
Commercial Demand Billed	141,460	131,940	109,335	90,719	70,732	59,192	54,085	52,974	61,429	65,236	93,581	117,656
Interruptible	445,412	430,903	373,652	315,591	240,178	193,114	189,808	184,257	190,215	236,915	364,569	428,975
Transport	681,267	441,528	519,123	472,843	439,730	851,534	1,064,130	1,126,456	497,223	568,317	550,029	615,359
Total Revenue Collections	5,185,287	4,385,539	3,675,649	2,427,491	1,652,059	1,605,803	1,817,588	1,823,866	1,338,320	2,003,555	3,142,437	4,639,123
Carryover Ending Balance	**31,496,598**	**24,125,890**	**20,450,241**	**18,022,750**	**16,370,691**	**14,764,888**	**12,947,300**	**11,123,434**	**9,785,115**	**7,781,560**	**4,639,123**	**(0)**

Carryover Rollforward:	**Jan-23**	**Feb-23**	**Mar-23**
Carryover Beginning Balance	(0)	36,492,842	27,992,676
Revenue Requirement	3,523,906	3,525,609	3,526,266
3 month deferral impact	38,774,569	(7,049,515)	(3,526,266)
Cost Per Therm	0.039191	0.039191	0.039191
Revenue Collections	Forecast	Forecast	Forecast
Residential	2,828,417	2,402,061	1,891,159
Commercial Firm	1,560,035	1,383,190	1,122,098
Commercial Demand Billed	157,850	146,624	127,783
Interruptible	491,262	473,339	419,254
Transport	768,070	571,046	548,315
Total Revenue Collections	5,805,634	4,976,260	4,108,609
Carryover Ending Balance	**36,492,842**	**27,992,676**	**23,884,066**

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	~~$0.027634~~$0.051938 per therm	R
Commercial Firm	~~$0.015080~~$0.027807 per therm	R
Commercial Demand Billed	~~$0.011332~~$0.020294 per therm	R
Interruptible	~~$0.008114~~$0.015563 per therm	R
Transportation	~~$0.003287~~$0.003889 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.

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	$0.051938 per therm	R
Commercial Firm	$0.027807 per therm	R
Commercial Demand Billed	$0.020294 per therm	R
Interruptible	$0.015563 per therm	R
Transportation	$0.003889 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, 2018

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 with offices in Washington D.C., Chicago, IL, and Calgary, AB, 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 2017 and 2018, 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 range of results from 9.08 percent to 11.48 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 my observations pertaining to capital market conditions, I believe that the range of reasonable

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.

returns is between 10.00 percent and 10.50 percent, and from within that range I recommend the Commission authorize an ROE for the GUIC of 10.25 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. 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 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 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 NSPM's GUIC petition filed in November 2016, the Commission determined that the authorized ROE for the GUIC rider should be reduced from 9.64 percent to 9.04 percent. The Commission has not issued a decision on the Company's GUIC petition filed in November 2017.[5] Given the changes in financial markets, in particular the increase in government bond yields that has occurred since the analysis was performed in the 2016 and 2017 GUIC petitions, Concentric presents an updated cost of equity analysis for the basis of its recommendation in this proceeding.

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3 Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), at 602.
4 Minn. Statute 216B.1635, subd.6.
5 G-002/M-16-891, February 8, 2018, at 5-6.

IV. CAPITAL MARKET CONDITIONS AND IMPLICATIONS FOR ROE

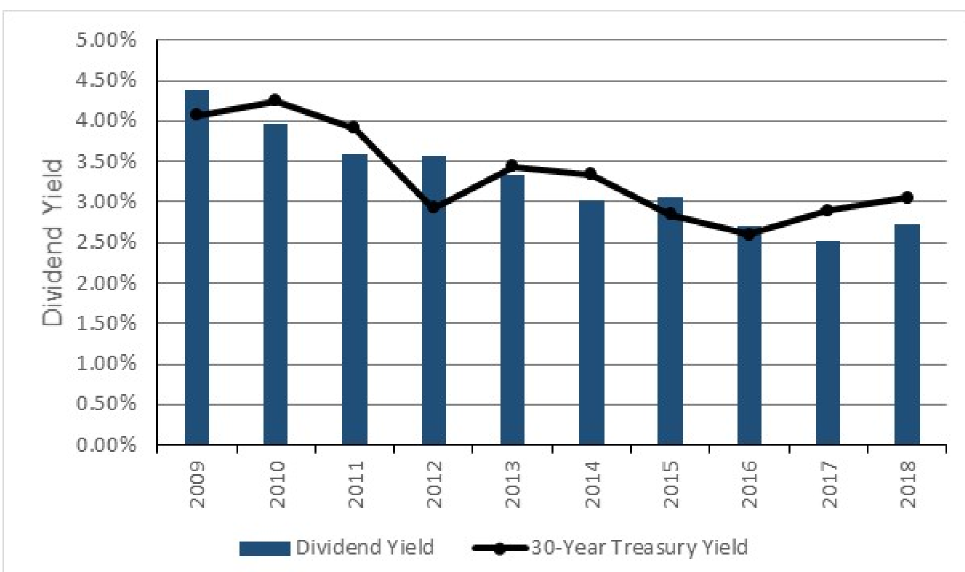
The required cost of capital, including the ROE, is a function of prevailing and expected conditions in the general economy and in financial markets. The standard ROE estimation tools, such as the DCF, CAPM and Risk Premium models, each reflect the state of the general economy and financial markets by 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, the ROE estimation models may 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 climbed to 3.05 percent as of September 28, 2018.

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, as 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 declined sharply. It is important to note that in spite of slight increases in 2018, the dividend yields for gas distributors are still well below their historical average. The yields on 30-year Treasury bonds in September 2018 averaged 3.15 percent and average dividend yields for gas distribution companies in 2018 have increased to 2.72 percent.

Figure 1: Dividend Yields for Natural Gas Utility Stocks



Following this pattern, Xcel Energy's average dividend yield declined from 5.15 percent in 2009 to 3.08 percent in 2017 and has increased to an average of 3.31 percent in the first nine months of 2018.

The DCF is one model used to estimate the cost of equity and typically 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 low dividend yields and high valuations in the utility industry:

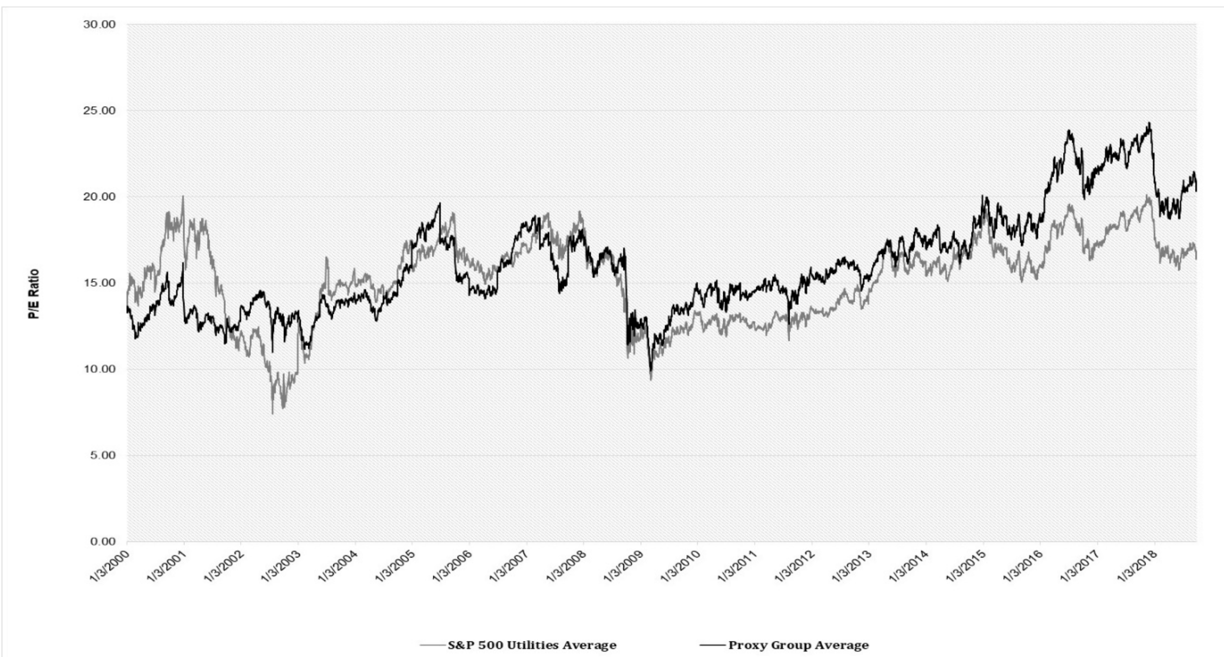
> Following a stellar showing (for most electric utility stocks) in 2017, the group has turned in a mixed performance in 2018. Most equities have risen or fallen modestly since the start of the year. For several months, the market has expected the Federal Reserve to raise interest rates, and this is coming to fruition. This has a negative effect on the prices of utility equities. However, some stocks have fared well for company-specific reasons. We mentioned takeover speculation above. In addition, the price of Sempra surged after two investors (with a combined 4.9% ownership interest) pushed the company to make changes intended to unlock shareholder value. We note that most of these equities have recent quotations within (or even above) their 2021-2023 Target Price Range. This indicates that most utility issues are still priced expensively. The industry mean for the dividend yield is just 3.4%, and the average 3- to 5-year total return potential is only 4%.[6]

As shown in Figure 2, the average price/earnings ("P/E") ratio for the proxy companies and utilities in general steadily increased after the financial crisis in 2008-09 through late 2017. Since that time, P/E ratios for utilities and the proxy companies have declined as interest rates on government and utility bonds have increased and investors have reacted to concerns over the effect of federal tax reform legislation on the cash flows and credit metrics of regulated utilities. Nevertheless, utility valuations remain at elevated levels compared with historical norms. These high valuations are important because the DCF model utilizes current dividend yields based on

6 Value Line Investment Survey, Electric Utility (West) Industry, July 27, 2018, at 2219.

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 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 current circumstances.

Figure 2: Utility P/E Ratios vs. Gas Proxy Group 2000 through September 2018

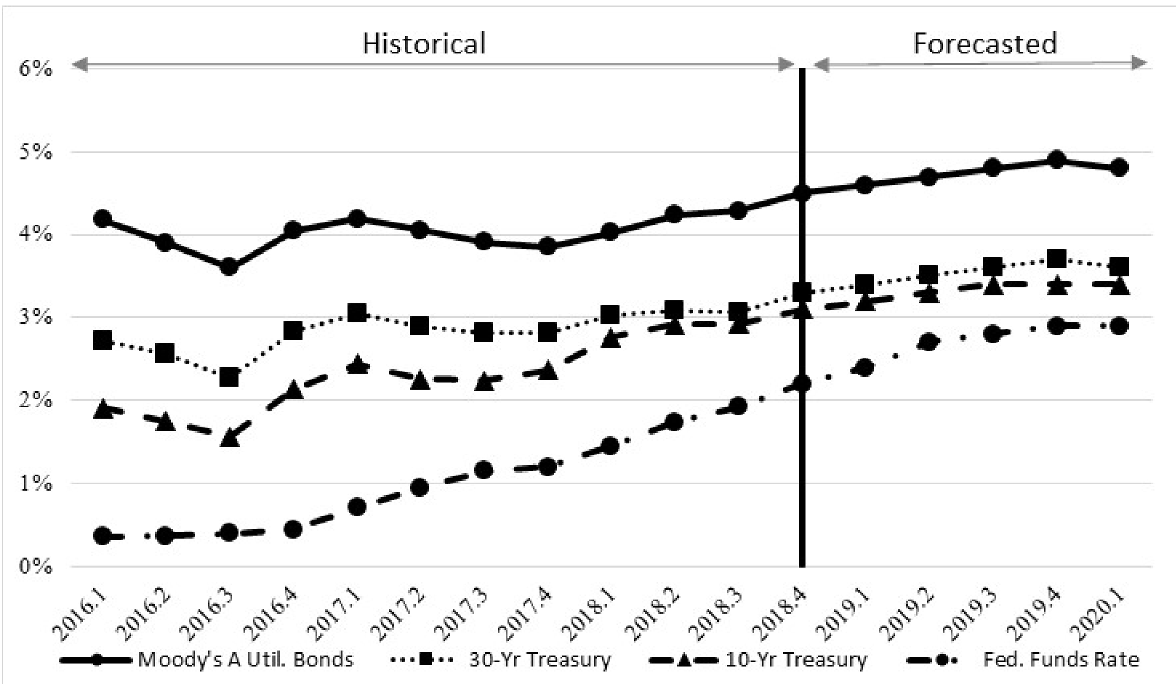


Since the process of estimating the cost of equity is a forward-looking analysis, it is not appropriate to base the ROE estimate on the low interest rate environment of the past few years, especially when interest rates are increasing and are expected to be substantially higher in the next several years. As shown in

Figure , the interest rate environment is changing, as the Federal Reserve has been tightening monetary policy, raising the federal funds rate in 25 basis point increments eight times since

December 2015. Yields on 10- 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 indicated that it intends to raise short-term rates once more in 2018 and likely three times in 2019.[9]

According to the October 2018 issue of Blue Chip Financial Forecasts, 93 percent of those surveyed expect the Federal Reserve will raise short-term interest rates again at the December

[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 37, No. 10, October 1, 2018, at 2.

[9] Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, September 2018.

2018 meeting.[10] In response to the question regarding expected increases in interest rates in 2019 by the Federal Reserve, 25 percent of those surveyed expect an increase of 50 basis points, 36 percent expect an increase of 75 basis points, and 18 percent expect an increase of 100 basis points.[11] These responses are aligned with the FOMC target rate projections noted above.

In October 2017, the Federal Reserve began 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 continued to reinvest the proceeds from the bonds it holds. The FOMC started 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. Under the new policy, the FOMC is gradually reducing the Federal Reserve's securities holdings by $10 billion per month initially, ramping up to $50 billion per month by the end of the first twelve months.[12] The Federal Reserve's unwinding plan provides additional support for the investor 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 10.0 percent ROE. This petition was filed in November 2017 based on market data through September 2017. At the time of this pending petition, interest rates on 10-year Treasury bonds in the third quarter of 2017 averaged 2.24 percent, as compared with 2.92 percent in the third quarter of 2018. This increase of 68 basis points in 10-year government bond yields

[10] Blue Chip Financial Forecasts, Vol. 37, Issue No. 10, October 1, 2018, at 14.
[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.

indicates that the cost of capital is higher now than it was one year ago, especially for interest sensitive sectors such as public utilities.

It is therefore 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 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 based on current dividend yields. I also give weight to the Risk Premium model and the CAPM analysis, 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 those 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 1.28 million electric customers and 455,000 gas customers in Minnesota.[13] NSPM's regulated gas distribution operations accounted for approximately 11 percent of operating revenue, with the remaining 89 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 10 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");

13 Northern States Power – Minnesota FERC Form 1, December 31, 2017, at 304-304.3; Gas Jurisdictional Annual Report, Northern States Power – Minnesota, 2017.
14 Source: SNL Financial
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 90- day period prior to my analysis.

B. Combination Proxy Group

To develop the combination proxy group, I began with the 39 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 90- day period prior to my analysis.

I did not include Xcel Energy in either 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
South Jersey Industries, Inc.	SJI
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
DTE Energy Company	DTE
NorthWestern Corporation	NWE
Sempra Energy	SRE
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 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 by current market conditions that lead to unreasonably low ROE estimates. 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.

The Commission has recently recognized the need to consider the results of multiple methodologies to estimate the cost of equity. In its most recent Orders for both Minnesota Power and Otter Tail Power Company, the Commission relied on the results of the Risk Premium analysis in addition to the CAPM to check the reasonableness of the results of the DCF model.[16] In its Order for Minnesota Power, the Commission concluded that:

> [I]t is appropriate to establish an ROE toward the higher end of the DCF-supported results to adjust for the divergence between ROEs supported by the DCF models and the models the Commission has historically relied upon for confirmation of reasonableness—the CAPM and Bond Yield Plus Risk Premium models.[17]

[16] Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order, at 61; Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order, at 54.

[17] Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order, at 61.

In Docket No. E-015/GR-16-664 for Minnesota Power, the DCF results presented by the ROE witnesses tended to support an ROE towards the lower end of the range of results, while the CAPM and Risk Premium models tended to support an ROE towards the higher end of the range.[18] The Commission recognized the divergence among the ROE results produced by the DCF, CAPM and Risk Premium models and approved an ROE toward the higher end of the DCF-supported ROE results. In my view, the results of the Risk Premium and CAPM analyses are important data points for the Commission to consider in this proceeding.

A. <u>Constant Growth DCF Model</u>

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 28, 2018;
2) Annualized dividend per share as of September 28, 2018; and
3) Company-specific earnings growth forecasts.

Utility companies 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 relied on EPS 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

18 *Id.,* at 60.

measure of long-term growth in the DCF model. 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 calculated the Median 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 Median Low DCF results, using the minimum growth rate for each company. The Median DCF results reflect the average growth rate for each company in combination with the expected dividend yield. The Value Line EPS growth rates for NiSource and Northwest Natural Gas are skewed upward due to the way that Value Line calculates its five-year projected growth rates. Since these growth rates are not likely sustainable, I have reported the median rather than the mean DCF results in order to account for these outliers.

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

	Median Low	Median	Median High
30-day average	8.18%	10.05%	12.53%
90-day average	8.28%	10.14%	12.62%
180-day average	8.42%	10.30%	12.78%

Figure 7: Constant Growth DCF Results – Combination Proxy Group

	Mean Low	Mean	Mean High
30-day average	8.56%	9.36%	10.38%
90-day average	8.70%	9.51%	10.51%
180-day average	8.76%	9.57%	10.60%

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.

Utility 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") in Opinion No. 531 determined that anomalous capital market conditions have caused the DCF model to understate equity costs for regulated utilities. In October 2018, the FERC issued an Order in response to the remand order from the U.S. Court of Appeals for the District of Columbia indicating that it plans to establish ROEs based on an equal weighting of the results of four financial models: the DCF, CAPM, Expected Earnings and Risk Premium. FERC explains its reasons for moving away from sole reliance on the DCF model as follows:

> Our decision to rely on multiple methodologies in these four complaint proceedings is based on our conclusion that the DCF methodology may no longer singularly reflect how investors make their decisions. We believe that, since we adopted the DCF methodology as our sole method for determining utility ROEs in the 1980s, investors have increasingly used a diverse set of data sources and models to inform their investment decisions. Investors appear to base their decisions on numerous data points and models, including the DCF, CAPM, Risk Premium, and Expected Earnings methodologies.[19]

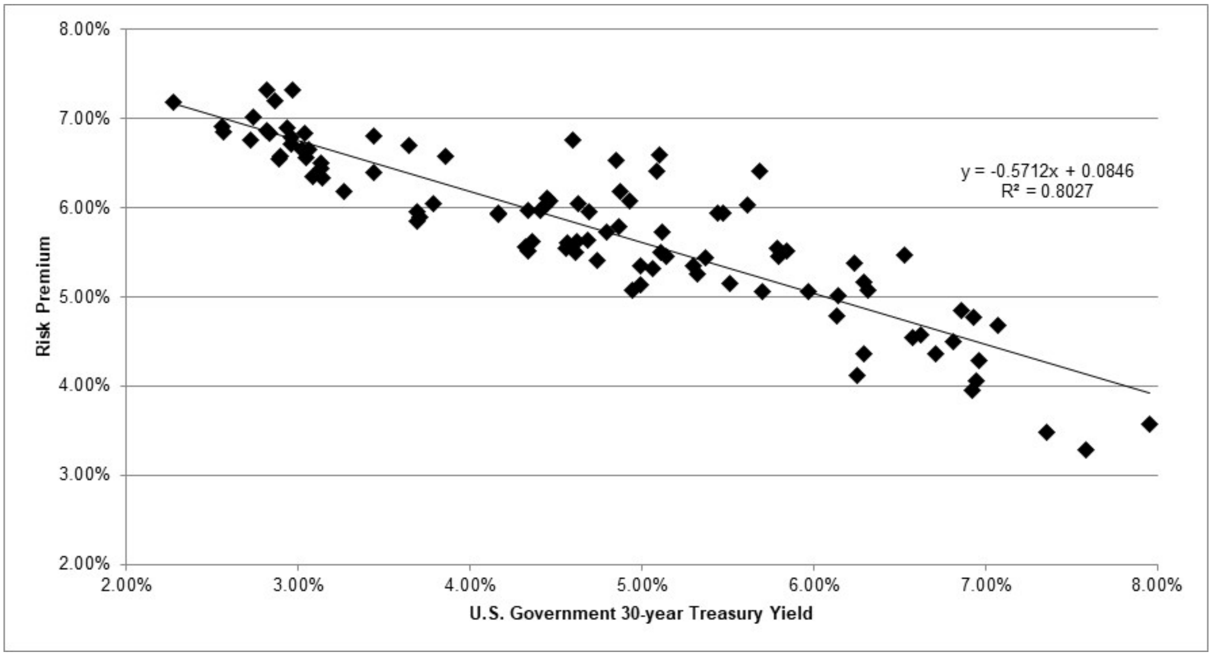
In summary, the results of the DCF model are understating the cost of equity under current market conditions due to the low interest rate environment that has reduced dividend yields and raised valuations on utility shares to unsustainable levels. Consequently, it is necessary to consider the results of Risk Premium models, such as the Risk Premium and CAPM analyses in order to determine where to set the appropriate return.

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 569 gas distribution rate cases from 1993 through September 28, 2018. The results of that regression are detailed in Figure 8.

[19] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at para. 40.

Figure 8: 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 2018-Q1 2020, and a "Long-Term" Blue Chip consensus forecast for 2020-2024. 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 28, 2018, the average implied risk premium over these historic Treasury yields is 5.76 percent. Based on the regression coefficients in Schedule 3.1, page 3, which allow for the estimation of the risk premium at varying bond yields, the results of my analysis are shown in Figure 9.

Figure 9: 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	3.10%	3.52%	4.20%
Risk Premium	6.70%	6.46%	6.07%
Resulting ROE	9.79%	9.97%	10.27%

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, 2016 through September 28, 2018. The average spread between the 30-year Treasury bond yield and the A-rated utility bond yield during this period was 1.19 percent. I added this spread to the Blue Chip consensus forecasts referenced above to arrive at a Near-Term forecast of 4.71 percent and a Long-Term forecast of 5.39 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 2018 – 1Q 2020, as of October 1, 2018.
21 Blue Chip consensus forecast for 2020 – 2024, as of June 1, 2018.

Figure 10: 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	4.29%	4.71%	5.39%
Risk Premium	5.45%	5.21%	4.81%
ROEs	9.74%	9.91%	10.20%

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 10.27 percent (based on Treasury yields) and 10.20 percent (based on Moody's A-rated utility bond yields).

C. CAPM Analysis

I also conducted a forward-looking 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 2020-2024 of 4.20 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, Vol. 37, Issue No. 6, June 1, 2018, 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 10.99 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 reflect investors' expected equity market returns relative to expected returns on Treasury securities, not historical return data. In Opinion No. 531, the FERC also developed a forward-looking MRP using a Constant Growth DCF analysis of the S&P 500 less the risk-free rate.[23]

The CAPM results are shown in Schedules 4.4 and 4.5 and summarized in Figure 11 and Figure 12.

Figure 11: Forward-Looking CAPM Results – Natural Gas Proxy Group

Using Value Line Betas	11.48%
Using Bloomberg Betas	10.54%
Mean Result	11.01%

[23] FERC Opinion No. 531, at para. 108.

Figure 12: Forward-Looking CAPM Results – Combination Proxy Group

Using Value Line Betas	11.34%
Using Bloomberg Betas	9.08%
Mean Result	10.21%

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 0.07 percent (i.e., 7 basis points) for the natural gas proxy group and as shown in Schedule 5.2, 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 adjustment for flotation costs. Rather, I took into consideration flotation costs in establishing

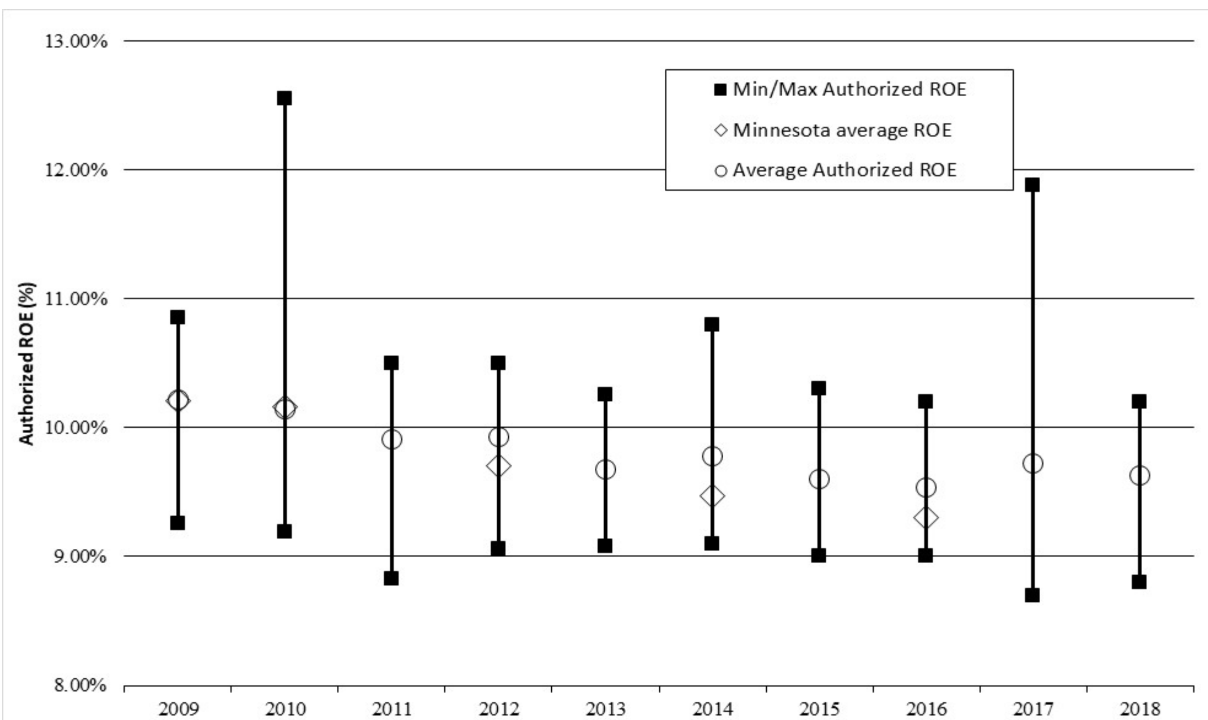
[24] Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order, at 9; Docket No. E002/GR-10-971, Findings of Fact, Conclusions, and Order, at 8; Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order, at 10-11; Docket No. E017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order, at 57-58; Docket No. G004/GR-04-1487, Findings of Fact, Conclusions of Law and Order, at 11.

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 addition 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 2017 and 2018 has been 9.67 percent, within a range from 8.70 percent to 11.88 percent.

Figure 13: 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 steadily declined from 2009 to 2017 and were near the bottom of the range produced by the authorized ROEs from other state jurisdictions. I believe this was 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.

It is important for the Commission to continue to consider the results of multiple methodologies, as it has in the Minnesota Power and Otter Tail decisions, as well as the ALJ's recent decision in MERC's rate case. Minnesota utility subsidiaries must compete for capital within their own corporate structure, which must in turn compete for capital with other utilities and businesses. If the authorized ROE for NSPM's GUIC rider is set at a level consistent with authorized ROEs outside Minnesota, this will support NSPM's access to capital and financial integrity over the longer-term. In addition, as noted in Sections IV and VI, the historically low yields on Treasury bonds have resulted in high valuations of utility stocks, which has reduced dividend yields and therefore the results of the DCF model. Given that interests 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 14: Summary of ROE Model Results

	Natural Gas Proxy Group	**Combination Proxy Group**
DCF – 90-day average		
Constant Growth	10.14%	9.51%
Risk Premium – 30 Yr. U.S. Treasury		
30 Yr. U.S. Treasury	10.27%	10.27%
Moody's A-rated Utility Index	10.20%	10.20%
CAPM		
Value Line Beta	11.48%	11.34%
Bloomberg Beta	10.54%	9.08%
Mean of All Methods	10.52%	10.08%
Proxy Group Weight	79%	21%
Weighted Average ROE	10.43%	

The results range from a low of 9.08 percent for the CAPM analysis for the combination proxy group using Bloomberg betas to a high of 11.48 percent for the CAPM analysis for the natural gas proxy group using Value Line betas. The mean of all methods for the gas distribution and combined gas/electric proxy groups is 10.52 percent and 10.08 percent, respectively. As discussed previously, the Commission has previously 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 produces an ROE estimate of 10.43 percent.

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 9.67 percent over the January 2017 – September 2018 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 2017 to the third quarter of 2018. This supports a return above NSPM's requested 10.0 percent ROE in the pending GUIC rider petition that was filed in November 2017, and the trailing average for allowed ROEs in other jurisdictions.

On balance, I believe that the range of reasonable returns is between 10.00 percent and 10.50 percent, and from within that range an authorized ROE of 10.25 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 is more representative of NSPM's cost of equity under current market conditions.

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

- "Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.
- "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

Community Rowing Inc., Board of Directors, 2015 - 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)
ENMAX Power Corporation	2017 2018	ENMAX Power Corporation	Proceeding 22570	2018 Generic Cost of Capital Proceeding (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)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
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	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities 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)

SPONSOR	**DATE**	**CASE/APPLICANT**	**DOCKET NO.**	**SUBJECT**
Northern States Power Company	2017	Northern States Power Company		Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2015 2016	Newfoundland Power	2016/2017 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2019/2020 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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
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

SPONSOR	**DATE**	**CASE/APPLICANT**	**DOCKET NO.**	**SUBJECT**
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)
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:

$$RP = a + (b \times Y)$$

<u>CAPM Analysis</u>

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	Positive 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 90 days from 9/28/2018
Atmos Energy Corporation	ATO	Yes	A	Yes	Yes	100.00%	68.59%	No
New Jersey Resources Corporation	NJR	Yes	A	Yes	Yes	96.45%	88.91%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	101.12%	64.67%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	99.50%	-21.56%	No
ONE Gas, Inc.	OGS	Yes	A	Yes	Yes	100.00%	100.00%	No
South Jersey Industries, Inc.	SJI	Yes	BBB	Yes	Yes	1078.62%	100.00%	No
Southwest Gas Corporation	SWX	Yes	BBB+	Yes	Yes	82.19%	100.00%	No
Spire, Inc.	SR	Yes	A-	Yes	Yes	99.77%	100.00%	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 2017, 2016, 2015, three-year average
[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 Operating Income > 50%	% Regulated Gas Operating Income > 10%	Announced Merger within 90 days from 9/28/2017
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	100.71%	88.81%	11.19%	No
Black Hills Corporation	BKH	Yes	BBB+	Yes	Yes	Yes	88.00%	55.94%	44.06%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	95.18%	73.61%	26.39%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	99.76%	80.29%	19.71%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	97.42%	85.31%	14.69%	No
Sempra Energy	SRE	Yes	BBB+	Yes	Yes	Yes	71.59%	52.81%	47.19%	No
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	Yes	Yes	77.91%	61.85%	37.45%	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 2017, 2016 & 2015, 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	$1.94	$93.25	2.08%	2.15%	7.50%	6.95%	6.50%	6.98%	8.65%	9.14%	9.66%
New Jersey Resources Corporation	NJR	$1.17	$46.24	2.53%	2.63%	9.50%	7.10%	7.00%	7.87%	9.62%	10.50%	12.15%
NiSource Inc.	NI	$0.78	$26.56	2.94%	3.08%	18.00%	6.07%	5.50%	9.86%	8.52%	12.94%	21.20%
Northwest Natural Gas Company	NWN	$1.89	$66.31	2.85%	3.04%	30.50%	4.50%	4.30%	13.10%	7.21%	16.14%	33.79%
ONE Gas, Inc.	OGS	$1.84	$80.44	2.29%	2.37%	10.50%	5.50%	5.70%	7.23%	7.85%	9.60%	12.91%
South Jersey Industries, Inc.	SJI	$1.12	$34.14	3.28%	3.47%	9.50%	12.00%	12.20%	11.23%	12.94%	14.70%	15.68%
Southwest Gas Corporation	SWX	$2.08	$79.47	2.62%	2.69%	9.00%	4.00%	4.00%	5.67%	6.67%	8.36%	11.74%
Spire, Inc.	SR	$2.25	$75.06	3.00%	3.07%	7.50%	3.53%	4.00%	5.01%	6.58%	8.08%	10.61%
MEAN				2.70%	2.81%	12.75%	6.21%	6.15%	8.37%	8.50%	11.18%	15.97%
MEDIAN				2.73%	2.86%	9.50%	5.79%	5.60%	7.55%	8.18%	10.05%	12.53%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 28, 2018
[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	$1.94	$90.93	2.13%	2.21%	7.50%	6.95%	6.50%	6.98%	8.70%	9.19%	9.71%
New Jersey Resources Corporation	NJR	$1.17	$45.21	2.59%	2.69%	9.50%	7.10%	7.00%	7.87%	9.68%	10.56%	12.21%
NiSource Inc.	NI	$0.78	$25.93	3.01%	3.16%	18.00%	6.07%	5.50%	9.86%	8.59%	13.01%	21.28%
Northwest Natural Gas Company	NWN	$1.89	$63.82	2.96%	3.16%	30.50%	4.50%	4.30%	13.10%	7.33%	16.26%	33.91%
ONE Gas, Inc.	OGS	$1.84	$76.73	2.40%	2.48%	10.50%	5.50%	5.70%	7.23%	7.96%	9.72%	13.02%
South Jersey Industries, Inc.	SJI	$1.12	$33.42	3.35%	3.54%	9.50%	12.00%	12.20%	11.23%	13.01%	14.77%	15.76%
Southwest Gas Corporation	SWX	$2.08	$77.91	2.67%	2.75%	9.00%	4.00%	4.00%	5.67%	6.72%	8.41%	11.79%
Spire, Inc.	SR	$2.25	$72.58	3.10%	3.18%	7.50%	3.53%	4.00%	5.01%	6.68%	8.19%	10.72%
MEAN				2.78%	2.89%	12.75%	6.21%	6.15%	8.37%	8.58%	11.26%	16.05%
MEDIAN				2.82%	2.95%	9.50%	5.79%	5.60%	7.55%	8.28%	10.14%	12.62%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 28, 2018
[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

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	$1.94	$86.98	2.23%	2.31%	7.50%	6.95%	6.50%	6.98%	8.80%	9.29%	9.81%
New Jersey Resources Corporation	NJR	$1.17	$42.59	2.75%	2.86%	9.50%	7.10%	7.00%	7.87%	9.84%	10.72%	12.38%
NiSource Inc.	NI	$0.78	$24.90	3.13%	3.29%	18.00%	6.07%	5.50%	9.86%	8.72%	13.14%	21.41%
Northwest Natural Gas Company	NWN	$1.89	$60.69	3.11%	3.32%	30.50%	4.50%	4.30%	13.10%	7.48%	16.42%	34.09%
ONE Gas, Inc.	OGS	$1.84	$72.34	2.54%	2.64%	10.50%	5.50%	5.70%	7.23%	8.11%	9.87%	13.18%
South Jersey Industries, Inc.	SJI	$1.12	$31.21	3.59%	3.79%	9.50%	12.00%	12.20%	11.23%	13.26%	15.02%	16.01%
Southwest Gas Corporation	SWX	$2.08	$74.21	2.80%	2.88%	9.00%	4.00%	4.00%	5.67%	6.86%	8.55%	11.93%
Spire, Inc.	SR	$2.25	$70.87	3.18%	3.25%	7.50%	3.53%	4.00%	5.01%	6.76%	8.26%	10.79%
MEAN				2.92%	3.04%	12.75%	6.21%	6.15%	8.37%	8.73%	11.41%	16.20%
MEDIAN				2.96%	3.07%	9.50%	5.79%	5.60%	7.55%	8.42%	10.30%	12.78%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 28, 2018
[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	$1.83	$64.21	2.85%	2.95%	7.50%	6.90%	6.60%	7.00%	9.54%	9.95%	10.46%
Black Hills Corporation	BKH	$1.90	$59.32	3.20%	3.28%	6.50%	4.32%	4.50%	5.11%	7.59%	8.39%	9.81%
CMS Energy Corporation	CMS	$1.43	$49.52	2.89%	2.98%	7.00%	6.97%	6.20%	6.72%	9.18%	9.71%	9.99%
DTE Energy Company	DTE	$3.53	$111.31	3.17%	3.27%	7.50%	5.49%	5.30%	6.10%	8.56%	9.36%	10.79%
NorthWestern Corporation	NWE	$2.20	$59.84	3.68%	3.73%	3.50%	2.45%	2.30%	2.75%	6.02%	6.48%	7.24%
Sempra Energy	SRE	$3.58	$116.06	3.08%	3.22%	9.50%	8.89%	8.00%	8.80%	11.21%	12.02%	12.73%
Wisconsin Energy Corporation	WEC	$2.21	$67.72	3.26%	3.35%	7.00%	4.54%	4.10%	5.21%	7.43%	8.56%	10.38%
MEAN				3.16%	3.25%	6.93%	5.65%	5.29%	5.96%	8.50%	9.21%	10.20%
MEDIAN				3.17%	3.27%	7.00%	5.49%	5.30%	6.10%	8.56%	9.36%	10.38%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 28, 2018
[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 Median ROE	[11] Mean High ROE
Ameren Corporation	AEE	$1.83	$61.54	2.97%	3.08%	7.50%	6.90%	6.60%	7.00%	9.67%	10.08%	10.59%
Black Hills Corporation	BKH	$1.90	$59.50	3.19%	3.27%	6.50%	4.32%	4.50%	5.11%	7.58%	8.38%	9.80%
CMS Energy Corporation	CMS	$1.43	$47.61	3.00%	3.10%	7.00%	6.97%	6.20%	6.72%	9.30%	9.83%	10.11%
DTE Energy Company	DTE	$3.53	$106.67	3.31%	3.41%	7.50%	5.49%	5.30%	6.10%	8.70%	9.51%	10.93%
NorthWestern Corporation	NWE	$2.20	$57.89	3.80%	3.85%	3.50%	2.45%	2.30%	2.75%	6.14%	6.60%	7.37%
Sempra Energy	SRE	$3.58	$113.99	3.14%	3.28%	9.50%	8.89%	8.00%	8.80%	11.27%	12.08%	12.79%
Wisconsin Energy Corporation	WEC	$2.21	$65.15	3.39%	3.48%	7.00%	4.54%	4.10%	5.21%	7.56%	8.69%	10.51%
MEAN				3.26%	3.35%	6.93%	5.65%	5.29%	5.96%	8.60%	9.31%	10.30%
MEDIAN				3.19%	3.28%	7.00%	5.49%	5.30%	6.10%	8.70%	9.51%	10.51%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 28, 2018
[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])

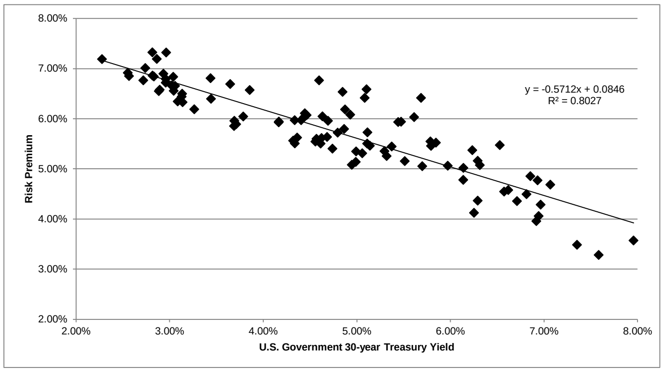
180-DAY CONSTANT GROWTH DCF - COMBINED UTILITY PROXY GROUP

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	$1.83	$58.69	3.12%	3.23%	7.50%	6.90%	6.60%	7.00%	9.82%	10.23%	10.74%
Black Hills Corporation	BKH	$1.90	$56.81	3.34%	3.43%	6.50%	4.32%	4.50%	5.11%	7.74%	8.54%	9.95%
CMS Energy Corporation	CMS	$1.43	$45.95	3.11%	3.22%	7.00%	6.97%	6.20%	6.72%	9.41%	9.94%	10.22%
DTE Energy Company	DTE	$3.53	$104.72	3.37%	3.47%	7.50%	5.49%	5.30%	6.10%	8.76%	9.57%	11.00%
NorthWestern Corporation	NWE	$2.20	$55.43	3.97%	4.02%	3.50%	2.45%	2.30%	2.75%	6.31%	6.77%	7.54%
Sempra Energy	SRE	$3.58	$111.19	3.22%	3.36%	9.50%	8.89%	8.00%	8.80%	11.35%	12.16%	12.87%
Wisconsin Energy Corporation	WEC	$2.21	$63.57	3.48%	3.57%	7.00%	4.54%	4.10%	5.21%	7.65%	8.78%	10.60%
MEAN				3.37%	3.47%	6.93%	5.65%	5.29%	5.96%	8.72%	9.43%	10.42%
MEDIAN				3.34%	3.43%	7.00%	5.49%	5.30%	6.10%	8.76%	9.57%	10.60%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 28, 2018
[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%
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%
2017.4	9.68%	2.82%	6.86%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
AVERAGE	10.49%	4.73%	5.76%
MEDIAN	10.43%	4.69%	5.89%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.895940
R Square	0.802708
Adjusted R Square	0.800674
Standard Error	0.003995
Observations	99

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006300	0.006300	394.657357	0.000000
Residual	97	0.001548	0.000016		
Total	98	0.007848			

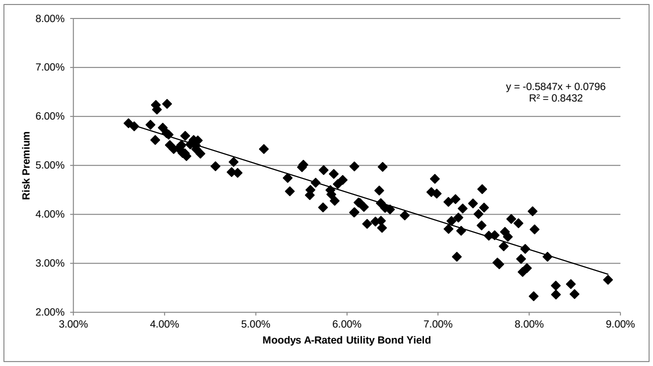
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0846	0.001418	59.69	0.000000	0.081834	0.087463	0.081834	0.087463
U.S. Govt. 30-year Treasury	(0.5712)	0.028754	(19.87)	0.000000	(0.628285)	(0.514150)	(0.628285)	(0.514150)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	3.10%	6.70%	9.79%
Blue Chip Consensus Forecast (Q4 2018-Q1 2020) [5]	3.52%	6.46%	9.97%
Blue Chip Consensus Forecast (2020-2024) [6]	4.20%	6.07%	10.27%
AVERAGE			10.01%

Notes:
[1] Source: Regulatory Research Associates, accessed October 11, 2018
[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. 37, No. 10, October 1, 2018, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.084648 + (-0.571218 x Column [7])
[9] Equals Column [7] + Column [8]

UTILITY BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Natural Gas ROE	[2] Moodys A-Rated Utility Bond	[3] 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%
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%
2017.4	9.68%	3.85%	5.83%
2018.1	9.68%	4.02%	5.66%
2018.2	9.43%	4.24%	5.19%
2018.3	9.71%	4.28%	5.43%
AVERAGE	10.49%	6.10%	4.39%
MEDIAN	10.43%	6.14%	4.39%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.918278
R Square	0.843234
Adjusted R Square	0.841618
Standard Error	0.003762
Observations	99

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007384	0.007384	521.757061	0.000000
Residual	97	0.001373	0.000014		
Total	98	0.008757			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0796	0.001607	49.52	0.000000	0.076399	0.082778	0.076399	0.082778
Moodys A-Rated Utility Bond	(0.5847)	0.025598	(22.84)	0.000000	(0.635503)	(0.533895)	(0.635503)	(0.533895)

	[7]	[8]	[9]
	Moodys A-Rated Utility Bond	Risk Premium	ROE
Current 30-Day Average [4]	4.29%	5.45%	9.74%
Near-Term Consensus Forecast (Q4 2018 - Q1 2020) [5]	4.71%	5.21%	9.91%
Long-Term Consensus Forecast (2020 - 2024) [6]	5.39%	4.81%	10.20%
AVERAGE			9.95%

Notes:
[1] Source: Regulatory Research Associates, accessed October 11, 2018
[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 2018-Q1 2020 Average: 3.52%) plus average daily spread between Treasury and utility bond yields from January 1, 2016 through September 28, 2018 (1.19%)
[6] Equals Blue Chip Financial Forecasts long-term 30-year Treasury bond yield (2020 - 2024 Forecast: 4.20%) plus average daily spread between Treasury and utility bond yields from January 1, 2016 through September 2018, 2018 (1.19%)
[7] *See notes [4], [5] & [6]*
[8] Equals 0.079589 + (-0.584699 x Column [7])
[9] Equals Column [7] + Column [8]

BETA - NATURAL GAS PROXY GROUP
AS OF SEPTEMBER 28, 2018

		[1]	[2]
		Bloomberg	Value Line
Atmos Energy Corporation	ATO	0.541	0.600
New Jersey Resources Corporation	NJR	0.704	0.700
NiSource Inc.	NI	0.416	0.550
Northwest Natural Gas Company	NWN	0.594	0.650
ONE Gas, Inc.	OGS	0.549	0.650
South Jersey Industries, Inc.	SJI	0.647	0.750
Southwest Gas Corporation	SWX	0.737	0.750
Spire, Inc.	SR	0.428	0.650
Average		0.577	0.663

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

BETA - COMBINED UTILITY PROXY GROUP
AS OF SEPTEMBER 28, 2018

		[1] Bloomberg	[2] Value Line
Ameren Corporation	AEE	0.362	0.600
Black Hills Corporation	BKH	0.548	0.850
CMS Energy Corporation	CMS	0.446	0.550
DTE Energy Company	DTE	0.448	0.600
NorthWestern Corporation	NWE	0.451	0.650
Sempra Energy	SRE	0.413	0.750
Wisconsin Energy Corporation	WEC	0.440	0.550
Average		0.444	0.650

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		1.88%	
[2] Estimated Weighted Average Long-Term Growth Rate		13.19%	
[3] S&P 500 Estimated Required Market Return		15.19%	
[4] Risk-Free Rate	3.10%	3.52%	4.20%
[5] Implied Market Risk Premium	12.09%	11.67%	10.99%

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	0.17%	3.90%	0.01%	8.00%	0.01%
American Express Co	AXP	0.36%	1.46%	0.01%	17.30%	0.06%
Verizon Communications Inc	VZ	0.86%	4.51%	0.04%	5.54%	0.05%
Broadcom Inc	AVGO	0.40%	2.84%	0.01%	13.10%	0.05%
Boeing Co/The	BA	0.84%	1.84%	0.02%	15.37%	0.13%
Caterpillar Inc	CAT	0.36%	2.26%	0.01%	25.28%	0.09%
JPMorgan Chase & Co	JPM	1.49%	2.84%	0.04%	9.80%	0.15%
Chevron Corp	CVX	0.92%	3.66%	0.03%	7.02%	0.06%
Coca-Cola Co/The	KO	0.77%	3.38%	0.03%	7.82%	0.06%
AbbVie Inc	ABBV	0.56%	4.06%	0.02%	10.84%	0.06%
Walt Disney Co/The	DIS	0.68%	1.44%	0.01%	12.93%	0.09%
FleetCor Technologies Inc	FLT	0.08%	n/a	n/a	n/a	n/a
Extra Space Storage Inc	EXR	0.04%	3.97%	0.00%	5.48%	0.00%
Exxon Mobil Corp	XOM	1.41%	3.86%	0.05%	11.51%	0.16%
Phillips 66	PSX	0.20%	2.84%	0.01%	5.50%	0.01%
General Electric Co	GE	0.38%	4.25%	0.02%	3.67%	0.01%
HP Inc	HPQ	0.16%	2.16%	0.00%	8.45%	0.01%
Home Depot Inc/The	HD	0.93%	1.99%	0.02%	13.27%	0.12%
International Business Machines Corp	IBM	0.54%	4.15%	0.02%	4.25%	0.02%
Concho Resources Inc	CXO	0.12%	n/a	n/a	30.75%	0.04%
Johnson & Johnson	JNJ	1.45%	2.61%	0.04%	7.49%	0.11%
McDonald's Corp	MCD	0.51%	2.77%	0.01%	8.69%	0.04%
Merck & Co Inc	MRK	0.74%	2.71%	0.02%	7.25%	0.05%
3M Co	MMM	0.48%	2.58%	0.01%	8.70%	0.04%
American Water Works Co Inc	AWK	0.06%	2.07%	0.00%	8.08%	0.01%
Bank of America Corp	BAC	1.15%	2.04%	0.02%	14.10%	0.16%
Brighthouse Financial Inc	BHF	0.02%	n/a	n/a	8.00%	0.00%
Baker Hughes a GE Co	BHGE	0.05%	2.13%	0.00%	33.00%	0.02%
Pfizer Inc	PFE	1.01%	3.09%	0.03%	6.88%	0.07%
Procter & Gamble Co/The	PG	0.81%	3.45%	0.03%	7.19%	0.06%
AT&T Inc	T	0.96%	5.96%	0.06%	4.85%	0.05%
Travelers Cos Inc/The	TRV	0.14%	2.37%	0.00%	17.75%	0.02%
United Technologies Corp	UTX	0.44%	2.00%	0.01%	10.59%	0.05%
Analog Devices Inc	ADI	0.13%	2.08%	0.00%	9.53%	0.01%
Walmart Inc	WMT	1.08%	2.21%	0.02%	6.29%	0.07%
Cisco Systems Inc	CSCO	0.87%	2.71%	0.02%	7.18%	0.06%
Intel Corp	INTC	0.85%	2.54%	0.02%	9.36%	0.08%
General Motors Co	GM	0.19%	4.51%	0.01%	10.78%	0.02%
Microsoft Corp	MSFT	3.44%	1.61%	0.06%	11.97%	0.41%
Dollar General Corp	DG	0.11%	1.06%	0.00%	15.06%	0.02%
Kinder Morgan Inc/DE	KMI	0.15%	4.51%	0.01%	12.00%	0.02%
Citigroup Inc	C	0.71%	2.51%	0.02%	12.80%	0.09%
American International Group Inc	AIG	0.19%	2.40%	0.00%	11.00%	0.02%
Honeywell International Inc	HON	0.48%	1.99%	0.01%	15.22%	0.07%
Altria Group Inc	MO	0.45%	5.31%	0.02%	4.87%	0.02%
HCA Healthcare Inc	HCA	0.19%	1.01%	0.00%	13.58%	0.03%
Under Armour Inc	UAA	0.02%	n/a	n/a	20.66%	0.00%
International Paper Co	IP	0.08%	3.87%	0.00%	7.90%	0.01%
Hewlett Packard Enterprise Co	HPE	0.09%	2.76%	0.00%	-6.50%	-0.01%
Abbott Laboratories	ABT	0.50%	1.53%	0.01%	13.00%	0.07%
Aflac Inc	AFL	0.14%	2.21%	0.00%	8.04%	0.01%
Air Products & Chemicals Inc	APD	0.14%	2.63%	0.00%	12.14%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.11%	2.15%	0.00%	15.60%	0.02%
American Electric Power Co Inc	AEP	0.14%	3.50%	0.00%	5.47%	0.01%
Hess Corp	HES	0.08%	1.40%	0.00%	-21.61%	-0.02%
Anadarko Petroleum Corp	APC	0.14%	1.48%	0.00%	17.00%	0.02%
Aon PLC	AON	0.15%	1.04%	0.00%	11.42%	0.02%
Apache Corp	APA	0.07%	2.10%	0.00%	2.04%	0.00%
Archer-Daniels-Midland Co	ADM	0.11%	2.67%	0.00%	11.40%	0.01%
Automatic Data Processing Inc	ADP	0.26%	1.83%	0.00%	13.50%	0.03%
Verisk Analytics Inc	VRSK	0.08%	n/a	n/a	13.03%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.88%	
[2] Estimated Weighted Average Long-Term Growth Rate		13.19%	
[3] S&P 500 Estimated Required Market Return		15.19%	
[4] Risk-Free Rate	3.10%	3.52%	4.20%
[5] Implied Market Risk Premium	12.09%	11.67%	10.99%

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
AutoZone Inc	AZO	0.08%	n/a	n/a	11.91%	0.01%
Avery Dennison Corp	AVY	0.04%	1.92%	0.00%	10.37%	0.00%
MSCI Inc	MSCI	0.06%	1.31%	0.00%	13.45%	0.01%
Ball Corp	BLL	0.06%	0.91%	0.00%	5.60%	0.00%
Bank of New York Mellon Corp/The	BK	0.20%	2.20%	0.00%	7.80%	0.02%
Baxter International Inc	BAX	0.16%	0.99%	0.00%	12.33%	0.02%
Becton Dickinson and Co	BDX	0.27%	1.15%	0.00%	15.23%	0.04%
Berkshire Hathaway Inc	BRK/B	1.15%	n/a	n/a	-5.60%	-0.06%
Best Buy Co Inc	BBY	0.09%	2.27%	0.00%	12.46%	0.01%
H&R Block Inc	HRB	0.02%	3.88%	0.00%	10.00%	0.00%
Boston Scientific Corp	BSX	0.21%	n/a	n/a	22.04%	0.05%
Bristol-Myers Squibb Co	BMY	0.40%	2.58%	0.01%	9.37%	0.04%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.53%	0.00%	12.83%	0.00%
Brown-Forman Corp	BF/B	0.06%	1.25%	0.00%	9.44%	0.01%
Cabot Oil & Gas Corp	COG	0.04%	1.07%	0.00%	44.61%	0.02%
Campbell Soup Co	CPB	0.04%	3.82%	0.00%	2.30%	0.00%
Kansas City Southern	KSU	0.05%	1.27%	0.00%	8.70%	0.00%
Advanced Micro Devices Inc	AMD	0.12%	n/a	n/a	23.40%	0.03%
Hilton Worldwide Holdings Inc	HLT	0.09%	0.74%	0.00%	11.20%	0.01%
Carnival Corp	CCL	0.13%	3.14%	0.00%	13.47%	0.02%
Qorvo Inc	QRVO	0.04%	n/a	n/a	12.62%	0.00%
CenturyLink Inc	CTL	0.09%	10.19%	0.01%	-15.12%	-0.01%
Cigna Corp	CI	0.20%	0.02%	0.00%	13.65%	0.03%
UDR Inc	UDR	0.04%	3.19%	0.00%	5.38%	0.00%
Clorox Co/The	CLX	0.08%	2.55%	0.00%	7.94%	0.01%
CMS Energy Corp	CMS	0.05%	2.92%	0.00%	6.16%	0.00%
Colgate-Palmolive Co	CL	0.23%	2.51%	0.01%	7.86%	0.02%
Comerica Inc	CMA	0.06%	2.66%	0.00%	21.22%	0.01%
IPG Photonics Corp	IPGP	0.03%	n/a	n/a	12.00%	0.00%
CA Inc	CA	0.07%	2.31%	0.00%	3.20%	0.00%
Conagra Brands Inc	CAG	0.05%	2.50%	0.00%	7.85%	0.00%
Consolidated Edison Inc	ED	0.09%	3.75%	0.00%	3.60%	0.00%
SL Green Realty Corp	SLG	0.03%	3.33%	0.00%	5.34%	0.00%
Corning Inc	GLW	0.11%	2.04%	0.00%	8.98%	0.01%
Cummins Inc	CMI	0.09%	3.12%	0.00%	9.16%	0.01%
Danaher Corp	DHR	0.30%	0.59%	0.00%	7.13%	0.02%
Target Corp	TGT	0.18%	2.90%	0.01%	6.97%	0.01%
Deere & Co	DE	0.19%	1.84%	0.00%	7.33%	0.01%
Dominion Energy Inc	D	0.18%	4.75%	0.01%	5.60%	0.01%
Dover Corp	DOV	0.05%	2.17%	0.00%	12.50%	0.01%
Duke Energy Corp	DUK	0.22%	4.64%	0.01%	5.04%	0.01%
Eaton Corp PLC	ETN	0.15%	3.04%	0.00%	8.92%	0.01%
Ecolab Inc	ECL	0.18%	1.05%	0.00%	13.03%	0.02%
PerkinElmer Inc	PKI	0.04%	0.29%	0.00%	16.35%	0.01%
Emerson Electric Co	EMR	0.19%	2.53%	0.00%	11.36%	0.02%
EOG Resources Inc	EOG	0.29%	0.69%	0.00%	12.14%	0.04%
Entergy Corp	ETR	0.06%	4.39%	0.00%	2.83%	0.00%
Equifax Inc	EFX	0.06%	1.19%	0.00%	7.43%	0.00%
EQT Corp	EQT	0.05%	0.27%	0.00%	17.50%	0.01%
IQVIA Holdings Inc	IQV	0.10%	n/a	n/a	15.25%	0.02%
Gartner Inc	IT	0.06%	n/a	n/a	15.00%	0.01%
FedEx Corp	FDX	0.25%	1.08%	0.00%	15.60%	0.04%
Macy's Inc	M	0.04%	4.35%	0.00%	0.50%	0.00%
FMC Corp	FMC	0.05%	0.76%	0.00%	23.40%	0.01%
Ford Motor Co	F	0.14%	6.49%	0.01%	-7.52%	-0.01%
NextEra Energy Inc	NEE	0.31%	2.65%	0.01%	8.38%	0.03%
Franklin Resources Inc	BEN	0.06%	3.03%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.08%	1.44%	0.00%	-16.60%	-0.01%
Gap Inc/The	GPS	0.04%	3.36%	0.00%	10.22%	0.00%
General Dynamics Corp	GD	0.24%	1.82%	0.00%	11.28%	0.03%
General Mills Inc	GIS	0.10%	4.57%	0.00%	6.43%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield		1.88%	
[2] Estimated Weighted Average Long-Term Growth Rate		13.19%	
[3] S&P 500 Estimated Required Market Return		15.19%	
[4] Risk-Free Rate	3.10%	3.52%	4.20%
[5] Implied Market Risk Premium	12.09%	11.67%	10.99%

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
Genuine Parts Co	GPC	0.06%	2.90%	0.00%	5.68%	0.00%
WW Grainger Inc	GWW	0.08%	1.52%	0.00%	14.87%	0.01%
Halliburton Co	HAL	0.14%	1.78%	0.00%	74.00%	0.10%
Harley-Davidson Inc	HOG	0.03%	3.27%	0.00%	10.00%	0.00%
Harris Corp	HRS	0.08%	1.62%	0.00%	n/a	n/a
HCP Inc	HCP	0.05%	5.62%	0.00%	2.80%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.13%	0.00%	n/a	n/a
Fortive Corp	FTV	0.12%	0.33%	0.00%	13.63%	0.02%
Hershey Co/The	HSY	0.06%	2.83%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	0.09%	2.70%	0.00%	7.35%	0.01%
Hormel Foods Corp	HRL	0.08%	1.90%	0.00%	5.00%	0.00%
Arthur J Gallagher & Co	AJG	0.05%	2.20%	0.00%	10.32%	0.01%
Mondelez International Inc	MDLZ	0.25%	2.42%	0.01%	9.91%	0.02%
CenterPoint Energy Inc	CNP	0.05%	4.01%	0.00%	6.17%	0.00%
Humana Inc	HUM	0.18%	0.59%	0.00%	14.50%	0.03%
Willis Towers Watson PLC	WLTW	0.07%	1.70%	0.00%	15.35%	0.01%
Illinois Tool Works Inc	ITW	0.19%	2.83%	0.01%	10.13%	0.02%
Ingersoll-Rand PLC	IR	0.10%	2.07%	0.00%	11.44%	0.01%
Foot Locker Inc	FL	0.02%	2.71%	0.00%	4.91%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.03%	3.67%	0.00%	6.43%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	2.10%	0.00%	9.20%	0.00%
Jacobs Engineering Group Inc	JEC	0.04%	0.78%	0.00%	17.01%	0.01%
Hanesbrands Inc	HBI	0.03%	3.26%	0.00%	5.04%	0.00%
Kellogg Co	K	0.10%	3.20%	0.00%	8.42%	0.01%
Broadridge Financial Solutions Inc	BR	0.06%	1.47%	0.00%	10.00%	0.01%
Perrigo Co PLC	PRGO	0.04%	1.07%	0.00%	6.00%	0.00%
Kimberly-Clark Corp	KMB	0.15%	3.52%	0.01%	6.26%	0.01%
Kimco Realty Corp	KIM	0.03%	6.69%	0.00%	3.16%	0.00%
Kohl's Corp	KSS	0.05%	3.27%	0.00%	7.23%	0.00%
Oracle Corp	ORCL	0.77%	1.47%	0.01%	7.90%	0.06%
Kroger Co/The	KR	0.09%	1.92%	0.00%	6.30%	0.01%
Leggett & Platt Inc	LEG	0.02%	3.47%	0.00%	10.00%	0.00%
Lennar Corp	LEN	0.05%	0.34%	0.00%	21.15%	0.01%
Jefferies Financial Group Inc	JEF	0.03%	2.28%	0.00%	18.00%	0.01%
Eli Lilly & Co	LLY	0.45%	2.10%	0.01%	11.73%	0.05%
L Brands Inc	LB	0.03%	7.92%	0.00%	9.33%	0.00%
Charter Communications Inc	CHTR	0.30%	n/a	n/a	45.75%	0.14%
Lincoln National Corp	LNC	0.06%	1.95%	0.00%	n/a	n/a
Loews Corp	L	0.06%	0.50%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.36%	1.67%	0.01%	15.58%	0.06%
Host Hotels & Resorts Inc	HST	0.06%	3.79%	0.00%	2.97%	0.00%
Marsh & McLennan Cos Inc	MMC	0.16%	2.01%	0.00%	14.81%	0.02%
Masco Corp	MAS	0.04%	1.31%	0.00%	15.72%	0.01%
Mattel Inc	MAT	0.02%	n/a	n/a	10.00%	0.00%
S&P Global Inc	SPGI	0.19%	1.02%	0.00%	11.60%	0.02%
Medtronic PLC	MDT	0.52%	2.03%	0.01%	7.84%	0.04%
CVS Health Corp	CVS	0.31%	2.54%	0.01%	11.66%	0.04%
DowDuPont Inc	DWDP	0.58%	2.36%	0.01%	8.37%	0.05%
Micron Technology Inc	MU	0.21%	n/a	n/a	0.27%	0.00%
Motorola Solutions Inc	MSI	0.08%	1.60%	0.00%	7.45%	0.01%
Cboe Global Markets Inc	CBOE	0.04%	1.29%	0.00%	12.92%	0.01%
Mylan NV	MYL	0.07%	n/a	n/a	6.07%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	8.95%	0.01%
Newell Brands Inc	NWL	0.04%	4.53%	0.00%	2.76%	0.00%
Newmont Mining Corp	NEM	0.06%	1.85%	0.00%	-3.00%	0.00%
Twenty-First Century Fox Inc	FOXA	0.19%	0.78%	0.00%	9.95%	0.02%
NIKE Inc	NKE	0.42%	0.94%	0.00%	18.11%	0.08%
NiSource Inc	NI	0.04%	3.13%	0.00%	5.63%	0.00%
Noble Energy Inc	NBL	0.06%	1.41%	0.00%	42.78%	0.03%
Norfolk Southern Corp	NSC	0.20%	1.77%	0.00%	10.20%	0.02%
Principal Financial Group Inc	PFG	0.07%	3.62%	0.00%	7.93%	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
Eversource Energy	ES	0.08%	3.29%	0.00%	6.03%	0.00%
Northrop Grumman Corp	NOC	0.22%	1.51%	0.00%	15.18%	0.03%
Wells Fargo & Co	WFC	0.99%	3.27%	0.03%	13.41%	0.13%
Nucor Corp	NUE	0.08%	2.40%	0.00%	5.65%	0.00%
PVH Corp	PVH	0.04%	0.10%	0.00%	10.98%	0.00%
Occidental Petroleum Corp	OXY	0.25%	3.80%	0.01%	14.30%	0.04%
Omnicom Group Inc	OMC	0.06%	3.53%	0.00%	5.44%	0.00%
ONEOK Inc	OKE	0.11%	4.87%	0.01%	26.88%	0.03%
Raymond James Financial Inc	RJF	0.05%	1.30%	0.00%	17.00%	0.01%
PG&E Corp	PCG	0.09%	n/a	n/a	5.05%	0.00%
Parker-Hannifin Corp	PH	0.10%	1.65%	0.00%	9.32%	0.01%
Rollins Inc	ROL	0.05%	0.92%	0.00%	10.00%	0.01%
PPL Corp	PPL	0.08%	5.60%	0.00%	8.10%	0.01%
Exelon Corp	EXC	0.17%	3.16%	0.01%	4.45%	0.01%
ConocoPhillips	COP	0.35%	1.47%	0.01%	6.00%	0.02%
PulteGroup Inc	PHM	0.03%	1.45%	0.00%	21.34%	0.01%
Pinnacle West Capital Corp	PNW	0.03%	3.51%	0.00%	4.56%	0.00%
PNC Financial Services Group Inc/The	PNC	0.25%	2.79%	0.01%	9.79%	0.02%
PPG Industries Inc	PPG	0.10%	1.76%	0.00%	8.06%	0.01%
Praxair Inc	PX	0.18%	2.05%	0.00%	13.90%	0.03%
Progressive Corp/The	PGR	0.16%	1.58%	0.00%	9.20%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.41%	0.00%	6.76%	0.01%
Raytheon Co	RTN	0.23%	1.68%	0.00%	14.87%	0.03%
Robert Half International Inc	RHI	0.03%	1.59%	0.00%	17.10%	0.01%
SCANA Corp	SCG	0.02%	1.27%	0.00%	-2.79%	0.00%
Edison International	EIX	0.09%	3.58%	0.00%	5.35%	0.00%
Schlumberger Ltd	SLB	0.33%	3.28%	0.01%	20.00%	0.07%
Charles Schwab Corp/The	SCHW	0.26%	1.06%	0.00%	21.63%	0.06%
Sherwin-Williams Co/The	SHW	0.17%	0.76%	0.00%	11.42%	0.02%
JM Smucker Co/The	SJM	0.05%	3.31%	0.00%	5.00%	0.00%
Snap-on Inc	SNA	0.04%	1.79%	0.00%	7.95%	0.00%
AMETEK Inc	AME	0.07%	0.71%	0.00%	11.81%	0.01%
Southern Co/The	SO	0.17%	5.50%	0.01%	4.00%	0.01%
BB&T Corp	BBT	0.15%	3.34%	0.00%	17.38%	0.03%
Southwest Airlines Co	LUV	0.14%	1.02%	0.00%	7.87%	0.01%
Stanley Black & Decker Inc	SWK	0.09%	1.80%	0.00%	10.65%	0.01%
Public Storage	PSA	0.14%	3.97%	0.01%	5.37%	0.01%
Arista Networks Inc	ANET	0.08%	n/a	n/a	26.03%	0.02%
SunTrust Banks Inc	STI	0.12%	2.99%	0.00%	14.78%	0.02%
Sysco Corp	SYY	0.15%	1.97%	0.00%	11.37%	0.02%
Texas Instruments Inc	TXN	0.41%	2.87%	0.01%	11.05%	0.05%
Textron Inc	TXT	0.07%	0.11%	0.00%	13.71%	0.01%
Thermo Fisher Scientific Inc	TMO	0.39%	0.28%	0.00%	11.00%	0.04%
Tiffany & Co	TIF	0.06%	1.71%	0.00%	12.54%	0.01%
TJX Cos Inc/The	TJX	0.27%	1.39%	0.00%	11.10%	0.03%
Torchmark Corp	TMK	0.04%	0.74%	0.00%	13.17%	0.01%
Total System Services Inc	TSS	0.07%	0.53%	0.00%	14.62%	0.01%
Johnson Controls International plc	JCI	0.13%	2.97%	0.00%	10.30%	0.01%
Ulta Beauty Inc	ULTA	0.07%	n/a	n/a	20.50%	0.01%
Union Pacific Corp	UNP	0.47%	1.97%	0.01%	14.20%	0.07%
UnitedHealth Group Inc	UNH	1.00%	1.35%	0.01%	13.33%	0.13%
Unum Group	UNM	0.03%	2.66%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.08%	0.86%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	12.05%	0.00%
Ventas Inc	VTR	0.08%	5.81%	0.00%	2.47%	0.00%
VF Corp	VFC	0.15%	1.97%	0.00%	9.43%	0.01%
Vornado Realty Trust	VNO	0.05%	3.45%	0.00%	3.88%	0.00%
Vulcan Materials Co	VMC	0.06%	1.01%	0.00%	20.36%	0.01%
Weyerhaeuser Co	WY	0.10%	4.21%	0.00%	16.20%	0.02%
Whirlpool Corp	WHR	0.03%	3.87%	0.00%	9.46%	0.00%
Williams Cos Inc/The	WMB	0.13%	5.00%	0.01%	-0.80%	0.00%

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STANDARD AND POOR'S 500 INDEX

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WEC Energy Group Inc	WEC	0.08%	3.31%	0.00%	3.23%	0.00%
Xerox Corp	XRX	0.03%	3.71%	0.00%	2.05%	0.00%
Adobe Systems Inc	ADBE	0.52%	n/a	n/a	16.88%	0.09%
AES Corp/VA	AES	0.04%	3.71%	0.00%	8.59%	0.00%
Amgen Inc	AMGN	0.53%	2.55%	0.01%	6.46%	0.03%
Apple Inc	AAPL	4.27%	1.29%	0.06%	9.84%	0.42%
Autodesk Inc	ADSK	0.13%	n/a	n/a	55.23%	0.07%
Cintas Corp	CTAS	0.08%	0.82%	0.00%	11.85%	0.01%
Comcast Corp	CMCSA	0.63%	2.15%	0.01%	14.85%	0.09%
Molson Coors Brewing Co	TAP	0.05%	2.67%	0.00%	2.70%	0.00%
KLA-Tencor Corp	KLAC	0.06%	2.95%	0.00%	7.37%	0.00%
Marriott International Inc/MD	MAR	0.18%	1.24%	0.00%	14.46%	0.03%
McCormick & Co Inc/MD	MKC	0.06%	1.58%	0.00%	8.80%	0.01%
Nordstrom Inc	JWN	0.04%	2.47%	0.00%	8.43%	0.00%
PACCAR Inc	PCAR	0.09%	1.64%	0.00%	6.03%	0.01%
Costco Wholesale Corp	COST	0.40%	0.97%	0.00%	10.81%	0.04%
Stryker Corp	SYK	0.26%	1.06%	0.00%	8.44%	0.02%
Tyson Foods Inc	TSN	0.07%	2.02%	0.00%	5.90%	0.00%
Applied Materials Inc	AMAT	0.15%	2.07%	0.00%	14.06%	0.02%
American Airlines Group Inc	AAL	0.07%	0.97%	0.00%	16.93%	0.01%
Cardinal Health Inc	CAH	0.06%	3.53%	0.00%	9.40%	0.01%
Celgene Corp	CELG	0.25%	n/a	n/a	21.09%	0.05%
Cerner Corp	CERN	0.08%	n/a	n/a	11.68%	0.01%
Cincinnati Financial Corp	CINF	0.05%	2.76%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.06%	1.19%	0.00%	20.70%	0.01%
Flowserve Corp	FLS	0.03%	1.39%	0.00%	19.90%	0.01%
Electronic Arts Inc	EA	0.14%	n/a	n/a	15.00%	0.02%
Express Scripts Holding Co	ESRX	0.21%	n/a	n/a	6.49%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.22%	0.00%	11.73%	0.01%
Fastenal Co	FAST	0.07%	2.76%	0.00%	17.55%	0.01%
M&T Bank Corp	MTB	0.09%	2.43%	0.00%	14.30%	0.01%
Xcel Energy Inc	XEL	0.09%	3.22%	0.00%	5.80%	0.01%
Fiserv Inc	FISV	0.13%	n/a	n/a	11.00%	0.01%
Fifth Third Bancorp	FITB	0.07%	2.58%	0.00%	5.65%	0.00%
Gilead Sciences Inc	GILD	0.39%	2.95%	0.01%	5.72%	0.02%
Hasbro Inc	HAS	0.05%	2.40%	0.00%	8.13%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.06%	3.75%	0.00%	13.36%	0.01%
Welltower Inc	WELL	0.09%	5.41%	0.01%	7.05%	0.01%
Biogen Inc	BIIB	0.28%	n/a	n/a	5.66%	0.02%
Northern Trust Corp	NTRS	0.09%	2.15%	0.00%	16.78%	0.01%
Packaging Corp of America	PKG	0.04%	2.88%	0.00%	10.00%	0.00%
Paychex Inc	PAYX	0.10%	3.04%	0.00%	9.13%	0.01%
People's United Financial Inc	PBCT	0.02%	4.09%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.41%	3.44%	0.01%	12.32%	0.05%
Roper Technologies Inc	ROP	0.12%	0.56%	0.00%	13.40%	0.02%
Ross Stores Inc	ROST	0.14%	0.91%	0.00%	10.43%	0.02%
IDEXX Laboratories Inc	IDXX	0.08%	n/a	n/a	21.88%	0.02%
Starbucks Corp	SBUX	0.30%	2.53%	0.01%	14.30%	0.04%
KeyCorp	KEY	0.08%	3.42%	0.00%	16.21%	0.01%
State Street Corp	STT	0.12%	2.24%	0.00%	12.36%	0.02%
Norwegian Cruise Line Holdings Ltd	NCLH	0.05%	n/a	n/a	20.32%	0.01%
US Bancorp	USB	0.34%	2.80%	0.01%	7.45%	0.03%
AO Smith Corp	AOS	0.03%	1.35%	0.00%	11.50%	0.00%
Symantec Corp	SYMC	0.05%	1.41%	0.00%	6.68%	0.00%
T Rowe Price Group Inc	TROW	0.10%	2.56%	0.00%	12.08%	0.01%
Waste Management Inc	WM	0.15%	2.06%	0.00%	11.61%	0.02%
CBS Corp	CBS	0.08%	1.25%	0.00%	16.37%	0.01%
Allergan PLC	AGN	0.25%	1.51%	0.00%	8.47%	0.02%
Constellation Brands Inc	STZ	0.14%	1.37%	0.00%	11.19%	0.02%
Xilinx Inc	XLNX	0.08%	1.80%	0.00%	7.57%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.03%	0.93%	0.00%	6.93%	0.00%

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Zions Bancorp NA	ZION	0.04%	2.39%	0.00%	10.30%	0.00%
Alaska Air Group Inc	ALK	0.03%	1.86%	0.00%	6.93%	0.00%
Invesco Ltd	IVZ	0.04%	5.24%	0.00%	6.08%	0.00%
Intuit Inc	INTU	0.23%	0.83%	0.00%	16.11%	0.04%
Morgan Stanley	MS	0.32%	2.58%	0.01%	16.88%	0.05%
Microchip Technology Inc	MCHP	0.07%	1.85%	0.00%	14.55%	0.01%
Chubb Ltd	CB	0.24%	2.19%	0.01%	10.83%	0.03%
Hologic Inc	HOLX	0.04%	n/a	n/a	8.74%	0.00%
Citizens Financial Group Inc	CFG	0.07%	2.80%	0.00%	21.50%	0.02%
O'Reilly Automotive Inc	ORLY	0.11%	n/a	n/a	15.47%	0.02%
Allstate Corp/The	ALL	0.13%	1.86%	0.00%	7.10%	0.01%
FLIR Systems Inc	FLIR	0.03%	1.04%	0.00%	n/a	n/a
Equity Residential	EQR	0.10%	3.26%	0.00%	5.69%	0.01%
BorgWarner Inc	BWA	0.04%	1.59%	0.00%	5.79%	0.00%
Newfield Exploration Co	NFX	0.02%	n/a	n/a	19.17%	0.00%
Incyte Corp	INCY	0.06%	n/a	n/a	52.58%	0.03%
Simon Property Group Inc	SPG	0.21%	4.53%	0.01%	6.18%	0.01%
Eastman Chemical Co	EMN	0.05%	2.34%	0.00%	5.90%	0.00%
Twitter Inc	TWTR	0.08%	n/a	n/a	45.77%	0.04%
AvalonBay Communities Inc	AVB	0.10%	3.25%	0.00%	6.74%	0.01%
Prudential Financial Inc	PRU	0.17%	3.55%	0.01%	6.00%	0.01%
United Parcel Service Inc	UPS	0.32%	3.12%	0.01%	8.97%	0.03%
Apartment Investment & Management Co	AIV	0.03%	3.44%	0.00%	6.20%	0.00%
Walgreens Boots Alliance Inc	WBA	0.28%	2.41%	0.01%	10.18%	0.03%
McKesson Corp	MCK	0.10%	1.18%	0.00%	5.83%	0.01%
Lockheed Martin Corp	LMT	0.39%	2.54%	0.01%	21.41%	0.08%
AmerisourceBergen Corp	ABC	0.08%	1.65%	0.00%	10.05%	0.01%
Capital One Financial Corp	COF	0.18%	1.69%	0.00%	16.00%	0.03%
Waters Corp	WAT	0.06%	n/a	n/a	9.10%	0.01%
Dollar Tree Inc	DLTR	0.08%	n/a	n/a	10.94%	0.01%
Darden Restaurants Inc	DRI	0.05%	2.70%	0.00%	10.54%	0.01%
NetApp Inc	NTAP	0.09%	1.86%	0.00%	15.95%	0.01%
Citrix Systems Inc	CTXS	0.06%	1.26%	0.00%	9.00%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.02%	2.39%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.10%	0.81%	0.00%	6.36%	0.01%
DaVita Inc	DVA	0.05%	n/a	n/a	18.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.07%	2.40%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.04%	6.81%	0.00%	10.10%	0.00%
Estee Lauder Cos Inc/The	EL	0.13%	1.05%	0.00%	16.20%	0.02%
Cadence Design Systems Inc	CDNS	0.05%	n/a	n/a	12.00%	0.01%
Stericycle Inc	SRCL	0.02%	n/a	n/a	10.00%	0.00%
Universal Health Services Inc	UHS	0.04%	0.31%	0.00%	7.93%	0.00%
E*TRADE Financial Corp	ETFC	0.05%	n/a	n/a	28.39%	0.02%
Skyworks Solutions Inc	SWKS	0.06%	1.68%	0.00%	12.04%	0.01%
National Oilwell Varco Inc	NOV	0.06%	0.46%	0.00%	41.00%	0.03%
Quest Diagnostics Inc	DGX	0.06%	1.85%	0.00%	9.20%	0.01%
Activision Blizzard Inc	ATVI	0.25%	0.41%	0.00%	15.13%	0.04%
Rockwell Automation Inc	ROK	0.09%	1.96%	0.00%	12.34%	0.01%
Kraft Heinz Co/The	KHC	0.26%	4.54%	0.01%	5.60%	0.01%
American Tower Corp	AMT	0.25%	2.17%	0.01%	16.10%	0.04%
HollyFrontier Corp	HFC	0.05%	1.89%	0.00%	7.14%	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.17%	n/a	n/a	14.03%	0.02%
Amazon.com Inc	AMZN	3.83%	n/a	n/a	47.42%	1.81%
Ralph Lauren Corp	RL	0.03%	1.82%	0.00%	6.87%	0.00%
Boston Properties Inc	BXP	0.07%	3.09%	0.00%	6.03%	0.00%
Amphenol Corp	APH	0.11%	0.98%	0.00%	11.81%	0.01%
Arconic Inc	ARNC	0.04%	1.09%	0.00%	16.00%	0.01%
Pioneer Natural Resources Co	PXD	0.12%	0.18%	0.00%	27.13%	0.03%
Valero Energy Corp	VLO	0.19%	2.81%	0.01%	17.15%	0.03%
Synopsys Inc	SNPS	0.06%	n/a	n/a	n/a	n/a
L3 Technologies Inc	LLL	0.07%	1.51%	0.00%	12.64%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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[2] Estimated Weighted Average Long-Term Growth Rate		13.19%	
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[4] Risk-Free Rate	3.10%	3.52%	4.20%
[5] Implied Market Risk Premium	12.09%	11.67%	10.99%

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
Western Union Co/The	WU	0.03%	3.99%	0.00%	4.20%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	1.88%	0.00%	10.23%	0.01%
Accenture PLC	ACN	0.43%	1.72%	0.01%	10.40%	0.04%
TransDigm Group Inc	TDG	0.08%	n/a	n/a	12.53%	0.01%
Yum! Brands Inc	YUM	0.11%	1.58%	0.00%	12.83%	0.01%
Prologis Inc	PLD	0.17%	2.83%	0.00%	6.81%	0.01%
FirstEnergy Corp	FE	0.07%	3.87%	0.00%	-0.35%	0.00%
VeriSign Inc	VRSN	0.08%	n/a	n/a	10.40%	0.01%
Quanta Services Inc	PWR	0.02%	n/a	n/a	8.00%	0.00%
Henry Schein Inc	HSIC	0.05%	n/a	n/a	6.65%	0.00%
Ameren Corp	AEE	0.06%	2.89%	0.00%	8.24%	0.00%
ANSYS Inc	ANSS	0.06%	n/a	n/a	13.83%	0.01%
NVIDIA Corp	NVDA	0.67%	0.21%	0.00%	11.23%	0.08%
Sealed Air Corp	SEE	0.02%	1.59%	0.00%	3.89%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.18%	1.04%	0.00%	14.03%	0.02%
SVB Financial Group	SIVB	0.06%	n/a	n/a	8.50%	0.01%
Intuitive Surgical Inc	ISRG	0.26%	n/a	n/a	14.02%	0.04%
Affiliated Managers Group Inc	AMG	0.03%	0.88%	0.00%	10.85%	0.00%
Aetna Inc	AET	0.26%	0.99%	0.00%	10.69%	0.03%
Take-Two Interactive Software Inc	TTWO	0.06%	n/a	n/a	10.00%	0.01%
Republic Services Inc	RSG	0.09%	2.06%	0.00%	11.92%	0.01%
eBay Inc	EBAY	0.13%	n/a	n/a	10.21%	0.01%
Goldman Sachs Group Inc/The	GS	0.33%	1.43%	0.00%	12.69%	0.04%
SBA Communications Corp	SBAC	0.07%	n/a	n/a	27.15%	0.02%
Sempra Energy	SRE	0.12%	3.15%	0.00%	16.39%	0.02%
Moody's Corp	MCO	0.13%	1.05%	0.00%	8.00%	0.01%
Booking Holdings Inc	BKNG	0.37%	n/a	n/a	13.73%	0.05%
F5 Networks Inc	FFIV	0.05%	n/a	n/a	10.27%	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	11.28%	0.01%
Devon Energy Corp	DVN	0.08%	0.80%	0.00%	14.46%	0.01%
Alphabet Inc	GOOGL	1.41%	n/a	n/a	18.22%	0.26%
Red Hat Inc	RHT	0.09%	n/a	n/a	18.93%	0.02%
Allegion PLC	ALLE	0.03%	0.93%	0.00%	11.23%	0.00%
Netflix Inc	NFLX	0.64%	n/a	n/a	41.07%	0.26%
Agilent Technologies Inc	A	0.09%	0.84%	0.00%	10.35%	0.01%
Anthem Inc	ANTM	0.28%	1.09%	0.00%	12.27%	0.03%
CME Group Inc	CME	0.23%	1.65%	0.00%	11.80%	0.03%
Juniper Networks Inc	JNPR	0.04%	2.40%	0.00%	9.40%	0.00%
BlackRock Inc	BLK	0.29%	2.66%	0.01%	9.81%	0.03%
DTE Energy Co	DTE	0.08%	3.23%	0.00%	6.03%	0.00%
Nasdaq Inc	NDAQ	0.06%	2.05%	0.00%	9.68%	0.01%
Philip Morris International Inc	PM	0.50%	5.59%	0.03%	10.13%	0.05%
salesforce.com Inc	CRM	0.47%	n/a	n/a	26.12%	0.12%
Huntington Ingalls Industries Inc	HII	0.04%	1.12%	0.00%	27.50%	0.01%
MetLife Inc	MET	0.18%	3.60%	0.01%	13.58%	0.02%
Under Armour Inc	UA	0.02%	n/a	n/a	26.97%	0.00%
Tapestry Inc	TPR	0.06%	2.69%	0.00%	10.96%	0.01%
Fluor Corp	FLR	0.03%	1.45%	0.00%	25.82%	0.01%
CSX Corp	CSX	0.25%	1.19%	0.00%	11.96%	0.03%
Edwards Lifesciences Corp	EW	0.14%	n/a	n/a	15.33%	0.02%
Ameriprise Financial Inc	AMP	0.08%	2.44%	0.00%	n/a	n/a
Rockwell Collins Inc	COL	0.09%	0.94%	0.00%	11.60%	0.01%
TechnipFMC PLC	FTI	0.06%	1.66%	0.00%	9.85%	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.73%	0.00%	3.64%	0.00%
CBRE Group Inc	CBRE	0.06%	n/a	n/a	9.75%	0.01%
Mastercard Inc	MA	0.89%	0.45%	0.00%	21.33%	0.19%
CarMax Inc	KMX	0.05%	n/a	n/a	13.21%	0.01%
Intercontinental Exchange Inc	ICE	0.17%	1.28%	0.00%	8.82%	0.01%
Fidelity National Information Services Inc	FIS	0.14%	1.17%	0.00%	4.40%	0.01%
Chipotle Mexican Grill Inc	CMG	0.05%	n/a	n/a	19.11%	0.01%
Wynn Resorts Ltd	WYNN	0.05%	2.36%	0.00%	18.30%	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

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[2] Estimated Weighted Average Long-Term Growth Rate		13.19%	
[3] S&P 500 Estimated Required Market Return		15.19%	
[4] Risk-Free Rate	3.10%	3.52%	4.20%
[5] Implied Market Risk Premium	12.09%	11.67%	10.99%

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
Assurant Inc	AIZ	0.03%	2.08%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.04%	0.32%	0.00%	16.81%	0.01%
Monster Beverage Corp	MNST	0.13%	n/a	n/a	17.00%	0.02%
Regions Financial Corp	RF	0.08%	3.05%	0.00%	12.14%	0.01%
Mosaic Co/The	MOS	0.05%	0.31%	0.00%	7.00%	0.00%
Expedia Group Inc	EXPE	0.07%	0.98%	0.00%	14.23%	0.01%
Evergy Inc	EVRG	0.06%	3.35%	0.00%	8.19%	0.00%
Discovery Inc	DISCA	0.02%	n/a	n/a	n/a	n/a
CF Industries Holdings Inc	CF	0.05%	2.20%	0.00%	15.30%	0.01%
Viacom Inc	VIAB	0.05%	2.37%	0.00%	6.56%	0.00%
Alphabet Inc	GOOG	1.64%	n/a	n/a	18.22%	0.30%
TE Connectivity Ltd	TEL	0.12%	2.00%	0.00%	9.25%	0.01%
Cooper Cos Inc/The	COO	0.05%	0.02%	0.00%	10.80%	0.01%
Discover Financial Services	DFS	0.10%	2.09%	0.00%	10.17%	0.01%
TripAdvisor Inc	TRIP	0.02%	n/a	n/a	18.29%	0.00%
Visa Inc	V	1.04%	0.56%	0.01%	18.18%	0.19%
Mid-America Apartment Communities Inc	MAA	0.04%	3.68%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.06%	1.05%	0.00%	8.60%	0.00%
Marathon Petroleum Corp	MPC	0.14%	2.30%	0.00%	n/a	n/a
Tractor Supply Co	TSCO	0.04%	1.36%	0.00%	13.54%	0.01%
ResMed Inc	RMD	0.06%	1.28%	0.00%	12.15%	0.01%
Garrett Motion Inc	GTX	0.00%	n/a	n/a	n/a	n/a
Mettler-Toledo International Inc	MTD	0.06%	n/a	n/a	11.95%	0.01%
Copart Inc	CPRT	0.05%	n/a	n/a	10.00%	0.00%
Albemarle Corp	ALB	0.04%	1.34%	0.00%	13.03%	0.01%
Essex Property Trust Inc	ESS	0.06%	3.02%	0.00%	5.94%	0.00%
Realty Income Corp	O	0.06%	4.65%	0.00%	4.36%	0.00%
Seagate Technology PLC	STX	0.05%	5.32%	0.00%	-2.44%	0.00%
WestRock Co	WRK	0.05%	3.22%	0.00%	6.50%	0.00%
IHS Markit Ltd	INFO	0.08%	n/a	n/a	13.37%	0.01%
Western Digital Corp	WDC	0.07%	3.42%	0.00%	3.52%	0.00%
PepsiCo Inc	PEP	0.62%	3.32%	0.02%	6.72%	0.04%
Nektar Therapeutics	NKTR	0.04%	n/a	n/a	n/a	n/a
Church & Dwight Co Inc	CHD	0.06%	1.47%	0.00%	9.63%	0.01%
Duke Realty Corp	DRE	0.04%	2.82%	0.00%	5.34%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.23%	0.00%	5.03%	0.00%
MGM Resorts International	MGM	0.06%	1.72%	0.00%	3.70%	0.00%
Twenty-First Century Fox Inc	FOX	0.14%	0.79%	0.00%	9.95%	0.01%
Alliant Energy Corp	LNT	0.04%	3.15%	0.00%	5.86%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.81%	0.00%	13.46%	0.01%
Lam Research Corp	LRCX	0.09%	2.90%	0.00%	13.55%	0.01%
Mohawk Industries Inc	MHK	0.05%	n/a	n/a	7.86%	0.00%
Pentair PLC	PNR	0.03%	1.61%	0.00%	11.01%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.19%	n/a	n/a	64.33%	0.12%
Facebook Inc	FB	1.55%	n/a	n/a	16.87%	0.26%
United Rentals Inc	URI	0.05%	n/a	n/a	23.52%	0.01%
Alexandria Real Estate Equities Inc	ARE	0.05%	2.96%	0.00%	6.57%	0.00%
ABIOMED Inc	ABMD	0.08%	n/a	n/a	36.00%	0.03%
Delta Air Lines Inc	DAL	0.16%	2.42%	0.00%	17.81%	0.03%
United Continental Holdings Inc	UAL	0.10%	n/a	n/a	14.56%	0.01%
News Corp	NWS	0.01%	1.47%	0.00%	26.30%	0.00%
Centene Corp	CNC	0.12%	n/a	n/a	15.27%	0.02%
Regency Centers Corp	REG	0.04%	3.43%	0.00%	5.65%	0.00%
Macerich Co/The	MAC	0.03%	5.35%	0.00%	6.72%	0.00%
Martin Marietta Materials Inc	MLM	0.04%	1.06%	0.00%	14.08%	0.01%
Envision Healthcare Corp	EVHC	0.02%	n/a	n/a	14.51%	0.00%
PayPal Holdings Inc	PYPL	0.41%	n/a	n/a	18.93%	0.08%
Coty Inc	COTY	0.04%	3.98%	0.00%	13.06%	0.00%
DISH Network Corp	DISH	0.03%	n/a	n/a	-12.71%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.12%	n/a	n/a	16.34%	0.02%
Everest Re Group Ltd	RE	0.04%	2.28%	0.00%	10.00%	0.00%

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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
WellCare Health Plans Inc	WCG	0.06%	n/a	n/a	16.54%	0.01%
News Corp	NWSA	0.02%	1.52%	0.00%	26.30%	0.01%
Global Payments Inc	GPN	0.08%	0.03%	0.00%	17.00%	0.01%
Crown Castle International Corp	CCI	0.18%	3.77%	0.01%	19.23%	0.03%
Aptiv PLC	APTV	0.09%	1.05%	0.00%	13.07%	0.01%
Advance Auto Parts Inc	AAP	0.05%	0.14%	0.00%	18.46%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	3.66%	0.00%
Align Technology Inc	ALGN	0.12%	n/a	n/a	33.09%	0.04%
Illumina Inc	ILMN	0.21%	n/a	n/a	19.34%	0.04%
Alliance Data Systems Corp	ADS	0.05%	0.97%	0.00%	12.51%	0.01%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.15%	0.01%
Nielsen Holdings PLC	NLSN	0.04%	5.06%	0.00%	12.00%	0.00%
Garmin Ltd	GRMN	0.05%	3.03%	0.00%	5.98%	0.00%
Cimarex Energy Co	XEC	0.03%	0.77%	0.00%	72.92%	0.03%
Zoetis Inc	ZTS	0.17%	0.55%	0.00%	17.87%	0.03%
Digital Realty Trust Inc	DLR	0.09%	3.59%	0.00%	7.28%	0.01%
Equinix Inc	EQIX	0.13%	2.11%	0.00%	19.55%	0.03%
Discovery Inc	DISCK	0.04%	n/a	n/a	n/a	n/a

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]	3.10%	0.577	15.19%	12.09%	10.07%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q1 2020) [2]	3.52%	0.577	15.19%	11.67%	10.25%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [3]	4.20%	0.577	15.19%	10.99%	10.54%
				Average:	**10.29%**
				Median:	**10.25%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	3.10%	0.663	15.19%	12.09%	11.11%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q1 2020) [2]	3.52%	0.663	15.19%	11.67%	11.25%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [3]	4.20%	0.663	15.19%	10.99%	11.48%
				Average:	**11.28%**
				Median:	**11.25%**

Notes:

[1] Source: Bloomberg Professional, 30-day average as of September 28, 2018
[2] Source: Blue Chip Financial Forecasts, Vol. 37, No. 10, October 1, 2018, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, 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

$K = Rf + \beta\ (Rm - Rf)$

	[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]	3.10%	0.444	15.19%	12.09%	8.47%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q1 2020) [2]	3.52%	0.444	15.19%	11.67%	8.70%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [3]	4.20%	0.444	15.19%	10.99%	9.08%
				Average:	**8.75%**
				Median:	**8.70%**
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	3.10%	0.650	15.19%	12.09%	10.96%
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q1 2020) [2]	3.52%	0.650	15.19%	11.67%	11.10%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [3]	4.20%	0.650	15.19%	10.99%	11.34%
				Average:	**11.14%**
				Median:	**11.10%**

Notes:

[1] Source: Bloomberg Professional, 30-day average as of September 28, 2018
[2] Source: Blue Chip Financial Forecasts, Vol. 37, No. 10, October 1, 2018, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, 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]	[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)
Atmos Energy Corporation	ATO	$93.25	$1.94	2.08%	2.15%	2.22%	7.50%	6.95%	6.50%	6.98%	9.14%	9.20%
New Jersey Resources Corporation	NJR	$46.24	$1.17	2.53%	2.63%	2.71%	9.50%	7.10%	7.00%	7.87%	10.50%	10.57%
NiSource Inc.	NI	$26.56	$0.78	2.94%	3.08%	3.17%	18.00%	6.07%	5.50%	9.86%	12.94%	13.03%
Northwest Natural Gas Company	NWN	$66.31	$1.89	2.85%	3.04%	3.13%	30.50%	4.50%	4.30%	13.10%	16.14%	16.23%
ONE Gas, Inc.	OGS	$80.44	$1.84	2.29%	2.37%	2.44%	10.50%	5.50%	5.70%	7.23%	9.60%	9.67%
South Jersey Industries, Inc.	SJI	$34.14	$1.12	3.28%	3.47%	3.57%	9.50%	12.00%	12.20%	11.23%	14.70%	14.80%
Southwest Gas Corporation	SWX	$79.47	$2.08	2.62%	2.69%	2.77%	9.00%	4.00%	4.00%	5.67%	8.36%	8.44%
Spire, Inc.	SR	$75.06	$2.25	3.00%	3.07%	3.16%	7.50%	3.53%	4.00%	5.01%	8.08%	8.17%
		PROXY GROUP MEDIAN		2.73%	2.86%	2.95%	9.50%	5.79%	5.60%	7.55%	10.05%	10.12%

MEDIAN		10.12%
UNADJUSTED CONSTANT GROWTH DCF MEDIAN		10.05%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.07%

[1] Source: Bloomberg Professional, equals 30-day average as of September 28, 2018
[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

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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%	
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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:

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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	$64.21	$1.83	2.85%	2.95%	3.04%	7.50%	6.90%	6.60%	7.00%	9.95%	10.04%
Black Hills Corporation	BKH	$59.32	$1.90	3.20%	3.28%	3.38%	6.50%	4.32%	4.50%	5.11%	8.39%	8.49%
CMS Energy Corporation	CMS	$49.52	$1.43	2.89%	2.98%	3.07%	7.00%	6.97%	6.20%	6.72%	9.71%	9.80%
DTE Energy Company	DTE	$111.31	$3.53	3.17%	3.27%	3.36%	7.50%	5.49%	5.30%	6.10%	9.36%	9.46%
NorthWestern Corporation	NWE	$59.84	$2.20	3.68%	3.73%	3.84%	3.50%	2.45%	2.30%	2.75%	6.48%	6.59%
Sempra Energy	SRE	$116.06	$3.58	3.08%	3.22%	3.31%	9.50%	8.89%	8.00%	8.80%	12.02%	12.11%
Wisconsin Energy Corporation	WEC	$67.72	$2.21	3.26%	3.35%	3.45%	7.00%	4.54%	4.10%	5.21%	8.56%	8.66%
		PROXY GROUP MEDIAN		3.17%	3.27%	3.36%	7.00%	5.49%	5.30%	6.10%	9.36%	9.46%

MEDIAN		9.46%
UNADJUSTED CONSTANT GROWTH DCF MEDIAN		9.36%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.10%

[1] Source: Bloomberg Professional, equals 30-day average as of September 28, 2018
[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[1] in Docket No. G002/M-15-808. That Order required 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.*

The Company made our initial metrics proposal, in compliance with that Order, as a supplemental filing in our 2017 GUIC Rider filing.[2] The Company developed this proposal, with stakeholder involvement, to provide metrics to measure the appropriateness of GUIC expenditures.

The Commission rejected our proposal in the 2017 GUIC Rider filing, and stated that:

> *Xcel shall continue to discuss with other parties, including the Department and the [Minnesota Office of Attorney General] OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GUIC proceedings.*[3]

The Company met on September 26, 2018 with stakeholders from the Commission, the Department, Minnesota Office of Pipeline Safety (MNOPS), and OAG, to continue the discussion of metrics to gauge GUIC operations. While we did not reach a consensus as to what metrics should be used to measure the GUIC, it was a fruitful meeting.

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[1] Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808 (August 18, 2016).
[2] *See* Supplement and Compliance Metrics Proposal, Docket No. G002/M-16-891 (January 13, 2017).
[3] *See* Order Approving GUIC Rider with Modifications, Docket No. G002/M-16-891 (February 8, 2018).

Below, we provide an update on all of our metrics results, similar to the metrics proposed in our previous GUIC filings, as well as a discussion of associated rules, goals, and benefits. Based on dialogue with stakeholders, the Company modified the presentation of our proposed metrics. For gas transmission anomalies, we now show the number of anomalies repaired by year, and also break those amounts down by type of anomaly repaired.

A. Summary of Program Expenditures, Relevant Rules and Guidelines, and Program Goals

The GUIC programs of work proposed for 2019 are summarized below in Table 1.

Table 1
Summary of 2019 GUIC Project Expenditures

Program	Project	Capital ($ Millions)	O&M ($ Millions)
TIMP	Transmission Pipeline Assessments	$1.0	$2.9
	ASV/RCV	$0.8	$0.0
	Programmatic Replacement/MAOP Remediation	$26.4	$0.0
DIMP	Poor Performing Main Replacement	$10.1	$0.0
	Poor Performing Service Replacement	$6.3	$0.0
	Intermediate Pressure (IP) Line Assessments	$0.0	$0.6
	Distribution Valve Replacement	$0.0	$0.0
	Sewer & Gas Line Conflict Investigation	$0.0	$2.2
	Federal Code Mitigation	$0.0	$0.0
TOTAL		$44.5	$5.7

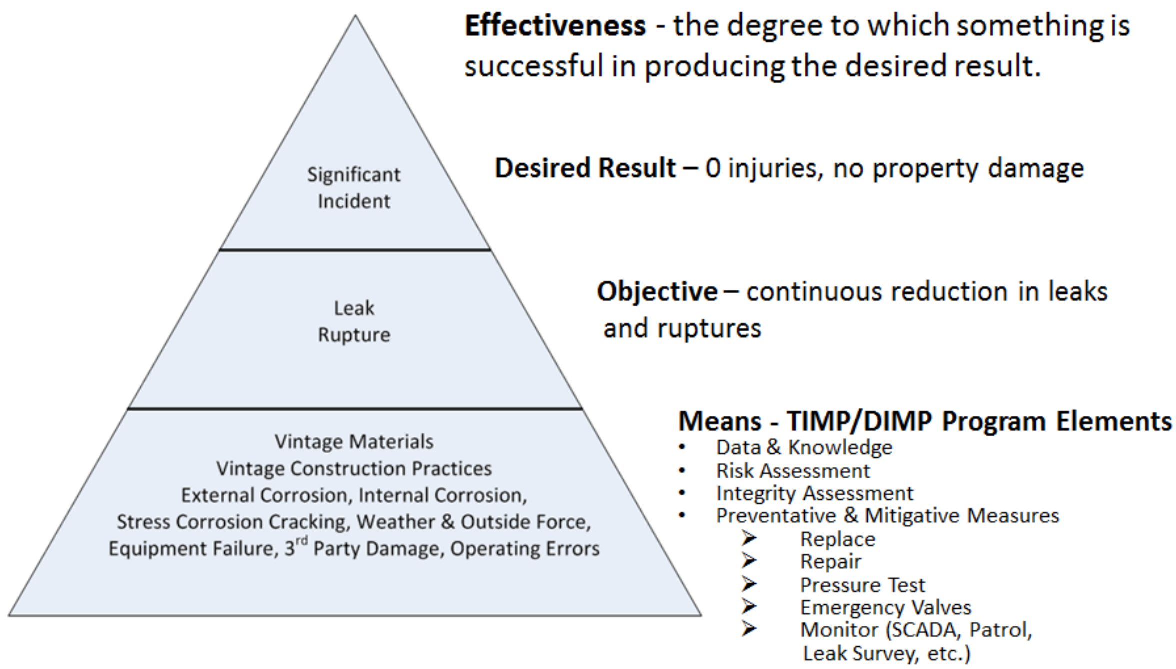
The GUIC projects proposed for 2019 fall into two broad categories, TIMP and DIMP. The related rules associated with each project are summarized below in Table 2 and discussed in more detail in our November 1, 2018 Petition.

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, prevention and mitigation measures are undertaken for TIMP and DIMP to reduce the likelihood or severity of gas leaks and pipeline ruptures.

The Company's proposed Metrics are summarized in Table 3 below.

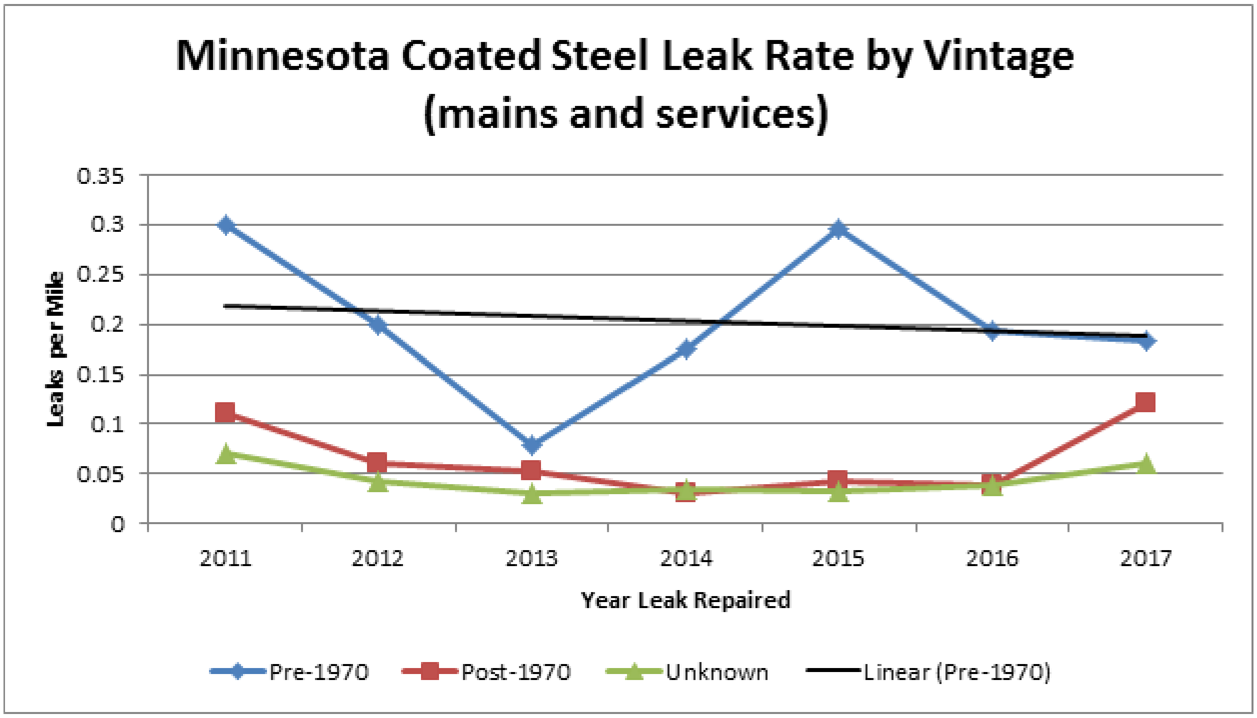
Table 3
Proposed GUIC Metrics

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.

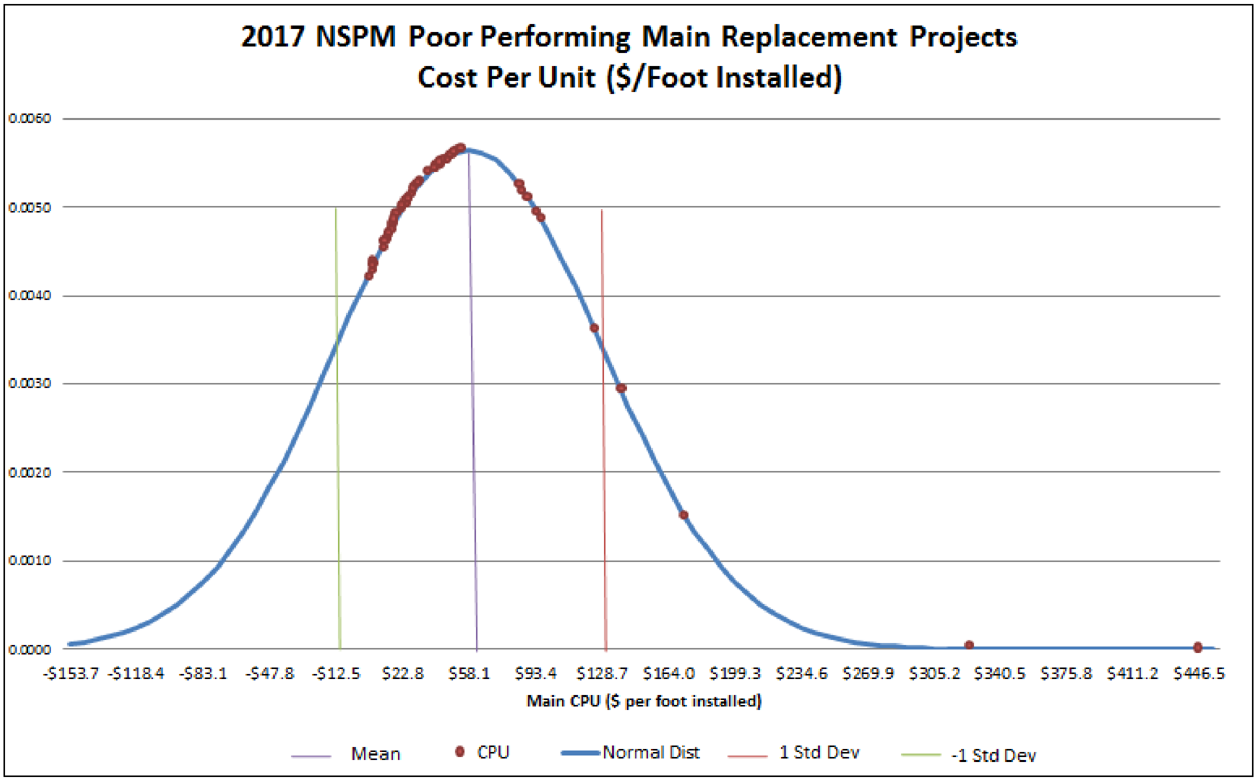
Figure 2
Number of Leaks Per Mile



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. 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, so 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, and 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 distribution of average cost per foot for poor performing main replacement projects. There were four projects in 2017 that exceeded the mean cost per foot plus one standard deviation ($114.08 per foot):

NORTH ST. PAUL – MARGARET ST./12TH AVE ($119.4 per foot): Project included 900 feet of 8-inch steel replacement (in addition to 950 feet of 4-inch plastic main replacement), and the costs reflect the additional cost for welders, tappers, certified weld inspectors, and support significantly a higher CPU. In addition, restoration for larger diameter steel is about twice the amount for 2-inch or 4-inch diameter plastic projects and also contributed to a higher cost per foot.

SARTELL – MISSISSIPPI RIVER CROSSING ($440.04 per foot): Equipment needed to bore the Mississippi River was significantly more substantial, requiring additional coordination, utilizing a boat or barge to help track the bore across the river and substantially more work on each shoreline, compared to other DIMP projects.

WINONA – 3RD ST BTW WINONA ST-LIBERTY ST DIMP ($146.74 per foot): The construction setting is in an urban area, in the heart of downtown Winona. Traffic control, restoration, contract inspection, and the storm water pollution prevention plan[4] were the greatest cost contributors, totaling $1,190,197 as compared to $99,956 for the actual main installation portion of the work. To minimize the impact to the City and businesses, a single block was constructed at a time and concrete jersey barriers were used to maintain open streets for traffic.

WINONA 3RD STREET DIMP – RAILROAD WORK ($175.13 per foot): Costs to mobilize equipment to bore under the railroad was substantial compared to the footage installed/replaced. Original estimates were $78,591 and actual costs totaled $52,540. The length of the project and boring requirements under railroad and associated coordination were the primary factors contributing to high cost per foot.

Figure 4
Unit Costs for Poor Performing Service Replacement Projects

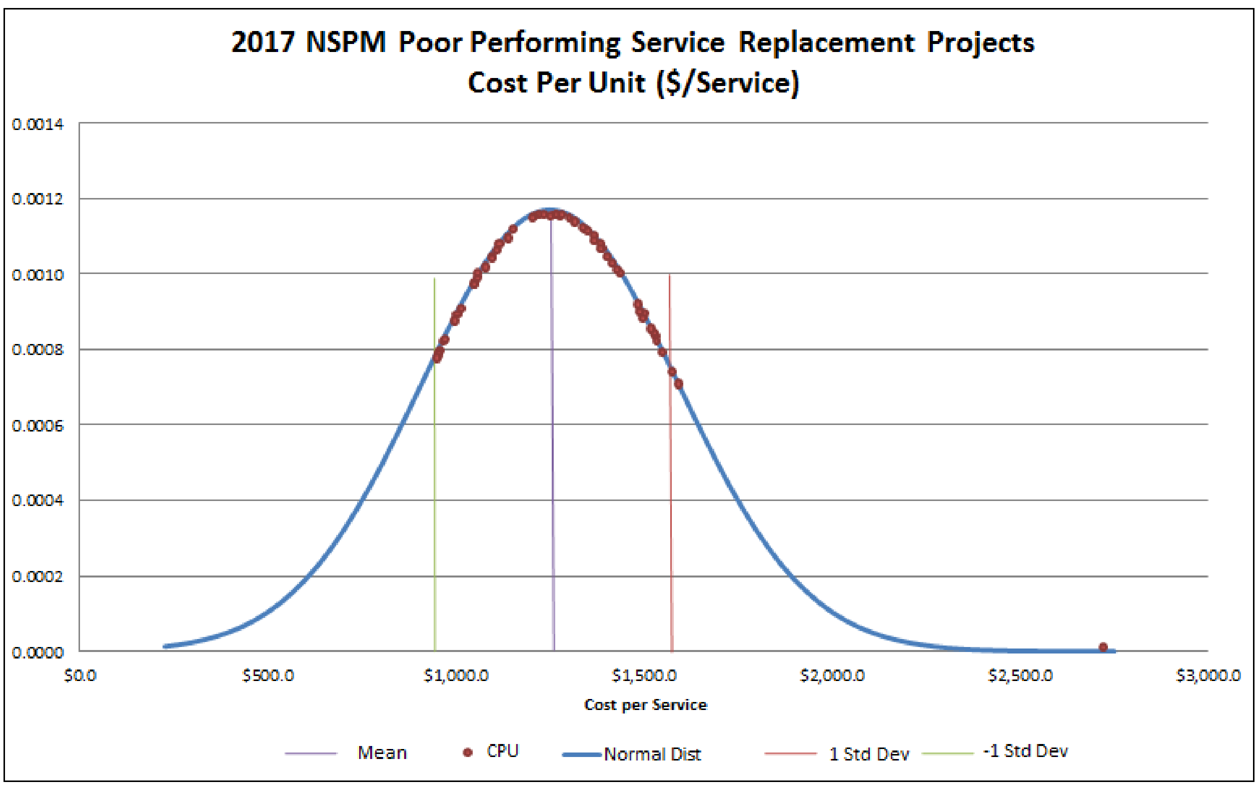


Figure 4 depicts the distribution of cost per average service installation for poor performing services installations. Three projects fell above the mean cost per gas

[4] Includes the use of curb drain protection as well as protection around each spoil pile to ensure sediment from a work area does not enter the storm water system or public waters.

service plus one standard deviation ($1,592). Cost variance explanations for these three projects are shown below:

NORTH OAKS – HAYCAMP RD ($2,743 per service): The average service length for this area is roughly three times the average service length and is the greatest contributing factor to high cost per service as compared to other projects. Every service at a minimum has a service tee, excess flow valve, service pipe, riser and meter. The greatest variable is the service length. Larger restoration costs than anticipated also contributed to the higher cost per service.

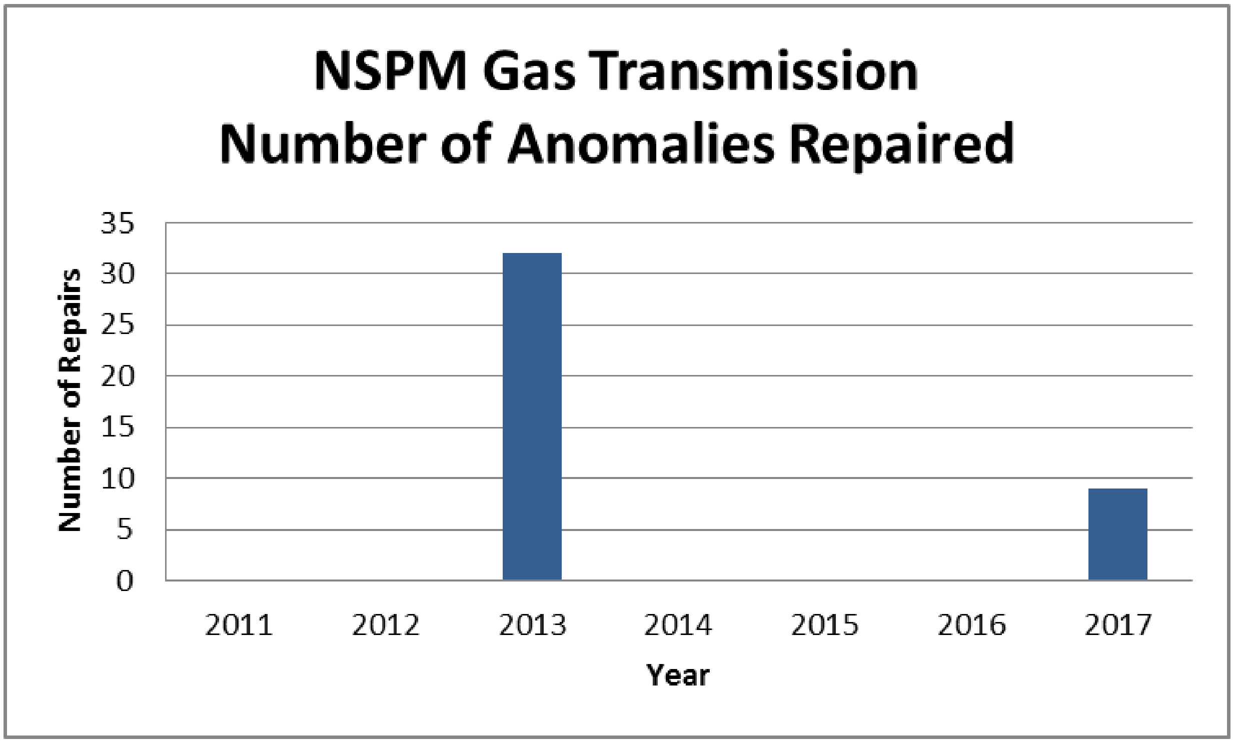
ST. CLOUD – 44TH AVE N, VA ($1,640 per service): The service length on this project was longer on average, and due to location, additional restoration costs were incurred that are typically not needed on most other projects. Specifically, the average service length was higher on this project due to the rural setting and the Veterans Affairs (VA) Hospital. Services were longer and or a greater diameter than average residential services, contributing to a higher average cost per service. The restoration at and near the hospital were more extensive than most services as well, and impacted the average cost per service for the project.

WINONA – 3RD ST BTW WINONA ST-LIBERTY ST DIMP ($1,599 per service): Excessive restoration and traffic control cost requirements contributed to high cost per service. Each service was under concrete or asphalt, and in addition to traffic control, steel plates were used over open holes to maintain pedestrian access to businesses.

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.

Table 4 below shows the anomalies repaired, by type of anomaly repaired.

Table 4
TIMP Repairs by Anomaly Type

Anomaly Type	Number of Repairs
External Corrosion	9
Internal Corrosion	0
Stress Corrosion Cracking	0
Manufacturing	2
Construction	4
Equipment	0
Third-Party Damage	26
Incorrect Operations	0
Weather and Outside Force	0
Total	41

The Company has also proposed a TIMP metric that monitors actual versus estimated costs for capital replacement projects as illustrated below in Table 5.

Table 5
TIMP Replacement Project Cost Monitoring

Project	Cost Estimate at Issue for Construction ($ Millions)	Actual Cost ($ Millions)	Variance Explanation
Montreal Line South Renewal, 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. **Island Line South Renewal,** 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.	$7.7M	$7.9M	Not significant.

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-17-787

Docket No. G002/GR-09-1153

Xcel Energy Miscellaneous Gas Service List

Dated this 1st day of November 2018

/s/

____

Carl Cronin
Regulatory Case Specialist

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