414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2022

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

—Via Electronic Filing—

RE: GAS UTILITY INFRASTRUCTURE COST RIDER
TRUE-UP REPORT FOR 2021, UPDATED COSTS FOR 2022,
REVENUE REQUIREMENTS FOR 2023, AND REVISED ADJUSTMENT FACTORS
DOCKET NO. G002/M-22-____

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Annual Report and Petition for approval of recovery of updated gas utility infrastructure costs (GUIC) through the GUIC Rider for 2023.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, which also constitutes service on the Minnesota Department of Commerce, Division of Energy Resources and the Minnesota Office of the Attorney General, Residential Utilities 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
DIRECTOR, REGULATORY PRICING & ANALYSIS

Attachments

c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matt Schuerger	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 2021, UPDATED COSTS FOR 2022, REVENUE REQUIREMENTS FOR 2023, AND REVISED ADJUSTMENT FACTORS	DOCKET NO. G002/M-22-___ **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 2023 Gas Utility Infrastructure Cost (GUIC) Rider revenue requirement.

For 2023, we request recovery of a GUIC Rider revenue requirement of approximately $37.5 million. This request amounts to an impact of about $4.53 per month for an average residential natural gas customer's bill. Our request includes integrity management project costs that are consistent with the eligibility requirements set forth in the GUIC statute.[1] These costs are incurred to continue important infrastructure work that promotes the safety of our natural gas system.

Background

We are dedicated to operating a safe and reliable gas system for our customers. With aging gas infrastructure that runs primarily through high-density urban and suburban areas, it is of critical importance that the Company invests in assessing the integrity of our system and repairing and replacing problematic equipment. Integrity management projects address our gas infrastructure's structural integrity, facilitating efficient

[1] Minn. Stat. § 216B.1635.

assessments going forward, and ensuring a safer gas system that will reduce the likelihood of incidents within the community.

To promote the continued safety and reliability of our gas system through our GUIC work, since 2015 the Company has completed the replacement of more than 368 miles of high- and medium-risk, aging, corroded, and otherwise damaged gas distribution pipeline as well as the replacement of more than 16,600 aging distribution service lines.

In addition to main and service replacements, the Company has completed a sewer and gas line conflict remediation program. As a part of this completed program, the Company performed more than 248,000 inspections and identified and cleared over 150 conflicts. In addition, at this time we have completed all work currently planned for automatic shut-off valves and remote-controlled valves. As a part of the completed valve replacement program, we have replaced 20 valves. The result of this GUIC work is a gas infrastructure system that is safer and more reliable.

Upcoming Transmission Integrity Management Programs (TIMP) work will include continued in-line inspections (ILI), programmatic replacement and maximum allowable operating pressure (MAOP) remediations, and casing renewals. Our MAOP project includes reconfirmation work and other costs required to meet new federal requirements.[2]

Upcoming major distribution renewal and replacement projects include the replacement of approximately 60 miles of poor performing distribution mains and 4,000 poor performing services. In addition, we will complete major replacement projects on one distribution intermediate pressure line segment near Brainerd and Nisswa. These replacement projects address several risk factors including external corrosion, legacy manufacturing and construction techniques, and third-party damage. Beyond main and service replacement projects, upcoming Distribution Integrity Management Programs (DIMP) work will include distribution pipeline assessments and replacements, valve replacements, and casing renewals.

Status of Statute Authorizing Recovery of GUIC

The recovery of GUIC costs through a rider is authorized via Minnesota Statute § 216B.1635 (the GUIC Statute). Currently there is a legislative note accompanying the statute indicating that this statute is set to expire June 30, 2023. In last year's GUIC filing, Docket No. G002/M-21-765, the parties began a policy discussion

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[2] New rule is the first of three parts of a Notice of Proposed Rulemaking issued by the Pipeline and Hazardous Materials Safety Administration in Docket No. PHMSA-2011-0023. The first part was published October 1, 2019 and carries progressive effective dates, the first of which was December 31, 2020. A greater discussion of this rule is provided in Attachment C.

about the statute's sunset and how it relates to the critical nature of the work TIMP and DIMP being done and the future of gas discussions happening in other dockets. As this proposal is being filed before the expiration of the statute, we believe that this docket can move forward like previous GUIC Rider filings and that the Commission is authorized to approve recovery of the full amount of 2023 GUIC costs included in this request. Considering the GUIC statute's anticipated expiration, however, we want to continue the policy discussion started earlier this year. We discuss this issue in greater detail in Section XI below.

Pending Natural Gas General Rate Case

The Company filed a natural gas general rate case on November 1, 2021.[3] As a part of that case, the Company has proposed to move (or "roll-in") part of the revenue requirements for the GUIC Rider to base rates when final base rates are implemented in the rate case. The proposed rider roll-in includes the revenue requirement for all GUIC Rider capital projects forecasted to be in service prior to December 31, 2021. The estimated revenue requirement for the GUIC assuming a final rate implementation date of July 1, 2023 would be approximately $22.7 million. This amount reflects a full revenue requirement for January – June 2023, and only those projects remaining in the GUIC Rider for July – December 2023. No costs included in this petition were included in our interim rate request, so there will be no double recovery between interim rates and the GUIC Rider.

The Company has entered into a settlement agreement with all participating parties to resolve all issues in the pending natural gas general rate case.[4] In conjunction with reaching that unanimous agreement, we are proposing to use the return on equity, capital structure, and rate of return agreed to in the settlement.

We have structured this rider filing with no adjustments to account for a base rate roll-in adjustment that may result with a final Order and implementation of final rates in the natural gas rate case. We propose to continue recovery of these projects through the GUIC Rider until the Commission acts on the settlement agreement, and final rates are implemented in the rate case.[5] In conjunction with this, we also have removed adjustments included with previous GUIC Rider requests to account for the

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[3] IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S PETITION FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN MINNESOTA, Docket No. G002/GR-21-678

[4] *See* COMPREHENSIVE AND UNANIMOUS SETTLEMENT AGREEMENT, filed October 4, 2022 in Docket No. G002/GR-21-678.

[5] If the final resolution of the rate case differs from what we have proposed here, we will adjust our GUIC Rider request accordingly in a supplemental filing.

revenue requirement impact of assets retired due to GUIC work and for amounts included in our currently approved base rates.[6]

Recently Decided and Pending GUIC Rider Dockets

The Commission recently verbally approved our request for recovery of the 2021 GUIC Rider revenue requirement.[7] Our request in this docket mostly reflects the positions verbally approved by the Commission in that 2021 request. For example, our 2023 GUIC Rider request excludes internal capitalized costs[8] and uses 12 months of actual sales data to calculate our initially proposed rate factors, rather than forecast sales data as we have used in previous filings.

Our request for recovery of the 2022 GUIC Rider revenue requirement is pending at the Commission.[9] We expect the Commission to hear our 2022 requests before the conclusion of this docket. If the resolution of our 2022 requests requires any carryover into our 2023 request, we will update this request accordingly.

Outline of Filing

The balance of this Petition is organized as follows:

- *Section I* – identification of the parties and state agencies that are being served with the filing
- *Section II* – general information that is required under the Commission's rules
- *Section III* – background of our GUIC Rider, including the applicable Minnesota State Statute, applicable standard of review, and GUIC Rider recovery as a part of our overall natural gas recovery
- *Section IV* – a summary of the planned 2023 TIMP projects
- *Section V* – a summary of the planned 2023 DIMP projects
- *Section VI* – a summary of the planned 2023 Mandated Relocation projects
- *Section VII* – demonstration that our request to recover costs through the GUIC Rider complies with the applicable standard of review and complies with previous Commission orders
- *Section VIII* – discussion of our proposed 2023 revenue requirement, rate factor calculations, timing of rate implementation, status of GUIC Rider tracker account, and proposed tariff sheet and customer notice

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[6] The removal of these adjustments was also reflected in our June 13, 2022 Reply Comments in Docket No. G002/M-21-765.
[7] Verbally approved during the Commission's October 27, 2022 agenda meeting.
[8] Includes overheads, transportation, and other costs.
[9] Docket No. G002/M-21-765

- *Section IX* – support for our proposed capital structure and return on equity (ROE)
- *Section X* – a summary of performance metrics
- *Section XI* – discussion of status of GUIC Statute

To aid the review of this filing, we provide, as Attachment A, a compliance matrix setting forth the requirements of the enabling GUIC statute and relevant Commission Orders and directing readers to the part of the filing that addresses each requirement. We also provide an index of the included attachments as Attachment B to this filing.

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, Division of Energy Resources and the Minnesota Office of the Attorney General, Residential Utilities Division.

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

Mara Ascheman
Principal Attorney
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
(612) 215-4605
mara.k.ascheman@xcelenergy.com

C. Date of Filing and Proposed Effective Date

The date of this filing is November 1, 2022. The proposed effective date for the

2023 GUIC Rider factors is March 1, 2024. 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
Director, Regulatory Pricing and Analysis
Xcel Energy
414 Nicollet Mall (401-7th Floor)
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(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:

Mara Ascheman
Principal Attorney
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
mara.k.ascheman@xcelenergy.com

Christine Schwartz
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 Christine Schwartz at the Regulatory Records email address above.

III. GUIC Rider Background

The GUIC Statute allows a utility to petition the Commission for the recovery of "gas utility infrastructure costs." As explained in this petition, TIMP and DIMP work makes up the majority of "gas utility infrastructure costs" we request to recovery through the GUIC Rider. The Commission has recognized that our TIMP and DIMP work is 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.[10]

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

A. Applicable Minnesota Statutes

As mentioned above, the GUIC Statute allows a utility to petition for the recovery of "gas utility infrastructure costs." According to the GUIC statute, GUIC costs can relate to two different types of "gas utility projects"—generally speaking, (1) replacement of natural gas facilities located in the public right-of-way 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, or (2) replacement or modification of existing natural gas facilities as required by a federal or state agency.

The importance of safety-related cost recovery is also specifically mentioned in Minnesota's pipeline safety statutes. 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.

As the Commission has previously recognized, the Company's TIMP and DIMP activities are precisely the type of expenditures for which Minn. Stat. § 216B.1635 authorizes recovery. With this request, the Company asks the Commission to allow continued recovery of our projected TIMP and DIMP expenses for 2023. This year, our TIMP and DIMP plans include the same programs that were included in our 2021 and 2022 GUIC Rider requests. The Company also requests GUIC Rider recovery of incremental mandated relocations that are necessary because of public works improvements being done by or on behalf of the municipalities in which our infrastructure is located.

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[10] *See* Docket No. G002/M-15-808, ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES at 6 (August 18, 2016).

The GUIC Statute explicitly authorizes the timely recovery of GUIC expenditures through a rider mechanism. As stated in the statute, the legal standard of review for this petition 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.*[11]

The Company's revenue requirement reflects the impact of ongoing integrity management projects already approved by the Commission in previous GUIC Rider filings, as well as new requests associated with casing renewals and mandated relocations included in our 2022 request but not yet approved by the Commission. We are proposing a change in rate of return with this request and support using the return on equity, capital structure, and rate of return agreed to in the unanimous settlement agreed to in our pending natural gas rate case.

B. GUIC Rider as a Part of Overall Gas Utility Cost Recovery

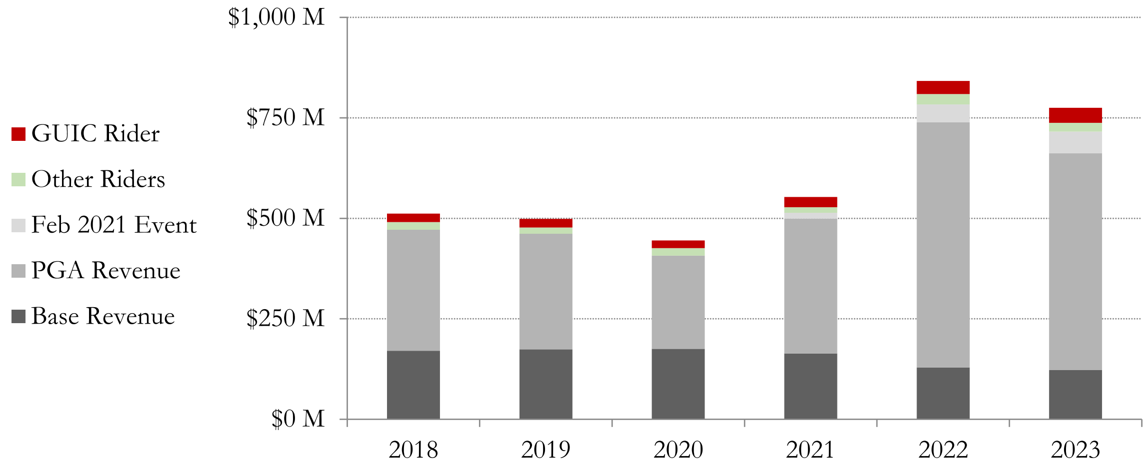
The recovery of GUIC Rider revenue requirements is a critical component in the Company's gas utility business and facilitates construction and assessment activities that help keep the gas system operating safely and efficiently. However, the total GUIC Rider revenue requirement related to integrity management project work 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 four components. These components are:

- Base rates recovery, stemming from the approved revenue requirement from the last general gas rate case,
- Fuel revenues (through the PGA and the February 2021 Event Surcharge),
- GUIC Rider annual revenue requirement,
- Other riders.

To provide context as to how the GUIC Rider fits into the Company's total gas utility recovery, Figure 1 below shows the total gas utility revenue collections by recovery mechanism.

[11] Minn. Stat. § 216B.1635 subd. 5.

Figure 1
Annual Revenue Collections by Recovery Mechanism



	2018	2019	2020	2021	2022	2023
GUIC % of total	4.1%	4.3%	4.3%	4.6%	3.9%	4.8%
Earned ROE	9.81%	8.54%	7.19%	3.85%		

The GUIC Rider represents 4.8 percent of total bill collections forecasted in 2023. In Figure 1 above, we also provide the earned ROE as reported in our jurisdictional annual reports. The reported earned ROEs include the costs and revenues across all the shown recovery methods.

IV. TIMP PROJECTS

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 70 miles of transmission pipeline in Minnesota. Our 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. Our 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.

The Company currently has three major TIMP initiatives under way.

- Transmission Pipeline Assessments
- Programmatic Replacement and MAOP Remediation Program
- Casing Renewals

We also note that work on the Automatic Shut-off Valves and Remote-Controlled Valves was completed in 2022, with no future work currently planned. Table 1 below shows the estimated 2023 TIMP project costs.

Table 1
2023 Estimated TIMP Project Costs ($ Millions)

Program	2023 Capital[12]	2023 O&M
Transmission Pipeline Assessments	$0.3	$0.6
Programmatic Replacement / MAOP Remediation	$8.6	$0.1
Casing Renewal	$2.1	$0.0
Total 2023 TIMP Expenditures	**$11.0**	**$0.7**
Total 2023 Minnesota TIMP Revenue Requirements	**$13.7**	**$0.6**

Project descriptions, scopes of work, estimated costs and in-service dates for specific TIMP projects are provided as Attachments C, C1, and C2. We also provide a brief explanation of new federal regulations that may influence future TIMP projects. Attachment F reports the capital expenditure costs and forecasted costs for incremental TIMP activities between March 2012 and December 2027. Attachment G shows the development of 2023 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment F.

A. Transmission Pipeline Assessments

Transmission pipeline assessments are an ongoing program, which began in 2002, to assess the health and condition of our gas transmission lines. Federal regulations require assessment of gas transmission pipelines using ILI, pressure testing, or direct assessment.[13] Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of the risks and threats that may cause pipeline damage.

The Company has completed requirements related to High Consequence Area (HCA) Baseline Assessments,[14] and is now focusing on the re-assessment of pipelines in HCAs as well as assessing remaining transmission pipe beyond HCAs. Federal transmission rules published in 2019 require that Moderate Consequence Areas must be assessed initially by July 3, 2034 and then must be reassessed at least once every 10 years thereafter or sooner based on the risks and threats to the pipeline segment. These assessments provide important information about the conditions of the Company's pipelines, including the existence of internal and external corrosion and other anomalies.

When performing gas transmission line assessments, the Company conducts ILI as a first preference. There are advantages to using ILI compared to alternative assessment

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[12] Estimated capital costs include estimated removal costs. Details can be seen in Attachment C1.
[13] The requirements are further defined in the Company's TIMP manual.
[14] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012. See 49 CFR Part 192.921.

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 and can assess 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 pipe segments. After an initial capital investment to prepare a pipeline for an ILI tool, subsequent assessments will be performed using ILI as an operations and maintenance (O&M) cost.

The forecasted capital and O&M costs for assessments included in our previous GUIC Rider filings are shown in Table 2 below.

Table 2
GUIC Transmission Pipeline Assessments[15] ($ Millions)

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 (18-692)	15.8	$1.0	$2.9
2020 (19-664)	26.2	$3.6	$1.7
2021 (20-799)	13.5	$1.5	$1.7
2022 (21-765)	3.2	$0.6	$0.6
2023 (22-___)	7.7	$0.3	$0.6

As shown in Table 3 below, the Company expects to complete two ILI projects and no direct assessment projects in 2023.[16]

[15] Numbers in Table 2 reflect estimated mileage and expenditure amounts as shown in our original 2016 through 2022 GUIC Rider filings for each year and may differ from actual amounts due to program modifications and scope changes occurring after the initial filings.
[16] Assessments are required every seven years according to Subpart O – Gas Transmission Pipeline Integrity Management 192.939.

Table 3
Transmission Integrity Assessments[17]

Number of Projects										
	2015	**2026**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
ILI	0	0	2	3	2	2	2	2	2	**15**
Pressure Test	2	1	0	0	0	0	0	0	0	**3**
Derate[18]	0	0	0	0	1	0	0	0	0	**1**
Direct Assessment	1	0	0	0	1	0	1	1	0	**4**
Total	**3**	**1**	**2**	**3**	**4**	**2**	**3**	**3**	**2**	**23**
Assessed Mileage										
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
ILI	0.0	0.0	7.8	20.6	2.9	16.1	3.2	3.2	7.7	**61.5**
Pressure Test	3.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**3.2**
Derate	0.0	0.0	0.0	0.0	5.8	0.0	0.0	0.0	0.0	**5.8**
Direct Assessment	6.5	0.0	0.0	0.0	0.4	0.0	10.3	0.01	0.0	**17.2**
Total	**9.6**	**0.1**	**7.8**	**20.6**	**9.1**	**16.1**	**13.5**	**3.2**	**7.7**	**87.7**

Beyond this year, we are forecasting annual costs associated with transmission pipeline assessments between $1.6 million and $2.2 million from 2024 through 2027. The costs incurred will likely be a combination of capital expenditures and O&M expenses, depending on the type of work being performed. Based on the current assessment plan, the Company expects to complete two to three projects each year in the 2024-2027 timeframe.

B. Programmatic Replacement and Maximum Allowable Operating Pressure Remediation

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 (TVC) records of a pipeline's MAOP. Through the initiative, the Company is validating existing MAOP records for our transmission pipelines and remediating any gaps in such records.[19] A new federal transmission rule was published on October 1, 2019. This rule is the first of three rules that originated from the Notice of Proposed Rulemaking (NPRM) published in March of 2016 under Docket No. PHMSA-2011-0023. MAOP reconfirmation is a key focus area of the rule

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[17] 2022 and 2023 amounts are estimates based on expected work scopes. Numbers may change as actual work is completed.

[18] A derate project involves lowering the line's maximum allowable operating pressure to reduce risk and reclassify the pipeline as distribution. The project noted for 2019 was for the Eagan Line.

[19] 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.

which provides prescriptive code requirements regarding the timeline, methodology, applicable pipeline segments, and historical documentation necessary for MAOP reconfirmation. These PHMSA requirements regarding records are a critical safety effort. We believe recent changes in the requirements necessitate the work that we have undertaken and show that the costs incurred are eligible for GUIC Rider recovery in full.

There are two multi-year MAOP replacement projects scheduled to be completed in 2023. The projects are planned for two different portions of the East County Line. Engineering work on both projects started in 2022, with construction occurring in 2023. We anticipate capital expenditures of $8.6 million and a small amount of O&M expenditures for the 2023 work. Beyond 2023, for these projects we expect future annual expenditures of about $2.6 to $3.8 million from 2024 through 2027.

C. Casing Renewals

The casing renewal project is a multi-year program which started in 2021. The objective of this project is to mitigate risks by renewing pipeline or installing equipment that allows ongoing testing to ensure isolation of pipelines from casings. Pipelines were installed inside casings to protect the pipe from a variety of forces. Casings were routinely used in a variety of situations, including under roads and railroads. Improved pipeline design has mostly eliminated the use of casings in modern gas construction. The Company has identified several instances where it is unknown whether a pipeline carrying gas is or is not isolated from the casing. Pipelines that are not isolated from the casing can create a corrosion risk and lead to pipeline failure. Identifying and remedying these instances are an important safety effort, and we believe the costs we will incur are eligible for GUIC Rider recovery in full.

The Company's Gas Standards Manual section 9.9.9 and 49 Code of Federal Regulations (CFR) § 192.467 require the ability to test for isolation of a pipe and casing. Both the federal code and our standards manual require the Company to take pipe-to-soil and casing-to-soil readings annually for all metallic carrier pipe installed in a metallic casing, with the purpose of determining whether the two pieces of pipe are in contact. If testing shows the pipe and casing are isolated, the casing is added to the annual test leak survey and will be monitored and maintained over time. If testing shows no isolation, the casing will be renewed under this project.

This project started during the 2021 construction season and will continue until all casing risks on the program list have been mitigated. We anticipate completing construction on one casing project, and engineering and design on two other projects in 2023, with associated capital expenditures of $2.1 million. Beyond 2023, for this project we expect future expenditures of about $0.9 million in 2024.

D. Automatic Shut-Off Valves and Remote-Controlled Valves

The automatic shutoff valve and remote-controlled shutoff valve installation project began in 2015. The installation of automatic shutoff valves and remote-controlled valves provides the Company with a mechanism to shut off the flow of gas more expediently. These valves can be useful tools to prevent negative impacts to public safety in the event of an incident. A small amount of final construction and commissioning work was completed in 2022, which finishes the scope of all known valve work that is needed currently.

PHMSA has recently released new guidance for valves 6 inches and larger.[20] We are currently reviewing the impact of this new guidance to determine if it will require additional work in the future. However currently the Company does not have any work planned for 2023 and beyond.

V. 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.[21] 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 currently has five major ongoing DIMP initiatives under way.

- Poor Performing Main Replacement
- Poor Performing Service Replacement
- Distribution Pipeline Inspection and Replacement
- Distribution Valve Replacement Project
- Casing Renewals

Table 4 below shows the estimated 2023 DIMP projects costs.

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[20] Docket No. PHMSA-2013-0255

[21] *See* 49 CFR. 192, Subpart P. PHMSA is a Department of Transportation agency created in 2004, responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of the Unites States' 2.6-million-mile pipeline transportation.

Table 4
2023 Estimated DIMP Project Costs ($ Millions)

Program	2023 Capital[22]	2023 O&M
Poor Performing Main Replacements	$18.6	$0.0
Poor Performing Service Replacements	$6.2	$0.0
Intermediate Pressure (IP) Line Assessments / Replacements	$1.7	$0.3
Distribution Valve Replacement Project	$0.4	$0.0
Casing Renewal	$1.7	$0.0
Total 2023 DIMP Capital Expenditures and O&M	**$28.5**	**$0.3**
Total 2023 Minnesota DIMP Revenue Requirement	**$26.0**	**$0.3**

To date, three major DIMP initiatives have been completed. They are:

- Sewer and Gas Line Conflict Remediation,
- Distribution Pipeline Data, and
- Federal Code Mitigation.

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided in Attachments D, D1, D2(a), and D2(b). Attachment F reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2027. Attachment H shows the development of 2023 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment F.

A. Poor Performing Main and Service Replacements

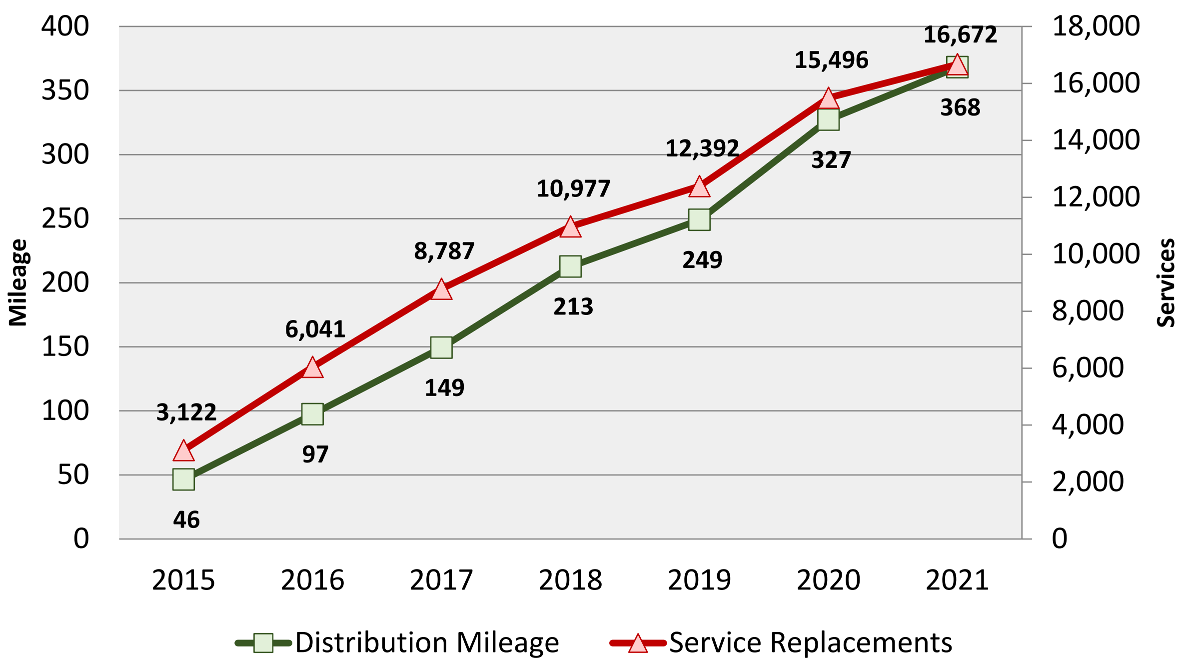
Under 49 CFR Part 192.1007(d), the Company must determine and implement measures designed to reduce the risks from failures of its gas distribution pipeline. As a result, the Company uses subject matter expertise, historical leak data, and industry information to identify risk factors that may lead to gas pipeline leaks or failures. The annual replacement levels of high- and medium-risk pipe are based on these factors. In this filing we are requesting $18.6 million in costs related to Poor Performing Mains and $6.2 million in costs related to Poor Performing Service Replacements. 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

[22] Estimated capital costs include estimated removal costs. Details can be seen in Attachment D1.

quality and Company processes are aiding the transition to a more proactive approach which benefits customers. Work undertaken systematically 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.

Figure 2 below illustrates the Company's achievements in integrity-related main and service distribution replacement.

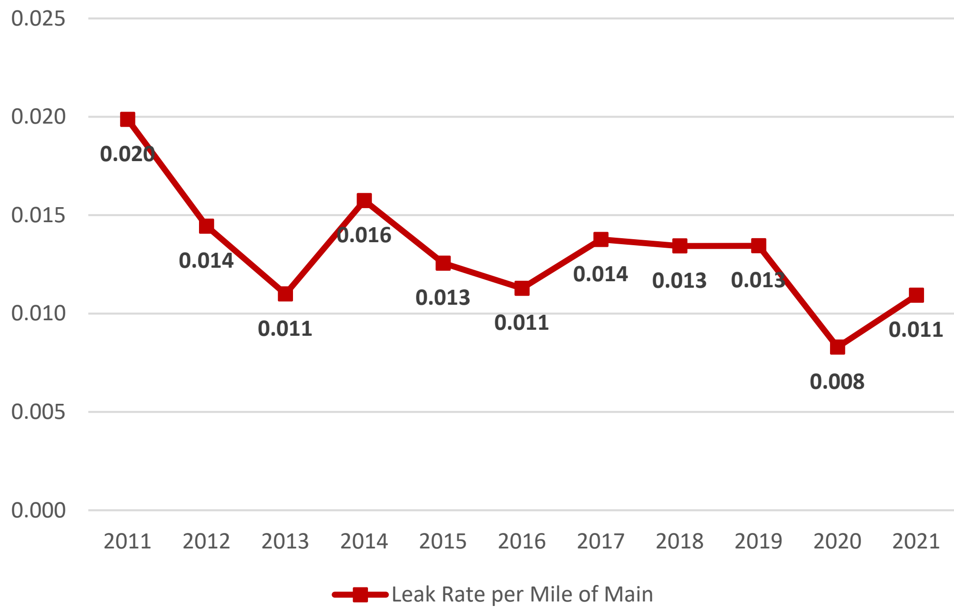
Figure 2
Cumulative Gas Distribution Pipeline Installation and Service Replacements[23]



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 leaks that have the potential to result in an event. Figure 3 below reflects leak data submitted to the United States Department of Transportation for the years 2011 through 2021.

[23] Please note that the number of 2016 Service Replacements has been corrected and does not tie to the same chart in previous-year filings. This change also affects the cumulative totals in subsequent years.

Figure 3
Distribution Mains Leak Rate
(Per Mile of Main)



As evidenced in Figure 3, the performance of the Company's distribution system has gradually improved, as measured by a decline in the leak rate per mile of main from 2011 to 2021.[24] Beyond 2023, our estimated future annual capital expenditures for the poor performing mains project are between $19 million and $21 million from 2024 through 2027. The estimated future annual capital expenditures for the poor performing services project are between $6 million and $7 million from 2024 through 2027. Replacement work 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.

B. Distribution Pipeline Inspection and Replacement

Distribution pipeline inspections and replacements are part of 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.[25]

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[24] Leak rates can occasionally increase year over year due to variances in areas where work is focused each year.

[25] *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.

The asset health data collected from these inspections will be used to develop plans for additional mitigation actions as needed to protect public safety. We expect capital expenditures of about $1.7 million and O&M expenditures of about $0.3 million in 2023 for the line assessment and replacement work.

As shown in Table 5 below, the Company expects to complete four direct assessment projects in 2022, along with excavations based on survey results from 2021. When adding the mileage for assessments already completed from 2016 to present, the Company expects to assess a total of 118.8 miles of distribution pipeline from 2016 through 2022.

Table 5
Distribution Pipeline Integrity Assessments[26]

Number of Projects									
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Pressure Test	0	0	0	1	0	0	0	0	1
Direct Assessment	2	1	2	0	1	4[27]	4	5	19
River Crossing Assessment	0	0	0	0	0	0	13	0	13
Total	**2**	**1**	**2**	**1**	**1**	**4**	**17**	**5**	**33**
Assessed Mileage									
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Pressure Test	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	2.4
Direct Assessment	30.7	11.1	5.5	0.0	36.2	22.8	24.3	8.0	138.6
Total	**30.7**	**11.1**	**5.0**	**2.4**	**36.2**	**22.8**	**24.3**	**8.0**	**138.6**

In addition to the five direct assessment projects and excavations planned for 2023, the Company also plans to complete one pipeline replacement project. Based on 2020 indirect survey data, the Company performed follow up digs on the Brainerd Lakes C line in 2021. These assessments found a section of bare steel along County Rd 13. The Brainerd/Nisswa/Co Rd 13 replacement project will replace this section of bare steel in 2023. As a part of this project, the Company will replace about 0.5 miles of distribution pipeline. The replacement of this line will support the integrity management of the Company's high-pressure distribution system.

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[26] 2022 and 2023 amounts are estimates based on expected work scopes. Numbers may change as actual work is completed.
[27] Number includes two excavation projects based on survey results in 2014 and 2020.

Beyond 2023, we have no capital expenditures planned, although assessments will continue being performed to direct future projects. We anticipate annual O&M costs of about $0.3 million from 2024 through 2027 to complete the assessment work.

C. Distribution Valve Replacement Project

The distribution valve replacement project is an ongoing project focusing on the replacement adding, replacing, or otherwise rehabilitating existing distribution valves. This work is in response to the Company's obligation under 49 CFR Part 192.1007(d). We estimate that the annual capital expenditures for distribution valve replacements will be about $0.4 million in 2023.

One aspect of the program will focus on existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life. The Company determines the need for a valve replacement based on valve conditions and locations. Initially, the Company anticipated valve replacement work ending in 2019. However, additional valves have been identified as inoperable while performing periodic maintenance and operating procedures. The Company currently estimates a total of 15 distribution valves will be replaced in the South Metro and Southeast areas. Of these valves, two are expected to be replaced in 2023 with the remaining to be replaced in 2024 through 2027. Replacing these valves will allow the Company more options to isolate sections to address an emergency or system incident, while impacting the smallest number of customers.

A second aspect of this project is the installation of new valves. After a review in 2020 determined that new valves were needed to reduce shutdown times during emergencies, we began new valve installations in 2021. Twelve new valves are expected to be installed in 2023, with the remaining to be installed in future years as a part of the DIMP work.

We estimate that the annual capital expenditures for all distribution valve replacements and installation of new values in 2024 through 2027 will be approximately $0.4 million annually.

D. Casing Renewal

As with the transmission casing renewal project, this work is being done in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467. The casing renewal project is a multi-year program that started in 2021. This is a comparable project to the TIMP casing renewal project discussed earlier, but instead focused on distribution pipelines. Under this project, the Company isolates pipes and casings that are determined to be in contact with one another (or unable to take readings), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe. Metallic pipes need to remain isolated from each other to reduce corrosion risk.

This project shall continue annually until all casings risks on the program list have been mitigated. We anticipate completing three casing renewals in 2023, with associated capital expenditures of $1.7 million. Beyond 2023, we anticipate additional annual capital expenditures between $1.5 million and $2.8 million from 2024 through 2027.

VI. Mandated Relocations

The mandated relocations program is dedicated to moving existing infrastructure to meet federal, state, or local requirements. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. The Company must invest capital to achieve these relocations and establishment of service via infrastructure at a different location.

We began including mandated relocations as a GUIC project in 2021.[28] We believe mandated relocations to move facilities that are in direct conflict with street expansions within public rights-of-way is the type of program specifically considered by the statute. One of the two definitions of a project to be included in the GUIC is:

> *…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[.]*[29]

The Company has been notified of five mandated relocation projects occurring in 2023. These projects are in Inver Grove Heights, Maplewood, May Township, St. Paul, and Stillwater. One of these projects, a relocation for the Washington County Road 5 reconstruction project, was initially expected to be completed in 2021 or 2022, but now has been pushed back to 2023 or possibly 2024. In addition, the costs related to work to relocate infrastructure around the Metro Transit Gold Line construction is expected to be reimbursed.

In addition to the discrete projects, we have already been notified of, the Company also expects to complete several other mandated relocation projects in 2023, as additional infrastructure work is planned by budgets for routine relocation projects that arise during each year. These projects typically have a cost less than $0.3 million.

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[28] Mandated relocation work was also included in our 2022 request.
[29] Minn. Stat. § 216B.1635 subd. 1.c.1.

We estimate that the total capital expenditures for mandated relocations we are asking to recover in the GUIC Rider will be approximately $8.2 million in 2023. Table 6 below shows the estimated mandated relocation project costs.

Table 6
2023 Estimated Mandated Relocation Project Costs ($ Millions)

Mandated Relocation Program	2023 Capital	2023 O&M
Total 2023 Capital Expenditures and O&M	**$14.9**	**$0.0**
Total 2023 Minnesota Revenue Requirement	**$4.9**	**$0.0**

The amounts included in the 2023 GUIC Rider Petition are based on historical data and anticipated costs. The budget for routine main relocations is based on the average of 2020 and 2021 actuals escalated by the corporate inflation rate.[30] Further, inputs and assumptions regarding inflation factors are used to determine the assumed cost increases or decreases. Beyond 2023, we estimate that capital expenditures for mandatory relocations will be about $6 to $7 million annually from 2024 through 2027.

Project descriptions, scopes, estimated costs, and in-service dates for specific mandated relocation projects are provided in Section VI of Attachment D. Greater details on the mandated relocation projects are also provided in Attachment E. Attachment F reports the total capital expenditure forecast for mandated relocation activities through December 2027. Attachment H shows the development of the 2023 revenue requirements for DIMP and mandated relocation activities, based on the capital expenditures referenced in Attachment F.[31]

VII. Compliance with Commission Orders and Statutes

A. GUIC Rider Promotes Safety and Reliability and is in 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. As the Commission has recognized, by proactively addressing system risks, the Company can systematically and efficiently conduct critical work. Indeed, working from a proactive stance allows the Company to take advantage of improved economies of scale, engage in

[30] About 5 percent for 2022 and about 3 percent for 2023.
[31] Mandated relocations are shown with DIMP in Attachments H, O, and P.

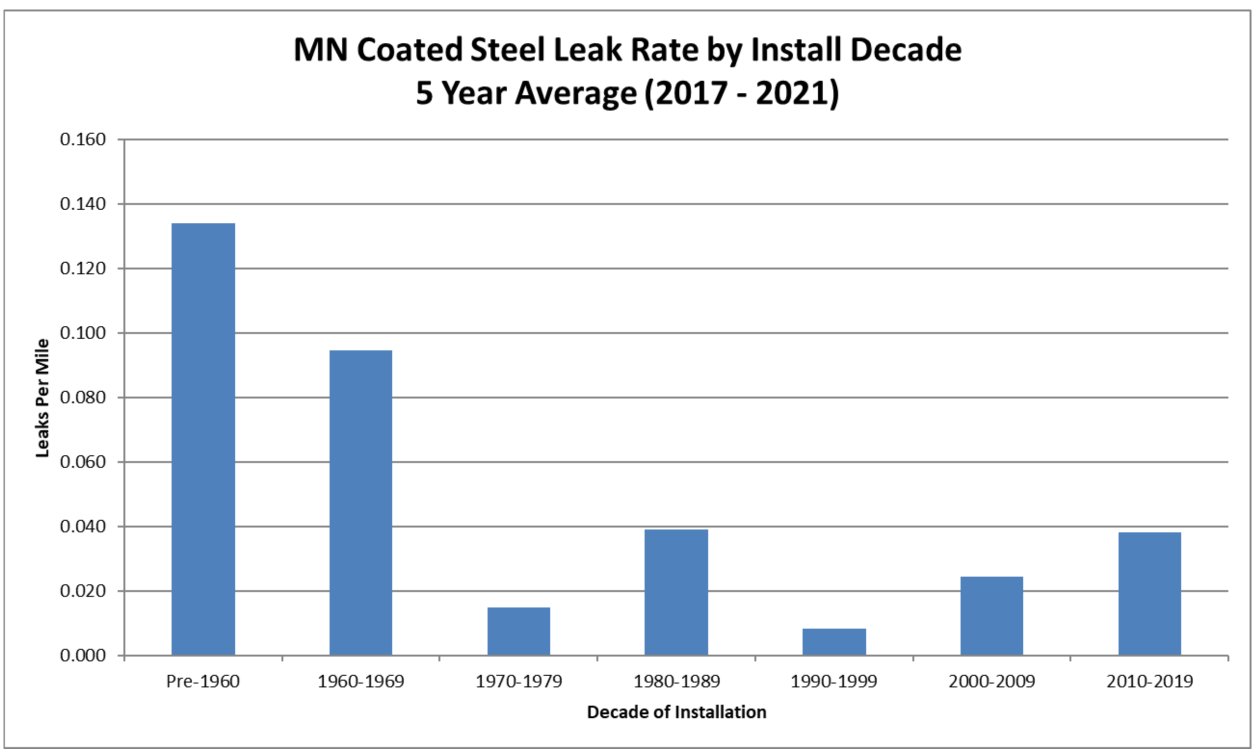
regional planning, minimize inconvenience to impacted communities, and efficiently deploy resources.

The public and customer benefits of increased safety and reliability that are delivered through integrity management project work are significant and ongoing, but continued efforts are needed. For instance, the needs of our aging infrastructure, particularly in densely populated areas, are addressed through our integrity management work. Thus, integrity management project work reduces the risks of major catastrophes in the event of a failure.

1. *Addressing Aging Assets*

Federal regulation requires pipeline operators to assess the integrity of their pipelines based on 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. A demonstration of this fact is shown in Figure 4 below. In this figure, leak rates per mile are shown for each decade of installation for our coated steel distribution pipelines.

Figure 4
Coated Steel Leak Rate by Install Decade
Five-Year Average

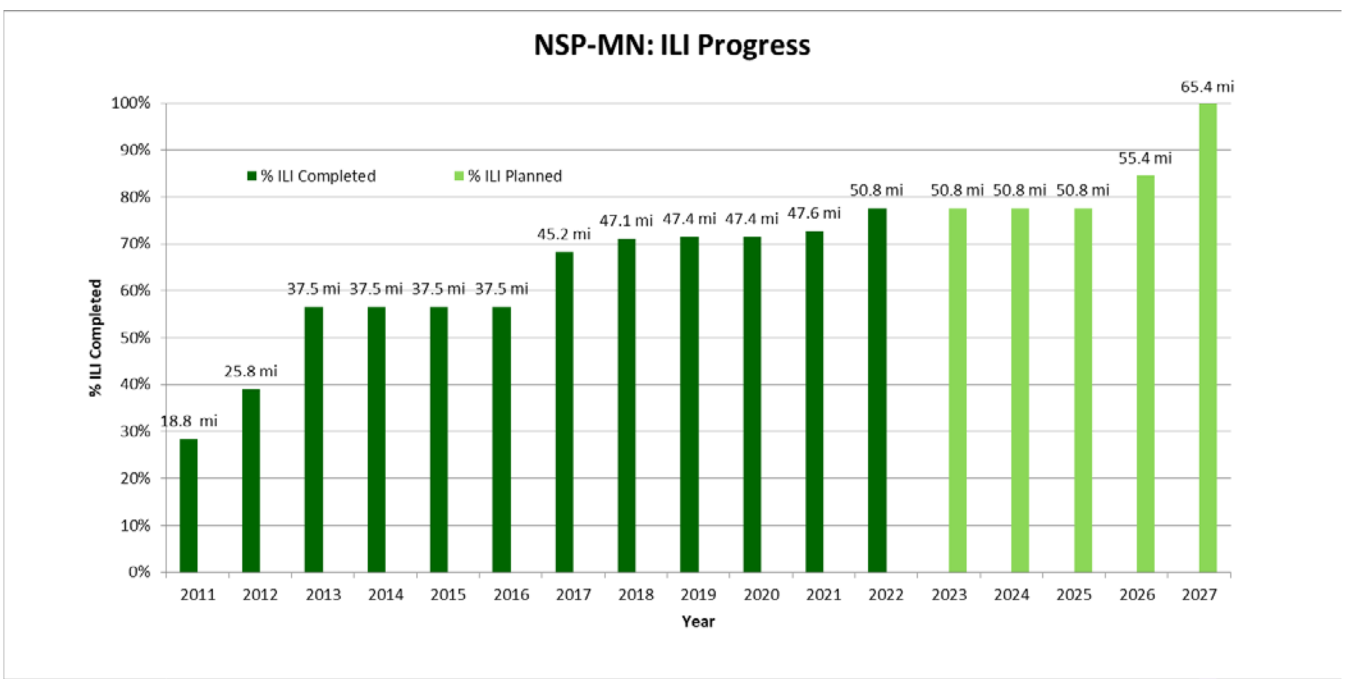


As can be seen, the leak rate for pipe installed in more recent decades is consistently lower than the leak rate for pipe installed earlier. While age alone does not indicate an imminent risk of failure, it is a predictive factor, and we must address risks posed by legacy construction techniques and materials. Leak rates for steel installed in 2020 and 2021 were not included in the figure above, as a five-year average will not be available until 2026. There were zero underground, non-excavation damage leaks recorded for steel installed in 2020 and 2021, corresponding to a two-year leak rate of zero leaks per mile.

To assess aging gas transmission assets, the Company primarily uses 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 the capabilities of available ILI tools. For example, the same ILI tool cannot be used on the entire length of a pipeline if the pipe diameter varies.

As shown in Figure 5 below, approximately 78 percent of the Company's gas transmission system that is planned to be assessable using ILI tools has been assessed. The Company's current assessment plan projects 100 percent of transmission pipelines that are feasible to be assessed by ILI tools will be ILI compatible by 2027. The Company has started utilizing robotic ILI tools which has expanded the transmission pipelines that can be assessed by ILI.

Figure 5
Transmission System ILI Assessment Progress[32]



[32] This chart does not include recently installed pipelines that are not yet due for their baseline assessment after being placed in-service.

2. *Safety and Population Density*

Many communities with older gas utility assets have grown significantly since the gas system in that area was initially built. Increased population density brings with it a higher risk of catastrophic consequences in the event of a failure. Population density is a critical focus of determining the criticality of pipeline work and is a factor in our risk modeling processes that help us prioritize work in high-density areas.[33] 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.

3. *Risk Assessment Methodology*

The Company evaluates the threats to our pipeline that may pose a safety or reliability risk. Pipeline asset information from existing records, operating data, and input from subject matter experts is initially used to identify events or conditions that could cause or increase the likelihood or consequence of pipeline failure. 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. The Company provides detailed explanations of our risk assessment processes in Attachments C and D.

The Company continues to assess our assessment processes to ensure that they are as useful as possible. The actual results of the risk assessments can be found in Attachments C2, D2(a), and D2(b).

B. GUIC Rider Activities are Reasonable and Prudent

The GUIC statute requires that our annual filing include information regarding the reasonableness and prudency of our integrity management project costs incurred.[34] Through stringent oversight processes and a contract and charge review process, the Company can ensure that costs are tracked and are reasonable in comparison to forecasted amounts. The Company looks for many opportunities to control costs and the following discussion will highlight these efforts undertaken by the Company to ensure the reasonableness and prudency of our integrity management project costs.

The Company believes integrity management project 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. Rider

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[33] High-density areas are also referred to as high consequence areas in PHMSA guidelines.
[34] Minn. Stat. § 216B.1635 subd. 4(2)(iv).

recovery also provides additional certainty by allowing the Company to develop multiyear programs of work that are more comprehensive and cost effective, which can deliver cost savings over time through more efficient work planning. 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.

1. Forecasting

Expenditures for integrity management projects must successfully pass through the Company's capital and O&M budgeting process, which is approved by Company officers and the board of directors. The Company leverages experience with assessments and repairs to assist in developing budgets for future work. Additionally, the Company's 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.

While the Company has strict cost controls in place to ensure that costs are prudently incurred, actual work requirements may cause actual costs to be either higher or lower than initial forecasts. To the extent actual costs are higher, this should not disqualify the additional costs from being considered reasonable, prudent, and eligible for GUIC Rider recovery consideration. The recovery of projects costs, whether in base rates or through a rider, depends on the prudency of those costs rather than the accuracy of an initial forecast. The Commission has previously concluded that "cost overruns can be prudently incurred" and that the "Commission will therefore permit utilities to seek higher recovery levels in future proceedings, with proper documentation and explanation in their rider filings."[35]

Beyond being consistent with longstanding Commission practice and precedent, allowing the Company to true-up GUIC Rider costs if costs differ from initial forecasts, is also good policy. Utilities should be encouraged to provide forecasts that are as accurate as possible, given the best information available at the time of the forecast and based on the expertise and judgment of their engineering and project teams. This promotes transparency and predictability when it comes to the costs (and ultimately the rates) associated with these projects. Adopting a bright-line rule with

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[35] *In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota-Iowa 345 kV Transmission Line Projects in Jackson, Martin, and Faribault Counties*, Docket No. ET-6675/CN-12-1053, at 6 (November 25, 2014).

respect to any costs above a utility's forecast—whether due to permitting delays, weather, or any other factor beyond a utility's control—would distort utility incentives around forecasting accuracy. Specifically, it would create significant incentives for utilities to adopt more conservative approaches to forecasting project costs to avoid disallowances for the sole reason that actual costs exceeded the forecast.

2. *Cost Controls*

The Company's gas business unit monitors capital expenditures to ensure that authorized projects align with the established budget to achieve the lowest reasonable and prudent cost. On a monthly basis, budget to actual spend is compared and financial forecasts are updated for programs and projects.

Integrity management 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[36] are awarded on a documented competitive basis.[37] In the limited circumstances where a competitive process is not required, written justification and director level authorization from the business area and the Company's supply chain department is required.[38]

Furthermore, where practical, the Company establishes bid-unit contracts for activities that are reproducible. Contracts are awarded to the vendors that provide the best 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.[39]

Aging infrastructure across the country has resulted in many gas operators implementing multi-year replacement programs. This has resulted in heavy competition to secure specialized equipment, engineers, and construction crews required for renewal work. The contractors that 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

[36] Including cumulative amounts in multi-year agreements.
[37] 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.
[38] Some examples of situations where a competitive bid would not be used include emergency work and the absence of competitive firms.
[39] 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.

end, we have invested not only in robust supply chain procedures, but also in human resources, including engineers and construction crews.

3. *Oversight Methods and Contract/Charge Review*

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 integrity management projects. We review actual overall capital spending in comparison with forecasted spending monthly and at year-end.

The Company's Rider Review Committee (RRC) reviews projects included in our various rider recovery mechanisms. For the GUIC Rider, the RRC is tasked with ensuring that modifications made to integrity management projects met the intent of the GUIC statute and Company's GUIC Rider. The RRC process is 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 recovered through 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 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. Also, using 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, MNOPS conducts scheduled field and records inspections throughout our 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 51 planned inspections and evaluated 26 unplanned events in 2022. Inspections included a review of field locations and records, operations and maintenance procedures, safety-related concerns, and outages.

Integrity management projects have internal personnel identified that oversee the 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.

As part of our cost review process, all capital and O&M transactions identified as integrity management-related are now individually reviewed monthly and require management approval. We believe this enhanced examination of individual transactions and subsequent validation that each transaction relates to a master service agreement involving Minnesota-specific work and 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 projects. In these instances, the Company seeks and relies on outside assistance.

The Company uses internal resources when the work falls within the Company's core competencies. External resources are used when the Company has neither the internal expertise nor the equipment available to perform the specialized aspects of a project. By outsourcing the specialized portion of work, 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:

- Work is completed and invoiced in a timely manner and invoicing is accurate.
- Contractor safety performance is acceptable; damages to existing Company and customer facilities and customer outages are reported accurately and resolved in a timely manner.
- 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.

C. GUIC Rider Costs are Incremental

The projects for which recovery is being requested in this filing are incremental expenditures not included in neither the Company's last natural gas rate case nor the pending natural gas rate case. The federal Call to Action leading to the emergence of TIMP and DIMP post-dated the Company's last approved 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 approved rate case.[40] There have been no foundational changes to TIMP and DIMP that would counsel toward a different result. As such, the Commission should again conclude that the projects that are the subject of this petition were not requested in our previous natural gas rate case, and—in that way—are appropriate for rider recovery.

In addition, as was discussed previously, all GUIC Rider work completed before December 31, 2021 has been included as a part of our pending natural gas rate case. While costs incurred before this date are included as a part of this request, we will adjust our GUIC Rider revenue requirement request at the resolution of that case to remove any costs rolled in to the newly established base rates.

We also note that in previous GUIC Rider filings, we included an adjustment to account for the impact of projects included in our previous base rates that were subsequently replaced as a part of our GUIC work. We are no longer including this adjustment. As a part of our pending rate case, we have implemented interim rates. The amount of assets included in those interim rates (and that will be included in base rates if the case is approved) impacted by retirements related to GUIC work is minimal and the adjustment is not currently needed.[41]

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[40] *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.

[41] If for some reason our rate base proposal is not accepted by the Commission, we will make an adjustment to our request in this docket to remove the impact of retirements once again.

Attachment J includes the calculation of our estimate of annual integrity management project-related retirements from 2012 through 2023. In conjunction with the information contained in Table 8 in Section VII.F. 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 2021. For retirements in 2022 and 2023, complete actual data was not yet available.

1. *Internal Capitalized Costs*

While the Company maintains that recovery of internal capitalized costs[42] is allowable as a part of our GUIC Rider requests and the costs are legitimate for our GUIC work, we understand that the Commission does not agree with this position. Since the Commission has denied recovery of these costs in their last several Orders in GUIC dockets, we have removed these costs from this year's proposal. We do reserve the ability to reassess the inclusion of these costs in future requests.

D. 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 2021 through 2027 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."[43]

E. Estimated Revenue Requirement

Table 7 below presents Xcel Energy's estimated 2023 GUIC Rider revenue requirement of $37.5 million for TIMP, DIMP, and Mandatory Relocation activities.

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[42] Overhead, other, and transportation costs
[43] *See* ORDER APPROVING RIDER WITH MODIFICATIONS, Docket No. G002/M-14-336 (January 27, 2015) at page 7.

Capital-related revenue requirements and O&M expenses total $44.6 million and $0.8 million, respectively.[44]

Table 7
2022-2023 GUIC Rider Revenue Requirement ($ Millions)

	2021 Actuals[45]	2022 Current Forecast	2023 Forecast
Capital-Related Revenue Requirement			
TIMP	$13.7	$13.7	$13.7
DIMP	16.5	22.2	26.0
Mandated Relocations	0.6	2.5	4.9
Total	$30.8	$38.4	$44.6
O&M Expenses			
TIMP	$0.6	$0.1	$0.6
DIMP	0.8	0.2	0.3
Total	$1.4	$0.3	$0.8
GUIC Retirement Revenue Credits	$(0.7)	$0.0	$0.0
Annual Internal Capitalized Costs	(0.4)	(0.4)	(0.8)
MAOP Projects at Long-term Debt Rate of Return	(1.7)	(1.7)	(1.8)
Low-Risk Infrastructure	(0.0) [46]	(0.0) [47]	(0.1)
Revenue Requirement in Base Rates	(0.8)	0.0	0.0
Prior-year Disallowances	(3.1)	(4.0)	(5.1)
Revenue Requirement Subtotal	$(6.7)	$(6.2)	$(7.8)
True-up Carryover	0.2	1.2	-
Total GUIC Rider Revenue Requirement	**$25.8**	**$33.8**	**$37.5**

In this request, we are no longer including an adjustment to remove the GUIC Retirement Revenue Credits and Recovery in Base Rates for 2022 and 2023 that was included in prior GUIC Rider petitions. As noted earlier in this petition the Company filed a gas rate case on November 1, 2021. In our rate case filing and interim rate petition, all costs associated with these two line items have been removed to reflect recovery in the GUIC rider or the retirements have been reset to the appropriate test year level. With interim rates being put in place on January 1, 2022, including these two adjustments in this request is no longer necessary. If a Commission decision results in this needing to be reconsidered, we will do so in a future submittal in this docket.

[44] Numbers in this sentence do not include reductions related to regulatory treatment. Those amounts are shown as separate adjustments in Table 8.
[45] Amount verbally approved during Commission's October 27, 2022 Agenda Meeting
[46] About $-8,000.
[47] About $-40,000.

F. Estimated Costs and Salvage Value

Capital expenditure estimates from 2012 through 2027 total approximately $153 million for TIMP and $419 million for DIMP, reflecting an estimated total of about $572 million. Distribution mains and services are depreciated using a composite depreciation rate of 2.34 percent and transmission mains are depreciated using a depreciation rate of 1.51 percent. The Company's depreciation calculations assume an average remaining life of 38.77 years[48] and a net salvage rate of negative 22.85 percent for distribution mains and services and average remaining life of 63.30 years[49] and net salvage rate of negative 15 percent for transmission mains. The Company's annual cost and salvage estimates related to actual and planned integrity management project capital investments are shown in Table 8 below.

Table 8
GUIC Capital Expenditures and Net Salvage: 2012-2027 ($ Thousands)

	TIMP				**Mandated**	
Year	Transmission	Distribution[51]	Total	**DIMP[50]**	**Relocates**	**Total**
2012	$95	$0	$95	$83	$0	$178
2013	65	9,497	9,562	343	0	9,906
2014	(24)	11,651	11,628	240	0	11,868
2015	1,073	17,937	19,010	10,011	0	29,021
2016	4,556	14,196	18,752	13,227	0	31,978
2017	6,191	600	6,791	13,444	0	20,235
2018	8,763	(33)	8,730	36,974	0	45,704
2019	18,603	0	18,603	24,409	0	43,012
2020	28,961	0	28,966	28,441	0	57,406
2021	3,613	0	3,613	51,280	12,915	67,808
2022	4,558	0	4,558	48,432	19,839	72,829
2023	10,210	0	10,210	27,054	13,773	51,037
2024	4,166	0	4,166	27,249	13,209	44,625
2025	4,565	0	4,565	26,559	11,859	42,984
2026	3,557	0	3,557	27,276	12,181	43,013
2027	4,538	0	4,538	28,048	12,904	45,490
Total	**$103,491**	**$53,849**	**$157,341**	**$363,072**	**$96,679**	**$617,091**
Salvage Rate[52]	-15.00%	-22.85%		-22.85%	-22.85%	
Net Salvage	**$(15,524)**	**$(12,305)**	**$(27,828)**	**$(82,962)**	**$(22,091)**	**$(132,881)**

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48 Composite average service life for distribution mains and services is 51.42 years.
49 Average service life for transmission mains is 75 years.
50 Includes approximately $445,000 in software in 2016,
51 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.
52 Depreciation lives and salvage rates approved on July 12, 2022 in Docket No. E,G002/D-21-584. The depreciation lives and salvage rates can be found in Attachment L.

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

On October 4, 2022, a settlement of the Company's most recent gas general rate case was reached by all parties.[53] The settlement includes total related revenue of $806.430 million for the test year ending December 31, 2022. Excluding $5.36 million of other operating income for customer-related charges not included in retail rates and $558.25 million for gas purchase and transportation charges, the total settled base retail revenue was $242.82 million. The revenue collection estimates using the sales information based on a proposed 2023 GUIC Rider rate generates $37.5 million of GUIC Rider-related revenues from March 1, 2024 to February 28, 2025. The GUIC Rider revenue estimates reflect 15.5 percent of the base revenues of $242.82 million included in the settlement for the pending natural gas rate case.

For more details on the expected 2023 revenues in relation to the last rate case, please reference Attachment M.[54]

VIII. GUIC Rider Factor Calculations, Timing of Implementation, Tracker Accounting, and Tariff Sheet

A. Revenue Requirements and Proposed 2023 GUIC Rider Rate Adjustment Factor

In this section, we provide the 2023 revenue requirement and 2023 rate adjustments factor calculations for the proposed GUIC Rider.

1. *Revenue Requirement*

The projected 2023 revenue requirement proposed for recovery through the 2023 GUIC Rider adjustment factors from Minnesota gas customers is $37.5 million. The proposed revenue requirement includes recovery of capital property taxes, current and deferred taxes, and book depreciation.

Attachments G and H summarize the projected revenue requirements for the TIMP, DIMP, and mandated relocation projects respectively. The projected GUIC Rider revenue requirements for 2021 through 2027 are summarized in Attachment O to this filing. The supporting revenue requirements and projected 2021 through 2023 GUIC Rider Tracker activity are provided in Attachment P. Attachment Q provides descriptions of the rate base and return calculation categories included in Attachments G and H.

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[53] See Docket No. G002/GR-21-678.
[54] Filed in Docket No. E,G999-PR-21-4.

2. Proposed 2021 and 2022 Rates and Carryover Balance

The Commission recently verbally approved our 2021 GUIC Rider request.[55] Our 2022 GUIC Rider request is still pending in front of the Commission.[56] The Company is currently recovering its GUIC Rider revenue requirements based on the rate factors approved in our Company's 2020 GUIC Rider request approved by the Commission in their May 3, 2021 ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS.[57] We will be implementing new rates based on the verbally approved 2021 GUIC Rider request soon after the Commission's Order is issued. For illustrative purposes in this docket, we have assumed that the 2020 carryover balance, 2021 revenue requirements, and 2022 revenue requirements will be recovered from March 2023 through February 2024. The presumed rate factors are shown in Table 10 below.

3. GUIC Rider Rate Adjustment Factors

The Company's GUIC Rider adjustment factor rate design currently provides for rates specific to five customer groups (residential, commercial firm, commercial demand billed, interruptible, and transportation). The revenue requirement is allocated to classes in the same manner as revenues were apportioned in our 2010 natural gas rate case,[58] consistent with the Commission's Orders in our 2015 through 2020 GUIC Rider dockets. Currently, the transportation class is apportioned less GUIC Rider revenue requirement than their corresponding demand or interruptible class on a per therm basis. As we did in last year's petition, the Company is proposing apportionment that combines transportation customers with their respective firm or interruptible sales classes. This aligns with our rate design goal to remain indifferent to a customer's choice of sales or transportation service. This proposed apportionment is consistent with the apportionment used in our 2022 GUIC Rider request. Further, the Company is proposing to utilize revenues that were included in the recently filed October 4, 2022 Settlement Agreement in the Company's current natural gas rate case.[59] The Company will update this apportionment once the Company files its final rates compliance filing in the current rate case. Table 9 below compares the current and proposed revenue apportionment.

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[55] Approved during the Commission's October 27, 2022 agenda meeting in Docket No. G002/M-20-799 and G002/M-21-765, respectively.
[56] Docket No G002/M-21-765.
[57] Docket No. G002/M-19-664.
[58] Docket No. G002/GR-09-1153.
[59] Docket No. G002/GR-21-678.

Table 9
Current vs. Proposed Revenue Apportionment

Class	Current Allocator	Class	Proposed Allocator
Residential	67.2244%	Residential	64.0327%
Commercial Firm	21.2597%	Commercial	23.8945%
Commercial Demand-Billed	2.1010%	Demand (including Firm Transport)	6.5583%
Interruptible	5.6521%	Interruptible (including Interruptible Transport)	5.5144%
Transport	3.7628%	N/A	N/A
Total	**100%**	**Total**	**100%**

Proposed class factors are calculated by dividing the class revenue responsibility by 12 months of weather-normalized actual sales data. The GUIC Rider adjustment factor is included in the Resource Adjustment line on customer bills. Consistent with our 2022 GUIC Rider filing, we are using actual sales data in our 2023 GUIC factor calculation for this request.

The 2022 and 2023 GUIC Rider adjustment factor calculations are shown in Attachment R. Table 10 below shows the currently approved GUIC Rider adjustment factors, proposed 2022 factors, proposed 2023 factors, currently approved classes, and proposed classes.[60]

Table 10
Proposed GUIC Rider Adjustment Factors (Dollars per therm)

Current Classes	Current Factors	2022 Proposed Classes	2022 Proposed Factors[61]	2023 Proposed Factors[62]
Residential	$0.033864	Residential	$0.0588859	$0.062247
Commercial Firm	$0.018572	Commercial Firm	$0.030854	$0.038502
Commercial Demand Billed	$0.014666	Demand	$0.004626	$0.005892
Interruptible	$0.010591	Interruptible	$0.014235	$0.015029
Transportation	$0.001602			

[60] 2021 Factors were recently verbally approved by the Commission during their October 27, 2022 agenda hearing. The final approved factors will be filed in a Compliance Filing no more than 10 days after the Order is issued.
[61] Assumes the 2022 GUIC Rider revenue requirement is recovered March 1, 2023 through February 28, 2024.
[62] Assumes the 2023 GUIC Rider revenue requirement is recovered March 1, 2024 through February 28, 2025.

The residential bill impacts under each factor are listed in Table 11 below.

Table 11
Monthly Residential Bill Impacts

	Impact of Current Factors	Impact of 2022 Proposed Factors	Impact of 2023 Proposed Factors
Monthly Bill Impact	$2.47	$4.29	$4.53
Incremental Bill Impact Change as % of Total Bill		2.30%	0.31%

B. Timing of 2023 GUIC Rider Factor Implementation

We request approval to implement GUIC Rider factors in this annual report, effective March 1, 2024, pending review and approval by the Commission. The factor calculations assume that the 2023 GUIC Rider costs are recovered starting March 1, 2024 through February 28, 2025. Our proposed timing for 2023 GUIC Rider recovery is consistent with the timing of recovery we proposed in our 2021 and 2022 GUIC Rider filings. This has the added benefit of eliminating the need to prorate our ADIT calculation, as recovery will not start until after the end of the cost period. In addition, the proposed timing will allow us to collect 12 months of GUIC Rider costs over 12 months of bills, which allows for more stable factors.

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 mandated natural gas infrastructure investments. It also maintains appropriate regulatory protections and oversight by allowing the Commission and other state agencies the time required to audit and review costs sought for recovery, thus ensuring that any regulatory adjustments will be recognized and implemented appropriately.

C. GUIC Rider Tracker Account

To ensure that customers are not under or overcharged, we record the actual GUIC Rider revenue recovery and requirements in a tracker account as the accounting mechanism for eligible integrity management project costs. As revenues are collected from retail customers each month, the Company tracks the amount of recovery under the GUIC Rider 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 considered by reducing the subsequent year's rate factor calculation. Under-recovery is similarly considered 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 integrity management 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 Rider activity estimated in 2021 and 2022 are shown on Attachment R within the carryover rollforward section. Attachment S includes a tracker that presents revenue requirement, rates, and recoveries within the same page to provide a clearer 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 2023 GUIC Rider factors can be found in the clean and redline formats of Tariff Sheet No. 5-64 provided in Attachment T.

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 Rider 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; and $x.xxxx per therm for Interruptible customers.

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

IX. 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."[63]

For our 2023 GUIC Rider request, the Company is using the return on equity, capital structure, and rate of return agreed to in the unanimous settlement in our pending natural gas rate case for recovery purposes in this GUIC Rider request. In the settlement, parties agreed to a return of equity of 9.57 percent, a cost of short-term debt of 0.94 percent, and a cost of long-term debt of 4.13 percent.[64] When paired with the settled-upon capital structure from the rate case, we propose using an overall rate of return of 6.97 percent for this request. Table 12 below shows the capital structure ratios and costs proposed in the rate case and the calculation of the overall rate of return.

Table 12
Recommend Capital Structure, Costs, and Rate of Return

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	0.61%	0.94%	0.01%
Long-Term Debt	46.89%	4.13%	1.94%
Common Equity	52.50%	9.57%	5.02%
Total	100.00%		6.97%

While the settlement has not been approved by the Administrative Law Judge or the Commission, we believe it is possible that the rate case will be resolved before the Commission decides on our 2023 GUIC Rider request. As such, we will be able to adjust this proposal as necessary to reflect the Commission's final decision in the rate case since there are aspects of both the rate case and this GUIC Rider request that will need to be adjusted to ensure no double recovery.

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

[64] Recommended return on equity and long-term and long-term debt are discussed in Direct Testimony of Company Witness Mr. Dylan D'Ascendis and recommended capital structure, costs, and rate of return discussed in Direct Testimony of Company Witness Mr. Paul Johnson in Docket No. G002/GR-21-678

X. GUIC RIDER PERFORMANCE METRICS

The development of performance metrics has been an ongoing effort since our 2016 GUIC Rider filing. This effort started at the behest of the Commission. In its August 18, 2016 Order,[65] 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 a 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 met with stakeholders on several occasions to understand their needs and develop a set of metrics acceptable to the Commission. The Commission recently verbally approved a set of metrics that have been developed through this process. Table 13 below shows the TIMP and DIMP performance metrics verbally approved by the Commission.[66] Attachment U further discusses this set of the metrics to measure the appropriateness of GUIC expenditures.

Table 13
Recommended Performance Metrics

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
TIMP	Transmission Pipeline Integrity Assessments	Estimated versus actual costs per project	Anomalies repaired by type
	ASVs and RCVs	Estimated versus actual costs per project	Reduction in response time per project
	Programmatic Replacement and MAOP Remediation	Estimated versus actual costs per project	Percentage of high/medium risk projects system-wide
DIMP	Poor Performing Main Replacement	Poor performing main replacement unit cost (per foot)	Leak rate by vintage

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[65] ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES, Docket No. G002/M-15-808.
[66] The metrics for Casing Renewals and Distribution Valve Replacement were verbally approved during the Commission's October 27, 2022 agenda meeting for Docket No. G002/M-20-799. We note that the Commission also verbally approved a requirement to provide more details on the cost effectiveness of our casing renewal projects as compared to other remediation options. The Company will submit this information with our Reply Comments in this docket.

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
	Poor Performing Service Replacement	Poor performing service replacement unit cost (per foot)	Leak rate by vintage
	Distribution Pipeline Integrity Assessment	Estimated versus actual costs per project	Anomalies repaired by type
	Distribution Valve Replacement	Estimated versus actual costs per project	Percentage of inoperable valves replaced
	Distribution Valve Replacement (New Valves Only)	Estimated versus actual costs per project	Reduction in potential customer outages
	Sewer and Gas Line Conflict Remediation	Inspection Unit Cost	Percentage of Total Premises Inspected
TIMP/DIMP	Casing Renewals	Estimated versus actual costs per project	Percentage of casing projects planned for the year completed Total number completed compared to Total number requiring remediation, since inception
	Mandated Relocations	Estimated versus actual costs per project	Number of planned mandated relocations versus actual relocations

XI. Status of GUIC Statute

As mentioned earlier, the GUIC Statute is set to expire June 30, 2023. The Statute does not spell out exactly what should take place after this date and therefore there are at least two open questions:

- After June 30, 2023, what happens to pending GUIC requests? and
- After June 30, 2023, what happens to recovery of GUIC-related costs?

On the first question, the Company believes that the Commission is free to consider GUIC requests at any time so long as they are filed before the expiration of the statute. If June 30, 2023 was the date after which no further GUIC decisions could be made by the Commission, then that would suggest to the Company it should not agree to time extensions in this docket in an effort to reach a final Commission decision by June 30, 2023. While a Commission decision by June 30, 2023 is perhaps possible, it does not afford the Commission and stakeholders the time it customarily takes to evaluate GUIC requests. Further, we believe we are authorized to request approval of costs through the end of the 2023 and continue to use the GUIC Rider mechanism until all our GUIC costs through 2023 are recovered.

In comments in our 2022 GUIC Rider Docket, the Department stated the following:

> *Under such a course of events [i.e., the expiration of the GUIC statute], Xcel could file a GUIC Rider petition for recovery of 2023 costs in next year's filing; the subsequent year, the Company could simply file a true up of 2023 expenses. In this scenario, the GUIC rider would remain in place for 2024, but would only reflect any 2023 over-or-under recoveries. All post-2023 expenses that might otherwise be recorded in the Company's GUIC tracker would instead simply be moved to its tracker for general rates.*[67]

These comments seem to support our interpretation that the Commission can consider requests for 2023 recovery after the June 30, 2023 expiration of the statute, and that we can request and if authorized, recover, the full scope of 2023 GUIC Rider costs with this filing. Furthermore, the GUIC Rider can remain in place beyond the end of 2023 to finish recovery of the 2023 costs as we have proposed here. As such, we ask that the Commission authorize recovery of our 2023 costs over our proposed timeline.

We think the second question is an important policy matter for stakeholders to discuss. As has been highlighted throughout this request, our TIMP and DIMP work completed over the years allows the Company to continue the safe and reliable operations of our gas system. The GUIC Rider has been integral in ensuring timely recovery of the cost of this work, which provides the Company the resources necessary to ensure that the work is completed in the timeframes required by federal and state rules or requested by municipalities. The GUIC has also been an effective tool in helping the Company to avoid the need to file natural gas rate cases in the past.

In last year's GUIC, Fresh Energy suggested that in light of the expiration of the GUIC statute, the Company should file plans to wind-down the TIMP and DIMP work traditionally recovered through the GUIC. In the natural gas rate case settlement, we agreed to address Fresh Energy's concerns by providing an estimate of TIMP and DIMP costs for the next five years and a narrative of the type of projects included in the cost estimates and the extent to which it would be possible to delay or cancel the expected projects while continuing compliance with federal and state pipeline safety laws and regulations, and identification and replacement of High and Medium risk infrastructure to reduce risk and maintain appropriate levels of work to support system safety and integrity. The Company agreed to provide this information in its annual GUIC petition starting next year.

There are three potential paths forward for the usage of the GUIC Rider beyond 2023. The first is the legislature passing a change to the GUIC Rider statute that would explicitly authorize it beyond 2023. Under this scenario the Company would

[67] *See* Page 5 of the Department's July 11, 2022 Response Comments in Docket No. G002/M-21-765.

continue to file GUIC Rider filings in future years as we have been doing for the last several years.

However, if no legislative action is taken to extend the expiration date in statute, we believe the Commission should consider allowing for the continued use of the GUIC Rider beyond the expiration date of the statute. The Commission allowed this type of recovery with the State Energy Policy (SEP) Rider after its repeal. We believe the importance of the TIMP and DIMP work and the efficiency provided by the GUIC Rider proceedings supports the continued use; and the analysis described immediately above that the Company agreed to provide to Fresh Energy will help to inform the reasonableness of the investments.

If recovery through the GUIC Rider is no longer possible, either through statutory authorization or by Commission approval, then the Company will need to include these costs in future general rate case proposals, and it will likely lead to more frequent rate requests from the Company.

CONCLUSION

The Company implemented transmission and distribution integrity management plans to be able to follow evolving 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 2021 and 2022 investment that has not yet been recovered and outline our proposal to recover the 2023 investments. Xcel Energy respectfully requests that the Commission, consistent with its previous GUIC Rider Orders, grant recovery of gas utility infrastructure costs through the GUIC Rider and approve the proposed 2023 GUIC Rider factors.

Dated: November 1, 2022

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matt Schuerger	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 2021, UPDATED COSTS FOR 2022, REVENUE REQUIREMENTS FOR 2023, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-22-___

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. 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 2023 Transmission and Distribution Integrity Management Programs costs pursuant to Minn. Stat. § 216B.1635, which permits a utility to petition the Commission for recovery. The Company also seeks approval of its 2023 GUIC Rider adjustment factors and its proposed capital structure and ROE for 2023.

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.	The filing date of this Petition, November 1, 2022 is 486 days before our proposed implementation date of March 1, 2024. We discuss the proposed implementation date in Section II.C of our Petition. The report is for a one-year forecast period from January 1, 2023 through December 2023.
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.	Details on each TIMP project can be found in Attachments C and C1. Details on each DIMP project can be found in Attachments D and D1. Details on the Mandated Relocation projects can be found in Attachments D and E.
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:	The filing date of this Petition is November 1, 2022. Our 2022 GUIC Rider Petition was filed on October 29, 2021.

Compliance Matrix

Petition Requirements	Reference
(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;	Details on each TIMP project can be found in Attachments C and C1. Details on each DIMP project can be found in Attachments D and D1. Details on the Mandated Relocation projects can be found in Attachments D and E.
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	The government entity ordering each project and purpose for project for each TIMP project can be found in Attachment C1. The same information can be found for each DIMP project in Attachment D1 and the Mandated Relocation projects in Attachment E.
(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;	A description and quantification of the assets retired because of GUIC work is included in Attachment J. The estimated salvage value of our GUIC projects is shown in Table 8 in Section VII.F of our Petition.
(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;	Actual and estimated cost information and a discussion of the reasonableness and prudence of our TIMP projects can be found in Attachment C. The same information can be found for our DIMP projects can be found in 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;	The public interest support for our request is found in Section VII.A of our Petition. The revenue requirements and proposed GUIC Rider Rate Adjustment Factors are discussed in Section VIII.A of our Petition. Details of our revenue requirement request can be found in Attachments F,G,H,K,O,P,Q,R.

Compliance Matrix

Petition Requirements	Reference
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	Details of the magnitude and timing of known future TIMP projects through 2022 can be found in Attachment C1. A higher-level summary of the magnitude and timing of costs through 2026, by program, can be found in Attachments C and Attachment F. Details of the magnitude and timing of our DIMP projects can be found in Attachment D1, and higher-level information of magnitude and timing can be found in Attachments D and Attachment F. Details of the magnitude and timing of our Mandated Relocation projects can be found in Attachments D and E, and higher-level information of magnitude and timing can be found in 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; (viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and	A comparison of our requested GUIC Rider recovery in relation to the base revenues and capital expenditures agreed to in the pending general natural gas rate case settlement agreement is shown in Section VII.G of our Petition and Attachment M.

Compliance Matrix

Petition Requirements	Reference
(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.	The Company last filed a general rate case in 2022. The Company has reached a settlement agreement with parties, but that settlement has not yet been approved by the ALJ or the Commission. The Commission last approved base rates in a rate case filed in 2009 with a 2010 test year. We note this Commission approval in Section VII.G of our Petition. We discuss our reasons for seeking recovery through the GUIC Rider mechanism in Sections III, VII.A, VII.B, and VII.D of our Petition.
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.	We are requesting the rate of return from the settlement agreement reached between the Company and parties in our current gas rate case. Please note that settlement agreement has not yet been approved. We discuss this in Section IX of our Petition.
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**	

Compliance Matrix

Petition Requirements	Reference
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.	We provide a discussion of performance metrics in Section X of our Petition. The Commission verbally approved the set of metrics proposed here during their October 27, 2022 agenda meeting. The results of the performance metrics are provided in Attachment U.
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.	The proposed customer notice for our 2023 request reflects this language. We show the proposed customer notice in Section VIII.D.2 of our Petition.
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**	
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.	The Company met with the Department, OAG, MPCA, and Commission staff on September 26, 2018 and August 27, 2019. We also had informal discussions with parties in late 2019/early 2020. We discuss the work done with parties in Section X of our Petition.

Compliance Matrix

Petition Requirements	Reference
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.	A discussion of each TIMP program is provided in Section IV of our Petition, with details of each project in Attachments C and C1. A discussion of each DIMP program is provided in Section V of our Petition, with details of each project in Attachment D and D1. A discussion of our Mandated Relocation program is provided in Section VI of our Petition, with details of each project in Attachments D and E.
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.	Not applicable for this filing. 12 months of weather-normalized actual sales data was used to calculate proposed rate factors.
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.	Required work related to Sewer and Gas Line Conflict remediation has been completed and no work is included in our 2023 GUIC Rider request.
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 True-up Report for 2017, the Forecasted 2018 Revenue Requirements, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER APPROVING RIDER RECOVERY WITH MODIFICATIONS **August 12, 2019 Docket No. G002/M-17-787**	

Compliance Matrix

Petition Requirements	Reference
15. The Commission directs Xcel, the Department, and the OAG to continue discussion on the establishment of performance metrics in future GUIC proceedings.	The Company met with the Department, OAG, MPCA, and Commission staff on September 26, 2018 and August 27, 2019. We also had informal discussions with parties in late 2019/early 2020. We discuss the work done with parties in Section X of our Petition.
16. In all future GUIC rider Petitions, Xcel must include the reporting required by Minn. Stat. § 216B.1635, subd. 4(2)(iii).	A description and quantification of the assets retired because of GUIC work is included in Attachment J. The estimated salvage value of our GUIC projects is shown in Table 8 in Section VII.F of our Petition.
17. In all future GUIC rider Petitions, Xcel must include only incremental rate base amounts in its GUIC rider rate base.	The costs removed from our GUIC Rider request to ensure that only incremental costs are included are discuss in Section VII.C of our Petition. Examples of adjustments include removal of internal capital costs, such as overheads and other costs.
18. Xcel must include, prior to applying its calculated property tax rate, only the incremental property tax expense amount for all GUIC years by adjusting the original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year.	With interim rates in place as a part of our pending gas rate case, this adjustment is no longer needed.
22. In all future GUIC filings, Xcel must include historical and projected GUIC revenue requirements, rates, and recoveries within a single tracker for each year.	This information is shown in Attachment R.
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 True-Up Report for 2018, the Forecasted 2019 Revenue Requirements, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS **January 9, 2020 Docket No. G002/M-18-692**	

Compliance Matrix

Petition Requirements	Reference
3. Xcel shall not apply prorated accumulated deferred income tax (ADIT) to rate base when it is not required by the Internal Revenue Service for normalization purposes.	As our requested recovery period begins after the end of our requested test year, there is no need to prorate ADIT. This issue is discussed in Petition, Section VIII.B.
5. Xcel shall use the most recent 12 months of actual natural gas sales to calculate the final GUIC rate.	12 months of weather-normalized actual sales data was used to calculate proposed rate factors. This is noted in Section VIII.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.
6. The Commission denies Xcel's request for a carrying charge in the GUIC tracker account.	Request does not include carrying charge.
7. Xcel shall remove and exclude from the GUIC rider costs related to low-risk infrastructure replacement that is not mandated by government regulations or public work requirements.	We removed all known low-risk infrastructure work from the 2018 through 2023 revenue requirements.
8. The return on the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel's weighted long-term cost of debt.	Our request includes an adjustment to limit the return on 2018 through 2023 capital costs for the MAOP program to the Company's weighted long-term cost of debt. The adjustment is reflected in the 2018 through 2023 regulatory treatment adjustments in Attachments O and P.

Compliance Matrix

<table>
<tr><th>Petition Requirements</th><th>Reference</th></tr>
<tr><td>9. Xcel shall remove the costs of Overhead, Transportation, and Other, totaling $8,157,695, from the GUIC rider.</td><td>Our request includes adjustments to remove the costs from revenue requirement calculations for 2023. The adjustments reflect the amount of overheads, transportation, and other costs removed from 2018 through 2022 GUIC projects.

The adjustment is reflected in the 2021 through 2023 regulatory treatment adjustments in Attachments O and P.

We discussed this in Section VII.C.1 of our Petition.</td></tr>
<tr><td>10. The Commission approves the following cost of capital for Xcel's 2019 GUIC Rider:
<table>
<tr><th></th><th>Capital Structure</th><th>Cost</th><th>Weighted Cost</th></tr>
<tr><td>Long-Term Debt</td><td>45.81%</td><td>4.75%</td><td>2.18%</td></tr>
<tr><td>Short-Term Debt</td><td>1.69%</td><td>4.31%</td><td>0.07%</td></tr>
<tr><td>Common Equity</td><td>52.50%</td><td>9.04%</td><td>4.75%</td></tr>
<tr><td>Rate of Return</td><td></td><td></td><td>7.00%</td></tr>
</table></td><td>Calculation of revenue requirements for 2020 through 2022 are based on this approved capital structure. For 2023, we use the agreed to capital structure included in the settlement agreement from our pending gas rate case. Issue is discussed in section IX of our Petition and shown in Attachment L.</td></tr>
<tr><td>11. Xcel shall exclude from its 2019 and future GUIC rider revenue requirements all costs related to emergency sewer-conflict work. Accordingly, Xcel shall adjust its 2019 GUIC rider revenue requirement to remove (1) $50,000 for these costs applicable to 2019, and (2) $371,364 for costs that were erroneously included in the rider in previous years.</td><td>An adjustment was previously included for our 2019 revenue requirement to reflect the removal of emergency sewer-conflict work. No adjustment is currently necessary as no emergency sewer work is included in our 2020 through 2023 requests.</td></tr>
<tr><td>14. Xcel shall continue to improve its risk assessment reporting in future GUIC filings, with the goal of providing better explanations of the Company's assets.</td><td>We discuss our continued improvement process for risk assessments in Section VII.A.3 of the Petition.</td></tr>
</table>

Compliance Matrix

Petition Requirements	Reference
15. Xcel shall provide consequence class information for both plastic and steel mains and services in future GUIC filings.	Consequence class information for mains and services is included in Attachments C, C2, D, and D2 and is discussed in Section VII.A.3 of the Petition.
16. Xcel shall develop full risk-assessment profiles for the TIMP Transmission Pipeline Assessment program and the TIMP Programmatic/MAOP Remediation program.	Full risk-assessments profiles are included for the TIMP programs. Issue is discussed in Section VII.A.3 of our Petition and information is shown in Attachments C and C2.
18. The Department and Xcel shall continue efforts to reach a consensus on establishing performance metrics in future GUIC Petitions.	We provide a discussion of performance metrics in Section X of our Petition. The Commission verbally approved the set of metrics proposed here during their October 27, 2022 agenda meeting. The results of the performance metrics are provided in Attachment U.
In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2019, Revenue Requirements for 2020, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS **May 3, 2021 Docket No. G002/M-19-664**	
3. Xcel Energy shall use the most recent 12 months of actual natural gas sales to calculate the final GUIC rate.	12 months of weather-normalized actual sales data was used to calculate proposed rate factors. This is noted in Section VIII.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.

Compliance Matrix

Petition Requirements	Reference
4. The "return on" the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel Energy's weighted long-term cost of debt over the life of these capital expenditures.	Our request includes an adjustment to limit the return on 2018 through 2023 capital costs for the MAOP program to the Company's weighted long-term cost of debt. The adjustment is reflected in the 2018 through 2023 regulatory treatment adjustments in Attachments O and P.
5. The Company's proposed recovery of GUIC internal capital costs for Overheads, Other, and Transportation is denied, to the extent these costs are not removed elsewhere.	Our request includes adjustments to remove the costs from revenue requirement calculations for 2023. The adjustments reflect the amount of overheads, transportation, and other costs removed from 2018 through 2022 GUIC projects. The adjustment is reflected in the 2021 through 2023 regulatory treatment adjustments in Attachments O and P. We discussed this in Section VII.C.1 of our Petition.

Index of Attachments

Attachment	Item
A	Compliance Matrix
B	Index of Attachments
C	TIMP Project Overview
C1	TIMP Project Detail
C2	TIMP Quantitative Risk Assessment Scores
D	DIMP and Mandatory Relocation Project Overviews
D1	DIMP Project Detail
D2(a)	DIMP Quantitative Risk Assessment Scores
D2(b)	DIMP Replacements Risk Assessment Scores for 2023
E	Mandated Relocations Project Detail for 2021-2023
F	Capital TIMP, DIMP, and Mandated Relocations Expenditures Actual and Forecast Through 2027
G	TIMP Capital Revenue Requirements for 2023
H	DIMP and Mandated Relocations Capital Revenue Requirements for 2023
I	Current Mandated Relocations Revenue Requirement Comparison to Last Approved Natural Gas Rate Case Docket No. G002/GR-09-1153 – *Not in use. Held in reserve.*
J	Calculation of Estimated Annual GUIC-Related Retirements for 2012-2023
K	TIMP and DIMP O&M Actuals for 2021 and Budget Estimates for 2022-2027

Index of Attachments

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 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 evaluation processes into determining planned risk mitigation activities. Typical risk

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[1] Known as high consequence areas (HCA) and moderate consequence areas (MCA).
[2] https://www.phmsa.dot.gov/regulations-fr/rulemaking/2019-20306.

mitigation measures include excavation of the pipeline, repair or complete removal of the anomaly, and reducing the operating pressure of the system.

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 proposed revisions to the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposed changes to the integrity management (IM) requirements as well as changes to non-IM requirements. The NPRM was originally published as one rule in 2016 and was later split into three separate rules. The first of the three rules was published on October 1, 2019.[3] The second rule was published on August 24, 2022.[4] The third rule was published on November 15, 2021.[5]

The focus of the first rule is records retention, material verification, MAOP reconfirmation and integrity assessments outside of HCAs. The rule carries progressive effective dates, the first of which was July 1, 2020, but was extended to December 31, 2020, due to the impacts of COVID-19. The 2023 GUIC includes MAOP reconfirmation projects and costs needed to comply with this new rule.

The specific IM requirement changes from the first rule include:

- Expansion of IM beyond high consequence areas (HCAs),
- Establishment of moderate consequence areas (MCAs),
- Maximum Allowable Operating Pressure (MAOP) validation and reconfirmation,
- Materials verification requirements, and
- Spike testing.

The IM requirement changes from the second rule include:

- HCA and non-HCA assessment response criteria

[3] Docket No. PHMSA-2011-0023; Amdt. Nos. 191-26; 192-125.
[4] Docket No. PHMSA-2011-0023; Amdt. No. 192-132.
[5] Docket No. PHMSA-2011-0023; Amdt. Nos. 191-30; 192-129.

- Corrosion control,
- Risk assessment requirements,
- New construction and repairs,
- Management of change, and
- Inspection of pipelines following weather events.

Finally, the IM requirement changes from the third rule address the expansion of regulated 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 2023 TIMP project detail is presented in Attachment C1 and the risk assessment scores for 2023 TIMP projects are presented in Attachment C2.

II. 2023 TIMP PROJECTS

In this filing, the Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with three 2023 TIMP programs:

2023 Estimated TIMP Project Costs
($ Millions)

Program	2023 Capital[6]	2023 O&M
Transmission Pipeline Assessments	$0.26	$0.63
Programmatic Replacement / MAOP Remediation	$8.64	$0.05
Casing Renewal	$2.10	$0.00
Total 2023 TIMP Expenditures	**$11.00**	**$0.68**
Total 2023 Minnesota TIMP Revenue Requirements	**$13.67**[7]	**$0.55**

[6] Estimated capital costs include estimated removal costs. Details can be seen in Attachment C1.
[7] 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.

These projects, except for Casing Renewal, were included in the Company's 2015 through 2022 Gas Utility Infrastructure Cost (GUIC) Rider petitions.[8] The Casing Renewal project began in 2021. The capital-related cost estimates for 2023 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads. The 2023 project detail for each project is presented in Attachment C1 and the risk assessment scores for 2023 projects are presented in Attachments C2.

Projects planned for completion in 2023 and outlined below will begin during the 2nd and 3rd quarters of 2023 and will be placed in service during the 3rd and 4th quarters of 2023.

1) Transmission Pipeline Assessments
Work Breakdown Structure (WBS): E.0000018.052 (Capital); A.0008610.004.002.002 (O&M)

2023 Estimated Project Costs:
$0.26 million Capital expenditure
$0.63 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.[9] Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of the risks and threats.

The Company met the HCA Baseline Assessment requirements,[10] 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.[11]
The Company has selected ILI as the primary assessment methodology due

[8] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, G002/M-17-787, G002/M-18-692, G002/M-19-664, G002/M-20-799, and G002/M-21-765.
[9] The requirements are further defined in the Company's TIMP manual.
[10] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012.
[11] This standard is incorporated by reference into 49 C.F.R. § 192, Subpart O.

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

ILI requires unique inspection equipment and specialized knowledge. Outside vendors maintain fleets of such tools, which may cost 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 2023 includes three projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Rosemount Line – Inver Hills Lateral	Reassessment ILI	1.95	Capital/O&M
Lake Elmo Line	Reassessment ILI	5.79	Capital/O&M
Blue Lake Line	Make Piggable Modifications	10.9	Capital

- **Rosemount Line – Inver Hills Lateral:** This project involves reassessment of approximately 1.95 miles of 16-inch pipeline utilizing in-line inspection. Costs associated with a second time ILI are typically classified as O&M and most repairs as a result of ILI assessment are capitalized, but some repairs may be classified as O&M per the Company's capitalization policy

- **Lake Elmo:** This project involves reassessment of approximately 5.79 miles of 12-inch pipeline utilizing in-line inspection. Costs associated with a second time ILI are typically classified as O&M and most repairs as a result of ILI assessment are capitalized, but some repairs may be classified as O&M per the Company's capitalization policy

- **Blue Lake:** This project is to prepare for a reassessment ILI in 2023 on the 10.9 mile, 16-inch Blue Lake Line. In previous ILI inspections a temporary launcher was used to launch pigs from the Blue Lake TBS. The Company plans to build and install a new pig launcher to be permanently installed at the Blue Lake TBS. All costs with this project would be capital costs.

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

The costs to modify pipelines for 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 with the exception of repairs resulting from data collected during ILI runs, in most cases repair costs are capitalized. 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 involving cut-out of the existing pipe or sleeve repairs are defined by the capitalization policy as Capital. If a cut-out is required, capitalization policy defines the O&M or capital designation based upon the length of the required cut-out.

2) Programmatic Replacement/MAOP Remediation
WBS: E.0010073.011 (Capital); A.0008610.004.002.003 (O&M)

2023 Estimated Project Costs:
$8.64 million Capital expenditure
$0.05 million O&M expenditure

Project Summary and Scope
The MAOP Remediation Advisory Bulletin[12] issued by PHMSA in 2012, 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." As discussed earlier, the first of the three new PHMSA Gas Transmission and Gathering Pipeline final rules was published in October of 2019. The focus of the first rule is records retention, material verification, MAOP reconfirmation and integrity assessments outside of HCAs.

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

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 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.

In the new rule published on October 1, 2019, PHMSA[13] required operators to reconfirm MAOP for the following categories:

1) Grandfathered pipelines in HCAs, MCAs, and Class 3 and 4 locations
2) Pipelines for which records to support the MAOP are not traceable, verifiable, and complete in:
    a. HCAs,
    b. Class 3 and 4 locations, and
    c. Piggable grandfathered pipelines operating at greater than 30% SMYS within MCAs.

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

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

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 the project management group'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.

[13] Docket No. PHMSA-2011-0023; Amdt. Nos. 191-26; 192-125.

In 2023 we will complete four projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
East County Line	Replace	0.5	Capital
East County Line (West of the Mississippi)	Pressure Test	1.6	Capital
Various regulator stations	Pressure Test	3 stations	Capital
Various lines	Records Review	Approximately 22	O&M

- **East County Line:** This project involves replacing approximately 2,400 feet of the East County Line pipeline. Engineering on the project will commence in 2022 with construction occurring in 2023.
- **East County Line West of the Mississippi:** This project involves pressure testing approximately 8,500 feet along the East County Line West of the Mississippi pipeline. Engineering on the project will commence in 2022 with construction occurring in 2023.
- **Regulator Stations:** As a part of MAOP reconfirmation and document reviews, the Company plans to execute pressure tests on approximately three transmission regulator stations in 2023. Individual station remediation projects will be determined in late 2022 or early 2023.
- **Records Review:** As part of MAOP reconfirmation, the Company will perform pressure test analyses on approximately eight pipelines totaling approximately 22 miles. In 2023, this will entail a records review of the elevation profiles of each line.

Cost associated with pressure testing and replacement are classified as capital per the Company's capitalization policy.

3) Casing Renewal
WBS: E.0010073.006 (Capital)

2023 Estimated Project Costs:
$2.10 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
This project is similar to the shorted casing – Distribution Project (see prior discussion). As an integrated part of the Company's DIMP plan, similar needs have been identified as part of TIMP for Transmission pipelines, which is a

principle requirement of managing risk under integrity management programs. Metallic pipes need to remain isolated from each other to reduce corrosion risk. The Company's Pipeline and Compliance Standards Manual section 9.9.9 and 49 C.F.R. § 192.467 provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually to determine whether the two pieces of pipe are in contact with each other, and thereby considered to be shorted. If the Company is unable to verify those readings and/or the readings indicate that both the pipe and casing are in contact, the Company shall perform gas leak surveys at a minimum of two times per year – four times per year in business districts – given the potential for corrosion between the two pieces of pipe.

Under this project, the Company isolates pipes and casings that are determined to be shorted (or unable to take readings), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe.

This project started in the 2021 construction season and shall continue annually until all casings risks on the program list have been mitigated. The locations proposed for replacement in 2023 and beyond are based on risk analysis originally completed in 2020 and reviewed in 2022.

The 2023 scope of work includes the following casing:

Casing Location	Pipe Size	Leaking	Shorted
20-inch Pt Douglas & SpringSide	20"	No	Unknown

The existing 20-inch high pressure transmission pipeline at Pt Douglas and SpringSide has a casing without test leads and therefore pipe to soil readings are not possible. This project entails renewing the US Highway 10/61 crossing with new and uncased 20-inch steel piping.

III. 2022 TIMP PROJECTS

In 2022, there are four projects under the TIMP:

1) Transmission Pipeline Assessments,
2) ASVs and RCV,
3) Programmatic Replacement / MAOP Remediation, and
4) Casing Renewal

The TIMP project costs included in the Company's 2022 GUIC Rider Petition, Docket No. G002/M-21-765, as compared to updated 2022 cost estimates[14] based on emerging project developments and actual construction activity, are provided below:

2022 Estimated TIMP Project Costs
($ Millions)

Program	2022 Capital, As Filed[15]	2022 Capital Estimates	Capital Variance	Capital Variance %	2022 O&M, As Filed	2022 O&M Estimates	O&M Variance	O&M Variance %
Transmission Pipeline Assessments	$0.60	$0.96	$0.36	60.00%	$0.60	$0.21	($0.39)	(65.00%)
ASV/RCV	$0.00	$0.12	$0.12	100.00%	$0.00	$0.00	$0.00	0.00%
Programmatic Replacement / MAOP Remediation	$1.36	$1.36	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Casing Renewal	$2.38	$2.38	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Total 2022 TIMP Expenditures	**$4.34**	**$4.82**	**$0.48**	**10.94%**	**$0.60**	**$0.21**	**($0.39)**	**(65.00%)**
Total 2022 Minnesota TIMP Revenue Requirement[16]	**$13.90**	**$13.73**	**($0.17)**	**(1.20%)**	**$0.53**	**$0.09**	**($0.44)**	**(82.73%)**

The capital-related cost estimates for 2022 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads not related to internal labor. TIMP projects planned for completion in 2022 and outlined below generally began during the 2nd and 3rd quarters of 2022 and will begin service during the 3rd and 4th quarters of 2022.

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[14] Based on actual costs as of 6/30/2022 and estimates from 7/1/2022 through 12/31/2022.
[15] Estimated capital costs include estimated removal costs. Detail of numbers shown in Attachment C1 included in our 2022 GUIC Rider Filing, Docket No. G002/M-21-765.
[16] 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.

1) Transmission Pipeline Assessments
WBS: E.0000018.052 (Capital); A.0008610.004.002.002 (O&M)

Project Summary and Scope

The scope of assessments in 2022 includes three projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Wescott Line 8-inch	Baseline ILI	1.6	Capital/O&M
Wescott Line 12-inch	Baseline ILI	1.6	Capital/O&M
Island Line North	Direct Examination	0.01	O&M

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.60	$0.96	$0.36	60.00%	$0.60	$0.21	($0.39)	(65.00%)

Variance Explanation

Capital: The increase in capital expenditures is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs; historically these repairs were considered O&M. The assessments on the Wescott 8" and Wescott 12" are therefore seeing a shift from O&M to capital.

O&M: The decrease in O&M is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs; historically these repairs were considered O&M.

Please note the variances between capital and O&M are not equal as the change in capital considers a portion of the costs will be related to internal labor and therefore non GUIC recoverable.

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

Project Summary and Scope

Expenses in 2022 relate to final costs from 2021 installations for the following valves:

Valve Location	Size	Description
South St. Paul Station Crossover Interconnect	12 inch	Install a new actuator and controls between Crossover Line and Rosemount Line interconnect.
Maplewood Propane to North St. Paul Station	20 inch	Install a new actuator and controls on EV0437.

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$0.12	$0.12	100.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to final activities that carried into 2022 from 2021.

O&M: None.

3) Programmatic Replacement/MAOP Remediation
WBS: E.0010073.011 (Capital)

<u>Project Summary and Scope</u>

In 2022 the scope of work includes two projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
East County Line	Replace	0.5	Capital
East County Line (West of the Mississippi)	Pressure Test	1.6	Capital

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$1.36	$1.36	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%

<u>Variance Explanation</u>

Capital: None.

O&M: None.

4) Casing Renewal
WBS: E.0010073.006 (Capital)

<u>Project Summary and Scope</u>

This project started in the 2021 construction season and shall continue annually until all casings risks on the program list have been mitigated. The locations proposed for replacement in 2022 are based on risk analysis originally completed in 2020 and reviewed in 2022.

The 2022 scope of work includes the following casing:

Casing Location	Pipe Size	Leaking	Shorted
24 inch High Pressure at Hardman and 494	24"	N	Unknown

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$2.38	$2.38	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None.

O&M: None.

IV. 2021 TIMP PROJECTS

In 2021, there were four projects under the TIMP:

1) Transmission Pipeline Assessments,
2) ASVs and RCVs,
3) Programmatic Replacements and MAOP Remediation, and
4) Casing Renewal.

Following are the TIMP project costs included in the Company's 2021 GUIC Rider Petition, Docket No. G002/M-20-799, as compared to actual 2021 costs.

2021 Actual TIMP Project Costs
($ Millions)

Program	2021 Capital, As Filed[17]	2021 Capital Actuals[18]	Capital Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	O&M Variance	% O&M Variance
Transmission Pipeline Assessments	$1.50	$1.63	$0.13	8.57%	$1.70	$0.73	($0.97)	-56.98%
ASV/RCV	$0.42	$0.10	($0.32)	-77.31%	$0.00	$0.00	$0.00	0.00%
Programmatic Replacement / MAOP Remediation	$0.00	$0.04	$0.04	0.00%	$0.00	$0.00	$0.00	0.00%
Transmission Casing Renewal	$0.30	$0.10	($0.20)	-65.16%	$0.00	$0.00	$0.00	100.00%
Total 2021 TIMP Expenditures	**$2.22**	**$1.87**	**($0.35)**	**-15.83%**	**$1.70**	**$0.73**	**($0.97)**	**-56.98%**
Total 2021 Minnesota TIMP Revenue Requirement[19]	**$14.08**	**$13.71**	**($0.37)**	**(2.7%)**	**$1.51**	**$0.64**	**-$0.87**	**-57.45%**

TIMP projects completed in 2021 and outlined below generally began during the 2nd and 3rd quarters of 2021 and were placed into service during the 3rd and 4th quarters of 2021.

1) Transmission Pipeline Assessments
WBS: E.0000018.052 (Capital); A.0008610.004.002.002 (O&M)

Project Summary and Scope

The project scope in 2021 included four projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Wescott Line 8-inch	Baseline ILI	1.6	Capital
Wescott Line 12-inch	Baseline ILI	1.6	Capital
East County Line 20-inch	DA/ILI	10.3	Capital/O&M
Crossover Line 12-inch	Capital Repair	0.1	Capital

[17] Estimated capital costs include estimated removal costs. Detail of numbers shown in Attachment C1 included in our 2021 GUIC Rider Filing, Docket No. G002/M-20-799.
[18] Includes removal costs (RWIP).
[19] 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.

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$1.50	$1.63	$0.13	8.57%	$1.70	$0.73	($0.97)	(56.98%)

Variance Explanation

Capital: The variance is primarily due to higher capital expenditures for the Crossover Line 12-inch repair and the Wescott Line 8-inch modifications offset by lower capital expenditures for the modifications on the Wescott Line 12-inch line.

O&M: The variance is due to fewer and less extensive O&M repairs and indications in 2021 than originally anticipated.

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

Project Summary and Scope
In 2021, the Company installed the following valve:

Valve Location	Size	Description
South St. Paul Station Crossover Interconnect	12 inch	Install a new actuator and controls between Crossover Line and Rosemount Line interconnect.

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$0.42	$0.10	($0.32)	(77.31%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The decrease in capital expenditures is due to updated cost estimates with reductions in labor and materials. As engineering began at the South St. Paul Station Crossover Interconnect, the number of valves requiring automation and cost of equipment to complete were both less than originally estimated.

O&M: None.

3) Programmatic Replacement/MAOP Remediation
WBS: E.0000042.001, E.0000042.002 (Capital)

Project Summary and Scope
Expenses relate to final restoration activities from the 2020 replacement on the following line:

Line/Loop	Type	Project Length (mi)	Project Type
County Road B Line (NSP to Rice)	Replacement	6.5	Capital

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Capital Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	O&M Variance	% O&M Variance
Programmatic Replacement / MAOP Remediation	$0.00	$0.04	$0.04	100.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to final restoration activities that carried into 2021 from 2020.

O&M: None.

4) Casing Renewal
WBS: E.0010073.006 (Capital)

Project Summary and Scope
The 2021 scope of work included the following casing:

Casing Location	Pipe Size	Leaking	Shorted
16-inch Rosemount Line Crossing at Cahill	16"	N	Y

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.30	$0.10	($0.20)	(65.16%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The decrease in capital expenditures was due to resource constraints and delays in receiving materials.

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 2023.

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 2024-2027 Plan[20]
($ Millions)

	2024 Estimates		2025 Estimates		2026 Estimates		2027 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Transmission Pipeline Assessments	$0.33	$1.25	$1.00	$0.55	$1.22	$0.73	$2.23	$0.60
Programmatic Replacement / MAOP Remediation	$3.26	$0.45	$3.86	$0.00	$2.56	$0.00	$2.56	$0.00
Casing Renewal	$0.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$4.48**	**$1.70**	**$4.86**	**$0.55**	**$3.77**	**$0.73**	**$4.79**	**$0.60**

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

Northern States Power Company

TIMP 2021-2023 Project Detail

Docket No. G002/M-22-____
Gas Utility Infrastructure Cost Rider - 2023 Factors
Attachment C1 - Page 1 of 1

CAPITAL

Program	Regulation	WBS Structure	2021 Actuals	2022 Actuals [1]	2022 Forecast	2022 Total	2023 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments	49 CFR Part 192, Subpart O	E.0000018.052	$ 1,628,514	$ 1,035,669	$ (75,669)	$ 960,000	$ 255,000	See Attachment C1(a)
ASV/RCV Replacements	49 CFR Part 192.935	E.0000018.041	$ 95,313	$ 43,353	$ 71,647	$ 115,000	$ -	See Attachment C1(b)
Programmatic 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.0000042.001 E.0000042.002 E.0010073.011	$ 40,185	$ -	$ 1,360,000	$ 1,360,000	$ 8,640,000	See Attachment C1(c)
Casing Renewal	49 CFR Part 192.467	E.0010073.006	$ 104,530	$ 6,122	$ 2,373,878	$ 2,380,000	$ 2,100,000	See Attachment C1(d)
TOTAL TIMP CAPITAL			**$ 1,868,542**	**$ 1,085,144**	**$ 3,729,856**	**$ 4,815,000**	**$ 10,995,000**	

O&M

Program	Regulation	WBS Structure	2021 Actuals	2022 Actuals [1]	2022 Forecast	2022 Total	2023 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments	49 CFR Part 192, Subpart O	A.0008610.004.002.002	$ 731,303	$ 43,626	$ 166,374	$ 210,000	$ 625,000	See Attachment C1(a)
MAOP Reconfirmation	49 CFR Part 192.624	A.0008610.004.002.003	$ -	$ -	$ -	$ -	$ 50,000	See Attachment C1(c)
TOTAL TIMP O&M			**$ 731,303**	**$ 43,626**	**$ 166,374**	**$ 210,000**	**$ 675,000**	

[1] Actual costs through June 2022.

2021

Line/Loop	Project Description	Actual Cost	O&M or Capital
Wescott Line 8"	**Baseline ILI**	**$633,368**	
Task 1	Make piggable modifications	$633,368	Capital
Wescott Line 12"	**Baseline ILI**	**$378,872**	
Task 1	Make piggable modifications	$378,872	Capital
E County Line	**Multiple Assessments**	**$932,783**	
Task 1	Make piggable modifications and ILI	$201,480	Capital
Task 2	ECDA & ICDA direct assessments	$731,303	O&M
Crossover 12"	**Capital Repairs**	**$414,795**	
Task 1	Permanent Receiver Installation	$408	Capital
Task 2	ILI Repair - Capital Cutout	$414,386	Capital
	Total Capital	**$1,628,514**	
	Total O&M	**$731,303**	

2022

Line/Loop	Project Description	Estimated Cost	O&M or Capital
Wescott Line 8"	**Baseline ILI**	**$615,000**	
Task 1	First Time ILI	$610,000	Capital
	O&M ILI Repairs	$5,000	O&M
Wescott Line 12"	**Baseline ILI**	**$615,000**	
Task 1	First Time ILI	$610,000	Capital
Task 2	O&M ILI Repairs	$5,000	O&M
Island Line North	**Direct Examination**	**$200,000**	
Task 1	O&M Assessment (DA)	$200,000	O&M
	Total Capital	**$1,220,000**	
	Total O&M	**$210,000**	

* Amounts above include non-GUIC recoverable costs associated with internal labor.

2023

Line/Loop	Project Description	Estimated Cost	O&M or Capital
Rosemount Line - Inver Hills Lateral	**2nd ILI**	**$350,000**	
Task 1	Pigging Runs/Validation Digs	$75,000	Capital
Task 2	O&M ILI Repairs	$275,000	O&M
Lake Elmo Line	**2nd ILI**	**$450,000**	
Task 1	Pigging Runs/Validation Digs	$100,000	Capital
Task 2	O&M ILI Repairs	$350,000	O&M
Blue Lake Line	**2nd ILI**	**$100,000**	
Task 1	Make piggable modifications	$100,000	Capital
	Total Capital	**$275,000**	
	Total O&M	**$625,000**	

* Amounts above include non-GUIC recoverable costs associated with internal labor.

TIMP 2021-2023 Project Detail - ASV/RCV

2021

Subproject	Size	Description	Actual Cost
Maplewood Propane to North St. Paul Station	20"	Install new actuator on EV0437	$37,309
Linwood & Century Avenue	20"	Install new valve and actuator on the East County Line	$5,612
South St. Paul Station Crossover Interconnect	12"	Install a new actuator and controls between Crossover Line and Rosemount Line interconnect.	$52,392
		Total	**$95,313**

2022

Subproject	Size	Description	Estimated Cost
Maplewood Propane to North St. Paul Station	20"	Install new actuator on EV0437	$77,000
South St. Paul Station Crossover Interconnect	12"	Install a new actuator and controls between Crossover Line and Rosemount Line interconnect.	$38,000
		Total	**$115,000**

2023

Subproject	Size	Description	Estimated Cost
None			$0
		Total	**$0**

TIMP 2021-2023 Project Detail - Programmatic Replacement/MAOP Validation

2021

Individual Project Name	Project Description		Actual Cost
County Rd B (NSP to Rice)	Construction	$	24,388
	Materials	$	9,329
	Permitting	$	-
	Engineering	$	6,467
	Total Capital	**$**	**40,185**

2022

Individual Project Name	Project Description		Estimated Cost	O&M or Capital
East County Line (Mississippi River to Carver Ave and Highway 61)	Replace approximately 2,400' of pipeline	$	450,000	Capital
East County Line (West of the Mississippi)	Pressure Test approximately 8,500' of pipeline	$	440,000	Capital
Regulator Stations	Initial engineering and design	$	470,000	Capital
	Total Capital	**$**	**1,360,000**	

2023

Individual Project Name	Project Description		Estimated Cost	O&M or Capital
East County Line (Mississippi River to Carver Ave and Highway 61)	Replace approximately 2,400' of pipeline	$	4,030,000	Capital
East County Line (West of the Mississippi)	Pressure Test approximately 8,500' of pipeline	$	1,430,000	Capital
Regulator Stations	Engineer five to six stations and execute three stations	$	3,180,000	Capital
Records Review	Pressure test analysis on approximately eight pipelines totaling approximately 22 miles	$	50,000	O&M
	Total Capital	**$**	**8,640,000**	
	Total O&M	**$**	**50,000**	

2021				
Casing Location	**Size**	**Leaking**	**Shorted**	**Actual Cost**
16in Rosemount Line Crossing at Cahill	16"	N	Y	$104,530
			Total	**$104,530**

2022				
Casing Location	**Size**	**Leaking**	**Shorted**	**Estimated Cost**
24in High Pressure at Hardman and 494	24"	N	Unknown	$2,380,000
			Total	**$2,380,000**

2023				
Casing Location	**Size**	**Leaking**	**Shorted**	**Estimated Cost**
20in High Pressure at Pt Douglas & SpringSide	20"	N	Unknown	$2,100,000
			Total	**$2,100,000**

Quantitative Risk Assessment for 2023 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

2023 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

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

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.

	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.

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.
Equipment	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results	An indication or anomaly that in the judgment of the person designated to evaluate the	An indication or anomaly that in the judgment of the person designated to evaluate the

	requires immediate action as per 192.933(d)(iii). A leaking defect.	assessment results requires remediation prior to the next assessment.	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.
Weather/Outside Force	An immediate repair condition as per 192.933(d)(1) A leaking defect.	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 does not

	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 indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	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.	N/A

Consequence of Failure Lookup Table

Class Location	Score
4	1.15
3	1.10
2	1.05
1	1

Risk Matrix

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

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

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

TIMP Transmission Pipeline Assessments
Integrity Assessments Project Risk

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Score	Risk Level
Rosemount Line – Inver Hills Lateral	Newport	16	1998	6	No	2	Medium
Lake Elmo Line	Rice Street	12	1975	6	Yes	4	High
Blue Lake Line	Western	16	2005	5	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

Risk Matrix

			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

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2021[1]	Percentage
High	Risk Score ≥ 4	1	6%
Medium	2 ≤ Risk Score < 4	14	88%
Low	Risk < 1	1	6%
Total	All	16	

[1] Reduction in number of pipelines identified from 2020 to 2021 due to the Granite City line being abandoned.

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, Rv	Risk Level
None							

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) = $A_H/A_{H,max}$

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

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

Risk Matrix

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

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

TIMP MAOP Project Risk

Project	Regulation	Project Location (Service Area)	Current Classification	Prior Test	Material	Consequence	Risk Score	Risk Level
East County Line (Mississippi River to Carver Ave and Highway 61)	49 CFR 192.619(a)(2)	Newport/White Bear Lake	Transmission	2	0.4	4	9.6	High
East County Line (West of the Mississippi)	49 CFR 192.619(a)(2)	Newport	Transmission	2	0.4	4	9.6	High
Regulator Stations	49 CFR 192.619(a)(2)	Multiple	Transmission	2	0.4	4	9.6	High

Data inputs:

- 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**
MAOP established in accordance with 192.619(c) “Grandfather Clause”	3
Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not Traceable, Verifiable, and Complete (“TVC”)	2
Test Pressure records are satisfactory	0

Material Lookup Table

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

Consequence Lookup Table

Condition	Consequence Score
Contains HCA	4
Class 3 or Class 4, no HCA	3
Class 1 or 2 with MCA	2
Class 1 or 2, no HCA	1

Risk Matrix

			Consequence			
			Class 1 or 2, no HCA	Class 1 or 2 with MCA, no HCA	Class 3 or Class 4, no HCA	Contains HCA
			1	**2**	**3**	**4**
Likelihood of Failure	MAOP established in accordance with 192.619(c) "Grandfather Clause", Material no validated	**3.4**	3.4	6.8	10.2	13.6
	MAOP established in accordance with 192.619(c) "Grandfather Clause", Material validated	**3**	3	6	9	12
	Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not TVC, Material not validated	**2.4**	2.4	4.8	7.2	9.6
	Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not TVC, Material validated	**2**	2	4	6	8
	Test Pressure Records Satisfactory; Pipe or Station Material NOT Validated	**0.4**	0.4	0.8	1.2	1.6
	Test Pressure Records Satisfactory; Pipe or Station Material Validated	**0**	0	0	0	0

High Risk: Risk Score ≥ 5
Low Risk: Risk Score < 5
No Risk: Risk Score = 0

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2021[2]	Percentage
High	Risk Score ≥ 5	9	56%
Low	Risk < 5	1	6%
No Risk	Risk Score = 0	0	0%
Under Evaluation	TBD	6	38%
Total	All	16	

[2] Reduction in number of pipelines identified from 2020 to 2021 due to the Granite City line being abandoned.

TIMP Transmission Casing Renewal Project Risk

Project Name/Location	Size	Likelihood of Failure	Consequence	Risk Score	Risk Level
20 in High Pressure at Pt Douglas & SpringSide	20”	4	4	16	High

Data inputs:

- Indication of a metallic short or electrolytic short between the casing and carrier pipe
- Guided Wave Ultrasonic Testing (“GWUT”) indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area, in accordance with PHMSA Guided Wave UT Go-No Go Procedures (I.e., “18-point checklist”)
- Carrier Pipe diameter, operating pressure and location

Risk Score = Likelihood of Failure x Consequence of Failure

Consequence of Failure = Potential Impact Radius of downstream pipeline (PIR)

$$PIR\ (ft) = .69 * \sqrt{Pressure(psig) * Diameter(in)^2}$$

Likelihood of Failure Lookup Table

Condition	Score
Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short. A leak on the carrier pipe.	4
Indication of an electrolytic contact between the casing and carrier pipe.	3
No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area.	2
Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using the PHMSA Guidelines for Integrity Assessment of Carrier Pipes.	1

Consequence of Failure Lookup Table

Condition	**Score**
Transmission Carrier Pipe that contains HCA	5
Transmission Carrier Pipe – Class 3 or Class 4; Distribution Main Carrier Pipe – PIR > 100 feet	4
Transmission Carrier Pipe – Class 1 or Class 2; Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	3
Distribution Main Carrier Pipe – PIR ≤ 20 feet	2
Distribution Service Carrier Pipe	1

Risk Matrix

			Consequence				
			Distribution Service Carrier Pipe	Distribution Main Carrier Pipe – PIR ≤ 20 ft.	Transmission Carrier Pipe – Class 1 or Class 2 OR Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	Transmission Carrier Pipe – Class 3 or Class 4 OR Distribution Main Carrier Pipe – PIR> 100 ft.	Transmission Carrier Pipe that Contains HCA
			1	**2**	**3**	**4**	**5**
Likelihood of Failure	Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short	**4**	4	8	12	16	20
Likelihood of Failure	Indication of an electrolytic contact between the casing and carrier pipe	**3**	3	6	9	12	15
Likelihood of Failure	No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area	**2**	2	4	6	8	10
Likelihood of Failure	Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using PHMSA Guidelines for Integrity Assessment of Cased Pipe	**1**	1	2	3	4	5

(dark)	High Risk, Risk Score ≥ 15
(medium)	Medium Risk, 6 ≤ Risk Score < 15
(light)	Low Risk, Risk < 6

Distribution Integrity Management Program and Mandated Relocations 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 ongoing 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 probabilistic risk score 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 — high, medium, or low – along with other outputs useful for risk mitigation planning.

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

The Company integrates 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 threat or multiple threats. One such measure is the targeted replacement of pipe segments that are poor performing or problematic. Xcel Energy's gas distribution replacement programs have traditionally been material-based, targeted towards removing identified higher risk materials (e.g. cast-iron, bare steel, vintage plastic, etc.). For material families that have noticeably higher risk than other families, this has been a reasonable approach, providing for reasonable optimization of risk reduced per unit of capital invested. 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 services and 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; and
- Replacement of IP pipelines to address corrosion and joint, material and welds concerns.

In continuing risk reduction efforts, as these material-based replacement programs start wrapping up, Xcel Energy has continued to develop strategies to continue to remove risk in the most beneficial and cost-effective ways.

The advent of true quantitative risk assessment methodologies provides a tool for developing such optimized replacement strategies - moving from the material-based approach to a true risk optimized approach. As shown below, this type of approach can be effective in developing optimized replacement strategies for assets outside the common bad actor families (e.g. cast-iron) and even within these families.

No two assets have the exact same risk profiles. Even within asset families, such as vintage plastic and bare steel, there is a distribution of risk based on the specifics of each asset and its environment. For example, vintage plastic – which is prone to slow crack growth failures due to rock impingement – installed in areas with rocky soils, in pipelines operating at higher pressures, and in areas with higher ground temperatures, will have higher failure rates than the same vintage plastic pipe installed in areas with sandy soils operating at lower pressures with lower ground temperatures. So, while the materials-based approach provides a gross level of risk ranking, it does not capture the subtleties of the risk distributions within each asset family and across the distribution system.

[1] Generally defined as lines operating above 60 pounds per square inch gauge and below transmission.

A true quantitative risk assessment, which assesses the risk for each individual asset based on its specific factors, provides for the ability to accurately rank risk across the entire distribution system and hence provide for a true risk-based prioritization for replacement programs. The J-DIMP™ by JANA, Xcel Energy gas distribution risk model does exactly that.

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 threat or multiple threats.

II. 2023 DIMP PROJECTS

The Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with five 2023 DIMP programs:

2023 Estimated DIMP Project Costs
($ Millions)

Program	2023 Capital[2]	2023 O&M
Poor Performing Main Replacements	$18.57	$0.00
Poor Performing Service Replacements	$6.18	$0.00
Intermediate Pressure (IP) Line Assessments / Replacements	$1.69	$0.25
Distribution Valve Replacement Project	$0.37	$0.00
Casing Renewal	$1.67	$0.00
Total 2023 DIMP Capital Expenditures and O&M	**$28.48**	**$0.25**
Total 2023 Minnesota DIMP Revenue Requirement	**$25.97**	**$0.25**

All of these projects, except for Casing Renewal, were included in the Company's 2015 through 2022 GUIC Rider petitions.[3] The Casing Renewal project began in

[2] Estimated capital costs include estimated removal costs. Details can be seen in Attachment D1.
[3] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, G002/M-17-787, G002/M-18-692, G002/M-19-664, G002/M-20-799, and G002/M-21-765.

2021. The capital-related cost estimates for 2023 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads. The 2023 project detail for each project is presented in Attachment D1 and the risk assessment scores for 2023 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, 2023 project identification typically occurs in the 3rd and 4th quarters of 2022 and 1st quarter of 2023, construction will commence during the 2nd quarter of 2023, and in-servicing will occur during the 3rd and 4th quarters of 2023.

1) Poor Performing Main Replacements
Work Breakdown Structure (WBS):[4] E.0010011.003; E.0010043.019 (Capital)

2023 Estimated Project Costs
$18.57 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 project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

[4] 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.

Materials and construction methods are a major contributing factor in poor main performance. For example, mains made from Polyethylene Aldyl-A (PEA)[5] 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.

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 are completed in-house using Company

[5] 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.

employees and contractor staff. Internal labor costs are excluded from the GUIC Rider.

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)

2023 Estimated Project Costs
$6.18 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 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.

3) IP Line Assessments
WBS: E.0000007.053, E.0000043.001, E.0000045.001 (Capital); A.0008610.004.001.005 (O&M)

2023 Estimated Project Costs
$1.69 million Capital expenditure
$0.25 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 threats from corrosion, manufacturing defects,[6] construction methods,[7] and third-

[6] Material defects, long seam defects.
[7] Compression couplings and welds.

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 two and five IP line assessments per year. The Company maintains a prioritized list of anomalies identified through indirect inspections 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.

In 2023, the Company will begin construction activities on one replacement project that supports the integrity management of the Company's high-pressure distribution pipelines. Final restoration efforts will also be performed for two replacement projects that had construction in 2021 and 2022. In addition, the Company will conduct integrity assessments including follow up excavations on two pipelines and indirect surveys on two pipelines. The IP Line Assessment work in 2023 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Hugo	AC Mitigation	11.2	O&M
Winona Support Line	Follow Up Digs	Various	O&M
Rice Royalton A	Follow Up Digs	Various	O&M
Rice Royalton B and C	Indirect Survey	4.2	O&M
Kwik Trip Lateral	Indirect Survey	3.8	O&M
County Road B – Rice to Hamline	Replacement	3.4	Capital
Langdon Line – TBS to 1st St in St. Paul Park	Replacement	5.8	Capital
BRD/Nisswa/Co Rd 13	Replacement	0.5	Capital

- **AC Mitigation Hugo Line:** Follow up design and installation of AC mitigation based on survey results from 2022 AC Inteference Study.
- **Follow Up Digs:**
  - Winona Support Line: Follow up excavations based on survey results from 2022 work will occur in 2023.
  - Rice Royalton A: Follow up excavations based on survey results from 2022 work will occur in 2023.
- **Indirect Survey:**
  - Rice Royalton B and C: This project covers 4.2 miles of high-pressure distribution pipe near Watab, MN. This segment will be assessed using indirect survey.
  - Kwik Trip Lateral: This project covers 3.8 miles of high-pressure distribution pipe near Inver Grove Heights, MN. This segment will be assessed using indirect survey.
- **County Road B – Lexington to Hamline & Cty Rd C:** This project is along County Road B in Roseville, MN and entails replacing 3.4 miles of 16-inch, and 12-inch pipe with a standardized 16-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 will eliminate poor performance, unknown construction specifications and establish MAOP. This is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022. Final restoration activities may continue into 2023.
- **Langdon Line – Scott Blvd in Cottage Grove to 1st St in St. Paul Park:** This project is along Hwy 61 in Cottage Grove and along Hastings Avenue in St. Paul Park, MN and entails replacing 5.8 miles of 12-inch, 8-inch and 6-inch pipe with a standardized 12-inch pipe. This pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter will eliminate poor performance, unknown construction specifications and establish MAOP. This is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022. Final restoration activities may continue into 2023.
- **Brainerd/Nisswa/Co Rd 13:** This project is along Country Road 13 in Nisswa, MN and entails replacing approximately 2,500 feet of 6-inch pipe. This pipeline was identified as bare steel through direct examination in 2021. This project will be a one-year project with engineering, permitting and construction occurring in 2023.

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

<u>2023 Estimated Project Costs</u>
$0.37 million Capital expenditure

<u>Project Summary and Scope</u>
The placement, accessibility, and functionality of valves in the gas distribution system are critical components of gas operations, as valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections during these events, the public can be better protected, and customer impacts can be minimized.

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

A review of existing valve isolation areas has identified the need for adding 53 new valves to reduce the time to shut down a section of main in an emergency. These valves range in size from 2-inch to 12-inch and will be installed throughout the service area. Of these new valves, 12 are expected to be installed in 2023 with the remaining 41 to be installed in 2024-2027.

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 noted in the 2022 GUIC Rider Filing, the Company anticipated concluding this project in 2019. However, additional valves have been identified as inoperable while performing periodic maintenance and operating procedures. The Company currently estimates a total of 15 distribution valves will be replaced in the South Metro and Southeast areas. These valves range in size from 2-inch to 16-inch. Of these valves, two are expected to be replaced in 2023 with the remaining to be replaced in 2024-2027. Replacing these valves will allow the Company more options to isolate sections to address an emergency or system incident, while impacting the smallest number of customers.

The 2023 scope of work includes the following valves:

Distribution Valve Location	Valve #	Size/Material
Summit & Fairview (Westside), St Paul	EV1325	16” Steel
Arlington Ave & HWY35	EV1154	12” Steel

5) Casing Renewal Project
WBS: E.0010011.012 (Capital)

<u>2023 Estimated Project Costs</u>
$1.67 million Capital expenditure

<u>Project Summary and Scope</u>
Casings were routinely installed for a variety of situations including under roads and railroads. Pipelines were installed inside the casings to protect the pipe from a variety of forces. Improved design has mostly eliminated the use of casings in modern gas construction. In several instances, the Company cannot determine if the pipeline carrying gas is isolated from the casing, a situation that can create a corrosion risk and lead to pipeline failure.
The objective of this project is to mitigate the risk by renewing the pipeline or installing equipment that allows ongoing testing to ensure isolation.

The ability to test for isolation is in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467 which provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually with the purpose of determining whether the two pieces of pipe are in contact (shorted).

The Company assumes all casings that cannot be tested for isolation between the carrier pipe and the casing are shorted (electrically continuous) until test leads can be installed and tested. If testing shows the pipe and casing are isolated, the casing is added to the annual test lead survey and will be monitored and maintained over time. If testing shows no isolation (shorted), the casing will be renewed under this project. Some casings were installed when road right of way (ROW) was narrower and casings were not extended when the road was widened. In these cases, the Company renews the carrier pipe and eliminates the casing, thus removing the corrosion risk.

This project began in 2021 and will continue annually until all casings risks on the program list have been mitigated.

The Company currently has 24 distribution casings remaining to be renewed in the East Metro, Southeast and Northwest areas. Of these casings, six are expected to be renewed in 2023 with the remaining casings being renewed in 2024-2027.

The 2023 scope of work includes the following casings:

Casing Location	Pipe Size	Leaking	Shorted
Renew 2" HP lateral under RR tracks	2"	N	Intermittent
Casing under RR tracks 400' E of Rice St. at entrance to 1900 Rice St. (St. Paul Water)*	4"	N	Y
RR Crossing at Fairview & Cty C*	4"	N	Y
6" Main of N Svc Dr, Red Wing	6"	Y	N
Old Hwy 8 & Co Rd D	8"	N	Y
12" bore across I-35E at Arlington	12"	N	Y

Projects denoted with an asterisk (*) above were originally planned for renewal in 2021. Due to these projects requiring rail road permits and potential easements construction was moved to 2023.

III. 2022 DIMP PROJECTS

There are five projects under the DIMP in 2022. Following are the DIMP project costs originally included in the Company's 2022 GUIC Rider Petition,[8] as compared to revised 2022 cost estimates[9] based on current-year project developments and actual construction activity:

2022 Estimated DIMP Project Costs
($ Millions)

Program	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Poor Performing Mains	$14.11	$14.11	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Poor Performing Services	$4.69	$4.69	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Intermediate Pressure (IP) Lines Assessments	$27.56	$26.96	($0.60)	(2.18%)	$0.25	$0.25	$0.00	0.00%
Distribution Valve Replacement	$0.44	$0.44	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Casing Renewal	$0.59	$1.00	$0.41	68.64%	$0.00	$0.00	$0.00	0.00%
Total 2022 DIMP Capital Expenditures and O&M	**$47.39**	**$47.20**	**($0.20)**	**(0.41%)**	**$0.25**	**$0.25**	**$0.00**	**0.00%**
Total 2022 MN DIMP Revenue Requirement	**$18.40**	**$22.19**	**$3.79**	**20.58%**	**$0.25**	**$0.21**	**($0.04)**	**(16.73%)**

The capital-related cost estimates for 2022 exclude internal labor and include materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2022 project detail for each project is presented in Attachment D1.

[8] Docket No. G002/M-21-765.
[9] Based on actual costs as of 6/30/2022 and estimates from 7/1/2022 through 12/31/2022.

1) Poor Performing Main Replacements
WBS: E.0010011.003, E.0010043.019 (Capital)

Project Summary and Scope
For 2022, the poor performing mains materials will primarily include PEA and vintage coated steel.

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital/O&M Expenditure	$14.11	$14.11	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None.

O&M: None.

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)

Project Summary and Scope
For 2022, the primary service-related material types will primarily include PEA and vintage coated steel. Additional material types are included as necessary based on their overall risks.

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital/O&M Expenditure	$4.69	$4.69	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None.

O&M: None.

3) IP Line Assessments
WBS: E.0000007.053, E.0000043.001, E.0000045.001, E.0000045.003, E.0010075.051 (Capital); A.0008610.004.001.005 (O&M)

Project Summary and Scope
This project includes health and condition assessments on IP lines. In 2022, the Company continued construction activities on two replacement projects that support the integrity management of the Company's high-pressure distribution pipelines. In addition, the Company is conducting integrity assessments including follow up excavations on two pipelines and indirect surveys on two pipelines to identify any potential threats of corrosion and repair any corrosion defects, and an alternating current interference study on one pipeline to identify any potential threats of AC corrosion, AC interference, and hazards to Company personnel. Lastly, the Company is assessing 13 river crossings using underwater divers to identify any potential threat from natural forces due to changing river flows and currents. The IP Line Assessment work in 2022 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Multiple River Crossings	Underwater Assessment	N/A	O&M
Hugo	AC Interference Study	11.2	O&M
Clear Lake	Follow Up Digs	2 Digs	O&M
Rice Royalton A	Indirect Survey	9.4	O&M
Winona Support Line	Indirect Survey	3.7	O&M
County Road B – Rice to Hamline	Replacement	3.4	Capital
Langdon Line – TBS to 1st St in St. Paul Park	Replacement	5.8	Capital

- **River Crossing Assessments:** This project includes using underwater divers to inspect for pipeline damage from debris at the bottom of the river and to assure that cover over the pipeline remains adequate due to changing riverbed depths from silt deposit changes. A total of 13 crossings will be assessed ranging in size from 4-inch to 20-inch in the communities of Brainerd, Clear Lake, Faribault, Newport, Northfield, St. Augusta, St. Cloud, St. Paul, St. Stephen, and Watab. Mitigation of anomalies will depend on the condition of the pipelines assessed and changes to river bottom depths identified.
- **AC Interference Study:** This project includes the collection of field data pertinent to AC interference and corrosion. This data will then be used to assess the risks pertaining to AC corrosion, AC interference and Company personnel safety.
- **Follow Up Digs:**
  - 11008 – Clear Lake Line: Two follow up excavations based on survey results from 2021 work are occurring in 2022.
- **Indirect Survey:**
  - Rice Royalton A: This project covers 9.4 miles of high-pressure distribution pipe in Watab, MN. This segment will be assessed using an ECDA like methodology.
  - Winona Support Line: This project covers 3.7 miles of high-pressure distribution pipe near Winona, MN. This segment will be assessed using an ECDA like methodology.
- **County Road B – Rice to Lexington:** As discussed previously, this is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022.
- **Langdon Line – TBS to Scott Blvd in Cottage Grove:** As discussed previously, this is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022.

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$27.56	$26.96	($0.60)	(2.18%)	$0.25	$0.25	$0.00	0.00%

Variance Explanation

Capital: The decrease is due to the H005 replacement work being on hold until further review can be completed.

O&M: None.

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

Project Summary and Scope
In 2022, the Company plans to install 29 new valves ranging in size from 2-inch to 12-inch. In addition, one inoperable 6-inch emergency distribution valve will be replaced. These valve projects are occurring in the South Metro area.

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.44	$0.44	$0.0	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None.

O&M: None.

5) Casing Renewal Project
WBS: E.0010011.012 (Capital)

Project Summary and Scope
This project began in 2021 and shall continue annually until all casings risks on the program list have been mitigated. In 2022, the Company plans to renew three casings in the Metro area.

The 2022 scope of work includes the following casings:

Casing Location	Pipe Size	Leaking	Shorted
Snelling & Transit Ave – Roseville	8”	N	Y
Bore Hwy 36 & Rice St.	12”	N	Y
Century & Stillwater	6”	N	Y

2022 Estimated Project Costs
($ Millions)

	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance	2022 O&M, As Filed	2022 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.59	$1.00	$0.41	68.64%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to casing renewal work carried over from 2021 to 2022 due to resource constraints.

O&M: None.

IV. 2021 DIMP PROJECTS

There were five projects under the DIMP in 2021. Following are the DIMP project costs originally included in the Company's 2021 GUIC Rider Petition,[10] as compared to actual 2021 costs.

2021 Actual DIMP Project Costs
($ Millions)

Program	2021 Capital, As Filed[11]	2021 Capital Actuals[12]	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Poor Performing Mains	$8.50	$21.79	$13.29	156.39%	$0.00	$0.00	$0.00	0.00%
Poor Performing Services	$7.35	$2.41	($4.93)	(67.15%)	$0.00	$0.00	$0.00	0.00%
Intermediate Pressure (IP) Lines Assessments	$24.43	$19.38	($5.05)	(20.69%)	$0.58	$0.79	$0.21	36.55%
Distribution Valve Replacement	$0.46	$0.25	($0.21)	(45.28%)	$0.00	$0.00	$0.00	0.00%
Distribution Casing Renewal	$2.65	$1.68	($0.97)	(36.43%)	$0.00	$0.00	$0.00	0.00%
Total 2021 DIMP Expenditures	**$43.38**	**$45.51**	**$2.13**	**4.91%**	**$0.58**	**$0.79**	**$0.21**	**36.55%**
Total 2021 MN DIMP Revenue Requirement[13]	**$15.73**	**$16.51**	**$0.78**	**4.94%**	**$0.58**	**$0.80**	**$0.22**	**37.59%**

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[10] Docket No. G002/M-20-799.
[11] Detail of numbers shown in Attachment D1 included in our 2020 GUIC Rider Filing, Docket No. G002/M-19-664.
[12] Includes removal costs (RWIP)
[13] 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 2021 exclude internal labor and include only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2021 project detail for each project is presented in Attachment D1.

1) Poor Performing Main Replacements
WBS: E.0010011.003, E.0010043.019, E.0010075.046 (Capital)

Project Summary and Scope

For 2021, the poor performing mains materials primarily included PEA and vintage coated steel. Actual replacement activity in 2021 included:

Geographic Area (by Division)	Main (Miles)
Grand Forks	0.5
Moorhead	3.2
Newport	3.9
Southeast	9.7
Northwest	4.3
St. Paul	4.0
White Bear Lake	13.1
Wyoming	2.3
Total	**41.0**

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$8.50	$21.79	$13.29	156.39%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: As was the case in 2020, 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 PEA mains and vintage coated steel. The construction resources and projects identified for 2021 were prioritized based on relative risk and SME input.

O&M: None.

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)

Project Summary and Scope

For 2021, the primary service-related material types addressed were PEA and vintage coated steel. Actual replacement activity in 2021 included:

Geographic Area (by Division)	Services (Number)
Grand Forks	15
Moorhead	27
Newport	61
Northwest	167
Southeast	369
St. Paul	157
White Bear Lake	336
Wyoming	44
Total	**1,176**

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$7.35	$2.41	($4.93)	(67.15%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The decrease in capital expenditures is primarily due to more main replacement work occurring relative to service replacements. Service replacement projects are connected to their associated main replacement projects. Each year the percentage of main work compared to service work can fluctuate based on the geographic area where the work is performed (i.e., downtown vs. suburb). The actual capital expenditures in 2021 reflect the split of main and service work.

O&M: None.

3) IP Line Assessments
WBS: E.0000043.001, E.0000043.002, E.0000045.001, E.0000045.003 (Capital); A.0008510.114.001.005, A.0008610.004.001.005 (O&M)

Project Summary and Scope
This project includes health and condition assessments on IP lines. In 2021, the Company began construction activities on the County Road B (Rice to Hamline) and Langdon Line (TBS to 1st St. in St. Paul Park) two replacement projects that support the integrity management of the Company's high-pressure distribution pipelines. In addition, the Company completed integrity assessments, similar to an external corrosion direct assessment (ECDA) on three pipelines to identify and potential threats of corrosion and repair any corrosion defects.

Line/Loop	Type	Project Length (mi)	Project Type
Brainerd Lakes Line	Follow Up Digs	6 Digs	O&M
St. Cloud	ECDA	2.2	O&M
Clear Lake	ECDA	20.6	O&M
H005	Follow Up Digs	6 Digs	O&M
County Road B – Rice to Hamline	Replacement	3.4	Capital
Langdon Line – TBS to 1st St in St. Paul Park	Replacement	5.8	Capital

- **<u>Brainerd Lakes Lines</u>:** Follow up excavations based on survey results from 2020 occurred in 2021.
- **<u>11008 – Clear Lake Line:</u>** This project included several high-pressure distribution pipe segments near Clear Lake, MN. These segments were assessed using an ECDA style methodology.
- **<u>H005:</u>** Follow up excavations based on survey results from 2014 occurred in 2021.
- **<u>County Road B – Rice to Hamline:</u>** As discussed previously, this is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022.
- **<u>Langdon Line – TBS to 1st St in St. Paul Park:</u>** As discussed previously, this is a three-year project with engineering and permitting completed in 2020, and construction in 2021 and 2022.

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$24.43	$19.38	($5.05)	(20.69%)	$0.58	$0.79	$0.21	36.55%

Variance Explanation

Capital: Of the $5.05 decrease million decrease, the primary driver was Langdon Line construction occurring over two years (2021 and 2022) originally planned for one year (2021). This created a $5.1 million shift in forecasted from 2021 to 2022.

O&M: The variance is due to an increase in 2021 direct examination scope and increased excavation and repair costs. The additional scope included direct examinations on the Brainerd Intermediate Pressure (IP) system. Increased excavation and repair costs were experienced on the H05 direct examinations due to examinations being in high traffic areas and many anomalies requiring repair found during examination.

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

Project Summary and Scope
In 2021, the Company installed 25 new valves ranging in size from 2-inch to 12-inch. In addition, six inoperable emergency distribution valves ranging in size from 3-inch to 12-inch were installed. These valve projects occurred in the South Metro and Southeast areas.

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.46	$0.25	($0.21)	(45.28%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to the installations being done primarily by internal crews. Internal labor is non-GUIC recoverable and is therefore not included in the 2021 capital actuals.

O&M: None.

5) Casing Renewal Project
WBS: E.0010011.012 (Capital)

Project Summary and Scope

This project began in 2021 and shall continue annually until all casings risks on the program list have been mitigated. Actual renewal activity in 2021 included:

Casing Location	Pipe Size	Leaking	Shorted
16" bore across Hwy 61-Winona	16"	N	Y
12" Dodd & Hwy 110	12"	N	Y
Snelling & Transit Ave – Roseville	8"	N	Y
Division St. & 18th Ave. – St. Cloud	8"	N	Y

2021 Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$2.65	$1.68	($0.97)	(36.43%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to three projects shifting from 2021 to 2022 due to resource constraints.

O&M: None.

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 2023. As the Company continues to execute its risk-based strategy and replacement projects planned in advance of 2024 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 2024-2027 Plan[14]
($ Millions)

	2024 Estimates		2025 Estimates		2026 Estimates		2027 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$19.06	$0.00	$19.57	$0.00	$20.10	$0.00	$20.66	$0.00
Poor Performing Services	$6.35	$0.00	$6.51	$0.00	$6.69	$0.00	$6.88	$0.00
Intermediate Pressure (IP) Lines Assessments	$0.00	$0.29	$0.00	$0.25	$0.00	$0.32	$0.00	$0.25
Distribution Valve Replacement	$0.41	$0.00	$0.41	$0.00	$0.42	$0.00	$0.44	$0.00
Casing Renewal	$2.79	$0.00	$1.49	$0.00	$1.53	$0.00	$1.57	$0.00
Total	**$28.61**	**$0.29**	**$27.98**	**$0.25**	**$28.74**	**$0.32**	**$29.55**	**$0.25**

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

VI. MANDATED RELOCATIONS

Mandated relocations are projects that require the Company to move existing infrastructure to meet federal, state, or local requirements. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. The Company must invest capital to achieve these relocations and establishment of service via infrastructure at a different location.

2023 Mandated Relocation Projects

The Company requests recovery of the following capital expenditures associated with Mandated Relocations:

**2023 Estimated Mandated Relocation Project Costs
($ Millions)**

Mandated Relocation Program	2023 Capital[15]	2023 O&M
Total 2023 Capital Expenditures and O&M	**$14.9**	**$0.00**
Total 2023 Minnesota Revenue Requirement	**$4.92**	**$0.00**

Mandated relocation projects were first included in the Company's 2021 GUIC Rider Petition.[16] The capital-related cost estimates for 2023 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads.

Project Summary and Scope
The Company has currently been notified of five discrete mandated relocation projects that will need to occur in 2023. The mandated relocation work in 2023 includes the following discrete projects:

- **Dawn Ave Relocation:** This is a multi-year (2023 and 2024) project. In 2023, the project is a relocation of 11,000 feet of 2-inch PE main near Inver Grove Heights, MN which is in conflict with a city reconstruction project.

[15] Estimated capital costs include estimated removal costs.
[16] Docket No. G002/M-20-799.

- **Summit Ave Recon:** This project is a relocation of 2,700 feet of 6-inch steel with 6-inch PE in St. Paul, MN which is in conflict with a city reconstruction project.
- **May Twnshp/Washington County:** This project is a relocation of 8,000 feet of 4-inch PE main near May Township which is in conflict with a County project.
- **Gold Line Relocation:** This project is a relocation of 1,400 feet of 20-inch HP steel main near Maplewood, MN which is in conflict with a Metro Transit reconstruction project. The majority of this project will be reimbursed by Metropolitan Council/Transit.
- **Stillwater County Rd 5 Relocate:** This project is a relocation of 2-inch and 4-inch main. Existing main conflicts with a Washington County reconstruction project for County Rd 5. This project was scheduled to begin in 2021; however, due to changes in Washington County's plans this project has been shifted to 2023 and 2024.

In addition to the discrete projects noted above, the Company also budgets for routine relocation projects each year. Relocation routines are comprised of smaller (typically less than $300,000) projects involving the renewal of mains due to relocations. The amounts included in the 2023 GUIC Rider Petition are based on historical data and anticipated costs, as the Company most often does not receive information about small relocations ahead of any given calendar year.

2022 Mandated Relocation Projects

Project Summary and Scope
The Company has several discrete mandated relocation projects as well as routine relocations (projects typically less than $300,000) taking placing in 2022. These projects are located throughout the service area as summarized below:

Geographic Area (by Division)	Number of Mandated Relocation Projects
Newport	1
Northwest	12
Southeast	2
St. Paul	4
White Bear Lake	5
Wyoming	2
Total	**26**

Following are the Mandated Relocation project costs originally included in the Company's 2022 GUIC Rider Petition,[17] as compared to revised 2022 costs estimates based on current-year project developments and actual construction activity:

2022 Estimated Project Costs
($ Millions)

Mandated Relocation Program	2022 Capital, As Filed	2022 Capital Estimates	Variance	% Capital Variance
Total 2022 Capital Expenditures and O&M	$4.59	$15.07	$10.48	228.32%
Total 2022 Minnesota Revenue Requirement	$1.94	$2.52	$0.58	29.87%

The capital-related cost estimates for 2022 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads not related to internal labor. The 2022 project detail for each project is presented in Attachment E.

Variance Explanation

Capital: The $10.48 million increase, is primarily driven by $11.5 million of emerging mandated relocation projects. This increase was offset by reductions in estimated costs for the County Rd 115 and Forest Lake N shore Circle projects ($0.5 million), Washington County shifting the Stillwater County Rd 5 relocate project to 2023 ($0.4 million), and estimated cost of routine relocation projects ($0.2 million).

2021 Mandated Relocation Projects

Project Summary and Scope

In 2021, the Company completed several discrete mandated relocation projects as well as routine relocations (project typically less than $300,000).

[17] Docket No. G002/M-21-765.

Following are the Mandated Relocation project costs originally included in the Company's 2021 GUIC Rider Petition,[18] as compared to actual 2021 costs.

2021 Actual Project Costs
($ Millions)

Mandated Relocation Program	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance
Total 2021 Capital Expenditures	$12.44	$7.77	($4.67)	(37.57%)
Total 2021 Minnesota Revenue Requirements[19]	$0.35	$0.27	($0.08)	(23.22%)

Variance Explanation

Capital: The $4.7 million decrease, was driven by a $2.0 million reduction in Phase 2 of the County Rd 13 relocation project due to lower outside vendor contract costs. This project was completed 2.5 weeks earlier than originally anticipated which further reduced costs. In addition the estimated cost of routine relocation projects decreased by $6.0 million due to a decrease in historical actuals. These decreases were offset by $3.3 million of emerging mandated relocation projects.

Mandated Relocations 2024-2027 Plan[20]
($ Millions)

Mandated Relocations	2024 Estimates		2025 Estimates		2026 Estimates		2027 Estimates	
	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M
Total	**$7.62**	**$0.00**	**$6.12**	**$0.00**	**$6.47**	**$0.00**	**$7.25**	**$0.00**

[18] Docket No. G002/M-20-799.
[19] 2021 revenue requirements for Mandated Relocation projects are net of the estimated revenue requirements of $0.37 million collected in base rates.
[20] Capital figures denoted represent total estimated capital expenditures, including removal costs.

CAPITAL

Program	Regulation	WBS Structure	2021 Actuals	Cost Per Unit (CPU)	2022 Actuals[1]	2022 Forecast	2022 Total	Cost Per Unit (CPU) Assumptions	2023 Plan	Cost Per Unit (CPU) Assumptions
Distribution Valve Replacement	Code 49 CFR Part 192.1007(d).	E.0010011.005	$ 248,988	See Attachment D1(e) for actual cost results.	$ 48,955	$ 391,045	$ 440,000	See Attachment D1(f)	$ 370,000	See Attachment D1(g)
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB-08-02.	E.0010011.003; E.0010043.019; E.0010075.046	$ 21,785,150	$88.14/ft. for mains installed by contractors and internal resources in 2021 (urban projects removed as they greatly impact the average). Difference between actuals and those on the detail Attachment D1(a) are for restoration charges related to work in-serviced in 2020, with carryover costs in 2021 as well as non-GUIC recoverable internal labor. Footage and CPU were already captured within previous detail.	$ 4,308,335	$ 9,801,665	$ 14,110,000	Based on 2021 actuals, 2022 forecast is $58.75/ft. for mains installed by contractors and internal resources. Difference between dollar forecast and those on the detail tab are for restoration charges related to work in-serviced in 2021, with carryover costs in 2022. Footage and CPU were already captured within previous detail.	$ 18,570,000	Based on 2021 actuals, 2023 forecast is $58.75/ft. for contractor-performed work and internal/local projects. Considered the best available information.
Poor Performing Services	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB-08-02.	E.0010011.004	$ 2,413,758	$1,859 per service installed by contractors and internal resources in 2021. Difference between actuals and those on the detail Attachment D1(a) are for restoration charges related to services in-serviced in 2020, with carryover costs in 2021 as well as non-GUIC recoverable internal labor. Footage and CPU were already captured within previous detail.	$ 585,746	$ 4,104,254	$ 4,690,000	Based on 2021 actuals, 2022 forecast is $1,859 per service installed by contractors and internal resources. Difference between forecast on 2022 tab and those on the detail tab are for restoration charges related to services in-serviced in 2021, with carryover costs in 2022. Footage and CPU were already captured within previous detail.	$ 6,180,000	Based on 2021 actuals, 2023 forecast is $1,859/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).	E.0000007.053; E.0000043.001; E.0000043.002; E.0000045.001; E.0000045.003	$ 19,376,315	See Attachment D1(d) for actual cost results.	$ 9,321,751	$ 17,638,249	$ 26,960,000	See Attachment D1(d)	$ 1,690,000	See Attachment D1(d)
Casing Renewal	Code 49 CFR Part 192.467	E.0010011.012; E.0010043.026	$ 1,684,557	See Attachment D1(h) for actual cost results.	$ 93,581	$ 901,419	$ 995,000	See Attachment D1(h)	$ 1,670,000	See Attachment D1(h)
TOTAL DIMP CAPITAL			**$ 45,508,767**		**$ 14,358,368**	**$ 32,836,632**	**$ 47,195,000**		**$ 28,480,000**	

O&M

Program	Regulation	WBS Structure	2021 Actuals	Cost Per Unit (CPU)	2022 Actuals[1]	2022 Forecast	2022 Total	Cost Per Unit (CPU) Assumptions	2023 Plan	Cost Per Unit (CPU) Assumptions
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).	A.0008510.114.001.005; A.0008610.004.001.005	$ 790,633	See Attachment D1(d) for actual cost results.	$ 18,718	$ 231,282	$ 250,000	See Attachment D1(d)	$ 250,000	See Attachment D1(d)
TOTAL DIMP O&M			**$ 790,633**		**$ 18,718**	**$ 231,282**	**$ 250,000**		**$ 250,000**	

[1] Actual costs through June 2022.

NSP-MN Main & Service Replacement Projects 2021										
Area	**City**	**Work Order Number**	**Description**	**Services Replaced**	**Total Service Cost**	**Service CPU ($/Srv Installed)**	**Installed Footage**	**Total Main Cost**	**Main CPU ($/Ft installed)**	**Class Location**
Moorhead	Moorhead	105806280	Moorhead - S 8th Street	4	$ 327	$ 82	1,020	$ 125,599	$ 123.14	4
Moorhead	Moorhead	105969030	Moorhead - Concordia College	3	$ 8,485	$ 2,828	1,781	$ 166,965	$ 93.75	1
Moorhead	Moorhead	106336322	Moorhead - S 30th Ave	20	$ 55,464	$ 2,773	14,295	$ 1,640,215	$ 114.74	4
Newport	West St. Paul	105936327	Concord St - St. Paul	30	$ 91,535	$ 3,051	12,282	$ 1,399,746	$ 113.97	4
Newport	West St. Paul	106005645	West St. Paul - Moreland Avenue	8	$ 27,787	$ 3,473	3,034	$ 284,570	$ 93.79	4
Newport	South St. Paul	106259610	South St. Paul - Marie Ave	23	$ 50,917	$ 2,214	5,065	$ 559,856	$ 110.53	4
Northwest	St. Cloud	106001011	St. Cloud - 14th Ave NE	11	$ 16,599	$ 1,509	680	$ 94,371	$ 138.78	4
Northwest	St. Cloud	106416526	St. Cloud - 6th Ave S	17	$ 52,774	$ 3,104	2,151	$ 169,229	$ 78.67	1
Northwest	St. Cloud	106717174	W. St. Germain St. - St. Cloud	20	$ 39,883	$ 1,994	5,022	$ 390,449	$ 77.75	4
St. Paul	Roseville	105989284	Roseville - Terminal Road	8	$ 20,095	$ 2,512	3,221	$ 595,044	$ 184.74	4
St. Paul	Roseville	106463788	County B 2 - DIMP/RECON	15	$ 26,558	$ 1,771	3,071	$ 271,420	$ 88.38	4
St. Paul	St. Paul	106381039	St. Paul - Churchill	100	$ 195,879	$ 1,959	8,678	$ 855,838	$ 98.62	4
St. Paul	St. Paul	106159361	STP 139651 - COMO Ave	14	$ 23,856	$ 1,704	2,327	$ 176,149	$ 75.70	4
Southeast	Faribault	106248428	Woodland Dr & Greenleaf Rd Faribault	27	$ 46,364	$ 1,717	7,054	$ 558,407	$ 79.16	1
Southeast	Faribault	106197407	Lincoln Ave NW & 2nd St NW Farib	72	$ 95,026	$ 1,320	7,457	$ 650,765	$ 87.27	1
Southeast	Goodview	106304442	Goodview - 54th	13	$ 44,287	$ 3,407	5,250	$ 787,070	$ 149.92	1
Southeast	Lake City	106871565	Lake City - N High St Ph 1	16	$ 24,977	$ 1,561	2,783	$ 180,456	$ 64.84	1
Southeast	Red Wing	105923680	Old W Main & Jackson - Red Wing	3	$ 10,349	$ 3,450	1,094	$ 116,560	$ 106.54	4
Southeast	Red Wing	106481185	Old Zumbrota St & Guernsey Ln - Red Wing	8	$ 8,204	$ 1,026	465	$ 76,352	$ 164.20	1
Southeast	Winona	105952117	Winona - Cottonwood Dr	6	$ 12,453	$ 2,076	1,247	$ 242,361	$ 194.36	4
Southeast	Winona	105948910	Winona - Marian & Gale	73	$ 115,318	$ 1,580	5,014	$ 428,208	$ 85.40	4
Southeast	Winona	106585009	Winona - Industrial Park Rd	11	$ 30,809	$ 2,801	5,749	$ 352,895	$ 61.38	4
Southeast	Winona	106627769	Winona - Frontenac Dr & Menard Rd	7	$ 19,563	$ 2,795	2,854	$ 206,658	$ 72.41	4
Southeast	Winona	106588360	Lion's Park - Winona	1	$ 2,300	$ 2,300	195	$ 12,891	$ 66.11	1
White Bear Lake	Little Canada	105720589	Little Canada - S Owasso Blvd	6	$ 10,498	$ 1,750	2,519	$ 285,959	$ 113.52	3
White Bear Lake	Little Canada	106245508	Maplewood - Kohlman Avenue	28	$ 42,144	$ 1,505	9,060	$ 669,509	$ 73.90	4
White Bear Lake	Little Canada	106344213	Arden Hills - Red Fox Rd	8	$ 26,293	$ 3,287	3,767	$ 269,585	$ 71.57	4
White Bear Lake	Mahtomedi	106295914	Mahtomedi - Wildwood Road	18	$ 39,207	$ 2,178	2,232	$ 209,444	$ 93.84	4
White Bear Lake	North Oaks	106901662	North Oaks - West Shore Rd	26	$ 56,812	$ 2,185	10,320	$ 558,425	$ 54.11	2
White Bear Lake	North St. Paul	104441355	HWY 36 - Castle Ave	9	$ 19,684	$ 2,187	3,626	$ 315,245	$ 86.94	4
White Bear Lake	White Bear Lake	105964022	Lakewood Ave - WBL	112	$ 143,572	$ 1,282	14,168	$ 618,450	$ 43.65	2
Wyoming	Forest Lake	106580862	Forest Lake - Harrow Ave	0	$ -	N/A	5,172	$ 318,815	$ 61.64	1
Wyoming	Stacy	106461769	Forest Ave - Stacy	10	$ 4,219	$ 422	1,031	$ 58,622	$ 56.86	4
Wyoming	Lindstrom	106102289	Broadway St - Lindstrom	23	$ 32,117	$ 1,396	2,738	$ 140,418	$ 51.28	4
2021 DIMP Main & Service Replacements				**750**	**$ 1,394,353**	**$ 1,859**	**156,422**	**$ 13,786,547**	**$ 88.14**	

2021 Urban Construction Projects										
Grand Forks	East Grand Forks	106061590	BW/EGF/GD/DIMP/3rd ST NW&3rd Ave NW	15	$ 72,539	$ 4,836	2,597	$ 680,480	$ 262.03	4
Northwest	St. Cloud	106549611	St. Cloud - Rusan Street	10	$ 42,323	$ 4,232	5,447	$ 653,942	$ 120.06	2
	St. Cloud	106172335/106400345	St. Cloud - Sherwood Mobile Home Park	109	$ 891,389	$ 8,178	9,212	$ 921,667	$ 100.05	4
Southeast	Red Wing	104983026	Red Wing - Levee Road	0	$ -	N/A	1,269	$ 291,708	$ 229.87	4
	Faribault	105868803	Faribault - Downtown	108	$ 298,236	$ 2,761	7,533	$ 1,831,543	$ 243.14	4
	Red Wing	105882269	West Ave & 9th St	0	$ -	N/A	51	$ 54,016	$ 1,059.14	1
	Red Wing	105833143	Red Wing - W 5th St	24	$ 37,450	$ 1,560	3,169	$ 2,258,409	$ 712.66	4
St. Paul	Roseville	106386279	Cleveland Ave N	20	$ 46,051	$ 2,303	3,907	$ 803,409	$ 205.63	4
White Bear Lake	Arden Hills	105972575	Arden Hills - Lexington Ave	24	$ 93,623	$ 3,901	5,794	$ 611,002	$ 105.45	4
	Little Canada	105380387/105804377	Little Canada - Country Drive	11	$ 42,058	$ 3,823	9,262	$ 1,375,400	$ 148.50	4
	New Brighton	106415196	New Brighton 7th St NW	0	$ -	N/A	209	$ 72,345	$ 346.15	4
	New Brighton	106387316	Windsor Court - New Brighton	82	$ 230,537	$ 2,811	3,744	$ 507,318	$ 135.50	3
	Shoreview	106815785	Lexington & Cannon	2	$ 10,840	$ 5,420	2,600	$ 511,765	$ 196.83	4
	Shoreview	103551422	Shoreview - Rice/Marie Street	10	$ 22,363	$ 2,236	1,693	$ 335,139	$ 197.96	2
Wyoming	Forest Lake	105033914	Forest Lake - Lake St & 4th Ave SW	11	$ 27,451	$ 2,496	3,375	$ 417,719	$ 123.77	4
2021 DIMP Main & Service Replacements - Urban Projects				**426**	**$ 1,814,859**		**59,862**	**$ 11,325,862**		
2021 DIMP Main & Service Replacements Total				**1,176**	**$ 3,209,211**		**216,284**	**$ 25,112,409**		

** Project list above includes non-recoverable internal labor.*

NSP-MN Main & Service Replacement Projects 2022

Area	City	Description	Estimated Services	Estimated Service Cost	Service CPU	Estimated Footage	Estimated Main Cost	Main CPU	Class Location
Grand Forks	East Grand Forks	17th St NW and 8th Ave NW	11	$ 20,451	$ 1,859	4,940	$ 290,225	$ 58.75	4
Moorhead	Moorhead	5th and 4th St S	296	$ 550,305	$ 1,859	26,000	$ 1,527,500	$ 58.75	4
	Moorhead	16th St N	28	$ 52,056	$ 1,859	2,850	$ 167,438	$ 58.75	4
	Moorhead	20th St N	84	$ 156,167	$ 1,859	7,750	$ 455,313	$ 58.75	1
	Moorhead	Moorhead Center Mall	4	$ 7,437	$ 1,859	2,950	$ 173,313	$ 58.75	4
	Moorhead	Highway 75	52	$ 96,675	$ 1,859	8,050	$ 472,938	$ 58.75	4
Newport	Inver Grove Heights	Cahill Ave & Carleda Way	35	$ 65,070	$ 1,859	4,350	$ 255,563	$ 58.75	4
	Inver Grove Heights	Maple Park Drive & Dodd	32	$ 59,492	$ 1,859	1,930	$ 113,388	$ 58.75	3
	Inver Grove Heights	S Robert Trail	31	$ 57,633	$ 1,859	6,050	$ 355,438	$ 58.75	4
	Oakdale	Pedersen St & Old Hudson St	4	$ 7,437	$ 1,859	1,200	$ 70,500	$ 58.75	4
Northwest	Delano	3rd St N	178	$ 330,926	$ 1,859	15,590	$ 915,913	$ 58.75	4
	Delano	Highlands Ridge	41	$ 76,225	$ 1,859	6,000	$ 352,500	$ 58.75	1
	Watertown	Hillside Dr	6	$ 11,155	$ 1,859	400	$ 23,500	$ 58.75	1
	Watertown	White St	5	$ 9,296	$ 1,859	2,100	$ 123,375	$ 58.75	1
St. Paul	Falcon Heights	Larpenteur Ave	4	$ 7,437	$ 1,859	1,250	$ 73,438	$ 58.75	4
	Roseville	Cty B2 & Cleveland Ave	30	$ 55,774	$ 1,859	5,800	$ 340,750	$ 58.75	4
	Roseville	Cty B2 & Lexington	92	$ 171,041	$ 1,859	7,450	$ 437,688	$ 58.75	4
	St. Paul	139472 - Rice Street	24	$ 44,619	$ 1,859	800	$ 47,000	$ 58.75	4
	St. Paul	Ohio Street	6	$ 11,155	$ 1,859	1,050	$ 61,688	$ 58.75	4
	St. Paul	4th Ave	38	$ 70,647	$ 1,859	2,675	$ 157,156	$ 58.75	4
	St. Paul	Prior Ave and University Ave	13	$ 24,169	$ 1,859	2,650	$ 155,688	$ 58.75	4
	St. Paul	Wabasha St and 4th St	10	$ 18,591	$ 1,859	1,870	$ 109,863	$ 58.75	4
	St. Paul	Pedersen St & Old Hudson St	23	$ 42,760	$ 1,859	6,900	$ 405,375	$ 58.75	4
	St. Paul	Larpenteur & Jackson	0	$ -	$ 1,859	5,100	$ 299,625	$ 58.75	3
	St. Paul	Whitall/Payne Ave	8	$ 14,873	$ 1,859	400	$ 23,500	$ 58.75	4
Southeast	Faribault	2nd St NW	83	$ 154,308	$ 1,859	4,007	$ 235,411	$ 58.75	4
	Faribault	Greenwood Place	43	$ 79,943	$ 1,859	4,570	$ 268,488	$ 58.75	1
	Northfield	Woodley St W	11	$ 20,451	$ 1,859	2,240	$ 131,600	$ 58.75	4
	Lake City	Oak St	25	$ 46,478	$ 1,859	2,400	$ 141,000	$ 58.75	4
	Lake City	N 6th St	40	$ 74,365	$ 1,859	3,400	$ 199,750	$ 58.75	1
	Lake City	High Street Ph 2	10	$ 18,591	$ 1,859	2,920	$ 171,550	$ 58.75	4
	Lake City	Oak St - Additional Work	18	$ 33,464	$ 1,859	1,600	$ 94,000	$ 58.75	4
	Red Wing	Featherstone Rd	15	$ 27,887	$ 1,859	1,790	$ 105,163	$ 58.75	4
	Winona	Frontenac Dr & Menard Rd	16	$ 29,746	$ 1,859	3,250	$ 190,938	$ 58.75	4
White Bear Lake	Forest Lake	North Shore Trail	100	$ 185,914	$ 1,859	7,280	$ 427,700	$ 58.75	1
	Little Canada	Rose & McMenemy	46	$ 85,520	$ 1,859	4,800	$ 282,000	$ 58.75	4
	Mahtomedi	Old Wildwood Rd	8	$ 14,873	$ 1,859	2,800	$ 164,500	$ 58.75	1
	Maplewood	McMenemy Street	55	$ 102,253	$ 1,859	5,000	$ 293,750	$ 58.75	3
	New Brighton	7th St NW	48	$ 89,239	$ 1,859	5,750	$ 337,813	$ 58.75	4
	Shoreview	Lexington & Cannon Phase 2	86	$ 159,886	$ 1,859	10,151	$ 596,371	$ 58.75	4
	Shoreview	Victoria St (former Cty Rd E) - Shoreview	13	$ 24,169	$ 1,859	4,780	$ 280,825	$ 58.75	4
	White Bear TWP	Chatham & Chippenham Lane	9	$ 16,732	$ 1,859	700	$ 41,125	$ 58.75	3
	White Bear TWP	Birch Knoll Dr	24	$ 44,619	$ 1,859	2,200	$ 129,250	$ 58.75	2
	White Bear TWP	Martin Way	40	$ 74,365	$ 1,859	9,700	$ 569,875	$ 58.75	2
Wyoming	Lindstrom	Elm Ave	36	$ 66,929	$ 1,859	3,150	$ 185,063	$ 58.75	4
	Lindstrom	Pleasant Ave	10	$ 18,591	$ 1,859	3,600	$ 211,500	$ 58.75	4
	Lindstrom	Newell Ave	24	$ 44,619	$ 1,859	3,150	$ 185,063	$ 58.75	4
	Wyoming	E Vikings Blvd	62	$ 115,266	$ 1,859	5,300	$ 311,375	$ 58.75	4
2022 Designed DIMP-related Main Replacement Total			**1,877**	**$ 3,489,600**	**$ 1,859**	**220,643**	**$ 12,962,776**	**$ 58.75**	

** Project list above includes non-recoverable internal labor.*
*** Cost estimates based on $58.75/ft of main and $1,859/service per Attachment D1*

NSP-MN Main & Service Replacement Projects 2023									
Area	**City**	**Description**	**Estimated Services**	**Estimated Service Cost**	**Service CPU**	**Estimated Footage**	**Estimated Main Cost**	**Main CPU**	**Class Location**
Moorhead	Moorhead	Romkey Park	85	$ 158,027	$ 1,859	4,712	$ 276,830	$ 58.75	4
Newport	West St. Paul	Oakdale Ave	27	$ 50,197	$ 1,859	5,500	$ 323,125	$ 58.75	4
	Woodbury	Woodlane Dr & Valley Creek Rd	23	$ 42,760	$ 1,859	4,800	$ 282,000	$ 58.75	4
Northwest	St. Cloud	1st St S	58	$ 107,830	$ 1,859	6,920	$ 406,550	$ 58.75	4
	St. Cloud	3rd Street N & 6th Ave N	21	$ 39,042	$ 1,859	3,202	$ 188,118	$ 58.75	4
	St. Cloud	14th St S & 9th Ave S	25	$ 46,478	$ 1,859	1,709	$ 100,404	$ 58.75	1
	St. Cloud	Cloverleaf Trailer	157	$ 291,884	$ 1,859	7,500	$ 440,625	$ 58.75	4
	St. Cloud	Hwy 10	4	$ 7,437	$ 1,859	0	$ -	$ 58.75	4
	Haven TWP (St. Cloud)	Minnesota Blvd	7	$ 13,014	$ 1,859	9,202	$ 540,641	$ 58.75	1
	Waite Park	3rd St N	42	$ 78,084	$ 1,859	3,570	$ 209,738	$ 58.75	4
Southeast	Faribault	7th St NW	30	$ 55,774	$ 1,859	2,300	$ 135,125	$ 58.75	4
	Faribault	Lyndale Ave N	40	$ 74,365	$ 1,859	7,900	$ 464,125	$ 58.75	4
	Faribault	Wilson Ave & 4th St NW	23	$ 42,760	$ 1,859	750	$ 44,051	$ 58.75	1
	Northfield	Maple Street - Northfield	26	$ 48,338	$ 1,859	2,687	$ 157,854	$ 58.75	4
	Red Wing	Cannon River Ave	13	$ 24,169	$ 1,859	5,665	$ 332,819	$ 58.75	1
	Red Wing	E 7th St - Red Wing - Phase 2	17	$ 31,605	$ 1,859	2,630	$ 154,513	$ 58.75	4
	Red Wing	W 3rd Street - Red Wing	38	$ 70,647	$ 1,859	8,585	$ 504,384	$ 58.75	4
	Winona	E 2nd St & Franklin St	45	$ 83,661	$ 1,859	3,635	$ 213,556	$ 58.75	4
	Winona	4th and 5th Street	57	$ 105,971	$ 1,859	3,608	$ 211,970	$ 58.75	4
	Winona	Theurer Blvd	9	$ 16,732	$ 1,859	4,200	$ 246,750	$ 58.75	1
St. Paul	St. Paul	Snelling & Concordia	44	$ 81,802	$ 1,859	2,750	$ 161,563	$ 58.75	4
	St. Paul	Water Street	28	$ 52,056	$ 1,859	4,250	$ 249,688	$ 58.75	4
	St. Paul	Edgerton & Wheelock	12	$ 22,310	$ 1,859	1,400	$ 82,250	$ 58.75	4
	St. Paul	W 7th and Homer	20	$ 37,183	$ 1,859	6,510	$ 382,463	$ 58.75	4
	St. Paul	Edgerton Street	53	$ 98,534	$ 1,859	10,000	$ 587,500	$ 58.75	4
	St. Paul	Milton St. N	18	$ 33,464	$ 1,859	1,800	$ 105,750	$ 58.75	4
	St. Paul	Hampden Ave	59	$ 109,689	$ 1,859	4,625	$ 271,719	$ 58.75	4
	St. Paul	Rice St N & Como Ave	29	$ 53,915	$ 1,859	3,248	$ 190,802	$ 58.75	4
	St. Paul	Milton St N & Pierce Butler Rte	12	$ 22,310	$ 1,859	1,845	$ 108,370	$ 58.75	4
	Roseville	Long Lake Rd & Ct Rd C2	19	$ 35,324	$ 1,859	5,459	$ 320,716	$ 58.75	4
	Roseville	Lexington Ave & Larpenteur Ave	17	$ 31,605	$ 1,859	724	$ 42,535	$ 58.75	4
	Roseville	Rice Street & CR C W	34	$ 63,211	$ 1,859	5,442	$ 319,718	$ 58.75	4
	Roseville	Cleveland Ave & Oakcrest Ave	29	$ 53,915	$ 1,859	2,499	$ 146,816	$ 58.75	4
	Roseville	Rice Street 6" - Roseville	50	$ 92,957	$ 1,859	7,400	$ 434,750	$ 58.75	4
	Roseville	Larpenteur Ave W	10	$ 18,591	$ 1,859	2,320	$ 136,300	$ 58.75	4
	Roseville	Cleveland Ave N	9	$ 16,732	$ 1,859	3,680	$ 216,200	$ 58.75	4
White Bear Lake	Arden Hills	Innovation Way (Fernwood St)	3	$ 5,577	$ 1,859	1,900	$ 111,625	$ 58.75	4
	Maplewood	Century & Stillwater	26	$ 48,338	$ 1,859	3,750	$ 220,313	$ 58.75	4
	Mounds View	Spring Lake Rd (S)	37	$ 68,788	$ 1,859	4,500	$ 264,375	$ 58.75	3
	Mounds View	Spring Lake Rd (N)	56	$ 104,112	$ 1,859	3,022	$ 177,543	$ 58.75	3
	Mounds View	County Rd I	2	$ 3,718	$ 1,859	301	$ 17,684	$ 58.75	3
	Mounds View	County Rd H	10	$ 18,591	$ 1,859	1,404	$ 82,485	$ 58.75	4
	New Brighton	Old Hwy 8 (Part 1)	20	$ 37,183	$ 1,859	4,442	$ 260,994	$ 58.75	4
	New Brighton	Forest Dale Rd	49	$ 91,098	$ 1,859	5,200	$ 305,500	$ 58.75	3
	New Brighton	County E	105	$ 195,209	$ 1,859	9,415	$ 553,131	$ 58.75	4
	North Oaks	Pleasant Lake Rd	2	$ 3,718	$ 1,859	900	$ 52,875	$ 58.75	2
Wyoming	Forest Lake	1st Street SE	39	$ 72,506	$ 1,859	2,847	$ 167,261	$ 58.75	4
	Forest Lake	1st ST NW	25	$ 46,478	$ 1,859	4,100	$ 240,875	$ 58.75	4
	Stacy	Sunrise Estates	139	$ 258,420	$ 1,859	5,251	$ 308,486	$ 58.75	1
2023 Designed DIMP-related Main Replacement Total			**1,703**	**$ 3,166,110**	**$ 1,859**	**200,059**	**$ 11,753,461**	**$ 58.75**	

** Remaining projects are in-process of development and design; this work will take place the last quarter of 2022 and the first two quarters of 2023.*
*** Cost estimates based on $58.75/ft of main and $1,859/service per Attachment D1*

2021

Project Name	Project Description	Assumptions
Brainerd Lakes IP	· Project Type: Follow up Digs from 2020 Survey · Regulation: 49 CFR 192.1007(d) · Overview: Reporting and follow up digs based on results of ECDA baseline assessment. · Location: Brainerd, MN · 2021 Assessment Period: May – October 2021	· Cost/mile of survey: N/A · Dig cost: $30,000 - $80,000
2021 Actual O&M Costs:	$235,183	
H005	· Project Type: Follow up Digs from 2014 Survey · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of baseline assessment. · Location: New Brighton MN · 2021 Assessment Period: September – October 2021	· Cost/mile of survey: N/A · Dig cost: $30,000 - $80,000
2021 Actual O&M Costs:	$332,421	
11006 - St. Cloud	· Project Type: ECDA · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: St. Cloud, MN · 2021 Assessment Period: September – October 2021	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
2021 Actual O&M Costs:	$30,329	
11008 - Clear Lake Line	· Project Type: ECDA · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Clear Lake, MN · 2021 Assessment Period: September – October 2021	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
2021 Actual O&M Costs:	$192,700	
County Road B - Rice to Lexington Capital Project (no O&M)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 3.4 mile replacement project; the pipeline was constructed in 1953-1959 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: Roseville, MN · Construction expected to be completed in 2021 and 2022	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
2021 Actual Costs:	$ 10,245,846	
Langdon Line - TBS to Scott Blvd Capital Project (no O&M)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 5.8 mile replacement project; the pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. · Location: Cottage Grove, MN & St. Paul Park, MN · Construction expected to be completed in 2021 and 2022	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
2021 Actual Costs:	$ 9,130,468	

2022		
Project Name	**Project Description**	**Assumptions**
River Crossing Assessments 2022 Estimated O&M Costs:	· Project Type: Underwater Assessment · Regulation: 49 CFR 192.1007(d) · Overview: Underwater assessment to inspect for pipeline damage. · Locations: Brainerd, Clear Lake, Faribault, Newport, Northfield, St. Augusta, St. · 2022 Assessment Period: September – October 2022 $110,000	· Mobilization: $4,000 · Assessment cost: $3,000 - $13,000
Hugo 2022 Estimated O&M Costs:	· Project Type: AC Interference Study · Regulation: 49 CFR 192.1007(d) · Overview: Collection of field data pertinent to AC interference and corrosion. · Location: Hugo, MN · 2022 Assessment Period: September – November 2022 $27,000	· Cost/mile of survey: $2,500
11008 - Clear Lake Line 2022 Estimated O&M Costs:	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of ECDA baseline assessment. · Location: Clear Lake, MN · 2022 Assessment Period: May – October 2022 $43,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
Rice Royalton A 2022 Estimated O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Watab, MN · 2022 Assessment Period: September – November 2022 $45,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
Winona Support Line 2022 Estimated O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Winona, MN · 2022 Assessment Period: May – October 2022 $25,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
County Road B - Lexington to Hamline & Cty Rd C Capital Project (no O&M) 2022 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 3.4 mile replacement project; the pipeline was constructed in 1953-1959 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: Roseville, MN · Construction expected to be completed in 2021 and 2022 16,690,000	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: · Future Classification: Distribution
Langdon Line - Scott Blvd to 1st St Capital Project (no O&M) 2022 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 5.8 mile replacement project; the pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. · Location: Cottage Grove, MN & St. Paul Park, MN · Construction expected to be completed in 2021 and 2022 9,880,000	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
H005 Capital Project (no O&M) 2022 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 2.9 mile replacement project; the pipeline was originally installed in the 1960's. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. · Location: Arden Hills, MN & New Brighton, MN · Engineering & Design in 2022; Construction in 2023 390,000	· Benefits: ILI assessable · Current Classification: Distribution · Future Classification: Distribution

2023

Project Name	Project Description	Assumptions
Hugo Line 2023 Estimated O&M Costs:	· Project Type: AC Mitigation · Regulation: 49 CFR 192.1007(d) · Overview: Design and installation of AC mitigation as required. · Location: Hugo, MN · 2023 Assessment Period: May – October 2022 $65,000	· Cost/mile of survey: $2,100 · Dig cost: $30,000 - $80,000
Rice Royalton A 2023 Estimated O&M Costs:	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of ECDA baseline assessment. · Location: Watab, MN · 2023 Assessment Period: May – October 2023 $60,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
Rice Royalton B and C 2023 Estimated O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Watab, MN · 2023 Assessment Period: May – October 2023 $40,000	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
Kwik Trip Lateral 2023 Estimated O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Inver Grove Heights, MN · 2023 Assessment Period: May – October 2023 $40,000	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
Winona Support Line 2023 Estimated O&M Costs:	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of ECDA baseline assessment. · Location: Winona, MN · 2023 Assessment Period: May – October 2023 $45,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
County Road B - Lexington to Hamline & Cty Rd C Capital Project (no O&M) 2023 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 3.4 mile replacement project; the pipeline was constructed in 1953-1959 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: Roseville, MN · Construction expected to be completed in 2021 and 2022; restoration in 2023 250,000	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
Langdon Line - Scott Blvd to 1st St Capital Project (no O&M) 2023 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 5.8 mile replacement project; the pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. · Location: Cottage Grove, MN & St. Paul Park, MN · Construction expected to be completed in 2021 and 2022; restoration in 2023 250,000	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
Brainerd/Nisswa/Co Rd 13 Capital Project (no O&M) 2023 Estimated Costs $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 2,500 feet of 6-inch pipe replacement project. This pipeline was identified as bare steel through direct examination in 2021. · Location: Nisswa, MN · Engineering, Design, and Construction in 2023 1,190,000	· Benefits: Removing identified high-risk bare steel · Current Classification: Distribution · Future Classification: Distribution

NSP-MN Distribution Valve Replacement Projects 2021			
Project Name/Location	**Valve #**	**Size/Mtl**	**Actual Cost**
St Albans & Arlington (Southside), St Paul	EV1074	12" SC	$ 243,766
Alrington & St Albans (West of Intersection), St Paul	NEW	12" SC	
Victoria St N & Co Rd C W (Eastside), Roseville	DV6781	4" SC	$ 10,428
Victoria St N & Woodhill Dr (Southside), Roseville	EV6149	4" SC	$ 13,272
Marion St & Thomas Ave (Westside), St Paul	DV1397	3" Steel	$ 14,652
Alley East of 7th Ave S & I-494 (North of Intersection), South St Paul	NEW	8" SC	$ 40,878
Dale & Minnehaha (East of Intersection), St Paul	NEW	6" PE	$ 6,321
Afton Rd & Tower Dr (West of Intersection), Woodbury	NEW	6" PE	$ 12,338
RDW / New EV / Tyler Rd & Bench St - Red Wing	NEW	6"PE	$ 21,572
St Johns Dr & Brookview Rd (East of Intersection), Woodbury	NEW	4" PE	$ 8,509
Interlachen & Duckwood (North of Intersection), Woodbury	NEW	4" PE	$ 11,663
Saratoga & Grand (North of Intersection), St Paul	NEW	4" PE	$ 5,355
Dale & Charles Ave (East of Intersection), St Paul	NEW	4" PE	$ 2,854
1355 Grant St, Lake City	NEW	4" PE	$ 17,910
North of 8316 Hadley Ave S, Cottage Grove	NEW	4" PE	$ 7,118
Ventura Dr & Courtly Rd (Northwest of Intersection), Woodbury	NEW	4" PE	$ 9,693
Radio Dr & Dale Rd (East of Intersection), Woodbury	EV4162	4" PE	$ 16,148
76 Dellwood Ave Replace InOp 4" Valve - Dellwood	EV3589	4" PE	$ 8,692
Annapolis St W & Ohio St (East of Intersection), St Paul	NEW	2" PE	$ 4,366
Baker St W & Smith Ave S (East of Intersection), St Paul	NEW	2" PE	$ 4,689
3rd Ave N & Marie Ave (North of Intersection), South St Paul	NEW	2" PE	$ 5,512
James Ave & Edgcumbe (South of Intersection), St Paul	NEW	2" PE	$ 4,454
Dewey St & Marshall Ave (West of Intersection), St Paul	NEW	2" PE	$ 1,996
Lakeview Dr & Hudson Rd (South of Intersection), Woodbury	NEW	2" PE	$ 5,206
Lake Rd & Kingsfield Ln (North of Intersection), Woodbury	NEW	2" PE	$ 5,499
Lake Rd & Eagle Valley Dr (Northwest of Intersection), Woodbury	NEW	2" PE	$ 7,696
Lake Rd & Eagle Valley Dr (Northeast of Intersection), Woodbury	NEW	2" PE	
75th St E & Dawn Ave (South of Intersection), Inver Grove Heights	NEW	2" PE	$ 3,084
210 Minnesota St, Lake City	NEW	2" SC	$ 28,067
SCL GS 3275 40th Ave S Valve Install, St. Cloud	NEW	2" PE	$ 84
FBT /GUIC New EV/ Prairie Ave-17th St SW - Faribault	NEW	2" PE	$ 5,771
		Total Cost:	$ 527,591

Total valves: 31

** Project list above includes non-recoverable internal labor.*

NSP-MN Distribution Valve Replacement Projects 2022			
Project Name/Location	**Valve #**	**Size/Mtl**	**Estimated Cost**
Fry St (between Edmund & Charles), St Paul	NEW	12" Steel	$ 75,000
Annapolis St E & Oakdale Ave (South of Intersection), West St Paul	NEW	8" PE	$ 50,000
HWY 61 Blvd, Redwing	EV3040	6" CS	$ 25,000
Upper 55th St E & 9th Ave S (North of Intersection), South St Paul	NEW	6" PE	$ 25,000
10th Ave S & 4th St S (East of Intersection), South St Paul	NEW	6" PE	$ 25,000
6th St & 44th Ave, Winona	NEW	6" SC	$ 40,000
Valley Creek Rd & Bielenberg Dr (North of Intersection), Woodbury	NEW	4" PE	$ 7,500
Pioneer Dr & Interlachen (North of Intersection), Woodbury	NEW	4" PE	$ 7,500
Otto Ave & Lexington (North of Intersection), St Paul	NEW	4" PE	$ 7,500
Lake Rd & Wyndham Way (East of Intersection), Woodbury	NEW	4" PE	$ 7,500
Lake Rd & Radio Dr (North of Intersection), Woodbury	NEW	4" PE	$ 7,500
1875 50th St E (South of Tee), Inver Grove Heights	NEW	4" PE	$ 7,500
Haskell St E & Robert St S (West of Intersection), West St Paul	NEW	4" PE	$ 7,500
Settlers Ridge Pkwy & Brookview Rd (West of Intersection), Woodbury	NEW	4" PE	$ 7,500
Settlers Ridge Pkwy & Oak Grove Blvd (West of Intersection), Woodbury	NEW	4" PE	$ 7,500
Settlers Ridge Pkwy & Halstead (North of Intersection), Woodbury	NEW	4" PE	$ 7,500
Hartford & Albert St (North of Intersection), St Paul	NEW	3" Steel	$ 10,000
6th Ave S & 9th St S (East of Intersection), South St Paul	NEW	2" PE	$ 5,000
Edgerton & Maryland (East of Intersection), St Paul	NEW	2" PE	$ 5,000
Hamline & Blair-Northside (East of Intersection), St Paul	NEW	2" PE	$ 5,000
St Johns Dr & Conifer Pass (East of Intersection), Woodbury	NEW	2" PE	$ 5,000
St Johns Dr & Water Lily Ln (East of Intersection), Woodbury	NEW	2" PE	$ 5,000
Concord St S (South of the East Co Rd Line Crossing), South St Paul	NEW	2" PE	$ 5,000
Cottage Grove Dr & Eagles Nest (west of Intersection), Woodbury	NEW	2" PE	$ 5,000
Woodcrest Dr & Grey Eagle Dr (South of Intersection), Woodbury	NEW	2" PE	$ 5,000
9th Ave S & 49th St E (West of Intersection), Inver Grove Heights	NEW	2" PE	$ 5,000
9th Ave S & Marie Ave (West of Intersection), South St Paul	NEW	2" PE	$ 5,000
Morton St W & Hall Ave (Northwest of Intersection), St Paul	NEW	2" PE	$ 5,000
Morton St W & Hall Ave (Northeast of Intersection), St Paul	NEW	2" PE	$ 5,000
Chestnut & 4th St, Winona	NEW	2" PE	$ 5,000
Valve(s) to be identified	TBD	TBD	$ 160,000
		Estimated Total Cost:	$ 550,000

Total valves: 30

** Known valves, subject to change.*

*** Project list above includes non-recoverable internal labor.*

NSP-MN Distribution Valve Replacement Projects 2023			
Project Name/Location	**Valve #**	**Size/Mtl**	**Estimated Cost**
Summit & Fairview (Westside), St Paul	EV1325	16" Steel	$ 150,000
Cretin Ave S (Between Goodrich & Fairmount), St Paul	NEW	12" Steel	$ 75,000
Cretin Ave N & Mississippi River Blvd (South of Intersection), St Paul	NEW	12" Steel	$ 75,000
Cretin & Marshall (North of Intersection), St Paul	NEW	12" Steel	$ 75,000
Arlington Ave & HWY35	EV1154	12" Steel	$ 75,000
Victoria & University (North of Intersection), St Paul	NEW	6" Steel	$ 40,000
Victoria St N (between Selby & Dayton), St Paul	NEW	4" PE	$ 7,500
Concord St N & Bryant Ave (south of Intersection), South St Paul	NEW	4" PE	$ 7,500
Robert St S & 60th St S (South of Intersection), Inver Grove Heights	NEW	4" PE	$ 7,500
Victoria St N & Summit Ave (North of Intersection), St Paul	NEW	2" Steel	$ 7,500
Cottage Grove Dr & Oak View Dr (West of Intersection), Woodbury	NEW	2" PE	$ 5,000
Timber Crest Dr & 70th St (North of Intersection), Cottage Grove	NEW	2" PE	$ 5,000
Hinton Ave & 72nd St (East of Intersection), Cottage Grove	NEW	2" PE	$ 5,000
Woodcrest Dr & Fyrie Dr (South of Intersection), Woodbury	NEW	2" PE	$ 5,000
Valve(s) to be identified	TBD	TBD	$ 10,000
		Estimated Total Cost:	$ 550,000

Total valves: 14

** Known valves, subject to change.*

*** Project list above includes non-recoverable internal labor.*

2021

Casing Location	Size	Leaking	Shorted	Actual Cost
16" Bore across Hwy 61-Winona	16"	N	Y	$1,424,109
12" Dodd & Hwy 110	12"	N	Unknown	$117,024
Snelling & Transit Ave - Roseville	8"	N	Y	$7,423
Division St. & 18th Ave - St. Cloud	8"	N	Y	$136,001
			Total	**$1,684,557**

2022

Casing Location	Size	Leaking	Shorted	Estimated Cost
Snelling & Transit Ave - Roseville	8"	N	Y	$200,000
Bore Hwy 36 & Rice St.	12"	N	Y	$595,000
Century & Stillwater	6"	N	Y	$200,000
			Total	**$995,000**

2023

Casing Location	Size	Leaking	Shorted	Estimated Cost
Renew 2" HP lateral under RR Tracks	2"	N	Intermittent	$100,000
Casing under RR tracks 400' E of Rice St. at entrance to 1900 Rice St. (St. Paul Water)	4"	N	Y	$155,000
RR Crossing at Fairview & Cty C	4"	N	Y	$155,000
6in main of N Svc Dr, Red Wing	6"	Y	N	$143,000
Old Hwy 8 & Co Rd D	8"	N	Y	$279,000
12in Bore across I-35E at Arlington	12"	N	Y	$838,000
			Total	**$1,670,000**

Quantitative Risk Assessment for 2023 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 Project Risk

SEE ATTACHMENT D2(b)

Uses Commercial Software: J-DIMP™ by JANA

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 Bundle (or project) is comprised of mains and services with similar material, diameter, pressure, cathodic protection status, and installation year. Typical projects consist of approximately 1500 feet of main and associated services and risers, and any valves that may be attached to the mains piping. Bundle lengths can vary significantly from project to project and serve as a starting point for establishing the scope of DIMP Poor Performing Main & Service projects.

The risk score used to rank the risk associated with each Bundle is calculated using the risk scores of each asset within the Bundle and is then normalized by the length (in feet) of the assets within the bundle.

Main Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Service Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Valve Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Riser Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

The risk scores are generated for each year over the course of the next decade (10 years) to allow for an understanding of the rate of change of the risk associated with the projects.

Likelihood of failure in the J-DIMP™ model is calculated utilizing a Weibul Proportional Hazard Model for 25 specific threat types derived from the 8 primary threat categories established by PHMSA in 192.1007PHMSA (and noted on page 2, Attachment D).

Consequence of failure in the J-DIMP™ model is calculated for each threat for each individual asset and is based on the probability and magnitude of a number of loss of function or loss of containment scenarios that may come about due to each threat, and considers consequence factors such as Health and Safety, Property Damage, and Economic Loss.

As can be noted from the calculation above, Main & Service project risk scores (i.e. the Bundle Risk / Length scores) are calculated on a per foot basis. This allows for a direct comparison of projects that may vary significantly in length. The projects are grouped into high-, medium- and low-risk categories based on the resulting Bundle Risk / Length scores generated by the model.

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 J-DIMP model, field observations that the pipe has significant corrosion, the presence of problematic material types such as bare steel or copper, the presence of mechanical compression couplings, the presence of poor CP conditions, or emerging risk factors based on industry incidents or findings.

As the J-DIMP™ model is primarily used to rank and evaluate potential replacement projects, it is important to calculate not only the inherent risk presented by an asset in the Xcel Energy gas distribution network, but also the risk reduction achieved by replacing the asset, or mitigated risk. Mitigated risk is calculated as the difference in risk between a current asset (the baseline risk condition) and a hypothetical new asset in the same location and subject to the same operating conditions.

The two risk profiles needed to calculate the mitigated risk for every Bundle (or project) are evaluated in the same way as the baseline Bundle Risk score, and the resulting Mitigated Bundle Risk score is provided on a per foot basis to allow for a direct comparison of assets and bundles that may vary significantly in length. As with the baseline risk scores, the mitigated risk scores are generated for each year over the course of the next decade (10 years); for project evaluation the sum of the mitigated risk score over the decade is used.

The projects are grouped into high-, medium- and low-risk reduction categories based on the resulting Mitigated Bundle Risk / Length scores by the model. The resulting distribution of these scores is shown in the tables below.

Projects that are in the high- or medium-risk baseline risk categories and are also in one of the high- or medium-risk reduction mitigated risk categories, are considered good candidates for selection in the Poor Performing Mains & Services replacement program. On the other hand, Bundles (or projects) that may be in the high- or medium-risk baseline risk categories but are ranked in the low-risk reduction category, may be good candidates for operational changes such as accelerated leak survey.

Risk Reduction Category	Project Risk Scores Range (Mitigated Risk/Foot)	Number of J-DIMP™ Projects Currently Identified as of April 2021	Percentage	Main Mileage Currently Identified as of April 2021	Percentage
High	Score > 1.18	1,255	2%	95	1%
Medium	0.6695 ≤ Score ≤ 1.18	2,420	5%	216	2%
Low	0 ≤ Score ≤ 0.6695	46,686	93%	9,134	97%
Total	**All**	**50,361**	**100%**	**9,445**	**100%**

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

Project	Regulation	Current Classific-tion	Mech-anical Joint	Manufac-turing/ Construct-ion Defect	Corros-ion	3rd Party Damage	Other Leak History	Conseq-uence	Risk Score	Risk Level
Langdon Line (Scott Blvd to 1st St)	49 CFR 192.1007(d)	Distribution	2	2	1	1	0	3	15	High
County Road B (Lexington to Hamline & Cty Rd C)	49 CFR 192.1007(d)	Distribution	2	2	1	1	1	3	15	High
BRD/Nisswa/Co Rd 13	49 CFR 192.1007(d)	Distribution	N/A	N/A	N/A	N/A	N/A	N/A	N/A	High SME

IP = 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

High Risk, Risk Score ≥ 10
Medium Risk, 4 ≤ Risk Score < 10
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
Hugo Line	Never Assessed	Class 4	SME	High
Rice Royalton A	Never Assessed	Class 4	12	High
Rice Royalton B and C	Never Assessed	Class 4	12	High
Kwik Trip Lateral	Never Assessed	Class 4	12	High
Winona Support Line	Never Assessed	Class 4	12	High

IP = 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

Risk Matrix

			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 / Material	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 Failue Score	Risk Score	Risk Level
Summit & Fairview (Westside), St Paul	16" Steel	N	Poor	Not Present	3.75	4	15	High
Arlington Ave & Hwy 35	12" Steel	N	Poor	Not Present	3.75	2	7.5	Medium

The current list of inoperable valves were identified during annual inspections and field operating procedures and require replacement. As valves continue to be inspected by field personnel, exceptions will be reported and will be scored using the method lined out below. If valves score in the medium to high risk, then they may be added to the DIMP Distribution Valve Replacement Program.

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 Distribution Casing Renewal Project Risk

Project Name/Location	Size	Likelihood of Failure Score	Consequence	Risk Score	Risk Level
Renew 2” HP lateral under RR tracks	2”	4	3	12	Medium
Casing under RR tracks 400' E of Rice St. at entrance to 1900 Rice St. (St. Paul Water)	4”	4	2	8	Medium
RR Crossing at Fairview & Cty C	4”	4	3	12	Medium
6” main of N Svc Dr, Red Wing	6”	2	3	12	Medium
Old Hwy 8 & Co Rd D	8”	4	3	12	Medium
12” Bore across I-35E at Arlington	12”	4	3	12	Medium

Data inputs:

- Indication of a metallic short or electrolytic short between the casing and carrier pipe
- Guided Wave Ultrasonic Testing (“GWUT”) indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area, in accordance with PHMSA Guided Wave UT Go-No Go Procedures (I.e., “18-point checklist)
- Carrier Pipe diameter, operating pressure and location

Risk Score = Likelihood of Failure x Consequence of Failure

Consequence of Failure = Potential Impact Radius of downstream pipeline (PIR)

$$PIR\ (ft) = .69 * \sqrt{Pressure(psig) * Diameter(in)^2}$$

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

Condition	Score
Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short. A leak on the carrier pipe.	4
Indication of an electrolytic contact between the casing and carrier pipe.	3
No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area.	2
Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using the PHMSA Guidelines for Integrity Assessment of Carrier Pipes.	1

Consequence of Failure Lookup Table

Condition	**Score**
Transmission Carrier Pipe that contains HCA	5
Transmission Carrier Pipe – Class 3 or Class 4; Distribution Main Carrier Pipe – PIR > 100 feet	4
Transmission Carrier Pipe – Class 1 or Class 2; Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	3
Distribution Main Carrier Pipe – PIR ≤ 20 feet	2
Distribution Service Carrier Pipe	1

Risk Matrix

			Consequence				
			Distribution Service Carrier Pipe	Distribution Main Carrier Pipe – PIR ≤ 20 ft.	Transmission Carrier Pipe – Class 1 or Class 2 OR Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	Transmission Carrier Pipe – Class 3 or Class 4 OR Distribution Main Carrier Pipe – PIR> 100 ft.	Transmission Carrier Pipe that Contains HCA
			1	**2**	**3**	**4**	**5**
Likelihood of Failure	Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short	**4**	4	8	12	16	20
	Indication of an electrolytic contact between the casing and carrier pipe	**3**	3	6	9	12	15
	No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area	**2**	2	4	6	8	10
	Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using PHMSA Guidelines for Integrity Assessment of Cased Pipe	**1**	1	2	3	4	5

(dark)	High Risk, Risk Score ≥ 15
(medium)	Medium Risk, 6 ≤ Risk Score < 15
(light)	Low Risk, Risk < 6

DIMP Problematic Mains & Services

Priority	J-DIMP Mitigated Risk/Foot	Priority Distribution
High	Score > 1.18	37
Medium	0.6695 ≤ Score ≤ 1.18	12
Low	Score < 0.6695	0
Total	All	49

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	J-DIMP Mitigated Risk/Foot	Class Location
TBD	Romkey Park - Moorhead	4,712	85	1962	Coated Steel	2 - 25 (psig)	4.58	4
TBD	Oakdale Ave - West St. Paul	5,500	27	1965	Coated Steel	26 - 66 (psig)	1.23	4
TBD	Woodlane Dr & Valley Creek Rd	4,800	23	1966	Steel	26 - 66 (psig)	1.62	4
TBD	St. Cloud - 1st St S	6,920	58	1969	Coated Stee/PE	2 - 25 (psig)	1.75	4
TBD	3rd Street N & 6th Ave N	3,202	21	1970	Coated Steel	26 - 66 (psig)	1.12	4
TBD	14th St S & 9th Ave S	1,709	25	1968	Coated Steel	26 - 66 (psig)	2.81	3
TBD	St. Cloud - Cloverleaf Trailer	7,500	157	Unknown	PE-Aldyl-A	26 - 66 (psig)	SME	4
TBD	Hwy 10 - St. Cloud	0	4	1971	PE (aldyl-A)	200 (psig)	21.55	4
TBD	Minnesota Blvd - Haven TWP	9,202	7	1974	PE (aldyl-A)	26 - 66 (psig)	4.40	3
TBD	Waite Park - 3rd St N	3,570	42	1961	Coated Steel/PE	26 - 66 (psig)	1.29	4
TBD	Faribault - 7th St NW	2,300	30	1954	Coated Steel	26 - 66 (psig)	1.50	4
TBD	Faribault - Lyndale Ave N	7,900	40	1957	Coated Steel/PE (Aldyl-A)	26 - 66 (psig)	1.19	4
TBD	Wilson Ave & 4th St NW	750	23	1981	PE (aldyl-A)	26 - 66 (psig)	6.75	3
TBD	Maple Street - Northfield	2,687	26	1950	Coated Steel	26 - 66 (psig)	1.38	4
TBD	Red Wing - Cannon River Ave	5,665	13	Unknown	Coated Steel	26 - 66 (psig)	1.29	1
TBD	E 7th St - Red Wing - Phase 2	2,630	17	1970	Coated Steel	26 - 66 (psig)	0.74	4
TBD	W 3rd Street - Red Wing	8,585	38	1954	Steel	26 - 66 (psig)	1.26	4
TBD	E 2nd St & Franklin St	3,635	45	1960	Coated Steel	26 - 66 (psig)	5.54	4
TBD	Winona - 4th and 5th Street	3,608	57	1962	PEA/Coated Steel	2 - 25 (psig)	2.80	4
TBD	Winona - Theurer Blvd	4,200	9	Unknown	PE	26 - 66 (psig)	0.68	1
TBD	Saint Paul - Snelling & Concordia	2,750	44	Unknown	PE/Steel	26 - 66 (psig)	0.86	4
TBD	Saint Paul - Water Street	4,250	28	1961	PE/Steel	26 - 66 (psig)	1.80	4
TBD	Edgerton & Wheelock	1,400	12	1927	Coated Steel	26 - 66 (psig)	1.20	4
TBD	W 7th and Homer - St. Paul	6,510	20	1964	Coated Steel/PE	26 - 66 (psig)	1.63	4
TBD	Saint Paul - Edgerton Street	10,000	53	1955	Coated Steel	2 - 25 (psig)	SME	4
TBD	St. Paul - Milton St. N	1,800	18	1965	Coated Steel	26 - 66 (psig)	2.27	4
TBD	Hampden Ave - St. Paul	4,625	59	1954	Coated Steel	26 - 66 (psig)	1.90	4
TBD	Rice St N & Como Ave	3,248	29	1980	PE (aldyl-A)	26 - 66 (psig)	6.65	4
TBD	Milton St N & Pierce Butler Rte	1,845	12	1950	Steel	26 - 66 (psig)	2.27	4
TBD	Long Lake Rd & Ct Rd C2	5,459	19	1969	PE (aldyl-A)	26 - 66 (psig)	1.08	4
TBD	Lexington Ave & Larpenteur Ave	724	17	1958	Coated Steel	2 - 25 (psig)	6.98	4
TBD	Rice Street & CR C W	5,442	34	1956	Coated Steel	26 - 66 (psig)	2.13	4
TBD	Cleveland Ave & Oakcrest Ave	2,499	29	1967	Coated Steel	26 - 66 (psig)	3.02	4
TBD	Rice Street 6" - Roseville	7,400	50	1956	Coated Steel	26 - 66 (psig)	1.65	4
TBD	Larpenteur Ave W - Roseville	2,320	10	1954	Coated Steel	2 - 25 (psig)	1.11	4
TBD	Cleveland Ave N	3,680	9	Unknown	Coated Steel	26 - 66 (psig)	1.29	4
TBD	Innovation Way (Fernwood St)	1,900	3	1968	PE (Aldyl-A)	26 - 66 (psig)	0.90	4
TBD	Century & Stillwater	3,750	26	1972	PE (Aldyl-A)	26 - 66 (psig)	0.72	4
TBD	Spring Lake Rd (S)	4,500	37	1967	Steel	2 - 25 (psig)	SME	3
TBD	Spring Lake Rd (N)	3,022	56	1967	Steel/PE	2 - 25 (psig)	1.90	3
TBD	County Rd I	301	2	1950	Steel	2 - 25 (psig)	SME	3
TBD	County Rd H	1,404	10	1971	PE (aldyl-A)	2 - 25 (psig)	SME	4
TBD	Old Hwy 8 (Part 1)	4,442	20	1950	Steel	2 - 25 (psig)	1.92	4
TBD	Forest Dale Rd - New Brighton	5,200	49	1959	Coated Steel	2 - 25 (psig)	0.81	3
TBD	New Brighton - County E	9,415	105	1965	Coated Steel/PE (Aldyl-A)	26 - 66 (psig)	0.88	4
TBD	Pleasant Lake Rd - North Oaks	900	2	1969	PE-Aldyl-A	26 - 66 (psig)	0.77	3
TBD	1st Street SE - Forest Lake	2,847	39	1960	Coated Steel	26 - 66 (psig)	4.61	4
TBD	1st ST NW - Forest Lake 8in	4,100	25	1968	Steel	26 - 66 (psig)	1.67	4
TBD	Sunrise Estates - Stacy	5,251	139	1977	PE (aldyl-A)	26 - 66 (psig)	1.14	3

*Scoring included for known 2023 projects with completed engineering design.

NSP-MN Mandated Relocation Projects 2021						
Area	**WBS L2**	**WBS L2 Description**	**Party Requesting Relocation**	**Size/Material**	**Actual Footage (feet)**	**Actual Cost**
Various	E.0000006.003	MNGD Main Relocation-MN	Various	Various	Various	$ 558
	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 6,902,113
Newport				4" PE	2,232	
	E.0010033.027	MN/NPT/WBD/Woodbury Dr Recon	Washington County	8" PE	5,817	$ 708,622
	E.0010038.044	MN/NPT/WDB/Hudson & Settlers Ridge	City of Woodbury	4" PE	3,824	$ 125,329
Northwest				2" PE	1,148	
	E.0010038.035	MN/BRD/County Rd 13 Relo Phase 2	Crow Wing County	4" PE	13,045	$ 3,460,110
				2" PE	6,189	
	E.0010038.047	MN/COSMOS N VENUS ST/RECON	City of Cosmos	4" PE	3,880	$ 292,543
St. Paul	E.0010038.001	Install 2 inch pe main Saint Paul	City of St. Paul Residential Street Vitality Program	2" PE	3,600	$ 784,395
				2" PE	950	
	E.0010038.046	MN/STP/Recon/Cleveland Ave	Ramsey County	8" Steel	2,896	$ 806,617
White Bear Lake	E.0010038.025	MN/WBL/Shvw/Hillview Dr relocate 2	City of Shoreview	2" PE	10,750	$ 508,780
				2" PE	6,100	
	E.0010038.036	MN/WBL/New Brighton/Sunnyside gas m	City of New Brighton	4" PE	3,325	$ 479,242
Wyoming	E.0010038.043	MN/WYO/Fiori gas main relocation	City of Wyoming	2" PE	9,071	$ 412,397
			Total Cost:			$ 14,480,706

** A portion of this total is recovered through base rates.*
*** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

NSP-MN Mandated Relocation Projects 2022						
Area	WBS L2	WBS L2 Description	Party Requesting Relocation	Size/Material	Estimated Footage (feet)	Estimated Cost
Various	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 9,418,781
Newport	E.0010038.052	MN/NPT/2022 Recon/70th St	MN Dept. of Transportation	4" PE	6,400	$ 452,453
Northwest	E.0000006.105	CR 115 Main Relocation	Crow Wing County	4" PE	26,000	$ 641,000
				2" PE	1,148	
	E.0010038.035	MN/BRD/County Rd 13 Relo Phase 2	Crow Wing County	4" PE	13,045	$ 636
				2" PE	2,250	
	E.0010038.047	MN/COSMOS N VENUS ST/RECON	City of Cosmos	4" PE	2,000	$ 520,419
				2" PE	2,600	
	E.0010038.055	MN/NW/REL/STC/COOPER	City of St. Cloud	6" PE	2,225	$ 370,982
				2" PE	3,600	
	E.0010038.058	MN/WG/MTR/REL/CENTER	City of Montrose	4" PE	2,600	$ 486,076
	E.0010038.059	Relocate existing distribution main Hwy 23, Foley	MN Dept. of Transportation	4" PE	6,000	$ 354,849
	E.0010038.060	MN/NW/REL/WSTC/MN BLVD	Sherburne County	4" PE	3,100	$ 60,000
				2" PE	100	
				4" PE	600	
				6" PE	3,800	
	E.0010038.061	MN/NW/STC/RLC/SARTELL/RIVERSIDE	City of Sartell	7" PE	1,000	$ 392,262
	E.0010038.062	MN/NW/STC/REL/CLEAR LAKE LINE-A	MN Dept. of Transportation	6" Steel	4,600	$ 2,133,793
				2" PE	1,600	
				4" PE	2,600	
	E.0010038.064	MN/BRD/REL/HWY 371	MN Dept. of Transportation	6" PE	5,200	$ 805,341
	E.0010038.066	MN/WATERTOWN/ST BONIFACIOUS CONFLIC	Carver County			$ 18,726
	E.0010074.259	MN/WATERTOWN/ST BONIFACIOUS CONFLICT	Carver County	4" Steel	1,400	$ 250,000
Southeast	E.0010073.012	MN/WIN/TH43 & TH61 Winona Reconstru	MN Dept. of Transportation	6" Steel	850	$ 1,696,118
				2" PE	900	
	E.0010073.014	MN/WIN/TH43 & TH61 Winona Reconst-GDIST	MN Dept. of Transportation	12" CS	1,000	$ 705,879
St. Paul	E.0010038.001	Install 2 inch pe main Saint Paul	City of St. Paul Residential Street Vitality Program	2" PE	3,600	$ 10,078
				2" PE	950	
	E.0010038.046	MN/STP/Recon/Cleveland Ave	Ramsey County	8" Steel	2,896	$ (5,547)
				4" PE	6,020	
	E.0010038.051	MN/STP/2022 Recon/Concord St	City of South St. Paul	6" CS	680	$ 704,946
	E.0010038.053	MN/NSPM/METRO/GOLD LINE RELOC PROG	Metro Transit	Various	7,360	$ 475,511
White Bear Lake				2" PE	24,000	
	E.0010038.026	MN/WBL/FRL/N Shore Cir 8700 of new	City of Forest Lake	4" PE	4,700	$ 176,300
				2" PE	2,800	
				6" PE	2,600	
	E.0010038.050	MN/WBL/2022 Washington Co Recon/Wil	Washington County	8" PE	3,000	$ 1,200,866
	E.0010038.054	MN/WBL/WYO/E Viking Blvd DIMP/Reloc	City of Wyoming	2" PE	7,500	$ 227,501
	E.0010038.057	MN/WBL/WBT/Martin Way Relo	White Bear Lake Township	2" PE	9,650	$ 46,000
				2" PE	500	
	E.0010038.065	MN/STP/Larpenteur Ave E/2800ft 8in	City of Maplewood / Ramsey County	8" PE	2,800	$ 549,000
Wyoming	E.0010038.043	MN/WYO/Fiori gas main relocation	City of Wyoming	2" PE	9,071	$ 10,266
				2" PE	6,800	
	E.0010038.056	MN/WYO/2022 Forest Lake Recon/N Sho	City of Forest Lake	4" PE	2,200	$ 68,000
			Total Cost:			$ 21,770,236

** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

NSP-MN Mandated Relocation Projects 2023						
Area	**WBS L2**	**WBS L2 Description**	**Party Requesting Relocation**	**Size/Material**	**Estimated Footage (feet)**	**Estimated Cost**
Various	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 8,425,703
	E.0010006.002	MN - Gas Mandates WCF	Various	Various	Various	$ 3,730,375
Newport	E.0010038.037	MN/NPT/IGH/Dawn Ave Recon	City of Inver Grove Heights	2" PE	11,000	$ 679,637
St. Paul	E.0010038.038	MN/STP/Summit Ave Recon	City of St. Paul	2"PE	1,800	
				6"PE	2,700	$ 470,753
	E.0010073.013	MN/NSPM/METRO/GOLD LINE RELOCATION	Metro Transit	20" HP Steel	1,200	$ 815,158
White Bear Lake	E.0010038.030	MN/WBL/Stillwater/Cty Rd 5 relocate	Washington County	2" PE	4,000	
				4" PE	1,200	$ 387,204
Wyoming	E.0010038.041	MN/WYO/May Twnshp/Washington County	Washington County	4" PE	8,000	$ 407,580
			Total Cost:			$ 14,916,410

** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

Capital TIMP, DIMP and Mandated Relocations Expenditures Actual and Forecast Through 2027

Total Expenditures (CWIP plus RWIP excluding Internal Labor)

	2012 - 2021 Expenditures	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**Total Expenditures**
Total TIMP	134,546,516	4,794,690	11,019,198	4,496,645	4,926,969	3,839,072	4,897,959	168,521,049
Total DIMP	191,901,527	50,081,847	28,213,266	28,427,238	27,728,576	28,476,423	29,282,539	384,111,416
Mandated Relocations	13,562,959	20,041,561	14,490,448	13,911,489	12,454,340	12,792,021	13,552,063	100,804,881
Total GUIC Expenditures	340,011,002	74,918,098	53,722,913	46,835,372	45,109,885	45,107,516	47,732,561	653,437,346

* Schedule does not include regulatory adjustments, disallowed projects, or base rate removals.

Northern States Power Company

TIMP Capital Revenue Requirements for 2023

Docket No. G002/M-22-____
Gas Utility Infrastructure Cost Rider - 2023 Factors
Attachment G - Page 1 of 1

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Annual 2023
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	131,699,746	131,831,586	131,981,801	132,148,035	132,329,700	132,528,847	132,740,770	132,962,323	133,183,679	133,397,098	133,597,885	133,778,915	133,778,915
Less Accumulated Book Depreciation Reserve	14,855,332	15,056,924	15,256,933	15,455,687	15,653,326	15,849,752	16,045,381	16,240,493	16,435,881	16,632,156	16,829,677	17,028,987	17,028,987
Less Accumulated Deferred Taxes	14,678,641	14,819,883	14,961,126	15,102,368	15,243,611	15,384,853	15,526,096	15,667,338	15,808,581	15,949,823	16,091,066	16,232,308	16,232,308
End Of Month Rate Base	102,165,774	101,954,779	101,763,742	101,589,979	101,432,763	101,294,242	101,169,294	101,054,492	100,939,217	100,815,119	100,677,142	100,517,619	100,517,619
Average Rate Base (Prior Mo + Cur Month/2)	102,290,830	102,060,277	101,859,261	101,676,861	101,511,371	101,363,503	101,231,768	101,111,893	100,996,854	100,877,168	100,746,130	100,597,381	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	166,223	165,848	165,521	165,225	164,956	164,716	164,502	164,307	164,120	163,925	163,712	163,471	1,976,525
Equity Return (Avg RB * Wtd Cost of Equity)	427,917	426,952	426,111	425,348	424,656	424,037	423,486	422,985	422,504	422,003	421,455	420,832	5,088,286
Total Return on Rate Base	594,139	592,800	591,633	590,573	589,612	588,753	587,988	587,292	586,623	585,928	585,167	584,303	7,064,811
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	551,298
Property Taxes	166,520	166,520	166,520	166,520	166,520	166,520	166,520	166,520	166,520	166,520	166,520	166,520	1,998,235
Book Depreciation	210,730	210,873	211,050	211,249	211,468	211,708	211,966	212,239	212,517	212,791	213,051	213,291	2,542,933
Deferred Taxes	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	1,694,910
Gross Up for Income Tax (see below)	37,273	37,397	37,219	28,146	22,658	17,469	18,805	20,155	27,741	35,047	36,224	46,327	364,462
Total Income Statement Expense	601,707	601,974	601,974	593,099	587,830	582,880	584,474	586,098	593,962	601,541	602,978	613,322	7,151,839
Total Revenue Requirement	**1,195,846**	**1,194,774**	**1,193,606**	**1,183,672**	**1,177,442**	**1,171,633**	**1,172,462**	**1,173,389**	**1,180,585**	**1,187,469**	**1,188,145**	**1,197,625**	**14,216,650**

Capital Structure	
Weighted Cost of Debt	1.94%
Weighted Cost of Equity	5.02%
Required Rate of Return	6.96%

Current Income Tax Calculation	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Annual 2023
Equity Return	427,917	426,952	426,111	425,348	424,656	424,037	423,486	422,985	422,504	422,003	421,455	420,832	5,088,286
Book Depreciation	210,730	210,873	211,050	211,249	211,468	211,708	211,966	212,239	212,517	212,791	213,051	213,291	2,542,933
Deferred Taxes	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	141,243	1,694,910
Less Tax Depreciation	695,360	695,360	696,329	720,023	735,813	751,603	751,603	751,603	735,813	720,023	719,046	695,360	8,667,936
Plus CPI-Tax Interest (If Applicable)	7,880	9,009	10,200	11,963	14,621	17,926	21,529	25,107	28,326	30,877	33,104	34,849	245,391
Total	92,409	92,716	92,275	69,780	56,175	43,310	46,621	49,970	68,776	86,890	89,807	114,855	903,584
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	
Gross Up for Income Tax	37,273	37,397	37,219	28,146	22,658	17,469	18,805	20,155	27,741	35,047	36,224	46,327	364,462

Northern States Power Company

DIMP and Mandated Relocations Capital Revenue Requirements for 2023

	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Annual 2023
Rate Base														
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	230,273,256	232,217,521	234,377,250	236,531,027	239,125,592	242,692,556	275,901,570	280,134,326	284,014,241	287,573,115	290,880,838	294,098,568	296,514,455	296,514,455
Less Accumulated Book Depreciation Reserve	10,980,337	11,322,113	11,665,471	11,985,654	12,335,335	12,645,048	12,961,731	13,318,601	13,655,518	12,742,846	13,122,901	13,544,428	14,033,935	14,033,935
Less Accumulated Deferred Taxes	15,096,393	15,254,510	15,412,627	15,570,745	15,728,862	15,886,979	16,045,096	16,203,213	16,361,330	16,519,448	16,677,565	16,835,682	16,993,799	16,993,799
End Of Month Rate Base	204,196,526	205,640,898	207,299,151	208,974,628	211,061,395	214,160,529	246,894,742	250,612,512	253,997,393	258,310,821	261,080,372	263,718,458	265,486,722	265,486,722
Average Rate Base (Prior Mo + Cur Month/2)	202,815,473	204,918,712	206,470,025	208,136,890	210,018,011	212,610,962	230,527,636	248,753,627	252,304,952	256,154,107	259,695,597	262,399,415	264,602,590	
Return on Rate Base														
Debt Return (Avg RB * Wtd Cost of Debt)	380,279	332,993	335,514	338,222	341,279	345,493	374,607	404,225	409,996	416,250	422,005	426,399	429,979	4,576,963
Equity Return (Avg RB * Wtd Cost of Equity)	802,811	857,243	863,733	870,706	878,575	889,423	964,374	1,040,619	1,055,476	1,071,578	1,086,393	1,097,704	1,106,921	11,782,745
Total Return on Rate Base	1,183,090	1,190,236	1,199,247	1,208,928	1,219,855	1,234,915	1,338,981	1,444,844	1,465,471	1,487,828	1,508,399	1,524,103	1,536,900	16,359,708
Income Statement Items														
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	40,208	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	250,000
Property Taxes	289,887	291,367	291,367	291,367	291,367	291,367	291,367	291,367	291,367	291,367	291,367	291,367	291,367	3,496,405
Book Depreciation	443,560	449,117	453,110	457,307	461,927	467,922	503,703	540,133	548,026	555,263	561,944	568,293	573,775	6,140,522
Deferred Taxes	153,637	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	1,897,406
Gross Up for Income Tax (see below)	288,342	161,907	160,084	164,331	153,999	171,688	222,992	290,487	318,006	347,678	342,390	319,602	345,296	2,998,462
Total Income Statement Expense	1,215,634	1,081,342	1,083,512	1,091,955	1,086,244	1,109,928	1,197,013	1,300,937	1,336,350	1,373,259	1,374,652	1,358,213	1,389,388	14,782,795
Total Revenue Requirement	**2,398,724**	**2,271,579**	**2,282,759**	**2,300,884**	**2,306,099**	**2,344,843**	**2,535,994**	**2,745,781**	**2,801,821**	**2,861,088**	**2,883,051**	**2,882,317**	**2,926,288**	**31,142,503**

Capital Structure	
Weighted Cost of Debt	1.94%
Weighted Cost of Equity	5.02%
Required Rate of Return	6.96%

Current Income Tax Calculation	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Annual 2023
Equity Return	802,811	857,243	863,733	870,706	878,575	889,423	964,374	1,040,619	1,055,476	1,071,578	1,086,393	1,097,704	1,106,921	11,782,745
Book Depreciation	443,560	449,117	453,110	457,307	461,927	467,922	503,703	540,133	548,026	555,263	561,944	568,293	573,775	6,140,522
Deferred Taxes	153,637	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	158,117	1,897,406
Less Tax Depreciation	1,205,429	1,418,437	1,432,146	1,433,890	1,474,076	1,534,497	1,561,887	1,551,824	1,544,326	1,509,953	1,494,512	1,492,244	1,412,266	17,860,062
Plus CPI-Tax Interest (If Applicable)	520,287	355,365	354,070	355,173	357,257	444,690	488,540	533,139	571,118	586,969	536,922	460,497	429,522	5,473,262
Total	714,867	401,405	396,885	407,413	381,800	425,655	552,848	720,183	788,410	861,975	848,864	792,368	856,068	7,433,874
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	0.403351
Gross Up for Income Tax	288,342	161,907	160,084	164,331	153,999	171,688	222,992	290,487	318,006	347,678	342,390	319,602	345,296	2,998,462

* Schedule does not include regulatory adjustments, disallowed projects, or base rate removals. Final revenue requirement removes $6.7M in Mandated Relocates currently in base rates.

Calculation of Estimated Annual GUIC-Related Retirements for 2012-2023

Annual Summary

		Annual Retirements
2012	$	47
2013		1,053
2014		537,681
2015		1,801,071
2016		1,269,324
2017		2,669,862
2018		370,315
2019		679,259
2020		1,968,282
2021		693,051
2022		1,113,531
2023		1,113,531
Total	$	12,217,006

	3-Yr Average Retirements 2019-2021
$	1,113,531

Replacement Projects Summary

Project No	Project Description	Install Dates of Replaced Assets
GUIC TIMP		
11503515	ASV/REV Installation on High Pressure systems - MN Rider	No related retirements. New installations
50001418	ASV/REV Instalation on HP	No related retirements. New installations
11615874	East Metro Pipe Replac. Proj HP Gas	1940s/1950s
12013233	East Metro Pipeline Replacement - Reg Installation	1940s/1950s
11676981	East Metro Pipe Replac. Proj Distr	1940s/1950s
11706370	Install Rice & Co Rd Regulator	1940s/1950s
11819647	RTUs - East Metro Pipe Replacement	1940s/1950s
11649797	High Bridge Lateral Replacement	1948/but partial relocation in 1960
34000342	High Bridge Lat Replace Dist Reg	1948/but partial relocation in 1960
11649521	NSPM TIMP Mitigation of ILI Results	Island Line 1950s / East County Line Casings 1960
11651650	NSPM Pre 1950 Trans and IP Pipe	1950s
34003261	NSPM Trans and IP Pipe - Distr	1950s
50000704	MN/WBL/County Rd B Replacement-NSP to Rice	1950s
50000709	MN/STP/ECL Replace-Maplewood to NSP	1957
GUIC DIMP		
11649520	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations
50000646	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations
11649522	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
50000644	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
11649766	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs
50000645	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs
50002555	MN - Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
50002156	MN/STP/STP/St Peter St DIMP	See Detail on Valve/Mains/Services Tabs
50002199	MN/Downtown St Cloud/Low Pressure	See Detail on Valve/Mains/Services Tabs
11813698	Pipeline Data Project Dist - NSPM	No related retirements. New installations
11980562	Hugo Line ILI improvements	No related retirements. Assessment work only
12173704	Replace Emr Vlvs in NSPM metro Dist Sys	See Detail on Valve/Mains/Services Tabs
12173830	NSPM Programmatic Service Reply	See Detail on Valve/Mains/Services Tabs
12173831	NSPM Programmatic Main Replace	See Detail on Valve/Mains/Services Tabs
34000462	Sartell Bridge Replacement	See Detail on Valve/Mains/Services Tabs
50000705	MN/STP/County Rd B Replace-Rice to Hamline	1950s
50000939	MN/Colby Lake Lateral Replace	1964-1965
50000937	MN/Arden Hills/System H05 Replace	1964
50000708	MN/NPT/Langdon Line Replacement	1958

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	7th & Dale, STP	Unknown	1	2017	EV1241	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	Unknown	1	2017	EV1069	6" 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	McKnight & Hudson Rd	1954	1	2017	EV1291	8" SC
Distribution	Valve	Inoperable Emergency Valve	St. Albans & Alley South of Selby, STP	1974	1	2018	EV1373	4" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria & St. Anthony, STP	Unknown	1	2018	EV1069	6" SC
Distribution	Valve	Inoperable Emergency Valve	Henry Ave & Fleming Field, SSTP	Unknown	1	2018	EV1245	12" SC
Distribution	Valve	Inoperable Emergency Valve	Hamline & County Road "B", RSV	N/A	1	2018	R063 bypass	4" SC
Distribution	Valve	Inoperable Emergency Valve	Forest & Rose, STP	1974	1	2018	EV1202	12" SC
Distribution	Valve	Inoperable Emergency Valve	Robert & Page, STP	1963	1	2018	EV1178	8" SC
Distribution	Valve	Inoperable Emergency Valve	Snelling & Englewood, STP	Unknown	1	2019	EV1020	12" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Juno, STP	1974	1	2019	EV1030	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1976	1	2019	EV1037	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1974	1	2019	EV1038	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1975	1	2019	EV1316	16" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2019	EV1275	12" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2019	EV1276	6" SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2019	EV3512	8" SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2019	EV3513	6" SC
Distribution	Valve	Inoperable Emergency Valve	St Albans & Arlington, STP	Unknown	1	2021	EV1074	12" SC
Distribution	Valve	Inoperable Emergency Valve	Dodd Rd & Hwy 110, Mendota Heights	1977	2	2021	EV1107 EV1108	12" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria St N & Co Rd C W, Roseville	1973	1	2021	DV6781	4" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria St N & Woodhill Dr, Roseville	1974	1	2021	EV6149	4" SC
Distribution	Valve	Inoperable Emergency Valve	Marion St & Thomas Ave, St Paul	1974	1	2021	DV1397	3" Steel
Distribution	Valve	Inoperable Emergency Valve	Radio Dr & Dale Rd, Woodbury	1989	1	2021	EV4162	4" PE
Distribution	Valve	Inoperable Emergency Valve	HWY 61 Blvd, Redwing	1958	1	2022	EV3040	6" CS

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									
2015 DIMP Main and Service Replacements Total					**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)

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	-	8,900	118
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	-	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	-	1,200	5
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	-	23,400	305
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	-	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	-	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	-	7,000	85
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	-	320	5
	12320156	OAKDALE - GROSPOINT AVE	1960	-	16,200	178
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	11	16,600	109
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	-	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 Main and Service Replacements 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)

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	-	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	-	4,200	62
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	-	9,600	141
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	-	2,300	34
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	-	4,700	58
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3	3,200	39
	12092590	BAYPORT - 7TH ST	1964	-	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	-	11,715	147
	DE 522036	COTTAGE GROVE - HYDE	1961	-	3,710	41
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	-	4,735	56
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	-	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 DIMP Main and Service Replacements Total					**168,703**	**2,453**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528).

2018 Mains and Service Replacements

NSP-MN Main & Services DIMP Replacement Projects 2018						
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	102002462	ROSEVILLE / CO RD 2 & LAKEVIEW / DIMP	Unknown	-	14,150	70
	101157888	RSV/OXFORD ST/ DIMP/ INSTALL 1200' 2" PE	Unknown	-	1,200	4
	101746906	ST PAUL - ISABELL / CONGRESS	1965	-	4,700	2
	101592642	STP/ 2018 DIMP / AREA N-UPP AFTON	1960	-	7,510	106
White Bear Lake/Wyoming	100382714	01432348 NO ST PAUL 18TH AVE INSTALL 560	Unknown	-	560	2
	101756642	MPW/Raditz Ave/ Install 3800' of 2"	1965	-	3,800	26
	100412206	MWD/ EDGERTON ST/ INSTALL 4200' OF 2" PE	1955	-	4,200	1
	101509812	BIR / 2018 DIMP / BIRCHWOOD AVE	1968	3	2,921	39
	101776492	DIMP OAK GERSHWIN AVE INST 1100' - 2" PE	1970	5	1,100	-
	101879289	DIMP OAK GRAFTON AVE INST 1600' 2" MAIN	1970	5	1,600	10
	102146268	DIMP OAK GRANADA AVE 4100' - 2" MAIN	1970	-	4,100	24
	101359567	Forest Lake / 2018 DIMP / HARROW AVE N	1969	4	1,900	7
	100441816	LTC/ EDGERTON ST/ DIMP	1968	3	5,000	29
	100441817	LTC/ LABORE RD/ DIMP	1969	4	5,400	33
	101756827	LTL / 2018 DIMP / EDGERTON N OF LITTLE C	1968	3	8,500	35
	101155888	LTL / GREENBRIER ST /DIMP/ 5100' of 2"	1970	5	5,400	42
	100920813	LTL-WESTWIND DR-DIMP-INSTALL 2700' 2" PE	1969	4	2,700	19
	101946663	MAPLEWOOD - ROSELAWN	1954	-	2,400	7
	101947593	MAPLEWOOD / COPE AVE	1957	-	3,500	32
	101947594	MAPLEWOOD / CRAIG PL	1959	-	5,700	44
	101834990	MAPLEWOOD / HOLLOWAY / DIMP	1955	-	3,500	28
	101947595	MAPLEWOOD / JACKSON ST	1956	-	4,800	36
	101692533	MPW / 2018 DIMP / MAYHILL - MINNEHAHA #4	1961	-	5,500	43
	101756635	MPW/ /ARCADE ST/DIMP/INSTALL 5000' OF 2"	1966	1	5,000	23
	101163818	MPW/ BEAUMONT ST/ DIMP/ INSTALL 1400' 2"	1955	-	1,400	16
	101876643	MPW/MARYLAND AVE/DIMP/ INSTALL 1900' 2"	1965	-	1,900	14
	101627154	MWD - ELM ST DIMP	1970	5	1,250	8
	100588988	NEW BRIGHTON / WINDSOR CT - PHASE 3	1967	2	1,850	57
	100439830	NO ST PAUL HILLTOP CT INSTALL	1969	-	2,700	27
	101833922	NORTH ST PAUL / 1ST AVE	1966	1	4,652	44
	102001637	NORTH ST PAUL / 4TH & MARGARET / DIMP	1953	-	4,500	-
	101834533	NORTH ST PAUL / IVY ST N	1970	5	1,048	30
	101524703	NSP / 2018 DIMP / COWERN-HOWARD	1969	4	2,300	28
	101693184	NSP / 2018 DIMP / NAVAJO RD	1958	-	2,300	27
	101693177	NSP / 2018 DIMP / SHOSHONE RD E	1958	-	2,500	25
	101784580	NSP / 2018 DIMP / SKILLMAN	1954	-	9,340	57
	101916855	NSP / 2018 DIMP / WEST SIDE OF IVY ST N	1970	5	800	-
	101919344	NSP / MARY JO LN	1955	-	4,750	37
	101508477	NWB /2018 DIMP / 10th AVE NW	1970	5	4,180	-
	101985751	SHOREVIEW / HODGSON / DIMP	1962	-	4,600	-
	101693170	SHV / 2018 DIMP / BRIGADOON DR	1968	3	2,500	44
	101496871	SHV / 2018 DIMP / MERCURY-WOODLAND	1967	2	3,840	17
	101582735	SHV / 2018 DIMP / SNAIL LK RD & JANSA	1962	-	7,354	12
	101383583	SLL/ OLIVE ST W/ RECON/ INS 2400' 2" PE	Unknown	-	2,350	23
	101960298	SLL/SYCAMORE ST W/ INSTALL 5000' 2" PE	1968	3	4,700	32
	101582727	WBL / 2018 DIMP / CLARENCE ST	1968	3	4,163	-
	101688133	WHITE BEAR LAKE - STILLWATER ST-BALD-GARDEN	1961	-	14,049	89
	101660586	WHITE BEAR LAKE / EAST COUNTY LINE	1961	-	2,175	17
	101556528	WHITE BEAR LAKE / SOUTHWOOD	1968	3	3,461	35
	101832776	WHITE BEAR TOWNSHIP / BELLAIRE / DIMP	1961	-	7,000	38
	101838144	FOREST LAKE / FONDANT / DIMP	1970	5	5,000	31
	101463010	SHV / 2018 DIMP / VIRGINIA AVE	1968	3	1,800	-
Newport	101547248	COTTAGE GROVE - IDEAL-85TH ST DIMP	1961	-	4,160	35
	101876838	CTG / 2018 DIMP / HAMLET-HALLMARK-HALE	1959	-	6,950	83
	101478741	CTG / DIMP / HEARTHSIDE RD / RNW MAIN	1964	-	2,300	14
	101587426	IGH - CONROY CT DIMP	1972	7	5,385	-
	101886606	IGH / 2018 DIMP / DAWN AVE - UPPER 75TH	1955	-	4,300	-
	102028709	MEH / 2018 DIMP / WINSTON CT-DOWNING	1968	3	4,600	20
	101692530	MPW / 2018 DIMP / CRESTVIEW-HIGHWOOD	1969	4	11,000	61
	101685475	MEH / 2018 DIMP / MARIE-OVERLOOK	1969	4	5,700	41
	101692534	MPW / 2018 DIMP / MAYHILL-UPP AFTON (Metz)	1959	-	3,827	8
	101417261	SPP / DIMP / SUMMIT AVE / RENEW MAIN	Unknown	-	3,900	36
	101697233	WSP / 2018 DIMP / MENDOTA RD W	1969	4	2,940	10
St Cloud	101379226	SCL / 2018 DIMP / KINGS WAY	Unknown	-	1,600	16
	101714442	ST CLOUD / 6TH ST / 11TH AVE / 10TH AVE / DIMP	Unknown	-	1,630	12
	101579939	ST CLOUD / PROSPER DR-PROGRESS RD	1970	5	2,870	3
	101602512	STC - 4TH AVE N / DIMP	1970	5	5,055	39
Southeast	101804538	RDW / 2018 DIMP / 21ST ST	1960	-	1,300	16
	101802475	RDW / 2018 DIMP / CENTRAL PARK-18TH ST	1955	-	1,600	17
	101711329	RDW / 2018 DIMP / FINRID-WRIGHT	1971	6	10,400	105
	101794997	RED WING 189784 - 9TH ST	1955	-	850	2
	101728125	WINONA / DIMP / 107558 - E 7TH ST	1964	-	3,500	46
	101591201	WINONA / DIMP / 107603 - 7TH ST W	1966	1	5,800	23
	101780666	WINONA 107542 - E 10TH ST	1965	-	3,000	37
	101889468	WINONA 107587 - E 9TH ST	1961	-	1,400	11
	101913103	WNA / 2018 DIMP / 44TH AVE-VARIOUS	1961	-	4,300	34
	101544613	WNA / 2018 DIMP / COLLEGE VIEW-PARK	1960	-	2,515	18
	101692535	WNA / 2018 DIMP / CONRAD - WINCREST	1961	-	6,860	44
	101747565	WNA / 2018 DIMP / KNOLLWOOD LN	1969	4	1,950	4
	101903273	WNA / 2018 DIMP / W 9TH-ORRIN-WAYNE	1960	-	3,400	21
Moorhead	101490329	MHD / 2018 DIMP / CEDAR LANE	1970	5	4,215	34
	101483693	MHD / 2018 DIMP/Cedar-BIRCH	1970	5	4,000	30
2018 DIMP Main and Service Replacements Total					**334,910**	**2,190**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

2019 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2019					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Moorhead	MHD / 2019 DIMP / 11TH & 12TH St S	1961	-	8,341	40
Newport	CTG / 2019 DIMP / HYDE AVE S	1961	-	3,834	81
	CTG / 2019 DIMP / E PT DOUGLAS - IDEAL	1961	-	4,723	-
	MEH / 2019 DIMP / LANSFORD - STANWICH	1967	2	6,562	38
	MEH / 2019 DIMP / FREMONT - CHIPPEWA	1954	-	8,814	77
Northwest	MHD / 2019 DIMP / 19TH ST S - 24TH AVE S	1967	2	9,743	87
Southeast	LKC / 2019 DIMP / 10TH ST - W IOWA	1972	7	2,737	22
	LKC / 2019 DIMP / LILAC LN_PINE GROVE LN	1971	6	8,012	67
	WAB/DIMP/INDUSTRIAL CT & HWY 61	1970	5	4,814	16
	WNA / DIMP / EDGEWOOD RD	1965	-	3,656	39
	WNA / DIMP / E 8TH ST-BRIDGE	1960	-	4,658	51
	WNA / 2019 DIMP / SUNSET-VARIOUS	1960	-	17,135	143
	WNA / DIMP / LAIRD ST & E.BROADWAY	1960	-	475	1
	WNA / DIMP / W 6TH ST 54TH AVE	1963	-	3,722	39
	WNA / DIMP / HILBERT ST & W.6TH ST	1948	-	7,679	33
St. Paul	RSV / DIMP / CO RD C2 - LAKEVIEW	1954	-	3,551	-
	RSV / 2019 DIMP / LEXINGTON - DIONNE	1954	-	2,136	46
	TP / 2019 DIMP / BATTLE CREEK 1	1960	-	5,005	47
	STP / 2019 DIMP / BATTLE CREEK 2	1960	-	15,593	142
White Bear Lake	MWP / DIMP / CENTURY AVE	1962	-	4,097	20
	NSP / 2019 DIMP / INDIAN WAY - 2ND ST N	1959	-	4,197	54
	MPW/ Keller Pkwy/ 1120' 2"" PE - DIMP	1969	4	1,174	1
	SHV / DIMP / HODGSON RD	1964	-	5,390	17
	SHV / 2019 DIMP / CHURCHILL - HARRIET	1963	-	3,034	-
	SHV / 2019 DIMP / KENT ST - HARRIET AVE	1972	7	6,837	36
	SHV / 2019 DIMP / INGERSON RD	1955	-	6,257	67
	VDH / 2019 DIMP / MC MENEMY	1973	8	8,625	36
2019 DIMP Main and Service Replacements - Non-Urban Project Subtotal				**160,801**	**1,200**

Northwest	Downtown St Cloud LPS Retirement Prj	1972	7	5,487	-
Southeast	RDW/ DIMP/ W MAIN - 3RD ST.	1958	-	2,584	56
St. Paul	STP / 2019 DIMP / CONGRESS-ISABEL	1965	-	6,667	42
	STP / 2019 DIMP / ROBIE ST E	1971	6	3,066	43
	STP/ 2019 DIMP/ Flandrau St	1953	-	2,188	1
	STP / 2019 DIMP / ST. PETER STREET	1951	-	3,801	12
	STP / 2019 DIMP / LOWERTOWN	1956	-	2,833	1
White Bear Lake	LTL / DIMP / EDGERTON N OF LITTLE C	1965	-	2,227	-
	NWB / 2019 DIMP / BRIGHTON SQ	1968	3	2,499	60
2019 DIMP Main and Service Replacements - Urban Project Subtotal				**31,352**	**215**

2019 DIMP Main and Service Replacements Total			**192,153**	**1,415**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

2020 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2020					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	Grand Forks - Gateway Dr NE (MN Side)	1970	5	2502	0
Moorhead	Moorhead - 30th Ave S	1970	5	4312	0
	Moorhead - 2nd Ave/6th Street	1965	-	5564	27
	Moorhead - Appletree Ln	1971	6	4252	27
	Moorhead - Rensvold Blvd	1973	8	4788	22
	Moorhead - Maple Lane	1970	5	4166	37
Newport	122935 - Cottage Grove Grospoint	1958	-	2931	35
	122943 - Cottage Grove - Grenadier	1958	-	2779	32
	122954 - Cottage Grove - Greystone	1958	-	3102	35
	Newport - 377436 5th Ave & 3rd Ave	1958	-	8836	47
	South St. Paul - Wentworth Ave	1955	-	678	0
Southeast	Bayport - 3rd Street	1961	-	3886	24
	Faribault 109442 - Irving Ave	1971	6	3512	36
	Faribault - Division St W	Unknown	-	240	1
	Goodview - 44th Ave S Phase 2	1961	-	9628	96
	117747 - Lake City - Garden and Prarie	1975	10	7798	48
	117698 - Lake City - Camp Lakeview Rd	1965	-	3922	5
	Lake City - South 7th Street	1966	1	8379	79
	Lake City - Woodburn Street	1964	-	13871	72
	Lake City - Washington St	1964	-	8125	35
	Northfield - 321 ST W	1967	2	5378	26
	Red Wing 189276 - Woodland Dr	1969	4	5077	39
	195249 - Red Wing - Maple 1	1959	-	8758	84
	Red Wing 189336 - Reding Ave	1968	3	6067	26
	195287 Maple St 2 - Red Wing	1957	-	16280	145
	189424 - Hawthorne St Red Wing	1954	-	7446	81
	Winona - Goodview Phase 1	1961	-	17259	117
	Winona - Kansas & 3rd 98289	1960	-	1672	7
	Winona - Bundy Blvd	Unknown	-	1535	1
	Winona - Carimona St	1960	-	9094	80
St. Cloud	Sauk Rapids - Hwy 23 Renew	Unknown	-	3040	11
	215835 34th Ave N St. Cloud	1964	-	7148	54
	215817 35th Ave N St. Cloud	1965	-	5262	61
	198334 - 11th St S St Cloud	1967	2	2456	35
	Westminster Ave, Watertown 356007	1965	-	7289	122
	Watertown - Angel Ave	1965	-	10401	95
St. Paul	Falcon Heights - Tatum St	1956	-	2557	24
	Falcon Heights - Arona St	1957	-	4186	43
	Roseville - Victoria Street	Unknown	-	2559	12
	Roseville - Roseville Shopping Ctr	1969	4	426	0
	Roseville - Perimeter Drive	1971	6	3570	9
	St. Paul - South of Upper Afton Phase 1	1960	-	10454	124
	St. Paul - South of Upper Afton Phase 2	1960	-	7238	93
	St. Paul - Valley View/Highwood	1967	2	4178	29
	St. Paul - Cypress & Reaney	1960	-	8478	63
	St. Paul - Highwood Ave	1967	2	2279	9
	St. Paul - Hampden	1954	-	17	0
	St. Paul - 10th St. W	1951	-	1757	0
White Bear Lake	Dellwood - Old Hwy 8	1965	-	158	0
	Lake Elmo - 31st/Jamley/Janero	1967	2	6568	34
	336199 - Lake Elmo - Stillwater Blvd.	1967	2	3746	13
	MahtomediI - Neptune	1962	-	1524	7
	18354 - Maplewood - Larpenteur Ave E	1954	-	2389	17
	Maplewood - County B E	1968	3	4552	16
	9th Avenue New Brighton	1957	-	4865	70
	12th Avenue New Brighton	1957	-	3075	26
	365726 - 10th Avenue New Brighton	1957	-	3570	39
	11th Avenue New Brighton	1957	-	3780	47
	347751 Poppyseed Drive New Brighton	1969	4	8015	71
	North Oaks - Spring Farm Lane	1965	-	8852	30
	North Oaks - Mallard Rd	1969	4	535	0
	North St. Paul - 15th Ave E	1953	-	5942	46
	North St. Paul - Oakhill Pl	Unknown	-	600	1
	North St. Paul - Division St. Phase 1	1953	-	7184	49
	North St. Paul - Division St. Phase 2	1953	-	17508	206
	North St. Paul - 11th Ave E	1968	3	2045	8
	Oakdale - 52nd Street North	1963	-	3711	20
	Shoreview - Victoria St	1959	-	4415	17
	Shoreview - Ingerson Rd	1955	-	6257	4
	Shoreview - Pinewood Dr	1970	5	9153	54
	Shoreview - Brigadoon Dr	1969	4	7737	89
	White Bear Township - South Shore Blvd - 2020	1970	5	9823	56
	White Bear Lake - Lincoln Avenue	1963	-	2467	22
	White Bear Lake - Bellaire Ave	Unkown	-	268	0
Wyoming	Forest Lake - 210th St N	1967	2	2872	16
	Wyoming - E Viking Blvd	1971	6	7175	78
	Wyoming - Forest Blvd N	1966	1	8646	20
2020 DIMP Main and Service Replacements Total				**412,564**	**3,104**

2021 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2021					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	BW/EGF/GD/DIMP/3rd ST NW&3rd Ave NW	Unknown	-	2,597	15
Moorhead	Moorhead - S 8th Street	1965	-	1,020	4
	Moorhead - Concordia College	1962	-	1,781	3
	Moorhead - S 30th Ave	1973	8	14,295	20
Newport	Concord St - St. Paul	1967	2	12,282	30
	West St. Paul - Moreland Avenue	Unknown	-	3,034	8
	South St. Paul - Marie Ave	Unknown	-	5,065	23
Northwest	St. Cloud - 14th Ave NE	Unknown	-	680	11
	St. Cloud - 6th Ave S	1979	14	2,151	17
	St. Cloud - Rusan Street	1969	4	5,447	10
	St. Cloud - Sherwood Mobile Home Park	1968	3	9,212	109
	W. St. Germain St. - St. Cloud	1977	12	5,022	20
St. Paul	Roseville - Terminal Road	1966	1	3,221	8
	County B 2 - DIMP/RECON	1967	2	3,071	15
	Cleveland Ave N	Unknown	-	3,907	20
	St. Paul - Churchill	1920	-	8,678	100
	STP 139651 - COMO Ave	1955	-	2,327	14
Southeast	Woodland Dr & Greenleaf Rd Faribault	1971	6	7,054	27
	Faribault - Downtown	1959	-	7,533	108
	Lincoln Ave NW & 2nd St NW Farib	1971	6	7,457	72
	Goodview - 54th	1961	-	5,250	13
	Lake City - N High St Ph 1	1964	-	2,783	16
	Old W Main & Jackson - Red Wing	1960	-	1,094	3
	West Ave & 9th St	1955	-	51	0
	Old Zumbrota St & Guernsey Ln - Red Wing	1977	12	465	8
	Red Wing - Levee Road	1955	-	1,269	0
	Red Wing - W 5th St	1967	2	3,169	24
	Winona - Cottonwood Dr	1977	12	1,247	6
	Winona - Marian & Gale	1965	-	5,014	73
	Winona - Industrial Park Rd	1965	-	5,749	11
	Winona - Frontenac Dr & Menard Rd	1975	10	2,854	7
	Lion's Park - Winona	Unknown	-	195	1
White Bear Lake	Arden Hills - Lexington Ave	1965	-	5,794	24
	Little Canada - S Owasso Blvd	1961	-	2,519	6
	Little Canada - Country Drive	1972	7	9,262	11
	Maplewood - Kohlman Avenue	1970	5	9,060	28
	Arden Hills - Red Fox Rd	1968	3	3,767	8
	Mahtomedi - Wildwood Road	1962	-	2,232	18
	North Oaks - West Shore Rd	1969	4	10,320	26
	New Brighton 7th St NW	1959	-	209	0
	Windsor Court - New Brighton	1967	2	3,744	82
	HWY 36 - Castle Ave	1970	5	3,626	9
	Lexington & Cannon	1961	-	2,600	2
	Shoreview - Rice/Marie Street	1967	2	1,693	10
	Lakewood Ave - WBL	1959	-	14,168	112
Wyoming	Forest Lake - Harrow Ave	1968	3	5,172	0
	Forest Ave - Stacy	1970	5	1,031	10
	Forest Lake - Lake St & 4th Ave SW	1961	-	3,375	11
	Broadway St - Lindstrom	1966	1	2,738	23
2021 DIMP Main and Service Replacements Total				**216,284**	**1,176**

2022 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2022					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	EGF - 17th St NW and 8th Ave NW	Unknown	-	4,940	11
Moorhead	Moorhead - 5th and 4th St S	1961	-	26,000	296
	Moorhead - 16th St N	1962	-	2,850	28
	Moorhead - 20th St N	1961	-	7,750	84
	Moorhead Center Mall	1972	7	2,950	4
	Moorhead - Highway 75	1961	-	8,050	52
Newport	IGH -Cahill Ave & Carleda Way	Unknown	-	4,350	35
	IGH - Maple Park Drive & Dodd	1966	1	1,930	32
	IGH - S Robert Trail	1970	5	6,050	31
	Oakdale - Pedersen St & Old Hudson St	1963	-	1,200	4
Northwest	Delano - 3rd St N	1966	1	15,590	178
	Delano - Highlands Ridge	Unknown	-	6,000	41
	Watertown - Hillside Dr	Unknown	-	400	6
	Watertown - White St	Unknown	-	2,100	5
St. Paul	Falcon Heights - Larpenteur Ave	Unknown	-	1,250	4
	Roseville - Cty B2 & Cleveland Ave	1967	2	5,800	30
	Roseville - Cty B2 & Lexington	1954	-	7,450	92
	STP 139472 - Rice Street	1980	15	800	24
	St. Paul - Ohio Street	1931	-	1,050	6
	St. Paul - 4th Ave	1978	13	2,675	38
	St. Paul - Prior Ave and University Ave	Unknown	-	2,650	13
	St. Paul - Wabasha St and 4th St	1967	2	1,870	10
	St. Paul - Pedersen St & Old Hudson St	1963	-	6,900	23
	St. Paul - Larpenteur & Jackson	1959	-	5,100	0
	St. Paul - Whitall/Payne Ave	1973	8	400	8
Southeast	Faribault - 2nd St NW	1956	-	4,007	83
	Faribault - Greenwood Place	1968	3	4,570	43
	Northfield - Woodley St W	1971	6	2,240	11
	Lake City - Oak St	1965	-	2,400	25
	Lake City - N 6th St	1965	-	3,400	40
	Lake City - High Street Ph 2	1955	-	2,920	10
	Lake City - Oak St - Additional Work	1965	-	1,600	18
	Red Wing - Featherstone Rd	1972	7	1,790	15
	Winona - Frontenac Dr & Menard Rd	1975	10	3,250	16
White Bear Lake	North Shore Trail	1965	-	7,280	100
	Little Canada - Rose & McMenemy	1965	-	4,800	46
	Old Wildwood Rd	1962	-	2,800	8
	McMenemy Street	1965	-	5,000	55
	New Brighton – 7th St NW	1959	-	5,750	48
	Lexington & Cannon Phase 2	1961	-	10,151	86
	Victoria St (former Cty Rd E) - Shoreview	1970	5	4,780	13
	WBT - Chatham & Chippenham Lane	1967	2	700	9
	Birch Knoll Dr	1965	-	2,200	24
	White Bear - Martin Way	1961	-	9,700	40
Wyoming	Lindstrom - Elm Ave	1965	-	3,150	36
	Lindstrom - Pleasant Ave	1965	-	3,600	10
	Lindstrom - Newell Ave	1966	1	3,150	24
	Wyoming - E Vikings Blvd	1967	2	5,300	62
2022 DIMP Main and Service Replacements Total				**220,643**	**1,877**

TIMP and DIMP O&M Actuals for 2021 and Budget Estimates for 2022-2027

	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
TIMP Projects							
NSPM Transmission Pipeline Assessments O&M	723,410	103,626	625,000	1,250,000	550,000	725,000	600,000
State of Minnesota Load Dispatch Jurisdictional Al	88.66%	88.14%	88.21%	88.40%	88.38%	87.96%	88.13%
TIMP O&M allocated to MN Jurisdiction	**641,397**	**91,337**	**551,298**	**1,104,986**	**486,069**	**637,745**	**528,787**
DIMP Projects							
DIMP O&M direct assigned to MN Jurisdiction	798,020	208,172	250,000	294,000	250,000	320,000	250,000
Total Operations & Maintenance Expenses	**1,439,417**	**299,508**	**801,298**	**1,398,986**	**736,069**	**957,745**	**778,787**

		2023	
Cap Structure (Last Authorized)			
	Long Term Debt %	46.89%	
	Long Term Debt Cost	4.13%	1.94%
	Short Term Debt %	0.61%	
	Short Term Debt Cost	0.94%	0.00573400%
	Weighted Cost of Debt	1.94%	1.94229100%
	Common Stock %	52.50%	
	Common Stock Cost	9.57%	
	Weighted Cost of Equity	5.02%	
	Rate of Return	6.96%	
Tax Rates			
Income Tax Rates			
	State Income Tax Rate	9.80%	
	Federal Income Tax Rate	21.00%	
Composite Income Tax Rate			
	State Composite Income Tax Rate	28.742%	
	Company Composite Income Tax Rate	28.032%	
Property Tax Rate		1.52%	
Book Depreciation Lives			
	Transmission	63.30	
	Distribution	38.77	
	Software	2.16	
Net Salvage %			
	Transmission	-15.00%	
	Distribution	-22.85%	
	Software	-	
Book Depreciation Rates			
	Transmission	1.51%	
	Distribution	2.34%	
	Software	20.53%	

*Note: Book Depreciation Rates reflect Average Remaining Life

Magnitude of GUIC in Relation to
Natural Gas Rate Case - Docket No. G002/GR-21-678

" 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"

2022 Rate Case Settlement, Cost of Service Study - Docket G002/GR-21-678
($000s)

Operating Revenues	2022 TY	
Retail	801,070	Fn 1
Base Cost of Gas	558,249	
Base Retail Revenue, Net of Base Cost of Gas	242,821	[A]
Capital Expenditures	163,636	[B]

Proposed Gas Utility Infrastructure Costs (GUIC) Rider
($000s)

	2022	2023		
Revenue Requirement Forecast	33,818	37,547	Fn 2	[C]
% of GUIC Revenue as Compared to Base Revenue Approved in Docket G-002/GR-21-678 (2022 TY)	13.9%	15.5%		= [C] / [A]
Capital Expenditures Forecast	74,918	53,723		[D]
% of GUIC Capital Expenditures as Compared to Expenditures Approved in Docket G-002/GR-21-678 (2022 TY)	45.8%	32.8%		= [D] / [B]

Notes

Fn 1 Excludes $5.09 million of retail revenue that will continue to be collected through the GUIC Rider

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. The Company anticipates final base rate implementation in 2023, which will reduce the 2023 GUIC revenue requirements due to projects rolling into base rates.

Annual Revenue Requirements Tracker Summary for 2021-2027

	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Operations & Maintenance Expenses							
TIMP	641,397	91,337	551,298	1,104,986	486,069	637,745	528,787
DIMP	798,020	208,172	250,000	294,000	250,000	320,000	250,000
Total Operations & Maintenance Expenses	1,439,417	299,508	801,298	1,398,986	736,069	957,745	778,787
Capital-Related Revenue Requirements							
TIMP	13,707,468	13,734,796	13,665,352	13,639,047	13,477,976	13,296,173	13,254,143
DIMP	16,507,807	22,186,467	25,973,675	30,668,912	33,518,442	36,369,161	39,311,030
Mandated Relocates	638,498	2,519,517	4,918,828	6,415,224	8,057,749	9,410,211	10,789,602
Total Capital-Related Revenue Requirements	30,853,773	38,440,780	44,557,855	50,723,182	55,054,167	59,075,545	63,354,775
Regulatory Treatment							
GUIC Retirement Revenue Credits	-	-	-	-	-	-	-
Revenue Requirement in Base Rates	(846,937)	-	-	-	-	-	-
Other Disallowances	(5,892,531)	(6,172,795)	(7,812,073)	(9,167,558)	(10,487,550)	(11,769,567)	(13,080,108)
Revenue Requirement Subtotal	**25,553,722**	**32,567,493**	**37,547,080**	**42,954,610**	**45,302,686**	**48,263,723**	**51,053,454**
Prior Year Carryover	216,971	1,250,331	-	-	-	-	-
Revenue Requirement (RR)	**25,770,693**	**33,817,824**	**37,547,080**	**42,954,610**	**45,302,686**	**48,263,723**	**51,053,454**
Revenue Collections (RC)	24,520,362	33,817,824	37,547,080	42,954,610	45,302,686	48,263,723	51,053,454
Carryover Balance (RR - RC)	1,250,331	-	-	-	-	-	-

	Jan-21 Actual	Feb-21 Actual	Mar-21 Actual	Apr-21 Actual	May-21 Actual	Jun-21 Actual	Jul-21 Actual	Aug-21 Actual	Sep-21 Actual	Oct-21 Actual	Nov-21 Actual	Dec-21 Actual	2021 Annual
Operations & Maintenance Expenses													
TIMP	1,505	19,354	8,056	13,032	14,671	6,751	11,514	213,948	284,754	(53,056)	111,897	8,971	641,397
DIMP	3,369	5,715	21,143	(4,628)	3,923	-	560	934	126,730	403,320	159,880	77,073	798,020
Total Operations & Maintenance Expenses	4,874	25,070	29,200	8,404	18,594	6,751	12,074	214,882	411,484	350,264	271,776	86,044	1,439,417
Capital-Related Revenue Requirements													
TIMP	1,125,657	1,568,355	1,127,443	1,016,307	1,117,832	1,115,145	1,113,914	1,110,131	1,108,479	1,099,938	1,093,270	1,110,996	13,707,468
DIMP	1,319,484	1,310,808	1,298,188	1,267,360	1,263,372	1,261,609	1,216,669	1,229,232	1,359,801	1,504,367	1,684,158	1,792,758	16,507,807
Mandated Relocates	89,576	17,141	15,824	(46,116)	(53,009)	(15,736)	73,923	76,758	108,836	102,178	133,226	135,897	638,498
Total Capital-Related Revenue Requirements	2,534,717	2,896,304	2,441,455	2,237,551	2,328,195	2,361,018	2,404,507	2,416,121	2,577,117	2,706,484	2,910,654	3,039,651	30,853,773
Revenue Requirement in Base Rates	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(70,578)	(846,937)
Regulatory Treatment	(2,693,286)	(255,607)	(256,779)	(261,957)	(270,889)	(279,572)	(287,686)	(298,801)	(309,738)	(318,795)	(327,347)	(332,073)	(5,892,531)
Revenue Requirement Subtotal	**(224,273)**	**2,595,189**	**2,143,297**	**1,913,420**	**2,005,322**	**2,017,618**	**2,058,317**	**2,261,624**	**2,608,284**	**2,667,374**	**2,784,505**	**2,723,044**	**25,553,722**

Prior Year Carryover Balance	216,971
Total Revenue Requirements	25,770,693
Revenue Collections (Mar 22 - Feb 23)	24,520,362
Current Year Carryover Balance	1,250,331

	Jan-22 Actual	Feb-22 Actual	Mar-22 Actual	Apr-22 Actual	May-22 Actual	Jun-22 Actual	Jul-22 Forecast	Aug-22 Forecast	Sep-22 Forecast	Oct-22 Forecast	Nov-22 Forecast	Dec-22 Forecast	2022 Annual
Operations & Maintenance Expenses													
TIMP	10,748	10,333	10,816	6,016	539	-	-	26,442	26,442	-	-	-	91,337
DIMP	(12,483)	28,298	1,370	1,233	300	-	-	36,445	39,928	23,260	49,613	40,208	208,172
Total Operations & Maintenance Expenses	(1,734)	38,631	12,186	7,249	839	-	-	62,887	66,370	23,260	49,613	40,208	299,508
Capital-Related Revenue Requirements													
TIMP	1,145,948	1,143,594	1,141,569	1,138,172	1,137,996	1,153,127	1,123,703	1,132,483	1,138,959	1,141,634	1,161,121	1,176,493	13,734,796
DIMP	1,713,512	1,722,789	1,713,073	1,695,306	1,732,881	1,858,848	1,929,611	1,913,644	1,931,571	1,965,984	1,995,869	2,013,380	22,186,467
Mandated Relocates	155,139	154,085	226,118	136,040	112,228	113,696	136,617	227,638	273,393	302,153	337,272	345,136	2,519,517
Total Capital-Related Revenue Requirements	3,014,598	3,020,468	3,080,760	2,969,518	2,983,105	3,125,671	3,189,931	3,273,764	3,343,922	3,409,771	3,494,262	3,535,009	38,440,780
Revenue Requirement in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Treatment	(1,991,516)	(340,494)	(341,879)	(346,712)	(358,952)	(374,341)	(382,496)	(389,256)	(398,844)	(406,702)	(415,649)	(425,954)	(6,172,795)
Revenue Requirement Subtotal	**1,021,348**	**2,718,605**	**2,751,067**	**2,630,056**	**2,624,992**	**2,751,329**	**2,807,434**	**2,947,396**	**3,011,448**	**3,026,329**	**3,128,226**	**3,149,262**	**32,567,493**

Prior Year Carryover Balance	1,250,331
Total Revenue Requirements	33,817,824
Revenue Collections (Mar 22 - Feb 23)	33,817,824
Current Year Carryover Balance	-

	Jan-23 Forecast	Feb-23 Forecast	Mar-23 Forecast	Apr-23 Forecast	May-23 Forecast	Jun-23 Forecast	Jul-23 Forecast	Aug-23 Forecast	Sep-23 Forecast	Oct-23 Forecast	Nov-23 Forecast	Dec-23 Forecast	2023 Annual
Operations & Maintenance Expenses													
TIMP	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	45,942	551,298
DIMP	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	250,000
Total Operations & Maintenance Expenses	66,775	66,775	66,775	66,775	66,775	66,775	66,775	66,775	66,775	66,775	66,775	66,775	801,298
Capital-Related Revenue Requirements													
TIMP	1,149,904	1,148,833	1,147,665	1,137,731	1,131,500	1,125,692	1,126,521	1,127,448	1,134,644	1,141,528	1,142,204	1,151,683	13,665,352
DIMP	1,893,247	1,897,472	1,907,807	1,912,264	1,945,624	2,123,367	2,315,418	2,354,504	2,397,828	2,405,304	2,396,056	2,424,784	25,973,675
Mandated Relocates	357,499	364,453	372,244	373,002	378,386	391,793	409,530	426,483	442,426	456,914	465,427	480,671	4,918,828
Total Capital-Related Revenue Requirements	3,400,650	3,410,758	3,427,715	3,422,996	3,455,510	3,640,853	3,851,468	3,908,435	3,974,898	4,003,745	4,003,687	4,057,138	44,557,855
Revenue Requirement in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Treatment	(2,258,760)	(430,808)	(430,878)	(437,362)	(461,423)	(500,357)	(524,998)	(535,730)	(546,286)	(554,953)	(563,117)	(567,402)	(7,812,073)
Revenue Requirement Subtotal	**1,208,665**	**3,046,725**	**3,063,612**	**3,052,409**	**3,060,862**	**3,207,271**	**3,393,246**	**3,439,480**	**3,495,387**	**3,515,567**	**3,507,345**	**3,556,512**	**37,547,080**
												Prior Year Carryover Balance	-
												Total Revenue Requirements	**37,547,080**

Revenue Requirements Category Descriptions

Attachments G and H to this Petition respectively provide the TIMP and DIMP annual revenue requirements for 2023. 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 2023 plant in service for gas utility infrastructure projects (GUIC), the $133.8 million for TIMP (Attachment G) and $296.5 million for DIMP and Mandated Relocations (Attachment H) reflect the dollar-value portion of the project in service as of December 31, 2023, 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 2023 book depreciation reserve for GUIC projects, the $17.0 million for TIMP (Attachment G) and $14.0 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of the plant in service that has been recovered as of December 31, 2023, 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 2023 accumulated deferred taxes for GUIC projects, the $16.2 million for TIMP (Attachment G) and $17.0 million for DIMP and Mandated Relocations (Attachment H) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2023, 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 2023 debt return for GUIC return the Company is allowed in order to recover its weighted cost of debt for financing its capital projects, the $2.0 million for TIMP (Attachment G) and $3.3 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of debt return the Company is allowed for January 2023 - December 2023 based on the cost of debt and ratios in the Company's recently settled natural gas rate case, Docket No. G002/GR-21-678.

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 2023 equity return for GUIC projects, the $5.1 million for TIMP (Attachment G) and $11.8 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of return on equity the Company is allowed for January 2023 - December 2023 based on the equity ratio in the Company's recently settled natural gas rate case, Docket No. G002/GR-21-678.

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 2023 property tax amount for GUIC projects, the $2.0 million for TIMP (Attachment G) and $3.5 million for DIMP and Mandated Relocations (Attachment H) reflect property tax rates based on ending plant in service as of December 31, 2020 payable in 2023.

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 2023 book depreciation for GUIC projects, the $2.5 million for TIMP (Attachment G) and $6.1 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of plant in service that is being recovered through depreciation expense from January 2023-December 2023 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 2023 deferred taxes for GUIC projects, the $1.7 million for TIMP (Attachment G) and $1.9 million for DIMP and Mandated Relocations (Attachment H) reflect the January 1, 2023 - December 31, 2023 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 2023 current taxes for GUIC projects, the $0.4 million for TIMP (Attachment G) and $3.0 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of current income taxes the Company is anticipating paying as a result of the taxable income being generated by GUIC projects.

Northern States Power Company

Monthly Collection Pattern
GUIC Rate Factor Calculations

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22
Revenue Requirement Subtotal	(224,273)	2,595,189	2,143,297	1,913,420	2,005,322	2,017,618	2,058,317	2,261,624	2,608,284	2,667,374	2,784,505	2,723,044	1,021,348	2,718,605
Revenue Collections	3,320,619	3,469,930	2,186,730	1,420,000	848,115	510,703	452,590	483,098	505,076	969,805	1,921,177	2,891,149	3,876,734	3,387,264
Carryover Rollforward:														
Carryover Beginning Balance	7,280,725	3,960,105	490,176	19,625,979	16,062,682	15,214,567	14,703,864	14,251,274	13,768,176	13,263,100	12,293,295	10,372,118	7,480,969	3,604,235
Activity (Under/(Over) Collection)	(3,544,892)	(874,741)	(43,433)	493,420	1,157,207	1,506,915	1,605,727	1,778,526	2,103,208	1,697,569	863,328	(168,105)	(2,855,386)	(668,658)
Deferral Impact	224,273	(2,595,189)	19,179,237	(4,056,717)	(2,005,322)	(2,017,618)	(2,058,317)	(2,261,624)	(2,608,284)	(2,667,374)	(2,784,505)	(2,723,044)	(1,021,348)	(2,718,605)
Carryover Ending Balance	3,960,105	490,176	19,625,979	16,062,682	15,214,567	14,703,864	14,251,274	13,768,176	13,263,100	12,293,295	10,372,118	7,480,969	3,604,235	216,971

2019 Annual Rev Req (Jan 2019-Dec 2019)	22,041,523	matches Docket M-19-664 Compliance
Carryover Balance at beginning of collection period	(1,189,269)	matches DR-15 Att A in 20-798
Total 2019 Revenue Requirement	20,852,254	matches Docket M-19-664 Compliance
Revenue Collections from Mar 2020-Feb 2021	20,362,078	matches Docket M-19-664 Compliance
Carryover Balance at End of collection period	490,176	matches Docket M-19-664 Compliance

2020 Annual Revenue Requirements (Jan 2020-Dec 2020)	19,179,237
Carryover Balance at beginning of collection period	490,176
Total 2020 Revenue Requirement	19,669,412
Revenue Collections from Mar 2021-Feb 2022	19,452,441
Carryover Balance at End of collection period	216,971

Rate by Class:	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Estimated Revenue Collections	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22
Residential	2,370,755	2,483,388	1,539,963	964,757	522,954	249,389	208,047	235,587	271,658	578,200	1,309,318	2,006,342	2,776,178	2,402,531
Commercial Firm	701,810	743,709	486,481	290,778	165,051	105,569	80,156	88,331	105,118	210,362	426,384	643,549	856,464	776,155
Commercial Demand Billed	50,763	55,411	48,688	32,189	28,440	21,872	20,847	23,662	24,914	32,252	39,572	48,314	63,348	60,960
Interruptible	133,036	126,953	65,373	70,585	55,036	48,719	53,117	52,488	52,763	72,042	82,620	115,864	132,488	89,386
Transport	64,257	60,469	46,226	61,691	76,634	85,155	90,423	83,030	50,623	76,949	63,283	77,079	48,256	58,231
	3,320,619	3,469,930	2,186,730	1,420,000	848,115	510,703	452,590	483,098	505,076	969,805	1,921,177	2,891,149	3,876,734	3,387,264

Sales by Customer Group
Residential
Commercial Firm
Commercial Demand Billed
Interruptible
Transport
Total Sales

Allocated Cost Per therm
Residential
Commercial Firm
Commercial Demand Billed
Interruptible
Transport

Monthly Collection Pattern
GUIC Rate Factor Calculations

	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
Revenue Requirement Subtotal	2,751,067	2,630,056	2,624,992	2,751,329	2,807,434	2,947,396	3,011,448	3,026,329	3,128,226	3,149,262	1,208,665	3,046,725
Revenue Collections	2,622,769	1,787,374	817,750	526,030	652,698	690,937	732,947	1,631,751	2,587,827	3,935,244	4,496,040	4,038,996
	11%	7%	3%	2%	3%	3%	3%	7%	11%	16%	18%	16%
Carryover Rollforward:												
Carryover Beginning Balance	216,971	25,898,991	21,360,550	20,542,800	20,016,770	19,364,071	18,673,135	17,940,188	16,308,437	13,720,610	9,785,366	5,289,327
Activity (Under/(Over) Collection)	128,297	842,682	1,807,242	2,225,299	2,154,736	2,256,459	2,278,501	1,394,578	540,399	(785,981)	(3,287,375)	(992,271)
Deferral Impact	25,553,722	(5,381,122)	(2,624,992)	(2,751,329)	(2,807,434)	(2,947,396)	(3,011,448)	(3,026,329)	(3,128,226)	(3,149,262)	(1,208,665)	(3,046,725)
Carryover Ending Balance	25,898,991	21,360,550	20,542,800	20,016,770	19,364,071	18,673,135	17,940,188	16,308,437	13,720,610	9,785,366	5,289,327	1,250,331

2019 Annual Rev Req (Jan slight change from 20-xx Reply comments due to additional two months of actuals
Carryover Balance at beginning o
Total 2019 Reve

Revenue Collections from Ma has not been filed anywhere yet
Carryover Balance at End o

2021 Annual Revenue Requirements (Jan 2021-Dec 2021)	25,553,722
Carryover Balance at beginning of collection period	216,971
Total 2021 Revenue Requirement	25,770,693
Revenue Collections from Mar 2022-Feb 2023	24,520,362
Carryover Balance at End of collection period	1,250,331

Rate by Class:	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Estimated Revenue Collections	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
Residential	1,811,597	1,211,076	500,690		274,471	311,151	393,816	1,011,011	1,769,141	2,757,504	3,257,249	2,894,274
Commercial Firm	599,251	407,298	181,704		100,818	111,603	141,831	333,071	549,804	844,348	958,755	894,319
Commercial Demand Billed	50,907	40,574	30,792		185,752	174,467	106,610	165,828	132,563	159,898	98,885	114,050
Interruptible	115,551	85,046	67,972		91,657	93,716	90,689	121,842	136,319	173,493	181,151	136,352
Transport	45,463	43,380	36,592			-	-	-	-	-	-	-
	2,622,769	1,787,374	817,750	526,030	652,698	690,937	732,947	1,631,751	2,587,827	3,935,244	4,496,040	4,038,996

Reflects last twelve months of actual sales (June 2021 - July 2022)

Sales by Customer Group	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
Residential	613,596	695,596	880,398	2,260,171	3,955,013	6,164,554	7,281,762	6,470,311
Commercial Firm	429,950	475,942	604,857	1,420,419	2,344,703	3,600,819	4,088,720	3,813,928
Commercial Demand Billed	5,283,007	4,962,053	3,032,102	4,716,324	3,770,239	4,547,694	2,812,399	3,243,713
Interruptible	847,260	866,292	838,318	1,126,285	1,260,107	1,603,740	1,674,528	1,260,416
Transport	-	-	-	-	-	-	-	-
Total Sales	7,173,814	6,999,883	5,355,676	9,523,200	11,330,063	15,916,808	15,857,408	14,788,368

Allocated Cost Per therm								
Residential	$0.4473161	$0.4473161	$0.4473161	$0.4473161	$0.4473161	$0.4473161	$0.4473161	$0.4473161
Commercial Firm	$0.2344878	$0.2344878	$0.2344878	$0.2344878	$0.2344878	$0.2344878	$0.2344878	$0.2344878
Commercial Demand Billed	$0.0351603	$0.0351603	$0.0351603	$0.0351603	$0.0351603	$0.0351603	$0.0351603	$0.0351603
Interruptible	$0.1081801	$0.1081801	$0.1081801	$0.1081801	$0.1081801	$0.1081801	$0.1081801	$0.1081801
Transport	$0.0000000	$0.0000000	$0.0000000	$0.0000000	$0.0000000	$0.0000000	$0.0000000	$0.0000000

GUIC Over / Under Collection

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**	**Jan-21**	**Feb-21**
Carryover Beginning Balance	4,274,251	1,351,490	(1,189,269)	20,282,215	17,044,266	16,174,716	15,591,606	15,124,029	14,654,261	14,056,062	12,473,261	10,337,052	7,280,725	3,960,105
Revenue Requirement	380,782	1,576,972	1,635,200	1,575,500	1,522,193	1,548,740	1,593,753	1,640,329	1,935,668	1,756,430	2,128,637	1,885,030	(224,273)	2,595,189
Deferral Impact	(380,782)	(1,576,972)	22,041,523	(3,210,700)	(1,522,193)	(1,548,740)	(1,593,753)	(1,640,329)	(1,935,668)	(1,756,430)	(2,128,637)	(1,885,030)	224,273	(2,595,189)
Revenue Collections														
Residential														
Commercial Firm														
Commercial Demand Billed														
Interruptible														
Transport														
Total Revenue Collections	2,922,760	2,540,760	2,205,239	1,602,749	869,550	583,110	467,577	469,767	598,200	1,582,800	2,136,209	3,056,328	3,320,619	3,469,930
Activity (Under/(Over) Collection)	**1,351,490**	**(1,189,269)**	**20,282,215**	**17,044,266**	**16,174,716**	**15,591,606**	**15,124,029**	**14,654,261**	**14,056,062**	**12,473,261**	**10,337,052**	**7,280,725**	**3,960,105**	**490,176**

GUIC Over / Under Collection

Carryover Rollforward:	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**
Carryover Beginning Balance	490,176	19,625,979	16,062,682	15,214,567	14,703,864	14,251,274	13,768,176	13,263,100	12,293,295	10,372,118	7,480,969	3,604,235
Revenue Requirement	2,143,297	1,913,420	2,005,322	2,017,618	2,058,317	2,261,624	2,608,284	2,667,374	2,784,505	2,723,044	1,021,348	2,718,605
Deferral Impact	19,179,237	(4,056,717)	(2,005,322)	(2,017,618)	(2,058,317)	(2,261,624)	(2,608,284)	(2,667,374)	(2,784,505)	(2,723,044)	(1,021,348)	(2,718,605)
Revenue Collections												
Residential												
Commercial Firm												
Commercial Demand Billed												
Interruptible												
Transport												
Total Revenue Collections	2,186,730	1,420,000	848,115	510,703	452,590	483,098	505,076	969,805	1,921,177	2,891,149	3,876,734	3,387,264
Activity (Under/(Over) Collection)	**19,625,979**	**16,062,682**	**15,214,567**	**14,703,864**	**14,251,274**	**13,768,176**	**13,263,100**	**12,293,295**	**10,372,118**	**7,480,969**	**3,604,235**	**216,971**

GUIC Over / Under Collection

Carryover Rollforward:	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**
Carryover Beginning Balance	216,971	25,898,991	21,360,550	20,542,800	20,016,770	19,364,071	18,673,135	17,940,188	16,308,437	13,720,610	9,785,366	5,289,327
Revenue Requirement	2,751,067	2,630,056	2,624,992	2,751,329	2,807,434	2,947,396	3,011,448	3,026,329	3,128,226	3,149,262	1,208,665	3,046,725
Deferral Impact	25,553,722	(5,381,122)	(2,624,992)	(2,751,329)	(2,807,434)	(2,947,396)	(3,011,448)	(3,026,329)	(3,128,226)	(3,149,262)	(1,208,665)	(3,046,725)
Revenue Collections					Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential					274,471	311,151	393,816	1,011,011	1,769,141	2,757,504	3,257,249	2,894,274
Commercial Firm					100,818	111,603	141,831	333,071	549,804	844,348	958,755	894,319
Commercial Demand Billed					185,752	174,467	106,610	165,828	132,563	159,898	98,885	114,050
Interruptible					91,657	93,716	90,689	121,842	136,319	173,493	181,151	136,352
Transport					-	-	-	-	-	-	-	-
Total Revenue Collections	2,622,769	1,787,374	817,750	526,030	652,698	690,937	732,947	1,631,751	2,587,827	3,935,244	4,496,040	4,038,996
Activity (Under/(Over) Collection)	**25,898,991**	**21,360,550**	**20,542,800**	**20,016,770**	**19,364,071**	**18,673,135**	**17,940,188**	**16,308,437**	**13,720,610**	**9,785,366**	**5,289,327**	**1,250,331**

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 Rider charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Rider Factor for the appropriate customer group. ~~T~~ ~~T~~

DETERMINATION OF GUIC RIDER FACTORS
A separate GUIC Rider Factor shall be calculated for the following ~~five~~four customer groups: (1) Residential, (2) Commercial Firm, (3) Commercial Demand Billed, and (4) Interruptible~~, and (5) Transportation~~. The GUIC Rider Factor for each customer group shall be the value obtained by multiplying the balance of the GUIC Rider Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period. T T ~~T~~ ~~T~~

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

The current GUIC Rider Factor for each customer group is:

Residential	\$0.~~033864~~062247 per therm	R
Commercial Firm	\$0.~~018572~~038502 per therm	R
Commercial Demand Billed	\$0.~~014666~~005892 per therm	R
Interruptible	\$0.~~010591~~015029 per therm	R
~~Transportation~~	~~\$0.001602 per therm~~	D

Recoverable GUIC Rider Expenses ~~T~~
Recoverable GUIC Rider 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 Rider Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Rider Factor shall be credited to the GUIC Rider Tracker Account. The GUIC Rider Tracker Account includes adjustments for forecasted revenue requirements compared to actual revenue requirements and for actual revenue requirements compared to actual revenue recovery. ~~T~~ ~~T~~ ~~T~~ ~~T~~

(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 Rider charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Rider Factor for the appropriate customer group.

DETERMINATION OF GUIC RIDER FACTORS
A separate GUIC Rider Factor shall be calculated for the following four customer groups: (1) Residential, (2) T
Commercial Firm, (3) Commercial Demand Billed, and (4) Interruptible. The GUIC Rider Factor for each customer T
group shall be the value obtained by multiplying the balance of the GUIC Rider Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period.

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

The current GUIC Rider Factor for each customer group is:

Residential	$0.062247 per therm	R
Commercial Firm	$0.038502 per therm	R
Commercial Demand Billed	$0.005892 per therm	R
Interruptible	$0.015029 per therm	R
		D

<u>Recoverable GUIC Rider Expenses</u>
Recoverable GUIC Rider 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 Rider Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Rider Factor shall be credited to the GUIC Rider Tracker Account. The GUIC Rider 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)

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 Minnesota Public Utilities 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] Before submitting the original 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.[3]

In its February 8, 2018 Order,[4] the Commission declined to adopt the proposed metrics and ordered us to continue to discuss metrics with other parties. The Company continued the discussion with stakeholders on metrics prior to submitting the metrics proposal below, through meetings with stakeholders from the Commission Staff, the Department of Commerce (Department), Minnesota Office of Pipeline Safety (MNOPS), and Office of the Attorney General (OAG), on September 26, 2018 and again on August 27, 2019.

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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* Petition, Compliance Filing, and Annual Report, Page 42, Docket No. G002/M-17-787 (November 1, 2017).
[4] *See* ORDER APPROVING RIDER WITH MODIFICATIONS, Docket No. G002/M-16-891 (February 8, 2018).

The Commission also declined to approve the performance metrics we proposed in our 2019 GUIC Rider filing and required continued discussions to gain consensus.[5] In late 2019, the Company asked stakeholders to provide informal comments on the current proposal. Both the Department and OAG provided information laying out their positions on metrics for the GUIC. Based on the comments provided by the parties, the differences between the Company and parties appeared to be small.

On September 16, 2020, the Department filed Comments in our 2020 GUIC Rider docket and discussed their current position on metrics. They stated:

> *Given Xcel's ongoing efforts to address the Department's concerns, the Department is reassured that the Company will continue to refine performance metrics reporting as it is able to. Therefore, the Department is no longer opposed to the metrics currently proposed by the Company.*[6]

Given the Department's statement, we believe we have reached a consensus on a baseline set of GUIC Rider metrics that we can start with. We take to heart their understanding that we will continue to refine our metrics over time in order to provide a level of information that will make the review of our GUIC Rider filings easier.

In its May 3, 2021 Order[7], the Commission stated it would not establish any specific performance metrics or related requirements in the Order, and that the Commission anticipates that it will have the opportunity to evaluate a proposal for specific, concrete performance metrics in Xcel Energy's 2021 GUIC Petition.

On June 23, 2021, the Department filed Comments in our 2021 GUIC Rider docket and discussed their current position on metrics. They stated:

> *The Department also reviewed the performance metric outcomes of Xcel's prior years' project work, included in Attachment U, and concludes that Xcel's reported performance results appear reasonable.*[8]

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[5] *See* ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS, Docket No. G002/M-18-692 (January 9, 2020), Order Point 18.
[6] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-19-664 (September 16, 2020), Pages 15-16.
[7] *See* ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS, Docket No. G002/M-19-664 (May 3,2021), Order Point 6.
[8] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-20-799 (June 23, 2021), Pages 18-19.

Within our 2022 GUIC Rider docket, we proposed new cost and effectiveness performance metrics for the new programs that started in 2021 (casing renewal and mandated relocation programs), and additional metrics for the new portion of our distribution valve replacement program. These proposed metrics are relevant measurements of performance. Having full experience data for 2021 the Company is now providing these metric results. We look forward to continuing our work with the Department to refine these metrics over time.

On July 11, 2022, the Department filed Comments in our 2022 GUIC Rider docket and the only reference to performance metrics was regarding using them as gas asset planning tools in the future of gas docket. They stated:

> *The Commission may also wish to consider discussing other gas asset planning tools used in the GUIC proceedings – such as risk assessments and performance metrics – in the future of gas docket.*[9]

Table 1 below shows the TIMP and DIMP performance metrics we believe would be most useful at this time.

Table 1

Recommended Performance Metrics - TIMP

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
TIMP	Transmission Pipeline Integrity Assessments	Estimated versus actual costs per project	Anomalies repaired by type
	ASVs and RCVs	Estimated versus actual costs per project	Reduction in response time per project
	Programmatic Replacement and MAOP Remediation	Estimated versus actual costs per project	Percentage of high/medium risk projects system-wide
	Casing Renewal	Estimated versus actual costs per project	Percentage of Planned Casings Remediated

[9] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-21-765 (July 11, 2022), Page 6.

Table 1 (continued)
Recommended Performance Metrics - DIMP

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
DIMP	Poor Performing Main Replacement	Poor performing main replacement unit cost (per foot)	Leak rate by vintage
	Poor Performing Service Replacement	Poor performing service replacement unit cost (per foot)	Leak rate by vintage
	Distribution Pipeline Integrity Assessment	Estimated versus actual costs per project	Anomalies repaired by type
	Distribution Valve Replacement	Estimated versus actual costs per project	Percentage of Inoperable Valves Replaced
			Reduction in potential customer outage
	Casing Renewal	Estimated versus actual costs per project	Percentage of Planned Casings Remediated
Mandated Relocations		Estimated versus actual costs per project	Number of Planned vs. Actual Relocations

A. 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).

1) Transmission Pipeline Integrity Assessments

2021 Estimated vs. Actual Project Costs
($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$1.5	$1.63	$0.13	8.57%	$1.70	$0.73	($0.97)	(56.98%)

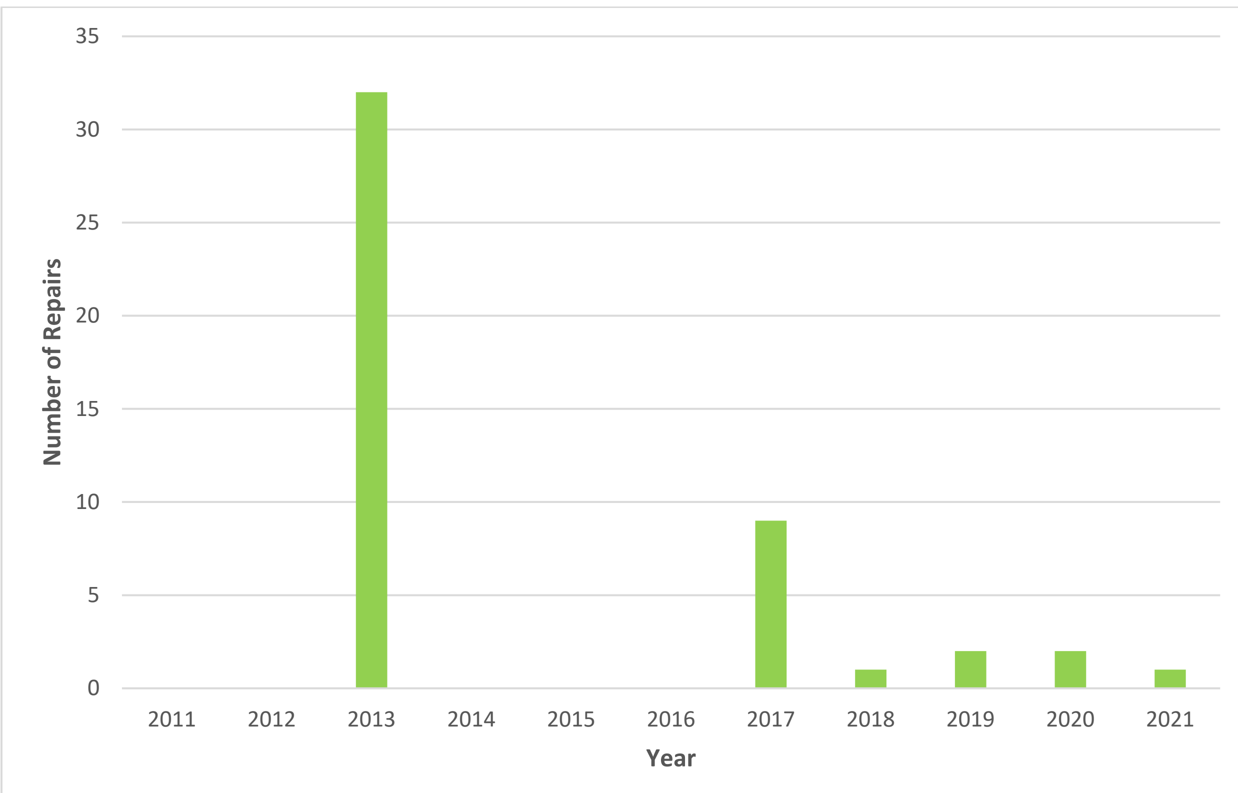
Variance Explanation

Capital: The variance is primarily due to higher capital expenditures for the Crossover Line 12-inch repair and the Wescott Line 8-inch modifications offset by lower capital expenditures for the modifications on the Wescott Line 12-inch line.

O&M: The variance is due to fewer and less extensive O&M repairs and indications in 2021 than originally anticipated.

Figure 1

NSPM Gas Transmission 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 2 below shows the anomalies repaired, by type of anomaly repaired.

Table 2

TIMP Repairs by Anomaly Type

Anomaly Type	Number of Repairs
External Corrosion	14
Internal Corrosion	0
Stress Corrosion Cracking	0
Manufacturing	2
Construction	4
Equipment	0
Third-Party Damage	27
Incorrect Operations	0
Weather and Outside Force	0
Total	47

2) ASVs and RCVs

2021 Estimated vs. Actual Project Costs

($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditure	$0.42	$0.10	($0.32)	(77.31%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The decrease in capital expenditures is due to updated cost estimates with reductions in labor and materials. As engineering began at the South St. Paul Station Crossover Interconnect, the number of valves requiring automation and cost of equipment to complete were both less than originally estimated.

O&M: None.

Figure 2

Reduction in Response Time per Project

Line #	Line Name	RCV Location	Nearest Service Center	Response Time (Min)
TL0209	East County Line – West of Mississippi	South St. Paul Station Crossover Interconnect	Newport	5
TL0209	East County Line – East of Mississippi	Maplewood Propane to North St. Paul Station	White Bear Lake	13

As mentioned previously, the potential consequences of a pipe failure are mitigated primarily by the installation of Remote-Control Valves (RCVs). Installation of RCVs reduces the response time needed to shut off the flow of gas in the event of an incident.

3) Programmatic Replacement / MAOP Remediation

2021 Estimated vs. Actual Project Costs

($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditures	$0.00	$0.04	$0.04	100.00%	$0.00	$0.00	$0.00	0.00%

<u>Variance Explanation</u>

Capital: The variance is due to final restoration activities that carried into 2021 from 2020.

O&M: None.

Figure 3

Percentage of High Risk Projects System-Wide

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2020	Percentage
High	Risk Score ≥ 5	9	56%
Low	Risk < 5	1	6%
No Risk	Risk Score = 0	0	0%
Under Evaluation	TBD	6	38%
Total	All	16	

4) Casing Renewal

2021 Estimated vs. Actual Project Costs

($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditures	$0.30	$0.10	($0.20)	(65.16%)	$0.00	$0.00	$0.00	0.00%

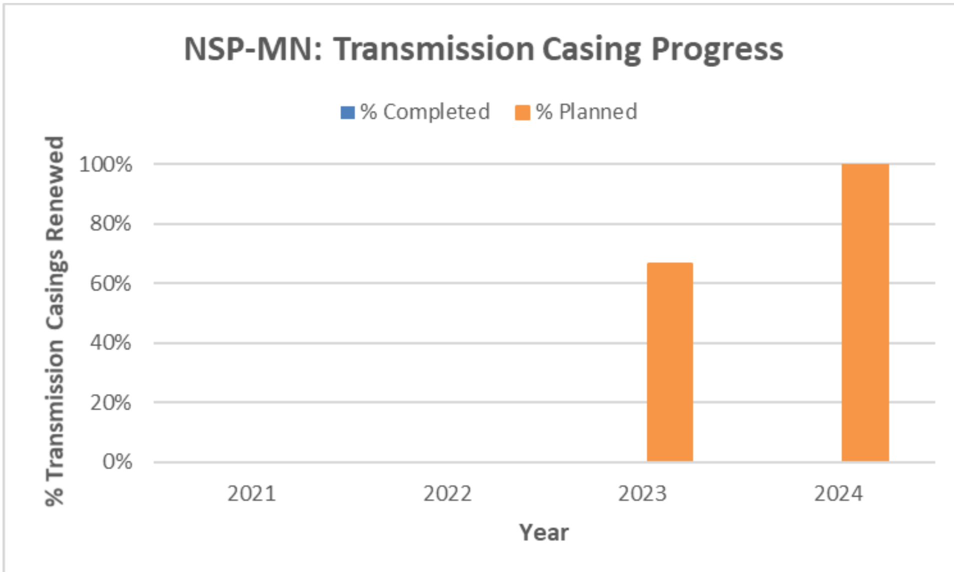
<u>Variance Explanation</u>

Capital: The decrease in capital expenditures was due to resource constraints and delays in receiving materials.

O&M: None.

Figure 4

Percentage of Casings Remediated



As shown in Figure 4 above, none of the identified transmission casings were completed in 2021. The Company started work on the 16-inch Rosemount Line Crossing at Cahill in 2021; however, due to material delays the work had to continue into 2022. The Wescott peaking plant ties into the Rosemount line upstream of the casing location and therefore close coordination with projects at the Wescott plant have been required. During the third quarter of 2022 it was determined that the in servicing of this casing would be delayed until 2023 due to unknown operational risks related to project at the Wescott peaking plant. The Company's transmission casing renewal plan projects 100 percent will be renewed by 2024.

B. DIMP Metrics

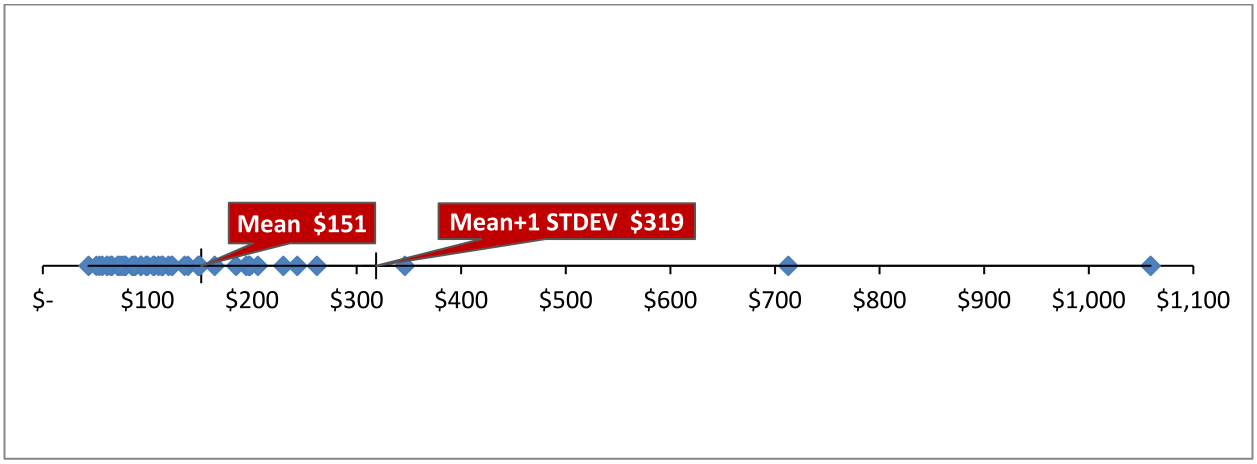
49 CFR Part 192.1007(e) currently requires performance metrics for DIMP, including the total number of leaks either eliminated or repaired, categorized by cause.

1) Poor Performing Main Replacement

Figure 5

2021 NSPM Poor Performing Main Replacement Projects

Cost per Unit ($/foot installed)



The cost metric shown in Figure 5 above depicts the distribution of average cost per foot for poor performing main replacement projects. Unit costs may vary for many reasons including differences in soil conditions, paving requirements, traffic-control requirements, and permit restrictions. In general, projects that the Company considers urban construction exhibit similar traits: congested right of way that necessitates we utilize more or exclusively open trenching and hydrovac instead of directional boring to avoid damaging and safely excavating around existing facilities. Additionally, these projects often require additional concrete and asphalt restoration that impact productivity, equipment, and cost. With a heightened focus on safety procedures, many "non-urban" projects are utilizing a hydrovac approach to illuminate discrepancies or risks within the field. There were three projects in 2021 that exceeded the mean cost per foot plus one standard deviation ($319 per foot). All these projects were urban construction projects.

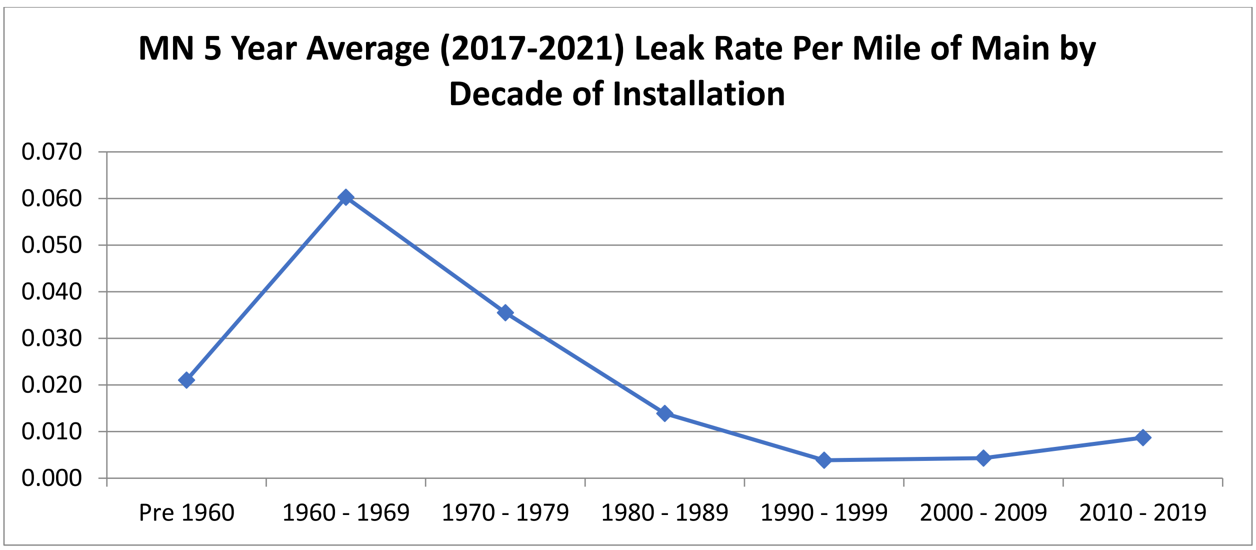
West Ave & 9th St:
This project was in an urban/downtown setting, asphalt and concrete restoration was greater than typical and congested running line led to more vacuum excavation, both of which impacted project cost.

Red Wing - W 5th St:
This project was completed in a very congested area, asphalt and concrete restoration was greater than typical, and vacuum excavation was needed for the entire length of installation, resulting in a higher cost per foot relative to other work.

New Brighton 7th St NW:
This was an open cut main replacement project through rock; therefore, rock breaking, sand padding and spoil hauling greatly impacted the per unit cost.

Figure 6

Leak Rate by Vintage



Leak rates for assets installed in 2020 and 2021 were not included in Figure 6 above, as a five-year average will not be available until 2025. There were 10 underground, non-excavation damage leaks recorded for assets installed in 2020 and 2021, corresponding to a two-year leak rate of 0.033 leaks per mile.

2) Poor Performing Service Replacement

Figure 7

2021 Cost per Unit ($/service installed)

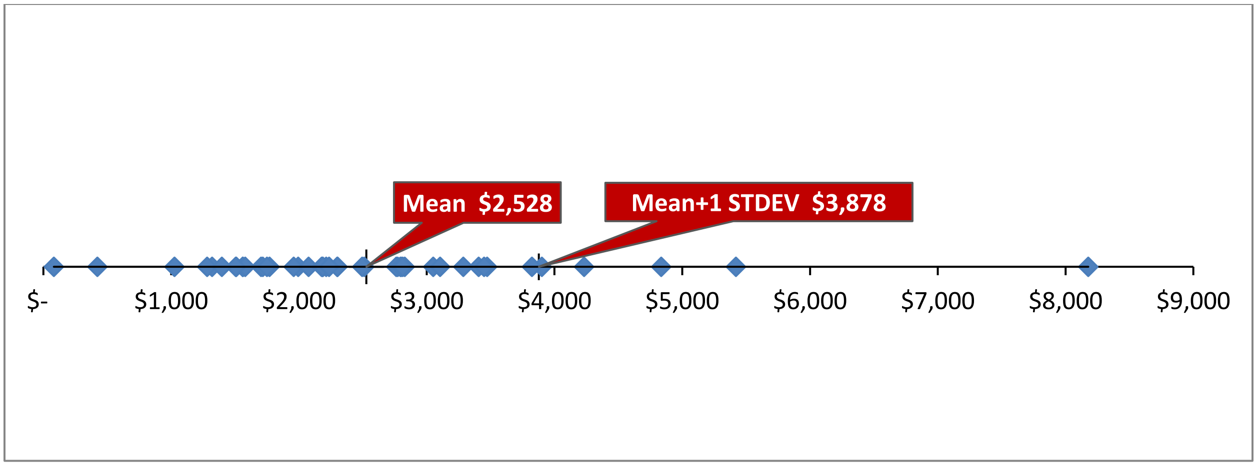


Figure 7 depicts the distribution of cost per average service installation for poor performing services installations. Due to material constraints, many gas services were tied over to new main project. This approach creates construction cost and restoration charges without any footage to account for as a result increases the cost per unit. There were five projects that fell above the mean cost per gas service plus one standard deviation ($3,878/service).

BW/EGF/GD/DIMP/3rd ST NW&3rd Ave NW:
Within this project several services were exceptionally long, contributing to the higher than normal unit pricing. A few of the services were commercial, which as compared to residential services have higher unit costs. In addition, increased restoration costs not typical on residential services contributed to the higher cost per unit.

St. Cloud - Rusan Street:
This project involved primarily commercial services that were exceptionally long installations. These factors attributed to the higher cost per service.

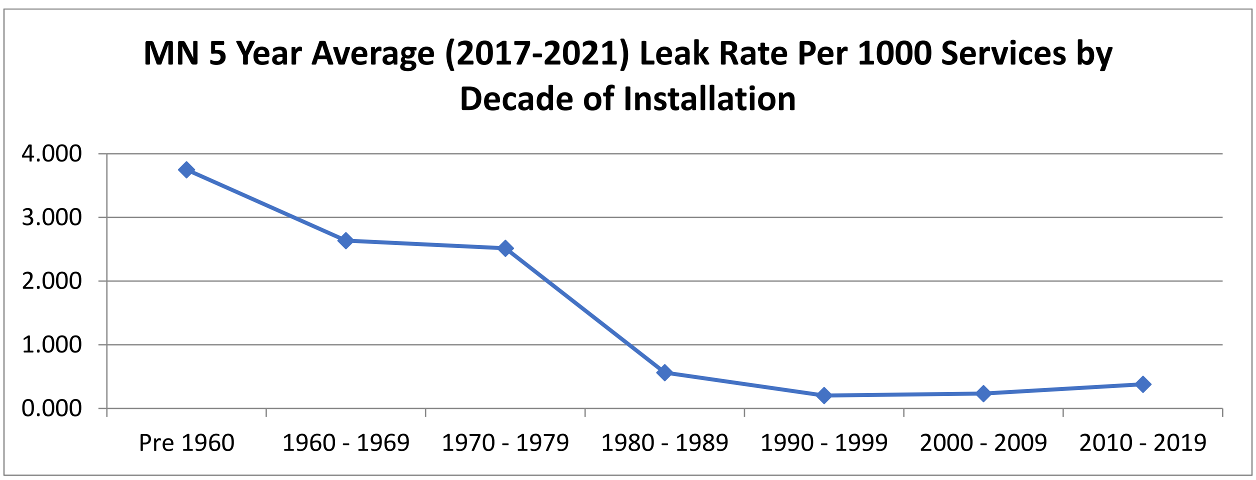
St. Cloud - Sherwood Mobile Home Park:
This project involved primarily residential but all under asphalt or concrete. This contributed to the higher restoration cost as well as more time during construction.

Arden Hills - Lexington Ave:
The service replacements for this project were primarily commercial and longer than average residential services. At this site there were also foreign utilities that had to be considered during construction. Services were predominantly commercial requiring more asphalt and concrete restoration.

Lexington & Cannon:
This project took place in an urban area with congested corridors and required hydrovac for installation. This technique comes with higher construction cost and more scope for restoration.

Figure 8

Leak Rate by Vintage



3) Distribution Pipeline Integrity Assessment

2021 Estimated vs. Actual Project Costs

($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$24.43	$19.38	($5.05)	(20.69%)	$0.58	$0.79	$0.21	36.55%

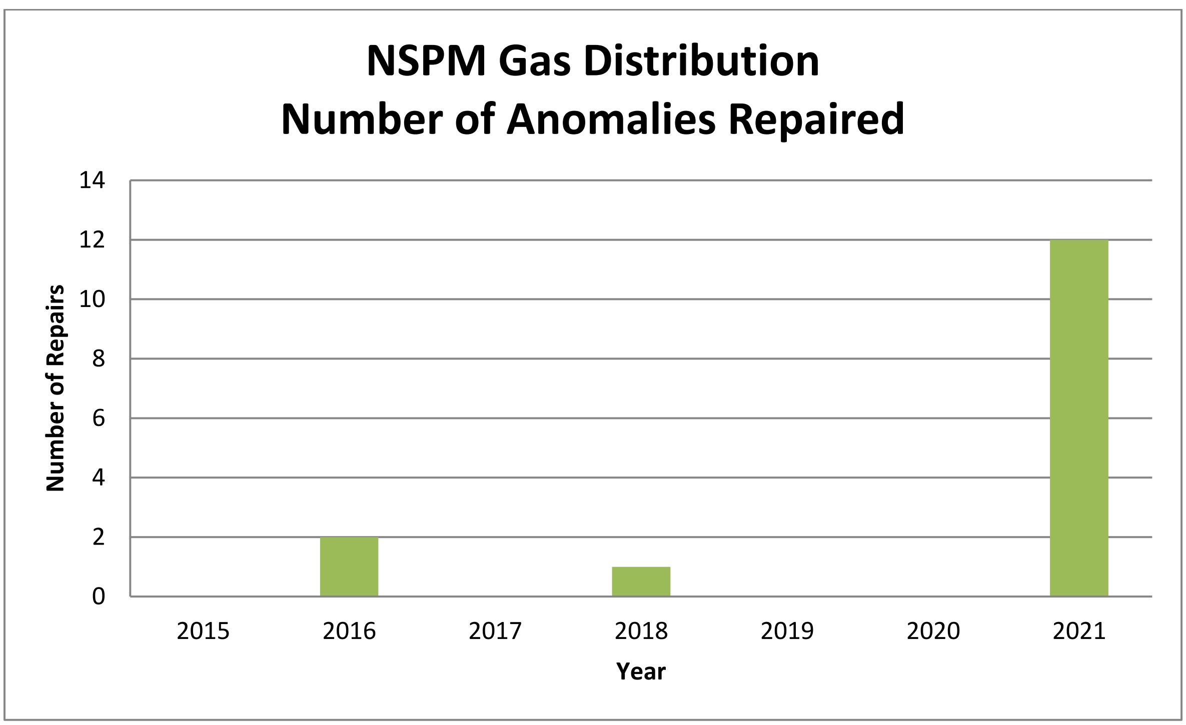
Variance Explanation

Capital: Of the $5.05 decrease million decrease, the primary driver was Langdon Line construction occurring over two years (2021 and 2022) originally planned for one year (2021). This created a $5.1 million shift in forecasted from 2021 to 2022.

O&M: The variance is due to an increase in 2021 direct examination scope and increased excavation and repair costs. The additional scope included direct examinations on the Brainerd Intermediate Pressure (IP) system. Increased excavation and repair costs were experienced on the H05 direct examinations due to examinations being in high traffic areas and many anomalies requiring repair found during examination.

Figure 9

Number of Anomalies Repaired



Anomaly repairs are expected to vary from year to year as different pipelines are inspected or assessed. However, the goal of each excavation is to remediate all potential anomalies and identify trends on each line to properly assess and mitigate integrity risks.

Since 2015, the Company has completed 27 excavations as part of the Gas Distribution Integrity Assessment project. Through these excavations the Company has identified anomalies.

Table 3 below shows the anomalies repaired, by type of anomaly repaired.

Table 3

DIMP Repairs by Anomaly Type

Anomaly Type	Number of Repairs
External Corrosion	4
Internal Corrosion	0
Stress Corrosion Cracking	0
Manufacturing	5
Construction	5
Equipment	0
Third-Party Damage	1
Incorrect Operations	0
Weather and Outside Force	0
Total	**15**

4) Distribution Valve Replacement

2021 Estimated vs. Actual Project Costs

($ Millions)

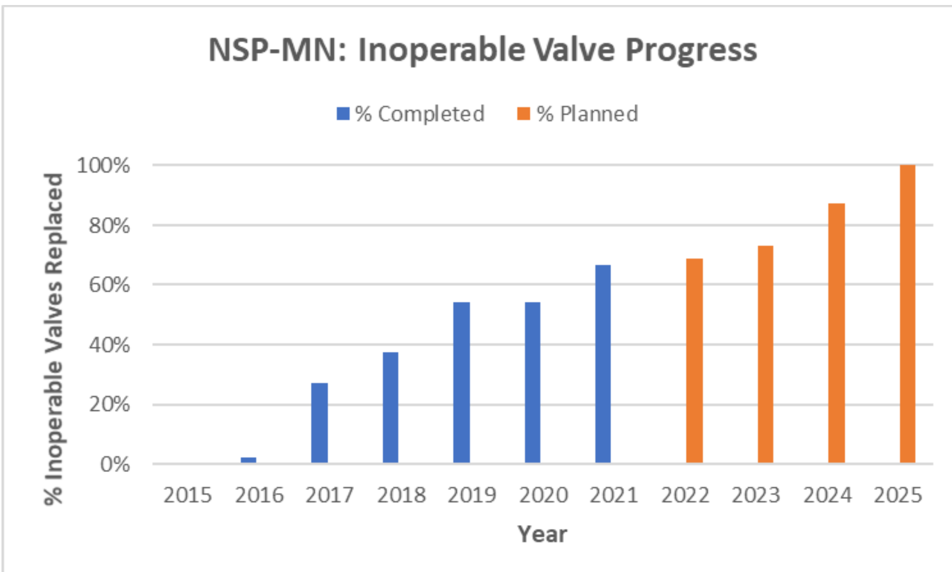
	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.46	$0.25	($0.21)	(45.28%)	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The variance is due to the installations being done primarily by internal crews. Internal labor is non-GUIC recoverable and is therefore not included in the 2021 capital actuals.

O&M: None.

Figure 10
Percentage of Inoperable Valves Replaced



As shown in Figure 10 above, approximately 67 percent of the Company's inoperable valves have been replaced. The Company's distribution valve replacement plan projects 100 percent of inoperable valves will be replaced by 2025. Please note the Company has forecasted spend in 2026 and 2027 in the event that additional inoperable valves are identified in the future.

Figure 11
Reduction in Potential Customer Outage

Geographic Area (by Division)	Reduction in Potential Customer Outage
Newport	33,156
Southeast	907
St. Paul	24,336

As shown in Figure 11 above, the installation of new distribution isolation valves has created a reduction in potential customer outages. In the case of an emergency, this gives the Company the ability to isolate a reduced number of customers in an area and therefore impacts fewer customers.

5) Casing Renewal

2021 Estimated vs. Actual Project Costs

($ Millions)

	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Capital/O&M Expenditures	$2.65	$1.68	($0.97)	(36.43%)	$0.00	$0.00	$0.00	0.00%

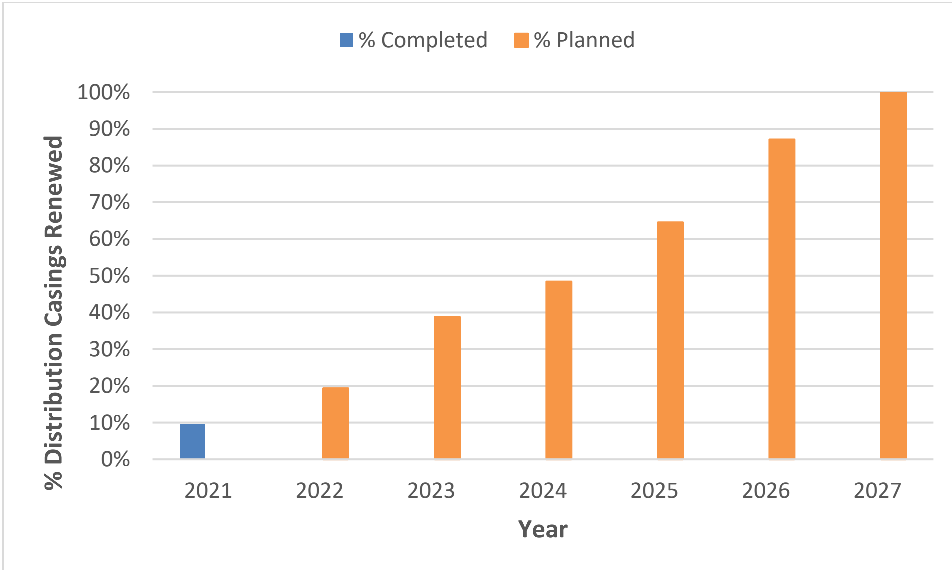
Variance Explanation

Capital: The variance is due to three projects shifting from 2021 to 2022 due to resource constraints.

O&M: None.

Figure 12

Percentage of Casings Remediated



As shown in Figure 12 above, approximately 10 percent of the Company's distribution casings have been renewed. The Company's plan projects 100 percent will be renewed by 2027.

C. Mandated Relocations Metrics

2021 Actual Project Costs
($ Millions)

Mandated Relocation Program	2021 Capital, As Filed	2021 Capital Actuals	Variance	% Capital Variance	2021 O&M, As Filed	2021 O&M Actuals	Variance	% O&M Variance
Mandated Relocations	$12.44	$7.77	($4.67)	(37.57%)	$0.00	$0.00	$0.00	0.00%

<u>Variance Explanation</u>

Capital: The $4.7 million decrease, was driven by a $2.0 million reduction in Phase 2 of the County Rd 13 relocation project due to lower outside vendor contract costs. This project was completed 2.5

weeks earlier than originally anticipated which further reduced costs. In addition, the estimated cost of routine relocation projects decreased by $6.0 million due to a decrease in historical actuals. These decreases were offset by $3.3 million of emerging mandated relocation projects.

O&M: None.

Figure 13

Number of Planned vs. Actual Discrete Mandated Relocations

NSP-MN Mandated Relocations	Planned as of 2021 GUIC Rider Filing	Planned as of 2022 GUIC Rider Filing	2021 Actual Mandated Relocations
2021	3	8	8

As shown in Figure 13 above, there were 3 discrete projects identified at the time the 2021 GUIC Rider Filing was submitted. Due to the nature of these projects, the Company was notified of additional discrete projects in 2021 that were not captured in the forecast for the 2021 GUIC Rider Filing.

CERTIFICATE OF SERVICE

I, Joshua DePauw, 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-21-765

Docket No. G002/GR-21-678

Xcel Energy Miscellaneous Gas Service List

Dated this 1st day of November 2022

/s/

____
Joshua DePauw
Regulatory Administrator

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-765_M-21-765
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David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-765_M-21-765
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Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_21-765_M-21-765

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-678_Official CC Service List
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-678_Official CC Service List
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
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