Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2016

PUBLIC DOCUMENT
TRADE SECRET INFORMATION AND
NON-PUBLIC DATA EXCISED

—Via Electronic Filing—

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

RE: GAS UTILITY INFRASTRUCTURE COST RIDER
PETITION, COMPLIANCE FILING, AND ANNUAL REPORT FOR 2017
DOCKET NO. G002/M-16-____

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Annual Report and Petition for approval of recovery of updated gas utility infrastructure costs (GUIC) through the GUIC Rider for 2017.

Attachment B1, subpart (c) to this filing is marked as "Non-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential contractor/vendor cost/pricing and sensitive competitive bidding information that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Thus Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

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

SINCERELY,

/s/

AMY A. LIBERKOWSKI
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	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 2016, REVENUE REQUIREMENTS FOR 2017, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-16-____

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 2017 Gas Utility Infrastructure Cost (GUIC) revenue requirement. These revenue requirements, totaling approximately $22 million, are incurred to promote the safety of our natural gas system and are consistent with the eligibility requirements set forth in the GUIC statute. The $22 million in revenue requirements includes approximately $3.8 million in revenue requirements related to capital expenditures in 2017 and the full year of revenue requirements for projects previously approved. The 2017 request is largely driven by increased activity regarding poor performing main and service replacements. This request also includes a $1.1 million increase over the 2016 Operations and Maintenance (O&M) expenses ($4.2 million), and $13 million related to previously approved capital expenditures and deferred O&M expenses.

We have previously described the state and federal regulatory requirements that arose out of concerns about the age of the country's natural gas infrastructure.[1] The Commission approved the Company's plan to implement Transmission and Distribution Integrity Management Programs (TIMP and DIMP) to assess and improve the safety, reliability, and integrity of our natural gas infrastructure pursuant to those regulatory requirements

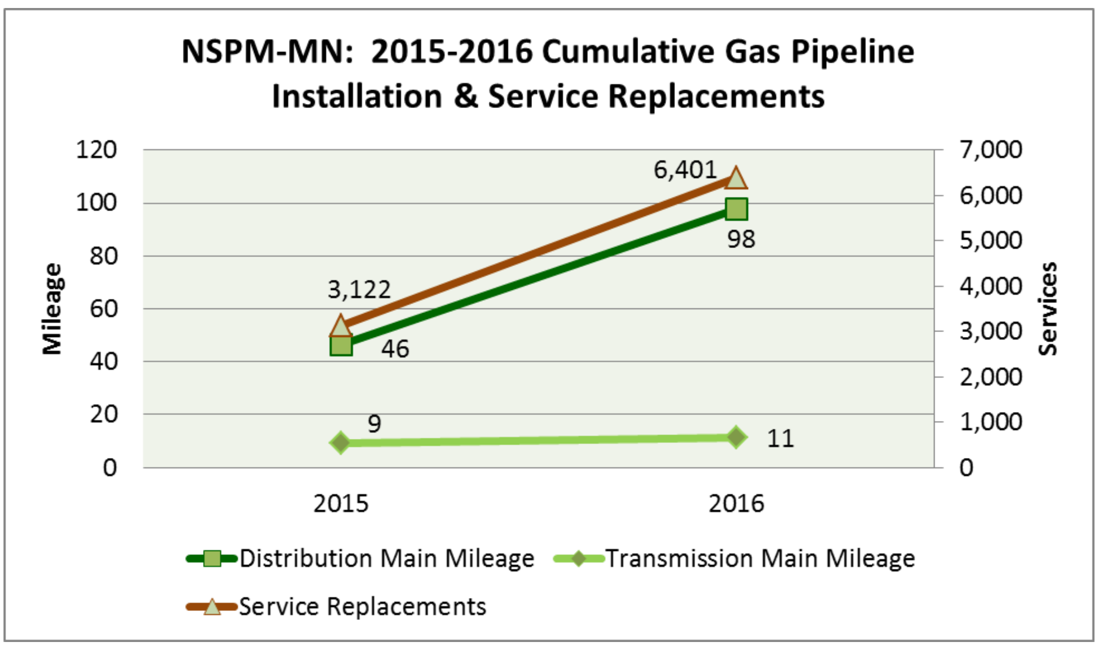
[1] See the Company's Petitions, August 1, 2014, Docket No. G002/M-14-336 and October 30, 2015, Docket No. G002/M-15-808.

and in the wake of headlines reporting grim safety incidents throughout the country.[2] With this request, the Company builds on the work of previously initiated projects pursuant to state and federal requirements. Significant progress has been made identifying pipeline risks and taking necessary corrective action to repair, rehabilitate, and replace the highest risk infrastructure since the GUIC Rider was established in 2015.

To date, the Company has replaced 98 miles of the highest-risk aging, corroded, and damaged gas distribution pipeline in our service area. The Company has replaced 6,401 aging distribution service lines, and over 11 miles of gas transmission line. As a result of the Company's GUIC efforts, the aging high pressure transmission line running between Saint Paul and Roseville, Minnesota will be fully replaced by year's end. Additionally, the Company has assessed more than 46 miles of pipeline, it has installed 145 new emergency distribution valves and has about 42 more to go. The Company is approximately one quarter of the way through its efforts to install Automatic or Remote Control Shutoff Valves. These efforts culminate in safer and more reliable gas service for customers and reduce the likelihood of catastrophic incidents in the metro.

Figure Nos. 1 through 3 below illustrates the progress of the Company's integrity work since inception:

Figure 1

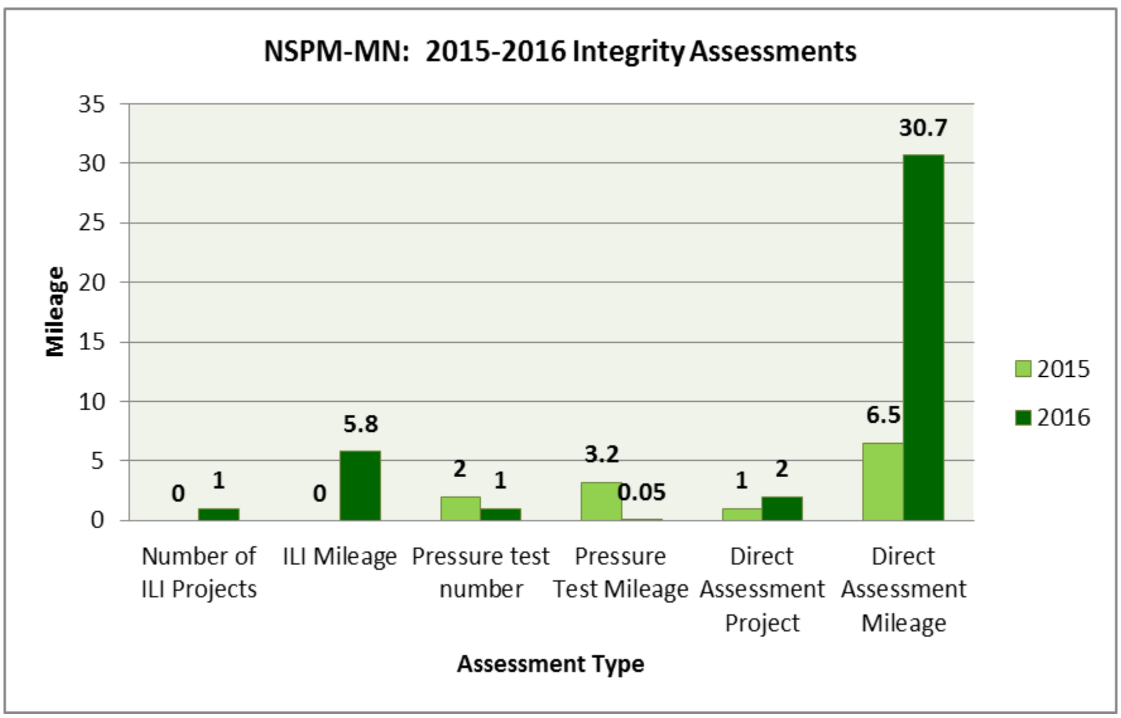


[2] "San Bruno explosion shows aging gas pipelines at risk nationwide," September 13, 2010, http://www.oregonlive.com/business/index.ssf/2010/09/san_bruno_explosion_shows_agin.html.; "2 homes destroyed in Adair County gas pipeline blast, 2 people slightly injured," February 13, 2014, http://www.kentucky.com/news/business/article44471313.html; "Northwestern Minnesota gas pipeline explosion: 'It was just hell on earth'" http://www.twincities.com/2014/05/25/northwestern-minnesota-gas-pipeline-explosion-it-was-just-hell-on-earth/ ".

As shown in Figure 1 above, through its DIMP Poor Performing Main and Service program, the Company has installed a total of 46 and 51 miles of gas distribution pipeline in 2015 and 2016, respectively. In addition, the Company has also replaced a total of 3,122 and 3,279 distribution service lines in 2015 and 2016, respectively. The Company expects to moderately increase annual investments for mileage and service line replacements through 2022.

Through its TIMP program the Company has cumulatively installed a total of 11.2 miles of gas transmission pipeline. The Company installed 4.2 and 1.9 miles in 2015 and 2016, respectively, and 5.1 miles prior to 2015. These replacements were associated with the East Metro Pipeline Replacement Project (East Metro Project) that is expected to conclude at the end of 2016[3]. With the East Metro Project completed, the Company will begin performing engineering and design work in 2017 that targets the renewal and replacement of portions of its high pressure distribution and transmission pipeline systems. Construction activities for these projects are expected to begin in 2018.

Figure 2

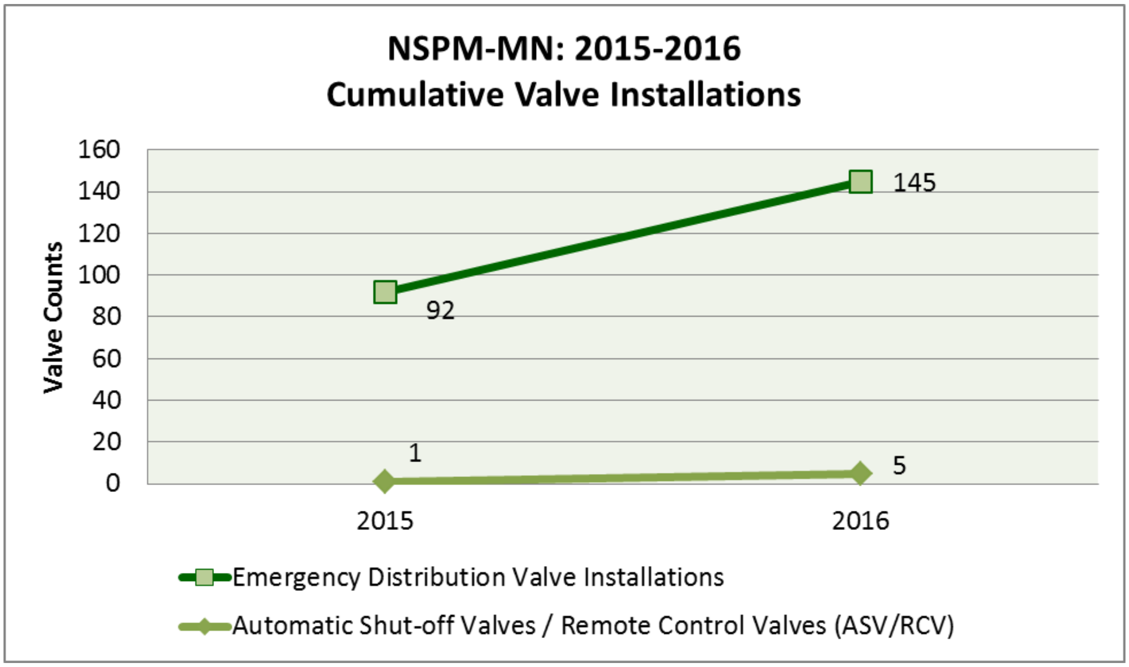


As shown in Figure 2 above, the Company has completed three Direct Assessment projects, three Pressure Test projects, and one In-Line Inspection project since the GUIC was established in 2015. The total mileage assessed as a result of completing these projects is 46.3 miles. Based on the current long-term TIMP assessment plan

[3] Carryover costs associated with the East Metro Project are expected in 2017.

ending in 2021, the Company expects to complete between three and five projects each year.

Figure 3



As shown in Figure 3 above, the Company has installed 145 new emergency distribution valves since 2015. By the end of 2016, the Company will have installed a total of 479 new emergency valves since the beginning of 2012. The scope of this program will change in 2017 to replacing existing distribution valves that have become inoperable. The Company anticipates replacing 40 existing distribution valves between 2017 and 2018. In addition, the Company has installed 5 mainline isolation valves through the ASV/RCV project since 2015. In 2017 and beyond, the Company anticipates installing a total of 14 additional valves. These safety initiatives have already conferred substantial public benefits, and continue to confer benefits as the projects progress.

Pursuant to the Commission's order in our 2016 GUIC request, we provide an increased level of detail on our TIMP and DIMP investments over previous requests. An index of attachments to this petition is provided as Attachment A to this filing. We provide additional project details to assist stakeholders in their review of the Company's request at Attachments B, B1(a-f) and B2, and Attachments C, C1(a-l), C2(a) and C2(b). The infrastructure work planned for 2017 is a continuation of the programs and initiatives described in our previous GUIC filings. In this Petition, we explain why the investments are necessary, the benefits they confer to the public and customers, as well as the regulatory requirements that give rise to the investments. We also highlight the Company's forthcoming stakeholder process to share the proposed risk-ranking metrics used to establish the relative priority of gas infrastructure projects.

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

The Commission wrote,

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

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

The Company respectfully requests recovery of $22 million in projected transmission and distribution natural gas infrastructure investments and associated O&M costs for 2017, including $4.6 million in amortized costs the Commission previously approved to be recovered in this rider.[5] We also seek approval of our proposed capital structure and Return on Equity (ROE) of 9.50 percent. Finally, we seek approval of the 2017 GUIC Rider Adjustment Factors, and the true-up for 2016.

The balance of this Petition is organized as follows:

- *Section I* – we identify the parties and state agencies that are being served with this filing.
- *Section II* – we provide information that is required under the Commission's rules.
- *Section III* – we provide a description of our TIMP projects and DIMP projects and the applicable standard of review. See Attachments B, B1(a-f) and B2, and Attachments C, C1(a-l), C2(a) and C(b). These attachments include the additional project detail ordered in the Company's 2016 GUIC Filing, Docket No. G002/M-15-808.

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[4] *See* Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808 (August 18, 2016) at page 6.

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

- *Section IV* – we demonstrate that our request to continue recovering certain costs through the Rider complies with the applicable standard of review and complies with previous Commission Orders.
- *Section V* – we provide additional accounting details pertinent to our request, including our true-up report and our adherence to an April-March fiscal year.
- *Section VI* – we provide support for our proposed capital structure and ROE and request the Commission issue a procedural schedule.
- *Section VII* – we provide GUIC metrics and stakeholder review.

Finally, we summarize our request and the reasons supporting our request.

I. SERVICE ON OTHER PARTIES

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

II. GENERAL FILING INFORMATION

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

A. Name, Address, and Telephone Number of Utility

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

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

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
(612) 215-4662
alison.c.archer@xcelenergy.com

C. Date of Filing and Proposed Effective Date

The date of this filing is November 1, 2016. The proposed effective date for the 2017 GUIC Rider factors is April 1, 2017.

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

D. Statutes Controlling Schedule for Processing the Filing

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

E. Utility Employee Responsible for Filing

Amy Liberkowski
Director, Regulatory Pricing and Analysis
Xcel Energy
414 Nicollet Mall (401- 7th Floor)
Minneapolis, MN 55401
(612) 330-6613
amy.a.liberkowski@xcelenergy.com

F. Miscellaneous Information

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

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall (401-8th Floor)
Minneapolis, MN 55401
alison.c.archer@xcelenergy.com

Carl J. Cronin
Regulatory Records
Xcel Energy
414 Nicollet Mall (401-7th Floor)
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

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

III. DESCRIPTION AND PURPOSE OF FILING

A. Background

We describe the scope and nature of our approved TIMP and DIMP projects and we describe the GUIC statute which establishes the legal standard for the Company's request.

1. *Deferral Orders*

The Company's approved TIMP and DIMP activities were initiated at the behest of federal regulators, and include a variety of projects to assess and mitigate safety risks associated with gas pipelines. The Company's activities include assessments, and specific projects, such as pipeline replacement and sewer line conflict remediation work. The Commission approved deferred accounting for the sewer line conflict remediation activities and other safety-related work with the possibility of recovery for prudently incurred expenditures.[6] In so doing, the Commission recognized that the costs associated with these TIMP and DIMP activities are unusual, unforeseeable, significant, and incurred to meet important public policy mandates. Because the deferred costs stem from the required TIMP and DIMP initiatives, the Commission granted Rider recovery of the deferred costs in its Order approving the GUIC Rider.

2. *TIMP Projects*

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 77 miles of transmission pipeline in the state of Minnesota. TIMP complies with federal regulations by identifying risks, systematically performing health and condition assessments, and evaluating and prioritizing corrective actions to mitigate the risks and threats.[7] TIMP focuses on giving the Company a comprehensive understanding of the health and condition of its gas transmission pipelines, with those located in highly concentrated areas as a higher priority.

When performing assessments, the Company conducts In Line Inspection (ILI) wherever practicable. The advantages of ILI are that the pipelines need not be taken out of service while the inspection tool is run, assessments can be completed in a cost-effective manner for longer distances, and the information from the assessments

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

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

is more thorough than information available through other methods. After an initial capital investment to prepare a pipeline for an ILI tool, the Company is able to perform subsequent runs on the same line in the future.

In addition to assessments, the Company currently has two other major TIMP initiatives under way: the East Metro Pipeline Project and installation of Automatic Shutoff Valves/Remote Controlled Valves (ASV/RCV).

For the East Metro Project, we are systematically replacing the aging high-pressure transmission pipeline that runs through the heavily populated urban corridor between St. Paul and Roseville.

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

In 2017, the Company will begin work on a third major TIMP initiative: Programmatic Replacement/Maximum Allowable Operating Pressure (MAOP) Remediation. This program was presented to the Commission in the Company's 2015 and 2016 GUIC Rider Petitions, Docket Nos. G002/M-14-336 and G002/M-15-808. This program targets capital intensive repairs or replacement efforts needed on transmission pipelines that have been assessed for asset health and condition in prior years.

Project descriptions, scopes, estimated costs and in-service dates for specific TIMP projects are provided as Attachment B. Attachment D reports the capital expenditure costs and forecasted costs for incremental TIMP activities between March 2012 and December 2021. Attachment E shows the development of 2017 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment D.

3. DIMP Projects

DIMP ensures and improves the safety and reliability of gas delivery in compliance with federal rules issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA).[8] The DIMP rules are intended to help gas utilities identify, prioritize, and evaluate risks; identify and implement measures to address risk, and validate the integrity of their gas distribution system.

One example of DIMP activity as previously noted is the Company's Sewer and Gas Line Conflict Remediation program. Through its plan, we comprehensively inspect sewer lines in locations where conflicts are more likely, reviewing records to determine

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

if the scope of inspections should be expanded, and updating the Company's construction practices to minimize risk and comply with industry standards. We also educate the public about potential conflicts between sewer and natural gas lines through our "Call before you Clear" program and also on our website[9].

Another example of DIMP work is activities to address poor performing mains. The Company deems a main or service line to be "poor performing" through analysis of performance as well as monitoring industry trends and issues. The Company monitors and reviews the leak history of pipe material types and/or vintage (year of installation). Trends of increasing leak ratio or cause associated with certain pipe types are studied further to determine if proactive action is required. The scope of this work is discussed in Attachment C.

The goal of the Company's risk analysis is to anticipate issues and address them before they become problems on the system. Improvements in data quality and Company processes are helping the Company to transition from a reactive approach to a predictive approach.

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided at Attachment C. Attachment D reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2021. Attachment F shows the development of 2017 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment D.

4. Minnesota's GUIC Statute

The 2013 GUIC amendment creates a cost-effective and prompt mechanism for recovery of GUIC costs. The text of Minn. Stat. § 216B.1635 is provided as Attachment G. The Commission agreed with the Company that the statute appropriately applies to the TIMP and DIMP activities undertaken by the Company, including the work approved for deferred accounting.

With respect to the recovery of TIMP and DIMP costs generally, the Commission found that these Company investments meet the statutory requirements for rider recovery as gas utility infrastructure costs.

The Commission also found that the "next general rate case" requirement governing the term of the deferred regulatory asset contained in the Orders in Docket Nos.

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

G002/M-10-422 and G002/M-12-248 was not a barrier to recovery under the GUIC. The Commission reasoned, "Since there was no option for Xcel to seek rider recovery of the TIMP and DIMP program costs in 2010 and 2012 when it originally sought deferred-accounting treatment of those costs, the Company should not be barred from seeking rider recovery now."[10]

As the Commission has already recognized, Xcel Energy's TIMP and DIMP activities are precisely the type of expenditures for which Minn. Stat. § 216B.1635 authorizes prompt recovery. With this request, the Company asks the Commission for permission to continue to recover its projected TIMP and DIMP expenses for 2017, including the costs for which the Commission previously granted deferred accounting through the GUIC Rider.[11] The Company's revenue requirement reflects the impact of ongoing projects already approved by the Commission.

B. Standard of Review

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

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

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

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

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

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[10] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at pages 8-9.
[11] *See* Order Approving Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs, Docket No. G002/M-12-248 (Jan. 28, 2013); Order Granting Deferred Accounting Treatment, Docket No. G002/M-10-422 (Jan. 12, 2011).

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

The Company's proposed rate of return, 7.26 percent, is based on the capital structure and cost of debt recently approved by the Commission in its August 2016 order when it last considered the Company's GUIC Petition and Annual Report, and our proposed Return on Equity of 9.50 percent discussed in Section VI.

IV. COMPLIANCE WITH COMMISSION ORDERS AND STATUTE

Here we address why cost recovery through a rider for these activities continues to be in the public interest, we demonstrate the reasonableness and prudence of costs associated with these activities, and we further address the Company's compliance with the Orders and Statute. For ease of review, the Company provides a compliance matrix at Attachment H setting forth the requirements of the enabling statute and the relevant Orders, and directs the reader to the portion of the Company's petition which address each requirement.

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

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

There are a number of possible efficiency gains when work can be approached in a systematic, proactive manner versus being completed in a reactive or emergency driven manner. For example, specifically on the DIMP Poor Performing Main Replacement project, systematic work is designed and planned well in advance of actual construction. Therefore, construction crews can be optimized to reduce mobilization/demobilization costs, coordinate permitting and street construction with impacted communities, and minimize traffic control and rerouting to reduce the overall inconvenience of this type of work for our customers. When similar pipe replacement work must be completed due to a reactive or emergency driven situation, there is no ability to consider all of these various alternatives.

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

Additionally, the GUIC adjustment rate calculation is consistent with revenue apportionment in the most recent natural gas general rate case. When the Commission approved the rate design in our 2015 GUIC Petition, it reasoned, "There is nothing in the record to indicate that circumstances have changed [since the last natural-gas rate case] such that the allocation is no longer appropriate."[12] The Commission also approved the same methodology for the Company's GUIC customer class allocation in its 2016 Petition.

The Company's most recent gas rate case was in 2010.[13] Since that time, we have undertaken large-scale infrastructure improvement projects, including sewer and gas line conflict remediation and other proactive measures that are in direct support of the federal mandates of TIMP and DIMP. The costs of these initiatives have substantially exceeded any expenses anticipated at the time of the rate case, but the programs have conveyed significant benefits to ratepayers.

Prompt recovery promotes both prudent investment in utility infrastructure and efficient use of the Commission's time and resources.

B. The Public Interest Supports Ongoing GUIC Investments

Although significant progress has been made on the journey to identify and mitigate threats to the Company's gas system, there is still more work that needs to be done. The Company has made significant progress and continues to balance different variables in the development of its dynamic TIMP and DIMP plans. These variables include the age of assets, population growth around assets, competing with peers for specialized resources, and the inherent uncertainty that drives the inspections. The public and customer benefits delivered through the GUIC are significant and ongoing.

1. *Addressing Aging Assets*

First, the vintage of the Company's gas utility assets, including the varied material types and construction methods used at the time of installation, pose a level of uncertainty and risk. For example, steel pipes are prone to corrosion and have a higher risk of failure for assets installed before there was effective cathodic protection. Older assets also have a higher risk of material or construction flaws. Approximately 50 percent of the Company's gas transmission system was constructed prior to the use

[12] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 12.
[13] *See* Findings of Fact, Conclusions of Law, and Order, Docket No. G002/GR-09-1153 (Dec. 6, 2010).

of what is now considered modern welding techniques, which emerged in the industry in the 1970s. While age alone is no indication of failure, we must address risks posed by legacy construction techniques and materials.

Thousands of miles of the Company's gas transmission, distribution, and service lines were constructed prior to the 1990s. The Company's GUIC activities are addressing the risk posed by pipeline corrosion and failure through systematic inspection, assessment, and replacement.

Federal regulation requires pipeline operators to assess the integrity of their pipelines based on the threats to which the pipeline is susceptible. In order to assess these aging assets, the Company has selected in-line inspection as the primary assessment methodology due to its superior ability to provide detailed information regarding the current pipeline condition. As part of the on-going re-assessment efforts the Company is modifying its pipelines to allow passage of in-line inspection tools. As shown in Figure 10 below, this effort is 60% complete. Based on the current long-term TIMP assessment plan, efforts to modify pipelines to allow passage of in-line inspection tools is scheduled to be completed by 2022.

Figure 4

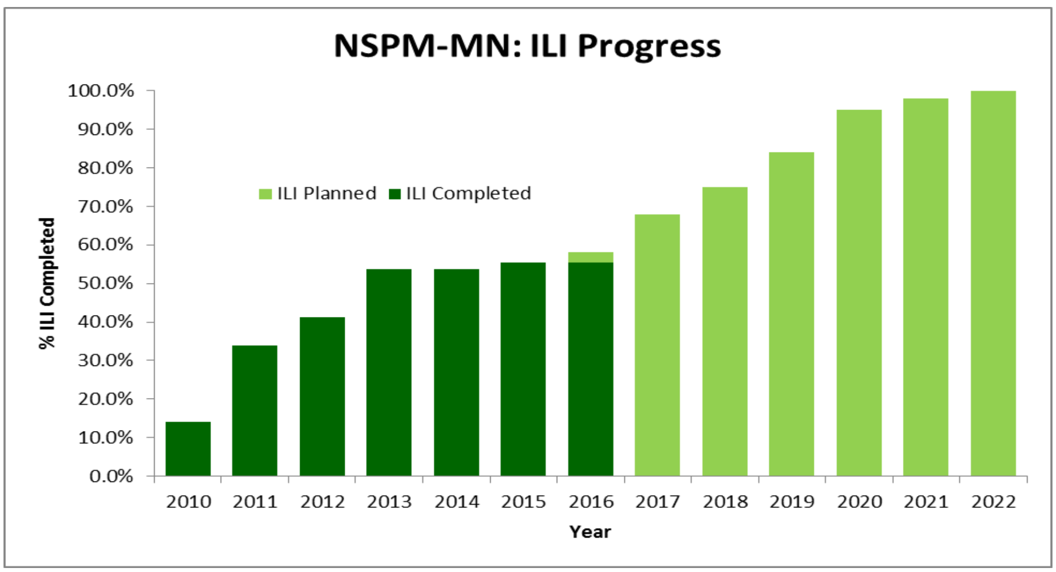

Figure 5 below displays a section of removed pipeline with a compression coupling from the East Metro Project worksite near Lexington and Montreal in St. Paul. This is an example of the Company's effort to replace pipeline facilities to eliminate construction and manufacturing threats posed by existing compression (or mechanical) couplings used in construction of the East Metro line (installed in the 1940s and 1950s) in accordance with 49 C.F.R. § 192, Subpart O.

Figure 5

Figure 6 below displays an East Metro Replacement Project worksite at Sylvan St. and Arlington in St. Paul.

Figure 6

Figure Nos. 7 and 8 below display the results of the first verification dig of the External Corrosion Direct Assessment (ECDA) pipeline inspection of the County Rd. B 24"-30" Line, part of the Intermediate Pressure (IP) Assessment program.

Figure 7

Coupling with broken support bars; 8 out of 9 failed.

Figure 8

Coating failure from 6" to 3.5"

Figure 9 below is a picture taken during the third verification dig of the External Corrosion Direct Assessment (ECDA) pipeline inspection of the County Rd. B 20" Line, part of the Intermediate Pressure (IP) Assessment program. The large coating holiday appeared to be caused by third party damage, but could not be 100% verified. The pipe was recoated and backfilled.

Figure 9

Coating Holiday 1 (6"W X 18"L); appears to be caused by third-party damage.

As indicated by these images, the Company is taking corrective actions to address a variety of conditions caused by asset age, corrosion, or damage.

2. Safety and Population Density

Second, many communities with older gas utility assets have sustained significant population growth and/or increased density since initial installation. With increased population density comes increased risk that safety incidents could have catastrophic consequences. When communities develop around aging transmission and higher-pressure distribution lines, it drives increased effort and related expense to safely and reliably operating these systems.[14]

3. Remaining in Step with Regulatory Requirements, Peer Integrity Management Activities, and Competition for Resources

Third, a "Call to Action to Improve the Safety of the Nation's Energy Pipeline System"[15] was issued by the USDOT and PHMSA in 2011 in response to incidents in California,

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

Michigan, and Pennsylvania. In particular, then-U.S. Secretary of Transportation Ray LaHood announced a "Pipeline Safety Action Plan," calling for pipeline operators to conduct a comprehensive review of their pipeline systems to identify the highest risk pipelines and prioritize critical repair needs. Pipeline operators were asked to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of network facilities to prevent potentially catastrophic incidents. The Call to Action also called upon state regulators to provide timely recovery of pipeline replacement investments, recognizing that reliance on traditional cost recovery approaches is likely to impede efforts to accelerate these activities.

Xcel Energy, like other local distribution companies across the country, has implemented measures as part of their comprehensive integrity management programs. These programs require substantial investments in human resources, including engineers and construction crews. In pursuing TIMP and DIMP, the Company competes nationally to obtain the specialized equipment, engineers, and construction crews it needs to complete necessary renewal work.

4. Dynamic Planning

Though TIMP and DIMP are improving the Company's knowledge of system and asset conditions, much remains unknown until the systems are actually inspected. As inspections are conducted, we discover risks that may require more immediate intervention requiring dynamic planning.

The variability of these needs puts the Company in a position of requiring some flexibility with respect to O&M and other resources to address conditions as they are identified. The Commission previously recognized the need for flexibility. It wrote, "The costs of these investments can vary widely from year to year and are difficult to forecast with accuracy. Approving a rider will give Xcel the ability to implement multi-year pipeline-replacement programs, adjusting the rates annually to correct for over- or under-recovery."[16]

Despite aging infrastructure, population growth, federal mandates on all pipeline operators, and uncertainty in addressing emerging conditions, the Company must meet its safety and reliability obligations. These challenges require more flexibility than traditional rate making methods offer.

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

5. Conferring Public Benefits

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

C. GUIC Activities Are Prudent

We provide a discussion of the GUIC controls and oversight methods the Company uses to ensure prudent cost management over the Company's approved GUIC activities.

1. Cost Controls

GUIC projects have been planned and reviewed through the Company's capital and O&M budgeting process, which is approved by Company officers and the Board of Directors. The project controls department of the Gas Engineering and Operations business unit monitors all capital dollars to ensure that authorized projects align with the established budget to achieve the lowest reasonable and prudent cost to rate payers. On a monthly basis, budget to actual spend is compared and financial forecasts are updated for programs and projects. The Company also leverages past experience with assessments and repairs to assist in developing budgets for future assessment work.

Additionally, the Company's dedicated Gas Project Management Department handles large gas projects and programs. This department provides centralized project management to address overall scope, scheduling, and budgeting for major capital projects.

GUIC projects comply with the competitive bid process[17] that states all normal goods and services Agreements with a value greater than $50,000 (including cumulative amounts in multi-year Agreements) shall be awarded on a documented competitive basis unless precluded, when justified, for reasons of emergency or unavailability/impracticality of competition. In circumstances where a competitive process is precluded (e.g., unique process/knowledge, etc.), written justification and director level authorization from a business area and Supply Chain for the sole

[17] Xcel Energy's sourcing objective is found in the Company's Corporate Policy, 4.10 Procurement of Normal Goods and Services.

sourced or professionally sourced award, is required.[18] A Sole Source Justification must be included as part of the Agreement when it is filed.

Agreements with a value less than $50,000 shall be 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.

Xcel Energy solicits and opens all bids privately and unannounced, with the following exception. If a reverse auction is conducted as part of the bidding process, bid and rank information may be shared, but the identity of the supplier who submitted the bid remains confidential. Bid information is confidential and shared internally only on a need-to-know basis. Supply Chain solicits bids by invitation from a list of suppliers subject to pre-qualification.

One example of the effectiveness of this policy in delivering cost controls is the cost savings captured in the East Metro Project through the use of competitive bidding. In that case, the Company achieved over $1,000,000 of cost savings as a result of the 2015-2016 East Metro Project construction bid process. After the original contractor[19] completed the first two years of the project on time and under budget, the Company re-bid the contract in 2015.

In December 2014, the Company sent out a Request for Proposal (RFP) to ten different companies for planned 2015 and 2016 East Metro Project Construction work. Four different vendors submitted proposals for the project and the Company selected two of the competing companies for post bid interviews. During these interviews, one of the companies, Q3 Contracting, presented ideas that were ultimately responsible for the aforementioned cost savings. After completing the post bid interviews, the Company requested both contractors to re-submit bids based on clarifications discussed during the interview process. As a result, the Company awarded Q3 Contracting the contract for 2015-2016 East Metro Project work.

The selection of Q3 Contracting for the contract was ultimately based on the following:

- Low bidder
- Submitting the most complete bid demonstrating the most thorough understanding of the project

[18] The bid process also ensures compliance with Xcel Energy policies regarding the use of diverse contractors and suppliers as specified within corporate policy 4.3, Supplier Diversity.

[19] Q3 Contracting, a division of Primoris Services Corporation, is a publicly owned and operated construction contracting company that provides specific turnkey services in the gas, oil, electric and telecommunications industry.

- Demonstrating previous history of being a reliable contractor with completing large scale urban pipeline work
- Having an outstanding safety record
- Sound engineering ideas during bid process leading to $1 million of cost savings
- Providing the most accurate schedule based on internal requirements

Q3 was also able to replace 1.7 miles of water main for the St. Paul Regional Water Service that was in close proximity to the Company's pipeline. This had a positive public relations impact since the joint project reduced the amount of overall construction activities lowering the disturbance to local residents and businesses.

2. Oversight Methods

In addition to cost controls through competitive bidding, we also employ a variety of oversight methods. The Company conducts a monthly status review of major capital programs and projects, including the GUIC. We review actual overall capital spending in comparison with forecasted spending month-to-date and year-end.

In 2014, the Company established a Rider Review Committee (RRC) tasked with ensuring that modifications made to GUIC projects met the intent of the Company's GUIC Rider. The RRC process was designed to increase structure, transparency, and documentation around capital and O&M expenditures related to gas integrity initiatives utilizing rider cost-recovery mechanisms. So far in 2016, the RRC has met twice to review known GUIC-related changes to key project data, assumptions and overall program budgets. Program proposals modifying original plans were subject to review, approval, and sign-off based on cost thresholds governed by the RRC's approval matrix guidelines.

All of these efforts aim to ensure prudent management and ratepayer value.

D. GUIC Activities Are Reasonable

The Commission recognized the reasonableness of Xcel Energy's activities the first time when it authorized deferred accounting for past TIMP and DIMP expenses, which include the Gas Safety Costs and the Sewer/Gas Line Conflict Remediation Project. The Commission recognized the reasonableness of the activities a second and third time when it approved our 2015[20] and 2016[21] GUIC Petitions. In both cases

[20] *See* Order Approving Rider with Modifications, Docket No. G002/M-14-336 (January 27, 2015) at page 7.
[21] *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.

it stated, "[T]he costs are reasonable and prudent in view of the public safety purpose served by the TIMP and DIMP initiatives."

Additionally, the Company's commitment and response to the federal "Call to Action" for the review, assessment, and prioritization of initiatives to address high- risk gas-utility assets further substantiates the reasonableness of the activities proposed within the GUIC. The benefits of these evaluation and replacement efforts are several-fold: immediate safety and reliability benefits to customers and the public,[22] cost savings through economies of scale, comprehensive planning to preempt reactive (emergency) replacements, geographically-focused initiatives, efficient use of outside contractor services, efficient deployment of capital, and improved coordination with affected municipalities.

E. O&M Costs Are Specifically Authorized

At subd. 4, the GUIC statute authorizes approval of incremental O&M cost recovery. With this GUIC Rider request, the Company seeks to recover its O&M costs, consistent with the statute and the Commission's approval of this cost treatment in our 2016 GUIC Petition.

The Company provides the TIMP and DIMP budgets for 2017, as well as estimated and actual cost data for previous program years in Attachment I. Precise budgeting within these programs remains challenging. This is particularly true of TIMP assessments, where the Company cannot be sure of the condition of the pipe it will encounter—or the immediacy of needed repairs—until inspection occurs. As noted, the Company values flexibility in O&M budgeting to address conditions as they are identified.

F. Deferred Accounting Projects

A description of the projects approved for deferred accounting is available in our Annual Reports filed in the deferred accounting dockets.[23] The deferred amounts and 5-year amortization are provided in Attachment I.

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

Table 1 below presents Xcel Energy's 2017 total estimated costs of $22 million for TIMP- and DIMP-related activities. Capital-related revenue requirements and operations and maintenance expenses total $12.0 million and $5.7 million,

[22] *See* 49 C.F.R. 192, Subparts O and P.
[23] See 2014 Annual Report, Gas Safety Deferred Accounting, Docket No. G002/M-12-248, March 2, 2015. See also Annual Report, Sewer Conflict Deferred Accounting, Docket No. G002/M-10-422, January 30, 2015.

respectively. Costs associated with the amortization of deferred costs total $4.6 million as approved in Docket Nos. G002/M-10-422 and G002/M-12-248. O&M totaling $0.48 million was removed from this rider request, as it is recovered in our base rates. Additionally, the 2017 estimated costs include an under-recovery true-up of $0.3 million as the 2016 revenue requirements were higher than forecasted in last year's GUIC petition (Docket G002/M-15-808). This was caused by an increase in the 2015 carryover balance of $0.8 million due to lower revenues than forecasted, the addition of accumulated deferred income taxes (ADIT) proration of $0.1 million, offset by a decrease in capital revenue requirements of $0.6 million due to a lower ROE in 2016.

Table 1
2016-2017 Gas Utility Infrastructure Costs
($ Millions)

	2016 Forecast	2016 Estimated Actual	2017 Forecast
Capital-Related Revenue Requirements			
TIMP	6.13	5.93	7.86
DIMP	2.60	2.24	4.14
Total	**8.73**	**8.17**	**12.0**
Operations & Maintenance (O&M) Expenses			
TIMP	0	0.18	1.15
DIMP	4.64	4.43	4.55
Total	**4.64**	**4.61**	**5.70**
5-Year Amortization of Deferred Costs			
TIMP	0.82	0.82	0.82
DIMP	3.73	3.73	3.73
Total	**4.55**	**4.55**	**4.55**
ADIT Prorate	0	0.13	0.11
O&M Recovery in Base Rates	(0.48)	(0.48)	(0.48)
True-up Carryover	(1.94)	(1.18)	0.26
Total Revenue Requirement	**15.51**	**15.81**	**22.14**
Recovery		15.55	22.14
Difference – Under/(Over) Recovery		0.26	0
GUIC - Grand Total			**22.14**

H. Outsourcing

As required by the GUIC statute, the Company includes here a discussion of outsourcing. The Company seeks to minimize outsourcing when possible. In certain instances, however, additional external expertise is needed. For example, certain pipeline assessment techniques require specialized tools and equipment operated by uniquely skilled technicians. The Company does not have this equipment or this expertise. To the extent that additional equipment and expertise are needed to ensure the safe and efficient completion of assessments, the Company seeks and relies on outside assistance.

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

I. Compliance with Previous Commission Orders

In its January 12, 2011 Deferral Order,[24] the Commission requested that the Company explain "any legal actions or settlements regarding the natural gas explosion that led to the Notice of Probable Violation." The Company has no further updates to report on this topic since our 2016 GUIC Petition. Similarly, the Company has no further updates to provide on the topics of potential third party recovery or a cost analysis of an alternative 10 year plan.

In the August 18, 2016 Order[25], the Commission also requested that the Company include in future GUIC filings "specific information about each individual project in the GUIC Rider." In this filing, the Company has additionally included Attachments B, B1(a-f), C and C1(a-l), which provide detailed information describing each project, explaining the necessity and benefit to ratepayers, and identifying the agency, regulation, or order requiring the project.

The Commission has also directed the Company to file "a cost/revenue study based on 2015 actuals reconciled back to Xcel's 2015 Jurisdictional Annual Report." The Company has included Attachment J, which provides this cost/revenue reconciliation to the 2015 Jurisdictional Annual Report. We note the 2015 GUIC revenue requirements are less than 3 percent of the calculated 2015 Annual Report revenue requirements.

[24] Order Granting Deferred Accounting Treatment Subject to Conditions and Reporting Requirements, January 12, 2011. Docket No. G002/M-10-422.
[25] Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, Docket No. G002/M-15-808.

J. TIMP and DIMP Estimated Costs and Salvage Value

The Company's cost and salvage estimates related to actual and planned GUIC capital investments are shown in Table 2 below.

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

	TIMP			DIMP			Total
Year	**Transmission**	**Distribution***	**Total**	**Distribution**	**Software**	**Total**	**Expenditures**
2012	95	0	95	83	-	83	178
2013	65	9,497	9,562	343	-	343	9,906
2014	-24	11,651	11,628	240	-	240	11,868
2015	1,073	17,937	19,010	10,011	1,902	11,913	30,924
2016	5,666	15,569	21,235	10,076	171	10,247	31,482
2017	5,232	-	5,232	18,407	-	18,407	23,639
2018	28,584	-	28,584	17,057	-	17,057	45,641
2019	32,865	-	32,865	17,128	-	17,128	49,992
2020	31,058	-	31,058	17,128		17,128	48,185
2021	31,058		31,058	17,128		17,128	48,185
Total	**135,671**	**54,656**	**190,327**	**107,601**	**2,073**	**109,674**	**300,001**
Salvage Rate**	(15.00%)	(16.39%)		(16.39%)	0.00%		
Net Salvage	**20,351**	**8,958**	**29,309**	**17,636**	**-**	**17,636**	**46,945**

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

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

Capital expenditure estimates between 2012 and 2021 total $190.3 million for TIMP and $109.7 million for DIMP, reflecting an estimated total of $300 million. Xcel Energy calculates a depreciation rate of 2.52 percent and 1.53 percent for distribution mains and transmission mains, respectively[26]. The Company's calculations assume an average depreciable life of 46.14 years and a net salvage rate of 16.3898 percent for distribution mains and average depreciable life of 75years and net salvage rate of 15.00 percent for transmission mains. The Commission has approved Xcel Energy's proposed depreciation lives and salvage rates in Docket No. E, G002/D-12-858 (Order dated June 16, 2014).

K. Known Future Gas Utility Projects

1. TIMP

The federal TIMP is an ongoing program. Projects under TIMP, specifically, the Transmission Pipeline Assessment project, will continue beyond 2017. Further, PHMSA has been working on establishing a comprehensive program to effectively address a number of Congressional mandates and National Transportation Safety Board (NTSB) recommendations that will likely raise compliance standards for pipeline operators beyond the current TIMP rule.

A number of new regulatory requirements are expected to be enacted during 2017 that may impact Xcel Energy's obligations and required work activities to safely maintain and operate the gas system. These include:

- Safety of Gas Transmission and Gathering Pipelines
- Excess Flow Valves beyond Single Family Residences
- Operator Qualification, Cost Recovery and other Pipeline Safety Proposed Changes Plastic Pipe Rupture Detection and Valve (ASV/RCV) Rule
- Quality Management

The most significant of these is the impending rulemaking on the Safety of Gas Transmission and Gathering Pipelines. PHMSA issued a Notice of Proposed Rulemaking (NPRM) on April 8, 2016 that proposes to revise Pipeline Safety Regulations applicable to onshore gas transmission and gathering pipelines.

PHMSA describes the Proposed Rule as a response to multiple Congressional mandates from the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act), recommendations from the National Transportation Safety Board (NTSB), as well as addressing other aspects of natural gas pipeline operations that PHMSA has identified as requiring additional guidance. The proposed rules are expected to be issued as rulemaking in 2017. PHMSA's proposal represents the most

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

significant revision to the regulation of gas transmission and gathering pipelines since 1970 when PHMSA's predecessor first developed minimum pipeline safety standards.

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

1. Integrity Assessment and Remediation for Segments Outside High Consequence Areas (HCAs)
2. Requirements for re-establishing Maximum Allowable Operating Pressure (MAOP)
3. Integrity Management Program Process Clarifications
4. Management of Change
5. Corrosion Control
6. Inspection of Pipelines Following Extreme Events
7. MAOP Exceedance Reports and Records Verification
8. Launcher/Receiver Pressure Relief
9. Expansion of Regulated Gas Gathering Pipelines

Xcel Energy expects incremental spending related to compliance activities in the following areas:

a. Assessments

Elements of anticipated future Transmission Assessment Projects include:

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

Future costs (including O&M) associated with assessments could vary between $2.5 million and $8.9 million depending on the specific segments being assessed. Additionally, the costs incurred will likely be a combination of capital expenditures and O&M expenses, which depends on the type of work being performed and specific capital asset accounting associated with the types of repairs or remediation work done as a result of the assessments.

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

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

Filing	Assessment Mileage	Capital	O&M
2016 (15-808)	10.5	4.9	0.0
2017 (16-____)	13.7	1.6	1.1

* *Assessment types include In-Line Inspection, Replacement, Renewal, and Pressure Testing.*

The 2016 capital work is includes the installation of launcher and receivers and pipe replacement, while most of the 2017 work is the actual in line inspection runs and validation digs.

b. East Metro Project

Work associated with the four-year East Metro Project will conclude at the end of 2016. The majority of costs associated with this project will end in late 2016 with the possibility of some carry-over costs, such as restoration and other work that is difficult to complete in the winter, incurring in 2017. We currently estimate East Metro Project capital expenditures of approximately $15.7 million in 2016.

c. Automatic Shut-off Valve/Remote Controlled Valve

The ASV/RCV installation project commenced in 2015 and we expect it to continue over the next four years. We anticipate capital expenditures related to the project to range from $0.5 - $1.0 million per year. The actual number of valves installed per year, and the specific type of valves installed, will impact the annual expenditures. In 2016, the Company expects to install three valves. The Company is still evaluating the scope of this project and performing a risk-based engineering analysis to determine the overall duration of the project.

d. Programmatic Replacement/MAOP[27] Remediation

Finally, the Programmatic Replacement/MAOP Remediation program will fund investments addressing the integrity management of the Company's transmission pipelines. The potential need for capital intensive repairs or replacement efforts needed on transmission pipelines that are being assessed for asset health and condition in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures. In 2017, the Company will be entering the pre-work phase and completing the design and engineering work as well as Right-Of-Way/easement acquisitions for four transmission line replacement projects. After the 2017 pre-work phase of this program, the capital costs are expected to be approximately $25 million annually.

e. TIMP Summary

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

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

2. DIMP

a. Poor Performing Main and Service Replacement

Within the category of DIMP projects, the Poor Performing Main and Service Replacement Projects are multi-year initiatives. Future capital expenditures associated with Poor Performing Mains will range from $7 million to $11 million annually, while the Poor Performing Services expenses will likely fall between $4 million and $7 million annually. Both projects will require a period of design and construction resource procurement and deployment, with capital expenditures gradually increasing from 2016 to 2017. The Company does not expect to incur significant O&M costs for the project as a result of a change in the capitalization policy.

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[27] Maximum Allowable Operating Pressure (MAOP); MAOP verification and testing for transmission pipelines were initially defined in the Pipeline Safety Act of 2011.

b. Distribution Valves and Pipeline Data

DIMP projects focused on Distribution Valves and Pipeline Data are currently planned to have a limited duration. In particular, the Pipeline Data Project concluded in 2015[28]. The new valve installation component of the Distribution Valve Replacement Project is expected to conclude in 2016. In addition to the new valve installations, the proposed 2017-2018 program is roughly $0.8 million annually and is designed to replace existing distribution system isolation valves which have outlived their useful lifespan.

c. Sewer and Gas Line Conflict Remediation

Between 2011 and 2015, the annual cost for the sewer and gas line conflict remediation program averaged $3.5 million. We anticipate that costs for inspections will continue at this level for the next few years. We plan to continue inspections at the historic level until such time that it is appropriate to modify the number of annual inspections. In part, the expenses of the program in the future will reflect the results of those inspections. Depending on the number of conflicts found, the Company will evaluate the associated level of risk and adjust the number of inspections as needed.

d. Distribution Pipeline Inspection

The distribution pipeline inspections, or "Intermediate Pressure Line Assessment" is expected to continue for several years. We will continue to regularly inspect key segments of our gas distribution system. The Company will continue efforts to obtain important asset health data from these inspections. We will use the data to develop plans for additional mitigation actions to address risk and prioritize potential replacement of pipeline segments. Additionally, in 2017 the Company will be completing design and engineering work as well as Right-Of-Way/easement acquisitions for two IP line replacement projects. Future costs associated with distribution pipeline inspections and replacement could vary between $0.2 million and $1.0 million, depending on the specific pipeline segments being assessed.

e. Federal Code Mitigation

The Federal Code Mitigation was a new project in 2016 to comply with changing federal codes governing the operation and maintenance of the gas system. This work includes making corrective actions to legacy assets. We estimate the 2017 costs for corrective actions to be approximately $0.2 million in capital and $0.47 million in O&M annually until the conclusion of this project in 2018.

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[28] Although this program concluded in 2015, late invoices carried into 2016 caused roughly $171K of capital charges.

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

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

On December 6, 2010, Xcel Energy's most recent gas general rate case was approved by the Minnesota Public Utilities Commission in Docket No. G002/GR-09-1153. In that proceeding, the Commission approved a total retail related revenue of $592.87 million for the test year ending December 31, 2010. Excluding $4.69 million of other operating income for customer-related charges not included in retail rates and $429.08 million for gas purchase and transportation charges, the total approved base revenue was $159.10 million. The revenue collection estimates using the Company's most recent sales forecast based on a proposed 2017 GUIC rate generates $14.73 million of GUIC-related revenues in 2017. The GUIC revenue estimates reflect 9.26 percent of the base revenues of $159.10 million approved in the previous general rate case. Please reference Attachment L for details.

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

The Company's capital expenditures (construction work in progress or "CWIP" only) included in the 2010 test year approved in Docket No. G002/GR-09-1153 totaled $29.89 million. The 2017 forecasted GUIC-related capital expenditures (CWIP only) total $23.64 million. Accordingly, the incremental costs proposed in this filing reflect a 79.09 percent increase over currently approved base rate levels. Please reference Attachment L for details.

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

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

In this section, we provide the 2017 revenue requirement and 2017 rate adjustments factor calculations for the proposed GUIC.

1. *Revenue Requirements*

The projected GUIC revenue requirements for 2015 through 2021 are summarized in Attachment M to this filing. The projected 2017 revenue requirements proposed for recovery through the 2016 GUIC adjustment factors from Minnesota gas customers are approximately $22 million, including $0.3 million in under-recovery carried over from 2016. The supporting revenue requirements and projected 2015-2021 GUIC Tracker activity are provided in Attachment N. In addition, the eligible revenue requirements also include property taxes, current and deferred taxes, and book depreciation. Attachments E and F summarize the projected revenue requirements for the TIMP and DIMP projects respectively. Attachment O provides descriptions of the rate base and return calculation categories included in Attachments E and F.

The Company has included in its revenue requirements calculation the Federal portion of FERC Account 282, Accumulated Deferred Income Taxes – Other Property offset to rate base to assure it is calculated in accordance with the proration formula in IRS regulation section 1.167(1)-1(h)(6).[29] We have included Attachment P as a new attachment showing the ADIT calculation.

2. GUIC Rate Adjustment Factor

The Company's GUIC adjustment factor rate design provides for rates specific to five customer groups (residential, commercial firm, commercial demand billed, interruptible, and transportation). The 2017 tracker balance is allocated to class in the same manner as revenues were apportioned in our most recent natural gas rate case,[30] consistent with the Commission's 2015 and 2016 GUIC Orders.

Proposed class factors are calculated by dividing the class revenue responsibility by the forecasted Minnesota sales for the recovery period and include the GUIC Adjustment Factor as part of the Resource Adjustment line on customer bills. The 2017 GUIC Adjustment Factor calculation is shown in Attachment Q. We propose the following 2017 GUIC adjustment factors in Table 3 below:

Table 3
Proposed 2017 GUIC Adjustment Factors
(Dollars per therm)

	Current Factors	Proposed Factors
Residential	$0.010922	$0.041689
Commercial Firm	$0.006110	$0.023070
Commercial Demand Billed	$0.005274	$0.017177
Interruptible	$0.003860	$0.012162
Transportation	$0.001570	$0.004639

29 A technical description of this issue can be found in Docket No. E002/GR-15-826, Exhibit___(LHP-1), pages 53-56.
30 Docket No. G002/GR-09-1153.

Under the proposed adjustment factor, the average bill impact for a typical residential customer would be $2.95 per month, of which $0.66 (1.2 percent of the total bill) is due to 2017 capital expenditures and increased O&M. We propose these factors be effective April 1, 2017, and the above rates are calculated based on implementation of the new GUIC adjustment rate starting April 1, 2017.

To provide further assurance of the accuracy of our calculations, external consultants under contract with the Company have reviewed the GUIC revenue requirement and factor calculation model. This third-party review consisted of the following steps: (1) review of our revenue requirements and tracker calculations; (2) review of compliance of these calculations with the intent of statutes, orders, and previous filings, and (3) verify that costs proposed to be recovered through the 2017 GUIC Rider adjustment factors are not being recovered under any other mechanism. In addition to verifying the accuracy of the Company's calculations, the review also confirmed that the revenue requirement calculations include no double recovery costs.

B. Timing of GUIC Factor Calculation

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

If implementation of the 2017 GUIC adjustment factors occurs after April 1, 2017, the Company proposes to calculate the final rate adjustment factors to recover the remaining 2017 revenue requirements over the remaining months through March 31, 2018, which would be provided as part of a compliance filing after the Commission's Order approving the Petition.

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

C. GUIC Tracker Account

To ensure that customers are not under- or overcharged, we record the actual GUIC revenue recovery and requirements in a tracker account as the accounting mechanism for eligible GUIC project costs. As revenues are collected from retail customers each month, the Company tracks the amount of recovery under the GUIC rate factor and compares that amount with the monthly revenue requirements.

The difference is recorded in the tracker account as the amount of over- or under-recovery. The tracker also records differences in revenue requirements from forecasted to actual. Any over- or under-recovery balance at the end of the year is used in the calculation of the rate factor for the next year's forecasted revenue requirement. In other words, over-recovery is taken into account by reducing the subsequent year's rate factor calculation. Under-recovery is similarly taken into account by increasing the subsequent year's rate factor calculation. The revenue requirements included in the tracker are only those related to Minnesota's jurisdictional share of eligible GUIC projects.

We calculate the monthly Minnesota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes, and depreciation), compare them with monthly GUIC Rider recoveries from customers, and place the under-recovered amounts in FERC Account 182.3, Other Regulatory Assets and over-recovered amounts in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts). Tracker balances for GUIC activity estimated in 2016 are shown on Attachment N.

D. Proposed Tariff Sheet and Customer Notice

1. *Proposed Revised Tariff Sheet*

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

2. *Proposed Customer Notice*

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

> "This month's Resource Adjustment includes an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is \$x.xxxx per therm for Residential customers; \$x.xxxx per therm for Commercial Firm customers; \$x.xxxx per therm for Commercial Demand Billed customers; \$x.xxxx per therm for Interruptible

> customers, and $x.xxxx per therm for Transportation customers. Questions? Contact us at 1-800-895-4999."

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

VI. RATE OF RETURN

Here we describe our proposed capital structure and return on equity and address why our proposal is consistent the public interest. 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." Minn. Stat. § 216B.1635, Subd. 6. Additionally, other sources of law provide standards for determining the fairness or reasonableness of a utility's allowed return. The Supreme Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U. S. 695 (1923) ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591(1944) ("*Hope*").

In *Bluefield*, the Court stated:

> *A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.*[31]

The Court recognized that: (1) for a regulated public utility to remain financially sound, the allowed return on its invested capital should be at least equal to the cost of capital (the principle relating to the demand for capital); and (2) to attract capital, a regulated public utility must offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

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[31] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

In *Hope*, the Court reiterates the financial integrity and capital attraction principles of the *Bluefield* case:

> *From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.* [32]

In summary, the Court clearly has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and to support the company's credit and to attract capital. The Court also established the principle that the specific means of arriving at a fair return are not important, only that the end results lead to just and reasonable rates.

In its August 18, 2016 Order in our most recent GUIC Annual Report[33], the Commission determined that the Department's recommended ROE of 9.64 percent was within the public interest. The Commission also found:

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

The Company continues to supports the capital structure and cost of debt approved by the Commission in its August 18, 2016 Order. In recognition of recently declining returns on equity, the Company supports an ROE of 9.50 percent, which results in an overall rate of return of 7.26 percent. The rate of return is consistent with law and the public interest.

The Company retained an independent expert, ScottMadden, Inc., to perform an assessment of the appropriateness of the Company's proposed use of the 9.50 percent ROE in the ROR calculation for the 2017 GUIC revenue requirement. The report from ScottMadden is Attachment S to this Petition. ScottMadden's conclusion supports the proposed 9.50 percent ROE, resulting in an overall 7.26 percent ROR.

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[32] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[33] Docket No. G-002/M-15-808.

The independent consultant applied three commonly-used analytical tools to assess the reasonableness of the Company's proposed 9.50 percent ROE: (1) the Discounted Cash Flow Model, (2) the Capital Asset Pricing Model, and (3) a Risk Premium model.

To facilitate a comparison of appropriate companies, the expert identified similarly-situated utility companies and then analyzed the returns earned by those companies. The proxy groups consisted of 10 combination gas and electric utility companies and 8 gas utility companies. Proxy groups are used to moderate the effects of anomalous, temporary events that may be associated with a single company.

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

Key factors considered in the ScottMadden analysis include: (1) the effect of current capital market conditions on investors' return requirements and expectations about interest rates; (2) and the Company's business risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE. ScottMadden concludes that the Company's proposed ROE of 9.50 percent is a conservative estimate of its cost of equity, and is appropriate given the current and projected capital market environment. In fact, the report highlights at pages 25-27 the authorized gas ROEs since January 2015 average 9.525 percent. For these reasons, the Company's ROE is reasonable.

The Company's proposed 7.26 percent ROR is (1) expressly authorized by statute, (2) is consistent with comparable utility proxy groups, and (3) is within the range required by equity investors to invest in utilities similar to the Company under current capital market conditions. When applying the holdings of *Hope* and *Bluefield*, these facts demonstrate the fairness of the Company's ROR. For the foregoing reasons, the public interest supports the capital structure, cost of debt, and cost of equity proposed by the Company for use with its forthcoming 2017 GUIC Rider for an ROR of 7.26 percent.

The Company acknowledges that its last rate case was completed in 2010 which is the proceeding that last set the ROR for the Company's gas operations. Because several years have elapsed since the Commission reviewed the Company's ROR, there have been extensive discussions about whether that ROR remains consistent with the public interest in the Company's prior GUIC Rider proceedings. As a result, the Company believes it would be helpful for the Commission to issue a procedural schedule that allows for an evaluation of the Company's proposed ROR and supporting analysis, as well as an evaluation of any analysis provided by parties which support their recommendations.

VII. GUIC METRICS AND STAKEHOLDER REVIEW

In its August 18, 2016 Order[34], 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."

As a result, the Company is planning an informational workshop in November to provide key stakeholders an overview of its GUIC program and also present its proposal for risk ranking and performance metrics for GUIC projects. As such, stakeholder outreach is still in process and guidelines for risk ranking and performance metrics for inclusion in future GUIC filings are not yet finalized. However, to adhere to the Commission Order, the Company has included its proposed risk ranking methodology in Attachment B2, C2(a) and C2(b).

CONCLUSION

Increasing federal and state regulatory standards for transmission and distribution integrity management have prompted the Company to implement integrity management plans for prudent investments in our gas transmission and distribution systems. The Company's plans have resulted in the replacement of more than a hundred miles of aging pipeline. These investments minimize public safety risks associated with aging assets that deliver gas service.

The legislature recognized the importance of allowing prompt recovery mechanisms for these investments in 2013, when it authorized utilities to request recovery for integrity management expenses outside of general rate cases. The Commission validated the reasonableness and prudence of the Company's investments in its previous GUIC Rider Orders. In this filing, the Company describes its ongoing reasonable and prudent investments in pipeline safety and reliability planning and outlines its cost recovery proposal for these investments. Xcel Energy respectfully requests that the Commission, consistent with its previous GUIC Order, grant recovery of its gas utility infrastructure costs through a GUIC Rider and approve the proposed 2017 GUIC Rider factors.

Dated: November 1, 2016

Northern States Power Company

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

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	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 2016, REVENUE REQUIREMENTS FOR 2017, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-16-____

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. Xcel Energy has undertaken a variety of approved threat evaluation, assessment, and risk mitigation activities to promote the safe and reliable operation of its gas infrastructure assets in compliance with federal regulations. We request approval to recover gas utility infrastructure costs (GUIC) through the GUIC Rider (Rider). Xcel Energy requests cost recovery of its projected 2017 TIMP and DIMP costs (including deferred costs) pursuant to Minn. Stat. § 216B.1635, which permits a utility to petition the Commission for recovery. The Company also seeks approval of its 2016 true-up, its 2017 GUIC adjustment factors, and its proposed capital structure and ROE for 2017.

Index of Attachments

Attachment	Item
A	Index of Attachments
B	TIMP Project Overview
B1	TIMP Project Detail
B2	TIMP Quantitative Risk Assessment Scores
C	DIMP Project Overview
C1	DIMP Project Detail
C2(a)	DIMP Quantitative Risk Assessment Scores
C2(b)	DIMP Replacements 2017 Assessment Scores
D	Capital TIMP and DIMP Expenditures Through 2021
E	TIMP Revenue Requirements for 2015-2018
F	DIMP Revenue Requirements for 2015-2018
G	Minnesota Statute § 216B.1635
H	Compliance Matrix
I	TIMP and DIMP O&M Budget Estimates for 2016-2021 and Cost Data for Previous Years
J	Cost/Revenue Reconciliation to 2015 Jurisdictional Annual Report
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Attachment	**Item**
M	Annual Revenue Requirements Tracker Summary for 2015-2021
N	Revenue Requirements Tracker for 2015-2018
O	TIMP and DIMP Revenue Requirements Category Descriptions
P	ADIT Prorate Calculation
Q	GUIC Rate Factor Determination for 2015-2018
R	Proposed Tariff Sheet Revisions: Red-Line and Clean
S	ROE Analysis

Transmission Integrity Management Program (TIMP)
Overview and Project Detail

I. TIMP OVERVIEW

Xcel Energy's TIMP was developed pursuant to the Pipeline Safety Improvement Act of 2002 and the regulations promulgated by the Department of Transportation's Office of Pipeline Safety. On December 17, 2004, Xcel Energy published a TIMP Manual, in accordance with 49 C.F.R. § 192, Subpart O. The purpose of the TIMP Manual is to specify the procedures for gathering, integrating, and analyzing data; assessing pipelines; and implementing remedial actions to improve pipeline safety.

At its core, TIMP can be summarized in three steps: 1) understand your assets, 2) understand the threats to those assets (risk evaluation) and, 3) proactively address threats against those gas transmission assets (risk mitigation). Xcel Energy's processes for these three steps are outlined below.

1. Understand Your Assets

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

Managing the risk of gas transmission assets is an ongoing process and evolves over time. The Company's baseline assessment plan is the primary document that prioritizes pipeline segments based on a number of factors, including proximity to population and severity of consequences. The plan is updated regularly as new information becomes available on the health and condition of the assets as well as other system information.

The Company continues to update asset records and improve overall asset knowledge, as well as information on the surrounding area. Examples include geotechnical information, river data, soil conditions and asset information.

2. Risk Evaluation

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

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

- 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. This risk assessment process provides information to facilitate decisions such as the prioritization of pipelines and/or segments of pipelines for health and condition assessment, the frequency of the health and condition assessment, which assessment methodology is most appropriate, and, in certain cases, information to substantiate the need for replacement of an asset.

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

3. Risk Mitigation

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

As referenced in the Petition portion of this filing, one element of the "Pipeline Safety Action Plan"[1] issued by the Department of Transportation (DOT) called for operators, like Xcel Energy, to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of natural gas facilities. In direct support of that action plan, the Company's evaluation of the East Metro Pipeline revealed that replacement of that gas transmission line was in the best interest of public safety. Replacement would eliminate construction and manufacturing threats posed by the existing compression (or mechanical) couplings used in construction of the line (installed in the 1940s and 1950s).

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

In March of 2016, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking (NPRM) under Docket No. PHMSA-2011-0023. This NPRM proposes to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposes changes to the integrity management (IM) requirements and proposes changes to address issues related to non-IM requirements. The Company anticipates that the final rulemaking will be issued by PHMSA in 2017.

The potential specific IM requirements this NPRM proposes to change include:

- Expansion of Integrity Management beyond HCAs
- MAOP Validation
- Repair Criteria for Assessments in HCAs and MCAs
- Corrosion Control
- Risk Models

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

- New Construction and Repairs
- Spike Testing
- Inspection of Pipelines Following Weather Events
- Gas Gathering Lines

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

II. 2017 TIMP PROJECTS

In 2017, there are four projects proposed under the TIMP:

1) East Metro Pipeline Replacement;
2) Transmission Pipeline Assessments;
3) Automatic Shut-Off/Remote Control Valves; and
4) Programmatic Replacement/MAOP Remediation.

These projects were included in the Company's 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket No. G002/M-15-808. This is the first year the Programmatic Replacement/MAOP Remediation program is expected to incur costs. Primary construction activities associated with the East Metro Pipeline Replacement project will conclude in 2016. The only anticipated costs for this project in 2017 relate to carryover expenses, such restoration or other work that is difficult to complete during the winter.

In this filing, the Company requests recovery of the following O&M and capital expenditures associated with 2017 TIMP activities:

2017 Estimated TIMP Project Costs
($ Millions)

	2017 Capital	2017 O&M***
East Metro Pipeline Replacement	$0.00	$0.00
Transmission Pipeline Assessments	$1.61	$1.30
ASV/RCV	$0.90	$0.00
Programmatic Replacement / MAOP Remediation	$2.91	$0.00
TOTAL 2017 TIMP Capital Expenditures and O&M	**$5.42***	**$1.30**
TOTAL 2017 MN TIMP Revenue Requirements	**$7.86****	**$1.15*****

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

TIMP is an ongoing program to continuously reduce operating risk and improve overall public safety. Projects planned for completion in 2017 and outlined below will begin during the 2nd and 3rd quarters of 2017 and will be placed in service during the 3rd and 4th quarters of 2017.

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

2017 Estimated Project Costs:
$0.00 million Capital expenditure
$0.00 million O&M expenditure

Estimated Project Start Date
N/A

Estimated In-Service Date
The East Metro pipeline project is a four-year effort that began in 2013. The project is scheduled for completion and in-servicing during the fall of 2016. The only anticipated expenses in 2017 are for carryover costs from previous year's activities, which may include restoration or other work that is not able to be completed during the winter. The Company will continue to include the monthly revenue requirements associated with the East Metro pipeline project in the GUIC until the project is moved to base rate recovery, which will presumably be proposed in the Company's next gas rate case filing.

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

2017 Estimated Project Costs:
$1.61 million Capital expenditure
$1.30 million O&M expenditure

Project Summary and Scope
The scope of this program is to perform health and condition assessments on gas transmission lines in the NSPM gas system. The federal regulation requires assessment of gas transmission pipelines using limited approved methods including In-Line Assessment (ILI), Pressure Testing or Direct Assessment. The requirements are further defined in the Company's TIMP manual. This program is ongoing, with regular assessment of pipelines based on the health and condition of the assets as well as an evaluation of other operating information.

This program began in 2002 with the federal requirement to assess all pipelines in HCA's within 10 years (by December 17, 2012). The Company met the HCA Baseline Assessment requirements, and is now focusing on the re-assessment of pipelines in HCA's 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 (ASME) Standard B31.8S, which is incorporated by reference into 49 CFR 192 Subpart O.

Federal regulation requires pipeline operators to assess the integrity of their pipelines based on the threats to which the pipeline is susceptible. Of the aforementioned approved limited methods, the Company has selected ILI as the primary assessment methodology due to its superior ability to provide detailed information regarding the current pipeline condition over the entire length of the line. However, based on the threats to which a pipeline is susceptible and the feasibility of assessment methodologies, the Company may choose to utilize direct assessment and pressure testing as complementary assessment methodologies.

The Company's preferred ILI method requires unique inspection equipment and specialized knowledge. For example, a single ILI tool may be valued at $1 million. Outside vendors maintain fleets of such tools and have the expertise needed to conduct an ILI. The Company works with outside contractors to complete this work safely and efficiently.

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

There are two distinct elements in the selection and prioritization of work to be performed in this program: the assessment of pipelines and addressing issues found following an 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 and assess if they are stable or deteriorating.

The Company evaluates anomalous conditions found during the assessment. Factors in this evaluation include 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, which are used to prioritize when and how a particular anomaly will be excavated and remediated. Typical remediation measures include excavation and repair or removal of the anomaly, and/or reducing the operating pressure of the system.

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

In 2017, the Company plans on completing ILI activities on four projects:

1. Wescott 8" Line,
2. Rosemount Line,
3. Island Line South, and
4. Inver Hills Lateral.

The scope of work in 2017 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Wescott 8" Line	ILI	1.6	Capital
Rosemount Line	ILI	7.9	O&M
Island Line (South of River)	ILI*	1.9	Capital
Inver Hills Lateral	ILI*	2.0	Capital
Lake Elmo Line	ILI*	5.8	Capital
Montreal Line North	TBD	0.3	Capital

** Island Line S and Inver Hills Lateral are being made piggable in 2016, ILI runs to be completed in 2017.*

The Wescott 8" line requires modification to allow the passage of an ILI tool in order to effectively assess the integrity of the pipeline and to satisfy the requirements listed in 49 CFR 192.921. Pipeline modifications include installation of pig launchers and receivers, and new piping and valve configurations at the beginning and ending of the pipeline. A series of pigging runs will be completed, including a "smart pig" to assess the integrity of the line. Validation digs will occur after the smart pig run to validate the collected information. The Wescott 8" line supports Xcel Energy customers in the heating months, therefore conducting an ILI assessment of this line will allow Xcel Energy to continue to safely provide gas to its customers.

The Rosemount Line, Island Line S, and Inver Hills Lateral will all have a series of ILI runs and validation digs in the same fashion as the Wescott 8" line to satisfy the requirements of 49 CFR 192.921. The Rosemount line contains 2.8 miles of HCA and the Island Line S contains .5 miles of HCA, which require additional priority per 49 CFR 192.921.

The Montreal Line N line is a unique and difficult pipeline to assess, given that it runs down a steep and rocky slope, and is underneath a major roadway and interstate highway. A portion of the line is also within a HCA.

2017 project detail is presented in Attachment B1(a,d). Risk assessment scores for 2017 projects are presented in Attachment B2.

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

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

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

The number of digs required to validate an assessment and repair critical anomalies is estimated by evaluating the history of each pipeline (including installation date) and its environment. The length of the assessment will also play a role in increasing or decreasing the number of anticipated digs. The actual number of selected digs is prescriptive and is defined by federal code requirements[2] as well as impacted by pipeline condition.

Repairs to existing pipelines that do not involve cut-out of the existing pipe are defined by the Company's Capital Accounting policy as O&M. If a cut-out is required, Capital Accounting policy defines the O&M/Capital designation based upon pipe diameter and the length of the required cut-out.

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

2017 Estimated Project Costs:
$0.90 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
Section 4 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of the U.S. Department of Transportation (DOT) to require by regulation the use of automatic or remotely controlled shutoff valves, or equivalent technology, where it is economically, technically, and operationally feasible. On August 25, 2011, PHMSA issued an advanced notice of proposed rulemaking addressing ASV/RCV's and seeking comments on several broad areas for potentially expanding the TIMP rules. PHMSA has completed its study on ASV/RCV's, but has not yet issued a ruling.

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

The goal of the ASV/RCV project is to install mainline isolation valves or add actuators to existing valves in order to quickly minimize the impact of an unplanned gas release from a gas transmission pipelines. Long lead times on valve equipment and availability of construction resources could affect the exact timing of the proposed valve installations. However, any planned installation work not completed as scheduled in a current year would be deferred into a subsequent year, which could ultimately extend the full duration of this multiyear project. The final PHMSA rules will also have an impact on the overall scope of this program.

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

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

Subject matter experts (SMEs) worked with the Company's Quantitative Risk Services Department to identify and rank the sites. Further site specific items were considered, including whether a pipeline was scheduled for replacement in the near future. As a result, it may be appropriate to install an ASV or RCV at a location with a lower risk prior to one at a higher-risk location, if the higher-risk location is on a pipeline scheduled for replacement.

The determination of the applicable type of ACV or RCV to install in each situation is based on an overall risk analysis, evaluation of system operational needs, and engineering review. The Company generally anticipates installing 2 to 4 valves each year through 2021. The locations proposed for installation in 2017 are based on discovery work completed in January 2016. The number of valves, valve sizes, and activity occurring at each of the locations listed below was determined as a result of that survey. O&M expenses are not expected or estimated in future years. Known scope of work in 2017 includes the following valves:

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

2017 project detail is presented in Attachment B1(a,e). Risk assessment scores for 2017 projects are presented in Attachment B2.

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

2017 Estimated Project Costs:
$2.91 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
Construction practices, pipeline material and manufacturing methods have changed over the course of decades as the Company’s pipelines were installed. The codes and rules around material testing, welding standards, and record keeping have also evolved over time. Consequently, the Company is left with a significant history of facilities in service for which there are varying data gaps. Some data gaps are more critical than others. For instance, data supporting the construction and maintenance of gas transmission pipelines and operating pressures are critical to the safe operation of these assets.

MAOP Remediation Advisory Bulletin (ADB-12-06, Docket No. PMHSA-2012-0068) issued by PHMSA and contained in the Federal Register specifically addressed Pipeline Safety in terms of Verification of Records. The initial language in the advisory required operators to “take action as appropriate to assure that all MAOP and MOP (“Maximum Operating Pressure”) are supported by records that are traceable, verifiable and complete.” The MAOP initiative focuses on that requirement through obtaining adequate proof of said documents and ensuring that they become part of the Company’s official system of record. Remediation of data gaps is also part of the scope.

Pipelines are prioritized for renewal and pressure tested based on a variety of factors and competing demands, including: location (HCA's), type of documentation missing, criticality to system, and vintage of pipeline. All of the pipelines have been prioritized using the criteria described above to develop a schedule and budget to complete the work in an appropriate amount of time.

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

The cost estimates for this program reflect an initial high-level budgeting estimate related to the potential need for capital intensive repairs or replacement efforts needed on transmission pipelines that are being assessed for asset health and condition in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures.

Funding for 2017 will be used for replacement work on the Montreal Line South and Island Line South, and design and engineering and ROW/easement acquisition for the East County Line Renewal – South Saint Paul Station to RR Tracks project.

Line/Loop	Type	Project Length (mi)	Project Type
Montreal Line South	Replacement	0.2	Capital
Island Line South	Replacement	1.5	Capital
East County Line Renewal – S.St. Paul Station to RR Tracks	Design & Engineering/Easement Acquisition	0.5	Capital

2017 project detail is presented in Attachment B1(a,f). Risk assessment scores for 2017 projects are presented in Attachment B2.

III. 2016 TIMP PROJECTS

In 2016, there are three projects under the TIMP: 1) East Metro Pipeline Replacement; 2) Transmission Pipeline Assessments; and 3) Automatic Shut-Off/Remote Control Valves. Following are the TIMP project costs originally included in the Company's 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket No. G002/M-15-808, as compared to updated 2016 cost estimates[3] based on emerging project developments and actual construction activity:

2016 Estimated TIMP Project Costs
($ Millions)

	2016 Capital, As Filed	2016 Capital Estimates	Capital Variance	Capital Variance %	2016 O&M, As Filed	2016 O&M Estimates	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$15.70	$15.70	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Transmission Pipeline Assessments	$4.90	$5.38	$0.48	9.80%	$0.00	$0.20	$0.20	100.00%
ASV/RCV	$0.50	$0.45	($0.05)	(10.00%)	$0.00	$0.00	$0.00	0.00%
TOTAL 2016 TIMP Capital Expenditures and O&M	**$21.10***	**$21.53***	**$0.43**	**2.04%**	**$0.00**	**$0.20**	**$0.20**	**100.00%**
TOTAL 2016 MN TIMP Incremental Revenue Requirements	**$6.12****	**$5.93****	**($0.19)**	**3.10%**	**$0.00*****	**$0.18*****	**$0.18**	**100.00%**

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

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[3] Based on actual costs as of 8/31/2016 and estimates from 9/1/2016 through 12/31/2016.

TIMP projects planned for completion in 2016, and outlined below generally began during the 2nd and 3rd quarters of 2016 and will begin service during the 3rd and 4th quarters of 2016.

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

Estimated Project Start Date
05/01/2016

Estimated In-Service Date
The East Metro pipeline project is a four-year effort that began in 2013. The 2016 phase began during the 2nd quarter and is scheduled to begin service during the 3rd and 4th quarters.

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

In 2016, construction activities have occurred in areas with significant rock. The current pipe is also at a much shallower depth than current standards in various locations, requiring rock excavation to obtain a safer depth of cover. Construction activities are taking place in an urban environment and therefore, significant efforts are required to coordinate traffic control and perform hard surface restoration work on this project. The Company expects that the majority of costs associated with this project will end in late 2016 with the possibility of some carry-over costs incurring in 2017. 2016 project detail is presented in Attachment B1(a,c).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	**2016 Estimates***	**Variance**	**Variance %**
Capital Expenditure	$15.70	$15.70	$0.00	0.00%
O&M Expenditure	$0.0	$0.00	$0.00	0.00%

** Actual capital and O&M expenditures totaled $11.58 million and $0.00 million, respectively, through August.*

Specific tasks for 2016 include:

Tasks	**Cost ($ Millions)**
Permitting/ROW acquisition	$0.50
Engineering/Design	$0.20*
Material	$1.80
Construction/Testing	$13.85
Total	**$15.90**

** Internal Company Labor; the Company is not requesting recovery of these dollars through the GUIC rider. The project costs with internal labor removed are $15.70 million.*

Variance Explanation

Capital: None.

O&M: None.

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

Project Summary and Scope

In 2016, the Company is in the process of modifying three lines to prepare for an ILI assessment in an upcoming year. The Company is also performing replacement work on three other lines. The scope of work in 2016 includes the following lines:

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

2016 project detail is presented in Attachment B1(a,d).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$4.90	$5.38	$0.48	9.80%
O&M Expenditure	$0.00	$0.20	$0.20	100.00%

** Actual capital and O&M expenditures totaled $4.02 million and $0.00 million, respectively, through August.*

Variance Explanation

Capital: The main driver for the increase in capital expenditures is to complete the East County Line Casing Removal Project in 2016. Although this project was presented in last year's filing, the $1.1 million dollars needed to complete the project was inadvertently omitted from filed amounts for this program. As a result, the Company was originally planning on deferring the Inver Hills Lateral project into 2017 and using that funding to complete the East County Line Casing Removal Project. According to existing TIMP rules, the assessment deadline for this project is 2017. However, a more recent evaluation has caused the Company to re-establish the Inver Hills Lateral project in 2016 to prevent outages to the Inver Hills peaking plant during the plant's normal operating window (June-August).

O&M: The main driver for the increase in O&M expenditures is the East County Line casing removal project. At this time, the previously planned directional drill to replace one cased section of pipe with uncased pipe under the Union Pacific Rail Line is not feasible due to an un-locatable fiber optic cable which was improperly installed by Sprint. This development has precipitated the need to change the scope of the project from replacement to pressure test. Since pressure testing is an O&M activity, this has created an O&M cost component in 2016 in order to conduct the pressure test ($200,000). The scope of work for the second casing scheduled for replacement remains unchanged and will be replaced with an uncased pipe underneath Stillwater Blvd. using capital funds.

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

Project Summary and Scope

Discovery work was performed in January 2016 to determine the number of valves, valve sizes, and activity occurring at each of the locations required in 2016 to conform to the regulations set forth in 49 CFR Part 192.935. The following reflects the results of the survey:

Subproject	Size	Description
Rosemount Line Take0off	16"	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off
Rosemount TBS (St. Paul 1P)	16"	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS
Lake Elmo 1B TBS	12"	Add a valve and remote controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS
Maplewood plant	12"	Add a valve and remote controlled actuator on the Lake Elmo Line at the Maplewood Plant

2016 project detail is presented in Attachment B1(a,e).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.50	$0.45	($0.05)	(10.00%)
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

** Actual capital and O&M expenditures totaled $1.66 million and $0.00million, respectively, through August.*

Variance Explanation

Capital: The main driver for the reduction in capital expenditures is the removal of capitalized internal labor costs.

O&M: None.

IV. 2015 TIMP PROJECTS

In 2015, there were three projects under TIMP: 1) East Metro Pipeline Replacement; 2) Transmission Pipeline Assessments; and 3) Automatic Shut-Off/Remote Control Valves. Following are the TIMP project costs originally included in the Company's 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket No. G002/M-15-808, as compared to actual 2015 costs.

2015 Actual TIMP Project Costs
($ Millions)

	2015 Capital, As Filed	2015 Capital Actuals	Capital Variance	Capital Variance %	2015 O&M, As Filed	2015 O&M Actuals	O&M Variance	O&M Variance %
East Metro Pipeline Replacement	$23.10	$20.74	($2.36)	(10.22%)	$0.04	$0.00	($0.04)	(100.00%)
Transmission Pipeline Assessments	$0.35	$0.51	$0.16	45.71%	$0.75	$1.44	$0.69	92.00%
ASV/RCV	$0.50	$0.58	$0.08	16.00%	$0.00	$0.00	$0.00	0.00%
TOTAL 2015 TIMP Capital Expenditures and O&M	**$23.95***	**$21.83**	**($2.12)**	**(8.85%)**	**$0.79**	**$1.44**	**$0.65**	**82.28%**
TOTAL 2015 MN TIMP Revenue Requirements	**$4.96****	**$3.28****	**($1.68)**	**33.87%**	**$0.22*****	**$1.28*****	**$1.06**	**482%**

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

TIMP projects completed in 2015 and outlined below generally began during the 2nd and 3rd quarters of 2015 and were placed into service during the 3rd and 4th quarters of 2015.

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

Project Summary and Scope

The 2015 scope of work replaced approximately 4.2 miles of gas transmission line at Rose Avenue and Park Street to Pleasant Avenue and St. Albans Street.

Notable challenges on this project in 2015 included managing traffic control and road closures. Several arterial streets in St. Paul were closed to allow for construction. This required special coordination with the city and county to align schedules with other construction projects in the area to keep traffic moving through the city. For example, there is a joint portion of the project working with the St. Paul Regional Water Department to replace approximately 1.7 miles of water main simultaneously with the East Metro project. 2015 project detail is presented in Attachment B1(a,b).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$23.10	$20.74	($2.36)	(10.22%)
O&M Expenditure	$0.04	$0.00	($0.04)	(100.00%)

Variance Explanation

Capital: The main driver for the reduction in capital expenditures is a cost saving ($1.5M) associated with lower than expected contractor pricing achieved through a competitive bidding process. Other cost-saving measures included utilizing a unit pricing approach as opposed to lump-sum pricing and performing air tests on certain segments of the pipe versus hydro testing.

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

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

Project Summary and Scope
In 2015, the Company performed health and condition assessments on three individual gas transmission pipelines using Direct Assessment or Pressure Testing.

Specific TIMP O&M assessment projects in 2015 included a direct assessment of the County Road B Line, a pressure test of the third and final segment of the Crossover Line, and a pressure test of the Granite City Line. Pressure tests are performed to validate the Maximum Allowable Operating Pressure (MAOP). A TIMP capital project in 2015 involved the installation of a launcher and receiver on the Granite City Line. This capital investment is part of the Company's overall plan to make all transmission pipelines assessable with modern ILI tools, improving asset knowledge and allowing more proactive repairs.

The scope of work in 2015 included assessment work on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
County Road B Line	Direct Assessment	0.7	O&M
Crossover Line	Pressure Test	2.3	O&M
Granite City Line	Pressure Test	0.7	O&M
Granite City Line	ILI Assessable (Launcher & Receiver Installation)	n./a	Capital

2015 project detail is presented in Attachment B1(a,d).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	**2015 Actual**	**Variance**	**Variance %**
Capital Expenditure	$0.35	$0.51	$0.16	45.71%
O&M Expenditure	$0.75	$1.44	$0.69	92.00%

Variance Explanation

Capital: The main driver for the increase in capital expenditures is higher difficulty in modifying the Granite City line to make the line ILI assessable. Detailed engineering and design plans for this project were not finalized at the time the previous filing was submitted. Also, an unanticipated section of pipe needed replacement due to the existing pipeline being encased in concrete, adding material and contract labor costs. Finally, a previously unidentified dresser coupling fitting was unearthed during construction and needed to be reinforced, adding additional material and contract labor costs.

O&M: The main driver for the increase in O&M expenditures is an interpretation of the Company's Capital Asset Accounting policy clarifying that pressure testing is an O&M activity despite capital ILI modifications. This policy clarified that only certain line modifications could be capitalized and the remaining costs, including pressure test activities, must be considered O&M.

There were higher costs than anticipated for Granite City project due to multiple insulator leaks during the pressure test process. After the insulator installation, the entire line was leak tested resulting in additional contract labor costs required to complete this portion of the project.

For the County Road B ECDA project, a dresser coupling was discovered, requiring extra time, contract labor, and materials to complete the repair. Additionally, unmarked gas lines were uncovered and required validation as abandoned before commencing construction, adding time and labor costs.

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

Project Summary and Scope
One RCV was installed during calendar year 2015 for this project. The RCV was being installed at the Cedar Town Border Station. The capital expenditures associated with the RCV include a new 26' valve, actuator, and connections to a Remote Terminal Unit (RTU). After detailed planning and design of this valve occurred, the Company determined that no O&M expenses are required to complete the installation. 2015 project detail is presented in Attachment B1(a,e).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$0.50	$0.58	$0.08	16.00%
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: Construction costs for the Cedar TBS were higher than expected.

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 expand beyond 2018.

The table below depicts the estimated capital and O&M costs for this multi-year plan. Many of these projects require more detailed design and engineering work to improve the quality of the estimate. Other factors, including coordination with city entities, securing rights-of-way and permits, resource and equipment availability, and unforeseen circumstances all can have an impact on a final construction estimate.

The estimate in the table below provides an initial high-level budgeting estimate for this program. As described in the Petition, the current PHMSA rules are in process of being finalized regarding the validation of Maximum Allowable Operating Pressure (MAOP). This program and estimated budget assumes vintage gas transmission pipelines will be required to have a current and valid MAOP test performed.

TIMP 2018-2021 Plan
($ Millions)

	2018 Estimates		2019 Estimates		2020 Estimates		2021 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
East Metro Pipeline Replacement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transmission Pipeline Assessments	$1.6	$1.1	$7.2	$1.7	$5.3	$1.7	$5.3	$1.7
ASV/RCV	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0
Programmatic Replacement / MAOP Remediation	$26.6	$0.0	$25.5	$0.0	$25.5	$0.0	$25.5	$0.0
TOTAL	**$29.2**	**$1.1**	**$33.7**	**$1.7**	**$31.8**	**$1.7**	**31.8**	**$1.7**

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

CAPITAL

Program	Regulation	Parent Number	2015 Actuals	Cost Per Unit (CPU) Assumptions 2015	2016 Actuals [1]	2016 Forecast	2016 Total	Cost Per Unit (CPU) Assumptions 2016	2017 Plan	Cost Per Unit (CPU) Assumptions 2017
East Metro Pipeline Replacement Project	49 CFR 192, Subpart O	11615874, 11676981, 11706370, 11819647, 12013233	$ 21,078,108	• Estimates do not have any unit cost assumptions. The average cost per unit of the new pipeline for work completed thus far is approximately $5.3 million per mile. All pricing is based from competitively bid contractor pricing. • 10% contingency was applied to the estimates. This level of contingency is needed for a large construction project of this nature to cover unknown expenses. - Total - $21.3M - Contingency - 10%	$ 11,812,805	$ 3,887,000	$ 15,699,805	• Estimates do not have any unit cost assumptions. The average cost per unit of the new pipeline for work completed thus far is approximately $5.3 million per mile. All pricing is based from competitively bid contractor pricing. • 10% contingency was applied to the estimates. This level of contingency is needed for a large construction project of this nature to cover unknown expenses. - Total - $15.7M - Contingency - 10%	$ -	N/A
TIMP Assessments	49 CFR 192, Subpart O	11649521, 11649797, 34000342	$ 548,826	2015 Assessment Projects; cost estimates are on a per project basis, project costs are high level estimates based on the assessment method selected. Direct assessment costs include pre-assessment data analysis, indirect inspection cathodic protection surveys, excavation and examination of anomalies, and final post assessment reporting. Pressure test costs include test equipment, test medium (typically water), and disposal of the test medium. In-line inspection costs include costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. • Granite City Line, ILI Assessable Test: $548,826 capital; primary activities included installing launcher and receivers.	$ 4,081,382	$ 1,919,000	$ 6,000,382	2016 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs.	$ 1,784,000	2017 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs.
ASV/RCV Valve Replacements	49 CFR Part 192.935	11503515	$ 667,855	Unit cost is $668K/RCV.	$ 167,619	$ 332,000	$ 499,619	Unit cost is $125K/RCV.	$ 1,000,000	Unit cost is $266K/RCV.
Programmatic Main Replacement/MAOP Validation	49 CFR 192.921(a); ADB-12-06, Docket No. PMHSA-2012-0068	11651650, 11810375	$ -	n/a	$ -	$ -	$ -	n/a	$ 3,250,000	*See* Subpart 1(f)
TOTAL TIMP CAPITAL			**$ 22,294,788**		**$ 16,061,806**	**$ 6,138,000**	**$ 22,199,806**		**$ 6,034,000**	

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

O&M

Program		Parent Number	2015 Actuals	Cost Per Unit (CPU) Assumptions 2015	2016 Actuals [1]	2016 Forecast	2016 Total	Cost Per Unit (CPU) Assumptions 2016	2017 Plan	Cost Per Unit (CPU) Assumptions 2017
East Metro Pipeline Replacement Project	49 CFR 192, Subpart O	11984262	$ -	n/a	$ -	$ -	$ -	n/a	$ -	n/a
TIMP Assessments	49 CFR 192, Subpart O	11984286	$ 1,437,470	2015 Assessment Projects; cost estimates are on a per project basis, project costs are high level estimates based on the assessment method selected. Direct assessment costs include pre-assessment data analysis, indirect inspection cathodic protection surveys, excavation and examination of anomalies, and final post assessment reporting. Pressure test costs include test equipment, test medium (typically water), and disposal of the test medium. In-line inspection costs include costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool.	$ 39,977	$ 160,023	$ 200,000	2016 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs.	$ 1,300,000	2017 Assessment Projects; costs are high level estimates based on common activities associated with in-line inspection (ILI). Such activities include, but are not limited to costs to rent and run an ILI tool, complete anomaly digs, and line modifications associated with passage of an ILI tool. Costs to modify the configuration of a pipeline to allow passage of an ILI tool vary widely based on a number of factors and are estimated on a line by line basis. Depending on the individual pipeline, these factors include: the presence (or absence) of launchers and receivers, expected quantity of restrictions (for example, bends, heavier wall fittings, valves), location and depth of the line, diameter, pipeline age, operating pressure, right-of-way access, and permitting costs.
TOTAL TIMP O&M			**$ 1,437,470**		**$ 39,977**	**$ 160,023**	**$ 200,000**		**$ 1,300,000**	

[1] Actual costs through August 2016.

Northern States Power Company

Docket No. G002/M-16-___
Gas Utility Infrastructure Cost Rider - 2017 Factors
Attachment B1(b)

East Metro Pipeline Replacement Project, Project Detail - 2015

Prt Proj Num	Prt Proj Desc	Jan Act	Feb Act	Mar Act	Apr Act	May Act	Jun Act	Jul Act	Aug Act	Sep Act	Oct Act	Nov Act	Dec Act	Total
11676981	East Metro Pipe Replacement Project - Distr	$66,498	$224,809	$165,493	$741,822	$2,266,689	$2,726,538	$4,690,819	$3,922,076	$1,746,433	$1,206,089	($303,145)	$603,728	$18,057,850
11706370	Install Rice & Co Rd 8 Regulator	$0	$0	($19,318)	($4)	$0	$0	$0	($16,358)	$0	$0	$0	$0	($35,679)
11819647	RTU's - East Metro Pipe Replac	$0	$0	$19,318	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,318
12013233	East Metro Pipeline Replacemen	$0	$0	$15,007	$143,687	$73,068	($8,188)	$6,971	$13,864	$3,259	$2,667	$0	$0	$250,335
11615874	East Metro Pipe Replac. Proj HP Gas	$0	$0	$0	$15,155	$1,194,932	$693,143	$383,853	$463,299	$23,801	$12,647	($539)	($7)	$2,786,283
Total		**$66,498**	**$224,809**	**$180,500**	**$900,661**	**$3,534,689**	**$3,411,492**	**$5,081,643**	**$4,382,882**	**$1,773,493**	**$1,221,403**	**($303,684)**	**$603,721**	**$21,078,108**

PUBLIC DOCUMENT: TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Northern States Power Company

Docket No. G002/M-16-____
Gas Utility Infrastructure Cost Rider - 2017 Factors
Attachment B1(c)

East Metro Pipeline Replacement Project, Project Detail - 2016

11676981	East Metro Pipe Replace. Proj Distr	East Metro Detailed Cost Types	Jan Fcst	Feb Fcst	Mar Fcst	Apr Fcst	May Fcst	Jun Fcst	Jul Fcst	Aug Fcst	Sep Fcst	Oct Fcst	Nov Fcst	Dec Fcst	Total
		[TRADE SECRET BEGINS													
															TRADE SECRET ENDS]
11676981	(11818868) East Metro Pipe Replace. Proj Distr Totals:	Totals:	$30,000	$105,000	$1,141,000	$1,126,000	$2,224,000	$2,214,000	$2,074,000	$1,871,000	$1,699,000	$399,000	$751,546	$20,000	$13,654,546
11615874	(11819015) East Metro Pipe Replace. Proj HP Gas	Totals:					$200,000	$200,000	$200,000	$100,000	$100,000				$800,000
		Totals:	$30,000	$105,000	$1,141,000	$1,126,000	$2,424,000	$2,414,000	$2,274,000	$1,971,000	$1,799,000	$399,000	$751,546	$20,000	$14,454,546

Estimate To Complete:	$14,454,546
YTD Actual:	$11,812,805
Remaining YE Forecast	$4,087,195
Estimate at complete with 10% contingency on remaining spend:	$15,900,000
2016 Original Budget:	$15,900,000

*Includes $200K of non-GUIC recoverable internal labor

2015-2017 Project Detail - TIMP Assessments

2015

Line/Loop	Project Description	Actuals	O&M or Capital
Crossover Line	**Pressure Test**	**$ 678,866**	
Task 1	Purge line out of service	$ 190,506	O&M
Task 2	Mitigate farm taps	$ 248,528	
Task 3	Hydrostatic Test 12"	$ 239,832	
Granite City Line	**Pressure Test**	**$ 327,127**	
Task 1	Contractor Mobilization	$ 22,462	O&M
Task 2	Remove Pipeline from Service	$ 8,695	
Task 3	Test, Replace Elbows, Restoration	$ 215,706	
Task 4	Clean Pipeline, Pressure Test, Dry Pipeline	$ 67,343	
Task 5	Materials	$ 12,920	
Granite City Line	**ILI Assessable (Launcher & Receiver Installation)**	**$ 492,959**	
Task 1	Install Launcher and Receiver	$ 301,080	Capital
Task 2	Place Pipeline in Service	$ 20,000	
Task 3	Site Restoration	$ 51,460	
Task 4	Contractor Mobilization	$ 10,000	
Task 5	Materials	$ 110,419	
County Road B	**Direct Assessment**	**$ 397,124**	
Task 1	Pre-Assessment Data Analysis	$ 30,000	O&M
Task 2	Indirect Indirect Inspection on Cathodic Protection	$ 49,000	
Task 3	Excavation and Examination of Anomalies	$ 301,132	
Task 4	Final Post Assessment Reporting	$ 16,992	

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

2016

Line/Loop	Project Description	Estimates	O&M or Capital
East County Line Casing	**Pipe Replacement**	**$ 1,100,000**	
Task 1	Outside Contractor	$ 977,445	Capital
Task 2	Internal Labor	$ 70,000	
Task 3	Materials	$ 52,555	
East County Line Casing	**Pressure Test**	**$ 200,000**	
Task 1	Prepare Pipe for Pressure test	$ 125,000	O&M
Task 2	Pressure Test	$ 25,000	
Task 3	Place Pipeline in Service	$ 50,000	
Rosemount Line - Inverhills Lateral ILI	**In-Line Inspection**	**$ 1,100,000**	
Task 1	Outside Contractor	$ 464,679	Capital
Task 2	Internal Labor	$ 6,780	
Task 3	Materials	$ 131,242	
Lake Elmo Line ILI	**In-Line Inspection**	**$ 1,200,000**	
Task 1	Outside Contractor	$ 508,925	Capital
Task 2	Internal Labor	$ 8,660	
Task 3	Materials	$ 115,000	
Island Line (South of River)	**ILI & Replacement**	**$ 1,700,000**	
Task 1	Outside Engineering	$ 72,000	Capital
Task 2	Outside Contractor	$ 1,205,431	
Task 3	Internal Labor	$ 15,000	
Task 4	Materials	$ 407,569	
High Bridge Lateral Replacement	**ILI & Replacement**	**$ 900,000**	
Task 2	Distribution	$ 75,000	Capital
Task 3	Transmission	$ 825,000	

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

2017

Line/Loop	Project Description	Estimates	O&M or Capital
Rosemount Line	**2nd ILI**	**$ 1,300,000**	
Task 1	Pigging Runs	$ 250,000	O&M
Task 2	Validation Digs	$ 1,050,000	
Wescott Line	**In-Line Inspection**	**$ 300,000**	
Task 1	Make Piggable	$ 100,000	Capital
Task 2	Pigging Runs	$ 100,000	
Task 3	Validation Digs	$ 100,000	
Island Line (South of River)	**ILI Assessable (Launcher & Receiver Installation)**	**$ 350,000**	
Task 1	Pigging Runs	$ 150,000	Capital
Task 2	Validation Digs	$ 200,000	
Inver Hills Lateral	**ILI Assessable (Launcher & Receiver Installation)**	**$ 250,000**	
Task 1	Pigging Runs	$ 150,000	Capital
Task 2	Validation Digs	$ 100,000	
Lake Elmo Line ILI	**ILI Assessable (Launcher & Receiver Installation)**	**$ 300,000**	
Task 1	Pigging Runs	$ 100,000	Capital
Task 2	Validation Digs	$ 200,000	
Montreal Line North	**TBD**	**$ 584,000**	
Task 1	Unknown-Feasibility Studies Scheduled		Capital

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

2015-2017 TIMP Project Detail - ASV/RCV

2015			
Subproject	**Size**	**Description**	**Actual Cost**
RCV at the Cedar TBS	26”	The capital expenditures associated with the RCV project include a new 26" valve, actuator, and connections to a Remote Terminal Unit.	$667,855

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

2016			
Subproject	**Size**	**Description**	**Estimated Cost**
Rosemount Line Take0off	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount Take-off	$100,000
Rosemount TBS (St. Paul 1P)	16”	Add a remote controlled actuator to an existing valve on the Rosemount Line at the Rosemount TBS	$100,000
Lake Elmo 1B TBS	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Lake Elmo 1B TBS	$150,000
Maplewood palnt	12”	Add a valve and remote controlled actuator on the Lake Elmo Line at the Maplewood Plant	$150,000
Total			$500,000

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

2017			
Subproject	**Size**	**Description**	**Estimated Cost**
Rich Valley Station Inlet	16”	Install new valve and actuator on the Rosemount line at the Rich Valley Station Inlet	$550,000
Hwy 55 and Babcock	16”	Install new actuator on the Rosemount line at Hwy 55 and Babcock Rd	$100,000
South St. Paul Station Inlet	16”	Install new actuator on the Rosemount line at the South St. Paul Station Inlet	$150,000
All	n/a	Contingency	$200,000
Total			$1,000,000

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

2017 TIMP Project Detail - Programmatic Replacement/MAOP Validation

2017		
Individual Project Name	**Description***	**Assumptions***
Montreal Line South Renewal]	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace 1,300' of 20" Grade B pipe installed in 1948 by Northern Natural Gas and sold to Northern States Power with 1,300' of new 20" Grade X-52 pipe. · Location: Lillydale: From Mendota Station to the Montreal River Crossing. · Construction Period: May – October 2017	· Mileage: o Installation: 1,300' – 20" Pipe o Retirement: 1,300' – 20" Pipe · Cost Per Unit: $1.2 million or $920/ft · Asset Information (valves, reg. stations, etc): Initial planning calls for reuse of valves at Mendota Station and at the river crossing. A launcher and receiver would need to be installed with piping. · Constraints: Limited space for construction, potential conflicts with railroad and park lands.
Island Line South Renewal	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.921(a) · Overview: Replace 7,900' of 20" Grade B pipe installed in 1952 by Northern Natural Gas and sold to Northern States Power with 7,900' of new 20" Grade X-52 pipe. · Location: Lillydale: From Mendota Station to the Pickerel Lake. · Construction Period: May 2017– October 2018	· Mileage: o Installation: 7,900' – 20" Pipe o Retirement: 7,900' – 20" Pipe · Cost Per Unit: $7.3 million or $920/ft · Asset Information (valves, reg. stations, etc): Initial planning calls for reuse of valves at Mendota Station. · Constraints: Limited space for construction, potential conflicts with railroad and park lands. · Notes: In Line Inspection scheduled for early 2017. Extent and timing of renewal work pending in line inspection results
East County Line Renewal – South Saint Paul Station to RR Tracks	Design & Engineering/Easement Acquisition	

Quantitative Risk Assessment for 2017 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

2017 Projects by Risk Category
NONE

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

Risk = Σ (Likelihood x Consequence) for all threats

Likelihood of Failure Lookup Table

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

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

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

Threat Category	L = 5	L = 3	L = 0.25
	requires immediate action as per 192.933(d)(iii).		
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	A dent that meets the criteria established in 192.933 (d) (3) An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

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

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

Consequence of Failure Lookup Table

Class Location	Score
4	1.15
3	1.10
2	1.05
1	1

Risk Matrix

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

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

High Risk: Risk Score ≥ 5

Medium Risk: 3 ≤ Risk Score < 5

Low Risk: Risk Score < 3

TIMP Transmission Pipeline Assessments -

Integrity Assessments Project Risk

2017 Projects by Risk Category

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Score	Risk Level (High, Medium, Low)
Wescott 8" Line	Newport	8	1974	42	No	4	High
Rosemount Line ILI	Newport	16	1990	5	Yes	4	High
Island Line S ILI	Newport	20	1952	2	Yes	2	Medium
Inver Hills Lateral ILI	Newport	16	1998	6	No	2	Medium
Montreal Line N	St. Paul	20	1962	4	Yes	2	Medium

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

Used for decisions on prioritizing integrity assessments

Risk Score = Likelihood of Failure x Consequence of Failure

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

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

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

Line Name	Regulation	Proposed RCV Location	Nearest Service Center	Likelihood of Failure	COF	ASV/RCV Location Risk, R_V	Risk Level
Rosemount Line	49 CFR Part 192.935	Rosemount TBS	Newport	2.000	4.000	8.00	Medium
East County Line	49 CFR Part 192.935	Maplewood Propane	White Bear Lake	3.000	3.000	9.00	High
Rosemount Line - Inver Hills Lateral	49 CFR Part 192.935	Rosemount Line Connection	Newport	2.000	3.000	8.00	Medium
Lake Elmo Line	49 CFR Part 192.935	Lake Elmo 1B TBS	White Bear Lake	2.000	3.000	8.00	Medium

Data inputs:

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

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

Likelihood of Failure = ROF

Consequence of Failure = Location Factor + Protection Factor

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

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

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

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

<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

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

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

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

(dark)	High Risk: Risk Score ≥ 9
(medium)	Medium Risk: Medium Risk, 4 ≤ Risk Score < 9
(light)	Low Risk: Risk Score <4

TIMP MAOP Project Risk

Project	Regulation	Current Classification	Prior Test	Material	Consequence	Risk Score	Project Classification
Montreal Line South	49 CFR 192.921(a)	Transmission	3	0.4	3	10.2	High
Island Line South	49 CFR 192.921(a)	Transmission	3	0.4	3	10.2	High
East County line (30" SSP to RR Tracks)	49 CFR 192.921(a)	Transmission	3	0.4	3	10.2	High
Repl 12" Upper 55th to St Paul Reg Stat	49 CFR 192.921(a)	Transmission	3	0.4	3	10.2	High

Data inputs:

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

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Prior Test Score + Material Score

<u>Prior Test Lookup Table</u>

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

<u>Material Lookup Table</u>

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

Consequence Lookup Table

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

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

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

Distribution Integrity Management Program (DIMP)
Overview and Project Detail

I. DIMP OVERVIEW

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

The progression of these steps is part of the Company's proactive integrity management program and continually evolves as new 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. Using the processes identified below, Xcel Energy is continually updating its DIMP plans and projects to address the evolving needs of its gas distribution system.

1) Understand Your Assets

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

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

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

- Incorrect Operation, 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.

2) Risk Evaluation (Assessment of Risk)

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

3) Risk Mitigation

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

- Replacement of poor performing coated steel pipelines (*corrosion*);
- Renewal of mechanical/compression coupled mains and services (*material and welds, corrosion*);
- Renewal of a poor performing type of polyethylene pipe material installed called Aldyl-A (PEA) pipelines *(material and welds, equipment);*
- Replacement of copper loop risers *(corrosion);*
- Inspecting intermediate pressure (IP) pipelines, defined generally as lines operating above 60 pounds per square inch gage (PSIG) and below transmission pressure (less than 20% specific minimum yield strength); repairing or replacing as needed (*corrosion, material and welds*);
- Replacement of intermediate pressure pipelines *(corrosion, material and welds)* .

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

II. 2017 DIMP PROJECTS

In 2017, there are six total projects proposed under DIMP. All of these projects were included in the Company's 2015 and 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket Nos. G002/M-14-336 and G002/M-15-808. The Company requests recovery of the following O&M and capital expenditures associated with 2017 DIMP activities:

2017 Estimated DIMP Project Costs
($ Millions)

Program	2017 Capital	2017 O&M
Poor Performing Main Replacements	$11.03	$0.24
Poor Performing Service Replacements	$6.90	$0.04
Intermediate Pressure (IP) Line Assessments	$0.67	$0.30
Distribution Valve Replacement Project	$0.72	$0.00
Sewer and Gas Line Conflict Investigation	$0.00	$3.50
Federal Code Mitigation	$0.20	$0.47
TOTAL 2017 DIMP Capital Expenditures and O&M	**$19.52***	**$4.55**
TOTAL 2017 MN DIMP Revenue Requirement	**$4.14****	**$4.55**

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

2017 Estimated Project Costs
$11.03 million Capital expenditure
$0.24 million O&M expenditure

Project Summary and Scope
Through an annual risk analysis, the Company identifies system threats, ranks these threats, and identifies actions to address these threats. The systematic renewal of poor performing mains 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 distribution integrity risk model, deficiencies in coating or cathodic protection, and construction methods, particularly those joined using mechanical couplings. Additional reviews and input from engineering and SMEs were incorporated into the replacement decisions. Main replacement is a multi-year project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

PHMSA has issued several Advisory Bulletins[1] about a certain polyethylene pipe material type called Aldyl-A. This plastic material becomes brittle over time and is subject to sudden failure from cracking. The Company has also identified segments of vintage coated steel pipe that need to be removed due to the mechanical couplings that were used to join the pipe. Many of these mains appear to pose no risk unless they have been disturbed through third-party damage (excavation hits) or natural forces (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.

[1] *See* PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02.

The Company utilizes the aforementioned risk model for the initial relative ranking of poor performing mains. This list is then reviewed by SMEs, who may adjust the project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees.

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

Planned replacement activity in 2017 spans the key areas of:

Geographic Area (by Division)	Mains (Miles)
St. Paul	7.75
White Bear Lake	2.12
Wyoming	2.54
Newport	9.24
St. Cloud	1.25
Southeast	7.87
Moorhead	1.19
Not Identified	44.15
Total	**76.10**

**Estimates as of August 31, 2016. A majority of the 2017 projects are in the process of being identified and scoped.*

Construction is completed using master service agreements with a number of construction companies based on a unit cost basis. These master service agreement are 4-year agreements. Engineering and design is completed in-house using Xcel Energy employees and contractor staff. Internal Company labor costs are not recoverable through the GUIC Rider. Materials are sourced internally through the Company's standard procurement contracts.

For 2017, the poor performing mains and service materials will include Aldyl-A (PEA), vintage copper risers and additional material types based on their overall relative risk. A majority of the 2017 projects are in the process of being identified and scoped. The project cost estimates are based on 2015 average installation cost by operating area. Main costs are per linear foot, service costs are a unit cost per service. On average, it is estimated that the total capital cost per mile of main replaced is $159,509. 2017 project detail is presented in Attachment C1(a, d). Risk assessment scores for 2017 projects are presented in Attachment C2(b).

Main projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified main projects will generally begin during the 2nd quarter, and assets will typically be in-service during the 3rd and 4th quarters. For example, 2017 project identification occurs in the 3rd and 4th quarters of 2016, construction will commence during the 2nd quarter of 2017, and in-service will occur during the 3rd and 4th quarters of 2017.

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

<u>2017 Estimated Project Costs</u>
$6.90 million Capital expenditure
$0.04 million O&M expenditure

<u>Project Summary and Scope</u>
Through an annual risk analysis, the Company identifies system threats, ranks these threats, and identifies measures to address these risks. Replacing poor performing or problematic services in a reasonable timeframe is a practical way to ensure public safety.

As with the analysis of poor performing mains, the Company uses the aforementioned risk model to provide a relative ranking of problematic service segments. These problematic segments are then reviewed by SMEs, who may adjust project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees. This is a multi-year program with the areas identified as higher risk, as measured by leak ratios and other factors, being mitigated in the appropriate order. Where pertinent, service replacements are considered for simultaneous construction along with main replacements to minimize construction costs.

Planned replacement activity in 2017 spans the key areas of:

Geographic Area (by Division)	Services (Number)*
St. Paul	665
White Bear Lake	142
Wyoming	159
Newport	688
St. Cloud	36
Southeast	677
Moorhead	86
Sub-Total	2,453
Not Identified**	5,172
Total	**7,625**

* *Estimates as of August 31, 2016.*

***A majority of the 2017 projects are in the process of being identified and scoped.*

Service replacement projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be in-service during the 3rd and 4th quarters. For example, 2017 project identification occurs in the 3rd and 4th quarters of 2016, construction will commence during the 2nd quarter of 2017, and in-service will occur during the 3rd and 4th quarters of 2017. Project costs are estimated on 2016 average installation cost by operating area, and service costs are a unit cost per service. On average, it is estimated that the total capital cost per service replaced is $614. 2017 project detail is presented in Attachment C1(a,d). Risk assessment scores for 2017 projects are presented in Attachment C2(b).

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

2017 Estimated Project Costs
$0.67 million Capital expenditure
$0.30 million O&M expenditure

Project Summary and Scope
Federal Pipeline Safety rules require that operators determine and implement measures to reduce the risks from failure of their gas distribution pipelines. This project is for the assessment and/or renewal of IP (Intermediate Pressure) lines or distribution pipelines in excess of 60 PSIG. The IP system is comprised of steel pipe susceptible to the threats of corrosion, manufacturing defects (material defects, long seam defects), construction methods (compression couplings and welds), and third-party damage. The consequence associated with a failure of these pipelines is heightened due to the higher operating pressures and the location of many of these lines in heavily developed areas. In Minnesota, the general range of operating pressures on the Company's IP system is between 125-350 PSIG[2]. As a result of the lower pressures as compared to transmission pipelines, certain evaluation techniques, such as In-Line Inspections (ILI), can be difficult or impracticable. At present, the number of products on the market that perform in-line inspections of distribution lines while a pipeline is in service is extremely limited, but under development.

While the impact of an IP line break can be less than a gas transmission line, the risk of serious consequences to people and property is elevated in the event of an IP line failure due to the higher operating pressures and proximity to people and property. Additionally, many of these IP lines are critical in maintaining natural gas service to key metropolitan areas.

In 2017, the Company is performing an External Corrosion Direct Assessment (ECDA) test and completing design and engineering activities for two future replacement projects. The scope of work in 2017 includes the following lines:

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

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

- **Hugo IP Line:** The Company plans to assess this line using an ECDA test in order to evaluate for the presence of external corrosion threats. The Hugo line covers 11.1 miles and consists of 12 and 16" diameter steel pipe. The Hugo line starts at the Hugo TBS at the intersection of highway 61 and 175th N near Hugo, MN. The line travels south along highway 61, until joining an Xcel Energy power transmission right of way and continues to I-35E and tracks south until it joins the Shoreview IP system near the intersection of highway 96 and E Gilifillan Rd.

- **Colby Lake Lateral Renewal:** This is a 2.5 mile replacement project located in Woodbury, MN. Funding for 2017 will be for design and engineering as well as for ROW/easement acquisition. Construction is forecast for 2018. This line has been designated for renewal due to the following considerations:
    - The existing piping has been offset multiple times with fittings that will not allow for use of internal inspection devices. The new facility would allow for inline inspection of this critical pipeline.
    - The pipeline is located under a major roadway making it difficult to otherwise inspect and maintain methods other than in line inspection.
    - The pipeline was constructed in 1964-1965 using vintage materials and construction methods; resulting in threats associated with material defects and construction defects. Strength testing is a means of establishing that any manufacturing or construction defects that may exist are stable and not a threat to pipeline safety. However, this pipeline has incomplete strength testing documentation. Health assessment via ECDA is not capable of identifying manufacturing or construction defects.
    - The existing line is at capacity. Replacement with a larger single diameter pipe will allow for continued growth in Washington

County and will allow for future inspection using inline inspection tools. The incremental cost of installing a12 inch single diameter pipeline instead of replacing the pipeline in kind is $745,430. This incremental cost would not be recovered through the GUIC.

- **H005 System Renewal – Lexington to Snelling**: This is a 3.0 mile replacement project located in Arden Hills beginning at the intersection of Snelling and Hamline and continuing north to Lexington and I-694. Funding for 2017 will be for design and engineering as well as for ROW/easement acquisition. Construction is forecast for 2018. This line has been designated for renewal due to the following considerations:
    - The existing piping has been offset multiple times with fittings that will not allow for use of internal inspection devices. The new facility would allow for inline inspection with methods other than in line inspection.
    - The pipeline is located under a major roadway making it difficult to otherwise inspect and maintain.
    - The pipeline has a history of leak repairs, most notably caused by material failure, mechanical leaks (threads), 3rd party damage, and corrosion.
    - The pipeline was constructed in 1964 using vintage materials and construction methods; resulting in threats associated with material defects and construction defects. The pipeline has known mechanical couplings. Strength testing is a means of establishing that any manufacturing or construction defects that may exist are stable and not a threat to pipeline safety. However, this pipeline has incomplete strength testing documentation. Health assessment via ECDA is not capable of identifying manufacturing or construction defects.
    - This pipeline has a threat of unreported/unknown 3rd party damage due to a history of extensive road work around the line.

The capital-related costs estimated for this project in 2017 excludes internal Company labor and includes only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. Project detail for 2017 projects is presented in Attachment C1(a, e). Risk assessment scores for 2017 projects are presented in Attachment C2(a).

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

2017 Estimated Project Costs
$0.72 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
The placement, accessibility, and functionality of valves in the gas distribution system are critical components of gas operations, as valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections, the utility protects the public as well as minimizes customer impacts during these events. 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. Installation or replacing valves will allow the Company more options to isolating sections to address an emergency or system incident, while impacting the smallest number of customers. This work is in response to the Company's obligation under Code 49 CFR Part 192.1007(d).

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

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

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

The Company estimates a total of 53 existing distribution valves will be replaced in the Twin Cities Metro and Southeast areas. These valves, which are inoperable and require replacement, range in size from 2-inch to 12-inch. The Company anticipates a total of 22 emergency valves will be replaced in 2017 with the remainder completed in 2018. The capital-related costs estimated for this project in 2017 excludes internal Company labor and includes only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. 2017 project detail is presented in Attachment C1(a, h). Risk assessment scores for 2017 projects are presented in Attachment C2(a).

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

<u>2017 Estimated Project Costs</u>
$0.00 million Capital expenditure
$3.50 million O&M expenditure

<u>Project Summary and Scope</u>
Both the Minnesota Public Utilities Commission (MPUC) and PHMSA have asked Xcel Energy to develop and implement safety plans to reduce the risk to customers and minimize the threat of future cross bores. In particular, PHMSA's Gas Distribution Pipeline Integrity Management Enforcement Guidance[3] notes, "Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in

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

proximity of each other. As such, operators must determine the potential for cross bore of sewers resulting in gas lines intersecting with sewers."

The Company has been inspecting sewer laterals and mains since 2010 and has found 147 incidences of conflicts between sewer and gas lines. In 2016 through August, the Company has discovered two conflicts, leading to a determination that further inspections are prudent and necessary to understand and mitigate the risk posed by a cross bore.

Consistent with the level of effort for 2010-2016, the current plan estimates that approximately 20,000 services will be inspected for conflicts in 2017, the 8th year of legacy inspections. Approximately 1,298 of the 20,000 planned inspections have been identified and scoped at this time. Results from the previous year's inspections are reviewed and specific areas targeted that have been determined to have a higher probability of conflicts, as confirmed either through camera inspections or excavation of the service line and visual affirmation. Since the 2016 inspections are still being performed, the exact communities targeted in 2017 for inspections have not yet been determined.

Two primary contracts are in place through 12/31/2016. An Intent to Bid will be sent out prior to commencing 2017 work with competitive bids seeking both mainline and premise-out cameras to perform sewer lateral inspections primarily for the GUIC-related work. The bids will also include requests for additional inspections for current and ongoing gas installations clearing them of conflict prior to operation.

The inspection program is anticipated to be a 10-year program that began in 2010, subject to change. The Company will continue to monitor circumstances that may indicate a need to accelerate or scale back inspections. 2017 project detail is presented in Attachment C1(a, l). Risk assessment scores for 2017 projects are presented in Attachment C2(a).

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

<u>2017 Estimated Project Costs</u>
$0.20 million Capital expenditure
$0.47 million O&M expenditure

This was a new project in 2016. Over time, as the Federal code[4] governing the operation and maintenance of the gas system has changed, the Company's standards and compliance manual has also evolved. This has caused incremental field work related to repairs or changes on legacy assets to maintain compliance. Some of these items are relatively minor (such as ice shield installation) while others are more significant.

Field employees log the necessary repairs or exceptions as they perform routine three-year leak surveys and other work on the system. Based on the work expected to be completed in 2016, the Company anticipates a volume of 685 items of varying criticality in 2017 with an average cost of $550 per exception[5]. The Company will initially focus corrective action activities on the highest risk 167 of the 685 items. The remaining items will be reassessed after more data is collected from inspections. While some items might be relatively minor in nature, all are related to safety of the system and could, over time, lead to a leak or release of natural gas. Examples of 2017 projects include modifying risers, installing guard posts, and relocating meter sets. 2017 project detail is presented in Attachment C1(a, i). Risk assessment scores for 2017 projects are presented in Attachment C2(a).

The cost per exception reflected in current budgets was originally estimated at $800. These are initial estimates since only a portion of the system has been surveyed and documented. Assumptions include a split of 60/40 percent O&M to capital based on the current identified list of work.

III. 2016 DIMP PROJECTS

There are six projects under the DIMP in 2016. Following are the DIMP project costs originally included in the Company's 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket No. G002/M-15-808, as compared to revised 2016 cost estimates[6] based on current year project developments and actual construction activity:

[4] Inclusive of Title 49 of the Code of Federal Regulations (CFR) Part 192 Subparts A through P, PHMSA Advisory Bulletins, and other guidance provided by Federal institutions.
[5] Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line.
[6] Based on actual costs as of 8/31/2016 and estimates from 9/1/2016 through 12/31/2016.

2016 Estimated DIMP Project Costs
($ Millions)

	2016 Capital, As Filed	2016 Capital Estimates	Variance	% Capital Variance	2016 O&M, As Filed	2016 O&M Estimates	Variance	% O&M Variance
Poor Performing Main Replacements	$6.88	$6.51	($0.37)	(5.38%)	$0.14	$0.14	$0.00	0.00%
Poor Performing Service Replacements	$4.22	$4.01	($0.21)	(4.98%)	$0.00	$0.00	$0.00	0.00%
Intermediate Pressure (IP) Line Assessments	$0.00	$0.00	$0.00	0.00%	$0.75	$0.55	($0.20)	(26.67%)
Distribution Valve Replacement Project	$0.20	$0.20	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Pipeline Data Project (PDP) Distribution	$0.00	$0.17	$0.17	100.00%	$0.00	$0.00	$0.00	0.00%
Federal Code Mitigation	$0.20	$0.18	$(0.02)	(10.00%)	$0.47	$0.47	$0.00	0.00%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	0.00%	$3.28	$3.28	$0.00	0.00%
TOTAL 2016 DIMP Capital Expenditures and O&M	**$11.50***	**$11.07***	**($0.43)**	**(3.74%)**	**$4.64**	**$4.44**	**($0.20)**	**(4.31%)**
TOTAL 2016 MN DIMP Incremental Revenue Requirement	**$2.60****	**$2.24****	**($0.36)**	**(13.85%)**	**$4.64**	**$4.44**	**($0.20)**	**(4.31%)**

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

Project Summary and Scope
For 2016, the poor performing mains materials include Aldyl-A (PEA) and vintage coated steel, but additional material types are included as necessary based on their overall relative risk. Copper risers are also replaced. In total, the Company expects to replace around 51.22 miles of distribution main pipeline in 2016. 2016 project detail is presented in Attachment C1(a, c).

Actual and remaining replacement activity in 2016 spans the key areas of:

Geographic Area (by Division)	Main (Miles)
St. Paul	15.30
White Bear Lake	18.73
Wyoming	2.06
Newport	3.95
St. Cloud	4.86
Southeast	4.33
Moorhead	1.99
Total	**51.22**

Main projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified main projects will generally begin during the 2nd quarter and assets will typically be in-service during the 3rd and 4th quarters. For example, 2016 project identification occurred in the 3rd and 4th quarters of 2015, construction commenced during the 2nd quarter of 2016, and in-service has occurred throughout the 3rd and 4th quarters of 2016.

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$6.88	$6.51	($0.37)	(5.38%)
O&M Expenditure	$0.14	$0.14	$0.00	0.00%

** Actual capital and O&M expenditures totaled $5.06 million and $0.06 million, respectively, through August.*

Variance Explanation

Capital: The main driver for the reduced capital expenditures is the decrease in the number of miles of problematic pipeline replaced. The projects consist of coupled steel and PEA mains/services and copper loop risers. The construction resources and projects identified for 2016 have been prioritized based on relative risk and SME input.

O&M: None.

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

Project Summary and Scope
For 2016, the primary service-related material types addressed include Aldyl-A, vintage coated steel, and copper risers. Additional material types are included as necessary based on their overall risks. In total, the Company estimates the replacement of approximately 3,279 service lines in 2016. Project detail for 2016 is presented in Attachment C1(a, c).

Actual and remaining replacement activity in 2016 spans the key areas of:

Geographic Area (by Division)	Services (Number)
St. Paul	1,205
White Bear Lake	966
Wyoming	128
Newport	275
St. Cloud	206
Southeast	289
Moorhead	210
Total	**3,279**

Service replacement projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be brought in service during the 3rd and 4th quarters. As an example, 2016 project identification occurred in the 3rd and 4th quarter 2015, construction commenced during the 2nd quarter 2016, and in-service has occurred in the 3rd and 4th quarters of 2016.

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$4.22	$4.01	($0.21)	(4.98%)
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

** Actual capital and O&M expenditures totaled $1.11 million and $0.00 million, respectively, through August.*

Variance Explanation

Capital: The main driver for the reduced capital expenditures is a decrease in the number of miles of high-risk pipe and associated services.

O&M: None.

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

Project Summary and Scope
This project performs health and condition assessments on IP lines. There are currently two IP assessment project underway in 2016, the 12-mile Anoka IP line and the 19-mile Shoreview IP line. Prioritization of pipeline segments is based on an evaluation of specific DIMP threats. The IP system is comprised of steel pipe susceptible to the threats of corrosion, construction methods (compression couplings, materials and welds), and third-party damage.

In 2016, the Company is performing verification digs of the 12.3 mile Anoka IP line located in the northwest suburbs of the Twin Cities. Work will also be performed on the Shoreview IP line to complete inspection and verification digs as part of the External Corrosion Direct Assessment (ECDA) test. Project detail for 2016 is presented in Attachment C1(a, e).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	0.00%
O&M Expenditure	$0.75	$0.55	($0.20)	(26.67%)

** Actual capital and O&M expenditures totaled $0.00 million and $0.34 million, respectively, through August.*

Variance Explanation

Capital: None.

O&M: The main driver for reduction in O&M expenditures is revised reduction in the cost estimate for the Shoreview IP ECDA project.

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

Project Summary and Scope
By end of 2016, the Company estimates that a total of 479 new emergency distribution valves will have been installed, ranging in size from 2-inch to 12-inch. These new valves protect the public and minimize customer impacts when isolating sections. From 2012 through 2015, a total of 388 emergency distribution valves have been installed. Approximately 53 emergency valves have been installed to date in 2016 with plans to install all remaining new valves, except for one, by the end of 2016. One valve project has been deferred into 2017 to align with planned reconstruction work and reduce overall costs.

In 2016, one new valve will be installed near the intersection of Mankato Avenue and Lake Boulevard, in Winona, with the remainder of the new valves installed scattered throughout the Twin Cities Metro area. Work has been performed by internal resources. Costs associated with internal labor are not included for recovery through the GUIC rider. The 2016 capital-related charges included for this project include materials, outside services, transportation, and the portion of construction overheads not related to internal labor. Project detail for 2016 is presented in Attachment C1(a, g).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.20	$0.20	$0.00	0.00%
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

** Actual capital and O&M expenditures totaled $0.13 million and $0.00 million, respectively, through August.*

Variance Explanation

Capital: None.

O&M: None.

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

Project Summary and Scope
This project focuses on remediation of legacy records for the gas distribution mains and services into the Company's Geographic Information System (GIS).

Integrity programs are risk management programs that require significant information about assets, including construction and installation data, pipe material characteristics, and operating data. The primary purpose of the project is to improve asset knowledge and accessibility of those records via the GIS system. Improving the availability and quality of asset data improves the Company's ability to use the risk model, which is the primary tool for identifying and properly prioritizing the renewal of poor performing mains and services.

Improved data quality overall, along with improved data collection processes going forward, allows for better predictive models. Unfortunately, some historical data is unavailable. Key data gaps that cannot be resolved can be incorporated into the overall integrity plan. This approach reduces overall system risk, improves operating efficiency, and provides the basis for programs to renew or repair pipe before significant issues develop. Additionally, the project enhances public safety by providing accurate and robust asset knowledge, as well as improving the accessibility of data. For instance, valve information is used by gas emergency response personnel when addressing emergency situations. This project concluded in 2015, however, due to late invoice processing, there were 2015 related charges that occurred in 2016. Project detail for 2016 is presented in Attachment C1(a,).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.00	$0.17	($0.17)	100%
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

** Actual capital and O&M expenditures totaled $0.17 million and $0.00 million, respectively, through August.*

Variance Explanation

Capital: Some invoices for work in late 2015 were received and paid in 2016.

O&M: None.

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

Project Summary and Scope

The sewer and gas line conflict inspection program is anticipated to be a 10-year program that began in 2010. This program has risk mitigation at its core, and as such the Company continues to monitor circumstances that may indicate a need to accelerate or scale back inspections.

Consistent with the level of effort for 2010-2015, the current 2016 plan estimates that approximately 18,800 services will be inspected. In 2016 through August, the Company has discovered three conflicts. Based on findings to date, the Company expects to continue this program into 2017. Project detail for 2016 is presented in Attachment C1(a, k).

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	0.00%
O&M Expenditure	$3.28	$3.28	$0.00	0.00%

** Actual capital and O&M expenditures totaled $0.00 million and $1.50 million, respectively, through August.*

Variance Explanation

Capital: N/A.

O&M: None.

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

Project Summary and Scope

Work began in 2016 and will progress in a planned fashion until all issues are mitigated or risk no longer exists. This program will continue to evolve as well as a focus on documentation and risk management.

The assumed number of exceptions in 2016 has been revised to 860 based on updated information taken from continued field surveys and other mechanisms to obtain the data. Nearly all of the work planned in 2016 relates to the sleeving of risers in the St. Cloud area. Project detail for 2016 is presented in Attachment C1(a, i).

The cost per exception included in current budgets is estimated at $550. These are initial estimates since only a portion of the system has been surveyed and documented. Assumptions include a split of 60%/40% O&M to capital based on the current list and type of work.

2016 Estimated Project Costs
($ Millions)

	2016 As Filed, 15-808	2016 Estimates*	Variance	Variance %
Capital Expenditure	$0.20	$0.18	($0.02)	(10.00%)
O&M Expenditure	$0.47	$0.47	$0.00	0.00%

** Actual capital and O&M expenditures totaled $0.00 million and $0.00 million, respectively, through August.*

Variance Explanation

Capital: None.

O&M: None.

IV. 2015 DIMP PROJECTS

There were six projects under the DIMP in 2015. Following are the DIMP project costs originally included in the Company's 2016 Gas Utility Infrastructure Cost (GUIC) Rider Petition, Docket No. G002/M-15-808, as compared to actual 2015 costs.

2015 Actual DIMP Project Costs
($ Millions)

	2015 Capital, As Filed	2015 Capital Actuals	Variance	% Capital Variance	2015 O&M, As Filed	2015 O&M Actuals	Variance	% O&M Variance
Poor Performing Main Replacements	$4.50	$7.51	$3.01	66.89%	$0.27	$0.07	($0.20)	(74.07%)
Poor Performing Service Replacements	$2.10	$2.96	$0.86	40.95%	$0.13	$0.00	($0.13)	(100.00%)
Intermediate Pressure (IP) Line Assessments	$0.00	$0.00	$0.00	0.00%	$0.43	$0.06	($0.37)	(86.05%)
Distribution Valve Replacement Project	$0.77	$0.27	($0.50)	(64.94%)	$0.00	$0.00	$0.00	0.00%
Pipeline Data Project (PDP) Distribution	$1.75	$1.90	$0.15	8.57%	$0.00	$0.00	$0.00	0.00%
Sewer & Gas Line Conflict Investigation	$0.00	$0.00	$0.00	0.00%	$3.50	$3.42	($0.08)	(2.29%)
TOTAL 2015 DIMP Capital Expenditures and O&M	**$9.12***	**$12.64***	**$3.52**	**38.60%**	**$4.33**	**3.55**	**($0.78)**	**(18.01%)**
TOTAL 2015 MN DIMP Incremental Revenue Requirement	**$0.69****	**$0.33****	**($0.36)**	**(52.17%)**	**$4.33**	**3.55**	**($0.78)**	**(18.01%)**

** Total estimated capital expenditures, including removal costs (RWIP).*

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

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

Project Summary and Scope

For 2015, the poor performing mains materials included Aldyl-A (PEA) and vintage coated steel, but additional material types may be included as necessary based on their overall relative risk. Copper risers were also replaced. The Company replaced around 46.32 miles of distribution main pipeline in 2015. Project detail for 2015 is presented in Attachment C1(a, b).

Actual replacement activity in 2015 spans the key areas of:

Geographic Area (by Division)	Main (Miles)
St. Paul	10.58
White Bear Lake	12.21
Wyoming	3.16
Newport	7.27
St. Cloud	3.22
Southeast	9.57
Moorhead	0.30
Total	**46.32**

Main replacement projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be brought in service during the 3rd and 4th quarters. As an example, 2015 project identification occurred in the 3rd and 4th quarter 2014, construction commenced during the 2nd quarter 2015, and in-service has occurred in the 3rd and 4th quarters of 2015.

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$4.50	$7.51	$3.01	66.89%
O&M Expenditure	$0.27	$0.07	($0.20)	(74.07%)

Variance Explanation

Capital: The main driver for the increase in capital expenditures is the increase in the number of miles of problematic pipeline replaced. The projects consist of coupled steel and PEA mains/services and copper loop risers. Additionally, some projects were accelerated to 2015 to leverage City scheduled mill and overlay projects. Mill and overlay is the process of restoring a road surface through removing the top layer of asphalt (milling) and reinstalling new asphalt (overlay). Lastly, a single project in Lake Elmo went over budget by $650,000 in a manufactured home community due to unforeseen issues with unlocatable gas, electric and telephone cable facilities.

O&M: The main driver for the reduction in O&M expenditures is a reclassification of O&M to capital as a result of a capitalization policy change related to service transfers. Service transfers are no longer considered O&M and are capitalized as part of the renewal.

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

Project Summary and Scope

For 2015, the primary service-related material types that will be addressed include Aldyl-A, vintage coated steel, and copper risers. Additional material types may be included as necessary based on their overall risks. In total, the Company estimates the replacement of approximately 3,122 service lines in 2015. Project detail for 2015 is presented in Attachment C1(a, b).

Actual replacement activity in 2015 spans the key areas of:

Geographic Area (by Division)	Services (Number)
St. Paul	784
White Bear Lake	808
Wyoming	152
Newport	519
St. Cloud	94
Southeast	765
Moorhead	0
Total	**3,122**

Service replacement projects are generally planned six months to one year in advance and will be constructed and brought in service the following year. Actual construction on identified service projects will generally begin during the 2nd quarter, and assets will typically be brought in service during the 3rd and 4th quarters. As an example, 2015 project identification occurred in the 3rd and 4th quarter 2014, construction commenced during the 2nd quarter 2015, and in-service has occurred in the 3rd and 4th quarters of 2015.

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$2.10	$2.96	$0.86	40.95%
O&M Expenditure	$0.13	$0.00	($0.13)	(100%)

<u>Variance Explanation</u>

Capital: The main driver for the increase in capital expenditures is an increase in the number of miles of high-risk pipe and associated services.

O&M: The main driver for the reduction in O&M expenditures is due to a reclassification of O&M to capital as a result of a capitalization policy change related to service transfers. Service transfers are no longer considered O&M and are now capitalized.

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

Project Summary and Scope
This project performs health and condition assessments on IP lines. There was one IP assessment project underway in 2015, the 12-mile Anoka IP line. Prioritization of pipeline segments is based on an evaluation of specific threats. The IP system is comprised of steel pipe susceptible to the threats of corrosion, construction methods (compression couplings, materials and welds), and third-party damage due to location in heavily developed areas.

In 2015, the Company is assessing the 12.3 mile Anoka IP line located in the northwest suburbs of the Twin Cities. Project detail for 2015 is presented in Attachment C1(a, e).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	0.00%
O&M Expenditure	$0.43	$0.06	($0.37)	(86.05%)

Variance Explanation

Capital: None.

O&M: The main driver for the reduction in O&M expenditures is that the Company was unable to complete the necessary verification digs on the Anoka IP line due to resource constraints. As a result, the digs were not completed in 2015 and were reprioritized in 2016. Additionally, the contractor that performed the Anoka IP line integrity survey completed the work more economically than expected based on past experience.

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

Project Summary and Scope
Approximately 77 emergency valves ranging in size from 2-inch to 12-inch were installed in 2015 with plans to install the remaining 115 valves in 2016. Between 2012 and 2014, a total of 210 emergency distribution valves were installed.

In 2015, one valve was installed near the intersection of 2nd Street South and 33rd avenue, in St. Cloud, Minnesota. The remainder of the 2015 valve installations were scattered throughout the Twin Cities Metro area and were installed by internal labor resources. Costs associated with internal labor are not included for recovery through the GUIC rider. The 2015 capital-related charges included for this project include materials, outside services, transportation, and the portion of construction overheads not related to internal labor. Project detail for 2015 is presented in Attachment C1(a, f).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$0.77	$0.27	($0.50)	(64.94%)
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The main driver for the decrease in capital expenditures is the removal of capitalized internal labor charges.

O&M: None.

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

<u>Project Summary and Scope</u>
This project focuses on remediation of legacy records for the gas distribution mains and services into the Company's Geographic Information System (GIS).

Integrity programs are risk management programs and require significant information about assets, including construction and installation data, pipe material characteristics, and operating data. The primary purpose of the project is to improve asset knowledge and accessibility of those records via the GIS system. Improving the availability and quality of asset data improves the Company's ability to utilize the risk model, which is the primary tool for identifying and properly prioritizing the renewal of poor performing mains and services.

Improved data quality overall, along with improved data collection processes going forward, allows for better predictive models. Some historical data about pipelines is unavailable. Key data gaps that cannot be resolved can be incorporated into the overall integrity plan. This approach reduces overall system risk, improves operating efficiency, and provides the basis for programs to renew or repair pipe before significant issues develop. Additionally, the project enhances public safety by providing more accurate and robust asset knowledge, as well as accessibility of data. For instance, valve information is utilized by gas emergency response personnel when addressing emergency situations. This project concluded in 2015 as planned, however, invoices totaling $171,000 were not received and paid until January 2016. Project detail for 2015 is presented in Attachment C1(a).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$1.75	$1.90	$0.15	8.57%
O&M Expenditure	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: Contractor costs were slightly higher than anticipated.

O&M: None

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

Project Summary and Scope
The inspection program is anticipated to be a 10-year program that began in 2010, subject to change. This program has risk mitigation at its core, and the Company will continue to monitor circumstances that may indicate a need to accelerate or scale back inspections.

Consistent with the level of effort for 2010-2014, the 2015 plan had approximately 20,607 services inspected for conflicts. In 2015, the Company discovered six conflicts. Project detail for 2015 is presented in Attachment C1(a, j).

2015 Actual Project Costs
($ Millions)

	2015 As Filed, 15-808	2015 Actual	Variance	Variance %
Capital Expenditure	$0.00	$0.00	$0.00	0.00%
O&M Expenditure	$3.50	$3.42	($0.08)	(2.29%)

Variance Explanation

Capital: None.

O&M: Not significant.

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 extends beyond 2017. As the Company continues to execute its risk-based strategy, replacement projects planned for 2016, 2017, and beyond will target pipe segments displaying the highest level of relative risk. Therefore, it is anticipated that there will be an increase in the number of overall projects.

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

DIMP 2018-2021 Plan
($ Millions)

	2018 Estimates		2019 Estimates		2020 Estimates		2021 Estimates	
Sub-Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$10.52	$0.24	$11.20	$0.24	$11.20	$0.24	$11.20	$0.24
Poor Performing Services	$6.58	$0.04	$7.00	$0.04	$7.00	$0.04	$7.00	$0.04
Intermediate Pressure (IP) Line Assessments	$0.00	$0.00	$0.00	$0.20	$0.00	$0.30	$0.00	$0.30
Distribution Valve Replacement	$0.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pipeline Data Project (PDP)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sewer & Gas Line Conflict Remediation	$0.00	$3.50	$0.00	$3.50	$0.00	$0.00	$0.00	$0.00
Federal Code Mitigation	$0.20	$0.47	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	**$18.10**	**$4.25**	**$18.20**	**$3.98**	**$18.20**	**$0.58**	**$18.20**	**$0.58**

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

Northern States Power Company

Docket No. G002/M-16-____
Gas Utility Infrastructure Cost Rider - 2017 Factors
Attachment C1(a)

DIMP 2015-2017 Project Detail

CAPITAL

Program	Regulation	Parent Number	2015 Actuals	Cost Per Unit (CPU) Assumptions 2015	2016 Actuals [1]	2016 Forecast	2016 Total	Cost Per Unit (CPU) Assumptions 2016	2017 Plan	Cost Per Unit (CPU) Assumptions 2017
Distribution Valve Replacement	Code 49 CFR Part 192.1007(d).	11649520, 12173704	$ 586,157	2015 averaged costs were $5,194/valve for 92 valves.	$ 238,885	$ 240,900	$ 479,785	2016 forecasted costs are $5,133/valve for 90 valves.	$ 800,000	2017 estimated cost per valve is $36K/valve.
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02	11649522, 12173831, 34000462	$ 8,436,463	Based on 2014 actuals: $28.88/ft. for contractor-only projects, $39.69/ft. for internal/local projects - Took weighted average, based on 40 contractor projects and 6 internal/local projects - Resulting CPU Target is $30.29/ft. (includes all work part of GUIC) - Through October 21st, 2015, actual CPU for all DIMP work is $28.07/ft.	$ 5,203,967	$ 2,543,463	$ 7,747,430	Based on 2015 YTD actuals: $28.07/ft. for contractor-performed work and internal/local projects. This does not take into account Capitalization Policy change at end of June, 2015, nor that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to main projects from Capitalization change (air tests and tie-overs) = 2.5% or $0.70/ft., resulting in revised target of $28.77/ft. - Anticipated increase to contracts that will impact DIMP work = 5% or $1.44/ft., resulting in revised target of $30.21/ft. - 2016 Final CPU Target is $30.21/ft.	$ 12,140,220	Based on 2015 YTD actuals: $28.07/ft. for contractor-performed work and internal/local projects. This does not take into account Capitalization Policy change at end of June, 2015, nor that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016, currently a 2-yr extension is being negotiated, with no net impact to cost anticipated. - Anticipated increase to main projects from Capitalization change (air tests and tie-overs) = 2.5% or $0.70/ft., resulting in revised target of $28.77/ft. - Anticipated increase to contracts that will impact DIMP work = 5% or $1.44/ft., resulting in revised target of $30.21/ft. - 2017 CPU Target is $30.21/ft.
Poor Performing Services		11649766, 12173830	$ 3,336,132	Based on 2014 actuals: $737.84/service, regardless of resource performing work - Prior to 2015, we had not tracked the service costs separately from the main CPU, so creating a consistent target was challenging - Through October 31st, 2015, actual CPU for services is $584.73/service (Using Actual JDE costs divided by number of services completed)	$ 1,139,337	$ 3,146,939	$ 4,286,275	Based on 2015 YTD actuals: $584.73/service. The Capitalization Policy change at end of June does not impact this. This does not take into account that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to contracts that will impact DIMP work = 5% or $29.24/service, resulting in revised target of $613.97/service - 2016 Final CPU Target is $613.97/service	$ 7,590,490	Based on 2015 YTD actuals: $584.73/service. The Capitalization Policy change at end of June does not impact this. This does not take into account that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016. Currently, a 2-year extension is being negotiated, with no net impact to cost anticipated. - Anticipated increase to contracts that will impact DIMP work = 5% or $29.24/service, resulting in revised target of $613.97/service - 2017 CPU Target is $613.97/service
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).	11980562	$ -	N/A	$ -	$ -	$ -	N/A	$ 750,000	● Colby Lake Lateral Renewal- 2.5 miles - See Attachment C for project narrative. ● H005 System Renewal - Lexington to Snelling- 3.0 miles - See Attachment E for project narrative.
Pipeline Data Project (PDP)	Code 49 CFR Part 192.1007(a)	11813698	$ 1,902,271	See Attachment C from OAG 9.1 (Docket 15-808) - Consulting Services Agreement Pipeline Data Project Pricing Detail.	$ 170,898	$ -	$ 170,898	N/A	$ -	N/A
Federal Code Mitigation	Code 49 CFR Part 192: (192.365/192.357) ; (192.745/192.747) ; (192.707/192.327/192.361) ; (192.365/192.487) ; (192.479/192.461) ; (192.357/192.353) ; (PHMSA Advisory Bulletin 08-03) ; (192.321) ; (192.455/192.457)	12173398	$ -	N/A	$ -	$ 203,500	$ 203,500	• $550 per exception is an average, high-level estimate for all exception types, based on the type of repair as well as historical costs. Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line. • The primary focus for 2016 is mitigating risk posed by corrosion to meter sets and meter risers. The Company has identified approximately 860 locations where the risers are buried in concrete that require corrective action. • Locations that do not require a service line renewal will be O&M. The Company estimated that 60% of these locations will require meter and riser remediation (O&M), and that 40% of these locations will include a service replacement (capital).	$ 202,000	• $550 per exception is an average, high-level estimate for all exception types, based on the type of repair as well as historical costs. Costs for exceptions range from $150 for painting a meter set to $5,000 for relocating a meter or renewing a service line. • The primary focus for 2017 is to install Ice Shields, guard posts, removing idle risers, and addressing inaccessible meters and sleeving of risers. The Company had initially identified approximately 690 locations of these particular types of issues. The Company will focus on 173 of the 690 items and reassess the remaining items after more data is collected from inspections. • Locations that do not require a service line renewal will be O&M. The Company estimated that 60% of these locations will require meter and riser remediation (O&M), and that 40% of these locations will include a service replacement (capital).
TOTAL DIMP CAPITAL			**$ 14,261,023**		**$ 6,753,086**	**$ 6,134,802**	**$ 12,887,888**		**$ 21,482,710**	

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

DIMP 2015-2017 Project Detail

O&M

Program	Regulation	Parent Number	2015 Actuals	Cost Per Unit (CPU) Assumptions 2015	2016 Actuals [1]	2016 Forecast	2016 Total	Cost Per Unit (CPU) Assumptions 2016	2017 Plan	Cost Per Unit (CPU) Assumptions 2017
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02	11984265	$ 65,245	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M	$ (2,346)	$ 139,846	$ 137,500	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M	$ 243,000	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M
Poor Performing Services		11984268	$ -	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M	$ -	$ -	$ -	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M	$ 36,000	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(a)	11984278	$ 61,091	Anoka Line IP - 12.3 miles - See Attachment C for additional details - Survey costs $6,000/mile and digs cost $60,000/dig - Also included are additional minor costs (permitting, new CP test leads, etc.)	$ 79,208	$ 470,792	$ 550,000	Shoreview IP - 10 miles - See Attachment C for additional details - Survey costs $6,000/mile and digs cost $60,000/dig - 5 digs on the Anoka line - 7 digs on the Shoreview line - Also included are additional minor costs (permitting, new CP test leads, etc.)	$ 300,000	● Hugo Line - 11.1 miles - See Attachment C for additional details - Survey costs $6,000/mile and digs cost $60,000/dig - Also included are additional minor costs (permitting, new CP test leads, etc.)
Federal Code Mitigation	Code 49 CFR Part 192: (192.365/192.357) ; (192.745/192.747) ; (192.707/192.327/192.361) ; (192.365/192.487) ; (192.479/192.461) ; (192.357/192.353) ; (PHMSA Advisory Bulletin 08-03) ; (192.321) ; (192.455/192.457)	12173409	$ -	N/A	$ -	$ 472,500	$ 472,500	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M	$ 472,000	See cost assumptions included in capital section above; CPUs are inclusive of Capital and O&M
Sewer Conflict Investigation	Dockets Nos. G002/M-12-248 and G002/M-10-422	11984282	$ 3,415,261	Based on 2014 actuals: $215.47/inspection - In 2014, we had some work unique to the final year of an agreement with MNOPS to clear all premises in St Paul and South St Paul, leading to less productivity and slightly higher costs compared to previous years. - We continue this work into 2015 and the future, the impact in 2014 was more focused and prevalent. - Through September 30, 2015, actual CPU for services is $182.18/inspection. This compares more closely to 2012 and 2013 actuals of $172.20 and $172.53 respectively. -In 2015, there was 19,578 inspections completed, compared to 16,791 in 2014, 20,438 in 2013 and 21,040 in 2012 Sauk Rapids. - List of communities in 2015: St Joseph, New London, Nisswa, Baxter, Becker, Delano, Chisago, Wyoming. Mendota Heights, Winona, Mahtomedi, Northfield, Falcon Heights, Arden Hills, Lindstrom, Sartell, Inver Grove Heights, Cottage Grove, White Bear Lake, Roseville, Waite Park, Stillwater, East Grand Forks, St Cloud, Maplewood, Woodbury, Oakdale, Moorhead, Faribault, Lake City, Forest lake, Hugo, Little Canada, Mounds View, New Brighton, Newport, North Oaks, Oak, Park Heights, Red Wing, St Paul Park, Shoreview, Stillwater Township, Vadnais Heights, White Bear Lake Township, Wabasha, Glyndon.	$ 1,854,268	$ 1,423,232	$ 3,277,500	Based on 2015 YTD actuals: $182.18/inspection. This does not take into account that contracts expire in 2015, with new bids/contracts to be awarded 1st quarter 2016. - Anticipated increase to contracts that will impact Sewer Mitigation work = 4% or $7.29/inspection, resulting in revised target of $189.47/inspection - 2016 Final CPU Target is $189.47/inspection -2016 volume of inspections is estimated at 17,300. Projects are not tracked at the individual inspection level. - List of communities in 2016: Arden Hills, Baxter, Becker, Chisago, Cottage Grove, Delano, East Grand Forks, Falcon Heights, Faribault, Forest Lake, Glyndon, Hugo, Inver Grove Heights, Lake City, Lindstrom, Little Canada, Mahtomedi, Maplewood, Mendota Heights, Moorehead, Moorhead, Mounds View, New Brighton, New London, Newport, Nisswa, Northfield, Oak Park Heights, Oakdale, Red Wing, Roseville, Sartell, Sauk Rapids, Shoreview, St Cloud, St Joseph, St Paul Park, Stillwater, Stillwater Twp, Vadnais Heights, Wabasha, Waite Park, White Bear Lake, White Bear Lake Twp, Winona, Woodbury, Wyoming	$ 3,500,000	Based on 2015 YTD actuals: $182.18/inspection. This does not take into account that contracts expire in 2015, with new bids/contracts that were awarded 1st quarter 2016 through 2019. - Anticipated increase to contracts that will impact Sewer Mitigation work = 4% or $7.29/inspection, resulting in revised target of $189.47/inspection - 2016 Final CPU Target is $189.47/inspection -2017 volume of inspections is estimated at 17,300. Projects are not tracked at the individual inspection level. List of projects is being developed, not yet available.
TOTAL DIMP O&M			**$ 3,541,597**		**$ 1,931,130**	**$ 2,506,370**	**$ 4,437,500**		**$ 4,551,000**	

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

[1] Actual costs through August 2016.

Northern States Power Company — Docket No. G002/M-16-___

Gas Utility Infrastructure Cost Rider - 2017 Factors

DIMP Replacement Project Detail for 2015 — Attachment C1(b)

NSP-MN Main & Services DIMP Replacements				Main Footage			Service			Service Cost
Division	Project	WO	Actual from Passport	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred	Actual Cost for Services
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	$660,033	12,760	7,100	12,760	230	223	4	221,983
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	$222,657	7,500	4,530	7,517	74	71	2	70,676
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	$94,089	2,600	1,300	1,300	48	46	4	45,790
	Barclay/Dieter	12185039	$206,308	3,750	2,675	3,925	60	58	4	$57,736
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	$622,841	16,000	11,350	16,031	218	224	0	$222,979
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	$240,863	2,326	4,660	2,326	24	21	4	$20,904
	Idaho / Barclay / Clarence	12227467	$318,811	7,350	4,775	7,467	99	93	8	$92,576
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	$142,754	4,400	2,405	4,560	49	48	0	$47,781
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	$322,376	10,480	9,225	10,124	190	112	77	$111,489
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	$498,317	15,000	15,234	15,234	250	228	0	$226,960
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	$139,126	16,709	16,064	16,709	252	237	0	$235,919
	WBL/OPH/Area D	12200298	$157,590	5,000	4,520	5,097	12	14	7	$13,936
	Vad Heights - North Star Estates	12226824	$246,291	10,000	7,040	9,485	172	161	8	$160,266
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	$128,522	2,900	2,000	3,845	43	16	23	$15,927
	NO ST PAUL / 14th AVE E	11945105	$128,989	3,865	2,105	3,999	48	40	6	$39,818
Wyoming	Forest Lake - Carry-over from 2014	12185020	$411,767	9,000	10,850	8,741	93	68	28	$67,690
	Forest Lake - 11th Ave & 6th St	12233388	$112,887	4,100	3,310	3,310	36	41	6	$40,813
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	$180,857	4,650	3,750	4,642	27	43	9	$42,804
Newport	Cloman Way & Lower 67th St	12262781	$289,384	5,500	3,900	6,322	152	154	0	$153,298
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	$58,549	2,204	950	2,224	26	26	0	$25,881
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	$115,211	2,581	1,600	2,549	29	29	0	$28,868
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	$229,296	9,274	5,050	9,274	110	110	0	$109,498
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	$51,323	1,800	1,240	1,764	16	11	5	$10,950
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	$74,096	2,224	2,980	2,224	20	15	3	$14,932
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	$79,734	2,298	1,200	2,298	30	26	6	$25,881
	Denton	12255539	$147,674	4,828	4,220	4,828	75	75	0	$74,658
	Burns Ave	12170859	$244,420	6,901	3,900	6,902	85	73	11	$72,667
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	$41,844	250	256	270	2	0	0	$0
	St Cloud - Lincoln Ave*	12223516	$205,043	7,750	5,990	6,273	36	18	11	$17,918
	Watertown	12162124	$312,454	10,200	7,030	10,210	95	73	37	$72,667
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	$13,639	286	250	250	3	3	0	$2,986
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	$370,276	9,989	6,930	8,455	230	192	0	$191,124
	Northfield Viking Ter	12241776	$399,697	10,550	8,525	7,677	180	180	0	$179,179
	7th St S - Lake City	12205025	$74,600	1,400	-	1,256	6	0	0	$0
	Hallstrom Dr & Burton St - Red Wing	12218584	$448,078	17,000	14,482	14,482	270	136	25	$135,380
	Bluffview - Winona	12231997	$46,329	2,000	1,120	1,626	5	12	3	$11,945
	Bush St & Langsford Ave - Red Wing	12212950	$256,974	5,950	5,100	6,337	85	69	7	$68,685
	Hillsdale - Hidden Valley Mobile Home Park	12162836	$303,914	10,064	8,115	10,699	185	176	0	$175,197
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	$25,256	975	-		1	0	0	$0
	Moorehead Dale & 5th St S	12215099 & 12210767	$35,169	1,608	-	1,599	32	0	0	$0
	Service Materials		$117,369							
		Totals	**$8,775,406**	**254,022**	**195,731**	**244,591**	**3,598**	**3,122**	**298**	**$3,107,764**

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

DIMP Replacement Project Detail for 2016

NSP-MN Main & Services DIMP Replacement Projects 2016							
Area	Work Order Number	Description	Total Design FT.	Tot. Svc	Anticipated Main Cost	Anticipated Service Cost	GL Main Cost (2016 YTD August)
St Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1,350	28	$ 39,474	$ 28,000	$ 8,524
	12328949	ST PAUL - ARMSTRONG AVE	7,506	150	$ 219,475	$ 150,000	$ 30,364
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	8,900	118	$ 260,236	$ 118,000	$ 33,905
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	7,810	81	$ 228,364	$ 81,000	$ 12,230
	12398688	LAUDERDALE - EUSTIS ST	1,100	17	$ 32,164	$ 17,000	$ 43,054
	12380740	ROSEVILLE - WEWERS RD	1,400	15	$ 40,936	$ 15,000	$ 51,078
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1,200	5	$ 35,088	$ 5,000	$ 69,353
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	23,400	305	$ 684,216	$ 305,000	$ 641,601
	12444470	ST PAUL - DOWN TOWN (Kellogg)	150	-	$ 4,386	$ -	$ -
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	4,750	56	$ 138,890	$ 55,882	$ 135,824
	12358730	ST PAUL - JUNO LOCAL PORTION	1,260	20	$ 36,842	$ 20,000	$ 46,852
	12364882	ST PAUL - AURORA - LOCAL PORTION	960	36	$ 28,070	$ 36,000	$ 37,637
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	3,875	100	$ 113,305	$ 100,000	$ 13,299
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	10,440	195	$ 305,266	$ 195,000	$ 15,098
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	6,700	79	$ 195,908	$ 78,824	$ 18,344
White Bear Lake	12344860	LAKE ELMO - 32ND ST	8,600	77	$ 251,464	$ 77,000	$ 303,289
	12293638	LAKE ELMO - LAKE ELMO AVE	6,800	51	$ 198,832	$ 51,000	$ 219,505
	12334697	NORTH ST PAUL - 19TH AVE	7,000	85	$ 204,680	$ 85,000	$ 65,399
	12371725	BAYTOWN TWP/ 13606 30TH ST N	320	5	$ 9,357	$ 5,000	$ 17,807
	12320156	OAKDALE - GROSPOINT AVE	16,200	178	$ 473,688	$ 178,000	$ 250,615
	12317855	WHITE BEAR LAKE - FLORENCE ST	16,600	109	$ 485,384	$ 109,000	$ 310,730
	12320058	MAPLEWOOD - ROSELAWN AVE	12,900	179	$ 377,196	$ 179,000	$ 361,222
	12320143	OAKDALE - GERSHWIN AVE	9,500	70	$ 277,780	$ 70,000	$ -
	12320392	SHOREVIEW - DEBRA LN	11,200	105	$ 327,488	$ 105,000	$ 231,834
	12317856	SHOREVIEW - NANCY PL	7,600	85	$ 222,224	$ 85,000	$ -
	12275730	OAKDALE - GREENE AVE	2,150	22	$ 62,866	$ 22,000	$ -
Wyoming	12334677	FOREST LAKE - 2ND ST SE	10,900	128	$ 318,716	$ 128,235	$ 248,328
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	1,680	28	$ 49,123	$ 28,000	$ 79,806
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1,900	22	$ 55,556	$ 22,000	$ 459
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	8,815	100	$ 257,751	$ 100,000	$ -
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	7,530	120	$ 220,177	$ 120,000	$ -
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	911	5	$ 26,638	$ 5,000	$ 5,138
St Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	9,150	79	$ 267,546	$ 79,000	$ 169,520
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1,700	-	$ 136,000	$ -	$ -
	12249351	DELANO	14,800	127	$ 432,752	$ 127,000	$ 190,478
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	8,100	127	$ 236,844	$ 127,000	$ 77,222
	12354151	NORTHFIELD - FLORELLAS CT	1,550	22	$ 45,322	$ 22,000	$ -
	12328936	FARIBAULT - 8TH ST SW	5,320	48	$ 155,557	$ 48,000	$ 59,368
	12345274	FARIBAULT - 7TH ST NW	4,900	43	$ 143,276	$ 43,000	$ -
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	3,000	49	$ 87,720	$ 49,000	$ -
Moorhead	12359542	MOORHEAD - REGAL ESTATES	10,500	210	$ 307,020	$ 210,000	$ 87,753
2016 DIMP-related Main Replacement Total			**270,427**	**3,279**	**$ 7,993,577**	**$ 3,278,941**	**$ 3,835,636**

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

DIMP Replacement Project Detail for 2017

NSP-MN Main & Services DIMP Replacement Projects 2017					
Area	Work Order Number	Description	Total Design FT.	Tot. Svc	Anticipated Cost
St Paul	12294045	ROSEVILLE - FERNWOOD ST	3,760	44	$109,942
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	11,300	177	$330,412
	12328310	ST PAUL - HAGUE/SELBY	6,745	128	$197,224
	12326608	ST PAUL - EDMOND	5,290	113	$154,680
	N/A	ST PAUL - ST PETER, FORD 4TH	4,200	62	$122,808
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	9,600	141	$280,704
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	2,300	34	$67,252
	12320389	ARDEN HILLS - GLENPAUL AVE	4,700	58	$137,428
	12319969	MAHTOMEDI - GRIFFIN AVE	3,200	39	$93,568
	12092590	BAYPORT - 7TH ST	1,000	11	$29,240
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	2,100	25	$61,404
	12320051	FOREST LAKE - 208TH-209TH ST	4,000	47	$116,960
	12320027	FOREST LAKE - IVERSON AVE	3,700	53	$108,188
	N/A	FOREST LAKE - HEATH AVE	3,600	34	$105,264
Newport	12352434	COTTAGE GROVE - IRONWOOD	3,338	100	$97,603
	12438126	ST PAUL - BURNS-RUTH	11,715	147	$342,547
	DE 522036	COTTAGE GROVE - HYDE	3,710	41	$108,480
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	4,735	56	$138,451
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	4,160	36	$121,638
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	10,570	77	$309,067
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	5,160	89	$150,878
	DE 519457	INVER GROVE HTS - CONROY CT	5,400	142	$157,896
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	4,100	26	$119,884
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	2,500	10	$73,100
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	8,500	154	$248,540
	12320940	NORTHFIELD - WOODLEY ST E	500	13	$14,620
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	3,500	55	$102,340
	12356426	LAKE CITY - LAKEWOOD AVE	4,250	79	$124,270
	12360394	RED WING - SPRUCE/SOUTHWOOD	6,000	86	$175,440
	12356414	WINONA - 9TH/52ND	3,500	42	$102,340
	N/A	NORTHFIELD - EDWARDS LN	1,660	42	$48,538
	DE 525650	RED WING - BUSH ST - PLUM ST	3,250	76	$95,030
	N/A	RED WING - WRIGHT/FINRUD	10,400	130	$304,096
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1,260	38	$36,842
	12422040	DILWORTH - 1ST AVE SE	5,000	48	$146,200
2017 Designed DIMP-related Main Replacement Total			**168,703**	**2,453**	**$4,932,876**

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2016 and the first two quarters of 2017.

* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

Intermediate Pressure (IP) Line Assessment Project Detail - 2015-2017

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

2015

Anoka IP ECDA (12.3 Miles)			**2015 Actuals Total:**
		Days	N/A
ISFS Survey	$52,500	Miles	N/A
Traffic Control	N/A	Permits	N/A
Permitting	N/A	Test Leads	N/A
Test Leads	N/A		
Recon	N/A	**Project Total:**	**$52,500**

* Actual costs are through December 31, 2015.

2016

Anoka IP ECDA (12.3 Miles)			**2016 Estimates:**
Digs	5 Digs @ $50,000	Digs	$250,000
Shoreview 175# IP Line ECDA (10 Miles)		**Project Total:**	
ISFS Survey	$63,000	Days	N/A
Traffic Control	$1,500	Miles	N/A
Permitting	$150	Permits	N/A
Test Leads	$8,000	Test Leads	N/A
Recon	$6,000		
Digs	7 Digs @ $50,000	Digs	$350,000

2017

Hugo IP Line (11.1 miles)			**2017 Estimates:**
		Days	N/A
ISFS Survey	$40,000	Miles	N/A
Traffic Control	$9,000	Permits	N/A
Permitting	$1,000	Test Leads	N/A
Test Leads	$0		
Digs	$250,000	**Project Total:**	**$300,000**

*Number of digs subject to change pending results of data analysis.

Colby Lake Lateral Renewal - Replacement

o Location: Eagan, MN – Valley Creek Road from Woodlane Drive to Colby Lake Drive
o Mileage: 2.5 miles

H005 System Renewal - Lexington to Snelling - Replacement

o Location: Arden Hills beginning at the intersection of Snelling and Hamline and continuing north
* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due
o Mileage: 3 miles
o Cost breakdown: Estimated $300,000 for engineering.

DIMP Distribution Valve Project Detail for 2015

NSP-MN New Distribution Valve Installation DIMP Projects 2015 ($s)

Division	Size (in)	Material	Location	WO #	Estimated Cost	Actual Cost	Completed
NPT	2	PEYP	Ruth & Upper Afton	11764875	$3,000	$6,739	2/17/2015
NPT	3	PEA	Burlington & Mcknight	11762582	$4,000	$4,217	5/5/2015
NPT	4	PEYP	Sterling & Linwood	11764832	$5,000	$3,468	5/1/2015
NPT	4	PEYP	Century & Linwood	11761727	$5,000	$6,146	5/20/2015
NPT	4	PET	Ceasar Chavez & George	11771999	$5,000	$10,335	6/16/2015
NPT	4	PEYP	Manning & Dale	11793234	$5,000	$3,726	10/1/2015
NPT	4	PEYD	100th & Kimbro	11782690	$5,000	$3,373	5/1/2015
NPT	4	PET	Hudson & Woodduck	11770329	$5,000	$7,331	5/7/2015
NPT	4	PET	Hudson & Commons	11770403	$5,000	$3,698	5/4/2015
NPT	4	PEYP	Tamarack & Radio	11770675	$5,000	$5,161	5/8/2015
NPT	2	PEYP	Regatta & Woodbury	11774940	$3,000	$6,610	4/14/2015
NPT	2	PEYD	Bridgewater & Woodbury	11774909	$3,000	$7,287	4/15/2015
NPT	4	PET	Radio & Valleycreek	11770730	$5,000	$5,590	4/28/2015
NPT	4	PEYP	Radio & Valley	11770998	$5,000	$4,110	4/30/2015
NPT	4	PET	Colby Lake & Valley	11771822	$5,000	$12,918	4/23/2015
NPT	4	PET	Colby Lake & Valley	11772003	$5,000	$3,409	5/8/2015
NPT	2	PEYP	Grand Brooks & Valley	11774877	$3,000	$2,398	4/23/2015
NPT	4	PEYP	Grand Oaks & Valley	11774634	$5,000	$4,198	5/13/2015
NPT	4	PEYP	Cottage Grove & Valley	11774363	$5,000	$5,865	4/30/2015
NPT	4	PEYU	Settlers Ridge & Valley	11772521	$5,000	$3,181	5/19/2015
NPT	4	PEYU	Settlers Ridge & Valley	11772581	$5,000	$4,560	5/18/2015
STP	2	PEYU	Cypress & Pacific	11777989	$3,000	$4,572	5/27/2015
NPT	2	PEYP	7th & 5th	11777330	$3,000	$2,474	5/21/2015
NPT	2	PEYP	7th & 7th	11799992	$3,000	$3,056	5/21/2015
STP	4	PE	Larpenteur & Jackson	11790685	$5,000	$7,141	2/23/2015
STP	4	PE	Lexington & CR-B	11790855	$5,000	$5,683	1/27/2015
STP	4	PE	Victoria & Parker	11791352	$5,000	$4,820	1/29/2015
STP	2	PE	Shryer & Chatsworth	11791573	$3,000	$3,717	1/22/2015
STC	12	SC	3130 2nd St S	12190722	$102,000	$99,289	10/28/2015
WBL-WYO	2	PEYP	Chatsworth St & Shryer Ave	11791573	$3,000	$3,717	1/22/2015
WBL-WYO	2	PEYU	Kenwood Dr & Roselawn Ave	11791485	$3,000	$2,392	2/6/2015
WBL-WYO	2	PEYU	Silver Ln & Fordham Dr	11784179	$3,000	$3,399	2/3/2015
WBL-WYO	2	C	14th St NW & Silver Lake Rd	11789933	$3,000	$10,504	1/15/2015
WBL-WYO	2	PEYP	Long Lake Rd & Sherwood Rd	11792203	$3,000	$3,884	5/7/2015
WBL-WYO	2	PEYU	Ridge Ln & Long Lake Rd	11792024	$3,000	$2,589	5/6/2015
WBL-WYO	2	PEYP	Victoria St & Snail Lake Blvd	11782313	$3,000	$1,829	4/1/2015
WBL-WYO	2	PET	South Oak Dr & Clover Ave	11786444	$3,000	$2,974	4/1/2015
WBL-WYO	2	PEA	Hwy 96 E & Carolyn Lane	11760557	$3,000	$2,629	2/12/2015
WBL-WYO	2	PET	County Rd E & Linden Ave	11775697	$3,000	$3,023	4/15/2015
WBL-WYO	2	PEYP	Gervais Ave & German St	11797442	$3,000	$3,422	2/11/2015
WBL-WYO	2	PEYU	Birch St & Jay Lane	11797301	$3,000	$2,712	2/12/2015
WBL-WYO	2	PEYP	Mohawk Rd & McKnight Rd	11797651	$3,000	$2,502	5/20/2015
WBL-WYO	2	PEYP	140th St N & Finale Ave N	11771206	$3,000	$1,934	4/23/2015
WBL-WYO	2	PE	Portland Ave & 3rd St	11763432	$3,000	$3,818	3/9/2015
WBL-WYO	2	PET	Goodview Ave & Egg Lake Rd	11770693	$3,000	$1,559	4/23/2015
WBL-WYO	2	PET	80th St & Imperial Ct	11799906	$3,000	$1,846	4/28/2015
WBL-WYO	2	PET	88th St & Kimbro Ave	11799985	$3,000	$2,032	4/28/2015
WBL-WYO	2	PEYU	Ferndale St & Geranium Ave E	11780075	$3,000	$3,333	2/9/2015
WBL-WYO	2	C	Northwestern Ave & 60th St N	11820569	$3,000	$4,295	1/20/2015
WBL-WYO	2	PEYU	Yancy St & 146th Ave	11782581	$3,000	$1,778	5/19/2015
WBL-WYO	2	PEYP	Arnold Palmer Dr & London St	11799596	$3,000	$3,465	2/9/2015
WBL-WYO	2	PET	149th Ave NE & Lexington Ave	11780902	$3,000	$2,023	12/3/1914
WBL-WYO	3	PE	Bald Eagle Blvd & Summit St	11762065	$4,000	$2,588	3/16/2015
WBL-WYO	3	PET	130th St N & Forest Blvd N	11771502	$4,000	$3,385	5/13/2015
WBL-WYO	3	PE	Standridge Ave & McKnight Rd	11797533	$4,000	$6,655	3/11/2015
WBL-WYO	3	PEA	Forest Blvd & 175th St	11803098	$4,000	$2,705	4/15/2015

DIMP Distribution Valve Project Detail for 2015

NSP-MN New Distribution Valve Installation DIMP Projects 2015 ($s)

Division	Size (in)	Material	Location	WO #	Estimated Cost	Actual Cost	Completed
WBL-WYO	3	PEA	27th St N & Gershwin Ave N	11806023	$4,000	$2,920	3/17/2015
WBL-WYO	3	PE	31st St N & Stillwater Blvd	11804445	$4,000	$4,388	3/19/2015
WBL-WYO	3	PE	Scandia N & Harrow Ave N	11895772	$4,000	$2,093	4/13/2015
WBL-WYO	3	PET	Olinda Trl & 295th St	11899010	$4,000	$2,578	4/28/2015
WBL-WYO	3	PEYP	320th St & Falcon Ave N	11790666	$4,000	$1,823	5/26/2015
WBL-WYO	3	PEYP	Falcon Ave N & 320th St	11790669	$4,000	$2,954	6/2/2015
WBL-WYO	4	PEYU	Rice Creek Rd & 20th Ave NW	11790654	$5,000	$3,341	1/23/2015
WBL-WYO	4	C	Pike Lake Dr & 14th St NW	11789973	$5,000	$13,290	1/19/2015
WBL-WYO	4	PEYP	17th Ave NW & 7th St NW	11786169	$5,000	$2,598	5/13/2015
WBL-WYO	4	PEYP	10th St NW & Oakwood Dr	11787008	$5,000	$2,945	1/26/2015
WBL-WYO	4	PEYU	Silver Lake Rd & 14th St NW	11789509	$5,000	$3,155	5/18/2015
WBL-WYO	4	PEYP	Long Lake Rd & County Rd H2	11792099	$5,000	$4,804	5/15/2015
WBL-WYO	4	PEYP	Hwy 96 W & Village Center Dr	11787233	$5,000	$5,535	4/17/2015
WBL-WYO	4	PEYU	Edgerton St & County Rd D	11790930	$5,000	$6,661	5/5/2015
WBL-WYO	4	PET	Centerville Rd & Stoddart Ln	11786923	$5,000	$4,821	3/30/2015
WBL-WYO	4	PEY	Centerville Rd & County Rd F	11782182	$5,000	$5,906	4/7/2015
WBL-WYO	4	PEYD	Thornhill Ln & County Rd F	11782646	$5,000	$5,108	3/31/2015
WBL-WYO	4	PEYU	Turtle Lake Rd & Hodgson Rd	11786444	$4,000	$2,974	4/1/2015
WBL-WYO	4	PEYP	8th Ave SW & 1st St NW	11791508	$5,000	$4,588	1/27/2015
WBL-WYO	4	PET	Otter Lake Rd & Stillwater St	11761771	$5,000	$3,320	5/8/2015
WBL-WYO	4	PEYU	County Rd F & Hwy 61	11763693	$5,000	$4,944	4/27/2015
WBL-WYO	4	PE	Forest Blvd & 175th St	11803081	$5,000	$2,586	4/8/2015
WBL-WYO	4	PET	Jamaca Ave N & Jeffrey Blvd	11799959	$5,000	$2,893	4/16/2015
WBL-WYO	4	PET	Lakewood Dr & Maryland Ave	11780048	$5,000	$6,013	4/30/2015
WBL-WYO	4	PEYD	Stillwater Blvd & 22nd Ct N	11780111	$5,000	$2,694	4/7/2015
WBL-WYO	4	PEYD	Hadley Ave & Stillwater Blvd	11805983	$5,000	$4,632	1/22/2015
WBL-WYO	4	PET	15th St N & Inwood Ave	11781712	$5,000	$2,850	3/20/2015
WBL-WYO	4	PET	Pioneer Rd & Wyoming Trl N	11900952	$5,000	$3,188	4/27/2015
WBL-WYO	4	PEYP	Oasis Rd N & 325th St N	11897071	$5,000	$3,283	5/11/2015
WBL-WYO	4	PEYP	221st Ave NE & Palisade St NE	11780992	$5,000	$2,158	5/20/2015
WBL-WYO	4	PEYP	362nd St & Forest Blvd	11785266	$5,000	$3,303	4/29/2015
WBL-WYO	4	PEYP	Forest Blvd & Lent Trail	11785254	$5,000	$4,518	4/30/2015
WBL-WYO	4	PET	Fawn Lake Dr NE & Thames St	11785250	$4,000	$6,431	10/13/2015
WBL-WYO	4	PEYP	Tournament Players Pkwy & Radisson Rd NE	11799261	$5,000	$3,559	1/20/2015
WBL-WYO	4	PET	Xylite St NE & 153rd Ave NE	11783108	$5,000	$3,193	5/19/2015
WBL-WYO	4	PEYP	109th Ave NE & Tournament Players Pkwy	11803250	$5,000	$3,716	1/29/2015
				Total	**$540,000**	**$518,619**	

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

Total Valves	92
Average Cost	$5,194

DIMP Distribution Valve Project Detail for 2016

NSP-MN New Distribution Valve Installation DIMP Projects 2016

Division	Size (in)	Material	Location	WO #	Estimated Cost	Completed
NPT	2	PE	Linwood & Century	11762634	$3,000	3/22/2016
NPT	2	PEYP	6th & 7th	11794426	$3,000	3/28/2016
NPT	3	PES	Rich Valley & Alverno	11800143	$4,000	2/29/2016
NPT	4	PEYU	Upper Afton & Oakwood	11759132	$5,000	2/23/2016
NPT	4	PEYU	Oakwood & Century	11760021	$5,000	2/26/2016
NPT	4	PEYU	Mcknight & Burlington	11760501	$5,000	3/4/2016
NPT	4	PET	Cliff & Akron	11775030	$5,000	2/25/2016
NPT	4	PEA	Cahill & Buckley	11797338	$5,000	4/4/2016
NPT	4	PEYP	Cahill & 80th	11785263	$5,000	3/3/2016
NPT	4	PEYU	Concord & Concord Path	11797699	$5,000	2/26/2016
NPT	4	PE	Ruth & Burns	11760816	$5,000	7/14/2016
NPT	8	PEYU	Cypress & Pacific	11778091	$10,000	3/14/2016
SE	4	C	Mankato Ave & Lake Blvd	13998435	$9,000	
STP	2	PEYU	Armstrong & View	11713907	$4,043	
STP	2	PEYU	Case & Forest	11777324	$3,000	4/4/2016
STP	4	PEYP	Palace & View	12394529	$3,925	6/3/2016
STP	4	PEYP	Forest & Hawthorne	11777092	$5,000	6/20/2016
WBL	2	PET	County Rd E & Auger Ave	11774994	$2,500	
WBL	2	PEYD	Hallam Ave & Stillwater Rd	11799929	$2,500	
WBL	2	PEYP	Forest Blvd & 159th St	11803546	$2,500	2/25/2016
WBL	2	PEA	W Pleasant Lake Rd & Red Fox Rd	11786256	$2,500	2/23/2016
WBL	2	PET	Heron Ave & 19th St N	11781532	$2,500	3/4/2016
WBL	2	PEYP	Myrtle St W & William St N	11824591	$2,500	
WBL	2	PET	Pine St W & 3rd St S	11819422	$2,500	
WBL	2	PE	Olinda Blvd N & Omaha Ave N	11799609	$2,500	
WBL	2	PET	30th St N & Oakgreen Ave N	11799089	$2,500	3/14/2016
WBL	2	PEYP	20th St N & Neal Ave N	11794772	$2,500	3/8/2016
WBL	2	PEYP	11th Ave NE & Club West Pkwy	11804884	$2,500	3/7/2016
WBL	2	PEYP	Baltimore St & 12th Ave NE	11800149	$2,500	3/7/2016
WBL	2	PEYU	113th Ave NE & Club West Pkwy	11800011	$2,500	
WBL	2	PEYP	7th St NW & Glenbrook Ave N	11820751	$2,500	
WBL	2	PEYP	Grand Ave & 4th St N	11801917	$2,500	3/3/2016
WBL	2	PEYP	Grovner Ave & 5th St N	11802649	$2,500	3/2/2016
WBL	3	PET	Little Canada Rd & Centerville Rd	11792047	$3,000	
WBL	3	PEA	McMenemy St & McMenemy Circle	11803601	$3,000	
WBL	3	PEA	Robb Farm Rd & E Gilfillan Rd	11784200	$3,000	2/24/2016
WBL	3	PE	Division St N & South Ave E	11821649	$3,000	
WBL	3	PE	Stillwater Blvd & Hale Ave N	11805856	$3,000	

DIMP Distribution Valve Project Detail for 2016

NSP-MN New Distribution Valve Installation DIMP Projects 2016

Division	Size (in)	Material	Location	WO #	Estimated Cost	Completed
WBL	3	PE	Scandia N & Jewel Ln	11895527	$3,000	3/22/2016
WBL	3	PE	Scandia N & Forest Blvd N	11896580	$3,000	
WBL	3	PE	Forest Blvd N & Thurnbeck Dr	11899087	$3,000	42452
WBL	4	PEA	Otter Lake Rd & Hammond Rd	11761488	$4,000	42522
WBL	4	PEYD	Hwy 96 E & White Bear Pkwy	11759043	$4,000	
WBL	4	C	Birch Lake Blvd & Otter Lake Rd	11760184	$9,000	
WBL	4	C	4th St & Bald Eagle Ave	11761163	$9,000	
WBL	4	PEYP	117th St & Portland Ave	11770029	$4,000	
WBL	4	PET	129th St N & Elmcrest Ave	11774429	$4,000	
WBL	4	C	County Rd F & Bellaire Ave	11765476	$9,000	
WBL	4	PEYD	Arcade St & Berwood Ave	11779412	$4,000	
WBL	4	PEYP	Edgerton St & Centerville Rd	11790811	$4,000	
WBL	4	PEYU	Farnham Ave N & Oneka Pkwy	11803572	$4,000	42430
WBL	4	PEYU	Heritage Pkwy & Education Dr	11803585	$4,000	42426
WBL	4	PEYP	County Rd D & White Bear Ave	11797366	$4,000	
WBL	4	PEYU	White Bear Ave & Beam Ave	11798542	$4,000	
WBL	4	PE	McKnight Rd & Lydia Ave	11798614	$4,000	
WBL	4	PEYP	County Rd J & Pheasant Dr	11786563	$4,000	
WBL	4	PET	50th St & Hadley Ave	11798029	$4,000	
WBL	4	PEYP	Hadley Ave & 34th St N	11805498	$4,000	42522
WBL	4	PEYP	15th St N & 15th St Ct N	11780159	$4,000	
WBL	4	PEYP	15th St N & Hwy 694 N	11780218	$4,000	
WBL	4	PET	Norell Ave N & Dellwood Rd	11800020	$4,000	3/9/2016
WBL	4	PEYU	Stillwater Blvd & Oakridge Rd	11823047	$4,000	3/17/2016
WBL	4	PEYD	Stonebridge N & Penfield Ave N	11800054	$4,000	42447
WBL	4	PEYD	30th St N & Manning Ave N	11798215	$4,000	3/11/2016
WBL	4	PEYP	Stillwater Blvd N & 40th St N	11796603	$4,000	
WBL	4	PEYP	Stillwater Blvd N & 58th St N	11795996	$4,000	42439
WBL	4	PET	Northbrook Blvd N & 51st St N	11799730	$4,000	3/14/2016
WBL	4	PET	10th St N & Neal Ave N	11829021	$4,000	
WBL	4	PEYD	10th St N & Oakgreen Ave N	11795073	$4,000	5/4/2016
WBL	4	C	County Rd E & 20th Ave SW	11784983	$9,000	
WBL	4	PEYP	Greenway Ave & 5th St N	11802222	$4,000	42522
WBL	4	PEYU	Roselawn Ave & Edgerton St	11790765	$4,000	
WBL	4	PET	Lexington Ave & Ingerson Rd	11794394	$4,000	
WBL	6	C	Cedar Ave & Keri Ann Ln	11764478	$15,000	
WBL	6	C	White Bear Ave & Hwy 694	11764950	$15,000	
WBL	6	C	Flandreau St & Kennard St	11798472	$15,000	

DIMP Distribution Valve Project Detail for 2016

NSP-MN New Distribution Valve Installation DIMP Projects 2016

Division	Size (in)	Material	Location	WO #	Estimated Cost	Completed
WBL	6	PEYU	Hodgson Rd & Hwy 96 W	11791524	$6,000	
WBL	6	C	Larpenteur Ave E & English St	11791740	$15,000	
WBL	6	C	Hillview Rd & Long Lake Rd	11792760	$15,000	
WBL	6	C	Hadley Ave & 7th St N	11821649	$15,000	
WBL	8	C	Larpenteur Ave & Mcknight Rd	11780179	$20,000	
WBL	8	C	Larpenteur Ave E & Kennard St	11791892	$20,000	
WBL	2	PET	South Oaks & Clover Ave.	11779311	$2,500	3/7/2016
WYO	2	PEYP	Europa N & 132nd St	11771874	$2,500	3/1/2016
WYO	4	PEYP	Itasca Ave N & Green Lake	11901363	$4,000	42450
WYO	4	PEYP	Wyoming Trl N & Ironwood	11901106	$4,000	3/22/2016
WYO	4	PEYP	Scandia N & Forest Blvd N	11896688	$4,000	
WYO	4	PEYU	264th St N & Forest Blvd N	11902308	$4,000	42450
WYO	4	PEYU	113th Ave NE & Club West Pkwy	11802970	$4,000	
WYO	4	PEYU	Club West Pkwy & 114th Ave NE	11799971	$4,000	
				Total	**$461,968**	

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

Total Valves	90
Average Cost	$5,133

DIMP Distribution Valve Project Detail for 2017

NSP-MN New Distribution Valve Installation DIMP Projects 2017

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

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

** Known valves, subject to change.*

DIMP Federal Code Mitigation 2016-2017

2016			Division							
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN	Total Items	Unit Cost	Projected Spend
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	0	0	0	860	0	860	$ 550	**$ 472,500**
	Capital	TBD								**$ 203,500** *

2017			Division							
Job Type	Cost Type	Description	BRD	FARI	RW	STC	WIN	Total Items	Unit Cost	Projected Spend
IM	O&M	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	29	14	1		7	51	$ 550	$ 28,050
IS	O&M	MMIG RPTG ONLY- REMEDIATE IDLE RISER/NO METER	3	7	9	1	28	48	$ 800	$ 38,400
IE	O&M	MMIG RPTG ONLY- INSTALL GUARD POST - RESIDENTIAL	2	1	6	11	20	40	$ 1,000	$ 40,000
IF	O&M	MMIG RPTG ONLY- INSTALL GUARD POST - COMMERCIAL/INDUSTRIAL	3	2	2	2	9	18	$ 1,000	$ 18,000
IT	O&M	MMIG RPTG ONLY- RELOCATE INACCESSIBLE METER SET (IN TO OUT)	1	0	0	4	2	7	$ 1,600	$ 11,200
IC	O&M	MMIG RPTG ONLY- REPAIR RISER (ATMOS. CORR. - PITTING)	0	0	0	2	0	2	$ 1,000	$ 2,000
IH	O&M	MMIG RPTG ONLY- INSTALL ICE SHIELD - METER SET	0	0	0	1	0	1	$ 350	$ 350
Total	O&M	**Total Items**						167		**$ 138,000**
	Capital	TBD								**$ 202,000** *

* Final capital project list in-process of scope development.

DIMP 2017 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2015 Projects

2015				
Polygon ID	**City**	**State**	**Project**	**Estimated Service Count**
344832153	Sauk Rapids	MN	18th & Eastern	200
344832166	St Joseph	MN	Baker & 13th	531
344832061	New London	MN	New London	370
344832070	Nisswa	MN	Nashway & Gull Lake	260
344832079	Baxter	MN	Clearwater & Welton	229
344832088	Becker	MN	Edgewood & Brenda	309
344831953	Delano	MN	Marie & Country	251
344832597	Chisago	MN	Old Towne & Lacy	546
344832611	Wyoming	MN	Freeport & 258th	299
344832620	Mendota Heights	MN	Huber & Pond View	939
344832629	Winona	MN	5th & Ben	568
344832638	Winona	MN	3rd & Zumbro	290
344832647	Mahtomedi	MN	Hilton & 72nd	307
344832656	Northfield	MN	Linden & North	867
344832665	Falcon Heights	MN	Tatum & Larpenteur	284
344832674	Arden Hills	MN	Hamline & Hwy 96	703
344832683	Delano	MN	80th & 3rd	269
344832701	Lindstrom	MN	Lake & Olinda	348
344832710	Sartell	MN	6th & 15th	509
344832719	Invergrove Heights	MN	Cahill & 62nd	836
344832730	Cottage Grove	MN	Highland & 65th	756
344832748	White Bear Lake	MN	5th & Cook	811
344832757	Roseville	MN	Transit & Galtier	499
344832766	Waite Park	MN	2nd & 28th	420
344832777	Stillwater	MN	4th & marsh	350
312788466	East Grand Forks	MN	North Star Terrace	167
344832786	St Cloud	MN	4th & Wilson	438
344832795	Maplewood	MN	Stillwater & Sterling	508
344832806	Woodbury	MN	Seasons & Autumn	466
344832815	Oakdale	MN	Glenbrook & 25th	509
344832826	Moorehead	MN	Village Green & 28	537
344832844	Faribault	MN	St Paul & Shumway	618
344832855	Lake City	MN	Garden & Oak	371
344832864	Forest lake	MN	12th & 15th	241
344832873	Hugo	MN	Oneka & Heritage	327
312787481	Little Canada	MN	Terrace Heights MHC	193
312787573	Mounds View	MN	Colonial Village	195
344832884	Newport	MN	Glen & 11th	256
344832902	Oak Park Heigths	MN	Obrien & 55th	334
344832911	Red Wing	MN	Bluff & 7th	293
roject detail amount	St Paul Park		14th & Summit	339
344832929	Shoreview	MN	Hwy 96 & Dale	600
344832938	Stillwater Twp	MN	Macey & Atwood	349
344832947	Vadnais Heights	MN	Greenhaven & Morningside	315
344832956	White Bear Lake Twp	MN	Reed & Ross	536
344832965	Wabasha	MN	Gambia & 7th	263
350639407	Glyndon	MN	Parke Ave S & 12 St Se	103
312788235	Moorhead	MN	Greenwood MHP	61
344832184	Wabasha	MN	River & Angelique	215
344832193	Vadnais Heights	MN	Koehler & Edgerton	263
			Total	**20,248**

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

DIMP 2017 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2016 Projects

2016				
Polygon ID	**City**	**State**	**Project**	**Estimated Service Count**
312787367	Stacy	MN	Sunrise Estates Mobile Home Park	225
312787494	Landfall	MN	Landfall Terrace	274
312787518	Maplewood	MN	Rolling Hills Mobile Home Park	359
312787529	Maplewood	MN	Beaver Lake Estates	254
312787540	Shoreview	MN	Brookside	216
312787606	Arden Hills	MN	Arden Manor	287
312787661	Inver Grove Heights	MN	Emerald Hills Village	402
312787960	Rice	MN	Rockwood Estates	206
312788048	Sartell	MN	Evergreen Village	196
312788092	St Cloud	MN	Bel Clare Estates	293
312788103	St Cloud	MN	River View Park	70
312788114	St Cloud	MN	Shady Oak	18
312788136	St Cloud	MN	Sherwood Manor	72
312788147	St Cloud	MN	Cloverleaf MHP	169
317305364	Oakdale	MN	7th St & Gershwin	95
317305386	Oakdale	MN	9th St & Heron	86
317305971	Sartell	MN	Heritage & Anna	194
317305993	St Cloud	MN	33rd st s & Oregon	366
359596048	Forest Lake	MN	Shore and 4th	508
359596072	Forest Lake	MN	Broadway and Lake	570
359596139	Sauk Rapids	MN	5th Ave and 5th St	668
359596152	Nisswa	MN	Hwy 371 and Roy Lake	151
359596165	Nisswa	MN	Poplar and Cullen	204
359596178	Nisswa	MN	White Pine and Cnty Rd 13	184
359596230	Little Canada	MN	Cnty Rd C and Sylvan	447
359596243	Little Canada	MN	Allen and Payne	616
359596256	Hugo	MN	Falcon and 130th	1565
359596280	Grant	MN	Jasmine and 68th	430
359596307	Grant	MN	Jamaca and 105	130
359596320	Grant	MN	88th and Kimbro	185
359596333	Forest Lake	MN	216th and Scandia	618
359596347	Forest Lake	MN	15th and 9th	228
359596386	Cottage Grove	MN	70th St and Innsdale	2037
359596399	Woodbury	MN	Pheasant Run and Corral	1800
359596412	Woodbury	MN	Wynstone and Cnty Rd 19	1137
359596425	Becker	MN	Sherburn and Lee	541
359596438	Becker	MN	Jefferson and 14th	83
359596477	Baxter	MN	Highland Scenic & Chestnut	223
359596490	Moorhead	MN	Belsly & 12th St	402
359596503	Moorhead	MN	34 St and 12 Ave	678
ct detail amo	White Bear Township		Park and Beaver	525
359596530	White Bear Township	MN	Sandterra & Mallard	255
359596701	Oakdale	MN	22nd & Helmo Ave	1611
			Total	**19,578**

DIMP 2017 Sewer Mitigation Project Detail

NSP-MN Sewer Conflict Investigation - 2017 Projects

2017				
Polygon ID	**City**	**State**	**Project**	**Estimated Service Count**
312787299	Lindstrom	MN	Lake Shore Terrace Trailer Park	80
312787310	Lindstrom	MN	Blue Waters Leisure Park	63
312787321	Wyoming	MN	River Bend Trailer Park	53
312787332	Wyoming	MN	Birtchwood Terrace Trailer Parks	83
312787378	Lindstrom	MN	Lindstrom Mobile Home Park #1	25
312787389	Lindstrom	MN	Stone Gate Terrace	52
312787400	Shafer	MN	Shafer Mobile Home Park #1	25
312787411	Shafer	MN	Shafer Mobile Home Park #2	18
312787685	Inver Grove Heights	MN	52nd & Brent	65
312787740	Faribault	MN	Sunrise MHP	72
312787773	Lake City	MN	Maplewood Trailer Park	77
312787817	Cross Lake	MN	Sand Point	46
312787828	Cross Lake	MN	Peaceful Harbor	29
312787839	Brainerd	MN	Spencer Trailer Park	12
312787850	Cross Lake	MN	Chattum Park	43
312787861	Fifty Lakes	MN	Open Gate Resort	20
312787872	Pequot Lakes	MN	Pequot Terrace	39
312787883	Brainerd	MN	Lazy Acres MHP	23
312787894	Cosmos	MN	Cosmos MHP	19
312787905	Waverly	MN	12-HI MHP	11
312787916	Montrose	MN	Montrose Manor	11
312787927	Watertown	MN	Watertown	1
312787938	Watertown	MN	Riverside Terrace	10
312787949	Royalton	MN	East Trailer Park	33
312787971	Spicer	MN	Spicer MHP #2	2
312787982	Spicer	MN	Spicer MHP #1	5
312787993	New London	MN	New London MHP #1	45
312788004	Foley	MN	Foley Park #1	17
312788015	Foley	MN	Foley Park #2	24
312788026	Foley	MN	Foley MHP	29
312788114	St Cloud	MN	Shady Oak	18
312788125	Sauk Rapids	MN	Fischer's Garden MHP	81
312788158	Glyndon	MN	Praireview Estates	26
312788169	Glyndon	MN	Glyndon MHP	28
312788180	Dilworth	MN	Dilworth MHP	62
312788202	Dilworth	MN	Villa Del Sol	28
312787674	Maplewood	MN	Maplewood MHP	23
			Total	**1,298**

Quantitative Risk Assessment for 2017 GUIC Programs and Initiatives

DIMP

Methodology

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

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

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

DIMP Poor Performing Mains & Services –

Problematic Steel Project Risk

SEE ATTACHMENT C2(b)

Uses Commercial Software: Optimain DS by Opvantek

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

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

Project Risk = Main Risk + Service Risk

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

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

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

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

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

DIMP Poor Performing Mains & Services –

Problematic Plastic Project Risk

SEE ATTACHMENT C2(b)

Data inputs:

- Material Risk Factor
- Pressure Leak Factor
- Population Density

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Material Risk Factor + Pressure Risk Factor

Material Risk Factor Lookup Table

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

Pressure Risk Factor Lookup Table

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

Consequence of Failure Lookup Table

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

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

Risk Matrix

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

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

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

Project	Regulation	Current Classification	Mechanical Joint	Manufacturing/ Construct-ion Defect	Corrosion	3rd Party Damage	Other Leak History	Conseque-nce	Risk Score	Project Classificati-on
Colby Lake Lateral	49 CFR 192.921(a)	Distribution	0	2	1	1	1	3	15	High
H005 - Lexington to Snelling	49 CFR 192.921(a)	Distribution	2	2	1	1	1	3	21	High

HP = distribution pipeline with MAOP > 60 psig

Used for decisions on replacement or other mitigation necessity

Data inputs:

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

Risk Score = Likelihood of Failure x Consequence of Failure

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

<u>Mechanical Joint Risk Factor Lookup Table</u>

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

<u>Manufacturing/Construction Defect Risk Factor Lookup Table</u>

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

Corrosion Risk Factor Lookup Table

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

3rd Party Damage Risk Factor Lookup Table

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

Other Leak History Risk Factor Lookup Table

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

Consequence of Failure Lookup Table

Class Location	Score
4	4
3	3
2	2
1	0.5

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

Risk Matrix

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

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

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

Project	Years Since Assessment	Pipeline Class Location	Risk Score	Risk Level
Hugo IP ECDA	24	Class 3	6	Medium

HP = distribution pipeline with MAOP > 60 psig

Used for decisions on prioritizing integrity assessments

Data inputs:

- Years since last integrity assessment
- Pipeline Class Location

Risk Score = Likelihood of Failure x Consequence of Failure

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

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

DIMP Distribution Valve Replacement –

Project Risk

Project Name/Location	Valve Count	Size/Mtl	Main Line Valve Operable? Y or N	Vault Condition? Good or Poor	Atmospheric Corrosion Status? Present or not Present	Likelihood of Failure Score	Consequence of Failure Score	Risk Score	Risk Category High Risk: Risk Score ≥ 12 Medium Risk: 9 ≤ Risk Score < 12 Low Risk: Risk Score < 9
Henry Ave & Fleming Field, SSTP	1	12" SC	N	Good	N	3	2	6	Medium Risk
Algonquin & Iroquois, STP	1	12" SC	N	Good	N	3	4	12	High Risk
7th & Dale, STP	1	12" SC	N	Good	N	3	2	6	Medium Risk
Forest & Rose, STP	1	12" SC	N	Good	N	3	4	12	High Risk
Cypress & 6th, STP	1	6" SC	N	Good	Y	3.25	4	13	High Risk
Victoria & St. Anthony, STP	1	6" SC	N	Good	Y	3.25	4	13	High Risk
Algonquin & Iroquois, STP	1	6" SC	N	Good	N	3	4	12	High Risk
Robert & Page, STP	1	8" SC	N	Good	N	3	4	12	High Risk
Cypress & Reaney, STP	1	8" SC	N	Good	N	3	4	12	High Risk
Roselawn & McMenomie	3	4" SC	N	Good	Y	3.25	4	13	High Risk
McKnight & 3rd St E	2	4" SC	N	Poor	Y	4	4	16	High Risk
McKnight & 3rd St E	1	8" SC	N	Poor	Y	4	4	16	High Risk
Larpenter & Gary	4	8" SC	N	Good	Y	3.25	4	13	High Risk
McKnight & Hudson Rd	1	8" SC	N	Poor	Y	4	2	8	Medium Risk
Hwy 19 W TBS	1	8" SC	N	Poor	Y	3.75	4	15	High Risk
Hwy 19 W TBS	1	6" SC	N	Poor	Y	3.75	4	15	High Risk

Data inputs:

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

Risk Score = Likelihood of Failure x Consequence of Failure

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

Valve Operability Risk Factor Lookup Table

Valve Operable	**Score**
No	3
Yes	0

Vault Condition Risk Factor Lookup Table

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

Atmospheric Corrosion Risk Factor Lookup Table

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

Consequence of Failure Lookup Table

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

Risk Matrix

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

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

DIMP Sewer & Gas Line Conflict - Project Risk

Polygon ID	City	State	Project	Estimated Service Count	Risk Score	Risk Level
312787299	Lindstrom	MN	Lake Shore Terrace Trailer Park	80	6	High
312787310	Lindstrom	MN	Blue Waters Leisure Park	63	6	High
312787321	Wyoming	MN	River Bend Trailer Park	53	6	High
312787332	Wyoming	MN	Birtchwood Terrace Trailer Parks	83	6	High
312787378	Lindstrom	MN	Lindstrom Mobile Home Park #1	25	6	High
312787389	Lindstrom	MN	Stone Gate Terrace	52	6	High
312787400	Shafer	MN	Shafer Mobile Home Park #1	25	6	High
312787411	Shafer	MN	Shafer Mobile Home Park #2	18	6	High
312787685	Inver Grove Heights	MN	52nd & Brent	65	6	High
312787740	Faribault	MN	Sunrise MHP	72	6	High
312787773	Lake City	MN	Maplewood Trailer Park	77	6	High
312787817	Cross Lake	MN	Sand Point	46	6	High
312787828	Cross Lake	MN	Peaceful Harbor	29	6	High
312787839	Brainerd	MN	Spencer Trailer Park	12	6	High
312787850	Cross Lake	MN	Chattum Park	43	6	High
312787861	Fifty Lakes	MN	Open Gate Resort	20	6	High
312787872	Pequot Lakes	MN	Pequot Terrace	39	6	High
312787883	Brainerd	MN	Lazy Acres MHP	23	6	High
312787894	Cosmos	MN	Cosmos MHP	19	6	High
312787905	Waverly	MN	12-HI MHP	11	6	High
312787916	Montrose	MN	Montrose Manor	11	6	High
312787927	Watertown	MN	Watertown	1	6	High
312787938	Watertown	MN	Riverside Terrace	10	6	High
312787949	Royalton	MN	East Trailer Park	33	6	High
312787971	Spicer	MN	Spicer MHP #2	2	6	High
312787982	Spicer	MN	Spicer MHP #1	5	6	High
312787993	New London	MN	New London MHP #1	45	6	High
312788004	Foley	MN	Foley Park #1	17	6	High
312788015	Foley	MN	Foley Park #2	24	6	High
312788026	Foley	MN	Foley MHP	29	6	High
312788114	St Cloud	MN	Shady Oak	18	6	High
312788125	Sauk Rapids	MN	Fischer's Garden MHP	81	6	High
312788158	Glyndon	MN	Praireview Estates	26	6	High
312788169	Glyndon	MN	Glyndon MHP	28	6	High
312788180	Dilworth	MN	Dilworth MHP	62	6	High
312788202	Dilworth	MN	Villa Del Sol	28	6	High
312787674	Maplewood	MN	Maplewood MHP	23	6	High
Total Valves				**1,298***		

*The current plan estimates that approximately 20,000 services will be inspected for conflicts in 2017, the 8th year of legacy inspections. Approximately 1,298 of the 20,000 planned inspections have been identified and scoped at this time.

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

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

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

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

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

DIMP Federal Code Mitigation –

Project Risk

Job Type	Description	Total Items	Risk Scores	Risk Level
IM	MMIG RPTG ONLY- SLEEVE RISER (RISER IN CONCRETE)	51	≥ 2	Medium, High
IS	MMIG RPTG ONLY- REMEDIATE IDLE RISER/NO METER	48	≥ 2	Medium, High
IE	MMIG RPTG ONLY- INSTALL GUARD POST - RESIDENTIAL	40	≥ 5	Medium, High
IF	MMIG RPTG ONLY- INSTALL GUARD POST - COMMERCIAL/INDUSTRIAL	18	≥ 2	Medium, High
IT	MMIG RPTG ONLY- RELOCATE INACCESSIBLE METER SET (IN TO OUT)	7	≥ 2	Medium, High
IC	MMIG RPTG ONLY- REPAIR RISER (ATMOS. CORR. - PITTING)	2	≥ 2	Medium, High
IH	MMIG RPTG ONLY- INSTALL ICE SHIELD - METER SET	1	≥ 2	Medium, High
Total	**Total Items**	**167**		

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

Install Guard Post

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

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

Install Ice Shield

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

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

Riser in Concrete with no Sleeve

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

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

Riser Repair

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

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

Idle Riser

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

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

Inaccessible Meter

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

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

DIMP Replacements 2017 Risk Assessment Scores

Coated Steel

Priority	Optimain Total (RiskProject) Score	Priority Distribution
High	Score ≥ 36	14
Medium	24 ≤ Score < 36	0
Low	1 ≤ Score < 24	0
None	Score < 1	0
Total	**All**	**14**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	OPTIMAIN SCORE
DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST DIMP	8500	154.0	1968	Coated Steel	786
12294045	ROSEVILLE - FERNWOOD ST DIMP	3760	44.2	1955	Coated Steel	100
12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE.	1260	38.0	1972	Coated Steel	98
12438126	ST PAUL - BURNS-RUTH DIMP 2017	11715	147.0		Coated Steel	50
	ST PAUL - ST PETER, FORD 4TH DIMP	4200	62.0	1980	Coated Steel	84
12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL DIMP 2017	9600	141.0	1962	Coated Steel	55
12320389	ARDEN HILLS - GLENPAUL AVE DIMP	4700	58.0		Coated Steel	161
12360394	RED WING - SPRUCE/SOUTHWOOD DIMP	6000	86.0		Coated Steel	730
12356414	WINONA - 9TH/52ND DIMP	3500	42.0	1978	Coated Steel	168
DE 522036	COTTAGE GROVE - HYDE DIMP	3710	41.0	1961	Coated Steel	231
DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE DIMP	4735	55.7	1961	Coated Steel	92
DE 521609	COTTAGE GROVE - IDEAL-85TH ST DIMP	4160	36.0	1962	Coated Steel	182
12092590	BAYPORT - 7TH ST DIMP	1000	11.0	1964	Coated Steel	159
	RED WING - WRIGHT/FINRUD DIMP	10400	130.0	1975	Coated Steel	131

*Scoring included for known 2017 projects with completed engineering and design.

Poor Performing Plastic - Aldyl-A

Priority	Quantitative Risk Assessment Score	Priority Distribution
High	Score ≥ 7	4
Medium	4 ≤ Score < 7	6
Low	0 ≤ Score < 4	0
Total	**All**	**10**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	QRA SCORE
12422040	DILWORTH - 1ST AVE SE DIMP	5000	48.0	1972	Aldyl-A	4.500
12352434	COTTAGE GROVE - IRONWOOD DIMP	3338	100.0	1971	Aldyl-A	5.938
12320027	FOREST LAKE - IVERSON AVE DIMP	3700	53.0	1967	Aldyl-A	7.125
12356426	LAKE CITY - LAKEWOOD AVE DIMP	4250	79.0	1972	Aldyl-A	4.750
DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH DIMP	5160	89.0	1971	Aldyl-A	7.125
DE 519457	INVER GROVE HTS - CONROY CT DIMP	5400	142.0	1972	Aldyl-A	7.125
	FOREST LAKE - HEATH AVE DIMP	3600	34.0	1968	Aldyl-A	7.125
	NORTHFIELD - EDWARDS LN DIMP	1660	42.0	1968	Aldyl-A	4.750
	ST CLOUD - 16TH AVE - 3RD ST N DIMP			1972	Aldyl-A	4.750
12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA DIMP	2500	10	1972	Aldyl-A	4.750

*Scoring included for known 2017 projects with completed engineering and design.

Capital Expenditure (CWIP Only)
Actual and Forecast Through 2021

Total: GUIC Statute Projects			**178,258**	**9,905,516**	**11,868,014**	**30,923,657**	**31,482,349**	**23,639,064**	**45,641,440**	**49,992,300**	**48,185,400**	**48,185,400**	**300,001,398**	**300,001,398**
Project Name	**Sub Project**	**Eligibility Date**	**Pre-2013**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total by Subproject**	**Total by Project**
TIMP	Transmission	Jan-15	94,714	65,049	(23,664)	1,073,019	5,665,902	5,232,073	28,584,100	32,864,700	31,057,800	31,057,800	135,671,492	-
TIMP	Distribution	Jan-15	318	9,497,340	11,651,414	17,937,370	15,569,331	-	-	-	-	-	54,655,773	190,327,265
DIMP	Distribution	Jan-15	83,226	343,127	240,264	10,010,997	10,076,219	18,406,991	17,057,340	17,127,600	17,127,600	17,127,600	107,600,964	-
DIMP	Software	Jan-15	-	-	-	1,902,271	170,898	-	-	-	-	-	2,073,169	109,674,133

TIMP
Capital Related Revenue Requirements 2015-2018

TIMP **Transmission, Distribution & Software**	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Rate Base													
Plant In-Service	21,938,154	22,133,204	22,147,885	22,151,148	22,168,031	22,439,025	22,338,149	22,657,121	22,589,045	39,961,666	40,808,989	41,643,044	41,643,044
Less Accumulated Book Depreciation Reserve	365,544	411,863	458,402	504,961	551,540	598,422	645,483	692,773	740,327	806,016	890,389	976,013	976,013
Less Accumulated Deferred Taxes	3,340,929	3,643,059	3,946,572	4,249,608	4,550,434	4,850,615	5,148,774	5,443,318	5,734,617	6,158,297	6,769,171	7,449,615	7,449,615
End Of Month Rate Base	**18,231,682**	**18,078,282**	**17,742,911**	**17,396,580**	**17,066,057**	**16,989,988**	**16,543,892**	**16,521,030**	**16,114,101**	**32,997,354**	**33,149,428**	**33,217,416**	**33,217,416**
Return on Rate Base													
Debt Return	34,779	34,343	33,881	33,236	32,596	32,211	31,717	31,274	30,867	46,451	62,564	62,772	466,692
Equity Return	81,202	80,185	79,105	77,600	76,105	75,207	74,054	73,018	72,069	108,454	146,074	146,560	1,089,634
Total Return on Rate Base	**115,981**	**114,528**	**112,986**	**110,836**	**108,701**	**107,418**	**105,771**	**104,292**	**102,937**	**154,906**	**208,638**	**209,332**	**1,556,326**
Income Statement Items													
Property Taxes	33,638	33,638	33,638	33,638	33,638	33,638	33,638	33,638	33,638	33,638	33,638	33,638	403,656
Book Depreciation	45,944	46,319	46,539	46,558	46,579	46,882	47,061	47,290	47,554	65,689	84,373	85,624	656,413
Deferred Taxes	299,650	302,130	303,513	303,036	300,826	300,181	298,159	294,544	291,300	423,679	610,875	680,444	4,408,336
Gross Up for Income Tax	(249,297)	(252,553)	(254,729)	(255,303)	(254,096)	(254,068)	(252,810)	(249,840)	(247,187)	(356,969)	(521,995)	(592,869)	(3,741,717)
Total Income Statement Expense	**129,935**	**129,534**	**128,961**	**127,929**	**126,948**	**126,633**	**126,047**	**125,632**	**125,304**	**166,037**	**206,891**	**206,837**	**1,726,689**
Revenue Requirement													
Total	**245,916**	**244,062**	**241,947**	**238,765**	**235,649**	**234,052**	**231,818**	**229,924**	**228,240**	**320,943**	**415,529**	**416,169**	**3,283,015**

TIMP
Capital Related Revenue Requirements 2015-2018

TIMP **Transmission, Distribution & Software**	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
Plant In-Service	41,503,081	41,716,894	41,718,471	41,839,649	41,845,696	49,101,568	47,696,317	53,053,390	55,865,471	57,195,315	58,027,423	62,241,772	62,241,772
Less Accumulated Book Depreciation Reserve	1,062,249	1,148,549	1,235,074	1,321,727	1,408,512	1,502,928	1,603,494	1,708,214	1,820,468	1,935,511	2,051,984	2,173,115	2,173,115
Less Accumulated Deferred Taxes	7,765,657	8,082,478	8,399,888	8,717,309	9,033,863	9,372,999	9,729,857	10,098,717	10,535,817	11,046,799	11,597,505	12,191,892	12,191,892
End Of Month Rate Base	**32,675,175**	**32,485,867**	**32,083,509**	**31,800,613**	**31,403,321**	**38,225,641**	**36,362,965**	**41,246,459**	**43,509,186**	**44,213,005**	**44,377,934**	**47,876,765**	**47,876,765**
Return on Rate Base													
Debt Return	62,323	61,631	61,072	60,424	59,780	65,857	70,548	73,406	80,165	82,971	83,792	87,258	849,227
Equity Return	138,924	137,381	136,134	134,689	133,255	146,801	157,258	163,627	178,693	184,948	186,779	194,504	1,892,991
Total Return on Rate Base	**201,247**	**199,013**	**197,206**	**195,113**	**193,035**	**212,658**	**227,806**	**237,032**	**258,858**	**267,918**	**270,571**	**281,761**	**2,742,219**
Income Statement Items													
Property Taxes	63,963	63,963	63,963	63,963	63,963	63,963	63,963	63,963	63,963	63,963	63,963	63,963	767,560
Book Depreciation	86,236	86,300	86,525	86,653	86,785	94,416	100,566	104,720	112,254	115,043	116,473	121,131	1,197,102
Deferred Taxes	316,042	316,821	317,410	317,421	316,553	339,136	356,858	368,860	437,099	510,982	550,706	594,387	4,742,277
Gross Up for Income Tax	(225,216)	(227,101)	(228,584)	(229,614)	(229,737)	(243,271)	(254,013)	(261,791)	(320,996)	(392,216)	(431,589)	(470,842)	(3,514,969)
Total Income Statement Expense	**241,026**	**239,983**	**239,315**	**238,423**	**237,564**	**254,245**	**267,375**	**275,752**	**292,320**	**297,773**	**299,554**	**308,639**	**3,191,969**
Revenue Requirement													
Total	**442,273**	**438,996**	**436,521**	**433,536**	**430,599**	**466,904**	**495,181**	**512,784**	**551,178**	**565,691**	**570,125**	**590,400**	**5,934,188**

TIMP
Capital Related Revenue Requirements 2015-2018

TIMP **Transmission, Distribution & Software**	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
Plant In-Service	62,591,418	62,792,614	62,919,287	63,100,560	63,388,960	63,786,351	64,287,926	64,893,603	65,579,651	66,286,212	66,957,583	67,485,509	67,485,509
Less Accumulated Book Depreciation Reserve	2,298,581	2,424,399	2,550,427	2,676,651	2,803,176	2,930,138	3,057,675	3,185,920	3,314,989	3,444,948	3,575,788	3,707,394	3,707,394
Less Accumulated Deferred Taxes	12,314,740	12,440,990	12,569,238	12,699,198	12,831,674	12,967,872	13,109,003	13,256,250	13,410,685	13,572,958	13,743,075	13,920,161	13,920,161
End Of Month Rate Base	**47,978,096**	**47,927,224**	**47,799,622**	**47,724,710**	**47,754,110**	**47,888,341**	**48,121,248**	**48,451,433**	**48,853,977**	**49,268,306**	**49,638,720**	**49,857,955**	**49,857,955**
Return on Rate Base													
Debt Return	90,663	90,710	90,542	90,350	90,307	90,462	90,809	91,342	92,035	92,807	93,550	94,107	1,097,683
Equity Return	199,298	199,403	199,032	198,611	198,516	198,857	199,620	200,791	202,314	204,013	205,644	206,870	2,412,969
Total Return on Rate Base	**289,961**	**290,114**	**289,574**	**288,961**	**288,823**	**289,318**	**290,429**	**292,132**	**294,349**	**296,820**	**299,194**	**300,977**	**3,510,653**
Income Statement Items													
Property Taxes	95,603	95,603	95,603	95,603	95,603	95,603	95,603	95,603	95,603	95,603	95,603	95,603	1,147,233
Book Depreciation	125,466	125,818	126,028	126,224	126,524	126,963	127,537	128,244	129,070	129,959	130,840	131,606	1,534,279
Deferred Taxes	122,849	126,250	128,248	129,960	132,476	136,198	141,131	147,247	154,435	162,272	170,117	177,086	1,728,269
Gross Up for Income Tax	15,270	11,862	9,555	7,505	4,863	1,293	(3,219)	(8,654)	(14,937)	(21,762)	(28,641)	(34,910)	(61,775)
Total Income Statement Expense	**359,188**	**359,533**	**359,433**	**359,292**	**359,466**	**360,056**	**361,052**	**362,440**	**364,170**	**366,073**	**367,918**	**369,384**	**4,348,005**
Revenue Requirement **Total**	**649,149**	**649,647**	**649,007**	**648,253**	**648,289**	**649,374**	**651,481**	**654,573**	**658,519**	**662,893**	**667,112**	**670,362**	**7,858,658**

TIMP
Capital Related Revenue Requirements 2015-2018

TIMP **Transmission, Distribution & Software**	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
Plant In-Service	67,941,810	68,343,905	68,882,309	69,865,474	71,071,904	73,055,709	75,477,340	79,373,206	84,641,836	88,432,467	91,642,117	94,304,472	94,304,472
Less Accumulated Book Depreciation Reserve	3,839,628	3,972,411	4,105,795	4,240,151	4,375,906	4,513,699	4,654,306	4,798,950	4,949,448	5,105,735	5,266,493	5,431,003	5,431,003
Less Accumulated Deferred Taxes	14,182,441	14,452,808	14,731,826	15,024,431	15,336,805	15,677,849	16,058,929	16,497,036	17,020,070	17,628,249	18,302,210	19,031,590	19,031,590
End Of Month Rate Base	**49,919,741**	**49,918,686**	**50,044,688**	**50,600,893**	**51,359,193**	**52,864,162**	**54,764,105**	**58,077,221**	**62,672,318**	**65,698,484**	**68,073,414**	**69,841,879**	**69,841,879**
Return on Rate Base													
Debt Return	94,373	94,431	94,549	95,194	96,437	98,578	101,798	106,729	114,209	121,417	126,526	130,445	1,274,686
Equity Return	207,454	207,581	207,841	209,259	211,992	216,698	223,777	234,616	251,058	266,904	278,134	286,749	2,802,063
Total Return on Rate Base	**301,828**	**302,011**	**302,389**	**304,453**	**308,429**	**315,276**	**325,576**	**341,345**	**365,267**	**388,322**	**404,660**	**417,194**	**4,076,749**
Income Statement Items													
Property Taxes	103,657	103,657	103,657	103,657	103,657	103,657	103,657	103,657	103,657	103,657	103,657	103,657	1,243,885
Book Depreciation	132,235	132,783	133,384	134,356	135,755	137,793	140,607	144,644	150,499	156,286	160,759	164,510	1,723,610
Deferred Taxes	262,280	270,367	279,018	292,605	312,374	341,044	381,080	438,107	523,034	608,179	673,961	729,380	5,111,429
Gross Up for Income Tax	(121,712)	(129,902)	(138,573)	(151,482)	(169,791)	(195,820)	(231,810)	(282,541)	(357,879)	(433,861)	(493,279)	(543,933)	(3,250,582)
Total Income Statement Expense	**376,460**	**376,906**	**377,485**	**379,136**	**381,995**	**386,674**	**393,535**	**403,867**	**419,311**	**434,261**	**445,098**	**453,615**	**4,828,342**
Revenue Requirement **Total**	**678,288**	**678,917**	**679,874**	**683,589**	**690,424**	**701,949**	**719,110**	**745,212**	**784,578**	**822,583**	**849,758**	**870,808**	**8,905,091**

DIMP
Capital Related Revenue Requirements 2015-2018

DIMP Transmission, Distribution & Software	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Rate Base													
Plant In-Service	1,102,697	1,128,280	1,173,169	1,240,769	1,368,116	1,505,931	1,750,532	2,768,217	4,627,668	6,571,349	9,018,156	12,064,627	12,064,627
Less Accumulated Book Depreciation Reserve	31,851	34,196	36,615	39,152	41,894	44,914	48,337	53,086	60,859	72,629	89,014	111,172	111,172
Less Accumulated Deferred Taxes	268,549	327,077	387,451	450,760	519,143	594,363	679,326	796,368	987,750	1,278,769	1,684,769	2,236,825	2,236,825
End Of Month Rate Base	**802,297**	**767,006**	**749,103**	**750,857**	**807,079**	**866,653**	**1,022,870**	**1,918,763**	**3,579,059**	**5,219,951**	**7,244,373**	**9,716,630**	**9,716,630**
Return on Rate Base													
Debt Return	1,506	1,484	1,434	1,419	1,474	1,583	1,787	2,782	5,200	8,322	11,789	16,042	54,823
Equity Return	3,516	3,466	3,348	3,312	3,440	3,696	4,173	6,496	12,141	19,431	27,525	37,456	128,001
Total Return on Rate Base	**5,022**	**4,950**	**4,782**	**4,731**	**4,914**	**5,279**	**5,960**	**9,278**	**17,341**	**27,754**	**39,315**	**53,498**	**182,824**
Income Statement Items													
Property Taxes	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	19,025
Book Depreciation	2,238	2,345	2,419	2,537	2,742	3,021	3,423	4,749	7,773	11,770	16,385	22,158	81,558
Deferred Taxes	55,856	58,529	60,373	63,309	68,383	75,220	84,962	117,042	191,382	291,018	406,000	552,056	2,024,132
Gross Up for Income Tax	(54,699)	(57,471)	(59,442)	(62,472)	(67,577)	(74,395)	(84,032)	(115,233)	(187,352)	(284,206)	(396,202)	(538,714)	(1,981,796)
Total Income Statement Expense	**4,980**	**4,988**	**4,936**	**4,959**	**5,134**	**5,431**	**5,938**	**8,144**	**13,389**	**20,168**	**27,768**	**37,086**	**142,919**
Revenue Requirement **Total**	**10,002**	**9,938**	**9,718**	**9,690**	**10,048**	**10,710**	**11,898**	**17,422**	**30,730**	**47,921**	**67,082**	**90,584**	**325,743**

DIMP
Capital Related Revenue Requirements 2015-2018

DIMP **Transmission, Distribution & Software**	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
Plant In-Service	12,448,476	12,404,073	12,439,892	12,545,396	15,159,499	15,157,089	15,118,724	15,838,563	21,766,436	23,112,256	23,862,771	24,690,429	24,690,429
Less Accumulated Book Depreciation Reserve	136,935	163,055	189,166	215,426	242,296	269,663	296,987	325,027	360,053	402,725	447,599	494,133	494,133
Less Accumulated Deferred Taxes	2,395,017	2,555,502	2,715,874	2,876,820	3,036,598	3,194,537	3,350,467	3,508,918	3,712,849	3,966,417	4,233,625	4,511,170	4,511,170
End Of Month Rate Base	**9,916,523**	**9,685,515**	**9,534,852**	**9,453,151**	**11,880,604**	**11,692,889**	**11,471,271**	**12,004,619**	**17,693,534**	**18,743,114**	**19,181,547**	**19,685,126**	**19,685,126**
Return on Rate Base													
Debt Return	18,570	18,540	18,179	17,959	20,178	22,297	21,909	22,204	28,090	34,463	35,870	36,761	295,021
Equity Return	41,393	41,328	40,523	40,033	44,979	49,701	48,838	49,495	62,614	76,821	79,958	81,944	657,625
Total Return on Rate Base	**59,963**	**59,868**	**58,702**	**57,993**	**65,157**	**71,997**	**70,747**	**71,699**	**90,703**	**111,284**	**115,828**	**118,705**	**952,646**
Income Statement Items													
Property Taxes	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	222,374
Book Depreciation	25,763	26,120	26,111	26,260	44,693	63,014	62,973	63,689	70,676	78,321	80,524	82,183	650,327
Deferred Taxes	158,193	160,485	160,371	160,946	159,779	157,938	155,930	158,451	203,931	253,569	267,208	277,546	2,274,346
Gross Up for Income Tax	(132,735)	(135,128)	(135,579)	(136,513)	(131,829)	(126,613)	(125,166)	(127,283)	(164,584)	(205,374)	(217,123)	(226,304)	(1,864,232)
Total Income Statement Expense	**69,752**	**70,008**	**69,434**	**69,223**	**91,174**	**112,871**	**112,268**	**113,389**	**128,554**	**145,047**	**149,140**	**151,955**	**1,282,814**
Revenue Requirement													
Total	**129,715**	**129,876**	**128,136**	**127,216**	**156,330**	**184,868**	**183,016**	**185,088**	**219,257**	**256,330**	**264,968**	**270,660**	**2,235,461**

DIMP
Capital Related Revenue Requirements 2015-2018

DIMP **Transmission, Distribution & Software**	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
Plant In-Service	24,886,141	25,074,462	25,259,130	26,151,261	27,581,135	29,375,165	31,531,831	34,048,949	36,750,538	39,280,768	41,461,884	42,817,984	42,817,984
Less Accumulated Book Depreciation Reserve	541,742	589,754	638,159	687,695	739,671	795,036	854,554	918,983	988,897	1,064,310	1,144,674	1,228,756	1,228,756
Less Accumulated Deferred Taxes	4,760,362	5,011,740	5,265,241	5,524,592	5,796,893	6,087,335	6,400,039	6,739,080	7,107,660	7,505,956	7,931,118	8,376,728	8,376,728
End Of Month Rate Base	**19,584,038**	**19,472,968**	**19,355,730**	**19,938,974**	**21,044,571**	**22,492,794**	**24,277,239**	**26,390,887**	**28,653,981**	**30,710,502**	**32,386,092**	**33,212,500**	**33,212,500**
Return on Rate Base													
Debt Return	37,142	36,941	36,725	37,166	38,764	41,179	44,237	47,924	52,063	56,149	59,679	62,045	550,015
Equity Return	81,647	81,206	80,731	81,700	85,212	90,521	97,243	105,347	114,447	123,429	131,188	136,390	1,209,063
Total Return on Rate Base	**118,789**	**118,147**	**117,457**	**118,866**	**123,975**	**131,701**	**141,479**	**153,271**	**166,511**	**179,578**	**190,867**	**198,436**	**1,759,077**
Income Statement Items													
Property Taxes	37,924	37,924	37,924	37,924	37,924	37,924	37,924	37,924	37,924	37,924	37,924	37,924	455,091
Book Depreciation	83,258	83,662	84,054	85,186	87,626	91,014	95,167	100,079	105,564	111,062	116,014	119,731	1,162,416
Deferred Taxes	249,191	251,378	253,501	259,351	272,301	290,442	312,704	339,041	368,580	398,296	425,162	445,610	3,865,557
Gross Up for Income Tax	(197,487)	(200,037)	(202,546)	(207,850)	(218,629)	(233,454)	(251,501)	(272,744)	(296,562)	(320,645)	(342,672)	(359,935)	(3,104,062)
Total Income Statement Expense	**172,887**	**172,927**	**172,934**	**174,611**	**179,222**	**185,927**	**194,294**	**204,300**	**215,506**	**226,637**	**236,428**	**243,331**	**2,379,002**
Revenue Requirement **Total**	**291,676**	**291,074**	**290,391**	**293,477**	**303,197**	**317,627**	**335,773**	**357,571**	**382,017**	**406,215**	**427,295**	**441,767**	**4,138,079**

DIMP
Capital Related Revenue Requirements 2015-2018

DIMP **Transmission, Distribution & Software**	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
Plant In-Service	43,096,815	43,432,881	43,768,954	44,421,163	45,921,310	47,833,953	49,588,685	52,549,623	54,792,731	57,236,677	59,038,978	59,576,677	59,576,677
Less Accumulated Book Depreciation Reserve	1,314,557	1,401,003	1,488,156	1,576,348	1,666,802	1,760,843	1,858,738	1,961,589	2,069,910	2,183,156	2,300,866	2,421,035	2,421,035
Less Accumulated Deferred Taxes	8,599,248	8,823,487	9,049,630	9,278,458	9,513,091	9,757,242	10,011,812	10,279,312	10,561,774	10,857,420	11,165,294	11,480,212	11,480,212
End Of Month Rate Base	**33,183,010**	**33,208,390**	**33,231,168**	**33,566,357**	**34,741,417**	**36,315,869**	**37,718,135**	**40,308,722**	**42,161,047**	**44,196,100**	**45,572,818**	**45,675,430**	**45,675,430**
Return on Rate Base													
Debt Return	62,799	62,795	62,841	63,179	64,608	67,208	70,024	73,800	78,003	81,679	84,906	86,306	858,149
Equity Return	138,047	138,039	138,139	138,883	142,023	147,740	153,929	162,231	171,468	179,551	186,645	189,720	1,886,415
Total Return on Rate Base	**200,846**	**200,834**	**200,980**	**202,063**	**206,631**	**214,948**	**223,953**	**236,031**	**249,471**	**261,230**	**271,551**	**276,026**	**2,744,564**
Income Statement Items													
Property Taxes	65,768	65,768	65,768	65,768	65,768	65,768	65,768	65,768	65,768	65,768	65,768	65,768	789,216
Book Depreciation	121,450	122,096	122,802	123,841	126,103	129,690	133,544	138,501	143,970	148,896	153,359	155,818	1,620,071
Deferred Taxes	222,520	224,239	226,143	228,829	234,632	244,151	254,570	267,500	282,462	295,646	307,874	314,918	3,103,484
Gross Up for Income Tax	(130,387)	(132,153)	(134,031)	(136,256)	(139,981)	(145,692)	(151,991)	(159,369)	(168,168)	(175,961)	(183,474)	(188,514)	(1,845,976)
Total Income Statement Expense	**279,351**	**279,950**	**280,682**	**282,182**	**286,523**	**293,917**	**301,892**	**312,400**	**324,032**	**334,349**	**343,527**	**347,990**	**3,666,796**
Revenue Requirement **Total**	**480,197**	**480,784**	**481,662**	**484,245**	**493,154**	**508,866**	**525,845**	**548,431**	**573,503**	**595,579**	**615,078**	**624,016**	**6,411,360**

216B.1635 RECOVERY OF GAS UTILITY INFRASTRUCTURE COSTS.

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

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

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

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

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

(c) "Gas utility projects" means:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Compliance Matrix

Petition Requirements	Reference
Minnesota Statute § 216B.1635	
Subd. 2. **Gas infrastructure filing.** A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c). The report and petition must be made at least 150 days in advance of implementation of the rate schedule, provided that the rate schedule will not be implemented until the petition is approved by the commission pursuant to subdivision 5. The report must be for a forecast period of one year.	*See IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2016, REVENUE REQUIREMENTS FOR 2017, AND REVISED ADJUSTMENT FACTORS* Report and Petition Submitted November 1, 2016 Docket No. G002/M-16-____
Subd. 3. **Gas infrastructure project plan report.** The gas infrastructure project plan report required to be filed under subdivision 2 shall include all pertinent information and supporting data on each proposed project including, but not limited to, project description and scope, estimated project costs, and project in-service date.	Introduction Sections III.A Sections IV.B.,C.,E.,G.,J.,K. Attachments B,B1,B2,C,C1, C2(a),(C2b),E,F,I
Subd. 4. **Cost recovery petition for utility's facilities.** Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section, including a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs. A gas utility's petition for approval of a rate schedule to recover gas utility infrastructure costs outside of a general rate case under section 216B.16 is subject to the following: (1) a gas utility may submit a filing under this section no more than once per year; and (2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:	____________________

Compliance Matrix

Petition Requirements	Reference
(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;	Introduction Sections III.A Sections IV.B.,C.,E.,G.,J.,K. Attachments B,B1,B2,C,C1, C2(a),C2(b),E,F,H,I
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	Introduction Section III.A. Section IV.B.,K. Attachments B,B1,B2,C,C1, C2(a),C2(b)
(iii) a description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;	Section IV.J. Attachment K
(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;	Introduction Section IV.A.,B.,C.,D.,E.,G., H. Conclusion Attachments B,B1,C,C1,I
(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;	Section IV.A. Section V.A.,C. Attachments E,F,I,K,M,N, O,P,Q, S
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	Introduction Section III.A. Section IV.B.,E.,G.,K.,L.,M. Attachments B,B1,C,C1,D,E, F,I,L,M,N
(vii) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges;	Section IV.L. Attachment L
(viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and	Section IV.M. Attachment L

Compliance Matrix

Petition Requirements	Reference
(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.	Introduction Section III.A.4. Sections IV.A.,L.,M. Section VI. Conclusion
Subd. 6. **Rate of return.** The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case.	Section III.B. Section VI. Attachment S
In the Matter of the Petition of Northern States Power Company for Deferred Accounting Treatment of Costs Relating to Identifying and Eliminating Sewer/Natural Gas Line Conflicts **Minnesota Public Utilities Commission** ORDER GRANTING DEFERRED ACCOUNTING TREATMENT SUBJECT TO CONDITIONS AND REPORTING REQUIREMENTS **January 12, 2011 Docket G002/M-10-422**	
6. In any future filing seeking rate recovery of costs deferred under this order, the Company shall include the following:	___________________
A. Justification for the outsourcing of any tasks required to implement the inspection and remediation plan.	Section IV.H.
B. Details of the final resolution of the Notice of Probable Violation and the status of any proposed penalties.	*See In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider* Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.H. Current Petition - Section IV.I.

Compliance Matrix

Petition Requirements	Reference
C. Discussion and explanation of any legal actions or settlements regarding the natural gas explosion that led to the Notice of Probable Violation.	*See In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider* Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.H. Current Petition - Section IV.I.
D. Discussion and analysis regarding any potential third-party recovery for the costs of the plan.	*See In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider* Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.I. Current Petition - Section IV.I.
E. Discussion, analysis, and documentation demonstrating that plan costs were prudent.	Section IV.C.,D.,E. Conclusion Attachment I
F. Analysis of what it would have cost to conduct the plan over a ten-year period beginning in 2003.	Petition Submitted August 1, 2014 Docket No. G002/M-14-336 Section IV.J.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company for Approval of Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs **Minnesota Public Utilities Commission** ORDER **January 28, 2013 Docket G002/M-12-248**	
g. Xcel shall include in the initial filing in its next natural gas rate case, justification and supporting testimony regarding all deferred TIMP and DIMP costs for which it seeks rate recovery.	Section III.A. Sections IV.D.,F.,G. Attachment I
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for approval of a Gas Utility Infrastructure Cost Rider (GUIC) True-up Report for 2015, Forecasted 2016 GUIC Revenue Requirement, and Revised GUIC Adjustment Factors **Minnesota Public Utilities Commission** ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES **August 18, 2016 Docket G002/M-15-808**	
1. Xcel shall provide an updated 2015 GUIC True-up Report for informational purposes.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Current Petition Attachments M,N
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.	Section VII. Attachments B2,C2(a),C2(b)

Compliance Matrix

Petition Requirements	Reference
4. The Federal Code Mitigation (FCM) project is an eligible GUIC project. Xcel may recover the costs of this project through the GUIC Rider to the extent its costs are not included in base rates.	Section IV.K. Attachments C,C1,C2(a),C2(b)
5. The Commission approves a GUIC tracker year ending March 31. Xcel is authorized to recover the Commission-approved 2016 revenue requirements over the 15-month period, January 1, 2016 through March 31, 2017. Xcel shall recalculate the GUIC rate adjustment factors to recover the remaining Commission-approved 2016 revenue requirements over the remaining months through March 31, 2017.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808
6. Xcel shall adjust the projected GUIC true-up over recovery to actual amounts, both the 2015 recovery and revenue requirement amounts and the 2016 recovery activity balances, proximate to the implementation date of the 2016 factors.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808 Current Petition Attachments M,N
7. Within ten days of the date of this order, Xcel shall make a compliance filing to provide the final rate adjustment factors that reflect the Commission's decisions in this matter, including any underlying schedules and all related tariff changes.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808
8. Xcel shall modify the proposed customer notice to read: This month's Resource Adjustment includes ~~the addition of the~~ an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $x.xxxx per therm for Residential customers; $x.xxxx per therm for Commercial Firm customers; $x.xxxx per therm for Commercial Demand Billed customers; and $x.xxxx per therm for Interruptible customers. Questions? Contact us at 1-800-895-4999.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808
9. Xcel shall use the following capital structure: 52.50 percent equity, 45.61 percent long-term debt, and 1.89 percent short-term debt.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808

Compliance Matrix

Petition Requirements	Reference
10. The Commission makes the following determinations concerning the rate of return and its components: a. the cost of long-term debt approved in the last GUIC case, 4.94%, is appropriate. b. the cost of short-term debt should be updated to reflect the 1.12% cost in Xcel's electric rate case in Docket No. E-002/GR-13-868. c. a cost of equity of 9.64% as recommended by the Department is appropriate. d. an overall rate of return of 7.34% is appropriate.	Compliance Submitted August 29, 2016 Docket No. G002/M-15-808
11. As part of Xcel's next GUIC petition, the Company shall file a cost/revenue study based on 2015 actuals reconciled back to Xcel's 2015 Jurisdictional Annual Report.	Section IV.I. Attachment J
12. In future GUIC filings, Xcel shall provide specific information about each individual project in the GUIC Rider that sufficiently, (1) describes what the project is, (2) explains why the project is necessary, (3) discusses what benefits ratepayers will receive from the project, and (4) identifies the agency, regulation, or order that requires the project.	Introduction Sections III.A.2.,3., Sections IV.B.1.,C.1. Attachments B,B1,B2,C,C1 C2(a),C2(b)

O&M BUDGET ESTIMATES

DEFERRED ITEMS (Actual O&M Expense Only)	2010	2011	2012	2013	2014			Total	
11990774 - MN Rider Amortization									
TIMP	$ -	$ -	$ 580,929	$ 3,180,143	$ 340,062			$ 4,101,134	[A]
DIMP	$ 4,175,186	$ 3,639,148	$ 3,538,635	$ 3,630,020	$ 3,686,292			$ 18,669,281	[B]

	2015 YE Actuals	2016 YE Forecast	2017 YE Budget	2018 YE Budget	2019 YE Budget	2020 YE Budget	2021 YE Budget	Total
5 Year Amortization								
TIMP (annual amt. equals [A]/5)	$ 820,227	$ 820,227	$ 820,227	$ 820,227	$ 820,227			$ 4,101,134
DIMP (annual amt. equals [B]/5)	$ 3,733,856	$ 3,733,856	$ 3,733,856	$ 3,733,856	$ 3,733,856			$ 18,669,281
Grand Total	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**	**$ 4,554,083**	**$ -**	**$ -**	**$ 22,770,415**

MN GUIC RIDER - INCREMENTAL O&M

Subledger Full Desc	2015 YE Actuals	2016 YE Forecast	2017 YE Budget	2018 YE Budget	2019 YE Budget	2020 YE Budget	2021 YE Budget	Total
TIMP								
MN Transmission Pipeline Assessments	$ 1,437,470	$ 200,000	$ 1,300,000	$ 1,140,000	$ 1,700,000	$ 1,700,000	$ 1,700,000	$ 9,177,470
MN East Metro Pipeline Replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total TIMP	**$ 1,437,470**	**$ 200,000**	**$ 1,300,000**	**$ 1,140,000**	**$ 1,700,000**	**$ 1,700,000**	**$ 1,700,000**	**$ 9,177,470**
MN Allocator (2015-2021 Load Dispatch)	88.9069%	88.5739%	88.2300%	87.9943%	87.8159%	87.9455%	88.0415%	
Estimated MN TIMP O&M	$ 1,278,010	$ 177,148	$ 1,146,990	$ 1,003,135	$ 1,492,870	$ 1,495,074	$ 1,496,706	$ 8,089,932
less TIMP incl in MN base rates	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (480,000)	$ (3,360,000)
MN TIMP not in base rates	**$ 798,010**	**$ (302,852)**	**$ 666,990**	**$ 523,135**	**$ 1,012,870**	**$ 1,015,074**	**$ 1,016,706**	**$ 4,729,932**
DIMP								
MN IP Line Assessments	$ 61,091	$ 550,000	$ 300,000	$ -	$ 200,000	$ 300,000	$ 300,000	$ 1,711,091
MN Poor Performing Mains	$ 65,245	$ 137,500	$ 243,000	$ 243,000	$ 243,000	$ 243,000	$ 243,000	$ 1,417,745
MN Poor Performing Services	$ 460	$ -	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 180,460
MN Federal Code Mitigation	$ -	$ 472,500	$ 472,000	$ 472,000	$ -	$ -	$ -	$ 1,416,500
MN Sewer Conflict Investigation	$ 3,415,261	$ 3,277,500	$ 3,500,000	$ 3,500,000	$ 3,500,000	$ -	$ -	$ 17,192,761
MN DIMP not in base rates	**$ 3,542,056**	**$ 4,437,500**	**$ 4,551,000**	**$ 4,251,000**	**$ 3,979,000**	**$ 579,000**	**$ 579,000**	**$ 21,918,556**
Incremental TIMP + DIMP O&M	**$ 4,340,067**	**$ 4,134,648**	**$ 5,217,990**	**$ 4,774,135**	**$ 4,991,870**	**$ 1,594,074**	**$ 1,595,706**	**$ 26,648,489**

2015 Annual Report/GUIC Reconciliation

	GUIC Rider			Base Rates & PGA			MN Gas 2015 Annual Report			
Amounts in $000's	Dec - 2014	Dec - 2015	BOY/EOY Avg	Dec - 2014	Dec - 2015	BOY/EOY Avg	Dec - 2014	Dec - 2015	BOY/EOY Avg	Annual Report Page Reference
Rate Base										
Plant Investment	$ 22,932	$ 53,708	$ 38,320	$ 1,070,094	$ 1,110,510	$ 1,090,302	$ 1,093,026	$ 1,164,217	$ 1,128,622	G-2; G-16 + G-16A; G-34A
Depreciation Reserve	349	1,087	718	523,110	546,053	534,581	523,459	547,140	535,300	G-2; G-19 + G-19A; G-34A
Net Utility Plant	22,583	52,620	37,602	546,984	564,457	555,720	569,567	617,077	593,322	
CWIP				9,244	15,130	12,187	9,244	15,130	12,187	G-2; G-34A
Accumulated Deferred Taxes	3,254	9,686	6,470	161,565	159,674	160,620	164,819	169,360	167,090	sum G-29A
DTA - NOL Average Balance			-	(10,276)	(4)	(5,140)	(10,276)	(4)	(5,140)	G-29A; G-34B
Total Accum Deferred Taxes	3,254	9,686	6,470	151,290	159,669	155,480	154,544	169,356	161,950	G-29A
Cash Working Capital										
Materials and Supplies				763	763	763	763	763	763	G-34A
Fuel Inventory				27,935	27,935	27,935	27,935	27,935	27,935	G-34A
Non-plant Assets and Liabilities				(297)	(1,890)	(1,093)	(297)	(1,890)	(1,093)	G-34A
Prepaids and Other				(384)	(384)	(384)	(384)	(384)	(384)	G-34A
Regulatory Amortizations										
Total Other Rate Base Items				28,017	26,423	27,220	28,017	26,423	27,220	
Total Rate Base	**$ 19,329**	**$ 42,934**	**$ 31,131**	**$ 432,955**	**$ 446,340**	**$ 439,648**	**$ 452,284**	**$ 489,275**	**$ 470,779**	**G-34; G-34A**
	4.27%	8.78%	6.61%	95.73%	91.22%	93.39%	100.00%	100.00%	100.00%	
Revenues										
Operating Revenues		$ 13,688			$ 474,268			$ 487,955		G-2; G-30; G-34
Expenses										
Operating Expenses:										
Production					1,814			1,814		G-33
Purchased Gas					249,457			249,457		G-33
Natural Gas Storage					3,040			3,040		G-33
Gas Transmission		798			47,095			47,893		G-33
Gas Distribution		3,542			28,320			31,862		G-33
Customer Accounting					11,275			11,275		G-33
Customer Service & Information					13,522			13,522		G-33
Sales, Econ Dvlp & Other					7			7		G-33
Administrative & General					19,987			19,987		G-33
Total Operating Expenses		4,340			374,518			378,858		G-2; G-30
Book Depreciation		738			37,860			38,598		G-30
Amortization		4,554			2,433			6,987		G-30; G-30-1
Total Depreciation and Amortization		5,292			40,293			45,585		G-2
Taxes:										
Total Federal Income Taxes		(3,994)			4,909			915		G-30; G-42A
Total State Income Taxes		(1,240)			1,524			284		G-30; G-42A
Property Taxes		423			17,110			17,533		G-42A
Deferred Income Tax & ITC		6,432			5,390			11,822		G-42A
Payroll & Other Taxes					2,269			2,269		G-42A
Total Taxes Other Than Income		6,855			24,769			31,624		G-42A
Total Taxes		1,622			31,202			32,824		G-42A
Total Expenses		11,254			446,013			457,267		G-2; G-30; G-34
Net Operating Income		2,434			28,254			30,688		G-30; G-34
AFUDC					987			987		G-2; G-32; G-34
Net Income		**$ 2,434**			**$ 29,242**			**$ 31,676**		**G-2; G-34**
		7.68%			92.32%			100.00%		
Revenue Requirements Calculation										
ROR		7.57%			7.57%			7.57%		
Average Rate Base		22,974	GUIC 13 Mo Ave		439,648			470,779		
Required Operating Income		1,739			33,281			35,638		
Net Income		2,434			29,242			31,676		
Income Deficiency		(695)			4,040			3,962		
Revenue Conversion Factor		1.705611			1.705611			1.705611		
Revenue Deficiency		(1,185)			6,890			6,758		
Revenue Requirements		**$ 12,503**			**$ 481,158**			**$ 490,916**		
		2.55%			98.01%			100.00%		

Universal Inputs

Dates	Jan-15 Actuals	Jan-16 Forecast	Jan-17 Forecast	Jan-18 Forecast

Depreciation

Current

		Software	Distribution	Transmission
2010	Book Depreciation Life (yrs)	5.00	45.03	45.01
2010	Net Salvage %	0.00%	-18.41%	-30.00%
2011	Book Depreciation Life (yrs)	5.00	45.03	45.01
2011	Net Salvage %	0.00%	-18.41%	-30.00%
2012	Book Depreciation Life (yrs)	5.00	45.03	45.01
2012	Net Salvage %	0.00%	-18.41%	-30.00%
2013	Book Depreciation Life (yrs)	5.00	45.82	75.00
2013	Net Salvage %	0.00%	-15.74%	-15.00%
2014	Book Depreciation Life (yrs)	5.00	45.82	75.00
2014	Net Salvage %	0.00%	-15.74%	-15.00%
2015	Book Depreciation Life (yrs)	5.00	46.14	75.00
2015	Net Salvage %	0.00%	-16.39%	-15.00%
2016	Book Depreciation Life (yrs)	5.00	46.14	75.00
2016	Net Salvage %	0.00%	-16.39%	-15.00%
2017	Book Depreciation Life (yrs)	5.00	46.14	75.00
2017	Net Salvage %	0.00%	-16.39%	-15.00%

	Jan-15	Jan-16	Jan-17	Jan-18
Net Salvage %				
Software	0.00%	0.00%	0.00%	0.00%
Distribution	-16.39%	-16.39%	-16.39%	-16.39%
Transmission	-15.00%	-15.00%	-15.00%	-15.00%
Book Depreciation Lives				
Software	5.00	5.00	5.00	5.00
Distribution	46.14	46.14	46.14	46.14
Transmission	75.00	75.00	75.00	75.00
Book Depreciation Rates				
Software	20.00%	20.00%	20.00%	20.00%
Distribution	2.52%	2.52%	2.52%	2.52%
Transmission	1.53%	1.53%	1.53%	1.53%

Book Depreciation Rate: Final Period

Software	100%
Distribution	100%
Transmission	100%

Tax Rates

	Jan-15	Jan-16	Jan-17	Jan-18
Income Tax Rates				
State Income Tax Rate	9.8000%	9.8000%	9.8000%	9.8000%
Federal Income Tax Rate	35.0000%	35.0000%	35.0000%	35.0000%
Composite Income Tax Rate				
State Composite Income Tax Rate	41.3700%	41.3700%	41.3700%	41.3700%
Company Composite Income Tax Rate	40.8029%	40.8029%	40.8029%	40.8029%

Tax Depreciation Schedule: MACRS

Annual

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

Tax Depreciation Schedule: MACRS

Mid-Quarter 2010

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

Bonus Depreciation Rate

2014	50.00%
2015	50.00%
2016	50.00%
2017	50.00%
2018	40.00%
2019	30.00%

Cap Structure (Based on Previous Year's Actual Structure)

	Jan-15	Jan-16	Jan-17	Jan-18
Long Term Debt %	45.6100%	45.6100%	45.6100%	45.6100%
Long Term Debt Cost ($s as a % of total)	4.9400%	4.9400%	4.9400%	4.9400%
Short Term Debt %	1.8900%	1.8900%	1.8900%	1.8900%
Short Term Debt Cost ($s as a % of total)	1.1200%	1.1200%	1.1200%	1.1200%
Weighted Cost of Debt	2.27%	2.27%	2.27%	2.27%
Common Stock %	52.50%	52.50%	52.50%	52.50%
Common Stock Cost ($s as a % of total)	10.09%	9.64%	9.50%	9.50%
Preferred Stock %	0.00%	0.00%	0.00%	0.00%
Preferred Stock Cost ($s as a % of total)	0.00%	0.00%	0.00%	0.00%
Weighted Cost of Equity	5.30%	5.06%	4.99%	4.99%
Rate of Return	7.57%	7.33%	7.26%	7.26%

Property Tax Rates

	Jan-15	Jan-16	Jan-17	Jan-18
Percent Taxable	100.00%	100.00%	100.00%	100.00%
Asset Rate	1.843%	1.843%	1.843%	1.843%
Property Tax Rate	1.843%	1.843%	1.843%	1.843%

GUIC Rider in Relation to Last Approved Rate Case
Docket No. G002/GR-09-1153

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

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

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

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

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

	2015	2016	2017	2018	2019	2020	2021	
Revenue Collection Forecast	**13,688**	**12,851**	**14,726**	**23,617**	**27,918**	**29,530**	**31,718**	[C] Fn 2
% of GUIC Revenue as Compared to Base Revenue Approved in Docket G002/GR-09-1153 (2010 TY)	8.60%	8.08%	9.26%	14.84%	17.55%	18.56%	19.94%	= [C] / [A]
Capital Expenditures Forecast	**30,924**	**31,482**	**23,639**	**45,641**	**49,992**	**48,185**	**48,185**	[D]
% of GUIC Capital Expenditures as Compared to Expenditures Approved in Docket G002/GR-09-1153 (2010 TY)	103.46%	105.33%	79.09%	152.70%	167.26%	161.21%	161.21%	= [D] / [B]

Notes

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

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

MN GUIC Rider - Annual Tracker Summary for 2015-2021

	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Incremental Gas Utility Projects:							
Operations & Maintenance Expenses							
TIMP	1,278,010	177,148	1,146,990	1,003,135	1,492,870	1,495,074	1,496,706
DIMP	3,542,056	4,437,500	4,551,000	4,251,000	3,979,000	579,000	579,000
Gas O&M - Total	4,820,067	4,614,648	5,697,990	5,254,135	5,471,870	2,074,074	2,075,706
Capital-Related Revenue Requirements							
TIMP	3,283,015	5,934,188	7,858,658	8,905,091	12,365,366	16,334,302	20,124,550
DIMP	325,743	2,235,461	4,138,079	6,411,360	8,491,339	10,633,191	12,547,719
Gas Utility Projects - Capital RR Total	3,608,758	8,169,649	11,996,737	15,316,451	20,856,705	26,967,493	32,672,269
Deferred Gas Infrastructure Costs							
TIMP	820,227	820,227	820,227	820,227	820,227	-	-
DIMP	3,733,856	3,733,856	3,733,856	3,733,856	3,733,856	-	-
Gas Deferral Costs - Total	4,554,083	4,554,083	4,554,083	4,554,083	4,554,083	-	-
ADIT Prorate	-	134,029	108,767	156,574	153,016	55,916	82,211
Revenue Requirement in Base Rates	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)
GUIC True-up Carryover	-	(1,184,983)	261,276	-	-	-	-
Revenue Requirement (RR)	**12,502,907**	**15,807,425**	**22,138,854**	**24,801,243**	**30,555,675**	**28,617,482**	**34,350,186**
Revenue Collections (RC)	13,687,890	12,851,194	14,726,147	23,616,708	27,917,865	29,529,694	31,717,752
Collection Jan-March Current Impact		2,694,955	10,107,662	11,292,197	13,930,008	13,017,796	15,650,230
Collection Jan-March Future Impact			(2,694,955)	(10,107,662)	(11,292,197)	(13,930,008)	(13,017,796)
Balance	(1,184,983)	261,276	-	-	-	-	-

Northern States Power Company

Revenue Requirements Tracker for 2015-2018

2015 Tracker	Carryover	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual Total
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		778	1,782	-	79,556	267,747	227,227	13,450	3,812	133,817	165,876	257,219	126,746	1,278,010
DIMP		-	-	2,840	40,622	196,822	258,078	723,597	403,145	576,081	700,201	495,759	144,910	3,542,056
Gas O&M - Total		778	1,782	2,840	120,178	464,569	485,304	737,048	406,957	709,898	866,077	752,978	271,656	4,820,067
Capital-Related Revenue Requirements														
TIMP		245,916	244,062	241,947	238,765	235,649	234,052	231,818	229,924	228,240	320,943	415,529	416,169	3,283,015
DIMP		10,002	9,938	9,718	9,690	10,048	10,710	11,898	17,422	30,730	47,921	67,082	90,584	325,743
Gas Utility Projects - Capital RR Total		255,918	254,000	251,665	248,455	245,697	244,762	243,717	247,347	258,970	368,864	482,612	506,753	3,608,758
Deferred Gas Infrastructure Costs														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
Revenue Requirement in Base Rates		-	(270)	(267)	(12,219)	(46,850)	(48,208)	(69,327)	(38,264)	(66,149)	(66,149)	(66,149)	(66,147)	(480,000)
GUIC True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)		**636,203**	**635,018**	**633,745**	**735,922**	**1,042,923**	**1,061,365**	**1,290,944**	**995,547**	**1,282,226**	**1,548,299**	**1,548,947**	**1,091,768**	**12,502,907**
Revenue Collections (RC)		-	3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288	13,687,890
Monthly RR - RC		636,203	(2,667,268)	(1,456,923)	(405,543)	439,815	651,939	879,732	582,464	796,842	667,406	(53,131)	(1,256,520)	
Balance (RR - RC)		636,203	(2,031,065)	(3,487,988)	(3,893,530)	(3,453,715)	(2,801,776)	(1,922,044)	(1,339,580)	(542,738)	124,668	71,537	(1,184,983)	

Revenue Requirements Tracker for 2015-2018

2016 Tracker														
	Carryover	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Annual Total**
		Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		7,935	11,808	8,734	1,829	3,136	1,414	131	423	35,435	70,870	17,717	17,717	177,148
DIMP		(8,361)	24,614	7,973	19,764	351,428	237,412	658,004	640,296	626,599	516,306	681,745	681,720	4,437,500
Gas O&M - Total		(426)	36,422	16,707	21,593	354,564	238,826	658,135	640,718	662,034	587,176	699,462	699,437	4,614,648
Capital-Related Revenue Requirements														
TIMP		442,273	438,996	436,521	433,536	430,599	466,904	495,181	512,784	551,178	565,691	570,125	590,400	5,934,188
DIMP		129,715	129,876	128,136	127,216	156,330	184,868	183,016	185,088	219,257	256,330	264,968	270,660	2,235,461
Gas Utility Projects - Capital RR Total		571,988	568,872	564,657	560,752	586,930	651,772	678,197	697,872	770,435	822,021	835,094	861,061	8,169,649
Deferred Gas Infrastructure Costs:														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate		11,169	11,169	11,169	11,169	11,169	11,169	11,169	11,169	11,169	11,169	11,169	11,169	134,029
Revenue Requirement in Base Rates		-	(270)	(267)	(12,219)	(46,850)	(48,208)	(69,327)	(38,264)	(66,149)	(66,149)	(66,149)	(66,147)	(480,000)
2015 GUIC True-up Carryover	(1,184,983)	-	-	-	-	-	-	-	-	(296,246)	(296,246)	(296,246)	(296,246)	(1,184,983)
Revenue Requirement (RR)		**962,238**	**995,699**	**971,773**	**960,801**	**1,285,320**	**1,233,066**	**1,657,681**	**1,691,003**	**1,460,750**	**1,437,478**	**1,562,837**	**1,588,780**	**15,807,425**
Revenue Collections (RC)		3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733	339,298	620,485	944,036	12,851,194
Monthly RR - RC		(2,201,421)	(1,646,929)	(873,008)	(260,577)	679,036	801,172	1,235,507	1,245,159	1,292,017	1,098,180	942,352	644,744	
Collection Jan-Aug		-	-	-	-	-	-	-	-	(255,265)	(255,265)	(255,265)	(255,265)	
Balance (RR - RC)		(2,201,421)	(3,848,350)	(4,721,359)	(4,981,936)	(4,302,900)	(3,501,728)	(2,266,220)	(1,021,061)	1,036,752	1,879,667	2,566,753	2,956,232	

Recovery Timing	
2016 Revenue Requirement	15,807,425
Jan-Dec 2016 Recovery	12,851,194
Jan-March 2017 Recovery	2,694,955
Total Recovery	15,546,149
Difference	261,276

Revenue Requirements Tracker for 2015-2018

2017 Tracker														
	Carryover	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Annual Total**
		Forecast	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		-	882	882	29,998	115,581	118,228	169,402	93,524	167,637	204,694	180,872	65,290	1,146,990
DIMP		1,000	1,000	2,000	118,000	458,000	470,000	672,000	375,000	664,000	810,000	717,000	263,000	4,551,000
Gas O&M - Total		1,000	1,882	2,882	147,998	573,581	588,228	841,402	468,524	831,637	1,014,694	897,872	328,290	5,697,990
Capital-Related Revenue Requirements														
TIMP		649,149	649,647	649,007	648,253	648,289	649,374	651,481	654,573	658,519	662,893	667,112	670,362	7,858,658
DIMP		291,676	291,074	290,391	293,477	303,197	317,627	335,773	357,571	382,017	406,215	427,295	441,767	4,138,079
Gas Utility Projects - Capital RR Total		940,824	940,721	939,397	941,730	951,486	967,001	987,254	1,012,144	1,040,536	1,069,107	1,094,407	1,112,129	11,996,737
Deferred Gas Infrastructure Costs														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate		9,064	9,064	9,064	9,064	9,064	9,064	9,064	9,064	9,064	9,064	9,064	9,064	108,767
Revenue Requirement in Base Rates		(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
GUIC True-up Carryover	261,276	-	-	-	29,031	29,031	29,031	29,031	29,031	29,031	29,031	29,031	29,031	261,276
Revenue Requirement (RR)		**1,290,395**	**1,291,174**	**1,290,851**	**1,467,330**	**1,902,669**	**1,932,831**	**2,206,257**	**1,858,269**	**2,249,774**	**2,461,403**	**2,369,880**	**1,818,020**	**22,138,854**
Revenue Collections (RC)		1,060,372	893,057	741,527	1,573,714	987,337	605,766	572,013	545,468	633,888	1,234,940	2,326,142	3,551,925	14,726,147
Monthly RR - RC		230,023	398,117	549,324	(106,384)	915,333	1,327,065	1,634,244	1,312,802	1,615,887	1,226,462	43,738	(1,733,904)	
Collection Jan-March		-	-	-	430,269	430,269	430,269	430,269	430,269	430,269	430,269	430,269	430,269	
Balance (RR - RC)		2,924,979	3,323,096	3,872,420	323,884	1,669,486	3,426,820	5,491,333	7,234,404	9,280,560	10,937,291	11,411,298	10,107,662	

Recovery Timing	
2017 Revenue Requirement	22,138,854
Apr-Dec 2017 Recovery	12,031,192
Jan-March 2018 Recovery	10,107,485
Total Recovery	22,138,676
Difference	178

Revenue Requirements Tracker for 2015-2018

2018 Tracker														
	Carryover	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual Total
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		-	-	880	26,398	101,193	103,833	147,830	81,835	146,071	178,628	158,390	58,076	1,003,135
DIMP		1,000	1,000	2,000	110,000	428,000	439,000	628,000	350,000	620,000	756,000	671,000	245,000	4,251,000
Gas O&M - Total		1,000	1,000	2,880	136,398	529,193	542,833	775,830	431,835	766,071	934,628	829,390	303,076	5,254,135
Capital-Related Revenue Requirements														
TIMP		678,288	678,917	679,874	683,589	690,424	701,949	719,110	745,212	784,578	822,583	849,758	870,808	8,905,091
DIMP		480,197	480,784	481,662	484,245	493,154	508,866	525,845	548,431	573,503	595,579	615,078	624,016	6,411,360
Gas Utility Projects - Capital RR Total		1,158,485	1,159,701	1,161,536	1,167,834	1,183,578	1,210,815	1,244,955	1,293,643	1,358,082	1,418,162	1,464,836	1,494,824	15,316,451
Deferred Gas Infrastructure Costs														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate		13,048	13,048	13,048	13,048	13,048	13,048	13,048	13,048	13,048	13,048	13,048	13,048	156,574
Revenue Requirement in Base Rates		(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
GUIC True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)		**1,512,040**	**1,513,256**	**1,516,971**	**1,656,787**	**2,065,326**	**2,106,203**	**2,373,340**	**2,078,032**	**2,476,707**	**2,705,346**	**2,646,781**	**2,150,455**	**24,801,243**
Revenue Collections (RC)		3,978,172	3,354,214	2,775,099	1,775,434	1,112,314	687,984	664,963	616,967	737,311	1,352,726	2,603,141	3,958,384	23,616,708
Monthly RR - RC		(2,466,133)	(1,840,957)	(1,258,128)	(118,647)	953,012	1,418,219	1,708,377	1,461,065	1,739,396	1,352,620	43,640	(1,807,929)	
Collection Jan-March		-	-	-	504,716	504,716	504,716	504,716	504,716	504,716	504,716	504,716	504,716	
Balance (RR - RC)		7,641,530	5,800,572	4,542,444	386,069	1,843,797	3,766,732	5,979,825	7,945,606	10,189,718	12,047,054	12,595,410	11,292,197	

Recovery Timing	
2018 Revenue Requirement	24,801,243
Apr-Dec 2018 Recovery	13,509,223
Jan-March 2019 Recovery	11,292,191
Total Recovery	24,801,414
Difference	(171)

Revenue Requirements Category Descriptions

Attachments E and F to this Petition respectively provide the TIMP and DIMP annual revenue requirements for 2015-2021. 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 2017 plant in service for gas utility infrastructure projects (GUIC), the $67,485,509 for TIMP (Attachment E) and $42,817,984 for DIMP (Attachment F) reflect the dollar-value portion of the project in service as of December 31, 2017, 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 2017 book depreciation reserve for GUIC projects, the $3,707,394 for TIMP (Attachment E) and $1,228,756 for DIMP (Attachment F) reflect the amount of the plant in service that has been recovered as of December 31, 2017, which results in a decrease to rate base. Standard ratemaking methodology calls for the exclusion of this credit balance in an asset account (contra-asset) from plant in service in the determination of rate base.

Less Accum Deferred Taxes: This is a reduction to rate base. It reflects the tax timing differences between book and tax depreciation lives and other non-plant book/tax timing differences, multiplied by the tax rate. Over the life of an asset, the Accumulated Deferred Tax is zero. In the specific case of the 2017 accumulated deferred taxes for GUIC projects, the $13,920,161 for TIMP (Attachment E) and $8,376,728 for DIMP (Attachment F) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2017, 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 2017 debt return for GUIC projects, the $1,097,683 for TIMP (Attachment E) and $550,015 for DIMP (Attachment F) reflect the amount of debt return the Company is allowed for January 2017 - December 2017 based on the cost of debt and ratios approved in the most recent electric rate filing (Docket No. E002/GR-13-868) and the return on equity approved in the most recent gas rate filing (Docket No. G002/GR-09-1153).

Plus Equity Return: This category reflects the return the Company is allowed in order to recover its weighted cost of equity for financing its capital investments. In the specific case of the annual 2017 equity return for GUIC projects, the $2,412,969 for TIMP (Attachment E) and $1,209,063 for DIMP (Attachment F) reflect the amount of return on equity the Company is allowed for January 2017 - December 2017 based on the cost of debt and ratios approved in the most recent electric rate filing (Docket No. E002/GR-13-868) and the return on equity approved in the most recent gas rate filing (Docket No. G002/GR-09-1153).

The types of income statement categories, description and rationale for including costs in each category in the Company's proposed revenue requirements analysis are described below. For all 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 2017 property tax amount for GUIC projects, the $1,147,233 for TIMP (Attachment E) and $455,091 for DIMP (Attachment F) reflect property tax rates from the pay-2016 tax year using plant in service as of December 31, 2014 for property taxation.

Plus Book Depreciation: This category reflects the monthly/annual depreciation expense that is accumulated in the book depreciation reserve defined in part a) subsection ii). In the specific case of the annual 2017 book depreciation for GUIC projects, the $1,534,279 for TIMP (Attachment E) and $1,162,416 for DIMP (Attachment F) reflect the amount of plant in service that is being recovered through depreciation expense from January 2017 - December 2017 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 2017 deferred taxes for GUIC projects, the $1,728,269 for TIMP (Attachment E) and $3,865,557 for DIMP (Attachment F) reflect the January 1, 2017 - December 31, 2017 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 2017 current taxes for GUIC projects, the $(61,775) for TIMP (Attachment E) and $(3,104,062) for DIMP (Attachment F) reflect the amount of current income taxes the Company is anticipating to pay as a result of the taxable income being generated by GUIC projects.

ADIT Prorate Calculation

Annual	Monthly
2.2700%	0.1892%
5.0600%	0.4217%
3.5704%	0.2975%
10.9004%	0.9084% H

	Annual	Monthly
Debt Return %	2.2700%	0.1892%
Equity Return %	4.9900%	0.4158%
Tax RR on Equity Return @ 41.37 CTR	3.5210%	0.2934%
Rate Base Revenue Requirement Factor	10.7810%	0.8984% H

2016									2017				
Monthly DT Expense	Average Mo ADIT	Pro-Rated DT Expense	Average Mo Pro-Rate ADIT	Monthly Revenue Req	Days/Month		Pro-Rate Days	Pro-Rate Factor	Monthly DT Expense	Average Mo ADIT	Pro-Rated DT Expense	Average Mo Pro-Rate ADIT	Monthly Revenue Req
C = K	D = C (Mo Avg)	E = B*C	F = E (Mo Avg)	G = -(F-D)*H			A	B = A/365	C = K	D = C (Mo Avg)	E = B*C	F = E (Mo Avg)	G = -(F-D)*H
474,235	237,117	435,257	217,628	177	31	Jan	335	0.917808	372,040	186,020	341,461	170,731	137
477,306	712,888	401,460	635,987	699	28	Feb	307	0.841096	377,628	560,854	317,622	500,272	544
477,781	1,190,431	361,281	1,017,357	1,572	31	Mar	276	0.756164	381,749	940,543	288,665	803,415	1,232
478,367	1,668,505	322,407	1,359,201	2,810	30	Apr	246	0.673973	389,311	1,326,073	262,385	1,078,940	2,220
476,332	2,145,855	280,579	1,660,694	4,407	31	May	215	0.589041	404,777	1,723,116	238,430	1,329,348	3,538
497,075	2,632,559	251,942	1,926,954	6,409	30	Jun	185	0.506849	426,640	2,138,824	216,242	1,556,684	5,230
512,788	3,137,490	216,354	2,161,103	8,869	31	Jul	154	0.421918	453,835	2,579,062	191,481	1,760,545	7,354
527,311	3,657,540	177,697	2,358,128	11,803	31	Aug	123	0.336986	486,289	3,049,124	163,873	1,938,222	9,981
641,030	4,241,710	163,331	2,528,642	15,561	30	Sep	93	0.254795	523,015	3,553,776	133,261	2,086,789	13,180
764,551	4,944,501	129,869	2,675,242	20,613	31	Oct	62	0.169863	560,569	4,095,567	95,220	2,201,030	17,021
817,914	5,735,733	71,707	2,776,030	26,885	30	Nov	32	0.087671	595,279	4,673,491	52,189	2,274,734	21,551
871,933	6,580,656	2,389	2,813,078	34,223	31	Dec	1	0.002740	622,696	5,282,478	1,706	2,301,682	26,780
	36,884,985		22,130,044	134,029	365			Totals		30,108,927		18,002,392	108,767
Mth RR Factor	0.9084%		0.9084%						Mth RR Factor	0.8984%		0.8984%	
Annual RR	(335,051)		(201,022)						Annual RR	(270,504)		(161,737)	
		Total RR Adjustment	134,029								Total Company RR Adjustment	108,767	

Input Data
Monthly DT Expense

	K 2016	K 2017
Jan	474,235	372,040
Feb	477,306	377,628
Mar	477,781	381,749
Apr	478,367	389,311
May	476,332	404,777
Jun	497,075	426,640
Jul	512,788	453,835
Aug	527,311	486,289
Sep	641,030	523,015
Oct	764,551	560,569
Nov	817,914	595,279
Dec	871,933	622,696

Northern States Power Company

GUIC Rate Factor Determination for 2015-2018

Revenues	Jan-15 Actual	Feb-15 Actual	Mar-15 Actual	Apr-15 Actual	May-15 Actual	Jun-15 Actual	Jul-15 Actual	Aug-15 Actual	Sep-15 Actual	Oct-15 Actual	Nov-15 Actual	Dec-15 Actual
Monthly Inputs												
Revenue Requirement	636,203	635,018	633,745	735,922	1,042,923	1,061,365	1,290,944	995,547	1,282,226	1,548,299	1,548,947	1,091,768
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Carried-forward balance	636,203	-2,031,065	-3,487,988	-3,893,530	-3,453,715	-2,801,776	-1,922,044	-1,339,580	-542,738	124,668	71,537	-1,184,983
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153)												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	427,683.52	426,887.27	426,031.39	494,718.85	701,098.76	713,496.14	867,829.62	669,250.26	861,968.53	1,040,834.88	1,041,270.51	733,934.80
Commercial Firm	135,254.81	135,002.99	134,732.32	156,454.72	221,722.31	225,642.98	274,450.90	211,650.23	272,597.34	329,163.78	329,301.54	232,106.70
Commercial Demand Billed	13,366.62	13,341.74	13,314.99	15,461.71	21,911.81	22,299.28	27,122.74	20,916.43	26,939.56	32,529.77	32,543.38	22,938.06
Interruptible	35,958.82	35,891.87	35,819.91	41,595.02	58,947.05	59,989.40	72,965.47	56,269.29	72,472.68	87,511.42	87,548.05	61,707.85
Transport	23,939.04	23,894.47	23,846.56	27,691.26	39,243.11	39,937.04	48,575.66	37,460.43	48,247.59	58,259.40	58,283.79	41,081.06
Total	636,202.80	635,018.34	633,745.17	735,921.56	1,042,923.05	1,061,364.83	1,290,944.39	995,546.64	1,282,225.70	1,548,299.25	1,548,947.27	1,091,768.47
Sales by Customer Group (Billed by total Usage)												
Residential	69,329,287	59,695,740	45,753,721	25,845,215	11,164,131	7,009,553	6,608,509	6,694,477	8,791,180	20,055,698	40,206,278	59,123,398
Commercial Firm	37,201,235	32,273,605	26,445,582	13,039,826	7,876,474	3,950,082	4,053,841	4,421,990	5,148,287	10,543,900	21,125,735	32,225,244
Commercial Demand Billed	3,584,063	3,094,213	3,470,997	1,952,310	1,748,893	1,513,277	1,531,406	1,600,626	1,531,033	2,107,986	2,778,144	3,782,932
Interruptible	10,971,472	12,280,734	13,732,157	8,508,050	5,167,068	6,078,254	5,958,951	5,680,990	5,065,975	7,109,380	11,587,208	12,815,512
Transport	15,405,029	36,174,012	16,406,216	17,464,648	12,146,413	19,330,857	25,198,664	22,832,061	24,904,276	14,673,013	20,631,508	22,289,518
Total Therm Sales in Month	136,491,086	143,518,304	105,808,673	66,810,049	38,102,979	37,882,022	43,351,371	41,230,143	45,440,751	54,489,978	96,328,872	130,236,605
Flags												
Rate Change												
Rate Periods	0	0	0	0	0	0	0	0	0	0	0	0
Rate Period Calculations												
Revenue Requirement for Rate Period												
Remaining true-up in current calendar year												
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period												
Retail Dth Sales in Rate Period												
Cost Per therm												
Allocated Cost Per therm												
Residential												
Commercial Firm												
Commercial Demand Billed												
Interruptible												
Transport												
Revenues												
Residential												
Commercial Firm												
Commercial Demand Billed												
Interruptible												
Transport												
Forecast Revenues							0	0	0	0	0	0
Actual Revenues		3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288
Actual & Forecast Total	0	3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288
Annual Total												13,687,890

GUIC Rate Factor Determination for 2015-2018

Revenues	Jan-16 Actual	Feb-16 Actual	Mar-16 Actual	Apr-16 Actual	May-16 Actual	Jun-16 Actual	Jul-16 Actual	Aug-16 Actual	Sep-16 Forecast	Oct-16 Forecast	Nov-16 Forecast	Dec-16 Forecast
Monthly Inputs												
Revenue Requirement	970,599	971,085	963,800	941,038	933,892	995,654	999,676	1,050,707	1,130,397	1,217,417	1,177,338	1,203,306
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	-296,246	-296,246	-296,246	-296,246
Revenue Carried-forward balance	-2,201,421	-3,848,350	-4,721,359	-4,981,936	-4,302,900	-3,501,728	-2,266,220	-1,021,061	1,036,752	1,879,667	2,566,753	2,956,232
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	652,479.32	652,806.13	647,908.83	632,606.83	627,803.43	669,322.13	672,026.38	706,331.42	389,152.47	447,651.62	420,708.41	438,165.00
Commercial Firm	206,346.42	206,449.78	204,901.01	200,061.75	198,542.68	211,672.96	212,528.18	223,377.14	123,069.37	141,569.71	133,048.93	138,569.57
Commercial Demand Billed	20,392.28	20,402.50	20,249.44	19,771.20	19,621.08	20,918.68	21,003.20	22,075.35	12,162.39	13,990.69	13,148.62	13,694.20
Interruptible	54,859.22	54,886.70	54,474.94	53,188.38	52,784.52	56,275.33	56,502.70	59,387.01	32,719.20	37,637.70	35,372.37	36,840.08
Transport	36,521.70	36,539.99	36,265.87	35,409.36	35,140.50	37,464.45	37,615.82	39,536.00	21,782.31	25,056.73	23,548.62	24,525.73
Total	970,598.95	971,085.09	963,800.09	941,037.53	933,892.20	995,653.56	999,676.28	1,050,706.92	578,885.75	665,906.45	625,826.95	651,794.59
Sales by Customer Group (Billed by total Usage)												
Residential	68,347,473	56,468,255	46,220,639	25,081,110	14,740,988	8,906,845	6,435,105	6,570,745	8,647,552	18,724,809	38,318,515	59,364,541
Commercial Firm	36,782,234	30,859,812	26,556,962	13,434,879	9,702,243	4,956,830	3,909,831	4,147,409	5,295,143	10,881,204	21,341,201	33,661,319
Commercial Demand Billed	3,572,710	3,117,804	3,487,429	1,980,169	1,776,409	1,514,922	1,662,088	1,488,900	1,613,067	2,102,566	2,645,160	2,703,575
Interruptible	12,635,578	12,082,408	10,789,546	8,672,081	6,454,790	5,409,278	5,984,729	5,487,738	5,554,440	7,437,646	10,020,443	12,289,865
Transport	18,946,134	11,075,216	15,456,105	15,504,081	20,908,639	19,168,001	28,596,563	20,747,736	12,759,486	18,154,881	12,067,675	18,018,070
Total Therm Sales in Month	140,284,128	113,603,495	102,510,681	64,672,321	53,583,069	39,955,875	46,588,316	38,442,529	33,869,688	57,301,107	84,392,993	126,037,370
Flags												
Rate Change									x			
Rate Periods	0	0	0	0	0	0	0	0	1	1	1	1
Rate Period Calculations												
Revenue Requirement for Rate Period									4,728,458			
Remaining true-up in current calendar year									-2,206,044			
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period									2,522,414			
Retail Dth Sales in Rate Period									671,263,079			
Cost Per therm									$ 0.003758	$ 0.003758	$ 0.003758	$ 0.003758
Allocated Cost Per therm												
Residential									$ 0.010922	$ 0.010922	$ 0.010922	$ 0.010922
Commercial Firm									$ 0.006110	$ 0.006110	$ 0.006110	$ 0.006110
Commercial Demand Billed									$ 0.005274	$ 0.005274	$ 0.005274	$ 0.005274
Interruptible									$ 0.003860	$ 0.003860	$ 0.003860	$ 0.003860
Transport									$ 0.001570	$ 0.001570	$ 0.001570	$ 0.001570
Revenues												
Residential										204,512	418,515	648,380
Commercial Firm										66,484	130,395	205,671
Commercial Demand Billed										11,089	13,951	14,259
Interruptible										28,709	38,679	47,439
Transport										28,503	18,946	28,288
Forecast Revenues	0	0	0	0	0	0	0	0	0	339,298	620,485	944,036
Actual Revenues	3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733			
Actual & Forecast Total	3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733	339,298	620,485	944,036
Annual Total												12,851,194

GUIC Rate Factor Determination for 2015-2018

Revenues												
	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast
Monthly Inputs												
Revenue Requirement	1,290,395	1,291,174	1,290,851	1,438,299	1,873,638	1,903,800	2,177,226	1,829,239	2,220,744	2,432,372	2,340,849	1,788,990
Remaining true-up in current calendar year	0	0	0	29,031	29,031	29,031	29,031	29,031	29,031	29,031	29,031	29,031
Revenue Carried-forward balance	2,924,979	3,323,096	3,872,420	323,884	1,669,486	3,426,820	5,491,333	7,234,404	9,280,560	10,937,291	11,411,298	10,107,662
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	867,460.39	867,984.07	867,766.60	1,275,649.52	1,568,303.52	1,588,579.83	1,772,388.73	1,538,456.19	1,801,643.00	1,943,908.85	1,882,383.16	1,511,398.94
Commercial Firm	274,334.13	274,499.75	274,430.97	403,423.85	495,975.60	502,387.98	560,517.50	486,536.39	569,769.16	614,760.70	595,303.21	477,979.54
Commercial Demand Billed	27,111.20	27,127.57	27,120.77	39,868.55	49,015.03	49,648.73	55,393.41	48,082.19	56,307.71	60,754.02	58,831.12	47,236.56
Interruptible	72,934.42	72,978.45	72,960.17	107,254.19	131,859.98	133,564.78	149,019.08	129,350.48	151,478.73	163,440.17	158,267.20	127,075.55
Transport	48,554.99	48,584.30	48,572.13	71,402.85	87,783.79	88,918.73	99,207.20	86,113.12	100,844.67	108,807.82	105,364.00	84,598.63
Total	1,290,395.14	1,291,174.14	1,290,850.64	1,897,598.97	2,332,937.92	2,363,100.05	2,636,525.91	2,288,538.37	2,680,043.26	2,891,671.54	2,800,148.69	2,248,289.22
Sales by Customer Group (Billed by total Usage)												
Residential	68,368,938	57,400,677	45,591,199	25,622,491	14,105,793	8,074,948	6,480,071	6,547,950	8,485,676	18,763,638	38,397,247	59,483,913
Commercial Firm	36,992,880	31,037,926	26,707,660	13,511,076	9,757,419	4,172,031	3,932,713	4,171,695	5,326,020	11,090,199	21,751,301	34,307,529
Commercial Demand Billed	3,297,774	3,543,830	2,778,197	1,861,098	1,846,201	1,515,639	1,662,485	1,489,696	1,616,610	2,099,604	2,646,311	2,712,874
Interruptible	12,743,223	11,344,338	10,915,849	8,707,681	6,256,040	5,568,671	5,932,718	5,653,844	5,905,382	7,407,749	10,202,161	12,485,596
Transport	13,400,291	8,920,664	15,037,356	12,064,463	14,308,757	17,055,491	23,804,050	17,654,387	12,430,942	15,239,130	11,653,801	17,714,221
Total Therm Sales in Month	134,803,106	112,247,435	101,030,260	61,766,809	46,274,210	36,386,780	41,812,036	35,517,572	33,764,630	54,600,321	84,650,821	126,704,133
Flags												
Rate Change				x								
Rate Periods	0	0	0	2	2	2	2	2	2	2	2	2
Rate Period Calculations												
Revenue Requirement for Rate Period				18,005,158								
Remaining true-up in current calendar year				4,133,696								
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period				22,138,854								
Retail Dth Sales in Rate Period				521,477,311								
Cost Per therm	**$ 0.003758**	**$ 0.003758**	**$ 0.003758**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**
Allocated Cost Per therm												
Residential	**$ 0.010922**	**$ 0.010922**	**$ 0.010922**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**
Commercial Firm	**$ 0.006110**	**$ 0.006110**	**$ 0.006110**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**
Commercial Demand Billed	**$ 0.005274**	**$ 0.005274**	**$ 0.005274**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**
Interruptible	**$ 0.003860**	**$ 0.003860**	**$ 0.003860**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**
Transport	**$ 0.001570**	**$ 0.001570**	**$ 0.001570**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**
Revenues												
Residential	746,726	626,930	497,947	1,068,176	588,056	336,637	270,148	272,977	353,759	782,237	1,600,743	2,479,825
Commercial Firm	226,026	189,642	163,184	311,701	225,104	96,249	90,728	96,241	122,871	255,851	501,803	791,475
Commercial Demand Billed	17,392	18,690	14,652	31,968	31,712	26,034	28,556	25,589	27,769	36,065	45,456	46,599
Interruptible	49,189	43,789	42,135	105,903	76,086	67,726	72,154	68,762	71,821	90,093	124,079	151,850
Transport	21,038	14,005	23,609	55,967	66,378	79,120	110,427	81,899	57,667	70,694	54,062	82,176
Forecast Revenues	1,060,372	893,057	741,527	1,573,714	987,337	605,766	572,013	545,468	633,888	1,234,940	2,326,142	3,551,925
Actual Revenues												
Actual & Forecast Total	1,060,372	893,057	741,527	1,573,714	987,337	605,766	572,013	545,468	633,888	1,234,940	2,326,142	3,551,925
Annual Total												14,726,147

GUIC Rate Factor Determination for 2015-2018

Revenues	Jan-18 Forecast	Feb-18 Forecast	Mar-18 Forecast	Apr-18 Forecast	May-18 Forecast	Jun-18 Forecast	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast
Monthly Inputs												
Revenue Requirement	1,512,040	1,513,256	1,516,971	1,656,787	2,065,326	2,106,203	2,373,340	2,078,032	2,476,707	2,705,346	2,646,781	2,150,455
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Carried-forward balance	7,641,530	5,800,572	4,542,444	386,069	1,843,797	3,766,732	5,979,825	7,945,606	10,189,718	12,047,054	12,595,410	11,292,197
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	1,016,459.53	1,017,277.36	1,019,774.52	1,453,057.24	1,727,695.15	1,755,174.75	1,934,755.92	1,736,236.89	2,004,243.60	2,157,944.60	2,118,574.88	1,784,923.01
Commercial Firm	321,455.08	321,713.71	322,503.44	459,529.00	546,383.17	555,073.58	611,866.08	549,084.49	633,841.55	682,449.45	669,998.79	564,481.46
Commercial Demand Billed	31,767.95	31,793.51	31,871.56	45,413.17	53,996.58	54,855.41	60,467.96	54,263.54	62,639.69	67,443.39	66,212.95	55,785.15
Interruptible	85,461.99	85,530.75	85,740.71	122,170.30	145,261.33	147,571.76	162,670.61	145,979.50	168,513.00	181,435.89	178,125.76	150,072.94
Transport	56,895.03	56,940.80	57,080.58	81,333.02	96,705.53	98,243.67	108,295.49	97,183.64	112,184.98	120,788.20	118,584.53	99,908.79
Total	1,512,039.58	1,513,256.13	1,516,970.80	2,161,502.73	2,570,041.75	2,610,919.17	2,878,056.06	2,582,748.06	2,981,422.82	3,210,061.53	3,151,496.90	2,655,171.35
Sales by Customer Group (Billed by total Usage)												
Residential	68,236,496	57,288,483	45,503,585	25,572,273	14,079,167	8,060,217	6,467,471	6,535,293	8,469,418	18,728,194	38,324,064	59,368,208
Commercial Firm	37,482,949	31,448,960	27,061,212	13,689,957	9,886,003	4,227,975	3,984,776	4,226,931	5,396,403	11,236,786	22,039,026	34,760,745
Commercial Demand Billed	3,294,746	3,546,625	2,786,805	1,857,668	1,848,053	1,520,095	1,660,806	1,491,175	1,621,223	2,097,827	2,648,325	2,715,414
Interruptible	12,467,811	11,292,034	11,006,483	8,429,106	6,191,836	5,714,928	5,745,819	5,651,197	6,129,216	7,231,313	10,027,869	12,363,674
Transport	13,042,023	9,082,201	15,535,243	13,547,994	14,062,385	16,632,149	26,187,948	16,954,006	15,360,313	8,676,534	10,136,555	12,236,999
Total Therm Sales in Month	134,524,024	112,658,303	101,893,328	63,096,998	46,067,444	36,155,363	44,046,820	34,858,603	36,976,573	47,970,655	83,175,839	121,445,041
Flags												
Rate Change				x								
Rate Periods	0	0	0	3	3	3	3	3	3	3	3	3
Rate Period Calculations												
Revenue Requirement for Rate Period				20,258,976								
Remaining true-up in current calendar year				4,542,444								
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period				24,801,420								
Retail Dth Sales in Rate Period				513,793,336								
Cost Per therm	**$ 0.042454**	**$ 0.042454**	**$ 0.042454**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**	**$ 0.048271**
Allocated Cost Per therm												
Residential	**$ 0.041689**	**$ 0.041689**	**$ 0.041689**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**	**$ 0.046822**
Commercial Firm	**$ 0.023070**	**$ 0.023070**	**$ 0.023070**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**	**$ 0.025513**
Commercial Demand Billed	**$ 0.017177**	**$ 0.017177**	**$ 0.017177**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**	**$ 0.019226**
Interruptible	**$ 0.012162**	**$ 0.012162**	**$ 0.012162**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**	**$ 0.013720**
Transport	**$ 0.004639**	**$ 0.004639**	**$ 0.004639**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**	**$ 0.005717**
Revenues												
Residential	2,844,711	2,388,300	1,896,999	1,197,345	659,215	377,395	302,820	305,995	396,555	876,892	1,794,409	2,779,738
Commercial Firm	864,732	725,528	624,302	349,272	252,222	107,868	101,664	107,842	137,678	286,684	562,282	886,851
Commercial Demand Billed	56,594	60,920	47,869	35,716	35,531	29,225	31,931	28,669	31,170	40,333	50,917	52,207
Interruptible	151,634	137,334	133,861	115,647	84,952	78,409	78,833	77,534	84,093	99,214	137,582	169,630
Transport	60,502	42,132	72,068	77,454	80,395	95,086	149,717	96,926	87,815	49,604	57,951	69,959
Forecast Revenues	3,978,172	3,354,214	2,775,099	1,775,434	1,112,314	687,984	664,963	616,967	737,311	1,352,726	2,603,141	3,958,384
Actual Revenues												
Actual & Forecast Total	3,978,172	3,354,214	2,775,099	1,775,434	1,112,314	687,984	664,963	616,967	737,311	1,352,726	2,603,141	3,958,384
Annual Total												23,616,708

Proposed Tariff Sheets

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

Minnesota Gas Rate Book—MPUC No. 2

Sheet No. 5-64, revision 4

Redline

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

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

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

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

The current GUIC Factor for each customer group is:

Residential	~~$0.010922~~$0.041689 per therm	R
Commercial Firm	~~$0.006110~~$0.023070 per therm	R
Commercial Demand Billed	~~$0.005274~~$0.017177 per therm	R
Interruptible	~~$0.003860~~$0.012162 per therm	R
Transportation	~~$0.001570~~$0.004639 per therm	R

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

(Continued on Sheet No. 5-65)

Clean

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

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

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

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

The current GUIC Factor for each customer group is:

Residential	$0.041689 per therm	R
Commercial Firm	$0.023070 per therm	R
Commercial Demand Billed	$0.017177 per therm	R
Interruptible	$0.012162 per therm	R
Transportation	$0.004639 per therm	R

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

(Continued on Sheet No. 5-65)

Docket No. G002/M-16-_____

Gas Utility Infrastructure Cost Rider and the Applicable Return on Equity

Prepared for Northern States Power – Minnesota

d/b/a/ Xcel Energy

November 1, 2016

Smart. Focused. Done Right.®

scottmadden
MANAGEMENT CONSULTANTS

Table of Contents

1.0 Introduction

ScottMadden, Inc. ("ScottMadden") was retained by Northern States Power Company – Minnesota ("NSPM" or the "Company") to assist the Company in its 2017 Gas Utility Infrastructure Cost ("GUIC") Rider regulatory filing relating to the recovery of certain gas infrastructure investments, and, in particular, the Return on Equity ("ROE", or "Cost of Equity") to be applied to those investments. The purpose of this report is to support NSPM's 2017 GUIC filing by providing evidence of the Company's current Cost of Equity in a manner that complies with the Minnesota Public Utilities Commission's ("Commission") Order in Docket No. G-002/M-14-336 and Docket No. G-002/M-15-808.

1.1 Minnesota Statutory Background

Pursuant to §216B.1635, a gas utility may petition the Commission to recover the rate of return, income taxes on the rate of return, incremental property taxes, and incremental depreciation expenses associated with GUIC investments (such applications are referred to herein as "GUIC Rider filings"); *see*, §216B.1635 Subd. 2. GUIC Rider filings are subject to the following conditions:

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

(2) A gas utility must file sufficient information to satisfy the Commission regarding the proposed GUIC Rider including, but not limited to:

   a. Project description and scope, estimated project costs, and project in-service date;
   b. The government entity ordering the gas utility project and the purpose for which the project is undertaken;
   c. A description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;
   d. 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;
   e. 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;

f. The magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;
g. 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;
h. The magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and
i. 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. [1]

Subdivision 5 of the Statute states that:

…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.[2]

Lastly, Subdivision 6 of the Statute speaks specifically to the rate of return applicable to GUIC investments:

[t]he 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.[3]

[1] Minnesota Statute §216B.1635 Subd. 4.

[2] Minnesota Statute §216B.1635 Subd. 5.

[3] Minnesota Statute §216B.1635 Subd. 6.

1.2 Regulatory Background and History

In prior filings (made in 2010 and 2012[4]), the Company requested deferred accounting treatment for similar investments. In connection with those applications, the Commission noted that deferred accounting treatment may be used to hold utilities harmless when they incur out-of-test-year expenses that should be eligible for recovery as a matter of public policy. In particular, the Commission stated that deferred accounting treatment would be appropriate when the subject costs are unusual, unforeseeable, and large enough to have a significant financial effect.[5]

Regarding GUIC-eligible costs in particular, the Commission observed that it may approve recovery if (1) the costs had been prudently incurred, and (2) the infrastructure improvements were achieved at the lowest reasonable and prudent cost.[6] In summary, the Commission has stated that to be eligible for recovery through a rider such as the GUIC, investments must be large, variable, and unforeseeable; to be recovered, they must have been prudently incurred.

On September 2, 2015, Xcel filed a proposed rate of return (7.57%) for its 2015 GUIC rider petition (Docket No. G-002/M-15-808). On October 30, 2015, Xcel filed a petition, compliance filing, and annual report, seeking continued rider recovery for infrastructure costs, proposing new adjustment factors, and requesting a true-up of the rider balance. The Company proposed a revenue requirement of $15,509,869 through December 2016, after truing-up a carryover amount from 2015.

On August 18, 2016, the Commission approved the Company's application, with certain modifications and requirements. Among those conditions was that the return applied to the GUIC investments reflect NSPM's capital structure and cost of long-term debt as approved in the last GUIC filing (Docket No. Docket No. G-002/M-14-336), the cost of short-term debt in the Company's most recent electric rate

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[4] *See In the Matter of the Petition of Northern States Power Company for Deferred Accounting Treatment of Costs Relating to Identifying and Eliminating Sewer/Natural Gas Line Conflicts* Docket No. G-002/M-10-422; and, *In the Matter of the Petition of Northern States Power Company for Approval of Deferred Accounting for Costs to Comply with Gas Pipeline Safety Programs,* Docket No. G002/M-12-248.

[5] *In the Matter of the Petition of Northern States Power Company for Deferred Accounting Treatment of Costs Relating to Identifying and Eliminating Sewer/Natural Gas Line Conflicts* Docket No. G-002/M-10-422, Order Granting Deferred Accounting Treatment Subject to Conditions and Reporting Requirements, January 12, 2011.

[6] *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,* Docket No. G-002/M-14-336, Order Approving Rider with Modifications, January 27, 2015, at 3, *citing*, §216B.1635 Subd. 5.

case (*i.e.*, Docket No. E-002/GR-13-868), and the Return on Equity as proposed by the Department of Commerce.[7] Table 1 (below) provides the final rate of return authorized by the Commission in Docket No. G-002/M-15-808.

Table 1. Authorized Rate of Return, Docket No. G-002/M-15-808[8]

	Capital Structure	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.50%	9.64%	5.06%
Rate of Return	**100.00%**		**7.34%**

Regarding future GUIC filings, the Commission required the Company to file a cost/revenue study based on 2015 actuals reconciled back to Xcel's 2015 Jurisdictional Annual Report, as well as provide more detailed information about each individual project in the GUIC Rider.[9]

[7] *Ibid*. at 12.

[8] *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*, Docket No. G-002/M-15-808, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, August 18, 2016, at 8-9.

[9] *Ibid*., at 9.

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2.0 Cost of Capital

2.1 Cost of Capital Background

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

The "Cost of Debt" and the "Cost of Equity" often are analyzed separately; together, they are referred to as the "Cost of Capital" or the overall "Rate of Return" (*see for example*, Table 1 above). From the firm's perspective, the required return, whether to debt or equity investors, has a cost. Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined, and can be directly observed as the interest rate or yield on debt securities. The Cost of Equity, on the other hand, is neither observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders require. In that basic sense, equity investors and debt investors differ: they invest in different securities, face different risks, and require different returns.

The Cost of Equity is the return that investors *require* to take on the risks associated with equity investment. That is, investors will only provide equity to a firm if the return that they expect is equal to, or greater than, the return that they require. Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated based on market data and various financial models. Because the Cost of Equity is premised on opportunity costs, those models typically are applied to a group of "comparable", or "proxy", companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments.

The United States Supreme Court's ("Court") precedent-setting *Hope* and *Bluefield*[10] cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.

Minnesota precedent provides similar guidance. Chapter 216B of the Minnesota statute states:

The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

The Commission likewise has noted that it "must set rates at a level that permits stockholders to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment."[11]

2.2 Rate of Return Relating to the GUIC Rider

In this GUIC filing, NSPM proposes the following overall rate of return (see Table 2 below):

[10] See, *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[11] *In the Matter of the Application CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Rates in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. G-008/GR-13-316, June 9, 2014, at 30.

Table 2. NSPM's Proposed 2017 GUIC Rate of Return[12]

	Capital Structure	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.50%	9.50%	4.99%
Rate of Return	**100.00%**		**7.26%**

2.3 Cost of Equity

ScottMadden performed three commonly used analyses in order to estimate NSPM's ROE in this proceeding: (1) the Discounted Cash Flow Model, (2) the Capital Asset Pricing Model, and (3) a Risk Premium model. Consistent with the Administrative Law Judge's ("ALJ") ruling upheld by the Commission in the Company's prior natural gas rate case (and upheld by the Commission in the Company's 2016 GUIC filing[13]), those three models were applied to two proxy groups: (1) a proxy group composed of both electric and natural gas utilities ("Combination Proxy Group"), and (2) a proxy group composed of local distribution companies ("LDC Proxy Group"). [14] As discussed later in this report, ScottMadden also reviewed the ROE in the context of the current capital market environment. On balance, and giving particular weight to the Commission's recent 9.11 percent authorized ROE for

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[12] Provided by the Company.

[13] *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*, Docket No. G-002/M-15-808, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, August 18, 2016, at 7.

[14] *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rate for Natural Gas Service in Minnesota,* Docket No. G-002/GR-09-1153, Summary of Testimony at the Public Hearings, Findings of Fact, Conclusions, and Recommendations, October 15, 2010, at para. 63; and upheld by the Commission in Findings of Fact, Conclusions of Law, and Order issued December 6, 2010.

Minnesota Energy Resources, Corp. ("MERC"),[15] ScottMadden believes that 9.50 percent is a reasonable, if not a somewhat conservative, estimate of NSPM's Cost of Equity.

2.3.1 Proxy Group Selection

Because the Cost of Equity is a market-based concept and NSPM is not a publicly traded entity, it is necessary to establish a group of comparable, publicly traded companies to serve as its "proxy." Even if the Company were publicly traded, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

NSPM is a wholly owned subsidiary of Xcel Energy, Inc. and provides electric and natural gas service to approximately 1.26 million electric customers and 448,000 gas customers in Minnesota.[16] NSPM's gas operating revenue accounted for approximately 11.60 percent of its total operating revenue in 2015.[17] The Company's long-term issuer credit ratings from Standard & Poor's (S&P), Moody's, and Fitch Ratings (Fitch) currently are A- (outlook: stable), A2, (outlook: stable), and A- (outlook: stable), respectively.[18]

2.3.1.1 Combination Proxy Group

To develop the Combination Proxy Group, ScottMadden began with the universe of companies that Value Line classifies as Electric or Natural Gas Utilities, which includes a group of 52 domestic U.S. utilities, and applied the following screening criteria:

- Excluded companies that do not consistently pay quarterly cash dividends;
- Excluded companies not covered by at least two utility industry equity analysts;

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[15] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota,* Docket No. G011/GR-15-736, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016 at 16.

[16] Northern States Power – Minnesota FERC Form 1, December 31, 2015, at 304-305; 2015 Gas Jurisdictional Report to the Minnesota Department of Commerce, Page G-36.

[17] Source: SNL Financial.

[18] *Ibid*.

- Excluded companies that do not have investment grade senior bond and/or corporate credit ratings from Standard and Poor's;
- Excluded companies whose regulated operating income over the three most recently reported fiscal years comprised less than 60.00 percent of the respective total operating income for that company;
- Excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 10.00 percent of total regulated operating income;
- Excluded companies whose regulated natural gas utility operating income over the three most recently reported fiscal years represented less than 10.00 percent of total regulated operating income;
- Excluded companies that are currently known to be party to a merger, or other significant transaction; and
- Excluded Xcel Energy, Inc. in order to avoid the circular logic that otherwise would occur.

The criteria discussed above resulted in a proxy group consisting of the following ten electric and gas companies:

Table 3. Combination Proxy Group Screening Results

Company	Ticker
Ameren Corporation	AEE
Avista Corporation	AVA
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
DTE Energy Company	DTE
NiSource Inc.	NI
NorthWestern Corporation	NWE
SCANA Corporation	SCG
Vectren Corporation	VVC
WEC Energy Group, Inc.	WEC

2.3.1.2 LDC Proxy Group

To develop the LDC Proxy Group, ScottMadden began with the universe of companies that Value Line classifies as Electric or Natural Gas Utilities, which includes a group of 52 domestic U.S. utilities, and excluded companies that:

- Do not consistently pay quarterly cash dividends;
- Are not covered by at least two utility industry equity analysts;
- Do not have investment grade senior bond and/or corporate credit ratings from Standard and Poor's;
- Derive less than 60.00 percent of net operating income from regulated natural gas utility operations; and
- Are currently known to be party to a merger, or other significant transaction.

Those criteria produced the following group of eight natural gas utility companies:

Table 4. LDC Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[19]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire Inc	SR
WGL Holdings, Inc.	WGL

The following section describes the three analytical models ScottMadden applied to each of the two proxy groups described above in order to assess the reasonableness of the Company's current ROE.

[19] Even though Chesapeake Utilities Corp is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group.

2.3.2 Cost of Equity Estimation Methods

The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns. By their very nature, quantitative models produce a range of results from which the market required ROE must be selected. The key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' view of the financial markets in general, and the subject company (in the context of the proxy group) in particular.

Investors and analysts tend to use multiple approaches in developing their estimate of return requirements and understand that ROE models are tools to be used in the ROE estimation process and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed and unreliable conclusions. A reasonable ROE estimate therefore considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results. ScottMadden therefore applied three commonly used models: The Constant Growth and Two-Growth Rate forms of the Discounted Cash Flow method; the Capital Asset Pricing Model; and the Risk Premium approach. Each of those models is described in more detail in the following sections.[20]

2.3.2.1 Constant Growth Discounted Cash Flow ("DCF") Method

The DCF approach, which is widely recognized in regulatory proceedings, is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the Cost of Equity as the sum of the expected dividend yield and long-term growth rate, and is expressed as follows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

where *P* represents the current stock price, $D_1 \ldots D_\infty$ represent expected future dividends, and *k* is the discount rate, or required ROE. Equation [1] is a standard present value calculation, which can be simplified and rearranged into the form commonly referred to as the "Constant Growth DCF" model:

[20] Please see Appendix A for all of the Cost of Equity analytical results.

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [2]$$

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; (4) a discount rate greater than the expected growth rate; and (5) that the Cost of Equity remains constant, also in perpetuity. Those assumptions, and their implications for the model's results, should be considered in the context of prevailing and expected market conditions.

For the purposes of its analysis, ScottMadden applied the Constant Growth DCF model to each proxy group, using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended September 30, 2016 for the term P_0; and
2. The annualized dividend per share as of September 30, 2016 for the term D_0.

ScottMadden then calculated the DCF results using each of the following growth estimates:

1. The Zacks consensus long-term Earnings Per Share ("EPS") growth estimates;
2. The Yahoo! First Call consensus long-term EPS growth estimates; and
3. The Value Line long-term EPS growth estimates.

ScottMadden then calculated the mean, mean high, and mean low result for each proxy company. To calculate the mean result, ScottMadden combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. ScottMadden calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield; mean high result simply is the average of those estimates. ScottMadden applied the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, and First Call estimate for each proxy company, and calculating the average result for those estimates. Table 5 (below) summarizes the Constant Growth DCF Model results for both the Combination and LDC proxy groups.

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Table 5. Constant Growth DCF Results, with Flotation Costs[21]

Combination Proxy Group	Mean Low	Mean	Mean High
30-Day Average	8.06%	9.06%	10.10%
90-Day Average	8.00%	9.00%	10.04%
180-Day Average	8.15%	9.15%	10.19%
LDC Proxy Group	**Mean Low**	**Mean**	**Mean High**
30-Day Average	6.63%	8.75%	10.92%
90-Day Average	6.55%	8.66%	10.83%
180-Day Average	6.65%	8.77%	10.94%

2.3.2.2 Two-Growth Rate DCF Model

To address the limiting nature of certain assumptions underlying the Constant Growth form of the DCF model, ScottMadden also applied a Two-Growth Rate DCF Model, consistent with the Department of Commerce's ("Department") analysis filed in the Company's 2016 GUIC proceeding (and upheld by the Commission).[22] The Two-Growth Rate model, which is an extension of the Constant Growth form, enables the analyst to specify a near-term growth rate and a long-term growth rate.[23] As with the

[21] See Appendix A.

[22] *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*, Docket No. G-002/M-15-808, Appendix A to the Comments of the Minnesota Department of Commerce, Division of Energy Resources, March 17, 2016, at 8-9; *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*, Docket No. G-002/M-15-808, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, August 18, 2016, at 7.

[23] In prior proceedings, the Commission has considered the results of the Two Growth DCF model, which is a Multi-Stage DCF model that enables the analyst to specify growth rates over two stages. See, for example, Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order at 10-11; Docket No. E017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order at 56-58; Docket No. E015/GR-08-415, Findings of Fact, Conclusions of Law and Order at 23-24; *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*, Docket No. G-002/M-15-808, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, August 18, 2016, at 7.

Constant Growth form of the DCF model, the Two-Growth Rate form defines the Cost of Equity as the discount rate that sets the current price equal to the discounted value of future cash flows.

The Constant Growth DCF model assumes that earnings, dividends, and book value will grow at the same, constant rate in perpetuity, and the return required today will be the same return required every year in the future. However, those assumptions are not likely to hold. The Two-Growth Rate DCF model enables the analyst to address the limiting, and often unrealistic, assumptions underlying the Constant Growth form of the model. Because the model provides the ability to specify a near-term and long-term growth rate, for example, it avoids the sometimes limiting assumption that the subject company will grow at the same, constant rate in perpetuity.

The Two-Growth DCF formula as shown below uses the short-term growth rate for the first five years, and the long-term growth rate in years six and beyond, consistent with the Department's analysis filed in Docket No. G-002/M-15-808:[24]

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \frac{D_5}{(1+k)^5} + \frac{D_1(1+g_1)^4\,(1+g_2)}{(k-g_2)}\; x\; \frac{1}{(1+k)^5} \quad [3]$$

The first five terms in the equation above are the dividends in years one through five, growing at the first growth rate, g_1, discounted to the present using the required Return on Equity, k. The sixth term in the equation is the stock price in year five, estimated as the dividend in year six divided by the Return on Equity minus the second growth rate (i.e., k-g_2), discounted back to the current year.

ScottMadden used the same five-year projected earnings growth rates from Zacks, Value Line, and Yahoo! First Call as in the Constant Growth DCF analysis. As the short-term period in the Two-Growth Rate DCF analysis represents the first five years of the analysis, analysts' five year earnings projections are appropriate for the short-term growth rate in the Two-Growth Rate DCF model.

For the second growth rate used in years six and beyond, ScottMadden calculated the average short-term growth rate for each of its two proxy groups, as well as the standard deviation of each group's

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[24] *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*, Docket No. G-002/M-15-808, Appendix A to the Comments of the Minnesota Department of Commerce, Division of Energy Resources, March 17, 2016, at 8-9.

growth rates. Consistent with the Department's methodology, ScottMadden applied a growth rate ceiling and floor equal to one standard deviation above and below each proxy group's average short-term growth rate. For growth rates that were more than one standard deviation below the proxy group's average, ScottMadden substituted the proxy group's average less one standard deviation. Similarly, for growth rates that were more than one standard deviation above the proxy group's average, ScottMadden substituted the proxy group's short-term average growth rate plus one standard deviation.

Table 6 summarizes the Two-Growth Rate DCF Model results for both the Combination and LDC proxy groups.

Table 6. Two-Growth Rate DCF Results, with Flotation Costs[25]

	Low Mean ROE	Mean ROE	High Mean ROE
Combination Proxy Group	8.30%	9.10%	10.00%
LDC Proxy Group	6.61%	8.74%	10.84%

2.3.2.3 Flotation Costs

Consistent with Commission precedent, ScottMadden adjusted its DCF-based ROE results to account for flotation costs.[26] Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting and other issuance costs of common stock, which reduces a company's net proceeds when stock is issued. Because of this reduction in proceeds, a company's required return must be greater to compensate for

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[25] See Appendix A.

[26] *See for example*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order, at 9; Docket No. E002/GR-10-971, Findings of Fact, Conclusions, and Order, at 8; Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order, at 10-11; Docket No. E017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order, at 57-58; Docket No. G004/GR-04-1487, Findings of Fact, Conclusions of Law and Order, at 22.

the additional expenses.[27] Investors are reimbursed for the costs of issuing debt; consequently, the need to reimburse investors for issuing equity is similarly appropriate.

Consistent with the Department's methodology filed in Docket No. G-002/M-15-808, ScottMadden adjusted the dividend yield component of the DCF equation by (1-F), where F is flotation costs as a percentage of gross proceeds from common equity issuances. ScottMadden applied a 2.926 percent flotation cost adjustment, consistent with the Department's adjustment, as recently authorized by the Commission.[28]

2.3.2.4 Capital Asset Pricing Model ("CAPM")

The CAPM is a risk premium model that estimates the Cost of Equity as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [4], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$k = r_f + \beta(r_m - r_f) \quad [4]$$

where:

k = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

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[27] Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th ed. (John Wiley & Sons, Inc., 2010), page 586.

[28] *See*, *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*, Docket No. G-002/M-15-808, Appendix A to the Comments of the Minnesota Department of Commerce, Division of Energy Resources, March 17, 2016, at 7; *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*, Docket No. G-002/M-15-808, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures, August 18, 2016, at 7. *See also, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota,* Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, May 8, 2015, at 54, 56, 57.

In Equation [5], the term (r_m – r_f) represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \qquad [5]$$

where σ_j is the standard deviation of returns for company "*j*"; σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns between company *j* and the broad market. Thus, the Beta coefficient represents both relative volatility (i.e., the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Because utility assets represent long-term investments, two different estimates of the risk-free rate were used: (1) the current 30-day average yield on 30-year Treasury bonds (i.e., 2.32 percent)[29]; and (2) the near-term (that is, through the first calendar quarter of 2018) projected 30-year Treasury yield (i.e., 2.80 percent).[30]

ScottMadden developed a forward-looking (*ex-ante*) estimate of the Market Risk Premium based on the market required return (defined as the S&P 500), less the current 30-year Treasury bond yield, relying on data from two sources: (1) Bloomberg; and (2) Value Line. For Bloomberg, ScottMadden calculated the market capitalization weighted expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the market capitalization weighted projected earnings growth rate to arrive at the market capitalization weighted average DCF result. ScottMadden then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived ex-ante Market Risk Premium estimate. For Value Line, ScottMadden calculated the projected long-term market return based on the implied annual price appreciation and dividend yield for Value Line's composite index.

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[29] Source: Bloomberg Professional.

[30] Source: Blue Chip Financial Forecasts, Vol. 35, No. 10, October 1, 2016, at 2.

For the Beta component, ScottMadden employed the average of the reported Beta coefficient from both Bloomberg and Value Line for each proxy group company (0.627 and 0.71, respectively, for the Combination Proxy Group; 0.627 and 0.73, respectively, for the LDC Proxy Group).

Consistent with the Department's analysis filed in the Company's 2016 GUIC proceeding, ScottMadden also applied the Empirical CAPM ("ECAPM") model. The empirical CAPM ("ECAPM") reflects the finding that although the results of numerous tests support the notion that Beta coefficients are related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[31] Fama and French, for example, state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[32] Consequently, for low beta stocks such as utilities, the traditional CAPM methodology will understate the Return on Equity.

The Empirical CAPM calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00% to that result. The model then applies a 25.00% weight to the Market Risk Premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the Empirical CAPM result, as provided in Equation [5]:

$$k = r_f + 0.75\beta\left(r_m - r_f\right) + 0.25(r_m - r_f) \quad [5]$$

Tables 7 and 8 (below) summarize the CAPM results for the Combination and LDC proxy groups.

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[31] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 175.

[32] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004, at 33.

Table 7. Combination Proxy Group CAPM Results[33]

	CAPM		*ECAPM*	
Combination Proxy Group	*Bloomberg Derived Market Risk Premium*	*Value Line Derived Market Risk Premium*	*Bloomberg Derived Market Risk Premium*	*Value Line Derived Market Risk Premium*
Average Bloomberg Beta Coefficient				
Current 30-Year Treasury (2.32%)	9.03%	9.66%	10.03%	10.75%
Near-Term Projected 30-Year Treasury (2.80%)	9.51%	10.14%	10.51%	11.23%
Average Value Line Beta Coefficient				
Current 30-Year Treasury (2.32%)	9.93%	10.64%	10.71%	11.49%
Near-Term Projected 30-Year Treasury (2.80%)	10.41%	11.12%	11.18%	11.97%

Table 8. LDC Proxy Group CAPM Results[34]

	CAPM		*ECAPM*	
Combination Proxy Group	*Bloomberg Derived Market Risk Premium*	*Value Line Derived Market Risk Premium*	*Bloomberg Derived Market Risk Premium*	*Value Line Derived Market Risk Premium*
Average Bloomberg Beta Coefficient				
Current 30-Year Treasury (2.32%)	9.04%	9.66%	10.03%	10.75%
Near-Term Projected 30-Year Treasury (2.80%)	9.51%	10.14%	10.51%	11.23%
Average Value Line Beta Coefficient				
Current 30-Year Treasury (2.32%)	10.08%	10.81%	10.82%	11.61%
Near-Term Projected 30-Year Treasury (2.80%)	10.56%	11.28%	11.30%	12.09%

[33] See Appendix A.

[34] *Ibid*.

2.3.2.5 Bond Yield Plus Risk Premium Method

The Bond Yield Plus Risk Premium approach is based on the financial tenet that, because equity investors bear the residual risk of ownership, they require a premium over the returns available to debt holders. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of an Equity Risk Premium and a bond yield. Because we are calculating the Risk Premium for natural gas utilities, a reasonable approach is to use actual authorized returns for natural gas utilities as the measure of the Cost of Equity.

At issue when applying this approach is whether the Equity Risk Premium is static or whether it changes over time and with market conditions. Prior research has shown that the Equity Risk Premium is inversely related to the level of interest rates;[35] that finding is particularly relevant given the historically low level of current Treasury yields. To quantify the relationship between the two, ScottMadden first defined the Equity Risk Premium as the difference between the authorized ROE and the concurrent long-term (i.e., 30-year) Treasury yield. ScottMadden then gathered data for 1,045 natural gas rate proceedings between January 1980 and September 30, 2016 as reported by Regulatory Research Associates. In addition to the authorized ROE, the average period between the filing of the case and the date of the final order (the "lag period") was also calculated. In order to reflect the prevailing level of interest rates during the pendency of the proceedings, ScottMadden calculated the average 30-year Treasury yield over the average lag period (approximately 188 days).

The Equity Risk Premium was estimated using regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Because the analytical period includes interest rates and authorized ROEs that during one period (i.e., the 1980's) are quite high and another (the post-Lehman bankruptcy period) that are quite low relative to the long-term historical average, ScottMadden used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

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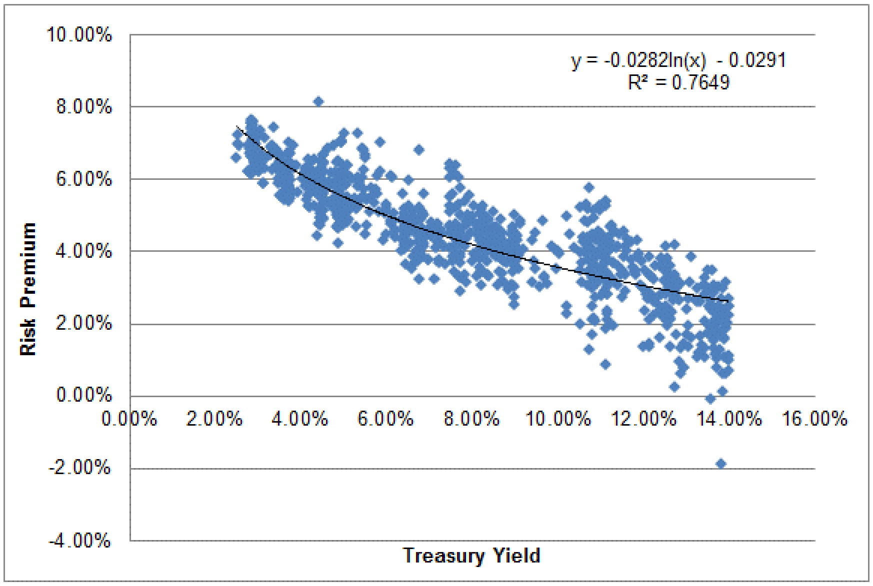
[35] See, e.g., Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

$$RP = \alpha + \beta(\mathrm{LN}(T_{30})) \qquad [6]$$

Chart 1 below plots the Equity Risk Premium and prevailing 30-year Treasury Yield for each of the 1,045 natural gas rate cases since 1980.

Chart 1. Equity Risk Premium[36]



As Chart 1 demonstrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. That is, as the Treasury yield declines, the Equity Risk Premium rises.

ScottMadden applied the regression coefficients shown in Chart 1 to three measures of interest rates as depicted in Equation [6], which produced the Bond Yield Plus Risk Premium results summarized in Table 9 below.

[36] See Appendix A.

Table 9. Bond Yield Plus Risk Premium Results[37]

	ROE
Current 30-Year Treasury (2.32%)	10.00%
Near-Term Projected 30-Year Treasury (2.80%)	9.95%
Long-Term Projected 30-Year Treasury (4.45%)	10.30%

2.3.2.6 Recently Authorized Gas Utility ROEs

It is important to recognize that in establishing their return requirements, investors consider a broad range of data, including returns authorized in other jurisdictions. Equity investors have many options available to them, and allocate their capital based on the expected risks and returns associated with those alternatives. Although the Commission is not bound by decisions in other regulatory jurisdictions, given that investors consider such data in framing their investment decisions, return recommendations that materially deviate from observed industry norms should be supported by clear and unambiguous reasons explaining those deviations.

Since January 2015, more than half of the authorized ROEs in gas utility rate cases (i.e., 22 of 32) have been set at a 9.50 percent ROE or higher (See Table 10 Below).

Table 10. Authorized Gas ROEs since January 2015[38]

Date	Company	Docket No.	Jurisdiction	Authorized ROE (%)
1/13/2015	Consumers Energy Co.	C-U-17643	Michigan	10.30
1/21/2015	North Shore Gas Co.	D-14-0224	Illinois	9.05
1/21/2015	Peoples Gas Light & Coke Co.	D-14-0225	Illinois	9.05

[37] *Ibid*.

[38] Source: Regulatory Research Associates.

Date	Company	Docket No.	Jurisdiction	Authorized ROE (%)
4/9/2015	Avista Corp.	D-UG-284	Oregon	9.50
5/11/2015	Atmos Energy Corp.	D-14-00146	Tennessee	9.80
6/17/2015	Central Hudson Gas & Electric	C-14-G-0319	New York	9.00
8/21/2015	Columbia Gas of Virginia Inc	C-PUE-2014-00020	Virginia	9.75
10/7/2015	Bay State Gas Company	DPU 15-50	Massachusetts	9.55
10/13/2015	Mountaineer Gas Company	C-15-0003-G-42T	West Virginia	9.75
10/15/2015	Orange & Rockland Utlts Inc.	C-14-G-0494	New York	9.00
10/30/2015	NSTAR Gas Co.	DPU 14-150	Massachusetts	9.80
11/19/2015	Wisconsin Public Service Corp.	D-6690-UR-124 (Gas)	Wisconsin	10.00
12/3/2015	Northern States Power Co - WI	D-4220-UR-121 (Gas)	Wisconsin	10.00
12/9/2015	Ameren Illinois	D-15-0142	Illinois	9.60
12/11/2015	Michigan Gas Utilities Corp	C-U-17880	Michigan	9.90
12/18/2015	Avista Corp.	C-AVU-G-15-01	Idaho	9.50
1/6/2016	Oklahoma Natural Gas Co	Ca-PUD201500213	Oklahoma	9.50
1/6/2016	Avista Corp.	D-UG-150205	Washington	9.50
1/28/2016	SourceGas Arkansas Inc	D-15-011-U	Arkansas	9.40
2/10/2016	Liberty Utilities (NE Nat Gas)	DPU 15-75	Massachusetts	9.60
2/16/2016	Public Service Co. of CO	D-15AL-0135G	Colorado	9.50
2/29/2016	Avista Corp.	D-UG 288	Oregon	9.40
4/29/2016	Fitchburg Gas & Electric Light	DPU 15-81	Massachusetts	9.80
5/5/2016	CenterPoint Energy Resources	D-G-008/GR-15-424	Minnesota	9.49
6/1/2016	Maine Natural Gas	D-2015-00005	Maine	9.55
6/3/2016	Baltimore Gas and Electric Co.	C-9406 (gas)	Maryland	9.65
6/15/2016	NY State Electric & Gas Corp.	C-15-G-0284	New York	9.00
6/15/2016	Rochester Gas & Electric Corp.	C-15-G-0286	New York	9.00

Date	Company	Docket No.	Jurisdiction	Authorized ROE (%)
9/2/2016	CenterPoint Energy Resources	D-15-098-U	Arkansas	9.50
9/23/2016	New Jersey Natural Gas Co.	D-GR-15111304	New Jersey	9.75
9/27/2016	Texas Gas Service Co.	D-GUD-10506	Texas	9.50
9/29/2016	Minnesota Energy Resources	D-G-011/GR-15-736	Minnesota	9.11
AVERAGE				**9.525**
Number 9.50 percent or greater				22
Total number of gas rate cases with authorized ROEs since January 2015				32

2.3.3 Current and Expected Capital Market Conditions

The models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. As such, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such data or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

From January 2000 through August 2012 (that is, immediately prior to the Federal Reserve's third round of Quantitative Easing) the LDC proxy group's P/E multiples traded at a 9.00 percent discount to the market. During the pendency of the Federal Reserve's third round of Quantitative Easing (September 2012 through October 2014) the proxy group *premium* averaged 11.00 percent; from November 2014 through mid-September 2016 that premium fell slightly to approximately 8.00 percent.[39]

An important analytical question, then, is whether it is reasonable to expect those high valuation levels (on both an absolute and relative basis) will persist. Because it is unlikely that utility P/E ratios would

[39] Sources: Bloomberg Professional; SNL Financial.

exceed the market in perpetuity (as noted above, the premium has begun to decline), and given that the Constant Growth DCF model assumes that P/E ratios will remain constant in perpetuity, it would be inappropriate to give that model's results undue weight in determining the Company's Cost of Equity. A more reasoned approach is to understand the relationships among Federal Reserve policies, interest rates, and risk, and to assess how those factors may affect different models and their results.

As noted above, the Federal Reserve began its asset purchases in September 2012 and although the Federal Reserve completed its Quantitative Easing initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate, and began the process of rate normalization.[40] More recently, the Federal Reserve Federal Open Market Committee ("FOMC") has hinted at another raise in the Federal Funds rate. For example, in its press release dated September 21, 2016, the FOMC noted "…that the case for an increase in the federal funds rate has strengthened". Although it decided to maintain the current target range of one-quarter to one-half percent, three of the ten members voted to raise the target range to one-half to three-quarter percent.[41]

The question as to when the Federal Reserve will complete the process of normalizing monetary policy has important implications for assessing the Company's Cost of Equity. As noted earlier, for example, the Constant Growth DCF model assumes constancy (in perpetuity) of both the P/E ratio, and the required Return on Equity. To the extent that the prices used in Constant Growth DCF analyses reflect the effect of Federal policies that have yet to be "normalized", the results assume that the underlying abnormal capital market conditions likewise will remain in place. As noted earlier, it therefore remains important to review a variety of models when estimating the Company's Cost of Equity.

Moreover, because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increased interest rates during the period in which the rates set in this proceeding will be in effect. In fact, Investors see over a near 70.00 percent probability of an increase in the short-term Federal Funds rate by the end of the year, and an 82.00 percent probability of an increase within the

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[40] *Federal Reserve Press Release* dated December 16, 2015.

[41] *Federal Reserve Press Release* dated September 21, 2016.

next year.[42] As to long-term interest rates, the 50 economists surveyed by Blue Chip Financial Forecast see the 30-year Treasury yield as increasing to 3.9 percent by 2018.[43] Those projections are supported by the fact that investors currently are willing to pay about twice the premium for the option to sell long-term Government bonds in January 2017 (with an exercise price equal to the current price) than they are willing to pay for the option to buy those bonds.[44] Because the prices of bonds move inversely with interest rates,[45] those option prices indicate that investors believe it is considerably more likely that interest rates will increase over the coming year, than it is likely that they will decrease.

On balance, considering past and expected capital market conditions, taking into account the effect that those conditions have on certain model results, and giving particular weight to the Commission's recent MERC decision of 9.11 percent, ScottMadden concludes that 9.50 percent is a reasonable, if not conservative, estimate of NSPM's Cost of Equity.

2.4 Conclusion

Tables 5 through 9 above summarize the basis and results of the DCF, CAPM, and Bond Yield Risk Premium models for both the Combination and LDC proxy groups. To estimate the ROE within the range of those results, ScottMadden reviewed the prior findings in the ALJ's recommended decision in Docket No. G-002/GR-09-1153 (and the Commission's order upholding the ALJ's recommended decision), as well as the Department's methodology in Docket No. G-002/M-15-808, also upheld by the Commission. Consistent with the ALJ's recommended decision in Docket No. G-002/GR-09-1153, ScottMadden applied weights of 21.00 percent and 79.00 percent, respectively, to the Combination and LDC proxy groups to calculate a weighted average ROE. Based on this calculation, the weighted average Return on Equity is 9.53 percent (see Table 11 below).

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[42] http://www.cmegroup.com/trading/interest-rates/countdown-to-fomc.html, accessed October 21, 2016.

[43] *See,* Blue Chip Financial Forecast, Vol. 35 No. 6, June 1, 2016, at 14.

[44] Source: http://www.nasdaq.com/symbol/tlt/option-chain?dateindex=7

[45] That is, as interest rates move up (down), bond prices move down (up).

Table 11. Average ROE Results, All Results

Model	Combination Proxy Group	LDC Proxy Group
Constant Growth DCF	9.08%	8.75%
Two-Growth Rate DCF	9.13%	8.49%
CAPM	10.52%	10.59%
Bond Yield Plus Risk Premium	10.08%	10.08%
Average	**9.71%**	**9.54%**
Proxy Group Weight	21%	79%
Weighted Average	**9.57%**	

Based on the models using data inputs as of September 30, 2016 and applied according to the same methodology approved in the Company's previous GUIC case, ScottMadden concludes that a Return on Equity of 9.50 percent is a reasonable, if not conservative, estimate of NSPM's Cost of Equity.

ScottMadden also considered the current capital market environment to determine the reasonableness of the 9.50 percent ROE within the range of analytical results. As described in Section 2.3.3 (above), market conditions and model results (in particular the Constant Growth DCF model) have been influenced by the Federal Reserve's Quantitative Easing program. In addition, market data and consensus forecasts indicate that investors believe it is considerably more likely that interest rates will increase over the coming year, than it is likely that they will decrease. Additionally, this recommendation gives particular weight to the Commission's recent 9.11 percent authorized ROE in the MERC rate case. For these reasons, ScottMadden believes 9.50 percent is a conservative estimate of the Company's Return on Equity.

3.0 Infrastructure Riders in Other Jurisdictions

The purpose of this section is to provide an overview of the GUIC Rider, discuss and compare infrastructure replacement riders in place in other jurisdictions, and provide analysis regarding the impact, if any, of such mechanisms on the Cost of Equity.

3.1 Review of Natural Gas Infrastructure Recovery Mechanisms

3.1.1 History and Intent

As the Regulatory Research Associates ("RRA") notes, infrastructure investments have long been a focus for natural gas LDCs in the United States.[46] In some parts of the U.S., LDC infrastructure is nearly as old as the community it was constructed to serve, and consists of materials that degrade over an extended period of time. The extensive use of cast iron and non-cathodically protected steel mains and services prior to 1970, as well as other leak-prone pipe, represents a critical ongoing challenge for LDCs and regulators. While these facilities continue to provide adequate service, they require more extensive integrity management efforts, including more frequent surveys and efforts to maintain their condition for service.[47]

Advances in modern technology and several high-profile incidents[48] suggest that extensive portions of gas utility infrastructure need to be replaced at an accelerated pace in the coming years in order to prevent similar occurrences in the future.[49]

In 2011, the Department of Transportation ("DOT"), which regulates the safety of certain gas pipelines, announced a "Pipeline Safety Action Plan", calling for industry stakeholders to pursue policies that support the accelerated replacement of at-risk LDC infrastructure with more resilient materials,

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[46] Regulatory Research Associates, "RRA study finds that two-thirds of states allow expedited recovery of gas infrastructure spending," July 1, 2015.

[47] Yardley Associates, *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades – Cost Recovery Issues and Approaches,* prepared for the American Gas Foundation, July 2012, at 3.

[48] *See for example*, the 2014 explosion in East Harlem, New York caused by a gas leak in an 1887-vintage main, and the 2010 explosion in San Bruno, California caused by a compromised pipeline.

[49] Regulatory Research Associates, RRA Topical Special Report "Gas Utility Infrastructure Investments: the Who, What, When, Where, How, and Why," July 1, 2015, at 1.

including protected steel and plastic.[50] According to the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA), which regulates pipeline safety, roughly eight percent of the nation's 1.2 million miles of gas distribution mains is made of material that the industry opines is ripe for replacement (e.g., cast iron, and bare and unprotected steel).[51]

The DOT's plan calls for state utility commissions to adopt constructive ratemaking policies that would support the DOT’s plan. Although many commissions had previously approved replacement plans for the utilities under their purview and adopted supportive ratemaking practices to address the related costs, the DOT's plan prompted regulators in other jurisdictions to give the issue increased attention.[52]

Because infrastructure replacement is necessary to maintain safe and reliable distribution systems, public utility commissions across the U.S. have identified the need for non-traditional cost recovery mechanisms. The infrastructure cost recovery mechanisms can be classified into three broad categories: (1) infrastructure cost trackers, (2) infrastructure base rate surcharges and (3) deferred regulatory assets. The purpose of these non-traditional cost recovery mechanisms is primarily to reduce regulatory lag. Timely cost recovery is an essential element of replacement programs because, unlike investments that connect new customers and load, replacement facilities do not lead to increased revenues that offset investment costs. While LDCs, regulators and other stakeholders have traditionally relied upon base rate cases to provide cost recovery of capital expenditures for facility replacement, recent industry trends require the consideration of new cost recovery approaches. These trends include increasing proportions of LDC capital expenditures on non-revenue producing plant, slower load growth, and tougher to achieve incremental operating efficiency gains.[53]

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[50] U.S. Department of Transportation Call to Action to Improve the Safety of the Nation’s Energy Pipeline System, April 4, 2011, at 2-3. http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/110404%20Action%20Plan%20Executive%20Version%20_2.pdf

[51] 2014 Gas Distribution Annual Data, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation.

[52] Regulatory Research Associates, RRA Topical Special Report “Gas Utility Infrastructure Investments: the Who, What, When, Where, How, and Why,” July 1, 2015, at 1-2.

[53] Yardley Associates, *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades – Cost Recovery Issues and Approaches,* prepared for the American Gas Foundation, July 2012, at ES-2.

As a 2012 Yardley Associates report ("Yardley Report") noted, these new recovery mechanisms have several valuable benefits related to efforts to address safety and reliability concerns associated with leak-prone elements of distribution systems including:

- Eliminating disincentives to the efficient deployment of capital for safety and reliability through timely cost recovery;
- Enabling accelerated investment in infrastructure replacement and enhancement to achieve benefits more rapidly;
- Providing appropriate, timely, and effective regulatory oversight of LDC initiatives to replace and upgrade important infrastructure; and
- Allowing LDCs to reduce investment costs through broad scale, multi-year commitments that lead to maximum efficiency in managing workflow, reduced outside contractor costs, and better coordination with municipalities.[54]

As further noted in the Yardley Report, cost recovery mechanisms complement rather than substitute for the base rate case process, applying the same fundamental cost-of-service ratemaking principles. Thus, they are designed to yield rates that are just and reasonable and recover all prudently incurred costs including a return on investment. Timely recovery helps preserve the matching principle as the incremental revenues are calculated to recover the incremental costs attributable to the infrastructure investments that occur after the conclusion of the test year relied upon to design base rates.[55]

Consequently, gas infrastructure replacement cost recovery mechanisms serve an important public policy role by encouraging replacement of old pipeline facilities that are constructed of obsolete materials (e.g., cast iron, copper, bare steel, and certain kinds of welded pipe), which may have degraded over time, and therefore allow gas utilities to continue to provide safe and reliable service.

[54] *Ibid*., at 15.

[55] Ibid. at 16.

3.1.2 Mechanisms in Place at Proxy Companies

The acute need for capital cost recovery for utilities has arisen due to the substantial amount of infrastructure that must be replaced over a relatively short period of time, and the capital requirements associated with those investments. As such, 41 states and the District of Columbia have approved cost recovery for gas infrastructure replacement programs (see Appendix B and Appendix C).[56]

Appendix B lists the gas utilities with an infrastructure replacement cost recovery mechanism in any of its jurisdictions. Of the 213 gas utilities, 118 (or approximately 55.00 percent) have an infrastructure tracking mechanism.[57] Further, as shown in Table 12, an infrastructure replacement mechanism is in place at least one operating company in each of the eight LDC proxy companies.

[56] American Gas Association, State Infrastructure Replacement Activity, March 2015.

[57] Please note this refers to infrastructure replacement-specific cost recovery mechanisms and does not include authorized cost recovery or pre-approval of accelerated replacement programs as part of a rate case.

Table 12. Gas Infrastructure Replacement Mechanisms – LDC Proxy Group[58]

Local Distribution Company	Ticker	State	Mechanism	Mechanism Name
Atmos Energy Corporation	ATO	KS	✓	Gas System Reliability Surcharge
Atmos Energy Corporation	ATO	KY	✓	Pipeline Replacement Rider
Atmos Energy Corporation	ATO	LA	✓	Rate Stabilization Clause
Atmos Energy Corporation	ATO	MS	✓	Formula Rate Plan Rider/System Integrity Plan
Atmos Energy Corporation	ATO	TN	✓	Annual Review Mechanism
Atmos Energy Corporation	ATO	TX	✓	Gas Reliability Infrastructure Program
Atmos Energy Corporation	ATO	VA	✓	Infrastructure Reliability and Replacement Adjustment
Atmos Energy Corporation	ATO	CO	✓	System Safety and Integrity Rider
Chesapeake Utilities Corporation	CPK	DE		
Central Florida Gas	CPK	FL	✓	Gas Reliability Infrastructure Program
Florida Public Utilities Company	CPK	FL	✓	Gas Reliability Infrastructure Program
Chesapeake Utilities Corporation	CPK	MD		
New Jersey Natural Gas Company	NJR	NJ	✓	NJ RISE
Northwest Natural Gas Company	NWN	OR	✓	System Integrity Program
Northwest Natural Gas Company	NWN	WA		
South Jersey Gas Company	SJI	NJ	✓	SHARP
Mobile Gas Service Corporation	SR	AL	✓	Rate Stabilization and Equalization Plan; Cast Iron Main Replacement Factor
Alabama Gas Corporation	SR	AL	✓	Rate Stabilization and Equalization Plan
Laclede Gas Company	SR	MO	✓	Infrastructure System Replacement Surcharge

[58] Sources: Review of individual company tariffs; Regulatory Research Associates, *RRA Topical Special Report* "Gas Utility Infrastructure Investments: the Who, What, When, Where, How, and Why," July 1, 2015; American Gas Association, State Infrastructure Replacement Activity, September 2015; U.S. DOT PHMSA.

Local Distribution Company	Ticker	State	Mechanism	Mechanism Name
Missouri Gas Energy	SR	MO	✓	Infrastructure System Replacement Surcharge
Southwest Gas Corporation	SWX	AZ	✓	Customer Owned Yard Line Replacement Program; TRIMP rider
Southwest Gas Corporation	SWX	CA	✓	Infrastructure Reliability & Replacement Adjustment Mechanism
Southwest Gas Corporation	SWX	NV	✓	Gas Infrastructure Replacement
Washington Gas Light Company	WGL	DC	✓	ACRP surcharge; VMCREP surcharge
Washington Gas Light Company	WGL	MD	✓	STRIDE Rider
Washington Gas Light Company	WGL	VA	✓	SAVE Rider

Similarly, an infrastructure replacement mechanism is in place at least one operating company in nine of the ten Combination proxy group companies (see Table 13 below).

Table 13. Gas Infrastructure Replacement Mechanisms – Combination Proxy Group[59]

Local Distribution Company	Ticker	State	Mechanism	Mechanism Name
Ameren Illinois Company	AEE	IL	✓	Qualifying Infrastructure Plant Surcharge
Union Electric Company	AEE	MO	✓	Infrastructure System Replacement Surcharge
Avista Corporation	AVA	OR	✓	Aldyl A Pipe Replacement
Avista Corporation	AVA	ID		
Avista Corporation	AVA	WA	✓	Recovers replacement costs on an annual basis outside of general rate case

[59] Sources: Review of individual company tariffs; Regulatory Research Associates, *RRA Topical Special Report* "Gas Utility Infrastructure Investments: the Who, What, When, Where, How, and Why," July 1, 2015; American Gas Association, State Infrastructure Replacement Activity, September 2015; U.S. DOT PHMSA.

Local Distribution Company	Ticker	State	Mechanism	Mechanism Name
Consumers Energy Company	CMS	MI	✓	Enhanced Infrastructure Replacement Program (EIRP)
CenterPoint Energy Resources Corp.	CNP	AR	✓	Main Replacement Program Rider
CenterPoint Energy Resources Corp.	CNP	LA	✓	Rate Stabilization Plan
CenterPoint Energy Resources Corp.	CNP	MS	✓	Rate Regulation Adjustment Rider
CenterPoint Energy Resources Corp.	CNP	TX	✓	Gas Reliability Infrastructure Program
CenterPoint Energy Resources Corp.	CNP	MN		
CenterPoint Energy Resources Corp.	CNP	OK	✓	Rider PBRC
DTE Gas Company	DTE	MI	✓	Infrastructure Recovery Mechanism
Citizens Gas Fuel Company	DTE	MI		
Northern Indiana Public Service Company	NI	IN	✓	Transmission, Distribution, and Storage System Improvement Charge
Columbia Gas of Kentucky, Incorporated	NI	KY	✓	Accelerated Main Replacement Program Rider
Bay State Gas Company	NI	MA	✓	GSEP
Columbia Gas of Maryland, Incorporated	NI	MD	✓	Infrastructure Replacement and Improvement Surcharge
Columbia Gas of Ohio, Incorporated	NI	OH	✓	Infrastructure Replacement Program Rider
Columbia Gas of Pennsylvania, Inc.	NI	PA	✓	Distribution System Improvement Charge
Columbia Gas of Virginia, Incorporated	NI	VA	✓	Infrastructure Reliability and Replacement Adjustment
NorthWestern Corporation	NWE	MT	✓	DSIP Accounting Order
NorthWestern Corporation	NWE	NE		
NorthWestern Corporation	NWE	SD		
Public Service Company of North Carolina, Incorporated	SCG	NC		
South Carolina Electric & Gas Co.	SCG	SC		

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Local Distribution Company	Ticker	State	Mechanism	Mechanism Name
Indiana Gas Company, Inc.	VVC	IN	✓	Compliance & System Improvement Adjustment; Pipeline Safety Adjustment
Southern Indiana Gas and Electric Company, Inc.	VVC	IN	✓	Compliance & System Improvement Adjustment; Pipeline Safety Adjustment
Vectren Energy Delivery of Ohio, Inc.	VVC	OH	✓	Distribution Replacement Rider
Peoples Gas Light and Coke Company	WEC	IL	✓	Qualifying Infrastructure Plant Surcharge
North Shore Gas Company	WEC	IL		
Michigan Gas Utilities Corporation	WEC	MI		
Wisconsin Public Service Corporation	WEC	MI		
Minnesota Energy Resources Corporation	WEC	MN		
Wisconsin Electric Power Company	WEC	WI		
Wisconsin Gas LLC	WEC	WI		
Wisconsin Public Service Corporation	WEC	WI		

3.1.3 Effect on Risk Profile in the Context of the Cost of Equity

As described in Section 2 above, because the Cost of Equity estimation is a comparative exercise, the relevant analytical issue is whether the cost recovery mechanisms are so risk mitigating relative to mechanisms in place at the proxy companies that investors would knowingly and measurably reduce their return requirements for NSPM. As discussed above, gas infrastructure replacement mechanisms are common in the industry in general, as well as within the proxy group companies specifically. As a result, investors have become accustomed to these mechanisms and there is no reason to assume that NSPM would be seen as materially less risky than its peers as a result of the GUIC Rider.

Additionally, absent the timely recovery of infrastructure costs, the additional investment will dilute earnings and cash flow, and put further pressure on the ability to earn authorized rates of return. As the American Gas Associated noted in 2012, the only alternative to infrastructure cost recovery mechanisms are more frequent rate filings, "which is a costly activity that also leads to higher rates for customers."[60] Although these mechanisms accelerate the recovery of certain costs, utilities continue to face significant business risks associated with incomplete cost recovery due to inflation in O&M expenses, the need for additional projects as a result of the safety-related assessments, and changes in costs that are beyond the Company's control due to factors such as such as terrain characteristics, population density and material prices.[61]

[60] American Gas Association, Infrastructure Cost Recovery Update, January, 2012, at 2.

[61] Yardley Associates, *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades – Cost Recovery Issues and Approaches*, prepared for the American Gas Foundation, July 2012, at 9.

4.0 Conclusion

4.1 Conclusion and Rate of Return Recommendation

A 9.50 percent Cost of Equity is (1) consistent with the analytical results from three commonly used Cost of Equity estimation methods, using current market data and applied using the methodology approved in the Company's last GUIC proceeding; (2) appropriate given the current and projected capital market environment; and (3) gives particular weight and consideration to the Commission's most recently authorized gas utility ROE. ScottMadden believes that because the use of infrastructure replacement cost recovery mechanisms is prevalent within the industry in general and the proxy groups specifically, the Company is no less risky than its peers as a result of the GUIC Rider.

For these reasons, ScottMadden concludes that the Company's proposed capital structure, cost of debt, and Cost of Equity are reasonable and that the resulting rate of return is appropriate for NSPM's GUIC assets for the coming year.

Table 14 summarizes NSPM's proposed overall rate of return:

Table 14. NSPM's 2017 GUIC Rate of Return[62]

	Capital Structure	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.50%	9.50%	4.99%
Rate of Return	**100.00%**		**7.26%**

[62] Provided by the Company.

Appendix A
Constant Growth DCF Results

Constant Growth Discounted Cash Flow Model - Combination Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Ameren Corporation	AEE	$1.70	$49.86	3.41%	3.51%	6.10%	5.20%	6.00%	5.77%	8.70%	9.27%	9.61%	3.50%	3.51%	3.51%
Avista Corporation	AVA	$1.37	$41.72	3.28%	3.37%	5.30%	5.00%	5.00%	5.10%	8.37%	8.47%	8.67%	3.37%	3.37%	3.37%
CenterPoint Energy, Inc.	CNP	$1.03	$23.10	4.46%	4.55%	5.50%	5.26%	2.00%	4.25%	6.50%	8.81%	10.08%	4.50%	4.55%	4.58%
CMS Energy Corporation	CMS	$1.24	$42.58	2.91%	3.01%	6.60%	7.27%	6.00%	6.62%	9.00%	9.63%	10.29%	3.00%	3.01%	3.02%
DTE Energy Company	DTE	$3.08	$93.94	3.28%	3.37%	5.80%	5.51%	6.00%	5.77%	8.88%	9.14%	9.38%	3.37%	3.37%	3.38%
NiSource Inc.	NI	$0.66	$24.33	2.71%	2.77%	7.40%	NA	1.50%	4.45%	4.23%	7.22%	10.21%	2.73%	2.77%	2.81%
NorthWestern Corporation	NWE	$2.00	$58.45	3.42%	3.52%	5.00%	5.00%	6.50%	5.50%	8.51%	9.02%	10.03%	3.51%	3.52%	3.53%
SCANA Corporation	SCG	$2.30	$72.11	3.19%	3.27%	5.50%	6.00%	4.50%	5.33%	7.76%	8.61%	9.29%	3.26%	3.27%	3.29%
Vectren Corporation	VVC	$1.60	$49.85	3.21%	3.31%	5.30%	5.00%	9.00%	6.43%	8.29%	9.75%	12.35%	3.29%	3.31%	3.35%
Wisconsin Energy Corporation	WEC	$1.98	$60.90	3.25%	3.35%	6.20%	6.72%	6.00%	6.31%	9.35%	9.66%	10.08%	3.35%	3.35%	3.36%
Proxy Group Mean				3.31%	3.40%	5.87%	5.66%	5.25%	5.55%	7.96%	8.96%	10.00%	3.39%	3.40%	3.42%
With Flotation Costs										8.06%	9.06%	10.10%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Appendix A
Constant Growth DCF Results

Constant Growth Discounted Cash Flow Model - Combination Proxy Group
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Ameren Corporation	AEE	$1.70	$50.90	3.34%	3.44%	6.10%	5.20%	6.00%	5.77%	8.63%	9.20%	9.54%	3.43%	3.44%	3.44%
Avista Corporation	AVA	$1.37	$42.36	3.23%	3.32%	5.30%	5.00%	5.00%	5.10%	8.32%	8.42%	8.62%	3.32%	3.32%	3.32%
CenterPoint Energy, Inc.	CNP	$1.03	$23.26	4.43%	4.52%	5.50%	5.26%	2.00%	4.25%	6.47%	8.78%	10.05%	4.47%	4.52%	4.55%
CMS Energy Corporation	CMS	$1.24	$43.55	2.85%	2.94%	6.60%	7.27%	6.00%	6.62%	8.93%	9.57%	10.22%	2.93%	2.94%	2.95%
DTE Energy Company	DTE	$3.08	$95.12	3.24%	3.33%	5.80%	5.51%	6.00%	5.77%	8.84%	9.10%	9.34%	3.33%	3.33%	3.34%
NiSource Inc.	NI	$0.66	$24.99	2.64%	2.70%	7.40%	NA	1.50%	4.45%	4.16%	7.15%	10.14%	2.66%	2.70%	2.74%
NorthWestern Corporation	NWE	$2.00	$59.80	3.34%	3.44%	5.00%	5.00%	6.50%	5.50%	8.43%	8.94%	9.95%	3.43%	3.44%	3.45%
SCANA Corporation	SCG	$2.30	$72.60	3.17%	3.25%	5.50%	6.00%	4.50%	5.33%	7.74%	8.59%	9.26%	3.24%	3.25%	3.26%
Vectren Corporation	VVC	$1.60	$50.76	3.15%	3.25%	5.30%	5.00%	9.00%	6.43%	8.23%	9.69%	12.29%	3.23%	3.25%	3.29%
Wisconsin Energy Corporation	WEC	$1.98	$62.36	3.18%	3.28%	6.20%	6.72%	6.00%	6.31%	9.27%	9.58%	10.00%	3.27%	3.28%	3.28%
Proxy Group Mean				3.26%	3.35%	5.87%	5.66%	5.25%	5.55%	7.90%	8.90%	9.94%	3.33%	3.35%	3.36%
With Flotation Costs										8.00%	9.00%	10.04%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Appendix A
Constant Growth DCF Results

Constant Growth Discounted Cash Flow Model - Combination Proxy Group
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Ameren Corporation	AEE	$1.70	$49.08	3.46%	3.56%	6.10%	5.20%	6.00%	5.77%	8.75%	9.33%	9.67%	3.55%	3.56%	3.57%
Avista Corporation	AVA	$1.37	$40.68	3.37%	3.45%	5.30%	5.00%	5.00%	5.10%	8.45%	8.55%	8.76%	3.45%	3.45%	3.46%
CenterPoint Energy, Inc.	CNP	$1.03	$21.65	4.76%	4.86%	5.50%	5.26%	2.00%	4.25%	6.80%	9.11%	10.39%	4.80%	4.86%	4.89%
CMS Energy Corporation	CMS	$1.24	$41.93	2.96%	3.06%	6.60%	7.27%	6.00%	6.62%	9.05%	9.68%	10.33%	3.05%	3.06%	3.06%
DTE Energy Company	DTE	$3.08	$91.14	3.38%	3.48%	5.80%	5.51%	6.00%	5.77%	8.98%	9.25%	9.48%	3.47%	3.48%	3.48%
NiSource Inc.	NI	$0.66	$23.72	2.78%	2.84%	7.40%	NA	1.50%	4.45%	4.30%	7.29%	10.29%	2.80%	2.84%	2.89%
NorthWestern Corporation	NWE	$2.00	$59.12	3.38%	3.48%	5.00%	5.00%	6.50%	5.50%	8.47%	8.98%	9.99%	3.47%	3.48%	3.49%
SCANA Corporation	SCG	$2.30	$69.76	3.30%	3.39%	5.50%	6.00%	4.50%	5.33%	7.87%	8.72%	9.40%	3.37%	3.39%	3.40%
Vectren Corporation	VVC	$1.60	$49.01	3.26%	3.37%	5.30%	5.00%	9.00%	6.43%	8.35%	9.80%	12.41%	3.35%	3.37%	3.41%
Wisconsin Energy Corporation	WEC	$1.98	$59.96	3.30%	3.41%	6.20%	6.72%	6.00%	6.31%	9.40%	9.71%	10.13%	3.40%	3.41%	3.41%
Proxy Group Mean				3.40%	3.49%	5.87%	5.66%	5.25%	5.55%	8.04%	9.04%	10.08%	3.47%	3.49%	3.51%
With Flotation Costs										8.15%	9.15%	10.19%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
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[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Appendix A
Constant Growth DCF Results

Constant Growth Discounted Cash Flow Model - LDC Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Atmos Energy Corporation	ATO	$1.68	$74.70	2.25%	2.33%	7.20%	7.30%	6.50%	7.00%	8.82%	9.33%	9.63%	2.32%	2.33%	2.33%
Chesapeake Utilities Corporation	CPK	$1.22	$63.07	1.93%	1.99%	NA	3.00%	8.50%	5.75%	4.96%	7.74%	10.52%	1.96%	1.99%	2.02%
New Jersey Resources Corporation	NJR	$1.02	$33.90	3.01%	3.08%	6.50%	6.50%	1.00%	4.67%	4.02%	7.75%	9.61%	3.02%	3.08%	3.11%
Northwest Natural Gas Company	NWN	$1.87	$60.69	3.08%	3.16%	4.00%	4.00%	7.00%	5.00%	7.14%	8.16%	10.19%	3.14%	3.16%	3.19%
South Jersey Industries, Inc.	SJI	$1.06	$29.80	3.54%	3.65%	10.00%	6.00%	3.00%	6.33%	6.59%	9.99%	13.72%	3.59%	3.65%	3.72%
Southwest Gas Corporation	SWX	$1.80	$70.95	2.54%	2.60%	4.50%	4.00%	7.00%	5.17%	6.59%	7.77%	9.63%	2.59%	2.60%	2.63%
Spire Inc	SR	$1.96	$64.95	3.02%	3.11%	4.60%	4.52%	9.00%	6.04%	7.61%	9.15%	12.15%	3.09%	3.11%	3.15%
WGL Holdings, Inc.	WGL	$1.95	$63.30	3.08%	3.18%	7.30%	8.00%	3.50%	6.27%	6.63%	9.44%	11.20%	3.13%	3.18%	3.20%
Proxy Group Mean				2.81%	2.89%	6.30%	5.42%	5.69%	5.78%	6.55%	8.66%	10.83%	2.86%	2.89%	2.92%
With Flotation Costs										6.63%	8.75%	10.92%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
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[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

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Constant Growth Discounted Cash Flow Model - LDC Proxy Group
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Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Atmos Energy Corporation	ATO	$1.68	$76.56	2.19%	2.27%	7.20%	7.30%	6.50%	7.00%	8.77%	9.27%	9.57%	2.27%	2.27%	2.27%
Chesapeake Utilities Corporation	CPK	$1.22	$62.96	1.94%	1.99%	NA	3.00%	8.50%	5.75%	4.97%	7.74%	10.52%	1.97%	1.99%	2.02%
New Jersey Resources Corporation	NJR	$1.02	$35.71	2.86%	2.92%	6.50%	6.50%	1.00%	4.67%	3.87%	7.59%	9.45%	2.87%	2.92%	2.95%
Northwest Natural Gas Company	NWN	$1.87	$61.56	3.04%	3.11%	4.00%	4.00%	7.00%	5.00%	7.10%	8.11%	10.14%	3.10%	3.11%	3.14%
South Jersey Industries, Inc.	SJI	$1.06	$30.42	3.47%	3.58%	10.00%	6.00%	3.00%	6.33%	6.52%	9.91%	13.64%	3.52%	3.58%	3.64%
Southwest Gas Corporation	SWX	$1.80	$73.67	2.44%	2.51%	4.50%	4.00%	7.00%	5.17%	6.49%	7.67%	9.53%	2.49%	2.51%	2.53%
Spire Inc	SR	$1.96	$66.80	2.93%	3.02%	4.60%	4.52%	9.00%	6.04%	7.52%	9.06%	12.07%	3.00%	3.02%	3.07%
WGL Holdings, Inc.	WGL	$1.95	$66.80	2.92%	3.01%	7.30%	8.00%	3.50%	6.27%	6.47%	9.28%	11.04%	2.97%	3.01%	3.04%
Proxy Group Mean				2.72%	2.80%	6.30%	5.42%	5.69%	5.78%	6.46%	8.58%	10.75%	2.77%	2.80%	2.83%
With Flotation Costs										6.55%	8.66%	10.83%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Appendix A
Constant Growth DCF Results

Constant Growth Discounted Cash Flow Model - LDC Proxy Group
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Atmos Energy Corporation	ATO	$1.68	$73.87	2.27%	2.35%	7.20%	7.30%	6.50%	7.00%	8.85%	9.35%	9.66%	2.35%	2.35%	2.36%
Chesapeake Utilities Corporation	CPK	$1.22	$62.05	1.97%	2.02%	NA	3.00%	8.50%	5.75%	5.00%	7.77%	10.55%	2.00%	2.02%	2.05%
New Jersey Resources Corporation	NJR	$1.02	$35.47	2.88%	2.94%	6.50%	6.50%	1.00%	4.67%	3.89%	7.61%	9.47%	2.89%	2.94%	2.97%
Northwest Natural Gas Company	NWN	$1.87	$56.98	3.28%	3.36%	4.00%	4.00%	7.00%	5.00%	7.35%	8.36%	10.40%	3.35%	3.36%	3.40%
South Jersey Industries, Inc.	SJI	$1.06	$28.60	3.69%	3.81%	10.00%	6.00%	3.00%	6.33%	6.74%	10.14%	13.87%	3.74%	3.81%	3.87%
Southwest Gas Corporation	SWX	$1.80	$68.40	2.63%	2.70%	4.50%	4.00%	7.00%	5.17%	6.68%	7.87%	9.72%	2.68%	2.70%	2.72%
Spire Inc	SR	$1.96	$65.80	2.98%	3.07%	4.60%	4.52%	9.00%	6.04%	7.57%	9.11%	12.11%	3.05%	3.07%	3.11%
WGL Holdings, Inc.	WGL	$1.95	$67.32	2.90%	2.99%	7.30%	8.00%	3.50%	6.27%	6.45%	9.25%	11.01%	2.95%	2.99%	3.01%
Proxy Group Mean				2.82%	2.91%	6.30%	5.42%	5.69%	5.78%	6.57%	8.68%	10.85%	2.88%	2.91%	2.94%
With Flotation Costs										6.65%	8.77%	10.94%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Appendix A
Two Growth Rate DCF Results

Two Growth Rate DCF Analysis with Flotation Costs - Average Growth Rate
Combination Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Mean Projected Growth Rate	[5] Mean Expected Dividend Yield	[6] Second Growth Rate	[7] Mean Expected ROE
Ameren Corporation	AEE	49.86	1.70	3.41%	5.77%	3.51%	5.77%	9.27%
Avista Corporation	AVA	41.72	1.37	3.28%	5.10%	3.37%	5.10%	8.47%
CenterPoint Energy, Inc.	CNP	23.10	1.03	4.46%	4.25%	4.55%	4.80%	9.26%
CMS Energy Corporation	CMS	42.58	1.24	2.91%	6.62%	3.01%	6.31%	9.35%
DTE Energy Company	DTE	93.94	3.08	3.28%	5.77%	3.37%	5.77%	9.14%
NiSource Inc.	NI	24.33	0.66	2.71%	4.45%	2.77%	4.80%	7.53%
NorthWestern Corporation	NWE	58.45	2.00	3.42%	5.50%	3.51%	5.50%	9.01%
SCANA Corporation	SCG	72.11	2.30	3.19%	5.33%	3.27%	5.33%	8.61%
Vectren Corporation	VVC	49.85	1.60	3.21%	6.43%	3.31%	6.31%	9.64%
Wisconsin Energy Corporation	WEC	60.90	1.98	3.25%	6.31%	3.35%	6.31%	9.66%
	Mean				5.55%	3.40%	5.60%	8.99%
	Flotation Costs							2.93%
	Mean with Flotation Costs							9.10%

Average	5.55%
SD	0.76%
Average - 1 SD	4.80%
Average + 1 SD	6.31%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Ameren Corporation	AEE	1.75	1.09	1.60	1.85	1.19	1.55	1.96	1.30	1.50	2.07	1.43	1.45	2.19	1.56	1.40	2.31	66.00	42.36	49.86	0.00
Avista Corporation	AVA	1.40	1.08	1.29	1.48	1.18	1.25	1.55	1.28	1.22	1.63	1.38	1.18	1.71	1.50	1.14	1.80	53.50	35.63	41.72	0.00
CenterPoint Energy, Inc.	CNP	1.05	1.09	0.96	1.10	1.19	0.92	1.14	1.30	0.88	1.19	1.43	0.84	1.24	1.56	0.80	1.30	29.14	18.71	23.10	0.00
CMS Energy Corporation	CMS	1.28	1.09	1.17	1.37	1.20	1.14	1.46	1.31	1.11	1.55	1.43	1.09	1.65	1.56	1.06	1.76	57.87	37.01	42.58	0.00
DTE Energy Company	DTE	3.17	1.09	2.90	3.35	1.19	2.81	3.54	1.30	2.73	3.75	1.42	2.64	3.96	1.55	2.56	4.19	124.36	80.30	93.94	0.00
NiSource Inc.	NI	0.67	1.08	0.63	0.70	1.16	0.61	0.74	1.24	0.59	0.77	1.34	0.57	0.80	1.44	0.56	0.84	30.73	21.37	24.33	0.00
NorthWestern Corporation	NWE	2.05	1.09	1.88	2.17	1.19	1.82	2.29	1.30	1.76	2.41	1.41	1.71	2.54	1.54	1.65	2.68	76.39	49.61	58.45	0.00
SCANA Corporation	SCG	2.36	1.09	2.17	2.49	1.18	2.11	2.62	1.28	2.04	2.76	1.39	1.98	2.91	1.51	1.92	3.06	93.50	61.88	72.11	0.00
Vectren Corporation	VVC	1.65	1.10	1.51	1.76	1.20	1.46	1.87	1.32	1.42	1.99	1.44	1.38	2.12	1.58	1.34	2.25	67.72	42.75	49.85	0.00
Wisconsin Energy Corporation	WEC	2.04	1.10	1.86	2.17	1.20	1.80	2.31	1.32	1.75	2.45	1.45	1.70	2.61	1.59	1.64	2.77	82.68	52.14	60.90	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (4.80%), then equal to 4.80%; if [4] is greater than Group Avg. plus St. Dev. (6.31%), then equal to 6.31%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Appendix A
Two Growth Rate DCF Results

Two Growth Rate DCF Analysis with Flotation Costs - Low Growth Rate
Combination Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Low Projected Growth Rate	[5] Low Expected Dividend Yield	[6] Second Growth Rate	[7] Low Expected ROE
Ameren Corporation	AEE	49.86	1.70	3.41%	5.20%	3.50%	5.20%	8.70%
Avista Corporation	AVA	41.72	1.37	3.28%	5.00%	3.36%	5.00%	8.36%
CenterPoint Energy, Inc.	CNP	23.10	1.03	4.46%	2.00%	4.50%	3.09%	7.42%
CMS Energy Corporation	CMS	42.58	1.24	2.91%	6.00%	3.00%	6.00%	9.00%
DTE Energy Company	DTE	93.94	3.08	3.28%	5.51%	3.37%	5.51%	8.88%
NiSource Inc.	NI	24.33	0.66	2.71%	1.50%	2.73%	3.09%	5.67%
NorthWestern Corporation	NWE	58.45	2.00	3.42%	5.00%	3.51%	5.00%	8.51%
SCANA Corporation	SCG	72.11	2.30	3.19%	4.50%	3.26%	4.50%	7.76%
Vectren Corporation	VVC	49.85	1.60	3.21%	5.00%	3.29%	5.00%	8.29%
Wisconsin Energy Corporation	WEC	60.90	1.98	3.25%	6.00%	3.35%	6.00%	9.35%
	Mean				4.57%	3.39%	4.84%	8.19%
	Flotation Costs							2.93%
	Mean with Flotation Costs							8.30%

Average	4.57%
SD	1.48%
Average - 1 SD	3.09%
Average + 1 SD	6.05%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Ameren Corporation	AEE	1.74	1.09	1.60	1.83	1.18	1.55	1.93	1.28	1.50	2.03	1.40	1.45	2.14	1.52	1.41	2.25	64.25	42.34	49.86	0.00
Avista Corporation	AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.38	1.18	1.71	1.49	1.14	1.79	53.25	35.63	41.72	0.00
CenterPoint Energy, Inc.	CNP	1.04	1.07	0.97	1.06	1.15	0.92	1.08	1.24	0.87	1.10	1.33	0.83	1.13	1.43	0.79	1.16	26.79	18.73	23.10	0.00
CMS Energy Corporation	CMS	1.28	1.09	1.17	1.35	1.19	1.14	1.43	1.29	1.11	1.52	1.41	1.08	1.61	1.54	1.05	1.71	56.98	37.04	42.58	0.00
DTE Energy Company	DTE	3.16	1.09	2.91	3.34	1.19	2.82	3.52	1.29	2.73	3.72	1.41	2.64	3.92	1.53	2.56	4.14	122.83	80.28	93.94	0.00
NiSource Inc.	NI	0.66	1.06	0.63	0.67	1.12	0.60	0.69	1.18	0.58	0.70	1.25	0.56	0.71	1.32	0.54	0.73	28.23	21.43	24.33	0.00
NorthWestern Corporation	NWE	2.05	1.09	1.89	2.15	1.18	1.83	2.26	1.28	1.77	2.37	1.39	1.71	2.49	1.50	1.66	2.62	74.60	49.60	58.45	0.00
SCANA Corporation	SCG	2.35	1.08	2.18	2.46	1.16	2.12	2.57	1.25	2.05	2.68	1.35	1.99	2.80	1.45	1.93	2.93	89.86	61.84	72.11	0.00
Vectren Corporation	VVC	1.64	1.08	1.51	1.72	1.17	1.47	1.81	1.27	1.42	1.90	1.38	1.38	1.99	1.49	1.34	2.09	63.62	42.73	49.85	0.00
Wisconsin Energy Corporation	WEC	2.04	1.09	1.86	2.16	1.20	1.81	2.29	1.31	1.75	2.43	1.43	1.70	2.57	1.56	1.65	2.73	81.50	52.13	60.90	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (3.09%), then equal to 3.09%; if [4] is greater than Group Avg. plus St. Dev. (6.05%), then equal to 6.05%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Appendix A
Two Growth Rate DCF Results

Two Growth Rate DCF Analysis with Flotation Costs - High Growth Rate
Combination Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] High Projected Growth Rate	[5] High Expected Dividend Yield	[6] Second Growth Rate	[7] High Expected ROE
Ameren Corporation	AEE	49.86	1.70	3.41%	6.10%	3.51%	6.10%	9.61%
Avista Corporation	AVA	41.72	1.37	3.28%	5.30%	3.37%	5.54%	8.88%
CenterPoint Energy, Inc.	CNP	23.10	1.03	4.46%	5.50%	4.58%	5.54%	10.12%
CMS Energy Corporation	CMS	42.58	1.24	2.91%	7.27%	3.02%	7.27%	10.29%
DTE Energy Company	DTE	93.94	3.08	3.28%	6.00%	3.38%	6.00%	9.38%
NiSource Inc.	NI	24.33	0.66	2.71%	7.40%	2.81%	7.40%	10.21%
NorthWestern Corporation	NWE	58.45	2.00	3.42%	6.50%	3.53%	6.50%	10.03%
SCANA Corporation	SCG	72.11	2.30	3.19%	6.00%	3.28%	6.00%	9.28%
Vectren Corporation	VVC	49.85	1.60	3.21%	9.00%	3.35%	7.62%	11.13%
Wisconsin Energy Corporation	WEC	60.90	1.98	3.25%	6.72%	3.36%	6.72%	10.08%
	Mean				6.58%	3.42%	6.47%	9.90%
	Flotation Costs							2.93%
	Mean with Flotation Costs							10.00%

Average	6.58%
SD	1.04%
Average - 1 SD	5.54%
Average + 1 SD	7.62%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Ameren Corporation	AEE	1.75	1.10	1.60	1.86	1.20	1.55	1.97	1.32	1.50	2.09	1.44	1.45	2.22	1.58	1.40	2.35	67.04	42.37	49.86	0.00
Avista Corporation	AVA	1.41	1.09	1.29	1.48	1.19	1.25	1.56	1.29	1.21	1.64	1.41	1.17	1.73	1.53	1.13	1.82	54.60	35.68	41.72	0.00
CenterPoint Energy, Inc.	CNP	1.06	1.10	0.96	1.12	1.21	0.92	1.18	1.34	0.88	1.24	1.47	0.84	1.31	1.62	0.81	1.38	30.25	18.69	23.10	0.00
CMS Energy Corporation	CMS	1.28	1.10	1.16	1.38	1.22	1.13	1.48	1.34	1.10	1.59	1.48	1.07	1.70	1.63	1.04	1.82	60.48	37.07	42.58	0.00
DTE Energy Company	DTE	3.17	1.09	2.90	3.36	1.20	2.81	3.56	1.31	2.72	3.78	1.43	2.64	4.00	1.57	2.56	4.24	125.71	80.31	93.94	0.00
NiSource Inc.	NI	0.68	1.10	0.62	0.73	1.21	0.60	0.79	1.34	0.59	0.85	1.48	0.57	0.91	1.63	0.56	0.98	34.77	21.39	24.33	0.00
NorthWestern Corporation	NWE	2.06	1.10	1.88	2.20	1.21	1.82	2.34	1.33	1.76	2.49	1.47	1.70	2.66	1.61	1.65	2.83	80.08	49.65	58.45	0.00
SCANA Corporation	SCG	2.37	1.09	2.17	2.51	1.19	2.10	2.66	1.31	2.04	2.82	1.43	1.98	2.99	1.56	1.92	3.17	96.50	61.91	72.11	0.00
Vectren Corporation	VVC	1.67	1.11	1.50	1.82	1.23	1.47	1.98	1.37	1.45	2.16	1.53	1.42	2.36	1.69	1.39	2.54	72.23	42.62	49.85	0.00
Wisconsin Energy Corporation	WEC	2.05	1.10	1.86	2.18	1.21	1.80	2.33	1.33	1.75	2.49	1.47	1.69	2.65	1.62	1.64	2.83	84.30	52.16	60.90	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (5.54%), then equal to 5.54%; if [4] is greater than Group Avg. plus St. Dev. (7.62%), then equal to 7.62%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Appendix A
Two Growth Rate DCF Results

Two Growth Rate DCF Analysis with Flotation Costs - Average Growth Rate
LDC Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Mean Projected Growth Rate	[5] Mean Expected Dividend Yield	[6] Second Growth Rate	[7] Mean Expected ROE
Atmos Energy Corporation	ATO	74.70	1.68	2.25%	7.00%	2.33%	6.51%	8.88%
Chesapeake Utilities Corporation	CPK	63.07	1.22	1.93%	5.75%	1.99%	5.75%	7.74%
New Jersey Resources Corporation	NJR	33.90	1.02	3.01%	4.67%	3.08%	5.04%	8.08%
Northwest Natural Gas Company	NWN	60.69	1.87	3.08%	5.00%	3.16%	5.04%	8.20%
South Jersey Industries, Inc.	SJI	29.80	1.06	3.54%	6.33%	3.65%	6.33%	9.98%
Southwest Gas Corporation	SWX	70.95	1.80	2.54%	5.17%	2.60%	5.17%	7.77%
Spire Inc	SR	64.95	1.96	3.02%	6.04%	3.11%	6.04%	9.15%
WGL Holdings, Inc.	WGL	63.30	1.95	3.08%	6.27%	3.18%	6.27%	9.44%
	Mean				5.78%	2.89%	5.77%	8.65%
	Flotation Costs							2.93%
	Mean with Flotation Costs							8.74%

Average	0.057779
SD	0.74%
Average - 1 SD	5.04%
Average + 1 SD	6.51%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Atmos Energy Corporation	ATO	1.74	1.09	1.60	1.86	1.19	1.57	1.99	1.29	1.54	2.13	1.41	1.51	2.28	1.53	1.49	2.43	102.51	66.99	74.70	0.00
Chesapeake Utilities Corporation	CPK	1.25	1.08	1.16	1.33	1.16	1.14	1.40	1.25	1.12	1.48	1.35	1.10	1.57	1.45	1.08	1.66	83.41	57.46	63.07	0.00
New Jersey Resources Corporation	NJR	1.04	1.08	0.97	1.09	1.17	0.94	1.14	1.26	0.91	1.20	1.36	0.88	1.25	1.47	0.85	1.32	43.31	29.37	33.90	0.00
Northwest Natural Gas Company	NWN	1.92	1.08	1.77	2.01	1.17	1.72	2.11	1.27	1.67	2.22	1.37	1.62	2.33	1.48	1.57	2.45	77.61	52.34	60.69	0.00
South Jersey Industries, Inc.	SJI	1.09	1.10	0.99	1.16	1.21	0.96	1.23	1.33	0.92	1.31	1.46	0.89	1.39	1.61	0.86	1.48	40.51	25.17	29.80	0.00
Southwest Gas Corporation	SWX	1.85	1.08	1.71	1.94	1.16	1.67	2.04	1.25	1.63	2.15	1.35	1.59	2.26	1.45	1.55	2.37	91.27	62.79	70.95	0.00
Spire Inc	SR	2.02	1.09	1.85	2.14	1.19	1.80	2.27	1.30	1.75	2.41	1.42	1.70	2.55	1.55	1.65	2.71	87.08	56.22	64.95	0.00
WGL Holdings, Inc.	WGL	2.01	1.09	1.84	2.14	1.20	1.78	2.27	1.31	1.73	2.41	1.43	1.68	2.56	1.57	1.63	2.72	85.79	54.64	63.30	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (5.04%), then equal to 5.04%; if [4] is greater than Group Avg. plus St. Dev. (6.51%), then equal to 6.51%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Appendix A
Two Growth Rate DCF Results

Two Growth Rate DCF Analysis with Flotation Costs - Low Growth Rate
LDC Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Low Projected Growth Rate	[5] Low Expected Dividend Yield	[6] Second Growth Rate	[7] Low Expected ROE
Atmos Energy Corporation	ATO	74.70	1.68	2.25%	6.50%	2.32%	5.15%	7.58%
Chesapeake Utilities Corporation	CPK	63.07	1.22	1.93%	3.00%	1.96%	3.00%	4.96%
New Jersey Resources Corporation	NJR	33.90	1.02	3.01%	1.00%	3.02%	2.23%	5.12%
Northwest Natural Gas Company	NWN	60.69	1.87	3.08%	4.00%	3.14%	4.00%	7.14%
South Jersey Industries, Inc.	SJI	29.80	1.06	3.54%	3.00%	3.59%	3.00%	6.59%
Southwest Gas Corporation	SWX	70.95	1.80	2.54%	4.00%	2.59%	4.00%	6.59%
Spire Inc	SR	64.95	1.96	3.02%	4.52%	3.09%	4.52%	7.61%
WGL Holdings, Inc.	WGL	63.30	1.95	3.08%	3.50%	3.13%	3.50%	6.63%
	Mean				3.69%	2.86%	3.68%	6.53%
	Flotation Costs							2.93%
	Mean with Flotation Costs							6.61%

Average	0.0369
SD	1.46%
Average - 1 SD	2.23%
Average + 1 SD	5.15%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.
Atmos Energy Corporation	ATO	1.73	1.08	1.61	1.85	1.16	1.60	1.97	1.25	1.58
Chesapeake Utilities Corporation	CPK	1.24	1.05	1.18	1.28	1.10	1.16	1.31	1.16	1.14
New Jersey Resources Corporation	NJR	1.03	1.05	0.98	1.04	1.11	0.94	1.05	1.16	0.90
Northwest Natural Gas Company	NWN	1.91	1.07	1.78	1.98	1.15	1.73	2.06	1.23	1.68
South Jersey Industries, Inc.	SJI	1.07	1.07	1.00	1.10	1.14	0.97	1.14	1.21	0.94
Southwest Gas Corporation	SWX	1.84	1.07	1.72	1.91	1.14	1.68	1.99	1.21	1.64
Spire Inc	SR	2.00	1.08	1.86	2.09	1.16	1.81	2.19	1.25	1.76
WGL Holdings, Inc.	WGL	1.98	1.07	1.86	2.05	1.14	1.81	2.13	1.21	1.75

Company	Ticker	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Atmos Energy Corporation	ATO	2.09	1.34	1.56	2.23	1.44	1.55	2.35	96.28	66.80	74.70	0.00
Chesapeake Utilities Corporation	CPK	1.35	1.21	1.11	1.39	1.27	1.09	1.44	73.11	57.39	63.07	0.00
New Jersey Resources Corporation	NJR	1.06	1.22	0.86	1.07	1.28	0.83	1.09	37.73	29.39	33.90	0.00
Northwest Natural Gas Company	NWN	2.15	1.32	1.63	2.23	1.41	1.58	2.32	73.84	52.30	60.69	0.00
South Jersey Industries, Inc.	SJI	1.17	1.29	0.91	1.21	1.38	0.88	1.24	34.54	25.10	29.80	0.00
Southwest Gas Corporation	SWX	2.06	1.29	1.60	2.15	1.38	1.56	2.23	86.32	62.75	70.95	0.00
Spire Inc	SR	2.29	1.34	1.71	2.39	1.44	1.66	2.50	81.02	56.16	64.95	0.00
WGL Holdings, Inc.	WGL	2.20	1.29	1.70	2.28	1.38	1.65	2.36	75.18	54.53	63.30	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (2.23%), then equal to 2.23%; if [4] is greater than Group Avg. plus St. Dev. (5.15%), then equal to 5.15%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis with Flotation Costs - High Growth Rate
LDC Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] High Projected Growth Rate	[5] High Expected Dividend Yield	[6] Second Growth Rate	[7] High Expected ROE
Atmos Energy Corporation	ATO	74.70	1.68	2.25%	7.30%	2.33%	7.30%	9.63%
Chesapeake Utilities Corporation	CPK	63.07	1.22	1.93%	8.50%	2.01%	8.50%	10.51%
New Jersey Resources Corporation	NJR	33.90	1.02	3.01%	6.50%	3.11%	6.80%	9.80%
Northwest Natural Gas Company	NWN	60.69	1.87	3.08%	7.00%	3.19%	7.00%	10.19%
South Jersey Industries, Inc.	SJI	29.80	1.06	3.54%	10.00%	3.71%	9.03%	12.93%
Southwest Gas Corporation	SWX	70.95	1.80	2.54%	7.00%	2.62%	7.00%	9.62%
Spire Inc	SR	64.95	1.96	3.02%	9.00%	3.15%	9.00%	12.15%
WGL Holdings, Inc.	WGL	63.30	1.95	3.08%	8.00%	3.20%	8.00%	11.20%
	Mean				7.91%	2.92%	7.83%	10.76%
	Flotation Costs							2.93%
	Mean with Flotation Costs							10.84%

Average	0.079125
SD	1.11%
Average - 1 SD	6.80%
Average + 1 SD	9.03%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Atmos Energy Corporation	ATO	1.74	1.10	1.59	1.87	1.20	1.55	2.00	1.32	1.52	2.15	1.44	1.49	2.31	1.58	1.46	2.48	106.25	67.09	74.70	0.00
Chesapeake Utilities Corporation	CPK	1.27	1.11	1.15	1.38	1.22	1.13	1.50	1.35	1.11	1.62	1.49	1.09	1.76	1.65	1.07	1.91	94.83	57.53	63.07	0.00
New Jersey Resources Corporation	NJR	1.05	1.10	0.96	1.12	1.21	0.93	1.19	1.32	0.90	1.27	1.45	0.87	1.35	1.60	0.85	1.45	48.14	30.16	34.67	0.77
Northwest Natural Gas Company	NWN	1.93	1.10	1.76	2.07	1.21	1.70	2.21	1.34	1.66	2.37	1.47	1.61	2.54	1.62	1.56	2.71	85.12	52.41	60.69	0.00
South Jersey Industries, Inc.	SJI	1.11	1.13	0.98	1.22	1.28	0.95	1.34	1.44	0.93	1.47	1.63	0.91	1.62	1.84	0.88	1.77	45.25	24.64	29.29	-0.51
Southwest Gas Corporation	SWX	1.86	1.10	1.70	1.99	1.20	1.66	2.13	1.32	1.62	2.28	1.44	1.58	2.44	1.58	1.54	2.61	99.51	62.86	70.95	0.00
Spire Inc	SR	2.05	1.12	1.82	2.23	1.26	1.77	2.43	1.41	1.72	2.65	1.58	1.68	2.89	1.77	1.63	3.15	99.94	56.33	64.95	0.00
WGL Holdings, Inc.	WGL	2.03	1.11	1.82	2.19	1.24	1.77	2.36	1.38	1.72	2.55	1.53	1.67	2.76	1.70	1.62	2.98	93.01	54.70	63.30	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[3] = [2] / [1]
[4] Constant Growth DCF
[5] = [3] x (1 + [4]) ^ 0.5
[6] if [4] is less than Group Avg. less St. Dev (6.80%), then equal to 6.80%; if [4] is greater than Group Avg. plus St. Dev. (9.03%), then equal to 9.03%; else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function; Adjustment for Flotation costs: ROE = [7] - [5] + [5] / (1-F)
[8] = [2] x (1 + [4]) ^ (1.0 - 0.5)
[9] = (1 + [7]) ^ (1.0)
[10] = [8] / [9]
[11] = [2] x (1 + [4]) ^ (2.0 - 0.5)
[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Appendix A
CAPM - Market Risk Premium

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
13.02%	2.32%	10.70%

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	15,275.28	0.08%	0.95%	10.43%	11.43%	0.0088%
ALCOA INC	AA	13,337.95	0.07%	1.18%	5.00%	6.21%	0.0042%
AMERICAN AIRLINES GROUP INC	AAL	19,400.13	0.10%	1.13%	-17.86%	-16.83%	-0.0165%
ADVANCE AUTO PARTS INC	AAP	10,981.22	0.06%	0.17%	10.67%	10.85%	0.0060%
APPLE INC	AAPL	609,163.48	3.07%	1.92%	9.63%	11.64%	0.3576%
ABBVIE INC	ABBV	102,712.17	0.52%	3.61%	11.23%	15.04%	0.0779%
AMERISOURCEBERGEN CORP	ABC	19,216.88	0.10%	1.68%	11.77%	13.55%	0.0131%
ABBOTT LABORATORIES	ABT	62,166.11	0.31%	2.45%	11.15%	13.74%	0.0431%
ACCENTURE PLC-CL A	ACN	82,072.15	0.41%	1.98%	8.25%	10.31%	0.0427%
ADOBE SYSTEMS INC	ADBE	53,969.02	0.27%	0.00%	17.32%	17.32%	0.0471%
ANALOG DEVICES INC	ADI	19,816.71	0.10%	2.51%	10.48%	13.11%	0.0131%
ARCHER-DANIELS-MIDLAND CO	ADM	24,532.95	0.12%	2.85%	3.67%	6.57%	0.0081%
AUTOMATIC DATA PROCESSING	ADP	40,075.89	0.20%	2.50%	10.42%	13.05%	0.0264%
ALLIANCE DATA SYSTEMS CORP	ADS	12,556.24	0.06%	0.00%	14.20%	14.20%	0.0090%
AUTODESK INC	ADSK	16,049.52	0.08%	0.00%	9.82%	9.82%	0.0079%
AMEREN CORPORATION	AEE	11,932.78	0.06%	3.54%	6.30%	9.95%	0.0060%
AMERICAN ELECTRIC POWER	AEP	31,572.66	0.16%	3.53%	4.26%	7.87%	0.0125%
AES CORP	AES	8,469.30	0.04%	3.43%	6.66%	10.20%	0.0044%
AETNA INC	AET	40,499.86	0.20%	0.87%	10.54%	11.45%	0.0234%
AFLAC INC	AFL	29,436.17	0.15%	2.33%	5.00%	7.39%	0.0110%
ALLERGAN PLC	AGN	91,191.75	0.46%	0.00%	12.83%	12.83%	0.0590%
AMERICAN INTERNATIONAL GROUP	AIG	63,532.96	0.32%	2.16%	18.48%	20.84%	0.0667%
APARTMENT INVT & MGMT CO -A	AIV	7,190.12	0.04%	2.87%	7.14%	10.12%	0.0037%
ASSURANT INC	AIZ	5,553.86	0.03%	2.20%	11.91%	14.25%	0.0040%
ARTHUR J GALLAGHER & CO	AJG	9,005.57	0.05%	2.99%	9.16%	12.29%	0.0056%
AKAMAI TECHNOLOGIES INC	AKAM	9,258.65	0.05%	0.00%	15.00%	15.00%	0.0070%
ALBEMARLE CORP	ALB	9,609.34	0.05%	1.39%	9.05%	10.51%	0.0051%
ALASKA AIR GROUP INC	ALK	8,106.71	0.04%	1.67%	2.05%	3.73%	0.0015%
ALLSTATE CORP	ALL	25,697.67	0.13%	1.90%	8.25%	10.23%	0.0133%
ALLEGION PLC	ALLE	6,608.33	0.03%	0.70%	13.05%	13.80%	0.0046%
ALEXION PHARMACEUTICALS INC	ALXN	27,479.35	0.14%	0.00%	28.06%	28.06%	0.0389%
APPLIED MATERIALS INC	AMAT	32,588.95	0.16%	1.34%	14.80%	16.24%	0.0267%
AMETEK INC	AME	11,104.98	0.06%	0.78%	9.59%	10.41%	0.0058%
AFFILIATED MANAGERS GROUP	AMG	7,795.29	0.04%	0.00%	13.21%	13.21%	0.0052%
AMGEN INC	AMGN	124,834.08	0.63%	2.39%	7.87%	10.35%	0.0652%
AMERIPRISE FINANCIAL INC	AMP	16,104.96	N/A	2.91%	N/A	N/A	N/A
AMERICAN TOWER CORP	AMT	48,220.69	0.24%	1.91%	15.73%	17.79%	0.0433%
AMAZON.COM INC	AMZN	396,946.52	2.00%	0.00%	48.29%	48.29%	0.9666%
AUTONATION INC	AN	4,972.77	0.03%	0.00%	7.71%	7.71%	0.0019%
ANTHEM INC	ANTM	32,977.96	0.17%	2.07%	8.66%	10.82%	0.0180%
AON PLC	AON	29,877.34	0.15%	1.15%	11.31%	12.52%	0.0189%
APACHE CORP	APA	24,233.75	0.12%	1.57%	6.71%	8.33%	0.0102%
ANADARKO PETROLEUM CORP	APC	35,077.20	0.18%	0.57%	1.48%	2.05%	0.0036%
AIR PRODUCTS & CHEMICALS INC	APD	32,556.08	0.16%	2.25%	7.08%	9.41%	0.0155%
AMPHENOL CORP-CL A	APH	20,042.40	0.10%	0.87%	9.66%	10.57%	0.0107%
ACTIVISION BLIZZARD INC	ATVI	32,846.99	0.17%	0.59%	17.34%	17.98%	0.0298%
AVALONBAY COMMUNITIES INC	AVB	24,419.84	0.12%	3.03%	7.48%	10.62%	0.0131%
BROADCOM LTD	AVGO	68,547.29	0.35%	1.11%	15.35%	16.54%	0.0572%
AVERY DENNISON CORP	AVY	6,912.19	0.03%	2.07%	6.75%	8.89%	0.0031%
AMERICAN WATER WORKS CO INC	AWK	13,314.22	0.07%	1.93%	7.64%	9.65%	0.0065%
AMERICAN EXPRESS CO	AXP	59,158.93	0.30%	1.90%	8.00%	9.97%	0.0298%
ACUITY BRANDS INC	AYI	11,612.52	0.06%	0.20%	22.60%	22.82%	0.0134%
AUTOZONE INC	AZO	22,460.14	0.11%	0.00%	13.09%	13.09%	0.0148%
BOEING CO/THE	BA	82,182.83	0.41%	3.31%	12.98%	16.50%	0.0684%
BANK OF AMERICA CORP	BAC	159,705.10	0.81%	1.60%	9.00%	10.67%	0.0859%
BAXTER INTERNATIONAL INC	BAX	25,889.05	0.13%	1.05%	11.92%	13.03%	0.0170%
BED BATH & BEYOND INC	BBBY	6,658.87	0.03%	1.00%	6.67%	7.71%	0.0026%
BB&T CORP	BBT	30,722.95	0.15%	3.05%	4.21%	7.32%	0.0113%
BEST BUY CO INC	BBY	12,113.54	0.06%	3.51%	11.18%	14.89%	0.0091%
CR BARD INC	BCR	16,474.40	0.08%	0.43%	10.75%	11.21%	0.0093%
BECTON DICKINSON AND CO	BDX	38,269.16	0.19%	1.47%	11.45%	13.00%	0.0251%
FRANKLIN RESOURCES INC	BEN	20,492.64	0.10%	2.02%	1.98%	4.01%	0.0041%
BROWN-FORMAN CORP-CLASS B	BF/B	19,078.17	0.10%	1.50%	9.22%	10.78%	0.0104%
BAKER HUGHES INC	BHI	21,596.18	0.11%	1.35%	32.00%	33.57%	0.0366%
BIOGEN INC	BIIB	68,591.37	0.35%	0.00%	8.88%	8.88%	0.0307%
BANK OF NEW YORK MELLON CORP	BK	42,578.86	0.21%	1.80%	16.11%	18.06%	0.0388%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BLACKROCK INC	BLK	59,505.32	0.30%	2.53%	12.00%	14.68%	0.0440%
BALL CORP	BLL	14,278.08	0.07%	0.63%	4.80%	5.44%	0.0039%
BRISTOL-MYERS SQUIBB CO	BMY	90,092.69	0.45%	2.83%	20.56%	23.68%	0.1076%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	355,849.14	1.79%	0.00%	2.00%	2.00%	0.0359%
BOSTON SCIENTIFIC CORP	BSX	32,385.69	0.16%	0.00%	12.40%	12.40%	0.0202%
BORGWARNER INC	BWA	7,537.87	0.04%	1.49%	11.59%	13.16%	0.0050%
BOSTON PROPERTIES INC	BXP	20,946.88	0.11%	2.19%	6.65%	8.91%	0.0094%
CITIGROUP INC	C	137,220.82	0.69%	0.89%	6.25%	7.16%	0.0496%
CA INC	CA	13,858.82	0.07%	3.10%	7.60%	10.82%	0.0076%
CONAGRA FOODS INC	CAG	20,697.59	0.10%	2.21%	7.70%	10.00%	0.0104%
CARDINAL HEALTH INC	CAH	24,860.31	0.13%	2.18%	10.99%	13.29%	0.0167%
CATERPILLAR INC	CAT	51,862.20	0.26%	3.47%	7.08%	10.67%	0.0279%
CHUBB LTD	CB	58,437.23	0.29%	2.19%	9.50%	11.80%	0.0348%
CBRE GROUP INC - A	CBG	9,390.60	0.05%	0.00%	10.03%	10.03%	0.0048%
CBS CORP-CLASS B NON VOTING	CBS	24,361.65	0.12%	1.19%	15.77%	17.06%	0.0210%
CROWN CASTLE INTL CORP	CCI	31,801.85	0.16%	3.80%	9.95%	13.94%	0.0224%
CARNIVAL CORP	CCL	36,207.61	0.18%	2.74%	15.90%	18.85%	0.0344%
CELGENE CORP	CELG	81,022.74	0.41%	0.00%	22.45%	22.45%	0.0917%
CERNER CORP	CERN	20,853.55	0.11%	0.00%	14.81%	14.81%	0.0156%
CF INDUSTRIES HOLDINGS INC	CF	5,676.71	0.03%	4.94%	1.20%	6.17%	0.0018%
CITIZENS FINANCIAL GROUP	CFG	12,836.13	0.06%	1.88%	16.73%	18.76%	0.0121%
CHURCH & DWIGHT CO INC	CHD	12,344.06	0.06%	1.67%	9.36%	11.11%	0.0069%
CHESAPEAKE ENERGY CORP	CHK	4,871.51	0.02%	0.00%	-1.17%	-1.17%	-0.0003%
C.H. ROBINSON WORLDWIDE INC	CHRW	10,055.17	0.05%	2.47%	10.30%	12.90%	0.0065%
CHARTER COMMUNICATIONS INC-A	CHTR	84,027.80	0.42%	0.00%	30.94%	30.94%	0.1311%
CIGNA CORP	CI	33,436.22	0.17%	0.03%	10.99%	11.02%	0.0186%
CINCINNATI FINANCIAL CORP	CINF	12,412.31	N/A	0.00%	N/A	N/A	N/A
COLGATE-PALMOLIVE CO	CL	66,095.30	0.33%	2.10%	8.05%	10.23%	0.0341%
CLOROX COMPANY	CLX	16,220.30	0.08%	2.59%	7.90%	10.59%	0.0087%
COMERICA INC	CMA	8,229.07	0.04%	1.87%	-1.63%	0.23%	0.0001%
COMCAST CORP-CLASS A	CMCSA	160,000.52	0.81%	1.67%	11.59%	13.35%	0.1077%
CME GROUP INC	CME	35,417.14	0.18%	4.98%	10.38%	15.62%	0.0279%
CHIPOTLE MEXICAN GRILL INC	CMG	12,330.53	0.06%	0.00%	13.63%	13.63%	0.0085%
CUMMINS INC	CMI	21,611.37	0.11%	3.10%	5.19%	8.37%	0.0091%
CMS ENERGY CORP	CMS	11,755.62	0.06%	2.95%	6.03%	9.07%	0.0054%
CENTENE CORP	CNC	11,432.54	0.06%	0.00%	16.05%	16.05%	0.0093%
CENTERPOINT ENERGY INC	CNP	10,004.74	0.05%	4.44%	5.10%	9.66%	0.0049%
CAPITAL ONE FINANCIAL CORP	COF	36,784.10	0.19%	2.23%	6.54%	8.84%	0.0164%
CABOT OIL & GAS CORP	COG	12,000.82	0.06%	0.31%	37.16%	37.53%	0.0227%
COACH INC	COH	10,248.21	0.05%	3.72%	12.17%	16.12%	0.0083%
ROCKWELL COLLINS INC	COL	10,958.40	0.06%	1.58%	8.24%	9.89%	0.0055%
COOPER COS INC/THE	COO	8,737.52	0.04%	0.03%	11.57%	11.60%	0.0051%
CONOCOPHILLIPS	COP	53,837.82	0.27%	2.30%	6.67%	9.05%	0.0246%
COSTCO WHOLESALE CORP	COST	66,809.38	0.34%	1.17%	10.49%	11.72%	0.0395%
CAMPBELL SOUP CO	CPB	16,840.76	0.08%	2.54%	4.80%	7.41%	0.0063%
SALESFORCE.COM INC	CRM	48,861.05	0.25%	0.00%	27.16%	27.16%	0.0669%
CISCO SYSTEMS INC	CSCO	159,055.30	0.80%	3.40%	8.19%	11.72%	0.0940%
CSRA INC	CSRA	4,401.59	0.02%	0.00%	10.00%	10.00%	0.0022%
CSX CORP	CSX	28,852.72	0.15%	2.40%	7.81%	10.30%	0.0150%
CINTAS CORP	CTAS	12,032.72	0.06%	1.01%	11.00%	12.06%	0.0073%
CENTURYLINK INC	CTL	14,975.94	0.08%	7.87%	-2.02%	5.77%	0.0044%
COGNIZANT TECH SOLUTIONS-A	CTSH	28,957.24	0.15%	0.00%	13.48%	13.48%	0.0197%
CITRIX SYSTEMS INC	CTXS	13,271.05	0.07%	0.00%	16.95%	16.95%	0.0113%
CVS HEALTH CORP	CVS	94,882.47	0.48%	1.84%	13.59%	15.55%	0.0744%
CHEVRON CORP	CVX	194,160.68	0.98%	4.18%	1.65%	5.85%	0.0573%
CONCHO RESOURCES INC	CXO	19,337.27	0.10%	0.00%	25.00%	25.00%	0.0244%
DOMINION RESOURCES INC/VA	D	46,475.42	0.23%	3.77%	6.42%	10.31%	0.0242%
DELTA AIR LINES INC	DAL	29,477.01	0.15%	1.70%	15.51%	17.34%	0.0258%
DU PONT (E.I.) DE NEMOURS	DD	58,553.55	0.30%	2.27%	7.88%	10.24%	0.0302%
DEERE & CO	DE	26,836.00	0.14%	2.83%	7.74%	10.68%	0.0144%
DISCOVER FINANCIAL SERVICES	DFS	22,825.11	0.12%	2.06%	8.17%	10.31%	0.0119%
DOLLAR GENERAL CORP	DG	19,719.28	0.10%	1.42%	13.16%	14.68%	0.0146%
QUEST DIAGNOSTICS INC	DGX	11,765.00	0.06%	1.88%	7.28%	9.23%	0.0055%
DR HORTON INC	DHI	11,243.03	0.06%	1.07%	13.30%	14.44%	0.0082%
DANAHER CORP	DHR	54,131.31	0.27%	0.80%	10.90%	11.75%	0.0321%
WALT DISNEY CO/THE	DIS	149,235.42	0.75%	1.53%	9.57%	11.17%	0.0841%
DISCOVERY COMMUNICATIONS-A	DISCA	16,182.88	0.08%	0.00%	17.65%	17.65%	0.0144%
DELPHI AUTOMOTIVE PLC	DLPH	19,453.58	0.10%	1.62%	9.67%	11.36%	0.0111%
DIGITAL REALTY TRUST INC	DLR	14,509.65	0.07%	3.62%	5.45%	9.17%	0.0067%
DOLLAR TREE INC	DLTR	18,609.75	0.09%	0.00%	17.50%	17.50%	0.0164%
DUN & BRADSTREET CORP	DNB	4,960.25	0.03%	1.40%	11.75%	13.24%	0.0033%
DIAMOND OFFSHORE DRILLING	DO	2,415.56	0.01%	0.00%	-42.14%	-42.14%	-0.0051%
DOVER CORP	DOV	11,430.10	0.06%	2.32%	10.85%	13.30%	0.0077%
DOW CHEMICAL CO/THE	DOW	58,403.61	0.29%	3.53%	3.53%	7.12%	0.0210%
DR PEPPER SNAPPLE GROUP INC	DPS	16,929.29	0.09%	2.31%	8.42%	10.83%	0.0092%
DARDEN RESTAURANTS INC	DRI	7,739.55	0.04%	3.64%	12.21%	16.06%	0.0063%
DTE ENERGY COMPANY	DTE	16,807.71	0.08%	3.23%	5.30%	8.62%	0.0073%

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DUKE ENERGY CORP	DUK	55,142.24	0.28%	4.26%	4.54%	8.90%	0.0248%
DAVITA INC	DVA	13,669.88	0.07%	0.00%	10.49%	10.49%	0.0072%
DEVON ENERGY CORP	DVN	23,096.00	0.12%	0.95%	9.49%	10.48%	0.0122%
ELECTRONIC ARTS INC	EA	25,685.32	0.13%	0.00%	15.00%	15.00%	0.0194%
EBAY INC	EBAY	37,144.72	0.19%	0.00%	9.71%	9.71%	0.0182%
ECOLAB INC	ECL	35,492.98	0.18%	1.17%	12.87%	14.11%	0.0253%
CONSOLIDATED EDISON INC	ED	22,922.45	0.12%	3.56%	3.54%	7.16%	0.0083%
EQUIFAX INC	EFX	16,060.15	0.08%	0.98%	12.20%	13.24%	0.0107%
EDISON INTERNATIONAL	EIX	23,539.86	0.12%	2.68%	5.72%	8.48%	0.0101%
ESTEE LAUDER COMPANIES-CL A	EL	32,437.57	0.16%	1.47%	9.98%	11.52%	0.0188%
EASTMAN CHEMICAL CO	EMN	9,997.15	0.05%	2.70%	5.43%	8.21%	0.0041%
EMERSON ELECTRIC CO	EMR	35,079.23	0.18%	3.49%	5.61%	9.20%	0.0163%
ENDO INTERNATIONAL PLC	ENDP	4,488.75	0.02%	0.00%	3.95%	3.95%	0.0009%
EOG RESOURCES INC	EOG	53,252.74	0.27%	0.69%	-4.74%	-4.07%	-0.0109%
EQUINIX INC	EQIX	25,604.61	0.13%	1.94%	22.86%	25.02%	0.0323%
EQUITY RESIDENTIAL	EQR	23,516.22	0.12%	20.24%	6.11%	26.97%	0.0320%
EQT CORP	EQT	12,544.89	0.06%	0.17%	17.50%	17.68%	0.0112%
EVERSOURCE ENERGY	ES	17,186.28	0.09%	3.30%	6.70%	10.11%	0.0088%
EXPRESS SCRIPTS HOLDING CO	ESRX	44,449.35	0.22%	0.00%	13.87%	13.87%	0.0311%
ESSEX PROPERTY TRUST INC	ESS	14,585.70	0.07%	2.87%	6.50%	9.47%	0.0070%
E*TRADE FINANCIAL CORP	ETFC	7,969.71	0.04%	0.02%	17.76%	17.78%	0.0071%
EATON CORP PLC	ETN	29,878.34	0.15%	3.47%	8.50%	12.12%	0.0183%
ENTERGY CORP	ETR	13,733.29	0.07%	4.48%	-0.24%	4.24%	0.0029%
EDWARDS LIFESCIENCES CORP	EW	25,664.67	0.13%	0.00%	17.73%	17.73%	0.0229%
EXELON CORP	EXC	30,683.22	0.15%	3.79%	5.25%	9.14%	0.0141%
EXPEDITORS INTL WASH INC	EXPD	9,327.80	0.05%	1.52%	7.32%	8.90%	0.0042%
EXPEDIA INC	EXPE	17,494.59	0.09%	0.76%	20.75%	21.59%	0.0190%
EXTRA SPACE STORAGE INC	EXR	9,988.93	0.05%	3.71%	7.58%	11.43%	0.0058%
FORD MOTOR CO	F	47,957.02	0.24%	4.97%	1.28%	6.29%	0.0152%
FASTENAL CO	FAST	12,073.00	0.06%	2.87%	15.50%	18.59%	0.0113%
FACEBOOK INC-A	FB	368,305.28	1.86%	0.00%	33.02%	33.02%	0.6133%
FORTUNE BRANDS HOME & SECURI	FBHS	8,941.71	0.05%	1.09%	17.49%	18.67%	0.0084%
FREEPORT-MCMORAN INC	FCX	14,424.88	0.07%	0.00%	3.00%	3.00%	0.0022%
FEDEX CORP	FDX	46,422.85	0.23%	0.92%	12.72%	13.70%	0.0321%
FIRSTENERGY CORP	FE	14,065.56	0.07%	4.35%	0.53%	4.89%	0.0035%
F5 NETWORKS INC	FFIV	8,251.75	0.04%	0.00%	12.91%	12.91%	0.0054%
FIDELITY NATIONAL INFO SERV	FIS	25,252.40	0.13%	1.36%	12.00%	13.44%	0.0171%
FISERV INC	FISV	21,865.01	0.11%	0.00%	12.18%	12.18%	0.0134%
FIFTH THIRD BANCORP	FITB	15,680.02	0.08%	2.60%	1.87%	4.49%	0.0035%
FOOT LOCKER INC	FL	9,023.66	0.05%	1.62%	9.76%	11.46%	0.0052%
FLIR SYSTEMS INC	FLIR	4,313.38	0.02%	1.53%	15.00%	16.64%	0.0036%
FLUOR CORP	FLR	7,146.23	0.04%	1.64%	5.18%	6.86%	0.0025%
FLOWSERVE CORP	FLS	6,289.53	0.03%	1.57%	8.56%	10.20%	0.0032%
FMC CORP	FMC	6,468.34	0.03%	1.36%	9.57%	11.00%	0.0036%
TWENTY-FIRST CENTURY FOX-A	FOXA	45,447.12	0.23%	1.57%	11.96%	13.63%	0.0312%
FEDERAL REALTY INVS TRUST	FRT	10,994.65	0.06%	2.50%	5.90%	8.47%	0.0047%
FIRST SOLAR INC	FSLR	4,042.18	0.02%	0.00%	-14.59%	-14.59%	-0.0030%
FMC TECHNOLOGIES INC	FTI	6,694.34	0.03%	0.00%	-10.45%	-10.45%	-0.0035%
FRONTIER COMMUNICATIONS CORP	FTR	4,879.98	0.02%	10.10%	3.00%	13.25%	0.0033%
FORTIVE CORP	FTV	17,589.87	0.09%	0.18%	7.44%	7.62%	0.0068%
GENERAL DYNAMICS CORP	GD	47,367.07	0.24%	1.94%	7.64%	9.65%	0.0231%
GENERAL ELECTRIC CO	GE	265,431.72	1.34%	3.13%	10.00%	13.28%	0.1778%
GENERAL GROWTH PROPERTIES	GGP	24,418.76	0.12%	3.29%	6.66%	10.06%	0.0124%
GILEAD SCIENCES INC	GILD	104,411.38	0.53%	2.31%	1.59%	3.92%	0.0206%
GENERAL MILLS INC	GIS	37,777.57	0.19%	2.97%	8.34%	11.43%	0.0218%
CORNING INC	GLW	24,522.14	0.12%	2.29%	14.05%	16.50%	0.0204%
GENERAL MOTORS CO	GM	49,622.26	0.25%	4.79%	9.41%	14.43%	0.0361%
ALPHABET INC-CL A	GOOGL	542,757.56	2.74%	0.00%	16.06%	16.06%	0.4395%
GENUINE PARTS CO	GPC	14,958.40	0.08%	2.62%	6.19%	8.89%	0.0067%
GLOBAL PAYMENTS INC	GPN	11,800.61	0.06%	0.05%	15.10%	15.16%	0.0090%
GAP INC/THE	GPS	8,862.13	0.04%	4.14%	5.98%	10.24%	0.0046%
GARMIN LTD	GRMN	9,086.87	0.05%	4.24%	2.63%	6.92%	0.0032%
GOLDMAN SACHS GROUP INC	GS	68,583.29	0.35%	1.66%	6.79%	8.50%	0.0294%
GOODYEAR TIRE & RUBBER CO	GT	8,477.07	0.04%	0.92%	7.00%	7.95%	0.0034%
WW GRAINGER INC	GWW	13,585.41	0.07%	2.16%	12.13%	14.42%	0.0099%
HALLIBURTON CO	HAL	38,646.28	0.19%	1.60%	12.53%	14.23%	0.0277%
HARMAN INTERNATIONAL	HAR	5,893.18	0.03%	1.74%	16.00%	17.88%	0.0053%
HASBRO INC	HAS	9,948.61	0.05%	2.57%	10.30%	13.00%	0.0065%
HUNTINGTON BANCSHARES INC	HBAN	10,697.73	0.05%	2.91%	5.17%	8.15%	0.0044%
HANESBRANDS INC	HBI	9,539.40	0.05%	1.74%	16.48%	18.36%	0.0088%
HCA HOLDINGS INC	HCA	28,637.01	0.14%	0.00%	11.60%	11.60%	0.0167%
WELLTOWER INC	HCN	26,761.32	0.13%	4.60%	6.26%	11.01%	0.0149%
HCP INC	HCP	17,744.79	0.09%	6.02%	3.79%	9.92%	0.0089%
HOME DEPOT INC	HD	158,993.62	0.80%	2.15%	13.55%	15.84%	0.1270%
HESS CORP	HES	16,980.08	0.09%	1.86%	-11.07%	-9.31%	-0.0080%
HARTFORD FINANCIAL SVCS GRP	HIG	16,527.13	0.08%	2.05%	9.67%	11.82%	0.0098%
HARLEY-DAVIDSON INC	HOG	9,402.95	0.05%	2.70%	10.33%	13.16%	0.0062%

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HOLOGIC INC	HOLX	10,772.33	0.05%	0.00%	11.61%	11.61%	0.0063%
HONEYWELL INTERNATIONAL INC	HON	88,710.38	0.45%	2.11%	9.30%	11.50%	0.0515%
HELMERICH & PAYNE	HP	7,272.85	0.04%	4.13%	-5.96%	-1.95%	-0.0007%
HEWLETT PACKARD ENTERPRIS	HPE	37,890.97	0.19%	0.99%	3.09%	4.09%	0.0078%
HP INC	HPQ	26,569.90	0.13%	3.30%	1.26%	4.57%	0.0061%
H&R BLOCK INC	HRB	5,072.01	0.03%	3.75%	11.00%	14.96%	0.0038%
HORMEL FOODS CORP	HRL	20,072.59	0.10%	1.69%	5.17%	6.90%	0.0070%
HARRIS CORP	HRS	11,320.79	N/A	2.29%	N/A	N/A	N/A
HENRY SCHEIN INC	HSIC	13,331.15	0.07%	0.00%	11.04%	11.04%	0.0074%
HOST HOTELS & RESORTS INC	HST	11,560.44	0.06%	5.15%	6.00%	11.31%	0.0066%
HERSHEY CO/THE	HSY	20,380.92	0.10%	2.48%	8.74%	11.33%	0.0116%
HUMANA INC	HUM	26,368.52	0.13%	0.66%	13.15%	13.85%	0.0184%
INTL BUSINESS MACHINES CORP	IBM	151,835.85	0.77%	3.41%	3.69%	7.16%	0.0548%
INTERCONTINENTAL EXCHANGE IN	ICE	32,095.35	0.16%	1.26%	13.38%	14.73%	0.0238%
INTL FLAVORS & FRAGRANCES	IFF	11,379.25	0.06%	1.63%	9.30%	11.01%	0.0063%
ILLUMINA INC	ILMN	26,631.36	0.13%	0.00%	13.10%	13.10%	0.0176%
INTEL CORP	INTC	178,595.25	0.90%	2.61%	8.70%	11.43%	0.1029%
INTUIT INC	INTU	28,375.77	0.14%	1.21%	16.51%	17.82%	0.0255%
INTERNATIONAL PAPER CO	IP	19,729.47	0.10%	3.71%	6.38%	10.21%	0.0102%
INTERPUBLIC GROUP OF COS INC	IPG	8,955.82	0.05%	2.64%	7.25%	9.99%	0.0045%
INGERSOLL-RAND PLC	IR	17,528.41	0.09%	1.89%	10.90%	12.89%	0.0114%
IRON MOUNTAIN INC	IRM	9,879.72	0.05%	4.99%	10.70%	15.96%	0.0079%
INTUITIVE SURGICAL INC	ISRG	27,901.15	0.14%	0.00%	13.98%	13.98%	0.0197%
ILLINOIS TOOL WORKS	ITW	42,538.44	0.21%	1.90%	7.37%	9.34%	0.0200%
INVESCO LTD	IVZ	12,818.08	0.06%	3.57%	11.09%	14.86%	0.0096%
HUNT (JB) TRANSPRT SVCS INC	JBHT	9,142.88	0.05%	1.09%	13.75%	14.91%	0.0069%
JOHNSON CONTROLS INTERNATION	JCI	43,542.79	N/A	2.45%	N/A	N/A	N/A
JACOBS ENGINEERING GROUP INC	JEC	6,280.27	0.03%	0.00%	8.34%	8.34%	0.0026%
JOHNSON & JOHNSON	JNJ	323,189.13	1.63%	2.67%	6.45%	9.20%	0.1500%
JUNIPER NETWORKS INC	JNPR	9,214.08	0.05%	1.72%	9.13%	10.93%	0.0051%
JPMORGAN CHASE & CO	JPM	240,521.91	1.21%	2.82%	4.84%	7.73%	0.0938%
NORDSTROM INC	JWN	8,998.07	0.05%	2.94%	8.12%	11.18%	0.0051%
KELLOGG CO	K	27,134.57	0.14%	2.65%	6.67%	9.40%	0.0129%
KEYCORP	KEY	13,170.14	0.07%	2.74%	5.15%	7.96%	0.0053%
KRAFT HEINZ CO/THE	KHC	108,991.93	0.55%	2.63%	21.39%	24.31%	0.1336%
KIMCO REALTY CORP	KIM	12,160.49	0.06%	3.56%	5.46%	9.12%	0.0056%
KLA-TENCOR CORP	KLAC	10,896.98	0.05%	3.01%	3.55%	6.61%	0.0036%
KIMBERLY-CLARK CORP	KMB	45,364.49	0.23%	2.91%	6.91%	9.91%	0.0227%
KINDER MORGAN INC	KMI	51,633.64	0.26%	2.17%	10.60%	12.88%	0.0335%
CARMAX INC	KMX	10,215.20	0.05%	0.00%	12.89%	12.89%	0.0066%
COCA-COLA CO/THE	KO	182,654.37	0.92%	3.31%	5.03%	8.43%	0.0776%
MICHAEL KORS HOLDINGS LTD	KORS	7,908.04	0.04%	0.00%	7.32%	7.32%	0.0029%
KROGER CO	KR	28,023.06	0.14%	1.56%	8.38%	10.00%	0.0141%
KOHLS CORP	KSS	7,857.20	0.04%	4.63%	2.63%	7.31%	0.0029%
KANSAS CITY SOUTHERN	KSU	10,077.02	0.05%	1.44%	9.75%	11.26%	0.0057%
LOEWS CORP	L	13,871.94	N/A	0.61%	N/A	N/A	N/A
L BRANDS INC	LB	20,238.22	0.10%	6.24%	10.61%	17.18%	0.0175%
LEGGETT & PLATT INC	LEG	6,092.75	0.03%	2.87%	10.00%	13.01%	0.0040%
LENNAR CORP-A	LEN	9,004.55	0.05%	0.38%	11.52%	11.91%	0.0054%
LABORATORY CRP OF AMER HLDGS	LH	14,064.20	0.07%	0.00%	11.77%	11.77%	0.0083%
LKQ CORP	LKQ	10,890.04	0.05%	0.00%	15.93%	15.93%	0.0087%
L-3 COMMUNICATIONS HOLDINGS	LLL	11,642.36	0.06%	1.86%	17.59%	19.61%	0.0115%
LINEAR TECHNOLOGY CORP	LLTC	14,564.61	0.07%	2.20%	7.39%	9.67%	0.0071%
ELI LILLY & CO	LLY	88,594.47	0.45%	2.56%	12.93%	15.66%	0.0699%
LEGG MASON INC	LM	3,469.45	0.02%	2.63%	10.83%	13.60%	0.0024%
LOCKHEED MARTIN CORP	LMT	72,612.58	0.37%	2.80%	6.83%	9.73%	0.0356%
LINCOLN NATIONAL CORP	LNC	10,938.28	0.06%	2.17%	9.90%	12.18%	0.0067%
ALLIANT ENERGY CORP	LNT	8,709.16	0.04%	3.69%	6.77%	10.58%	0.0046%
LOWE'S COS INC	LOW	63,159.16	0.32%	1.76%	15.83%	17.73%	0.0565%
LAM RESEARCH CORP	LRCX	15,273.35	0.08%	1.21%	7.55%	8.81%	0.0068%
LEUCADIA NATIONAL CORP	LUK	6,861.87	0.03%	1.31%	18.00%	19.43%	0.0067%
SOUTHWEST AIRLINES CO	LUV	24,120.85	0.12%	0.98%	9.37%	10.40%	0.0126%
LEVEL 3 COMMUNICATIONS INC	LVLT	16,674.77	0.08%	0.00%	-5.25%	-5.25%	-0.0044%
LYONDELLBASELL INDU-CL A	LYB	33,532.13	0.17%	4.16%	4.13%	8.38%	0.0142%
MACY'S INC	M	11,428.73	0.06%	4.09%	6.93%	11.16%	0.0064%
MASTERCARD INC	MA	111,717.36	0.56%	0.75%	16.20%	17.01%	0.0958%
MACERICH CO/THE	MAC	11,614.99	0.06%	5.34%	6.93%	12.45%	0.0073%
MARRIOTT INTERNATIONAL -CL A	MAR	26,261.42	0.13%	1.67%	10.82%	12.58%	0.0167%
MASCO CORP	MAS	11,329.66	0.06%	1.13%	17.81%	19.04%	0.0109%
MATTEL INC	MAT	10,313.95	0.05%	5.02%	10.40%	15.68%	0.0082%
MCDONALD'S CORP	MCD	98,443.84	0.50%	3.15%	10.27%	13.58%	0.0674%
MICROCHIP TECHNOLOGY INC	MCHP	13,378.02	0.07%	2.25%	12.73%	15.12%	0.0102%
MCKESSON CORP	MCK	37,635.80	0.19%	0.69%	11.22%	11.95%	0.0227%
MOODY'S CORP	MCO	20,822.24	0.10%	1.33%	11.00%	12.40%	0.0130%
MONDELEZ INTERNATIONAL INC-A	MDLZ	68,287.99	0.34%	1.56%	11.90%	13.55%	0.0467%
MEDTRONIC PLC	MDT	119,399.24	0.60%	1.87%	7.76%	9.71%	0.0585%
METLIFE INC	MET	48,822.90	0.25%	3.55%	8.00%	11.69%	0.0288%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
MOHAWK INDUSTRIES INC	MHK	14,855.89	0.07%	0.00%	9.39%	9.39%	0.0070%
MEAD JOHNSON NUTRITION CO	MJN	14,589.89	0.07%	2.17%	7.98%	10.24%	0.0075%
MCCORMICK & CO-NON VTG SHRS	MKC	12,657.73	0.06%	1.73%	5.55%	7.33%	0.0047%
MARTIN MARIETTA MATERIALS	MLM	11,362.30	0.06%	0.90%	22.45%	23.45%	0.0134%
MARSH & MCLENNAN COS	MMC	34,851.47	0.18%	1.98%	11.43%	13.52%	0.0238%
3M CO	MMM	106,513.46	0.54%	2.52%	8.88%	11.51%	0.0618%
MALLINCKRODT PLC	MNK	7,516.24	0.04%	0.00%	9.00%	9.00%	0.0034%
MONSTER BEVERAGE CORP	MNST	27,949.91	0.14%	0.00%	19.12%	19.12%	0.0270%
ALTRIA GROUP INC	MO	123,542.22	0.62%	3.76%	7.67%	11.57%	0.0721%
MONSANTO CO	MON	44,744.00	0.23%	2.11%	7.85%	10.05%	0.0227%
MOSAIC CO/THE	MOS	8,565.77	0.04%	4.50%	0.05%	4.55%	0.0020%
MARATHON PETROLEUM CORP	MPC	21,462.36	0.11%	3.38%	4.17%	7.62%	0.0082%
MERCK & CO. INC.	MRK	172,576.64	0.87%	2.95%	7.23%	10.29%	0.0896%
MARATHON OIL CORP	MRO	13,395.16	0.07%	1.27%	8.00%	9.32%	0.0063%
MORGAN STANLEY	MS	61,292.59	0.31%	2.21%	7.50%	9.79%	0.0303%
MICROSOFT CORP	MSFT	448,848.90	2.26%	2.67%	7.50%	10.27%	0.2323%
MOTOROLA SOLUTIONS INC	MSI	12,717.83	0.06%	2.17%	5.83%	8.06%	0.0052%
M & T BANK CORP	MTB	18,200.90	0.09%	2.43%	0.83%	3.28%	0.0030%
METTLER-TOLEDO INTERNATIONAL	MTD	11,121.13	0.06%	0.00%	11.79%	11.79%	0.0066%
MICRON TECHNOLOGY INC	MU	18,462.58	0.09%	0.00%	3.40%	3.40%	0.0032%
MURPHY OIL CORP	MUR	5,234.85	N/A	4.33%	N/A	N/A	N/A
MYLAN NV	MYL	20,390.83	0.10%	0.00%	9.21%	9.21%	0.0095%
NAVIENT CORP	NAVI	4,587.47	N/A	4.47%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	15,356.47	0.08%	1.12%	3.06%	4.20%	0.0033%
NASDAQ INC	NDAQ	11,174.74	0.06%	1.79%	8.30%	10.17%	0.0057%
NEXTERA ENERGY INC	NEE	56,508.53	0.28%	2.85%	6.44%	9.38%	0.0267%
NEWMONT MINING CORP	NEM	20,847.06	0.11%	0.34%	4.65%	4.99%	0.0052%
NETFLIX INC	NFLX	42,250.89	0.21%	0.00%	33.74%	33.74%	0.0719%
NEWFIELD EXPLORATION CO	NFX	8,631.34	0.04%	0.00%	20.48%	20.48%	0.0089%
NISOURCE INC	NI	7,767.89	0.04%	2.67%	5.70%	8.44%	0.0033%
NIKE INC -CL B	NKE	88,342.12	0.45%	1.32%	12.55%	13.95%	0.0621%
NIELSEN HOLDINGS PLC	NLSN	19,143.01	0.10%	2.26%	12.33%	14.73%	0.0142%
NORTHROP GRUMMAN CORP	NOC	38,206.05	0.19%	1.61%	7.08%	8.74%	0.0168%
NATIONAL OILWELL VARCO INC	NOV	13,874.17	0.07%	1.66%	-11.29%	-9.72%	-0.0068%
NRG ENERGY INC	NRG	3,534.29	0.02%	2.01%	0.90%	2.92%	0.0005%
NORFOLK SOUTHERN CORP	NSC	28,491.94	0.14%	2.44%	12.35%	14.95%	0.0215%
NETAPP INC	NTAP	9,981.88	0.05%	2.14%	9.58%	11.82%	0.0059%
NORTHERN TRUST CORP	NTRS	15,405.92	0.08%	2.18%	12.10%	14.41%	0.0112%
NUCOR CORP	NUE	15,742.69	0.08%	3.04%	8.33%	11.49%	0.0091%
NVIDIA CORP	NVDA	36,658.20	0.18%	0.68%	10.87%	11.58%	0.0214%
NEWELL BRANDS INC	NWL	25,392.65	0.13%	1.45%	13.92%	15.47%	0.0198%
NEWS CORP - CLASS A	NWSA	8,158.67	0.04%	1.42%	12.15%	13.65%	0.0056%
REALTY INCOME CORP	O	17,306.05	0.09%	3.57%	5.12%	8.78%	0.0077%
OWENS-ILLINOIS INC	OI	2,980.69	0.02%	0.00%	7.37%	7.37%	0.0011%
ONEOK INC	OKE	10,813.83	0.05%	4.79%	9.83%	14.86%	0.0081%
OMNICOM GROUP	OMC	20,105.75	0.10%	2.53%	5.68%	8.27%	0.0084%
ORACLE CORP	ORCL	161,269.72	0.81%	1.52%	8.25%	9.83%	0.0799%
O'REILLY AUTOMOTIVE INC	ORLY	26,590.21	0.13%	0.00%	15.44%	15.44%	0.0207%
OCCIDENTAL PETROLEUM CORP	OXY	55,705.50	0.28%	4.13%	8.00%	12.30%	0.0345%
PAYCHEX INC	PAYX	20,938.54	0.11%	3.17%	9.17%	12.49%	0.0132%
PEOPLE'S UNITED FINANCIAL	PBCT	4,923.44	N/A	4.30%	N/A	N/A	N/A
PITNEY BOWES INC	PBI	3,370.31	0.02%	4.13%	14.00%	18.42%	0.0031%
PACCAR INC	PCAR	20,604.05	0.10%	2.77%	4.88%	7.72%	0.0080%
P G & E CORP	PCG	30,830.46	0.16%	3.18%	4.83%	8.08%	0.0126%
PRICELINE GROUP INC/THE	PCLN	72,731.27	0.37%	0.00%	17.52%	17.52%	0.0642%
PATTERSON COS INC	PDCO	4,551.41	0.02%	2.16%	7.69%	9.93%	0.0023%
PUBLIC SERVICE ENTERPRISE GP	PEG	21,182.72	0.11%	3.91%	2.64%	6.60%	0.0071%
PEPSICO INC	PEP	155,996.10	0.79%	2.71%	6.67%	9.46%	0.0744%
PFIZER INC	PFE	205,443.65	1.04%	3.54%	6.27%	9.93%	0.1028%
PRINCIPAL FINANCIAL GROUP	PFG	14,813.94	0.07%	3.08%	8.20%	11.40%	0.0085%
PROCTER & GAMBLE CO/THE	PG	239,577.39	1.21%	3.04%	6.14%	9.27%	0.1120%
PROGRESSIVE CORP	PGR	18,330.34	0.09%	2.00%	8.95%	11.04%	0.0102%
PARKER HANNIFIN CORP	PH	16,792.41	0.08%	2.08%	8.57%	10.74%	0.0091%
PULTEGROUP INC	PHM	6,886.14	0.03%	1.80%	25.01%	27.03%	0.0094%
PERKINELMER INC	PKI	6,138.54	0.03%	0.50%	19.82%	20.37%	0.0063%
PROLOGIS INC	PLD	28,112.82	0.14%	3.14%	4.89%	8.10%	0.0115%
PHILIP MORRIS INTERNATIONAL	PM	150,820.01	0.76%	4.26%	8.30%	12.74%	0.0969%
PNC FINANCIAL SERVICES GROUP	PNC	44,271.05	0.22%	2.35%	4.30%	6.71%	0.0150%
PENTAIR PLC	PNR	11,633.44	0.06%	2.08%	8.47%	10.64%	0.0062%
PINNACLE WEST CAPITAL	PNW	8,448.17	0.04%	3.33%	4.91%	8.32%	0.0035%
PPG INDUSTRIES INC	PPG	27,522.94	0.14%	1.52%	9.23%	10.82%	0.0150%
PPL CORP	PPL	23,441.71	0.12%	4.40%	5.24%	9.75%	0.0115%
PERRIGO CO PLC	PRGO	13,229.12	0.07%	0.63%	9.23%	9.88%	0.0066%
PRUDENTIAL FINANCIAL INC	PRU	35,681.05	0.18%	3.49%	8.33%	11.96%	0.0215%
PUBLIC STORAGE	PSA	38,692.79	0.20%	3.19%	4.95%	8.21%	0.0160%
PHILLIPS 66	PSX	42,115.51	0.21%	3.02%	6.22%	9.33%	0.0198%
PVH CORP	PVH	8,865.30	0.04%	0.14%	7.08%	7.23%	0.0032%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
QUANTA SERVICES INC	PWR	4,228.44	0.02%	0.00%	8.00%	8.00%	0.0017%
PRAXAIR INC	PX	34,464.54	0.17%	2.48%	8.50%	11.09%	0.0193%
PIONEER NATURAL RESOURCES CO	PXD	31,487.70	0.16%	0.04%	20.00%	20.05%	0.0318%
PAYPAL HOLDINGS INC	PYPL	49,447.43	0.25%	0.00%	15.10%	15.10%	0.0376%
QUALCOMM INC	QCOM	100,944.91	0.51%	2.93%	8.08%	11.13%	0.0567%
QORVO INC	QRVO	7,128.94	0.04%	0.00%	15.83%	15.83%	0.0057%
RYDER SYSTEM INC	R	3,526.90	0.02%	1.74%	12.93%	14.78%	0.0026%
REYNOLDS AMERICAN INC	RAI	67,299.14	0.34%	3.74%	9.32%	13.23%	0.0449%
ROYAL CARIBBEAN CRUISES LTD	RCL	16,134.10	0.08%	2.09%	18.58%	20.86%	0.0170%
REGENERON PHARMACEUTICALS	REGN	42,330.50	0.21%	0.00%	24.34%	24.34%	0.0519%
REGIONS FINANCIAL CORP	RF	12,388.81	0.06%	2.65%	5.88%	8.61%	0.0054%
ROBERT HALF INTL INC	RHI	4,927.11	0.02%	2.30%	9.47%	11.88%	0.0030%
RED HAT INC	RHT	14,638.00	0.07%	0.00%	17.80%	17.80%	0.0131%
TRANSOCEAN LTD	RIG	3,895.08	N/A	0.36%	N/A	N/A	N/A
RALPH LAUREN CORP	RL	8,319.62	0.04%	2.04%	9.14%	11.27%	0.0047%
ROCKWELL AUTOMATION INC	ROK	15,830.80	0.08%	2.37%	4.40%	6.83%	0.0054%
ROPER TECHNOLOGIES INC	ROP	18,491.58	0.09%	0.63%	11.37%	12.04%	0.0112%
ROSS STORES INC	ROST	25,500.08	0.13%	0.84%	12.50%	13.40%	0.0172%
RANGE RESOURCES CORP	RRC	9,576.63	0.05%	0.21%	-16.25%	-16.06%	-0.0078%
REPUBLIC SERVICES INC	RSG	17,296.55	0.09%	2.46%	8.22%	10.78%	0.0094%
RAYTHEON COMPANY	RTN	40,171.28	0.20%	2.11%	7.54%	9.73%	0.0197%
STARBUCKS CORP	SBUX	79,401.72	0.40%	1.51%	19.57%	21.23%	0.0850%
SCANA CORP	SCG	10,342.90	0.05%	3.18%	6.07%	9.34%	0.0049%
SCHWAB (CHARLES) CORP	SCHW	41,767.23	0.21%	0.86%	17.54%	18.47%	0.0389%
SPECTRA ENERGY CORP	SE	29,972.05	0.15%	3.80%	10.47%	14.46%	0.0219%
SEALED AIR CORP	SEE	9,012.93	0.05%	1.33%	4.31%	5.67%	0.0026%
SHERWIN-WILLIAMS CO/THE	SHW	25,514.06	0.13%	1.21%	15.43%	16.74%	0.0215%
SIGNET JEWELERS LTD	SIG	5,634.13	0.03%	1.42%	11.20%	12.70%	0.0036%
JM SMUCKER CO/THE	SJM	15,779.29	0.08%	2.16%	8.08%	10.32%	0.0082%
SCHLUMBERGER LTD	SLB	109,364.14	0.55%	2.54%	7.32%	9.95%	0.0549%
SL GREEN REALTY CORP	SLG	11,277.04	0.06%	2.74%	5.09%	7.90%	0.0045%
SNAP-ON INC	SNA	8,826.83	0.04%	1.68%	4.90%	6.63%	0.0029%
SCRIPPS NETWORKS INTER-CL A	SNI	8,193.22	0.04%	1.58%	8.65%	10.29%	0.0043%
SOUTHERN CO/THE	SO	50,207.62	0.25%	4.33%	3.92%	8.33%	0.0211%
SIMON PROPERTY GROUP INC	SPG	65,049.09	0.33%	3.16%	8.53%	11.83%	0.0388%
S&P GLOBAL INC	SPGI	33,411.84	0.17%	1.14%	10.00%	11.20%	0.0189%
STAPLES INC	SPLS	5,561.12	0.03%	5.61%	0.00%	5.62%	0.0016%
STERICYCLE INC	SRCL	6,815.26	0.03%	0.00%	11.65%	11.65%	0.0040%
SEMPRA ENERGY	SRE	26,776.22	0.14%	2.82%	7.38%	10.30%	0.0139%
SUNTRUST BANKS INC	STI	21,713.36	0.11%	2.28%	4.89%	7.23%	0.0079%
ST JUDE MEDICAL INC	STJ	22,778.47	0.11%	1.54%	9.83%	11.45%	0.0131%
STATE STREET CORP	STT	27,156.76	0.14%	2.06%	13.00%	15.19%	0.0208%
SEAGATE TECHNOLOGY	STX	11,563.65	0.06%	6.35%	3.77%	10.24%	0.0060%
CONSTELLATION BRANDS INC-A	STZ	33,388.04	0.17%	0.95%	14.84%	15.86%	0.0267%
STANLEY BLACK & DECKER INC	SWK	18,499.38	0.09%	1.83%	10.35%	12.28%	0.0115%
SKYWORKS SOLUTIONS INC	SWKS	14,275.95	0.07%	1.33%	17.54%	18.99%	0.0137%
SOUTHWESTERN ENERGY CO	SWN	6,829.42	N/A	0.00%	N/A	N/A	N/A
SYNCHRONY FINANCIAL	SYF	23,349.91	0.12%	0.85%	4.74%	5.61%	0.0066%
STRYKER CORP	SYK	43,572.50	0.22%	1.32%	9.29%	10.67%	0.0234%
SYMANTEC CORP	SYMC	15,622.68	0.08%	1.24%	7.98%	9.27%	0.0073%
SYSCO CORP	SYY	27,207.08	0.14%	2.58%	10.01%	12.72%	0.0174%
AT&T INC	T	249,832.72	1.26%	4.75%	5.00%	9.86%	0.1243%
MOLSON COORS BREWING CO -B	TAP	23,575.94	0.12%	1.53%	16.70%	18.36%	0.0218%
TERADATA CORP	TDC	4,042.40	0.02%	0.00%	9.71%	9.71%	0.0020%
TRANSDIGM GROUP INC	TDG	15,400.10	0.08%	0.00%	13.98%	13.98%	0.0109%
TE CONNECTIVITY LTD	TEL	22,890.30	0.12%	2.12%	11.85%	14.09%	0.0163%
TEGNA INC	TGNA	4,685.11	0.02%	2.56%	4.67%	7.29%	0.0017%
TARGET CORP	TGT	39,481.71	0.20%	3.37%	8.28%	11.79%	0.0235%
TIFFANY & CO	TIF	9,070.88	0.05%	2.34%	9.34%	11.78%	0.0054%
TJX COMPANIES INC	TJX	49,103.91	0.25%	1.38%	11.74%	13.19%	0.0327%
TORCHMARK CORP	TMK	7,652.01	0.04%	0.89%	7.82%	8.74%	0.0034%
THERMO FISHER SCIENTIFIC INC	TMO	62,711.45	0.32%	0.38%	12.13%	12.53%	0.0396%
TRIPADVISOR INC	TRIP	9,202.65	0.05%	0.00%	11.37%	11.37%	0.0053%
T ROWE PRICE GROUP INC	TROW	16,528.72	0.08%	3.26%	9.55%	12.96%	0.0108%
TRAVELERS COS INC/THE	TRV	33,022.62	0.17%	2.30%	8.33%	10.73%	0.0179%
TRACTOR SUPPLY COMPANY	TSCO	9,002.32	0.05%	1.31%	14.91%	16.33%	0.0074%
TYSON FOODS INC-CL A	TSN	29,819.99	0.15%	0.82%	12.43%	13.30%	0.0200%
TESORO CORP	TSO	9,450.88	0.05%	2.64%	3.21%	5.89%	0.0028%
TOTAL SYSTEM SERVICES INC	TSS	8,667.87	0.04%	0.80%	11.00%	11.85%	0.0052%
TIME WARNER INC	TWX	61,924.02	0.31%	2.01%	12.47%	14.61%	0.0456%
TEXAS INSTRUMENTS INC	TXN	70,405.26	0.36%	2.19%	10.00%	12.30%	0.0437%
TEXTRON INC	TXT	10,711.18	0.05%	0.20%	7.31%	7.52%	0.0041%
UNDER ARMOUR INC-CLASS A	UA	15,773.70	0.08%	0.00%	23.73%	23.73%	0.0189%
UNITED CONTINENTAL HOLDINGS	UAL	16,916.76	0.09%	0.00%	-9.67%	-9.67%	-0.0082%
UDR INC	UDR	9,611.40	0.05%	3.28%	6.62%	10.00%	0.0048%
UNIVERSAL HEALTH SERVICES-B	UHS	11,998.98	0.06%	0.32%	9.24%	9.58%	0.0058%
ULTA SALON COSMETICS & FRAGR	ULTA	14,842.76	0.07%	0.00%	22.33%	22.33%	0.0167%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
UNITEDHEALTH GROUP INC	UNH	133,334.80	0.67%	1.70%	13.18%	14.99%	0.1008%
UNUM GROUP	UNM	8,285.24	0.04%	2.62%	6.73%	9.44%	0.0039%
UNION PACIFIC CORP	UNP	81,234.09	0.41%	2.32%	9.31%	11.73%	0.0481%
UNITED PARCEL SERVICE-CL B	UPS	96,025.26	0.48%	2.86%	11.15%	14.17%	0.0686%
URBAN OUTFITTERS INC	URBN	4,046.66	0.02%	0.00%	12.83%	12.83%	0.0026%
UNITED RENTALS INC	URI	6,762.78	0.03%	0.00%	12.89%	12.89%	0.0044%
US BANCORP	USB	73,407.68	0.37%	2.47%	5.45%	7.99%	0.0296%
UNITED TECHNOLOGIES CORP	UTX	85,031.78	0.43%	2.60%	9.54%	12.26%	0.0526%
VISA INC-CLASS A SHARES	V	195,238.99	0.98%	0.68%	16.30%	17.04%	0.1677%
VARIAN MEDICAL SYSTEMS INC	VAR	9,294.18	0.05%	0.00%	11.37%	11.37%	0.0053%
VF CORP	VFC	23,246.05	0.12%	2.67%	9.93%	12.74%	0.0149%
VIACOM INC-CLASS B	VIAB	15,345.91	0.08%	3.92%	5.68%	9.71%	0.0075%
VALERO ENERGY CORP	VLO	24,451.07	0.12%	4.56%	4.13%	8.79%	0.0108%
VULCAN MATERIALS CO	VMC	15,134.24	0.08%	0.70%	25.16%	25.95%	0.0198%
VORNADO REALTY TRUST	VNO	19,111.03	0.10%	2.50%	5.00%	7.56%	0.0073%
VERISK ANALYTICS INC	VRSK	13,733.90	0.07%	0.00%	12.33%	12.33%	0.0085%
VERISIGN INC	VRSN	8,353.41	0.04%	0.00%	10.20%	10.20%	0.0043%
VERTEX PHARMACEUTICALS INC	VRTX	21,608.78	0.11%	0.00%	53.69%	53.69%	0.0585%
VENTAS INC	VTR	24,815.85	0.13%	4.16%	5.82%	10.10%	0.0126%
VERIZON COMMUNICATIONS INC	VZ	211,886.17	1.07%	4.39%	5.24%	9.74%	0.1041%
WATERS CORP	WAT	12,770.17	0.06%	0.00%	9.26%	9.26%	0.0060%
WALGREENS BOOTS ALLIANCE INC	WBA	87,256.44	0.44%	1.79%	11.84%	13.73%	0.0604%
WESTERN DIGITAL CORP	WDC	16,620.95	0.08%	3.35%	2.44%	5.83%	0.0049%
WEC ENERGY GROUP INC	WEC	18,899.32	0.10%	3.31%	5.47%	8.86%	0.0084%
WELLS FARGO & CO	WFC	223,416.83	1.13%	3.43%	9.45%	13.05%	0.1470%
WHOLE FOODS MARKET INC	WFM	9,038.11	0.05%	1.90%	7.38%	9.36%	0.0043%
WHIRLPOOL CORP	WHR	12,234.04	0.06%	2.41%	16.45%	19.06%	0.0118%
WILLIS TOWERS WATSON PLC	WLTW	18,329.00	0.09%	1.45%	15.47%	17.02%	0.0157%
WASTE MANAGEMENT INC	WM	28,200.34	0.14%	2.57%	8.24%	10.91%	0.0155%
WILLIAMS COS INC	WMB	23,067.71	0.12%	5.47%	10.00%	15.74%	0.0183%
WAL-MART STORES INC	WMT	223,085.73	1.12%	2.77%	3.13%	5.94%	0.0668%
WESTROCK CO	WRK	12,192.46	0.06%	3.05%	-0.82%	2.22%	0.0014%
WESTERN UNION CO	WU	10,154.61	0.05%	3.07%	6.58%	9.76%	0.0050%
WEYERHAEUSER CO	WY	23,914.49	0.12%	3.91%	12.93%	17.09%	0.0206%
WYNDHAM WORLDWIDE CORP	WYN	7,397.88	0.04%	2.97%	7.60%	10.69%	0.0040%
WYNN RESORTS LTD	WYNN	9,916.47	0.05%	2.30%	23.03%	25.60%	0.0128%
CIMAREX ENERGY CO	XEC	12,763.38	0.06%	0.32%	55.91%	56.31%	0.0362%
XCEL ENERGY INC	XEL	20,897.18	0.11%	3.31%	4.95%	8.34%	0.0088%
XL GROUP LTD	XL	9,247.32	0.05%	2.40%	12.50%	15.05%	0.0070%
XILINX INC	XLNX	13,774.22	0.07%	2.58%	7.98%	10.66%	0.0074%
EXXON MOBIL CORP	XOM	361,919.62	1.82%	3.42%	11.63%	15.25%	0.2783%
DENTSPLY SIRONA INC	XRAY	13,847.92	0.07%	0.50%	9.76%	10.28%	0.0072%
XEROX CORP	XRX	10,264.77	0.05%	3.04%	11.60%	14.82%	0.0077%
XYLEM INC	XYL	9,398.07	0.05%	1.18%	11.10%	12.35%	0.0059%
YAHOO! INC	YHOO	41,021.83	0.21%	0.00%	4.39%	4.39%	0.0091%
YUM! BRANDS INC	YUM	35,405.65	0.18%	2.08%	11.87%	14.08%	0.0251%
ZIMMER BIOMET HOLDINGS INC	ZBH	26,005.62	0.13%	0.71%	11.06%	11.81%	0.0155%
ZIONS BANCORPORATION	ZION	6,362.54	0.03%	0.91%	12.67%	13.63%	0.0044%
ZOETIS INC	ZTS	25,747.22	0.13%	0.73%	14.73%	15.51%	0.0201%
	Total Market Capitalization:	19,832,215.86					13.02%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Appendix A
CAPM - Market Risk Premium

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
14.02%	2.32%	11.70%

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	15,121.08	0.08%	0.99%	4.50%	5.51%	0.0046%
ALCOA INC	AA	12,864.37	0.07%	1.23%	11.50%	12.80%	0.0092%
AMERICAN AIRLINES GROUP INC	AAL	18,934.22	N/A	1.14%	N/A	N/A	N/A
ADVANCE AUTO PARTS INC	AAP	10,979.38	0.06%	0.16%	11.50%	11.67%	0.0071%
APPLE INC	AAPL	618,164.60	3.44%	2.08%	11.50%	13.70%	0.4708%
ABBVIE INC	ABBV	105,985.50	0.59%	3.50%	13.00%	16.73%	0.0986%
AMERISOURCEBERGEN CORP	ABC	17,942.34	0.10%	1.63%	11.00%	12.72%	0.0127%
ABBOTT LABORATORIES	ABT	62,063.19	0.34%	2.46%	7.50%	10.05%	0.0347%
ACCENTURE PLC-CL A	ACN	73,280.24	0.41%	2.06%	6.50%	8.63%	0.0351%
ADOBE SYSTEMS INC	ADBE	53,849.06	0.30%	0.00%	35.50%	35.50%	0.1063%
ANALOG DEVICES INC	ADI	19,579.94	0.11%	2.64%	11.00%	13.79%	0.0150%
ARCHER-DANIELS-MIDLAND CO	ADM	25,057.34	0.14%	2.79%	6.00%	8.87%	0.0124%
AUTOMATIC DATA PROCESSING	ADP	40,802.71	0.23%	2.54%	9.50%	12.16%	0.0276%
ALLIANCE DATA SYSTEMS CORP	ADS	12,778.32	0.07%	0.00%	10.50%	10.50%	0.0075%
AUTODESK INC	ADSK	16,053.96	N/A	0.00%	N/A	N/A	N/A
AMEREN CORPORATION	AEE	12,472.07	0.07%	3.42%	6.00%	9.52%	0.0066%
AMERICAN ELECTRIC POWER	AEP	32,744.76	0.18%	3.54%	4.00%	7.61%	0.0139%
AES CORP	AES	8,692.22	0.05%	3.34%	8.50%	11.98%	0.0058%
AETNA INC	AET	41,019.04	0.23%	0.86%	9.50%	10.40%	0.0237%
AFLAC INC	AFL	30,151.66	0.17%	2.31%	4.50%	6.86%	0.0115%
ALLERGAN PLC	AGN	96,349.59	0.54%	0.00%	13.50%	13.50%	0.0723%
AMERICAN INTERNATIONAL GROUP	AIG	63,867.82	0.36%	2.17%	10.00%	12.28%	0.0436%
APARTMENT INVT & MGMT CO -A	AIV	-	N/A	2.83%	N/A	N/A	N/A
ASSURANT INC	AIZ	5,532.66	0.03%	2.19%	7.00%	9.27%	0.0028%
ARTHUR J GALLAGHER & CO	AJG	9,044.70	0.05%	2.98%	13.50%	16.68%	0.0084%
AKAMAI TECHNOLOGIES INC	AKAM	9,181.02	0.05%	0.00%	13.00%	13.00%	0.0066%
ALBEMARLE CORP	ALB	9,126.15	0.05%	1.50%	9.50%	11.07%	0.0056%
ALASKA AIR GROUP INC	ALK	8,128.20	0.05%	1.67%	10.50%	12.26%	0.0055%
ALLSTATE CORP	ALL	25,576.74	0.14%	1.92%	6.50%	8.48%	0.0121%
ALLEGION PLC	ALLE	6,621.76	0.04%	0.70%	10.50%	11.24%	0.0041%
ALEXION PHARMACEUTICALS INC	ALXN	29,976.51	0.17%	0.00%	27.50%	27.50%	0.0458%
APPLIED MATERIALS INC	AMAT	32,743.49	0.18%	1.32%	18.00%	19.44%	0.0354%
AMETEK INC	AME	11,181.68	0.06%	0.75%	6.00%	6.77%	0.0042%
AFFILIATED MANAGERS GROUP	AMG	8,218.78	0.05%	0.00%	8.50%	8.50%	0.0039%
AMGEN INC	AMGN	131,521.80	0.73%	2.45%	9.00%	11.56%	0.0845%
AMERIPRISE FINANCIAL INC	AMP	16,368.59	0.09%	2.97%	10.50%	13.63%	0.0124%
AMERICAN TOWER CORP	AMT	47,748.30	0.27%	2.14%	15.50%	17.81%	0.0473%
AMAZON.COM INC	AMZN	381,427.80	2.12%	0.00%	91.00%	91.00%	1.9294%
AUTONATION INC	AN	4,931.85	0.03%	0.00%	9.00%	9.00%	0.0025%
ANTHEM INC	ANTM	33,794.24	0.19%	2.03%	7.50%	9.61%	0.0180%
AON PLC	AON	30,131.09	0.17%	1.16%	12.00%	13.23%	0.0222%
APACHE CORP	APA	23,140.84	0.13%	1.64%	5.00%	6.68%	0.0086%
ANADARKO PETROLEUM CORP	APC	31,247.71	N/A	0.33%	N/A	N/A	N/A
AIR PRODUCTS & CHEMICALS INC	APD	32,081.88	0.18%	2.38%	11.00%	13.51%	0.0241%
AMPHENOL CORP-CL A	APH	20,277.06	0.11%	0.85%	8.00%	8.88%	0.0100%
ACTIVISION BLIZZARD INC	ATVI	32,994.06	0.18%	0.63%	8.00%	8.66%	0.0159%
AVALONBAY COMMUNITIES INC	AVB	-	N/A	3.09%	N/A	N/A	N/A
BROADCOM LTD	AVGO	66,935.09	0.37%	1.21%	23.00%	24.35%	0.0906%
AVERY DENNISON CORP	AVY	7,011.00	0.04%	2.16%	8.50%	10.75%	0.0042%
AMERICAN WATER WORKS CO INC	AWK	13,762.27	0.08%	1.99%	8.00%	10.07%	0.0077%
AMERICAN EXPRESS CO	AXP	59,782.75	0.33%	1.98%	3.00%	5.01%	0.0166%
ACUITY BRANDS INC	AYI	11,452.31	0.06%	0.20%	19.50%	19.72%	0.0126%
AUTOZONE INC	AZO	22,073.53	0.12%	0.00%	11.50%	11.50%	0.0141%
BOEING CO/THE	BA	82,531.89	0.46%	3.56%	10.50%	14.25%	0.0654%
BANK OF AMERICA CORP	BAC	159,381.80	0.89%	1.99%	15.50%	17.64%	0.1563%
BAXTER INTERNATIONAL INC	BAX	26,141.85	0.15%	1.08%	-4.50%	-3.44%	-0.0050%
BED BATH & BEYOND INC	BBBY	6,708.29	0.04%	1.15%	3.00%	4.17%	0.0016%
BB&T CORP	BBT	31,065.03	0.17%	3.15%	7.50%	10.77%	0.0186%
BEST BUY CO INC	BBY	12,194.99	0.07%	2.91%	8.00%	11.03%	0.0075%
CR BARD INC	BCR	16,993.81	0.09%	0.45%	9.50%	9.97%	0.0094%
BECTON DICKINSON AND CO	BDX	38,656.71	0.21%	1.60%	9.50%	11.18%	0.0240%
FRANKLIN RESOURCES INC	BEN	20,798.69	0.12%	2.25%	4.50%	6.80%	0.0079%
BROWN-FORMAN CORP-CLASS B	BF/B	18,620.31	0.10%	1.45%	8.00%	9.51%	0.0098%
BAKER HUGHES INC	BHI	21,459.24	0.12%	1.36%	29.00%	30.56%	0.0365%
BIOGEN INC	BIIB	68,981.48	0.38%	0.00%	11.50%	11.50%	0.0441%
BANK OF NEW YORK MELLON CORP	BK	43,080.64	0.24%	1.88%	10.50%	12.48%	0.0299%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BLACKROCK INC	BLK	60,894.45	0.34%	2.45%	8.00%	10.55%	0.0357%
BALL CORP	BLL	11,214.46	0.06%	0.65%	11.00%	11.69%	0.0073%
BRISTOL-MYERS SQUIBB CO	BMY	93,826.45	0.52%	2.69%	19.50%	22.45%	0.1171%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	-	N/A	0.00%	N/A	N/A	N/A
BOSTON SCIENTIFIC CORP	BSX	32,241.93	0.18%	0.00%	19.50%	19.50%	0.0349%
BORGWARNER INC	BWA	7,520.74	0.04%	1.48%	8.50%	10.04%	0.0042%
BOSTON PROPERTIES INC	BXP	-	N/A	1.94%	N/A	N/A	N/A
CITIGROUP INC	C	136,872.20	0.76%	1.36%	11.50%	12.94%	0.0984%
CA INC	CA	13,566.77	0.08%	3.11%	6.50%	9.71%	0.0073%
CONAGRA FOODS INC	CAG	19,023.33	0.11%	2.29%	5.50%	7.85%	0.0083%
CARDINAL HEALTH INC	CAH	25,284.56	0.14%	2.40%	14.00%	16.57%	0.0233%
CATERPILLAR INC	CAT	48,783.29	0.27%	3.69%	4.00%	7.76%	0.0211%
CHUBB LTD	CB	59,265.78	0.33%	2.17%	8.00%	10.26%	0.0338%
CBRE GROUP INC - A	CBG	9,835.70	0.05%	0.00%	10.00%	10.00%	0.0055%
CBS CORP-CLASS B NON VOTING	CBS	22,331.22	0.12%	1.44%	13.00%	14.53%	0.0180%
CROWN CASTLE INTL CORP	CCI	32,011.01	0.18%	3.99%	18.00%	22.35%	0.0398%
CARNIVAL CORP	CCL	34,895.80	0.19%	2.99%	15.50%	18.72%	0.0363%
CELGENE CORP	CELG	85,691.76	0.48%	0.00%	27.50%	27.50%	0.1310%
CERNER CORP	CERN	21,257.26	0.12%	0.00%	13.50%	13.50%	0.0160%
CF INDUSTRIES HOLDINGS INC	CF	5,415.68	0.03%	5.81%	4.50%	10.44%	0.0031%
CITIZENS FINANCIAL GROUP	CFG	12,825.26	N/A	2.06%	N/A	N/A	N/A
CHURCH & DWIGHT CO INC	CHD	12,556.53	0.07%	1.46%	7.00%	8.51%	0.0059%
CHESAPEAKE ENERGY CORP	CHK	5,326.96	N/A	0.00%	N/A	N/A	N/A
C.H. ROBINSON WORLDWIDE INC	CHRW	9,891.19	0.05%	2.48%	7.50%	10.07%	0.0055%
CHARTER COMMUNICATIONS INC-A	CHTR	74,973.90	N/A	0.00%	N/A	N/A	N/A
CIGNA CORP	CI	33,867.24	0.19%	0.03%	12.50%	12.53%	0.0236%
CINCINNATI FINANCIAL CORP	CINF	12,520.09	0.07%	2.52%	6.50%	9.10%	0.0063%
COLGATE-PALMOLIVE CO	CL	65,551.48	0.36%	2.20%	14.00%	16.35%	0.0596%
CLOROX COMPANY	CLX	16,372.46	0.09%	2.55%	9.50%	12.17%	0.0111%
COMERICA INC	CMA	8,128.88	0.05%	1.97%	6.50%	8.53%	0.0039%
COMCAST CORP-CLASS A	CMCSA	162,315.90	0.90%	1.63%	10.00%	11.71%	0.1057%
CME GROUP INC	CME	40,923.24	0.23%	2.21%	9.50%	11.81%	0.0269%
CHIPOTLE MEXICAN GRILL INC	CMG	11,956.16	0.07%	0.00%	12.50%	12.50%	0.0083%
CUMMINS INC	CMI	20,567.90	0.11%	3.36%	5.00%	8.44%	0.0097%
CMS ENERGY CORP	CMS	12,222.17	0.07%	2.97%	6.00%	9.06%	0.0062%
CENTENE CORP	CNC	11,775.06	0.07%	0.00%	24.50%	24.50%	0.0160%
CENTERPOINT ENERGY INC	CNP	10,383.72	0.06%	4.40%	2.00%	6.44%	0.0037%
CAPITAL ONE FINANCIAL CORP	COF	36,497.43	0.20%	2.22%	2.50%	4.75%	0.0096%
CABOT OIL & GAS CORP	COG	11,893.83	0.07%	0.31%	39.00%	39.37%	0.0260%
COACH INC	COH	10,176.70	0.06%	3.69%	4.00%	7.76%	0.0044%
ROCKWELL COLLINS INC	COL	11,044.10	0.06%	1.55%	8.00%	9.61%	0.0059%
COOPER COS INC/THE	COO	8,992.90	0.05%	0.03%	14.50%	14.53%	0.0073%
CONOCOPHILLIPS	COP	50,803.47	0.28%	2.44%	6.00%	8.51%	0.0240%
COSTCO WHOLESALE CORP	COST	67,136.05	0.37%	1.18%	9.00%	10.23%	0.0382%
CAMPBELL SOUP CO	CPB	17,115.51	0.10%	2.53%	5.50%	8.10%	0.0077%
SALESFORCE.COM INC	CRM	51,094.15	N/A	0.00%	N/A	N/A	N/A
CISCO SYSTEMS INC	CSCO	159,376.40	0.89%	3.54%	6.00%	9.65%	0.0855%
CSRA INC	CSRA	4,435.46	N/A	1.47%	N/A	N/A	N/A
CSX CORP	CSX	27,972.95	0.16%	2.44%	6.50%	9.02%	0.0140%
CINTAS CORP	CTAS	11,994.92	0.07%	0.91%	10.00%	10.96%	0.0073%
CENTURYLINK INC	CTL	15,072.96	0.08%	7.82%	14.00%	22.37%	0.0187%
COGNIZANT TECH SOLUTIONS-A	CTSH	32,921.73	0.18%	0.00%	12.50%	12.50%	0.0229%
CITRIX SYSTEMS INC	CTXS	13,205.85	0.07%	0.00%	11.00%	11.00%	0.0081%
CVS HEALTH CORP	CVS	96,457.05	0.54%	1.88%	11.50%	13.49%	0.0723%
CHEVRON CORP	CVX	188,614.30	1.05%	4.28%	3.50%	7.85%	0.0824%
CONCHO RESOURCES INC	CXO	16,828.44	0.09%	0.00%	16.50%	16.50%	0.0154%
DOMINION RESOURCES INC/VA	D	45,915.84	0.26%	3.86%	9.00%	13.03%	0.0333%
DELTA AIR LINES INC	DAL	28,832.96	0.16%	2.10%	12.00%	14.23%	0.0228%
DU PONT (E.I.) DE NEMOURS	DD	58,441.41	0.32%	2.42%	7.00%	9.50%	0.0309%
DEERE & CO	DE	26,461.84	0.15%	2.85%	-2.00%	0.82%	0.0012%
DISCOVER FINANCIAL SERVICES	DFS	23,497.55	0.13%	2.08%	5.00%	7.13%	0.0093%
DOLLAR GENERAL CORP	DG	20,254.58	0.11%	1.46%	13.50%	15.06%	0.0170%
QUEST DIAGNOSTICS INC	DGX	11,916.47	0.07%	1.87%	10.00%	11.96%	0.0079%
DR HORTON INC	DHI	11,392.18	0.06%	1.05%	13.00%	14.12%	0.0089%
DANAHER CORP	DHR	53,631.13	0.30%	0.64%	13.00%	13.68%	0.0408%
WALT DISNEY CO/THE	DIS	158,797.00	0.88%	1.52%	10.00%	11.60%	0.1024%
DISCOVERY COMMUNICATIONS-A	DISCA	10,179.67	0.06%	0.00%	15.50%	15.50%	0.0088%
DELPHI AUTOMOTIVE PLC	DLPH	19,156.29	0.11%	1.77%	14.50%	16.40%	0.0175%
DIGITAL REALTY TRUST INC	DLR	-	N/A	3.77%	N/A	N/A	N/A
DOLLAR TREE INC	DLTR	18,872.50	0.10%	0.00%	21.00%	21.00%	0.0220%
DUN & BRADSTREET CORP	DNB	4,924.10	0.03%	1.42%	4.50%	5.95%	0.0016%
DIAMOND OFFSHORE DRILLING	DO	2,226.25	0.01%	0.00%	11.50%	11.50%	0.0014%
DOVER CORP	DOV	11,105.71	0.06%	2.46%	3.50%	6.00%	0.0037%
DOW CHEMICAL CO/THE	DOW	59,226.18	0.33%	3.73%	9.50%	13.41%	0.0441%
DR PEPPER SNAPPLE GROUP INC	DPS	17,057.08	0.09%	2.35%	8.50%	10.95%	0.0104%
DARDEN RESTAURANTS INC	DRI	7,823.14	0.04%	3.61%	15.00%	18.88%	0.0082%
DTE ENERGY COMPANY	DTE	17,254.47	0.10%	3.25%	6.00%	9.35%	0.0090%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
DUKE ENERGY CORP	DUK	56,849.39	0.32%	4.18%	4.50%	8.77%	0.0277%
DAVITA INC	DVA	13,804.63	0.08%	0.00%	11.00%	11.00%	0.0084%
DEVON ENERGY CORP	DVN	21,945.12	0.12%	0.57%	1.00%	1.57%	0.0019%
ELECTRONIC ARTS INC	EA	25,034.17	0.14%	0.00%	14.00%	14.00%	0.0195%
EBAY INC	EBAY	36,540.96	0.20%	0.00%	3.50%	3.50%	0.0071%
ECOLAB INC	ECL	34,741.22	0.19%	1.18%	8.50%	9.73%	0.0188%
CONSOLIDATED EDISON INC	ED	22,156.85	0.12%	3.48%	2.50%	6.02%	0.0074%
EQUIFAX INC	EFX	15,945.64	0.09%	0.99%	11.00%	12.04%	0.0107%
EDISON INTERNATIONAL	EIX	24,601.99	0.14%	2.69%	3.50%	6.24%	0.0085%
ESTEE LAUDER COMPANIES-CL A	EL	32,760.32	0.18%	1.35%	8.00%	9.40%	0.0171%
EASTMAN CHEMICAL CO	EMN	9,711.67	0.05%	2.80%	9.50%	12.43%	0.0067%
EMERSON ELECTRIC CO	EMR	33,971.68	0.19%	3.60%	2.00%	5.64%	0.0106%
ENDO INTERNATIONAL PLC	ENDP	4,513.22	0.03%	0.00%	32.00%	32.00%	0.0080%
EOG RESOURCES INC	EOG	50,993.75	0.28%	0.77%	4.00%	4.79%	0.0136%
EQUINIX INC	EQIX	25,614.01	0.14%	1.94%	19.50%	21.63%	0.0308%
EQUITY RESIDENTIAL	EQR	-	N/A	3.25%	N/A	N/A	N/A
EQT CORP	EQT	12,842.01	0.07%	0.16%	12.00%	12.17%	0.0087%
EVERSOURCE ENERGY	ES	17,706.49	0.10%	3.35%	6.00%	9.45%	0.0093%
EXPRESS SCRIPTS HOLDING CO	ESRX	44,763.11	0.25%	0.00%	15.50%	15.50%	0.0386%
ESSEX PROPERTY TRUST INC	ESS	-	N/A	2.88%	N/A	N/A	N/A
E*TRADE FINANCIAL CORP	ETFC	7,799.80	0.04%	0.00%	17.50%	17.50%	0.0076%
EATON CORP PLC	ETN	29,141.72	0.16%	3.56%	5.00%	8.65%	0.0140%
ENTERGY CORP	ETR	14,621.17	0.08%	4.26%	2.00%	6.30%	0.0051%
EDWARDS LIFESCIENCES CORP	EW	25,709.05	0.14%	0.00%	18.00%	18.00%	0.0257%
EXELON CORP	EXC	31,275.36	0.17%	3.63%	7.00%	10.76%	0.0187%
EXPEDITORS INTL WASH INC	EXPD	9,204.81	0.05%	1.57%	10.00%	11.65%	0.0060%
EXPEDIA INC	EXPE	16,274.22	0.09%	0.96%	22.00%	23.07%	0.0209%
EXTRA SPACE STORAGE INC	EXR	-	N/A	3.93%	N/A	N/A	N/A
FORD MOTOR CO	F	47,531.10	0.26%	4.93%	5.50%	10.57%	0.0279%
FASTENAL CO	FAST	11,716.76	0.07%	2.96%	7.00%	10.06%	0.0066%
FACEBOOK INC-A	FB	373,329.60	2.08%	0.00%	36.50%	36.50%	0.7575%
FORTUNE BRANDS HOME & SECURI	FBHS	8,957.10	0.05%	1.10%	15.50%	16.69%	0.0083%
FREEPORT-MCMORAN INC	FCX	14,471.64	0.08%	0.00%	36.50%	36.50%	0.0294%
FEDEX CORP	FDX	46,151.71	0.26%	0.92%	13.50%	14.48%	0.0372%
FIRSTENERGY CORP	FE	14,813.90	0.08%	4.13%	7.50%	11.78%	0.0097%
F5 NETWORKS INC	FFIV	8,027.24	0.04%	0.00%	9.00%	9.00%	0.0040%
FIDELITY NATIONAL INFO SERV	FIS	25,349.04	0.14%	1.34%	15.50%	16.94%	0.0239%
FISERV INC	FISV	22,574.00	0.13%	0.00%	9.50%	9.50%	0.0119%
FIFTH THIRD BANCORP	FITB	15,940.00	0.09%	2.69%	3.00%	5.73%	0.0051%
FOOT LOCKER INC	FL	8,928.07	0.05%	1.64%	8.50%	10.21%	0.0051%
FLIR SYSTEMS INC	FLIR	4,325.22	0.02%	1.62%	8.00%	9.68%	0.0023%
FLUOR CORP	FLR	6,990.05	0.04%	1.67%	1.50%	3.18%	0.0012%
FLOWSERVE CORP	FLS	6,249.00	0.03%	1.58%	2.50%	4.10%	0.0014%
FMC CORP	FMC	6,543.26	0.04%	1.41%	4.00%	5.44%	0.0020%
TWENTY-FIRST CENTURY FOX-A	FOXA	46,030.18	0.26%	1.48%	10.50%	12.06%	0.0309%
FEDERAL REALTY INVS TRUST	FRT	-	N/A	2.55%	N/A	N/A	N/A
FIRST SOLAR INC	FSLR	3,625.24	0.02%	0.00%	8.50%	8.50%	0.0017%
FMC TECHNOLOGIES INC	FTI	6,314.54	0.04%	0.00%	-1.00%	-1.00%	-0.0004%
FRONTIER COMMUNICATIONS CORP	FTR	5,058.31	0.03%	9.70%	13.50%	23.85%	0.0067%
FORTIVE CORP	FTV	-	N/A	0.54%	N/A	N/A	N/A
GENERAL DYNAMICS CORP	GD	47,275.50	0.26%	1.96%	7.00%	9.03%	0.0237%
GENERAL ELECTRIC CO	GE	281,753.80	1.57%	3.06%	12.00%	15.24%	0.2387%
GENERAL GROWTH PROPERTIES	GGP	-	N/A	2.79%	N/A	N/A	N/A
GILEAD SCIENCES INC	GILD	108,503.10	0.60%	2.31%	10.00%	12.43%	0.0749%
GENERAL MILLS INC	GIS	38,684.68	0.22%	2.95%	7.00%	10.05%	0.0216%
CORNING INC	GLW	23,965.07	0.13%	2.34%	6.50%	8.92%	0.0119%
GENERAL MOTORS CO	GM	50,590.65	0.28%	4.69%	9.00%	13.90%	0.0391%
ALPHABET INC-CL A	GOOGL	N/A	N/A	0.00%	N/A	N/A	N/A
GENUINE PARTS CO	GPC	15,110.30	0.08%	2.59%	7.00%	9.68%	0.0081%
GLOBAL PAYMENTS INC	GPN	11,743.72	0.07%	0.05%	14.50%	14.55%	0.0095%
GAP INC/THE	GPS	8,986.84	0.05%	4.12%	-2.00%	2.08%	0.0010%
GARMIN LTD	GRMN	9,194.53	0.05%	4.25%	1.50%	5.78%	0.0030%
GOLDMAN SACHS GROUP INC	GS	68,315.41	0.38%	1.55%	7.00%	8.60%	0.0327%
GOODYEAR TIRE & RUBBER CO	GT	8,494.04	0.05%	1.23%	8.50%	9.78%	0.0046%
WW GRAINGER INC	GWW	13,323.27	0.07%	2.21%	6.00%	8.28%	0.0061%
HALLIBURTON CO	HAL	36,679.00	0.20%	1.69%	8.00%	9.76%	0.0199%
HARMAN INTERNATIONAL	HAR	5,904.75	0.03%	1.67%	17.00%	18.81%	0.0062%
HASBRO INC	HAS	9,961.05	0.06%	2.57%	11.50%	14.22%	0.0079%
HUNTINGTON BANCSHARES INC	HBAN	7,895.64	0.04%	3.24%	9.00%	12.39%	0.0054%
HANESBRANDS INC	HBI	9,879.21	0.05%	1.68%	13.50%	15.29%	0.0084%
HCA HOLDINGS INC	HCA	29,029.14	0.16%	0.00%	11.50%	11.50%	0.0186%
WELLTOWER INC	HCN	-	N/A	4.65%	N/A	N/A	N/A
HCP INC	HCP	-	N/A	5.96%	N/A	N/A	N/A
HOME DEPOT INC	HD	159,080.00	0.88%	2.38%	12.50%	15.03%	0.1329%
HESS CORP	HES	15,130.68	0.08%	2.09%	-1.00%	1.08%	0.0009%
HARTFORD FINANCIAL SVCS GRP	HIG	16,730.77	0.09%	1.95%	11.50%	13.56%	0.0126%
HARLEY-DAVIDSON INC	HOG	9,288.50	0.05%	2.70%	9.00%	11.82%	0.0061%

Appendix A
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Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
HOLOGIC INC	HOLX	10,744.85	0.06%	0.00%	21.00%	21.00%	0.0125%
HONEYWELL INTERNATIONAL INC	HON	88,893.03	0.49%	2.04%	9.00%	11.13%	0.0550%
HELMERICH & PAYNE	HP	6,442.78	0.04%	4.70%	-6.00%	-1.44%	-0.0005%
HEWLETT PACKARD ENTERPRIS	HPE	38,671.36	N/A	0.95%	N/A	N/A	N/A
HP INC	HPQ	25,868.45	N/A	3.31%	N/A	N/A	N/A
H&R BLOCK INC	HRB	5,052.29	0.03%	3.82%	10.00%	14.01%	0.0039%
HORMEL FOODS CORP	HRL	19,974.77	0.11%	1.64%	14.00%	15.75%	0.0175%
HARRIS CORP	HRS	11,318.83	0.06%	2.36%	7.50%	9.95%	0.0063%
HENRY SCHEIN INC	HSIC	13,686.18	0.08%	0.00%	9.00%	9.00%	0.0068%
HOST HOTELS & RESORTS INC	HST	-	N/A	4.97%	N/A	N/A	N/A
HERSHEY CO/THE	HSY	20,462.56	0.11%	2.57%	5.50%	8.14%	0.0093%
HUMANA INC	HUM	26,234.30	0.15%	0.66%	9.50%	10.19%	0.0149%
INTL BUSINESS MACHINES CORP	IBM	149,216.80	0.83%	3.65%	0.50%	4.16%	0.0345%
INTERCONTINENTAL EXCHANGE IN	ICE	33,405.68	0.19%	1.21%	13.50%	14.79%	0.0275%
INTL FLAVORS & FRAGRANCES	IFF	11,300.26	0.06%	1.80%	7.00%	8.86%	0.0056%
ILLUMINA INC	ILMN	26,291.24	0.15%	0.00%	21.50%	21.50%	0.0314%
INTEL CORP	INTC	177,536.40	0.99%	2.77%	9.50%	12.40%	0.1224%
INTUIT INC	INTU	28,397.53	0.16%	1.08%	13.00%	14.15%	0.0223%
INTERNATIONAL PAPER CO	IP	19,700.02	0.11%	3.67%	15.00%	18.95%	0.0207%
INTERPUBLIC GROUP OF COS INC	IPG	9,227.25	0.05%	2.93%	13.00%	16.12%	0.0083%
INGERSOLL-RAND PLC	IR	17,040.77	0.09%	1.94%	10.00%	12.04%	0.0114%
IRON MOUNTAIN INC	IRM	9,842.32	0.05%	5.18%	11.50%	16.98%	0.0093%
INTUITIVE SURGICAL INC	ISRG	27,650.70	0.15%	0.00%	11.50%	11.50%	0.0177%
ILLINOIS TOOL WORKS	ITW	42,485.16	0.24%	2.17%	10.50%	12.78%	0.0302%
INVESCO LTD	IVZ	12,748.39	0.07%	3.60%	7.00%	10.73%	0.0076%
HUNT (JB) TRANSPRT SVCS INC	JBHT	8,964.82	0.05%	1.11%	10.50%	11.67%	0.0058%
JOHNSON CONTROLS INTERNATION	JCI	28,673.06	0.16%	2.58%	9.50%	12.20%	0.0194%
JACOBS ENGINEERING GROUP INC	JEC	6,232.46	0.03%	0.00%	4.00%	4.00%	0.0014%
JOHNSON & JOHNSON	JNJ	327,040.20	1.82%	2.76%	8.50%	11.38%	0.2068%
JUNIPER NETWORKS INC	JNPR	9,133.61	0.05%	1.76%	10.00%	11.85%	0.0060%
JPMORGAN CHASE & CO	JPM	243,411.50	1.35%	2.88%	6.00%	8.97%	0.1213%
NORDSTROM INC	JWN	8,749.92	N/A	3.37%	N/A	N/A	N/A
KELLOGG CO	K	27,298.78	0.15%	2.66%	5.00%	7.73%	0.0117%
KEYCORP	KEY	10,398.96	0.06%	2.84%	7.50%	10.45%	0.0060%
KRAFT HEINZ CO/THE	KHC	108,405.40	N/A	2.67%	N/A	N/A	N/A
KIMCO REALTY CORP	KIM	-	N/A	3.61%	N/A	N/A	N/A
KLA-TENCOR CORP	KLAC	10,823.26	0.06%	2.99%	12.50%	15.68%	0.0094%
KIMBERLY-CLARK CORP	KMB	45,756.49	0.25%	2.89%	10.00%	13.03%	0.0332%
KINDER MORGAN INC	KMI	49,290.49	0.27%	2.26%	13.00%	15.41%	0.0422%
CARMAX INC	KMX	10,462.10	0.06%	0.00%	10.50%	10.50%	0.0061%
COCA-COLA CO/THE	KO	185,372.40	1.03%	3.35%	4.00%	7.42%	0.0764%
MICHAEL KORS HOLDINGS LTD	KORS	8,468.44	0.05%	0.00%	6.00%	6.00%	0.0028%
KROGER CO	KR	29,028.00	0.16%	1.56%	10.50%	12.14%	0.0196%
KOHLS CORP	KSS	7,814.09	0.04%	4.78%	8.00%	12.97%	0.0056%
KANSAS CITY SOUTHERN	KSU	9,715.32	0.05%	1.47%	9.00%	10.54%	0.0057%
LOEWS CORP	L	13,871.91	0.08%	0.61%	12.50%	13.15%	0.0101%
L BRANDS INC	LB	21,244.08	0.12%	3.23%	6.00%	9.33%	0.0110%
LEGGETT & PLATT INC	LEG	6,598.05	0.04%	2.76%	11.00%	13.91%	0.0051%
LENNAR CORP-A	LEN	9,555.20	0.05%	0.37%	12.50%	12.89%	0.0068%
LABORATORY CRP OF AMER HLDGS	LH	14,086.22	0.08%	0.00%	10.00%	10.00%	0.0078%
LKQ CORP	LKQ	10,964.53	0.06%	0.00%	15.00%	15.00%	0.0091%
L-3 COMMUNICATIONS HOLDINGS	LLL	11,584.52	0.06%	1.87%	6.50%	8.43%	0.0054%
LINEAR TECHNOLOGY CORP	LLTC	14,119.38	0.08%	2.17%	5.50%	7.73%	0.0061%
ELI LILLY & CO	LLY	89,731.39	0.50%	2.51%	9.50%	12.13%	0.0605%
LEGG MASON INC	LM	3,586.46	0.02%	2.54%	21.50%	24.31%	0.0048%
LOCKHEED MARTIN CORP	LMT	74,702.68	0.42%	2.86%	8.00%	10.97%	0.0456%
LINCOLN NATIONAL CORP	LNC	10,859.42	0.06%	2.32%	7.00%	9.40%	0.0057%
ALLIANT ENERGY CORP	LNT	9,088.81	0.05%	2.95%	6.50%	9.55%	0.0048%
LOWE'S COS INC	LOW	63,502.48	0.35%	1.94%	15.00%	17.09%	0.0603%
LAM RESEARCH CORP	LRCX	14,767.28	0.08%	1.30%	16.00%	17.40%	0.0143%
LEUCADIA NATIONAL CORP	LUK	N/A	N/A	0.00%	N/A	N/A	N/A
SOUTHWEST AIRLINES CO	LUV	23,153.30	0.13%	1.07%	16.50%	17.66%	0.0227%
LEVEL 3 COMMUNICATIONS INC	LVLT	16,971.05	0.09%	0.00%	37.00%	37.00%	0.0349%
LYONDELLBASELL INDU-CL A	LYB	32,787.28	0.18%	4.35%	6.50%	10.99%	0.0200%
MACY'S INC	M	11,185.05	N/A	4.19%	N/A	N/A	N/A
MASTERCARD INC	MA	112,025.60	0.62%	0.74%	11.00%	11.78%	0.0734%
MACERICH CO/THE	MAC	-	N/A	3.41%	N/A	N/A	N/A
MARRIOTT INTERNATIONAL -CL A	MAR	17,744.40	0.10%	1.72%	12.50%	14.33%	0.0141%
MASCO CORP	MAS	11,198.45	0.06%	1.17%	15.00%	16.26%	0.0101%
MATTEL INC	MAT	10,936.67	0.06%	4.73%	6.50%	11.38%	0.0069%
MCDONALD'S CORP	MCD	100,143.30	0.56%	3.14%	6.00%	9.23%	0.0514%
MICROCHIP TECHNOLOGY INC	MCHP	13,155.60	0.07%	2.35%	8.00%	10.44%	0.0076%
MCKESSON CORP	MCK	37,995.12	0.21%	0.67%	12.00%	12.71%	0.0268%
MOODY'S CORP	MCO	21,178.81	0.12%	1.34%	6.50%	7.88%	0.0093%
MONDELEZ INTERNATIONAL INC-A	MDLZ	67,442.83	0.37%	1.75%	11.50%	13.35%	0.0501%
MEDTRONIC PLC	MDT	121,361.60	0.67%	1.96%	6.50%	8.52%	0.0575%
METLIFE INC	MET	49,006.21	0.27%	3.66%	6.50%	10.28%	0.0280%

Appendix A
CAPM - Market Risk Premium

Company	Ticker	[4] Market Capitalization ($million)	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
MOHAWK INDUSTRIES INC	MHK	15,325.74	0.09%	0.00%	10.50%	10.50%	0.0089%
MEAD JOHNSON NUTRITION CO	MJN	14,634.23	0.08%	2.08%	6.50%	8.65%	0.0070%
MCCORMICK & CO-NON VTG SHRS	MKC	12,310.48	0.07%	1.77%	7.50%	9.34%	0.0064%
MARTIN MARIETTA MATERIALS	MLM	11,539.55	0.06%	0.92%	24.50%	25.53%	0.0164%
MARSH & MCLENNAN COS	MMC	35,404.27	0.20%	1.99%	9.00%	11.08%	0.0218%
3M CO	MMM	108,701.30	0.60%	2.47%	8.50%	11.07%	0.0669%
MALLINCKRODT PLC	MNK	8,007.97	N/A	0.00%	N/A	N/A	N/A
MONSTER BEVERAGE CORP	MNST	28,349.39	0.16%	0.00%	14.50%	14.50%	0.0229%
ALTRIA GROUP INC	MO	125,290.90	0.70%	3.81%	9.50%	13.49%	0.0940%
MONSANTO CO	MON	45,590.21	0.25%	2.30%	6.00%	8.37%	0.0212%
MOSAIC CO/THE	MOS	8,940.61	0.05%	4.81%	5.00%	9.93%	0.0049%
MARATHON PETROLEUM CORP	MPC	22,540.32	0.13%	3.47%	5.50%	9.07%	0.0114%
MERCK & CO. INC.	MRK	174,289.80	0.97%	2.92%	6.00%	9.01%	0.0873%
MARATHON OIL CORP	MRO	12,609.76	0.07%	1.35%	13.00%	14.44%	0.0101%
MORGAN STANLEY	MS	61,636.69	0.34%	2.48%	14.50%	17.16%	0.0588%
MICROSOFT CORP	MSFT	455,043.40	2.53%	2.70%	7.00%	9.79%	0.2478%
MOTOROLA SOLUTIONS INC	MSI	12,700.87	0.07%	2.36%	9.00%	11.47%	0.0081%
M & T BANK CORP	MTB	18,405.23	0.10%	2.40%	5.00%	7.46%	0.0076%
METTLER-TOLEDO INTERNATIONAL	MTD	10,891.89	0.06%	0.00%	10.00%	10.00%	0.0061%
MICRON TECHNOLOGY INC	MU	18,293.60	0.10%	0.00%	-3.50%	-3.50%	-0.0036%
MURPHY OIL CORP	MUR	4,744.08	N/A	3.63%	N/A	N/A	N/A
MYLAN NV	MYL	21,653.65	0.12%	0.00%	20.50%	20.50%	0.0247%
NAVIENT CORP	NAVI	4,349.69	N/A	4.67%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	14,734.99	N/A	1.18%	N/A	N/A	N/A
NASDAQ INC	NDAQ	11,660.78	0.06%	1.82%	10.00%	11.91%	0.0077%
NEXTERA ENERGY INC	NEE	59,149.86	0.33%	2.89%	6.00%	8.98%	0.0295%
NEWMONT MINING CORP	NEM	21,632.36	0.12%	0.25%	6.00%	6.26%	0.0075%
NETFLIX INC	NFLX	41,084.72	0.23%	0.00%	35.00%	35.00%	0.0799%
NEWFIELD EXPLORATION CO	NFX	8,599.08	0.05%	0.00%	11.50%	11.50%	0.0055%
NISOURCE INC	NI	8,137.04	0.05%	2.61%	1.50%	4.13%	0.0019%
NIKE INC -CL B	NKE	93,199.63	0.52%	1.16%	15.00%	16.25%	0.0842%
NIELSEN HOLDINGS PLC	NLSN	18,839.28	0.10%	2.35%	9.00%	11.46%	0.0120%
NORTHROP GRUMMAN CORP	NOC	38,742.40	0.22%	1.66%	7.50%	9.22%	0.0199%
NATIONAL OILWELL VARCO INC	NOV	12,982.95	0.07%	0.58%	-9.00%	-8.45%	-0.0061%
NRG ENERGY INC	NRG	3,703.77	N/A	1.02%	N/A	N/A	N/A
NORFOLK SOUTHERN CORP	NSC	27,567.28	0.15%	2.51%	6.50%	9.09%	0.0139%
NETAPP INC	NTAP	9,996.88	0.06%	2.11%	3.50%	5.65%	0.0031%
NORTHERN TRUST CORP	NTRS	15,725.41	0.09%	2.19%	7.50%	9.77%	0.0085%
NUCOR CORP	NUE	15,239.70	0.08%	3.13%	24.50%	28.01%	0.0237%
NVIDIA CORP	NVDA	34,785.70	0.19%	0.71%	15.50%	16.27%	0.0315%
NEWELL BRANDS INC	NWL	25,247.99	0.14%	1.45%	14.00%	15.55%	0.0218%
NEWS CORP - CLASS A	NWSA	8,200.03	0.05%	1.41%	27.50%	29.10%	0.0133%
REALTY INCOME CORP	O	-	N/A	3.57%	N/A	N/A	N/A
OWENS-ILLINOIS INC	OI	2,940.17	0.02%	0.00%	6.00%	6.00%	0.0010%
ONEOK INC	OKE	10,445.20	0.06%	5.12%	12.50%	17.94%	0.0104%
OMNICOM GROUP	OMC	20,190.88	0.11%	2.69%	9.00%	11.81%	0.0133%
ORACLE CORP	ORCL	162,228.10	0.90%	1.62%	6.00%	7.67%	0.0692%
O'REILLY AUTOMOTIVE INC	ORLY	26,907.59	0.15%	0.00%	13.00%	13.00%	0.0194%
OCCIDENTAL PETROLEUM CORP	OXY	54,551.96	0.30%	4.26%	4.00%	8.35%	0.0253%
PAYCHEX INC	PAYX	21,740.51	0.12%	3.10%	9.00%	12.24%	0.0148%
PEOPLE'S UNITED FINANCIAL	PBCT	4,924.60	0.03%	4.29%	10.50%	15.02%	0.0041%
PITNEY BOWES INC	PBI	3,306.95	0.02%	4.21%	4.50%	8.80%	0.0016%
PACCAR INC	PCAR	20,486.72	0.11%	4.28%	5.50%	9.90%	0.0113%
P G & E CORP	PCG	31,891.12	0.18%	3.12%	12.00%	15.31%	0.0271%
PRICELINE GROUP INC/THE	PCLN	72,528.32	0.40%	0.00%	15.50%	15.50%	0.0625%
PATTERSON COS INC	PDCO	4,674.26	0.03%	2.12%	11.50%	13.74%	0.0036%
PUBLIC SERVICE ENTERPRISE GP	PEG	22,053.35	0.12%	3.85%	3.00%	6.91%	0.0085%
PEPSICO INC	PEP	155,368.60	0.86%	2.80%	7.00%	9.90%	0.0855%
PFIZER INC	PFE	207,142.00	1.15%	3.51%	12.00%	15.72%	0.1810%
PRINCIPAL FINANCIAL GROUP	PFG	14,365.44	0.08%	3.29%	5.00%	8.37%	0.0067%
PROCTER & GAMBLE CO/THE	PG	237,431.80	1.32%	3.01%	9.00%	12.15%	0.1603%
PROGRESSIVE CORP	PGR	18,196.01	0.10%	2.85%	8.50%	11.47%	0.0116%
PARKER HANNIFIN CORP	PH	16,695.06	0.09%	2.03%	5.50%	7.59%	0.0070%
PULTEGROUP INC	PHM	6,824.29	0.04%	1.96%	13.00%	15.09%	0.0057%
PERKINELMER INC	PKI	6,083.40	0.03%	0.50%	8.50%	9.02%	0.0031%
PROLOGIS INC	PLD	-	N/A	3.09%	N/A	N/A	N/A
PHILIP MORRIS INTERNATIONAL	PM	157,800.80	0.88%	4.09%	5.00%	9.19%	0.0806%
PNC FINANCIAL SERVICES GROUP	PNC	44,370.00	0.25%	2.44%	4.00%	6.49%	0.0160%
PENTAIR PLC	PNR	11,273.04	0.06%	2.19%	13.00%	15.33%	0.0096%
PINNACLE WEST CAPITAL	PNW	8,792.75	0.05%	3.28%	4.00%	7.35%	0.0036%
PPG INDUSTRIES INC	PPG	27,464.32	0.15%	1.55%	9.50%	11.12%	0.0170%
PPL CORP	PPL	24,269.80	0.13%	4.38%	1.00%	5.40%	0.0073%
PERRIGO CO PLC	PRGO	13,907.58	0.08%	0.62%	11.50%	12.16%	0.0094%
PRUDENTIAL FINANCIAL INC	PRU	35,160.54	0.20%	3.49%	2.00%	5.52%	0.0108%
PUBLIC STORAGE	PSA	-	N/A	3.33%	N/A	N/A	N/A
PHILLIPS 66	PSX	41,843.61	0.23%	3.27%	2.50%	5.81%	0.0135%
PVH CORP	PVH	8,740.82	0.05%	0.14%	5.50%	5.64%	0.0027%

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QUANTA SERVICES INC	PWR	3,740.39	0.02%	0.00%	8.50%	8.50%	0.0018%
PRAXAIR INC	PX	33,762.91	0.19%	2.66%	6.50%	9.25%	0.0174%
PIONEER NATURAL RESOURCES CO	PXD	30,367.24	0.17%	0.05%	19.50%	19.55%	0.0330%
PAYPAL HOLDINGS INC	PYPL	48,871.43	N/A	0.00%	N/A	N/A	N/A
QUALCOMM INC	QCOM	93,564.95	0.52%	3.50%	4.50%	8.08%	0.0420%
QORVO INC	QRVO	7,224.22	N/A	0.00%	N/A	N/A	N/A
RYDER SYSTEM INC	R	3,452.54	0.02%	2.73%	9.00%	11.85%	0.0023%
REYNOLDS AMERICAN INC	RAI	69,625.70	0.39%	3.77%	14.00%	18.03%	0.0698%
ROYAL CARIBBEAN CRUISES LTD	RCL	15,280.88	0.08%	2.71%	16.50%	19.43%	0.0165%
REGENERON PHARMACEUTICALS	REGN	42,176.40	0.23%	0.00%	23.50%	23.50%	0.0551%
REGIONS FINANCIAL CORP	RF	12,300.58	0.07%	2.76%	7.00%	9.86%	0.0067%
ROBERT HALF INTL INC	RHI	4,938.74	0.03%	2.37%	9.50%	11.98%	0.0033%
RED HAT INC	RHT	14,490.74	0.08%	0.00%	16.50%	16.50%	0.0133%
TRANSOCEAN LTD	RIG	3,526.01	0.02%	0.00%	-19.00%	-19.00%	-0.0037%
RALPH LAUREN CORP	RL	8,145.23	0.05%	2.07%	3.50%	5.61%	0.0025%
ROCKWELL AUTOMATION INC	ROK	15,344.25	0.09%	2.69%	3.00%	5.73%	0.0049%
ROPER TECHNOLOGIES INC	ROP	18,457.05	0.10%	0.66%	7.00%	7.68%	0.0079%
ROSS STORES INC	ROST	25,373.19	0.14%	0.91%	8.50%	9.45%	0.0133%
RANGE RESOURCES CORP	RRC	6,517.48	0.04%	0.21%	12.00%	12.22%	0.0044%
REPUBLIC SERVICES INC	RSG	17,549.67	0.10%	2.50%	8.50%	11.11%	0.0108%
RAYTHEON COMPANY	RTN	41,143.65	0.23%	2.10%	9.00%	11.19%	0.0256%
STARBUCKS CORP	SBUX	79,757.49	0.44%	1.77%	16.50%	18.42%	0.0816%
SCANA CORP	SCG	10,651.60	0.06%	3.21%	4.50%	7.78%	0.0046%
SCHWAB (CHARLES) CORP	SCHW	41,326.55	0.23%	0.90%	12.00%	12.95%	0.0298%
SPECTRA ENERGY CORP	SE	29,782.77	0.17%	3.81%	11.50%	15.53%	0.0257%
SEALED AIR CORP	SEE	9,100.27	0.05%	1.38%	16.00%	17.49%	0.0088%
SHERWIN-WILLIAMS CO/THE	SHW	25,787.12	0.14%	1.29%	11.00%	12.36%	0.0177%
SIGNET JEWELERS LTD	SIG	5,841.61	0.03%	1.40%	14.50%	16.00%	0.0052%
JM SMUCKER CO/THE	SJM	16,050.96	0.09%	2.18%	8.00%	10.27%	0.0092%
SCHLUMBERGER LTD	SLB	107,097.30	0.60%	2.60%	10.00%	12.73%	0.0758%
SL GREEN REALTY CORP	SLG	-	N/A	2.60%	N/A	N/A	N/A
SNAP-ON INC	SNA	8,874.78	0.05%	1.60%	10.00%	11.68%	0.0058%
SCRIPPS NETWORKS INTER-CL A	SNI	7,936.08	0.04%	1.63%	9.00%	10.70%	0.0047%
SOUTHERN CO/THE	SO	50,335.38	0.28%	4.26%	4.00%	8.35%	0.0234%
SIMON PROPERTY GROUP INC	SPG	-	N/A	3.12%	N/A	N/A	N/A
S&P GLOBAL INC	SPGI	33,483.12	0.19%	1.18%	11.50%	12.75%	0.0237%
STAPLES INC	SPLS	5,561.07	N/A	5.61%	N/A	N/A	N/A
STERICYCLE INC	SRCL	6,734.33	0.04%	0.00%	6.50%	6.50%	0.0024%
SEMPRA ENERGY	SRE	27,645.00	0.15%	2.85%	8.00%	10.96%	0.0168%
SUNTRUST BANKS INC	STI	22,137.34	0.12%	2.40%	7.00%	9.48%	0.0117%
ST JUDE MEDICAL INC	STJ	22,656.77	0.13%	1.61%	5.50%	7.15%	0.0090%
STATE STREET CORP	STT	27,680.73	0.15%	2.20%	5.50%	7.76%	0.0119%
SEAGATE TECHNOLOGY	STX	10,868.02	0.06%	6.92%	-0.50%	6.40%	0.0039%
CONSTELLATION BRANDS INC-A	STZ	33,287.18	0.19%	0.99%	14.00%	15.06%	0.0279%
STANLEY BLACK & DECKER INC	SWK	18,532.36	0.10%	1.88%	9.00%	10.96%	0.0113%
SKYWORKS SOLUTIONS INC	SWKS	14,418.75	0.08%	1.46%	16.50%	18.08%	0.0145%
SOUTHWESTERN ENERGY CO	SWN	5,627.96	0.03%	0.00%	-3.00%	-3.00%	-0.0009%
SYNCHRONY FINANCIAL	SYF	22,916.15	N/A	1.89%	N/A	N/A	N/A
STRYKER CORP	SYK	44,296.56	0.25%	1.28%	18.50%	19.90%	0.0490%
SYMANTEC CORP	SYMC	15,438.95	0.09%	1.20%	5.00%	6.23%	0.0053%
SYSCO CORP	SYY	28,258.90	0.16%	2.54%	11.00%	13.68%	0.0215%
AT&T INC	T	252,901.90	1.41%	4.74%	6.50%	11.39%	0.1602%
MOLSON COORS BREWING CO -B	TAP	22,936.34	0.13%	1.54%	8.00%	9.60%	0.0122%
TERADATA CORP	TDC	3,957.52	0.02%	0.00%	3.50%	3.50%	0.0008%
TRANSDIGM GROUP INC	TDG	15,279.06	0.08%	0.00%	20.50%	20.50%	0.0174%
TE CONNECTIVITY LTD	TEL	22,955.92	0.13%	2.30%	9.00%	11.40%	0.0146%
TEGNA INC	TGNA	4,554.36	0.03%	2.64%	1.00%	3.65%	0.0009%
TARGET CORP	TGT	39,408.36	0.22%	3.50%	10.00%	13.68%	0.0300%
TIFFANY & CO	TIF	9,093.97	0.05%	2.50%	7.50%	10.09%	0.0051%
TJX COMPANIES INC	TJX	50,233.34	0.28%	1.36%	10.50%	11.93%	0.0333%
TORCHMARK CORP	TMK	7,773.67	0.04%	0.86%	7.00%	7.89%	0.0034%
THERMO FISHER SCIENTIFIC INC	TMO	62,159.51	0.35%	0.38%	10.50%	10.90%	0.0377%
TRIPADVISOR INC	TRIP	8,935.80	0.05%	0.00%	16.50%	16.50%	0.0082%
T ROWE PRICE GROUP INC	TROW	16,604.90	0.09%	3.32%	7.50%	10.94%	0.0101%
TRAVELERS COS INC/THE	TRV	33,653.26	0.19%	2.30%	1.50%	3.82%	0.0071%
TRACTOR SUPPLY COMPANY	TSCO	9,125.23	0.05%	1.41%	12.00%	13.49%	0.0068%
TYSON FOODS INC-CL A	TSN	28,206.00	0.16%	0.86%	12.50%	13.41%	0.0210%
TESORO CORP	TSO	9,853.55	0.05%	2.65%	8.50%	11.26%	0.0062%
TOTAL SYSTEM SERVICES INC	TSS	8,742.76	0.05%	0.84%	12.00%	12.89%	0.0063%
TIME WARNER INC	TWX	60,301.80	0.34%	2.08%	11.50%	13.70%	0.0459%
TEXAS INSTRUMENTS INC	TXN	69,993.55	0.39%	2.18%	8.00%	10.27%	0.0399%
TEXTRON INC	TXT	10,698.34	0.06%	0.20%	15.50%	15.72%	0.0093%
UNDER ARMOUR INC-CLASS A	UA	17,447.99	0.10%	0.00%	24.50%	24.50%	0.0238%
UNITED CONTINENTAL HOLDINGS	UAL	16,482.45	0.09%	0.00%	5.50%	5.50%	0.0050%
UDR INC	UDR	-	N/A	3.23%	N/A	N/A	N/A
UNIVERSAL HEALTH SERVICES-B	UHS	12,099.34	0.07%	0.32%	11.50%	11.84%	0.0080%
ULTA SALON COSMETICS & FRAGR	ULTA	14,875.39	0.08%	0.00%	19.00%	19.00%	0.0157%

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UNITEDHEALTH GROUP INC	UNH	134,129.00	0.75%	1.77%	14.00%	15.89%	0.1185%
UNUM GROUP	UNM	8,345.24	0.05%	2.25%	11.00%	13.37%	0.0062%
UNION PACIFIC CORP	UNP	79,303.38	0.44%	2.31%	7.00%	9.39%	0.0414%
UNITED PARCEL SERVICE-CL B	UPS	96,399.93	0.54%	2.98%	9.50%	12.62%	0.0676%
URBAN OUTFITTERS INC	URBN	4,185.31	0.02%	0.00%	13.50%	13.50%	0.0031%
UNITED RENTALS INC	URI	6,538.20	0.04%	0.00%	12.50%	12.50%	0.0045%
US BANCORP	USB	74,198.44	0.41%	2.59%	4.50%	7.15%	0.0295%
UNITED TECHNOLOGIES CORP	UTX	86,203.48	0.48%	2.56%	7.00%	9.65%	0.0462%
VISA INC-CLASS A SHARES	V	179,474.10	1.00%	0.74%	11.00%	11.78%	0.1175%
VARIAN MEDICAL SYSTEMS INC	VAR	9,289.14	0.05%	0.00%	7.50%	7.50%	0.0039%
VF CORP	VFC	23,625.28	0.13%	2.60%	10.00%	12.73%	0.0167%
VIACOM INC-CLASS B	VIAB	14,213.38	0.08%	2.23%	5.00%	7.29%	0.0058%
VALERO ENERGY CORP	VLO	25,704.21	0.14%	4.32%	5.50%	9.94%	0.0142%
VULCAN MATERIALS CO	VMC	15,013.43	0.08%	0.71%	33.50%	34.33%	0.0286%
VORNADO REALTY TRUST	VNO	19,569.93	0.11%	2.50%	22.50%	25.28%	0.0275%
VERISK ANALYTICS INC	VRSK	13,674.67	0.08%	0.00%	11.00%	11.00%	0.0084%
VERISIGN INC	VRSN	8,411.49	0.05%	0.00%	12.00%	12.00%	0.0056%
VERTEX PHARMACEUTICALS INC	VRTX	22,818.49	N/A	0.00%	N/A	N/A	N/A
VENTAS INC	VTR	-	N/A	4.14%	N/A	N/A	N/A
VERIZON COMMUNICATIONS INC	VZ	213,394.40	1.19%	4.41%	3.00%	7.48%	0.0887%
WATERS CORP	WAT	12,710.35	0.07%	0.00%	7.00%	7.00%	0.0049%
WALGREENS BOOTS ALLIANCE INC	WBA	89,118.85	0.50%	1.82%	13.00%	14.94%	0.0740%
WESTERN DIGITAL CORP	WDC	15,923.88	0.09%	3.57%	1.50%	5.10%	0.0045%
WEC ENERGY GROUP INC	WEC	19,824.09	0.11%	3.28%	6.00%	9.38%	0.0103%
WELLS FARGO & CO	WFC	230,817.10	1.28%	3.37%	5.00%	8.45%	0.1085%
WHOLE FOODS MARKET INC	WFM	9,140.00	0.05%	1.99%	7.00%	9.06%	0.0046%
WHIRLPOOL CORP	WHR	12,326.25	0.07%	2.43%	10.50%	13.06%	0.0089%
WILLIS TOWERS WATSON PLC	WLTW	N/A	N/A	0.00%	N/A	N/A	N/A
WASTE MANAGEMENT INC	WM	28,275.90	0.16%	2.63%	8.50%	11.24%	0.0177%
WILLIAMS COS INC	WMB	22,995.00	0.13%	2.61%	16.50%	19.33%	0.0247%
WAL-MART STORES INC	WMT	223,820.20	1.24%	2.77%	2.00%	4.80%	0.0597%
WESTROCK CO	WRK	12,162.54	N/A	3.10%	N/A	N/A	N/A
WESTERN UNION CO	WU	9,916.16	0.06%	3.15%	8.00%	11.28%	0.0062%
WEYERHAEUSER CO	WY	23,514.96	0.13%	3.87%	8.50%	12.53%	0.0164%
WYNDHAM WORLDWIDE CORP	WYN	7,539.97	0.04%	2.91%	5.50%	8.49%	0.0036%
WYNN RESORTS LTD	WYNN	10,412.20	0.06%	1.96%	6.50%	8.52%	0.0049%
CIMAREX ENERGY CO	XEC	12,156.44	0.07%	0.25%	16.50%	16.77%	0.0113%
XCEL ENERGY INC	XEL	21,791.18	0.12%	3.26%	5.50%	8.85%	0.0107%
XL GROUP LTD	XL	10,224.71	0.06%	2.31%	9.00%	11.41%	0.0065%
XILINX INC	XLNX	13,546.08	0.08%	2.47%	6.00%	8.54%	0.0064%
EXXON MOBIL CORP	XOM	346,440.30	1.93%	3.62%	5.00%	8.71%	0.1677%
DENTSPLY SIRONA INC	XRAY	13,982.33	0.08%	0.52%	8.00%	8.54%	0.0066%
XEROX CORP	XRX	10,143.17	0.06%	3.10%	4.50%	7.67%	0.0043%
XYLEM INC	XYL	9,429.50	0.05%	1.18%	9.50%	10.74%	0.0056%
YAHOO! INC	YHOO	41,975.66	N/A	0.00%	N/A	N/A	N/A
YUM! BRANDS INC	YUM	36,097.53	0.20%	2.21%	10.00%	12.32%	0.0247%
ZIMMER BIOMET HOLDINGS INC	ZBH	25,735.34	0.14%	0.78%	15.00%	15.84%	0.0227%
ZIONS BANCORPORATION	ZION	6,210.55	0.03%	1.09%	11.00%	12.15%	0.0042%
ZOETIS INC	ZTS	25,576.98	0.14%	0.74%	11.00%	11.78%	0.0167%
		17,989,572.54					14.02%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Appendix A
CAPM - Beta Coefficients

Bloomberg and Value Line Beta Coefficients - Combination Proxy

Company	Ticker	[1] Bloomberg	[2] Value Line
Ameren Corporation	AEE	0.619	0.700
Avista Corporation	AVA	0.593	0.750
CenterPoint Energy, Inc.	CNP	0.751	0.800
CMS Energy Corporation	CMS	0.537	0.650
DTE Energy Company	DTE	0.603	0.700
NiSource Inc.	NI	0.788	NMF
NorthWestern Corporation	NWE	0.590	0.700
SCANA Corporation	SCG	0.590	0.700
Vectren Corporation	VVC	0.690	0.750
Wisconsin Energy Corporation	WEC	0.512	0.650
Mean		0.627	0.71

Bloomberg and Value Line Beta Coefficients - LDC Proxy

Company	Ticker	[1] Bloomberg	[2] Value Line
Atmos Energy Corporation	ATO	0.624	0.750
Chesapeake Utilities Corporation	CPK	0.563	0.600
New Jersey Resources Corporation	NJR	0.708	0.800
Northwest Natural Gas Company	NWN	0.589	0.650
South Jersey Industries, Inc.	SJI	0.650	0.800
Southwest Gas Corporation	SWX	0.581	0.750
Spire Inc	SR	0.652	0.700
WGL Holdings, Inc.	WGL	0.652	0.750
Mean		0.627	0.73

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

Appendix A
CAPM Results

Capital Asset Pricing Model Results - Combination Proxy Group
Bloomberg and Value Line Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Ex-Ante Market Risk Premium		CAPM Result		ECAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP BLOOMBERG AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.32%	0.627	10.70%	11.70%	9.03%	9.66%	10.03%	10.75%
Near-Term Projected 30-Year Treasury [10]	2.80%	0.627	10.70%	11.70%	9.51%	10.14%	10.51%	11.23%
Mean					9.27%	9.90%	10.27%	10.99%

			Ex-Ante Market Risk Premium		CAPM Result		ECAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.32%	0.711	10.70%	11.70%	9.93%	10.64%	10.71%	11.49%
Near-Term Projected 30-Year Treasury [10]	2.80%	0.711	10.70%	11.70%	10.41%	11.12%	11.18%	11.97%
Mean					10.17%	10.88%	10.94%	11.73%

Capital Asset Pricing Model Results - LDC Proxy Group
Bloomberg and Value Line Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Ex-Ante Market Risk Premium		CAPM Result		ECAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP BLOOMBERG AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.32%	0.627	10.70%	11.70%	9.04%	9.66%	10.03%	10.75%
Near-Term Projected 30-Year Treasury [10]	2.80%	0.627	10.70%	11.70%	9.51%	10.14%	10.51%	11.23%
Mean					9.28%	9.90%	10.27%	10.99%

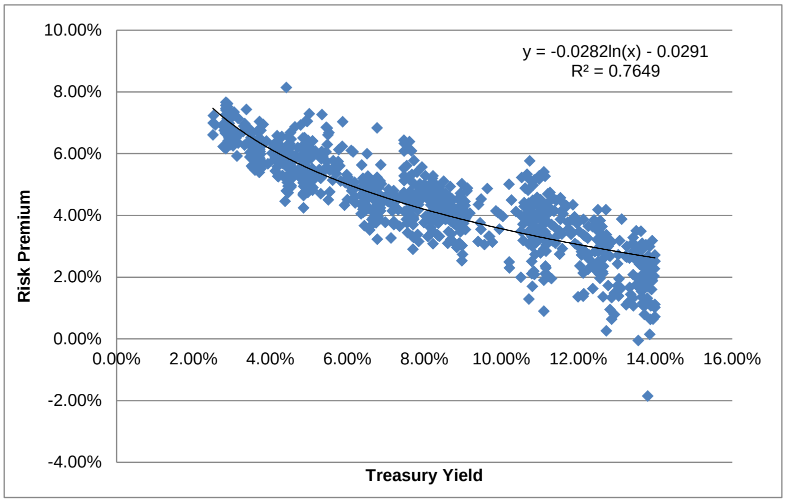
			Ex-Ante Market Risk Premium		CAPM Result		ECAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.32%	0.725	10.70%	11.70%	10.08%	10.81%	10.82%	11.61%
Near-Term Projected 30-Year Treasury [10]	2.80%	0.725	10.70%	11.70%	10.56%	11.28%	11.30%	12.09%
Mean					10.32%	11.04%	11.06%	11.85%

Notes:
[1] *See* Notes [7] and [8]
[2] Source: Schedule RBH-5
[3] Source: Schedule RBH-4
[4] Source: Schedule RBH-4
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + (25% x Col [3]) + 75% x Col. [2] x Col. [3])
[8] Equals Col. [1] + (25% x Col [4]) + 75% x Col. [2] x Col. [4])
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 35, No. 10, October 1, 2016, at 2

Appendix A
Bond Yield Plus Risk Premium Results

Bond Yield Plus Risk Premium

	[1]	[2]	[3]	[4]	[5]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
	-2.91%	-2.82%			
Current 30-Year Treasury			2.32%	7.68%	10.00%
Near-Term Projected 30-Year Treasury			2.80%	7.15%	9.95%
Long-Term Projected 30-Year Treasury			4.45%	5.85%	10.30%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 35, No. 10, October 1, 2016, at 2
Long Term Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 188-trading day average (i.e. lag period) as of September 30, 2016
[9] Equals [7] - [8]

Appendix A
Bond Yield Plus Risk Premium Results

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.86%	4.14%
3/5/1980	14.00%	9.91%	4.09%
3/7/1980	13.50%	9.95%	3.55%
3/14/1980	14.00%	10.04%	3.96%
3/27/1980	12.69%	10.20%	2.49%
4/1/1980	14.75%	10.26%	4.49%
4/29/1980	12.50%	10.51%	1.99%
5/7/1980	14.27%	10.56%	3.71%
5/8/1980	13.75%	10.56%	3.19%
5/19/1980	15.50%	10.62%	4.88%
5/27/1980	14.60%	10.65%	3.95%
5/29/1980	16.00%	10.67%	5.33%
6/10/1980	13.78%	10.71%	3.07%
6/25/1980	14.25%	10.74%	3.51%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.79%	2.11%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	13.61%	10.87%	2.74%
8/28/1980	14.00%	10.87%	3.13%
9/4/1980	14.00%	10.90%	3.10%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.12%	3.88%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.14%	2.36%
12/5/1980	14.60%	11.13%	3.47%
12/8/1980	16.40%	11.13%	5.27%
12/12/1980	15.45%	11.15%	4.30%
12/17/1980	14.20%	11.16%	3.04%
12/17/1980	14.40%	11.16%	3.24%
12/18/1980	14.00%	11.16%	2.84%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.14%	3.36%
12/31/1980	14.56%	11.14%	3.42%
1/7/1981	14.30%	11.13%	3.17%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.40%	3.10%
3/12/1981	15.65%	11.60%	4.05%
3/25/1981	15.30%	11.74%	3.56%
4/1/1981	15.30%	11.82%	3.48%
4/9/1981	15.00%	11.91%	3.09%
4/29/1981	13.50%	12.12%	1.38%
4/29/1981	14.25%	12.12%	2.13%
4/30/1981	13.60%	12.14%	1.46%
4/30/1981	15.00%	12.14%	2.86%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.46%	2.21%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.60%	2.15%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.69%	3.31%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.78%	3.00%
7/27/1981	13.77%	12.82%	0.95%
7/27/1981	15.50%	12.82%	2.68%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.02%	2.43%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.24%	1.10%
9/24/1981	16.25%	13.26%	2.99%
9/29/1981	14.50%	13.31%	1.19%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.36%	1.44%
10/12/1981	16.25%	13.43%	2.82%
10/20/1981	15.25%	13.50%	1.75%
10/20/1981	16.50%	13.50%	3.00%
10/20/1981	17.00%	13.50%	3.50%
10/23/1981	15.50%	13.54%	1.96%
10/26/1981	13.50%	13.56%	-0.06%
10/29/1981	16.50%	13.60%	2.90%
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.66%	3.09%
12/1/1981	15.70%	13.66%	2.04%
12/1/1981	16.00%	13.66%	2.34%
12/15/1981	15.81%	13.69%	2.12%
12/17/1981	14.75%	13.70%	1.05%
12/22/1981	15.70%	13.72%	1.98%
12/22/1981	16.00%	13.72%	2.28%
12/30/1981	16.00%	13.74%	2.26%
12/30/1981	16.25%	13.74%	2.51%
1/4/1982	15.50%	13.75%	1.75%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.86%	0.14%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.92%	3.18%
3/26/1982	16.00%	13.97%	2.03%
3/31/1982	16.25%	13.98%	2.27%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.99%	1.01%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.99%	1.11%
4/12/1982	16.70%	13.99%	2.71%
4/18/1982	14.70%	13.99%	0.71%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.85%	2.15%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	15.55%	13.79%	1.76%
7/1/1982	16.00%	13.79%	2.21%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.75%	3.05%
7/22/1982	14.50%	13.71%	0.79%
7/28/1982	16.10%	13.68%	2.42%
7/30/1982	14.82%	13.66%	1.16%
8/4/1982	15.58%	13.64%	1.94%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.59%	2.41%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.57%	1.93%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	14.74%	13.42%	1.32%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.33%	1.67%
10/15/1982	15.90%	13.26%	2.64%
10/19/1982	15.90%	13.22%	2.68%
10/27/1982	17.00%	13.12%	3.88%
10/28/1982	14.75%	13.11%	1.64%
11/2/1982	16.25%	13.07%	3.18%
11/4/1982	15.75%	13.03%	2.72%
11/5/1982	14.73%	13.01%	1.72%
11/17/1982	16.00%	12.86%	3.14%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	14.50%	12.77%	1.73%
11/24/1982	16.02%	12.77%	3.25%
11/30/1982	12.98%	12.72%	0.26%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.65%	12.72%	2.93%
11/30/1982	16.00%	12.72%	3.28%
11/30/1982	16.10%	12.72%	3.38%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.63%	3.12%
12/13/1982	16.00%	12.58%	3.42%
12/14/1982	16.40%	12.57%	3.83%
12/17/1982	16.25%	12.52%	3.73%
12/20/1982	15.00%	12.51%	2.49%
12/21/1982	15.70%	12.49%	3.21%
12/28/1982	15.25%	12.42%	2.83%
12/28/1982	15.25%	12.42%	2.83%
12/29/1982	16.25%	12.41%	3.84%
12/29/1982	16.25%	12.41%	3.84%
1/11/1983	15.90%	12.26%	3.64%
1/12/1983	15.50%	12.24%	3.26%
1/18/1983	15.00%	12.18%	2.82%
1/24/1983	15.50%	12.13%	3.37%
1/24/1983	16.00%	12.13%	3.87%
1/28/1983	14.90%	12.08%	2.82%
1/31/1983	15.00%	12.07%	2.93%
2/10/1983	15.00%	11.97%	3.03%
2/25/1983	15.70%	11.84%	3.86%
3/2/1983	15.25%	11.79%	3.46%
3/16/1983	16.00%	11.62%	4.38%
3/21/1983	14.96%	11.57%	3.39%
3/23/1983	15.40%	11.53%	3.87%
3/23/1983	16.10%	11.53%	4.57%
3/24/1983	15.00%	11.51%	3.49%
4/12/1983	13.25%	11.30%	1.95%
4/29/1983	15.05%	11.09%	3.96%
5/3/1983	15.40%	11.06%	4.34%
5/9/1983	15.50%	11.00%	4.50%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.84%	3.16%
6/2/1983	14.50%	10.82%	3.68%
6/7/1983	14.50%	10.80%	3.70%
6/9/1983	14.85%	10.79%	4.06%
6/20/1983	14.15%	10.74%	3.41%
6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.71%	3.79%
6/30/1983	14.80%	10.70%	4.10%
6/30/1983	15.90%	10.70%	5.20%
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.69%	4.31%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.70%	4.30%
7/19/1983	15.10%	10.70%	4.40%
8/18/1983	15.30%	10.81%	4.49%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	14.75%	10.87%	3.88%
8/31/1983	15.25%	10.87%	4.38%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	15.40%	11.26%	4.14%
12/20/1983	16.00%	11.26%	4.74%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.30%	3.70%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.42%	4.48%
2/14/1984	14.25%	11.51%	2.74%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.70%	4.30%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.86%	4.34%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.04%	2.36%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.37%	3.63%
8/7/1984	16.69%	12.51%	4.18%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.54%	2.28%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.57%	2.18%
8/30/1984	15.60%	12.58%	3.02%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.65%	2.35%
10/24/1984	15.50%	12.65%	2.85%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.63%	3.29%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.27%	2.73%
2/20/1985	14.50%	12.25%	2.25%
2/22/1985	14.86%	12.25%	2.61%
3/14/1985	15.50%	12.16%	3.34%
3/28/1985	14.80%	12.08%	2.72%
4/9/1985	15.50%	12.02%	3.48%
4/16/1985	15.70%	11.96%	3.74%
6/10/1985	15.75%	11.58%	4.17%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/26/1985	14.82%	11.46%	3.36%
7/9/1985	15.00%	11.38%	3.62%
7/26/1985	14.50%	11.26%	3.24%
8/29/1985	14.50%	11.11%	3.39%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.03%	4.27%
9/25/1985	14.50%	11.02%	3.48%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.91%	4.34%
11/8/1985	12.94%	10.85%	2.09%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.71%	1.29%
12/11/1985	14.90%	10.68%	4.22%
12/20/1985	14.88%	10.59%	4.29%
12/20/1985	15.00%	10.59%	4.41%
12/20/1985	15.00%	10.59%	4.41%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.51%	3.49%
12/31/1985	14.50%	10.51%	3.99%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.20%	2.30%
2/12/1986	15.20%	10.19%	5.01%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.76%	3.14%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.18%	4.07%
5/28/1986	14.00%	9.12%	4.88%
5/29/1986	13.90%	9.10%	4.80%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.97%	5.03%
6/13/1986	13.55%	8.94%	4.61%
6/27/1986	11.88%	8.77%	3.11%
7/14/1986	12.60%	8.59%	4.01%
7/30/1986	13.30%	8.38%	4.92%
8/14/1986	13.50%	8.22%	5.28%
9/5/1986	13.30%	8.02%	5.28%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.67%	5.33%
10/31/1986	13.75%	7.66%	6.09%
11/10/1986	14.00%	7.61%	6.39%
11/19/1986	13.75%	7.56%	6.19%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.47%	6.33%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.47%	5.53%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.73%	5.77%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.09%	3.31%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.60%	8.55%	4.05%
10/20/1987	12.98%	8.55%	4.43%
11/12/1987	12.75%	8.68%	4.07%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	12.85%	8.94%	3.91%
12/31/1987	13.25%	8.94%	4.31%
1/15/1988	13.15%	8.99%	4.16%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.95%	4.05%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.93%	3.07%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.94%	3.86%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%
10/28/1988	13.00%	8.95%	4.05%
11/15/1988	12.00%	8.98%	3.02%
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.81%	4.19%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.72%	4.18%
9/21/1989	12.10%	8.62%	3.48%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	12.60%	8.45%	4.15%
11/9/1989	13.00%	8.45%	4.55%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.32%	4.93%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.80%	8.25%	4.55%
12/21/1989	12.90%	8.25%	4.65%
12/27/1989	12.50%	8.23%	4.27%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.16%	4.34%
1/26/1990	12.10%	8.14%	3.96%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.35%	4.90%
7/6/1990	12.10%	8.36%	3.74%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.53%	3.97%
8/31/1990	12.50%	8.53%	3.97%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.10%	8.70%	3.40%
11/21/1990	12.50%	8.70%	3.80%
11/28/1990	12.75%	8.70%	4.05%

Appendix A

Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.63%	4.62%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.34%	3.36%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.30%	4.60%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.15%	3.60%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.98%	3.77%
3/18/1992	12.50%	7.94%	4.56%
5/15/1992	12.75%	7.86%	4.89%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.70%	5.05%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.30%	7.62%	4.68%
12/22/1992	12.40%	7.62%	4.78%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.06%	4.72%
7/21/1993	11.90%	7.06%	4.84%
7/23/1993	11.50%	7.05%	4.45%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.97%	3.78%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.25%	6.87%	4.38%
9/1/1993	11.47%	6.87%	4.60%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.72%	4.28%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.67%	4.83%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.64%	5.11%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.10%	6.57%	3.53%
10/29/1993	10.20%	6.57%	3.63%
10/29/1993	11.25%	6.57%	4.68%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.45%	4.15%
12/16/1993	11.20%	6.45%	4.75%
12/21/1993	11.30%	6.44%	4.86%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	10.90%	7.20%	3.70%
9/29/1994	11.00%	7.20%	3.80%
10/7/1994	11.87%	7.26%	4.61%
10/18/1994	11.50%	7.32%	4.18%
10/18/1994	11.50%	7.32%	4.18%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.72%	3.28%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.98%	3.78%
11/7/1995	12.50%	6.86%	5.64%
11/8/1995	11.10%	6.85%	4.25%
11/8/1995	11.30%	6.85%	4.45%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.45%	4.85%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.40%	4.37%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.40%	4.60%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/29/1996	11.00%	6.86%	4.14%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.00%	5.25%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.86%	6.24%
2/5/2001	11.50%	5.75%	5.75%
3/15/2001	11.25%	5.66%	5.59%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	10.30%	5.54%	4.76%
10/24/2001	11.00%	5.54%	5.46%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.48%	6.82%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.16%	6.09%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.92%	7.08%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%

Appendix A

Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.81%	5.39%
9/17/2003	9.90%	4.85%	5.05%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.53%	5.47%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.52%	5.88%
12/21/2005	11.00%	4.52%	6.48%
12/22/2005	10.20%	4.52%	5.68%
12/22/2005	11.00%	4.52%	6.48%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.87%	4.73%
7/24/2006	10.00%	4.87%	5.13%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.97%	4.74%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%

Appendix A

Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.84%	5.41%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.92%	4.78%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.48%	5.82%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.41%	6.09%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.89%	6.41%
3/25/2009	10.17%	3.84%	6.34%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.12%	6.03%
10/28/2009	10.15%	4.12%	6.03%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.26%	6.04%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.30%	6.08%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.46%	5.54%
6/18/2010	10.30%	4.46%	5.84%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.17%	5.58%
11/2/2010	9.75%	4.17%	5.58%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	9.56%	4.12%	5.44%
12/6/2010	10.09%	4.12%	5.97%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.11%	6.22%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.10%	5.82%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
4/21/2011	10.00%	4.24%	5.76%
5/26/2011	10.50%	4.32%	6.18%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.38%	4.45%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.06%	3.59%	5.47%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.45%	3.59%	5.86%
1/23/2012	10.20%	3.53%	6.67%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.50%	3.16%	6.34%
4/24/2012	9.75%	3.16%	6.59%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	10.00%	2.92%	7.08%
11/1/2012	9.45%	2.91%	6.54%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.90%	7.40%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.00%	2.87%	7.13%
12/4/2012	10.50%	2.87%	7.63%
12/14/2012	10.40%	2.85%	7.55%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.92%	6.88%
4/23/2013	9.80%	2.96%	6.84%
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.33%	6.27%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.53%	6.20%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.55%	6.17%
12/30/2013	10.00%	3.57%	6.43%
1/21/2014	9.65%	3.66%	5.99%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.72%	6.13%
2/28/2014	9.55%	3.73%	5.83%
3/16/2014	9.72%	3.74%	5.98%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.50%	5.60%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.44%	6.31%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.30%	6.90%
12/3/2014	10.00%	3.29%	6.71%

Appendix A
Bond Yield Plus Risk Premium Results

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.84%	6.16%
10/30/2015	9.80%	2.87%	6.93%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.94%	6.56%
1/6/2016	9.50%	2.97%	6.53%
1/6/2016	9.50%	2.97%	6.53%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.56%	6.94%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%
	22	# of Cases	1,045
		Average	4.55%

Appendix B: Gas Infrastructure Replacement Mechanisms[1]

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
ENSTAR Natural Gas Company		AK		
Alabama Gas Corporation	SR	AL	✓	Rate Stabilization and Equalization Plan
Mobile Gas Service Corporation	SR	AL	✓	Rate Stabilization and Equalization Plan; Cast Iron Main Replacement Factor
CenterPoint Energy Resources Corp.	CNP	AR	✓	Main Replacement Program Rider
Arkansas Oklahoma Gas Corp.		AR	✓	System Safety Enhancement rider
SourceGas Arkansas Inc.	BKH	AR	✓	Main Replacement Program Rider
Southwest Gas Corporation	SWX	AZ	✓	Customer Owned Yard Line Replacement Program; TRIMP rider
UNS Gas, Inc.	FTS	AZ		
Pacific Gas and Electric Company	PCG	CA		
San Diego Gas & Electric Co.	SRE	CA	✓	DIMP Balancing Account
Southern California Gas Company	SRE	CA	✓	DIMP Balancing Account
Southwest Gas Corporation	SWX	CA	✓	Infrastructure Reliability & Replacement Adjustment Mechanism
Atmos Energy Corporation	ATO	CO	✓	System Safety and Integrity Rider
Black Hills Colorado Gas Utility Company, LP	BKH	CO		

[1] Sources: Regulatory Research Associates, RRA Topical Special Report "Gas Utility Infrastructure Investments: the Who, What, When, Where, How, and Why," July 1, 2015; Regulatory Research Associates, RRA Regulatory Focus "Adjustment Clauses: A State-by-State Overview," August 22, 2016; U.S. DOT PHMSA, http://opsweb.phmsa.dot.gov/pipelineforum/pipeline-materials/state-pipeline-system/state-replacement-programs/; American Gas Association, State Infrastructure Replacement Activity, September 2016 Update; Company tariffs.

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Public Service Company of Colorado	XEL	CO	✓	Pipeline Safety Integrity Adjustment Rider
Colorado Natural Gas, Inc.	JPM	CO		
SourceGas Distribution LLC	BKH	CO	✓	System Safety and Integrity Rider
Yankee Gas Services Company	ES	CT	✓	DIMP
Connecticut Natural Gas Corporation		CT	✓	DIMP
Southern Connecticut Gas Company		CT		
Washington Gas Light Company	WGL	DC	✓	ACRP surcharge; VMCREP surcharge
Chesapeake Utilities Corporation	CPK	DE		
Delmarva Power & Light Company	POM	DE		
Florida Public Utilities Company	CPK	FL	✓	Gas Reliability Infrastructure Program
Central Florida Gas	CPK	FL	✓	Gas Reliability Infrastructure Program
Florida City Gas	SO	FL	✓	Safety, Access, and Facility Enhancement (SAFE)
Peoples Gas System		FL	✓	Cast Iron/Bare Steel Pipe Replacement Rider
St. Joe Natural Gas Co, Inc.		FL		
Atlanta Gas Light Company	SO	GA	✓	Pipeline Replacement Program Cost Recovery Rider
Liberty Utilities (Midstates Natural Gas) Corp		GA	✓	Pipe Replacement Surcharge
MidAmerican Energy Company	BKA	IA		
Black Hills Iowa Gas Utility Company, LLC	BKH	IA	✓	System Safety Maintenance Adjustment
Interstate Power and Light Company	LNT	IA		
Liberty Utilities (Midstates Natural Gas) Corp		IA		
Avista Corporation	AVA	ID		
MDU Resources Group, Inc.	MDU	ID		
Intermountain Gas Company	MDU	ID		
Questar Gas Company	STR	ID		

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Illinois Gas Company	BKA	IL		
MidAmerican Energy Company	BKA	IL		
Peoples Gas Light and Coke Company	WEC	IL	✓	Qualifying Infrastructure Plant Surcharge
North Shore Gas Company	WEC	IL		
Northern Illinois Gas Company	SO	IL	✓	Qualifying Infrastructure Plant Surcharge
Liberty Utilities (Midstates Natural Gas) Corp		IL		
Mt. Carmel Public Utility Company		IL		
Northern Indiana Public Service Company	NI	IN	✓	Transmission, Distribution, and Storage System Improvement Charge
Indiana Gas Company, Inc.	VVC	IN	✓	Compliance & System Improvement Adjustment; Pipeline Safety Adustment
Southern Indiana Gas and Electric Company, Inc.	VVC	IN	✓	Compliance & System Improvement Adjustment; Pipeline Safety Adustment
Ohio Valley Gas Corporation		IN	✓	Pipeline Safety Adjustment
Citizens Energy Group		IN		
Midwest Natural Gas Corporation		IN		
Sycamore Gas Company		IN		
Atmos Energy Corporation	ATO	KS	✓	Gas System Reliability Surcharge
Black Hills Energy	BKH	KS		
Black Hills Kansas Gas Utility Company, LLC	BKH	KS	✓	Accelerated Pipeline Replacement Rider; Gas System Reliability Surcharge
Kansas Gas Service Company	ONE	KS	✓	Gas System Reliability Surcharge
Atmos Energy Corporation	ATO	KY	✓	Pipeline Replacement Rider

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Delta Natural Gas Company, Inc.	DGAS	KY	✓	Pipe Replacement Program Rider
Duke Energy Kentucky, Inc.	DUK	KY	✓	Accelerated Service Replacement Program Rider
Public Gas Company, Inc.	EGAS	KY	✓	Pipeline Replacement Program Cost Recovery Rider
Columbia Gas of Kentucky, Incorporated	NI	KY	✓	Accelerated Main Replacement Program Rider
Louisville Gas and Electric Company		KY	✓	Gas Line Tracker
Equitable Gas Company, LLC		KY		
Atmos Energy Corporation	ATO	LA	✓	Rate Stabilization Clause
CenterPoint Energy Resources Corp.	CNP	LA	✓	Rate Stabilization Plan
Entergy Gulf States Louisiana, L.L.C.	ETR	LA	✓	Rate Stabilization Plan Rider; Gas Infrastructure Investment Recovery Rider
Entergy New Orleans, Inc.	ETR	LA		
NSTAR Gas Company	ES	MA	✓	GSEP
Boston Gas Company		MA	✓	GSEP
Colonial Gas Company		MA	✓	GSEP
Bay State Gas Company	NI	MA	✓	GSEP
Berkshire Gas Company		MA	✓	GSEP
Fitchburg Gas and Electric Light Company	UTL	MA	✓	GSEP
Liberty Utilities (New England Natural Gas Company) Corp.		MA	✓	GSEP
Chesapeake Utilities Corporation	CPK	MD		
Baltimore Gas and Electric Company	EXC	MD	✓	STRIDE Rider
Elkton Gas - Pivotal Utility Holdings, Inc.	SO	MD		
Columbia Gas of Maryland, Incorporated	NI	MD	✓	Infrastructure Replacement and Improvement Surcharge

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
UGI Utilities, Inc.	UGI	MD		
Washington Gas Light Company	WGL	MD	✓	STRIDE Rider
Bangor Gas Company, LLC	EGAS	ME		
Northern Utilities, Inc.	UTL	ME	✓	Targeted Infrastructure Replacement Adjustment
Maine Natural Gas		ME		
Consumers Energy Company	CMS	MI	✓	Enhanced Infrastructure Replacement Program (EIRP)
DTE Gas Company	DTE	MI	✓	Infrastructure Recovery Mechanism
Citizens Gas Fuel Company	DTE	MI		
Michigan Gas Utilities Corporation	WEC	MI		
Wisconsin Public Service Corporation	WEC	MI		
Northern States Power Company - WI	XEL	MI		
SEMCO Energy, Inc.		MI	✓	Rider MRP
CenterPoint Energy Resources Corp.	CNP	MN		
Interstate Power and Light Company	LNT	MN		
Great Plains - MDU Resources	MDU	MN		
Minnesota Energy Resources Corporation	WEC	MN		
Northern States Power Company - MN	XEL	MN	✓	GUIC Rider
Union Electric Company	AEE	MO	✓	Infrastructure System Replacement Surcharge
Empire District Gas Company	EDE	MO		
Missouri Gas Energy	SR	MO	✓	Infrastructure System Replacement Surcharge
Laclede Gas Company	SR	MO	✓	Infrastructure System Replacement Surcharge
Liberty Utilities (Midstates Natural Gas) Corp		MO	✓	Infrastructure System Replacement Surcharge
Summit Natural Gas of Missouri, Inc.		MO		
Atmos Energy Corporation	ATO	MS	✓	Formula Rate Plan Rider
CenterPoint Energy Resources Corp.	CNP	MS	✓	Rate Regulation Adjustment Rider
Willmut Gas & Oil Company	SRE	MS		

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Cut Bank Gas Co	EGAS	MT		
Energy West, Incorporated	EGAS	MT		
West Yellowstone Gas	EGAS	MT		
MDU Resources Group, Inc.	MDU	MT		
NorthWestern Corporation	NWE	MT	✓	DSIP Accounting Order
Frontier Natural Gas LLC	EGAS	NC		
Piedmont Natural Gas Company, Inc.	DUK	NC	✓	Integrity Management Rider
Public Service Company of North Carolina, Incorporated	SCG	NC		
MDU Resources Group, Inc.	MDU	ND		
Northern States Power Company - MN	XEL	ND		
MidAmerican Energy Company	BKA	NE		
Black Hills Nebraska Gas Utility Company LLC	BKH	NE	✓	Pipeline Replacement Charge
NorthWestern Corporation	NWE	NE		
SourceGas Distribution LLC		NE	✓	System Safety and Integrity Rider
Northern Utilities, Inc.	UTL	NH		
Liberty Utilities (EnergyNorth Natural Gas) Corp.		NH	✓	CIBS Program
Pivotal Utility Holdings, Inc. (Elizabethtown Gas)	SO	NJ	✓	ENDURE
New Jersey Natural Gas Company	NJR	NJ	✓	NJ RISE
Public Service Electric and Gas Company	PEG	NJ	✓	Capital Adjustment Charge
South Jersey Gas Company	SJI	NJ	✓	SHARP
New Mexico Gas Company, Inc.		NM		
Sierra Pacific Power Company	BKA	NV		
Southwest Gas Corporation	SWX	NV	✓	Gas Infrastructure Replacement
Consolidated Edison Company of New York, Inc.	ED	NY	✓	Deferred accounting treatment
Orange and Rockland Utilities, Inc.	ED	NY	✓	Reliability Surcharge Mechanism
Brooklyn Union Gas Company		NY	✓	Limited Pipeline Replacement mechanism
Niagara Mohawk Power Corporation		NY	✓	Limited Pipeline Replacement mechanism

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
KeySpan Gas East Corporation		NY	✓	LPP replacement surcharge
Central Hudson Gas & Electric Corporation		NY	✓	Deferred accounting treatment
Corning Natural Gas Corporation		NY	✓	Limited Pipeline Replacement mechanism
National Fuel Gas Distribution Corporation		NY	✓	LPP replacement surcharge
New York State Electric & Gas Corporation		NY	✓	Rate Adjustment Mechanism (RAM)
Rochester Gas and Electric Corporation		NY	✓	Rate Adjustment Mechanism (RAM)
St. Lawrence Gas Company, Inc.		NY		
Valley Energy Inc.		NY		
East Ohio Gas Company	D	OH	✓	Pipeline Infrastructure Replacement
Duke Energy Ohio, Inc.	DUK	OH	✓	Accelerated Main Replacement Program Rider
Brainard Gas Corp.	EGAS	OH		
Northeast Ohio Natural Gas Corp.	EGAS	OH		
Orwell Natural Gas Co.	EGAS	OH		
Columbia Gas of Ohio, Incorporated	NI	OH	✓	Infrastructure Replacement Program Rider
Vectren Energy Delivery of Ohio, Inc.	VVC	OH	✓	Distribution Replacement Rider
Ohio Valley Gas Corporation		OH	✓	Pipeline Safety Adjustment
Eastern Natural Gas Company		OH		
Ohio Gas Company		OH		
Pike Natural Gas Co		OH		
CenterPoint Energy Resources Corp.	CNP	OK	✓	Rider PBRC
Oklahoma Natural Gas Company	OGS	OK		
Arkansas Oklahoma Gas Corp.		OK		
Avista Corporation	AVA	OR	✓	Aldyl A Pipe Replacement
Cascade Natural Gas Corporation	MDU	OR		
MDU Resources Group, Inc.	MDU	OR		

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Northwest Natural Gas Company	NWN	OR	✓	System Integrity Program
Pike County Light and Power Company	ED	PA		
Orwell Natural Gas Co.	EGAS	PA		
PECO Energy Company	EXC	PA	✓	Distribution System Improvement Charge
Columbia Gas of Pennsylvania, Inc.	NI	PA	✓	Distribution System Improvement Charge
UGI Penn Natural Gas, Inc.	UGI	PA	✓	Distribution System Improvement Charge
UGI Central Penn Natural Gas, Inc.	UGI	PA	✓	Distribution System Improvement Charge
UGI Utilities, Inc.	UGI	PA	✓	Distribution System Improvement Charge
Equitable Gas Company, LLC		PA	✓	Distribution System Improvement Charge
Peoples Natural Gas Company LLC		PA	✓	Distribution System Improvement Charge
Peoples TWP LLC		PA	✓	Distribution System Improvement Charge
Philadelphia Gas Works Co.		PA	✓	Distribution System Improvement Charge
National Fuel Gas Distribution Corporation		PA		
Valley Energy Inc.		PA		
Narragansett Electric Company (Gas)		RI	✓	Distribution Adjustment Clause/Capital Expenditure Tracker
Piedmont Natural Gas Company, Inc.	DUK	SC	✓	Rate Stabilization Act
South Carolina Electric & Gas Co.	SCG	SC		
MidAmerican Energy Company	BKA	SD		
MDU Resources Group, Inc.	MDU	SD		
NorthWestern Corporation	NWE	SD		

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Atmos Energy Corporation	ATO	TN	✓	Annual Review Mechanism
Chattanooga Gas Company	SO	TN		
Piedmont Natural Gas Company, Inc.	DUK	TN	✓	Integrity Management Rider
Atmos Energy Corporation	ATO	TX	✓	Gas Reliability Infrastructure Program
CenterPoint Energy Resources Corp.	CNP	TX	✓	Gas Reliability Infrastructure Program
Texas Gas Service Company	OGS	TX	✓	Gas Reliability Infrastructure Program
Questar Gas Company	STR	UT	✓	Infrastructure Rate Adjustment Tracker
Atmos Energy Corporation	ATO	VA	✓	Infrastructure Reliability and Replacement Adjustment
Virginia Natural Gas, Inc.	SO	VA	✓	SAVE Plan Rider
Columbia Gas of Virginia, Incorporated	NI	VA	✓	Infrastructure Reliability and Replacement Adjustment
Washington Gas Light Company	WGL	VA	✓	SAVE Rider
Appalachian Natural Gas Distribution Company		VA		
Roanoke Gas Company		VA		
Vermont Gas Systems, Inc.		VT	✓	Vermont System Expansion & Reliability Fund
Avista Corporation	AVA	WA	✓	Elevated Risk Pipeline Facility Replacements
Cascade Natural Gas Corporation	MDU	WA	✓	Elevated Risk Pipeline Facility Replacements
Northwest Natural Gas Company	NWN	WA	✓	Elevated Risk Pipeline Facility Replacements
Puget Sound Energy, Inc.		WA	✓	CRM for Pipeline Replacement
Superior Water, Light and Power Company	ALE	WI		
Wisconsin Power and Light Company	LNT	WI		
Madison Gas and Electric Company	MGEE	WI		
Wisconsin Electric Power Company	WEC	WI		
Wisconsin Gas LLC	WEC	WI		

Local Distribution Company	Parent Ticker	State	Infrastructure Replacement Mechanism	Mechanism Name
Wisconsin Public Service Corporation	WEC	WI		
Northern States Power Company - WI	XEL	WI		
Midwest Natural Gas, Inc.		WI		
Hope Gas, Inc.	D	WV	✓	Pipeline Replacement and Expansion Program (PREP)
Bluefield Gas Company		WV		
Equitable Gas Company, LLC		WV		
Mountaineer Gas Company		WV	✓	Infrastructure Replacement and Expansion
Cheyenne Light, Fuel and Power Company	BKH	WY		
Black Hills Energy Northwest WY	BKH	WY	✓	Pipeline Safety and Integrity Mechanisms (PSIM)
MDU Resources Group, Inc.	MDU	WY		
Questar Gas Company	STR	WY		
SourceGas Distribution LLC	BKH	WY		
Wyoming Gas Company		WY		

Appendix C: State Infrastructure Replacement Activity

American Gas Association September 15, 2016 Update

State	Activity	Relevant Documents
Alabama	• In 1995, the Alabama PSC approved the Cast Iron Main Replacement Factor as part of Mobile Gas' general rate case. The program recovers the annual revenue requirement level of depreciation, taxes and return associated with cast iron main replacements. The tracking mechanism is applied to all rate classes and is updated annually for incremental investment in cast iron main replacements. • Mobile Gas and Alabama Gas presently utilize a Rate Stabilization and Equalization Plan.	Docket No. 24794
Arkansas	• In 1988, CenterPoint received approval from the Arkansas PSC for a Gas Main Replacement Program (GMRP) which provided for a tracker to be applied to the replacement of bare steel and cast iron mains and associated services. In 1992, the program was modified to include recovery of capital investment (depreciation) and was expanded to include all cast iron gas main and related services. At that time it was also renamed the Cast Iron Main Replacement Program (CIGMRP). In 2002, the program was modified again to include bare steel and associated services, and was renamed the Main Replacement Program (MRP). • On July 9, 2012, in Docket No. 12-045-TF, the Arkansas PSC authorized CenterPoint Energy to include as eligible for expedited replacement steel mains that do not have a cathodic protection system (unprotected steel main) along with any associated services. These mains were deemed eligible for cost recovery under CenterPoint's Main Replacement Program Rider (Rider MRP). • On July 7, 2014, the Arkansas Public Service Commission adopted a settlement in SourceGas Arkansas' (SGA) base rate proceeding. The approved settlement allows SGA to implement a main replacement program (MRP) rider and an at risk meter relocation program rider. The primary purpose of the MRP Rider is to support the expedited replacement of Subject Mains and Associated Services. Eligible mains and services under the MRP are: o 1) Bare steel mains; o 2) Coated steel mains that are not cathodically protected; and o 3) Mains that are the subject of an advisory issued by a federal or state agency and which the Company has determined to be in unsatisfactory condition. • On July 25, 2014, the Arkansas Public Service Commission adopted a settlement in Arkansas	Dockets 06-161-U and 10-108-U (CenterPoint) Docket No. 13-079-U (SourceGas Arkansas) Docket No. 13-078-U (Arkansas Oklahoma Gas) Docket No. 12-045-TF (CenterPoint MRP)

	Oklahoma Gas' base rate proceeding. The approved settlement also allowed for the implementation of a system safety and enhancement rider (SSER). The SSER will provide AOG with the opportunity to earn the Commission approved rate of return on investments made in replacing aging infrastructure. The SSER is designed to prioritize the replacement of the riskiest pipe in the system each year, but at a rate which has minimal impact on customers' bills. Mains covered under the SSER are: o 1) Bare steel mains; o 2) Any mains associated with the replacement of low pressure systems (AOG's tariff defines a low pressure system as one that is composed of distribution mains operated at less than or equal to 12 ounces of pressure); and o 3) Mains that are the subject of an advisory issued by a federal or Arkansas state agency and which the Company has determined to be in unsatisfactory condition.	
Arizona	• In January 2012, the Arizona Corporation Commission granted Southwest Gas approval to implement a Customer Owner Yard Line (COYL) program as part of its general rate case settlement. The program is designed to facilitate leak surveying and, when required, replacement of customer yard lines. The program includes a cost recovery component whereby Southwest Gas defers the actual COYL capital costs and files an annual application requesting authority from the Arizona CC to implement a per therm surcharge rate to recover the revenue requirement on the deferred COYL costs.	Docket No. G-01551A-10-0458 (Southwest Gas)
California	• In December 2010, San Diego Gas & Electric filed a request with the California PUC for a gas base rate increase. In its filing, the utility also proposes a post-test-year ratemaking mechanism for the three-year period 2013 through 2015, under which the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The CPUC approved the mechanism in May 2013. • In December 2010, Southern California Gas filed a request with the CPUC for a gas base rate increase. As part of that filing, the utility proposes a post-test-year ratemaking mechanism for the three year period 2013-2015, which under the company's revenue requirement would be adjusted to reflect increases in capital-related and other expenses. The company did not request specific rate increases under the mechanism. The CPUC approved the mechanism in May 2013. • As part of its 2013 GRC in California, Southwest Gas (Southwest) proposed an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) that is designed to facilitate and complement projects involving the enhancement and replacement of gas infrastructure. • In June of 2014, southwest received approval for an IRRAM mechanism. Southwest's approved IRRAM,	A1012005 (San Diego Gas & Electric) A1012006 (Southern California Gas) A1212024 (Southwest Gas)

	applies to infrastructure replacement and other non-revenue producing infrastructure projects. The PUC will allow SWG to assess a surcharge to collect the first year IRRAM budget of $232,665 in Southern California, $48,345 in Northern California, and $58,942 in South Lake Tahoe. The first phase of this program will be limited to surveying leaks on Customer Owned Yard Lines (COYL) on school properties. • Southwest will also continue with its Early Vintage Plastic Pipe (EEVP) replacement plan, which it began in 2007. Southwest had proposed to accelerate this program in order to complete replacement of the replacement of Aldyl-A pipe by 2018, however, the Commission denied this proposal. The company will adhere to its current EEVP schedule, which is due to be completed in 2026.	
Colorado	• In September 2011, Public Service Company of Colorado received approval from the Colorado PUC to implement a pipeline system integrity adjustment tracker to recover costs associated with reliability improvements and compliance with certain federal safety regulations. • SourceGas has Rate Schedules for natural gas service that are subject to a System Safety and Integrity Rider ("SSIR") designed to collect Eligible System Safety and Integrity Costs. Eligible project cost include: o Projects in accordance with Code of Federal Regulations ("CFR") Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart O (Gas Transmission Pipeline Integrity Management), including projects in accordance with the Company's transmission integrity management program ("TIMP") and projects in accordance with State enforcement of Subpart O and the Company's TIMP; o Projects in accordance with CFR Title 49 (Transportation), Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), Subpart P (Gas Distribution Pipeline Integrity Management), including projects in accordance with the Company's distribution integrity management program ("DIMP") and projects in accordance with State enforcement of Subpart P and the Company's DIMP; and o Projects in accordance with final rules and regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") that becomes effective on or after the filing date of the application requesting approval of the SSIR. • The SSIR rate will be subject to annual changes to be effective on January 1 of each year for a period of four years from the first effective date, after which period of time the Company's SSIR Tariff will expire unless the SSIR Tariff is reinstated upon consideration of the Public Utilities Commission of the State of Colorado (the	Docket No. 10AL-963G Docket No. 15AL-0135G (Xcel) 15AL-0299G (Atmos)

	"Commission") of an application filed by the Company no later than six months prior to the expiration date. The SSIR Tariff to be applied to each Rate Schedule is as set forth on the statement of effective rates, charges and fees, Sheet Nos. 8 through 10 of the Rocky Mountain Tariff. • In its March 2015 rate filing, Xcel Energy requested (in addition to its base rate increase) a cumulative increase of $42.9 million attributable to the extension and modification of the pipeline system integrity adjustment, spread out over three years. This mechanism was extended through 2018 on January 27, 2016. • On September 23, 2015, Atmos Energy filed a settlement signed by Commission Staff, the Office of Consumer Counsel, and Energy Outreach Colorado in with the Public Utilities Commission of Colorado in which the settling parties agreed to allow Atmos to separately recover system safety integrity costs through a System Safety and Integrity Rider (SSIR). • Projects eligible for recovery through the SSIR will include high and moderate risk integrity projects that are (a) identified by the Company and approved on a preliminary basis by the Commission based on filing made on or before February 1, 2016 (for 2016 Projects) and on or before each November 1 thereafter (for 2017 and beyond Projects), (b) implemented in consultation with the Staff of the Commission and the Office of Consumer Counsel, and (c) ultimately approved for inclusion in the SSIR by the Commission through a filing made on or before February 1, 2016 (for 2016 Projects) and each November 1 thereafter (for 2017 and beyond Projects). Such SSIR Projects shall be consistent with the Company's compliance with federal and state regulatory requirements including, but not limited to, 49 CFR Part 192, final rules and regulations of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Environmental Protection Agency (EPA) that become effective on or after the effective date of the SSIR. • The SSIR will be implemented for an initial three year term, from January 1, 2016, through December 31, 2018, and will recover capital investments made between September 1, 2015, and December 31, 2018, that are associated with integrity projects. Atmos will have the right to seek an extension of the initial three-year term in a future filing. This proposal was approved on November 4, 2015.	
Connecticut	• In a June 2011 order, the Public Utilities Regulatory Authority (PURA) approved Yankee Gas' proposal to increase its capital spending on cast iron and bare steel replacement by approximately $13 million in Rate Year 1, and approximately $25 million in Rate Year2. Yankee plans to maintain this $40 million capital spending level (i.e., $15 million authorized in 06-12-02PH01 plus an incremental $25 million) in each subsequent year. The Commission found that this level of spending was reasonable to adequately provide for the integrity of	Docket No13-06-08 Docket No 10-12-02 (Yankee Gas)

	Yankee's pipeline system and it anticipates that this level of replacement will reflect the improvement required by the DIMP regulations. • On January 22, 2014 the Public Utilities Regulatory Authority (PURA) approved a Distribution Integrity Management Program (DIMP) mechanism that allows recovery of the revenue requirement for main replacement activity between rate applications. Additionally, the PURA approved a schedule and budget for system integrity projects that target needed replacement of cast iron mains, bare steel mains and bare steel services.	
District of Columbia	• In February 2012, WGL filed a rate case with the DC PSC in which it proposed to expand its existing pipe replacement program (originally approved in 2007). In the filing, WGL proposes a 5-year accelerated pipeline replacement program and a surcharge recovery of $119 million to be invested in replacement infrastructure. The DC PSC ruled, in part, on this case in May 2013. It denied WGL's request to implement the initial 5 year phase of its Accelerated Pipeline Replacement Program. A decision on WGL's request to recover the costs of its Accelerated Pipeline Replacement Program in a Plant Recovery Adjustment was deferred until a later date. • The DC PSC conditionally approved WGL's program on March 31, 2014. WGL has since received full approval to implement the first five years of a 40-year Accelerated Pipe Replacement Plan (APRP). The APRP is designed to reduce risk and enhance safety by replacing aging, corroded or leaking pipe in the natural gas distribution system. • WGL will spend $110M during this period. The APRP is divided into multiple "programs", three of which were approved in this first phase: o $40 million to replace an undetermined number of bare and/or unprotected service replacements. o $32.5 million to replace 18 miles of bare and unprotected steel main and an undetermined number of services. o $37.5 million to replace 20 miles of cast iron mains.	Case No. 1093
Florida	• On August 14, 2012, the Florida Public Service Commission approved a Gas Reliability Infrastructure Program (GRIP) for Florida Public Utilities Company (FPU) and its partner company, Central Florida Gas (CFG). Under the program, the two providers plan to replace more than 350 miles of pipeline over the next ten years. At that time the Commission approved the same program for Chesapeake Utilities. • Also on August 14, 2012, the Florida PSC approved a GI Cast Iron/Bare Steel Replacement Rider for TECO Peoples Gas Systems. Under that program, TECO is expected to invest approximately $8 million and over the course of ten years will replace 150 miles of cast iron	Docket No. 120036-GU (GRIP for FPU/CFG and Chesapeake Utilities) Docket No. 110320-GI (GI Replacement Rider for TECO) Florida PSC News Release (8/14/2012) Docket No. 150116-GU Florida City Gas

	and 400 miles of bare steel pipeline, comprising about 4 percent of the company's system. • On September 15, 2015, the Florida Public Service Commission (PSC) issued an order approving Florida City Gas' (FCG) request to implement the Safety, Access, and Facility Enhancement (SAFE) program that is to replace aging pipes to improve system safety and reliability, FCG's SAFE program encompasses a 10-year, $105 million project that is to relocate and replace 254.3 miles of 4-inch and smaller mains and associated facilities from rear property easements to the street front. The relocation and replacement program will remove most of the utility's 61.3 miles of unprotected steel mains and improve service reliability, safety, and facility access. Expenditures for the first full calendar-year of the program will not exceed $9.5 million. • Recovery of the revenue requirement associated with the SAFE program, including a return on the investment, depreciation, ad valorem taxes, income taxes, and noticing expenses will be effectuated through a surcharge mechanism. The cost to remove the facilities identified in the SAFE program will not be recovered through the surcharge; rather, they will be recovered through the cost of removal component in FCG's existing depreciation rates.	
Georgia	• In 1998, AGL Resources began a 15 year Pipeline Replacement Program (PRP), which, at the time, was reviewed annually by the Georgia PSC—the PSC reviewed the utility's infrastructure replacement expenses from the previous year and then approved a new surcharge amount. Later, the commission agreed to a fixed dollar amount of expense to be recovered in rates over the remaining 7 years of the program. • In 2009, the Georgia PSC approved the expanding of the PRP to include investments for infrastructure expansion. PRP is now included as part of the Strategic Infrastructure Development and Enhancement (STRIDE) Program for AGL Resources. STRIDE provides for a rider on customer bills that will allow AGL to recover costs associated with both traditional infrastructure replacement, as well as infrastructure expansion relating to customer growth and economic development. • In 2000, Liberty Utilities (then Atmos) received approval to implement a pipe replacement surcharge for its Georgia customers. • In September of 2013, AGL received approval to replace 756 miles of vintage plastic pipe over 4 years.	Docket Nos. 8516 & 29950 (Approving Georgia STRIDE Program) Docket No. 12509-U (Atmos – now Liberty)
Illinois	• In May 2013, the Illinois General Assembly passed the Natural Gas Consumer, Safety and Reliability Act (SB 2266). The legislation will allow utilities to make incremental investments in infrastructure upgrades and recover those costs through a rider on customer bills. The rider/surcharge is to be regularly reviewed by the ICC. In addition, the measure requires utilities to file	Natural Gas Consumer, Safety and Reliability Act (Passed by legislature 5/28/13, Signed by Governor Quinn 7/5/13, Public Act 98-0057)

	annual plans with the ICC detailing performance improvements and reporting on progress. Performance improvements may include decreases in time to respond to gas emergency calls and/or preventing damage caused by utility or contractor error. • The Illinois Commerce Commission has authorized a cost recovery mechanism for the work, known as the rider qualified infrastructure program, that went into effect January 1, 2014 and sunsets after 2023. The rider enables Peoples to recover its costs with only a one-month cash flow lag, eliminating the regulatory lag between rate cases, and allows the company to earn a return on investment based on the cost of capital established in the most recent rate case. • Peoples had been replacing roughly 45 miles of cast iron and ductile iron main with modern polyethylene pipes annually, but in 2011 the utility ramped up the replacement program, aiming to tackle nearly 2,000 miles of gas pipe, or 40% of the company's system, over two decades. • On April 7, 2014, Nicor Gas filed for its infrastructure replacement surcharge with the ICC. Nicor's plan calls for approximately $171 million in spending in each of the three years beginning in 2015. Entitled the Qualifying Infrastructure Plant (QIP) tariff, this surcharge will allow NICOR to replace hundreds of miles of aging distribution lines and thousands of natural gas services. The company also plans to upgrade gas transmission and storage systems and refurbish regulating stations. This application was approved on July 30, 2014. This plan will allow the company to replace approximately 125 miles of gas mains and 15,000 natural gas service lines. The following projects are eligible for recovery under the QIP: 1) Replacing cast iron main and related services; 2) Replacing non-cast iron main, which may include wrought iron, ductile iron, unprotected coated steel, unprotected bare steel, pre-1973 DuPont Aldyl "A" polyethylene, polyvinylchloride ("PVC") plastic, or other vintage materials, and related services; 3) Replacing copper services; 4) Replacing high-pressure transmission pipelines and associated facilities; and 5) Replacing and/or installing regulator stations, regulators, valves, and associated facilities. • In August of 2014, Ameren Illinois announced its plan for a 10-year, $400 million overhaul of its natural gas distribution in central and southern Illinois. When the project is completed, up to 350 miles of steel pipe will be replaced with polyethylene pipe. The project includes upgrades to 70 stations that regulate gas from interstate pipelines and adding over 450,000 so-called 'smart meters.' • On January 6, 2015, the ICC approved a QIP rider for Ameren Illinois.	Case Number: 14-0292 Nicor Gas Case Number 14-0573 Ameren Illinois QIP

Indiana	• In 2013, the state legislature passed a bill that allowed for gas utilities to apply for a cost recovery tracker for infrastructure upgrades and extensions; under the legislation, utilities may propose a 7 year infrastructure plan to the IURC and, if considered reasonable, the utility may recover its investment in a timely manner through a tracker on the customer's bill. • In 2008, Indiana Gas (Vectren Corp.) received approval to implement a tracking mechanism that allows the utility to defer expenses associated with investments in infrastructure and replacement projects. • In 2006, Southern Indiana Gas and Electric Company (Vectren Corp.) received approval of a tracking mechanism for recovery of an accelerated bare steel and cast iron pipeline replacement program. • NIPSCO field its 7 year plan with the IURC on October 3, 2013. Among the projects which NIPSCO will pursue over the next seven years: installing 80 miles of transmission pipeline and adding automated valves ($280 million); eliminating bare steel gas mains and replacing them with low pressure systems ($61 million); and retrofitting lines for in-line inspection ($46 million).This plan was approved on April 30, 2014. • Vectren filed its 7 year plan with the IURC on November 26, 2013. The plan includes the replacement of 800 miles of bare steel and cast iron distribution mains with new mains in the 13,000-mile network in Vectren North, inspecting and upgrading its pipelines, and the expansion of gas delivery infrastructure to rural areas, which call for an estimated $650 million investment. The company will also replace 300 miles of bare steel and cast iron distribution mains with new mains in the 3,200-mile network of Vectren South, which call for an estimated $215 million investment. The costs will be recovered through a fixed charge to be included in residential customers' monthly bills. Gas bills will not be adjusted for these expenditures until 2015, with modest increases in adjustments up to 2021. The IURC approved this plan on August 27, 2014. • On March 30, 2016, the Indiana Utility Regulatory Commission approved gas infrastructure modernization projects representing $890 million in investments supported by recovery mechanisms for Vectren as part of the company's third update to its initial 7 year plan.	Indiana SB 560 (Became Public Law No. 133-2013 on 5/1/2013) Case No. 43298 (Indiana Gas) Case No. 43112 (Southern Indiana Gas and Electric Company) Cause Number 44403 (NIPSCO) Cause number 44429 (Vectren)
Iowa	• In October 2011, the Iowa Utilities Board adopted a rule that allows the state's natural gas utilities to implement either of two types of automatic adjustment mechanisms for recovery of a limited number of capital infrastructure investments outside of a general rate case, including those that are required by government mandates or are required by state or federal pipeline safety mandates. To date no utility has implemented either of the two types of mechanisms for cost recovery.	Docket No. RMU-2011-0002 (October 2011) Docket No. RPU 2002-0004 (April 2013)

	• Effective April 25, 2013, the Iowa Utilities Board has approved tariffs implementing a capital infrastructure investment automatic adjustment mechanism. • Black Hills utilizes this rider.	
Kansas	• In 2006, the Kansas State Legislature passed the Gas Safety and Reliability Policy Act, which approved the implementation of a gas system reliability surcharge (GSRS) between 0.5% and 10% of revenues to recover new infrastructure replacement costs not already included in rates; Atmos, Black Hills, and Kansas Gas Service utilize the surcharge. • GSRS balances are rolled into base rates in its next rate case. GSRS riders may be used for up to five years (or up to six years under certain circumstances) and the utilities must file new rate cases if their riders are to remain in place. GSRS rate changes may not be requested more frequently than every 12 months. Annualized GSRS revenues may not exceed 10% of the utility's base revenue level, as approved in its most recent rate case. GSRS rate changes are not permitted if they are less than 0.5% of the utility's base revenue level, or $1 million, whichever is lower. • On March 12, 2015, the Kansas Corporation Commission opened the General Investigation Regarding the Acceleration of Replacement of Natural Gas Pipelines Constructed of Obsolete Materials. In the Order Opening General Investigation, Staff reported that after meetings with Kansas natural gas utilities and Commission work studies, they had developed a framework with eleven parameters for a pipeline replacement program that could be uniformly applied to Kansas natural gas utilities. This proceeding is presently pending. • In its August 2015 rate filing, Atmos Energy proposed to implement a system integrity program (SIP) rider that would allow the company to accelerate the replacement of certain obsolete components of its distribution system. The SIP rider, which would be in place for a five-year pilot term and would be updated on a quarterly basis, is intended to address the "capital investment lag" associated with the GSRS and a $0.40 per customer, per month statutory cost recovery cap that applies to the GSRS. This proposal was rejected on March 17, 2016.	K.S.A 66-2201 through K.S.A 66-204 (Gas Safety Reliability Policy Act) Docket No. 16-ATMG-079-RTS (Atmos) Docket No. 15-GIMG-343-GIG
Kentucky	• In 2005, pursuant to passage of KY HB 440, Kentucky created a new section in the Kentucky Revised Code titled “Recovery of Costs for Investments in Natural Gas Pipeline Replacement Programs,” which allows the commission to approve the recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility; Atmos, Columbia Kentucky, Delta	KRS 278.509 Case No. 2009-00141 (Columbia Gas of Kentucky) Case No. 2009-00354 (Atmos) Case No. 2005-00042

	Natural Gas, and Duke Energy Kentucky utilize such programs.	(Duke Energy Kentucky) Case No. 2010-00116 (Delta Natural Gas)
Louisiana	• CenterPoint utilizes a rate stabilization program (Rider RSP) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • Under this program, for each twelve month period ended June 30, a determination shall be made pursuant to this Rider RSP as to whether the Company's revenue should be increased, decreased or left unchanged. If it is determined that the revenue should be increased or decreased, the natural gas rate schedules incorporating this Rider RSP will be adjusted accordingly. • On June 6, 2014, Atmos Energy received approval to establish a regulatory asset using an accounting deferral to recover significant increases in the amount of investment made for the replacement of its aging infrastructure. The mechanism will be reviewed annually as part of the Rate Stabilization Clause (RSC) filing. • In January of 2015, Entergy Gulf States received permission to start replacing many of the old pipes that carry natural gas in Baton Rouge. In the first phase, Entergy is replacing about 25 miles of cast iron pipe, then another two miles of bare steel, Another 72 miles of vintage plastic will be replaced in phase three. The Louisiana Public Service Commission, voted 3-1 to approve a special rider to pay for the work.	CenterPoint Rider RSP Docket U-32987 (Atmos) U-32682 (Entergy Gulf States)
Maine	• In 2011, the Maine Public Utilities Commission authorized Northern Utilities to implement a limited, one year, incremental step adjustment of $0.9 million effective 5/1/2012 to reflect investments made under the company's Cast Iron Replacement Program (CIRP); Initially the utility had sought a targeted infrastructure replacement adjustment (TIRA) tracker to reflect incremental CIRP investments; The Commission did not approve a permanent tracker, instead opting for the more limited mechanism for one year. • On December 17, 2013, the Maine Public Utilities Commission ("MPUC"), during its public deliberations, voted unanimously to approve a Settlement and Stipulation ("Stipulation") in Docket No. 2013-00133, the base rate proceeding for the Maine division of Northern Utilities, Inc. Unitil Corporation's natural gas distribution utility subsidiary. • The Stipulation included a Targeted Infrastructure Replacement Adjustment ("TIRA") rate mechanism, which will provide for annual adjustments to distribution base rates in future years to recover costs associated with the Unitil's investments in specified operational and safety-related infrastructure replacement and reliability upgrade projects to its natural gas distribution system.	Docket No. 2011-92 Docket No. 2013-00133

	The TIRA will have an initial term of four (4) years, and applies to investments made in eligible facilities in each of the calendar years 2013, 2014, 2015, and 2016.	
Maryland	• On February 22, 2013, the Maryland General Assembly passed SB 8, legislation that allows a gas company to recover costs associated with infrastructure replacement projects through a gas infrastructure replacement surcharge on customer bills. The bill specifies how the pretax rate of return is calculated and adjusted and what it includes, and states that it is the intent of the General Assembly to accelerate infrastructure improvements by establishing this mechanism for gas companies to recover reasonable and prudent costs of infrastructure replacement. • As of November 7, 2013, Washington Gas Light, Baltimore Gas and Electric and Columbia Gas of Maryland had all filed for approval of their STRIDE plans with the Maryland PSC. • On January 29, 2014, The Maryland PSC approved the first phase of Baltimore Gas and Electric's (BGE) $400 million, 30-year gas STRIDE Plan. BGE's plan targets five specific areas for improvement, including bare steel mains, cast iron mains and bare steel services. It calls for the replacement of the company's 42 miles of bare steel mains within 15 years and 1,292 miles of cast iron mains within 30 years. • On January 31, The Maryland PSC the Maryland Public Service Commission (PSC) rejected Columbia Gas of Maryland's (CGM's) proposed STRIDE plan and associated rider mechanism, finding that the plan failed to meet certain statutory requirements. In addition, the PSC found that the STRIDE plan would not improve safety and reliability in the gas distribution system, because the plan "does not keep pace" with the company's current replacement rate of aging mains and services and would thus decelerate its infrastructure replacement activity. The Commission noted that it may approve a gas infrastructure replacement plan in accordance with state law if it finds the proposed investments and estimated costs of eligible projects to be: reasonable and prudent; and, designed to improve public safety or infrastructure reliability. The PSC directed CGM to submit an amended application addressing the issues within 60 days; the Commission indicated that it would consider an amended application on an expedited basis. • On May 6, 2014, the Public Service Commission of Maryland (MDPSC) issued an Order conditionally approving Washington Gas' amended accelerated pipeline replacement plan, commonly referred to as STRIDE, which will accelerate natural gas infrastructure upgrades and replacement projects. The plan will also provide current cost recovery for the company, reduce greenhouse gas emissions and costs to utility customers. Washington Gas has accepted the conditions and will be able to recover eligible infrastructure replacements costs for projects initiated after January 1, 2014, that are not	Maryland SB 8 (Enrolled 5/2/2013, MD Chapter No. 161) Case No. 9331 Case No. 9332 Case No. 9335

	included in current base rates. The STRIDE surcharge will not exceed $2.00 per month for residential customers. Washington Gas will provide the MDPSC with an updated list of planned STRIDE projects for 2014 by June 5, 2014. Audits will be performed following each program year. • On August 18, 2014 the Maryland Public Service Commission (PSC) conditionally approved Columbia Gas of Maryland's (CGM's) proposed infrastructure replacement and improvement plan (IRIP) and an associated annually-adjusted rider (IRIS). CGM accepted the conditions and the IRIS surcharge will begin recovery of the forecasted $8.9 million of eligible investment. The IRIS mechanism covers investments made from January 1st through December 31st of each year. Audits will be performed following each program year.	
Massachusetts	• Several of the state's utilities utilize a Targeted Infrastructure Reinvestment Factor (TIRF) for cost recovery of infrastructure replacement: o Columbia Gas of Massachusetts received approval for its TIRF in 2009. The TIRF allows for the recovery of the revenue requirement associated with bare steal capital additions for the previous calendar year o National Grid companies Boston Gas, Essex Gas and Colonial Gas received approval for a TIRF as part of a 2010 general rate case. The TIRFs provide for the recovery of costs associated with the accelerated replacement of gas mains and the companies are allowed to surcharge customers up to 1% of total revenue o New England Gas (Now Liberty Utilities) received authorization to implement a TIRF to provide recovery of incremental expenditures associated with reinforcing the system and meeting public safety goals • On February 28, 2014, the Massachusetts Department of Public Utilities issued an order in Columbia Gas of Massachusetts' (Columbia) rate case (DPU 13-75) which allowed Columbia to increase the annual cap on amounts collected under the TIRF mechanism from 1% to 3.75% of distribution revenues. • Governor Deval Patrick signed H. 4164 into law on June 26, 2014. The bill provides for the following: o Civil penalties for violations of federal pipeline safety regulations; o Uniform natural gas leak classification for all gas companies; o Grade 1 leaks defined as representing an existing or probably hazard to persons or property and requiring immediate action; o Grade 2 leaks defined as non-hazardous to persons or property at time of detecting but justifies scheduled repair based on future hazard; Requires company to replace the main within 1 year from date of leak classification;	Docket No. DPU 09-30 (Columbia Gas of Massachusetts) Docket No. DPU 10-55 (National Grid) Docket No. DPU 10-114 (New England Gas) Docket No. DPU 13-75 (Columbia Gas of Massachusetts) H 4164 DPU 14-130 Unitil GSEP DPU 14-131 Berkshire Gas GSEP DPU 14-132 National Grid GSEP DPU 14-133 Liberty Utilities GSEP DPU 14-134 Columbia Gas of Massachusetts GSEP DPU 14-135 NSTAR Gas GSEP

	o Grad 3 leaks defined as non-hazardous to persons or property and can be reasonably expected to remain non-hazardous; Requires utilities to reevaluate during scheduled surveys or within 12 months until the main is replaced;
	o Prioritization of pipeline repairs in school zones
	o Cost recovery for eligible infrastructure replacement programs;
	o Eligible plans shall include, but not be limited to, the following:
	    o Eligible infrastructure replacement of mains, services and meter sets composed of non-cathodically protected steel, cast iron and wrought iron prioritized to implement the federal DIMP plan annually submitted to the department
	    o Anticipated timeline for the completion of each project—timelines should include a target end date of either not more than 20 years or a reasonable target end date considering the allowable recovery cap established
	    o Estimated cost of each project
	    o Rate change requests
	    o Customer costs/benefits under the plan
	o An expansion component which permits the DPU to authorize gas utilities to design and offer programs to customers which will increase the availability, affordability and feasibility of natural gas service for new customers;
	o A direction for the DPU to issue a report addressing the prevalence of natural gas leaks in the natural gas system including estimates for the number of Grade 1, 2 and 3 leaks and estimates for lost and unaccounted for gas and methane emissions.
	
	• Pursuant to H. 4164 (now G.L. c. 164, § 145), National Grid, Unitil, NSTAR Gas, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas all filed Gas System Enhancement Program Plans (GSEP) for 2015 on October 31, 2014. These plans were approved on April 30, 2015.
	
	• These plans will allow for the removal of all cast iron and bare steel mains to be eliminated in 20 years for National Grid, Unitil, Columbia Gas of Massachusetts, Liberty Utilities and Berkshire Gas and 25 years for NSTAR Gas.	

Michigan	• In January 2011, the Michigan PSC adopted a settlement that establishes a main replacement program rider. The mechanism will enable SEMCO Energy to recover the incremental capital-related costs associated with the accelerated removal and replacement of cast iron and unprotected steel service lines and mains. The program expires in 5 years unless extended by order or new rate case. • In June 2012, the Commission approved a settlement in a Consumers Energy gas rate case that will fund a main replacement program at $56 million annually until the program is reviewed and spending is reset by the Commission in a general rate proceeding. • In May 2013, the Commission approved an expanded main replacement program proposed by SEMCO Energy Gas Company that will double the amount spent annually on the program and double the miles of main replaced annually. Coupled with its existing program, SEMCO will replace 40.6 miles of high-risk main annually. This will allow SEMCO to accelerate the installation of excess flow valves at the homes of its customers, helping to protect customers in case of a service line leak. • On April 16, 2013, the Michigan PSC approved an expanded gas main replacement program (MRP) and a pipeline integrity program, and the recovery of the costs of those programs, as well as the ongoing meter move-out program, through an infrastructure recovery mechanism (IRM) for DTE Gas Company. This order allowed the company to accelerate its annual pace of main replacement from 30 miles to 66 miles per year. • On January 13, 2015, the Michigan Public Service Commission (PSC) adopted a settlement in a Consumers Energy (CE) gas base rate case. The settlement provides for an Enhanced Infrastructure Replacement Program (EIRP). The EIRP is a twenty-five year incremental investment program to upgrade natural gas infrastructure, including approximately 540 miles of cast iron pipe. The EIRP is based on transmission and distribution integrity management principles intended to eliminate cast iron pipe and other high-risk components as identified through existing federal and state code requirements. CE projects that it will spend about $75 million per year under the EIRP. • On June 3, 2015, The Michigan Public Service Commission (MPSC) approved a settlement agreement that authorized SEMCO Energy Gas Company to extend its natural gas main replacement program (MRP) and increase its MRP surcharge, effective with the next full billing cycle. The surcharge will continue until the earlier of either the establishment of base rates in a future contested case addressing the MRP through self-implementation or Commission order, or May 30, 2020. • Under the terms of the settlement, the parties agreed that SEMCO will:	Docket No. U-16169 (SEMCO) Docket No U-16999 (DTE) Docket No. U-16855 (Consumers) Case No. U-17643 (Consumers EIRP) Case No. U-17701 (DTE) Case No. U-17824 (SEMCO)

	o continue to annually replace 26 miles of main through the MRP and 14.6 miles under the base program, for a total of 40.6 miles of main from 2016 through 2020; o spend on average approximately $10.1 million annually for a total of $50.5 million on main replacement for 2016 through 2020; o not file any further requests for expansion, continuation, or modification of the MRP surcharge outside of a general rate case, unless there is a change in the law addressing infrastructure replacement programs; and o File an MRP planning report and MRP performance report by March 31 of each year for that year's main replacement spending. • On November 12, 2014, DTE Gas filed an application with the Michigan PSC to further improve the overall safety and reliability of the DTE Gas distribution system by revising its Main Replacement Program ("MRP" or "Program") to increase MRP capital expenditures by $46.9 million annually in 2016 and 2017 and increase the Infrastructure Recovery Mechanism ("IRM") surcharge to recover the capital costs associated with the Program. This program would accelerate the company's pace of replacement to approximately 120 miles per year. (Case No. Case No. U-17701). • On November 23, 2015, the Michigan Public Service Commission (PSC) issued a decision that modified DTE's proposal and authorized the company to expand its Main Replacement Program in 2016 by $15.6 million above the previously-approved spending levels, and to increase spending in 2017 by $31.4 million above previously-approved spending levels, contingent upon 2016 targets being met. • Additionally, the PSC directed its Staff to meet with DTE prior to July 1, 2016, to reassess the utility's target mileage for 2016 main replacement. In reassessing the target mileage for 2016, Staff is to consider all relevant information and documents provided by the company, the authorized increase for 2016, and the fact the utility exceeded mileage targets and completed more main replacement than expected under the current MR program to date. The PSC also determined that the parties should reassess 2017 targets in a similar manner prior to July 1, 2017, and that authorization of the 2017 spending increase is subject to reduction back to 2016 levels if 2016 targets are not substantially completed.	
Minnesota	• In May 2013, the Minnesota legislature passed an Omnibus jobs, economic development, housing, commerce and energy bill which included a rider for the recovery of gas utility infrastructure costs. Under the legislation, a gas utility may submit a gas infrastructure project plan report and a petition for cost recover. Upon receiving those items, the Minnesota Public Utilities Commission may approve a rider provided that the costs included for recovery through the rate schedule are	Minnesota H.F. 279 (As enrolled, 5/23/2013) Docket No. 14-336 (Xcel)

	prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers. • In August of 2014, Xcel Energy stated in a regulatory filing that it intends to spend $15 million in 2015 on pipeline safety improvements, which is roughly a twofold increase over past levels. In future years, the company envisions even larger safety-related investments, peaking in 2019 at more than $50 million. Should the Minnesota Public Utilities Commission approve the 2015 investment, it would increase customers' bills 3.5 percent in January, about $2 per month for a typical customer, the company said. Future investments could bring more increases, though they would need separate regulatory approval. • On January 27, 2015, The Commission approved Xcel's proposed GUIC rider, rate-adjustment factors, and tariff sheets with the following modifications: o A rate of return calculated using the capital structure and cost of debt from Xcel's electric rate case, Docket No. E-002/GR-13-868, and the cost of equity from its last natural-gas rate case, Docket No. G-002/GR-09-1153; o A rate design that allocates the 2015 revenue requirement to Xcel's customer classes in the same manner as revenues were apportioned in the Company's February 28, 2011 compliance filing in its last natural-gas rate case; and o An effective date of the date of this order, with final rate-adjustment factors calculated to recover the 2015 revenue requirement over the remaining months of 2015. • The Commission also determined that sixty days in advance of its next annual GUIC filing, Xcel shall submit information on what it believes the appropriate rate of return should be for the coming year. Lastly, in the initial filing in its next natural-gas rate case, Xcel must submit detailed schedules, any necessary supporting documentation, and an explanation of all O&M costs that were being recovered in the rider and are now included in the test year for recovery in base rates.	
Mississippi	• CenterPoint utilizes a rate stabilization mechanism (RRA Plan) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • For each twelve-month period ending December 31, a Commission determination shall be made pursuant to this RRA Plan as to whether the Company's revenue should be increased, decreased or left unchanged. • On September 8, 2015, the Mississippi Public Service Commission approved a stipulation which approved Atmos Energy's proposal to establish a long term system integrity plan and accelerate an investment program to make its system safer and ensure full compliance with federal (DOT/PHMSA) pipeline safety directives. '	CenterPoint RRA Plan Docket No. 2015-UN-049 (Atmos SIP)

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The docket involved a comprehensive review of Atmos Energy’s planned system integrity spending over the next 10 years and projected rate impact.
Among the key provisions approved:

A rigorous annual review of Atmos Energy’s proposed system integrity projects for the next fiscal year and annual rate impact, including
Project spending
Project objective and regulatory requirement being met
Start and completion dates
Historical spending analysis
Project analysis including safety benefit/alternatives considered/engineering support
Annual summary of operational metrics/savings/safety reports
A rolling five-year capital spending plan update including estimated rate impacts
Rate recovery though a combination of fixed and volumetric rates
Estimated impact of the first year of implementation (begins November 2016) is $0.85/month per residential customer

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<tr><td>Missouri</td><td>

Missouri established an Infrastructure Replacement Surcharge (ISRS) mechanism as part of a revision to Missouri Statute 393.1009-105. The ISRS allows rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 3 years; Ameren, Liberty Utilities, Laclede and Missouri Gas Energy use an ISRS mechanism.
The Missouri Legislature had considered legislation that would modify the provisions outlined above. SB 240 would have required the PSC to specify the annual amount of net write-off incurred by a gas corporation, after which the company would be allowed to recover 90% of the increase in net write offs from customers. The legislation would have also modified the provisions above by extending the amount of time in which a company must come in for a rate case to be eligible for the ISRS from three years to five years. It would have also increased the amount a utility may recover through ISRS from 10% of the company’s base revenue level to 13%. This legislation was vetoed by Governor Nixon on July 9, 2013.
In January of 2014, Laclede Gas filed for a $7.4 million increase in its ISRS, revenues to recover investments in replacement of distribution pipelines over the previous 13 months. Laclede proposed to spend $7.1 million annually from the new charge to fund roughly 68 miles of gas main replacements. This request was approved on April 3, 2014.

</td><td>Missouri Statute 393.1009-1015

Missouri SB 240 (Final Passage on 5/9/13; Governor Nixon vetoed this legislation on 7/9/13)</td></tr>
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Nebraska	• In 2009, Nebraska established an Infrastructure System Replacement Surcharge (ISRS) as part of revisions to Nebraska Statutes 66-1865, 66-1866 and 66-1867. The ISRS allows the rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure replacements. Companies that utilize the ISRS must file a rate case at least every 5 years. • SourceGas and Black Hills currently utilize these riders.	NRS 66-1865, 66-1866, 66-1867
Nevada	• As part of its GRC in 2011, Southwest Gas proposed a Gas Infrastructure Recovery Mechanism (GIR) that would have allowed the utility to invest in incremental non-revenue producing projects and collect on an annual basis the revenue requirement associated therewith. The GIR was not approved as part of the rate case; however, the Commission opened a rulemaking to develop regulations to facilitate the implementation of a GIR-type of recovery mechanism. Pursuant to the rulemaking, Southwest Gas is proposed a mechanism to allow the capital cost of qualifying investments to be deferred, and the associated revenue requirement recovered on an interim basis until its next general rate case. • On January 8, 2014, the Nevada Public Utilities Commission approved regulations establishing an application process for accelerated recovery of eligible costs associated with replacing natural gas pipelines to address safety and reliability concerns that are incurred by operators in between general rate cases.	Docket No. 11-03029 (2011 GRC) Docket Nos. 12-04005 and 12-02019
New Hampshire	• Energy North (now Liberty Utilities) established a Cast Iron Bare Steel (CIBS) Replacement Program as part of the National Grid/KeySpan merger settlement agreement approved by the Commission in Order No. 24,777 on July 12, 2007, in Docket No. DG 06-107. • In, 2009 National Grid (now Liberty Utilities) proposed to modify its annual CIBS rate adjustment mechanism to include public works projects and to eliminate the $0.5 million annual threshold required prior to cost recovery. In a March 2011 settlement, the New Hampshire PUC called for the CIBS rate adjustment mechanism, as it was originally structured, to remain in effect.	Docket No. DG 10-1017
New Jersey	• In 2009, the New Jersey Board of Public Utilities approved accelerated infrastructure programs for five of the seven major utilities that had filed such plans. In total, the plans provide that the utilities will invest $956 million in incremental infrastructure and energy efficiency programs over the following two years, and the costs of the various programs were to be recovered through various, separate adjustment mechanisms (see below). o New Jersey Natural Gas: In 2009, New Jersey Natural Gas received approval to invest $71 million in new infrastructure and system upgrades, which it completed in 2011. In 2011, the utility was granted approval for an additional $60 million. The recovery mechanism is not a traditional tracker or surcharge—the utility is	Docket No. GO09010052 (New Jersey Natural Gas) Docket No. GO09010053 (Elizabethtown Gas) Docket No. GO09010050 (PSE&G) Docket Nos GR09110907, GR10100765, GO1100632 (South Jersey Gas) PSEG Energy Strong Order

	recovering the costs through adjustments to base rates o Elizabethtown Gas: The utility implemented the Utilities Infrastructure Enhancement Program in 2009, which includes both the costs of replacing cast iron pipes and investments in specified new main extensions. The recovery mechanism was through a surcharge. In 2011, the utility was granted approval for the extension of the program through 2012, and the recovery mechanism continued to be a surcharge until October 2011 when the surcharge rolled into base rates o PSE&G: In 2009, the utility received approval for an infrastructure investment program. The recovery mechanism, the Capital Adjustment Charge (CAC), is a deferral account that is adjusted each January based on forecasted program expenditures. o South Jersey Gas: In 2009, South Jersey Gas received approval for its Capital Investment Recovery Tracker (CIRT) mechanism. The program has gone through several revisions in the last several years (CIRT-I, CIRT-II, CIRT-III) • In October of 2012, New Jersey Natural Gas received approval from the New Jersey Board of Public Utilities (BPU) to implement its Safety Acceleration and Facility Enhancement (SAFE) program. Through SAFE, NJNG will replace 276 miles, or approximately 50 percent, of the cast iron and unprotected steel mains and associated services in its delivery system over the next four years. • In August 2013, Elizabethtown Gas received unanimous approval from the New Jersey BPU to implement its Accelerated Infrastructure Replacement (AIR) program. The agreement will enable Elizabethtown Gas to invest up to $115 million over a four-year period to enhance the safety, reliability and integrity of the utility's distribution system. Under the terms, Elizabethtown Gas will file a rate case no later than September 1, 2016 at which time the AIR program costs will be subject to review. During the AIR program, Elizabethtown Gas will accrue Allowance for Funds Used During Construction (AFUDC) related to project expenditures during the construction period, and accrue associated carrying costs from the time the project is placed in service until the time its costs are recovered through base rates. This program allows the company to replace approximately 30 miles of year of cast and bare steel mains per year. • In the aftermath of Hurricane Sandy, Public Service Electric & Gas Co (PSEG) has proposed a multi-billion dollar network hardening plan to improve resiliency and allow its electric delivery system to recover more quickly after damaging events. Had it been approved as PSEG proposed, the program, referred to as Energy Strong, would have allowed PSEG to will invest $1.1 billion into gas service system upgrades over a 10-year period to proactively protect and strengthen its systems against increasingly frequent severe weather.	Docket No. GO12070693 (Elizabethtown Gas AIR Order) Docket No. GR13090828 (New Jersey Natural Gas RISE Order) Docket No. GR13009814 (South Jersey Gas SHARP Order)

	• On May 21, 2014 the New Jersey BPU adopted a settlement approving PSEG's Energy Strong infrastructure improvement program and related surcharge mechanisms. PSEG will improve its natural gas infrastructure over a three-year period. Under the now-approved settlement, over the next three years PSEG is to expend on natural gas investments: $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas and $50 million to protect five natural gas metering stations and a liquefied natural gas station affected by Hurricane Sandy or located in flood zones. • On July 23, 2014, the New Jersey Board of Public Utilities (BPU) approved New Jersey Natural Gas' (NJNG's) New Jersey Reinvestment in System Enhancements (NJ RISE) infrastructure program. The NJ RISE program is comprised of multiple investments over a five-year time frame of $102.5 million in gas distribution storm hardening and mitigation projects. The BPU also authorized an annual adjustment mechanism for this program. This mechanism covers program costs incurred through July 31, 2015. A base rate case must be filed no later than November 15, 2015. All costs incurred after July 31, 2015 will be addressed in the base rate proceeding. • Also on July 23, 2014, the BPU approved the Elizabethtown Natural Gas Distribution Utilities Reinforcement Effort (ENDURE) program, under which the company was authorized to invest approximately $15 million over a one-year period from January 1, 2014 to December 31, 2014 in its natural gas infrastructure to prevent damage from future major storm events, and to improve communication during and after weather-related emergencies. Elizabethtown Gas proposed to defer the costs of the program, with recovery of the ENDURE program-related deferrals to be determined in a base rate case to be filed in 2016. • On August 20, 2014, the New Jersey Board of Public Utilities approved the South Jersey Gas's $103.5 million storm hardening and reliability program (SHARP) to improve its infrastructure in advance of significant weather events. SHARP, which is expected to be completed in the next three years, will replace roughly 93 miles of natural gas mains and approximately 11,100 associated services. Program costs will be recovered through annual adjustments to South Jersey Gas base rates on October 1st of each year of the program. There will be no immediate impact to customer bills. • On March 2, 2015, PSE&G filed a proposal with the New Jersey Board of Public Utilities to invest $1.6 billion over the next five years to proactively modernize its gas systems. PSEG's Gas System Modernization Program would include replacing an average of approximately 160 miles of cast iron and unprotected steel gas mains, and about 11,000 unprotected steel service lines to homes and businesses per year, over the five year period of the program.	

	• On September 15, 2015, PSE&G announced a $905 million settlement in principle with the staff of the New Jersey Board of Public Utilities (BPU) and the New Jersey Division of Rate Counsel to expedite the replacement of aging gas pipelines. The settlement will enable the company to replace up to 510 miles of gas mains and 38,000 service lines over the three-year period. • Under the agreement, PSE&G will earn a return on equity of 9.75 percent on $650 million of investment based on an accelerated recovery mechanism, and will seek to recover the remaining $255 million in a base rate case, to be filed no later than November 1, 2017. This agreement was approved on November 16, 2015. • On September 23, 2015, Elizabethtown Gas Co. filed a plan a 10-year, $1.1 billion infrastructure program with the BPU. The program aims to replace 630 miles of aging cast iron, steel and copper pipelines. • The proposed Safety, Modernization and Reliability Tariff plan intends to eliminate all aging pipelines, along with 240 regulator stations associated with the utility's low-pressure distribution system, by 2027,and also includes the installation of excess flow valves on all new service lines, and the transferring of gas meters to the outside of homes and businesses. This matter is presently pending. • On February 29, 2016, South Jersey Gas (SJG) filed a petition with the New Jersey Board of Public Utilities seeking to continue its Accelerated Infrastructure Replacement Program (AIRP) for a period of seven years with a total program investment of $500 million. The proposed program will be referred to as AIRP II. Under the AIRP II program, SJG would continue its Distribution Integrity Management Program-based approach to addressing the most significant threats on its distribution system and would replace and retire a significant portion of the vintage and most leak prone mains and services in its distribution system. The company's targets for replacement include: o All remaining cast iron and unprotected bare steel mains and associated services; o The most leak prone coated steel mains that are 2" in diameter or less and associated services; and o Other pipe materials and sizes found within replacement grids that would be logical and necessary to complete the modernization of the grid • Approval of AIRP II would enable the company to continue enhancing the reliability and safety of its gas distribution system in a cost effective manner, achieve increased operational efficiencies and continue the employment benefits that have been created by its previous and existing main replacements programs. SJG proposes to recover the capital investment costs and expenses of the AIRP II program through annual base	

	rate adjustments. The company's first AIRP II rate adjustment filing would be made on April 1, 2017 and there would be no rate adjustment or customer bill impact from the AIRP II program until October 1, 2017. This matter is presently pending. • On September 23, the New Jersey Board of Public Utilities (BPU) adopted a settlement in New Jersey Natural Gas Company's (NJNG) base rate case. As part of the decision, the BPU granted a five-year extension on the utility's Safety and Facilities Enhancement program (SAFE). The SAFE program is a $200 million pipeline replacement effort to modernize NJNG's distribution system. The program allows NJNG to earn an allowance on its invested capital used in construction and request rate increases for spending in annual filings. These annual filings will consider the rate impacts associated with program spending of $157.5 million over its term.	
New York	• Corning Natural Gas has had a limited pipeline replacement cost recovery mechanism since 2006. • National Grid Long Island has had a limited infrastructure replacement tracker program since 2008. The program allows the utility to track only the costs of new or replacement infrastructure that are necessitated by city and state construction projects; National Grid NYC has a similar infrastructure replacement tracker that covers only those costs that are necessitated by city and state construction projects. • National Grid (NYC) uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal from service of 85 miles in CY 2013 and CY 2014, with a minimum of 40 miles during each calendar year, including at least 10 miles per year outside of City/State Construction-driven work. The Company will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 40 miles of LPP in each of CY 2013 and CY 2014 or a cumulative two year total of 85 miles of LPP by the end of CY 2014. • On September 10, 2010, The New York PSC approved a leak prone replacement schedule for New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE). The schedule requires that NYSEG replace a minimum of 24 miles of leak prone main per year and a minimum of 1200 leak prone services per year. RGE shall be required to replace 24 miles of leak prone main per year and 1000 services. • National Grid Niagara Mohawk has had a limited pipeline replacement cost recovery mechanism since 2008. The limited program was scheduled to run for 5 years. • National Grid Niagara Mohawk uses a risk based prioritization model to identify and rank segments of Leak Prone Pipe (LPP) to be removed from service. The Company will target LPP removal of 35 miles in CY13,	Docket No. 08-G-1137 (Corning Natural Gas) Docket No. 09-G-0716/ 09-G-0718 (NYSEG and RGE) Docket No. 06-M-0878 (National Grid Long Island, National Grid NYC, National Grid Niagara Mohawk) Docket No. 13-G-0031 (Con Ed) Docket No. 13-G-0136 National Fuel Docket No. 12-G-0202 (National Grid NIMO) Docket No. 12-G-0544 (National Grid NYC) Docket No. 14-G-0319 (Central Hudson) Docket No. 15-G-0151 (Commission Acceleration Proceeding) Docket No. 15-G-0284 (RGE and NYSEG) Docket No. 14-G-0494 (Orange and Rockland) Docket No. 16-G-0061 (Con Ed RSM)

	40 miles in CY14 and 45 miles in CY15. The Company will incur a negative revenue adjustment of 8 basis points should it fail to remove from service a minimum of 35 miles in CY13 and 35 miles in CY14 or a cumulative three-year total of 120 miles by the end of CY15. • On May 8, 2014, The New York PSC authorized a leak-prone pipe (LPP) removal plan for National Fuel Gas Distribution Corp. The Company will continue to use its risk based prioritization model to identify and rank segments of LPP to be removed from service. The Company will target removal from service of a cumulative total of leak prone pipe of 190 miles over CY 2014 and CY 2015, with a minimum of 90 miles removed in each year. • In February 2014, the New York PSC approved a multi-year Joint Proposal (JP) that resolved all issues in Consolidated Edison's (Con Ed) gas delivery rate proceeding. The JP provided for the following gas related expenditures relating to storm hardening which will allow Con Ed to modernize its system at an accelerated pace: o Rate Year 1: $524.2 million of which $5.021 million will go toward storm hardening; o Rate Year 2: $586 million of which $36.459 million will go toward storm hardening; o Rate Year 3: $627 million of which $56.942 will go towards storm hardening • Con Ed has approximately 1,100 miles of cast iron and bare steel pipe in their inventory in the state, and they replaced approximately 13-20 miles per year over the last four years. Under the new program outlined above, the company will replace 60 miles in 2014, 65 miles in 2015, and 70 miles in 2016. • In June of 2014, National Grid petitioned the Public Service Commission to accelerate the replacement of leak prone pipe on Long Island. On December 11, 2014, The PSC ordered the company to accelerate the annual pace of this program to 77.5 miles in 2015 and 95 miles in 2016 to improve public safety and system performance. • In its 2014 rate case, Orange and Rockland proposed to expand its current gas infrastructure replacement program so as to remove a total of 100,000 feet of main annually. In order to eliminate all low pressure mains in six years, the Company proposes to replace annually a minimum of 10,000 feet of low pressure mains. Orange and Rockland also proposes to replace an additional 500 bare steel services annually, as part of the Company's ten year program to remove all bare steel services in its service territory. • On October 15, 2015 the New York Public Service Commission (PSC) adopted a multi-year Joint Proposal (JP) in Orange and Rockland Utilities' (ORU) gas rate proceeding. The approved JP establishes funding for the removal of 21 miles, 22 miles, and 23 miles of leak	Docket No. 16-0059 (National Grid Brooklyn and Long Island)

	prone pipe in RY1, RY2, and RY3, respectively, with annual reporting by O&R on the status of its leak prone pipe replacement efforts. The JP also allows a negative revenue adjustment if the Company fails to replace at least 20 miles of leak prone pipe in any calendar year. The JP recommends a total negative revenue adjustment of up to eight basis points, rather than continuation of the current level of six basis points, which was initially recommended by Staff in its pre-filed testimony. • The approved JP also provides for an incentive mechanism for incremental replacement of leak prone pipe above the amounts provided for in base rates. This mechanism will allow for a positive revenue adjustment equivalent to two basis points for each whole incremental mile of leak prone main replaced in any calendar year above the targets provided for in base rates, up to a 10 basis point cap. ORU could recover the cumulative incremental revenue requirement for such costs through the Reliability Surcharge Mechanism, provided the company had also met its other targets for net plant under the approved agreement. • In a February 2015 Joint Proposal, Central Hudson Gas and Electric proposed a leak prone pipe replacement program that would allow for up to $1.4 million in deferred costs for every mile over 13 miles in 2016, up to $1.5 million for every mile over 14 miles in 2017, and up to $1.6 million for every mile above 15 miles in 2018. For the avoidance of doubt, the Company is expressly authorized to include Leak Prone Pipe eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Pipe while still serving the customer) in this deferral mechanism. • In the event the Company replaces or eliminates Leak Prone Pipe in excess of its mileage target in any calendar year, for each mile in excess of the applicable target, the Company shall receive a positive revenue adjustment of 2 basis points per additional mile, capped at a maximum of 5 miles (10 basis points) per calendar year, which the Company will defer for future recovery. This proposal was approved on June 17, 2015. • On April 17, 2015, The New York PSC issued an order instituting a proceeding to implement a cost recovery mechanism to further accelerate the replacement of leak prone pipe. The Commission's stated goal will be to reduce the statewide average replacement timeline to 20 years. This matter is presently pending. • On May 20, 2015, RGE and NYSEG filed rate cases in which the combined companies proposed an acceleration of leak prone gas main removal. The Companies propose to increase the leak prone main replacement target from 24 miles in 2016 to 26 miles in 2017, and to 28 miles each year thereafter. The combined annual cost is estimated to be approximately $27 million in 2017. Based on the increased miles, the Companies estimate that it will take approximately 11 years (a two year acceleration), beginning in 2016 to	

	replace all of their leak prone gas mains. This proposal was approved on n June 22, 2016. • In its January 29, 2016 rate filing, Con Ed proposed a Reliability Surcharge Mechanism (RSM). Under the RSM, beginning February 1, 2018, the company's Monthly Rate Adjustment would recover the cumulative net plant carrying costs and associated O&M costs for any capital expenditures associated with main replacement above the levels established in the Company's base delivery rates and installed since base rates were last reset. Carrying costs, including associated O&M costs, would be recovered through the RSM over the twelve-month period beginning February immediately following the end of each Rate Year until the Company's base delivery rates are reset. Both the allowed revenue requirement associated with the cost of main replacement as well as the targeted mileage of main replacement must be exceeded on a cumulative basis for any costs to be recovered through the RSM. • Any over- or under-collections for each period, including interest at the Commission's Other Customer Capital Rate, will be reconciled and included in a subsequent RSM. The RSM is applicable to Firm Sales Customers taking service under SC Nos. 1, 2, 3 and 13, applicable Riders and equivalent firm transportation service under SC No. 9. • ConEd's proposal also seeks to increase base gas rates by $154 million, including $77 million for infrastructure investments to support a significant acceleration of the replacement of cast iron and unprotected steel gas mains. The company is currently replacing, on average, approximately 65 miles of gas main per year. The company is proposing to ramp up that goal to 100 miles annually, reducing the time of total system replacement from over 30 years to 20 years. The proposed rate plan also would continue the company's monthly inspections of its gas delivery system. This matter is presently pending. • In its January 29, 2016 rate filing for its Brooklyn and Long Island service territories (KEDNY and KEDLI, respectively), National Grid outlined a proposal targeting the replacement of more than 300 miles of Leak Prone Pipe (LPP) over a five-year period (2017 through 2021). In recognition of the unprecedented incremental work associated with the company's accelerated main replacement targets, and to allow the company to begin recovering the actual costs of the accelerated replacement of LPP as the work is completed, the Company proposed a Gas Safety and Reliability Surcharge under which the Company would be allowed to recover a return on investment, depreciation expense and related O&M expense (i.e., disconnects and reconnects) associated with prudent investment in LPP replacement incremental to the level funded in base rates. Provided the Company exhausts its rate allowance for LPP replacements, incremental investment in LPP above the base level of 50 miles in any calendar year, in an amount not to exceed the company's average cost of	

	main replacement for comparable pipe materials, sizes, strata (e.g., pavement, grass) and working conditions, would be included in the Gas Safety and Reliability Surcharge. • Additionally, with regard to the LPP performance metric, KEDNY and KEDLI propose a negative revenue adjustment of eight pre-tax basis points if they fail to remove their Base LPP Targets of an average of 50 miles per year and 115 miles per year, respectively, over the next three years. The targets would have annual and cumulative targets similar to KEDNY's current LPP metric in Colander years (CY) 2013 and 2014. That is, KEDNY would incur a negative revenue adjustment in each year for failure to replace a minimum of 45 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 150 miles for CYs 2017 to 2019. KEDLI would incur a negative revenue adjustment in each year for failure to replace a minimum of 105 miles in CYs 2017 and 2018, and a minimum cumulative three-year total of 345 miles for CYs 2017 to 2019. Any replacement miles recovered through the Gas Safety and Reliability surcharge would not count toward the cumulative CY 2019 target. The proposal is presently pending.	
North Carolina	• In May 2013, the North Carolina General Assembly passed legislation that will authorize the NC PUC to adopt, implement, modify or eliminate a rate adjustment mechanism for natural gas local distribution company rates so that the utility can recover the prudently incurred costs associated with complying with federal gas pipeline safety requirements; Piedmont Natural Gas Company has applied for a tracker in accordance with this legislation as part of its recent rate filing. • In December of 2013, the NC PUC permitted Piedmont Natural Gas to implement an integrity management rider (IMR) that allows the company to track and recover future capital expenditures it expects to incur to comply with federal pipeline safety and integrity requirements outside of a general rate case. IMR filings are to occur annually, each November, to reflect costs incurred through the previous October, and the revised rates are to become effective the following February. • In March of 2015, Senator Robert Rucho (R) introduced Senate Bill 434, which would permit the NC PUC to adopt, implement, modify, or eliminate a rate adjustment mechanism to enable the company to recover the reasonable and prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return. Costs incurred for routine maintenance, repair, and replacement of system components shall not be included in a rate adjustment mechanism authorized under this legislation. The Commission shall adopt, implement, modify, or eliminate a rate adjustment mechanism authorized under this section only upon a finding by the Commission that the mechanism is in the public interest. The Commission may eliminate or modify any rate adjustment mechanism	NC H 119 (Signed by Governor 5/17/13) Docket No. G-9, Sub 631 (Piedmont) Senate Bill 434 (died)

	authorized pursuant to this section upon a finding that it is not in the public interest. This bill died at the end of the legislative session.	
Ohio	• In its 2008 base rate case, Columbia Gas of Ohio received approval for its Infrastructure Replacement Program (IRP) tracker. The IRP was authorized for an initial five year period, and no rate case is required. The approved 25-year plan called for $2.7 billion to replace approximately 4,100 miles of bare steel, cast and wrought iron and copper pipelines. • In 2011, in Case No. 11-55-15-ALT, the Commission approved a stipulation that Columbia may continue its Rider IRP mechanism to reflect IRP investments made through December 31, 2017. However, should Columbia file a base rate case with new rates effective before December 31, 2017, as part of any such rate case, interested parties may challenge any aspect of the IRP and the Commission may, as a result of such challenge, or on its own initiative, revise Columbia's IRP prior to December 31,2017. • This stipulation also expanded the scope of the AMRP component of Columbia's IRP to expressly include first generation plastic pipe or Aldyl-A plastic pipe when such pipe is associated with priority pipe in replacement projects. For each calendar year of the IRP, the footage of such first generation plastic pipe and Aldyl-A plastic pipe that may be included in Rider IRP may not exceed five percent of the total AMRP program footage for that same calendar year. • In its 2008 rate case, Dominion East Ohio received initial approval for its Pipeline Infrastructure Replacement (PIR) tracker program. In 2011, the utility filed a motion to modify the program due to an increase in the identified scope and in response to recent national concern about pipeline safety, which PUCO approved in August 2011. • Duke Energy has had an accelerated main replacement tracker in place since 2000. All customers, except interruptible transportation customers, are assessed a monthly charge in addition to the customer charge component of their applicable rate schedule. • In 2009, the Commission approved the establishment of a tracking mechanism for Vectren Energy Delivery of Ohio that allows the recovery of costs associated with an accelerated bare steel and cast iron pipeline replacement program. • In 2011 Dominion East Ohio (DEO) received Commission approval to further accelerate its replacement activities. PUCO authorized a modified program for another 5 years or until DEO's next rate	Case No. 08-72-GA-AIR (Columbia Gas of Ohio) Case No. 09-458-GA-RDR (Dominion East Ohio) Case No. 01-1228-GA-AIR (Duke Energy) Case No. 07-1080-GA-AIR (Vectren Ohio) Case No. 11-5515-GA-ALT (Columbia Gas) Case No. 11-3238-GA-RDR (Dominion) 15-0362-GA-ALT (Dominion)

	case. This approval raised the annual adjustment cap on the company's rider mechanism. • On February 9, 2015 Dominion East Ohio filed a notice of intent for approval of an alternative rate plan which would extend and increase its investment in pipeline replacement (Docket No. 15-0362-GA-ALT). On September 15, 2016, The Public Utilities Commission of Ohio (PUCO) authorized the continuance of Dominion's pipeline infrastructure replacement program through 2021. PUCO also approved an increase in the yearly spending for the replacement program from $160 million to $180 million in 2017, $200 million in 2018, and a 3% increase per year thereafter.	
Oklahoma	• CenterPoint utilizes a rate stabilization mechanism (Rider PBRC) to change its rates annually to reflect higher capital investment (rate base) and higher O&M costs relating to pipeline safety and other factors. • For each twelve-month period ended December 31, a Commission determination shall be made pursuant to this PBRC Plan as to whether the Company's revenue should be increased, decreased or left unchanged.	CenterPoint Rider PBRC
Oregon	• In the settlement of Avista's 2010 rate case, the Oregon Public Utility Commission provided for deferred accounting treatment for two capital additions: the second phase of the Roseburg Reinforcement Project and the Medford Integrity Management Pipe Replacement Project. A subsequent incremental rate adjustment was made on June 1, 2012 to recover the costs of the projects. • NW Natural has a tracker that recovers the cost of the acceleration of bare steel pipe replacement, transmission pipeline integrity costs and distribution pipeline integrity costs. • On October 21, 2014, NW Natural filed Advice No. 14-23 with an effective date of March 1, 2015. Subsequently, NW Natural filed on February 6, 2015, to extend the effective date to April 1, 2015. The filing requests that Northwest Natural's SIP Recovery Mechanism be extended beyond its sunset date of October 31, 2014. On March 3, 2015, NW Natural filed a supplement to Advice No. 14-23. The purpose of this supplemental filing is to add language requiring that SIP costs be subject to an earnings test. • NW Natural noted in its filing that the regulatory component of the SIP program consists of the ability to update NW Natural's rate base on an annual basis to reflect certain system safety investments. The SIP is comprised of three distinct programs: the Bare Steel Program, the Transmission Integrity Management Program (TIMP), and the Distribution Integrity Management Program (DIMP). On March 10, 2015, Staff recommended that the Commission suspend Northwest Natural's Advice No. 14-23, its request to continue Schedule 177, the System Integrity Program Recovery Mechanism, and open an investigation. The	Docket No. UG-201 (Avista) Docket No. UG-177 (NW Natural) UM 1722 (PUC Investigation Into Recovery of Safety Costs)

	Commission adopted Staff's recommendation and opened an Investigation into Recovery of Safety Costs by Natural Gas Utilities on March 25, 2015.	
Pennsylvania	• In February 2012, the Pennsylvania General Assembly passed HB 1244, legislation that amended Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes to provide an additional mechanism for distribution systems (gas, electric, water, wastewater) to recover costs related to the repair, improvement and replacement of eligible property. Under the amended law, the PA PUC may approve the establishment of a distribution system improvement charge (DSIC) to provide for the timely recovery of reasonable and prudent costs incurred by a utility to repair, improve or replace eligible infrastructure. • On March 14, 2013, The Pennsylvania Public Utility Commission approved the Distribution System Improvement Charge (DSIC) of Columbia Gas of Pennsylvania. Columbia anticipates completing the replacement of cast iron and bare steel mains in approximately 17 years, or by the end of 2029. • On April 4, 2013, The Pennsylvania Public Utility Commission approved the DSIC of Philadelphia Gas Works. PGW also received approval of its long-term infrastructure improvement plans (LTIIP) to accelerate its replacement of 8 inch and smaller cast iron main inventory (totaling 1,200 miles) by 17 years, and accelerating the replacement of all 12 inch and 30 inch high pressure cast iron main by more than 60 years. Without the LTIIP, PGW removed 18 miles of cast iron main as part of its baseline main replacement program. The approved LTIIP allows PGW to remove cast iron main from inventory at a rate of approximately 25 miles per year. • On May 9, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of PECO. • PECO will modernize all of the cast iron and bare steel mains in its gas system within approximately 34 years. This represents a significant acceleration over the 85-year replacement plan that existed prior to acceleration. All bare steel services will be modernized within 10 years versus the 22 year replacement period that existed prior to acceleration. • On May 23, 2013, The Pennsylvania Public Utility Commission approved the DSIC plans of Peoples Natural Gas and Peoples TWP. • Beginning in 2012, Peoples TWP commenced its SMP program to replace all of its unprotected bare steel and some cathodically-protected steel gas mains – a total of roughly 948 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in PTWP's LTIIP addressed in the Commission's order approving its DSIC and LTIIP.	Pennsylvania HB 1294 (Original legislation) Pennsylvania Consolidated Statute: Title 66, Chapter 13B, Section 1353 Docket No. P-2012-2338282 (Columbia Gas of PA) Docket No. P-2013-2347340 (PECO) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2012-2337737 (PGW) Docket No. P-2013-2344595 (Peoples TWP) Docket No. P-2013-2344596 (Peoples Natural Gas) Docket No. P-2013-2342745 (Equitable Gas) Docket No. P-2013-2398835 (UGI Utilities) Docket No. P-2013-2397056 (UGI Penn Natural Gas)

- Beginning in 2011, Peoples commenced its SMP program to replace all of its cast iron, unprotected bare steel, and some cathodically-protected steel gas mains – a total of roughly 2,300 miles of pipeline – over a twenty year period, the early years of which have been described and incorporated in Peoples' LTIIP addressed in the Commission's order approving its DSIC and LTIIP.

- On July 16, 2013, The Pennsylvania Public Utility Commission approved the DSIC plan of Equitable Gas Co.

- At the time of the approval of its DSIC and LTIIP, Equitable operated approximately 41 miles of cast iron distribution mainlines. In 2012, Equitable began to accelerate the replacement of small diameter cast iron. The Commission's order approving its DSIC and LTIIP will allow for the removal of all such pipe from Equitable's distribution system by 2017. During the same time period, Equitable intends to accelerate the replacement of larger diameter cast iron distribution mainline.

- This LTIIP will allow Equitable to replace all small diameter (<12 in.) cast iron distribution mains (9.8 miles), 11.4 miles of large diameter (>12 in.) cast iron distribution mains, 49.7 miles of bare steel and wrought iron distribution mains and 28.7 miles of bare steel and wrought iron gathering mains through calendar year 2017.

- On December 12, 2013, UGI Central Penn Gas filed for approval of a DSIC and DSIC Tariff.

- On December 12, 2013, UGI Penn Natural Gas filed for approval of a DSIC and DSIC Tariff.

- UGI-PNG plans to retire or replace all in-service cast iron mains over the period of 14 years and all bare steel mains over the period of 30 years beginning in March 2013.

- On July 9, 2014, The Pennsylvania Public Utility Commission approved UGI Utilities Inc.'s $256 million long-term infrastructure improvement plan. UGI's five-year plan puts the utility on track to replace its cast-iron mains within 14 years and its bare-steel mains within 30 years of March 2013. As of 2013, UGI had roughly 2,118 miles of steel and 316 miles of iron distribution main, along with 603 miles of steel service lines. UGI also plans to replace gas service lines in conjunction with the mains to which they are connected, the PUC noted in a news release.

- On September 11, 2014, the Pennsylvania Public Utility Commission (PUC) approved the long-term infrastructure improvement plans, or LTIIP, of UGI Penn Natural Gas Inc. (UGI-PNG) and UGI Central Penn Gas Inc. (UGI-CPG). In its order, the PUC also approved the companies' plans to implement the distribution system improvement charges, or DSIC. Under the LTIIP, each of the UGI Corp. subsidiaries are allowed to replace an average of 17 miles of pipeline per year in a five-year period. UGI-PNG plans to spend nearly $23 million per year, while UGI-CPG plans to spend almost $14 million per year, on pipeline replacements, service line improvements and safety device installations over the five-year period.

- In February of 2015, PECO filed a request with the Pennsylvania Public Utility Commission (PUC) for approval to accelerate the modernization of the company's natural gas distribution system. PECO's plan would increase the company's Long-Term Infrastructure Improvement Plan from $34 million per year to $61 million per year. Under the proposed plan, replacement of natural gas main would increase from about 30 miles per year to more than 50 miles per year by 2018. Bare steel service line replacement would remain at about 4,000 lines per year. This would accelerate the replacement of existing cast iron, bare steel, wrought iron and ductile iron gas main and bare steel service line from 34 years to 22 years. This plan was approved on May 7, 2015.

- On July 8, 2015 the Pennsylvania Public Utility Commission (PUC) issued orders finalizing previously approved distribution system improvement charge (DSIC) mechanisms for UGI Penn Natural Gas (UGI-PNG) Gas and UGI Central Penn Gas (UGI-CGP).

- This decision relates back to the PUC's September 2014 orders approving Long Term Infrastructure Improvement Plans (LTIIPs) and related DSICs for UGI-PNG and UGI-CPG, subject to subsequent review of certain issues. Pursuant to a 2012 settlement resolving an investigation into a gas pipeline explosion in Allentown, the companies were not permitted to implement adjustments under the DSIC until April 2015.

- Under its approved LTIIP, UGI-PNG is to expend roughly $23 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of the plan. Additionally, UGI-CPG, the company is to expend roughly $14 million annually on pipeline replacements (average of 17 miles per year), service line improvements, and safety device installations over the five-year term of its plan.

- On September 3, 2015, the Pennsylvania Public Utility Commission voted 5-0 to approve PECO Energy Co.'s plan to implement a distribution system improvement charge for its gas operations.

- On January 28, 2016, the Pennsylvania Public Utility Commission (PUC) voted to help Philadelphia Gas Works (PGW) fund faster pipeline replacement work. The commissioners unanimously approved an increase to the utility's distribution system improvement charge, or DSIC, raising the cap from 5% of the company's billed revenues to 7.5%. PGW will have to track and account for all its distribution system improvement charge, or

	DSIC, spending using a designated accounting mechanism, earmarking all unspent DSIC money for future infrastructure spending or refunds to customers, if necessary, according to the PUC decision. This increase would allow PGW to spend about $33 million annually on its main replacement program, which would cut the projected timeline to replace the company's aging gas mains to 48 years. • On March 10, 2016, the Pennsylvania Public Utility Commission issued an order approving Peoples Natural Gas' (Peoples) Second Revised Long Term Infrastructure Improvement Plan. The newly-approved plan will allow Peoples to implement the following changes: o Shift its replacement focus towards urban projects in order to more effectively target pipeline replacements for higher risk projects located in the higher population areas of its system; o Deploy automated meter reading technology; o Undertake various upgrades and improvements to M&R stations and related M&R equipment; o Expand the replacement of bare steel and other at-risk customer-owned service lines. • In addition, Peoples received approval to establish a Construction Division with in-house employees and construction crews that would perform 100% of capital related construction work at Peoples, the Equitable Division and its sister company – Peoples TWP, LLC. The Construction Division's scope of work will include design, planning, construction, and restoration. Peoples maintains that the move to an in-house staffed Construction Division will further improve the quality of capital work by reducing the cycle time of "planning to restoration" and improving the efficiency and operating costs of all construction activities. The transition to a full Construction Division is expected to be a two-year process that will continue through 2016. • By the end of 2016, the Construction Division will be staffed with superintendents, managers, supervisors, technicians and engineers, as well as approximately 300 field employees that will be located throughout the company's service territories to handle all construction and restoration work. Approximately 220 of these field employees (including field inspectors) will be assigned to 45 construction crews, and the remaining field employees (approximately 80) will be responsible for restoration work. While the Construction Division employees will be dedicated to performing capital work, they will be made available, on a limited basis, to support Operations and Maintenance (O&M) work activities, such as emergencies and overtime call outs, in order to ensure that all operations activities are done in the most cost-efficient manner. Should this occur, their time would be properly tracked and charged as an O&M expense. • On March 18, 2016 Columbia Gas of Pennsylvania (CGP) filed with the Pennsylvania Public Utility	

	Commission (PUC) for gas distribution base rate increase. CGP indicated that the rate increase is intended to allow the company to collect the revenue requirement associated with investments made under the company's accelerated pipeline replacement program. The company expended $152 million on infrastructure investments in 2015, and estimates that is will spend $162 million on infrastructure modernization in 2016. Over the years 2016 through 2020, Columbia estimates its total capital spending will be $958 million. The filing also reflects increases in operation and maintenance expenses associated with the facilities upgrades. This matter is presently pending. • On June 30, 2016, The Pennsylvania Public Utility Commission (PUC) approved the modified long-term infrastructure improvement plans (LTIIPs) for Peoples Natural Gas, UGI Utilities Inc. - Gas, UGI Penn Natural Gas Inc. and Central Penn Gas Inc. • The approved, revised LTIIP for Peoples Natural Gas replaces the currently approved, separate LTIIPs of the Peoples Division and the Equitable Division (previously Equitable Gas Company) of the Peoples Natural Gas Co. Peoples' Revised LTIIP is a five-year plan that builds off of, and expands upon, the previously-approved LTIIPs for the Peoples and Equitable Divisions. Peoples has replaced all known cast iron pipelines in its system, and plans to address accelerated replacement of the 37 miles of known cast iron pipelines acquired through its formation of the Equitable Division. Peoples proposes to replace all bare steel and cast iron pipelines over an approximately 20-year period. • In its revised LTIIP, Peoples indicates it will replace all at-risk customer-owned service lines, which is an update from its original LTIIP where the company said it planned to pressure test customer-owned service lines prior to replacement. Peoples provides natural gas service to approximately 640,000 residential, commercial, and industrial customers in all or portions of 17 Southwestern Pennsylvania Counties. • In a separate action, the Commission voted to approve the modified LTIIPs for UGI Gas, UGI Penn Natural Gas and UGI Central Penn Gas. Each of the UGI Companies' modified LTIIPs are five-year plans, spanning the years 2014-2018. The LTIIPs detail accelerated infrastructure improvements that are intended to enhance system resiliency. The instant petitions do not propose to change or extend the term of the current LTIIPs. Rather, the instant petitions propose to increase the amount of infrastructure spending over that of the currently effective LTIIPs by more than 20 percent. The UGI Companies as a group propose spending more than 50 percent additional capital in the final three years of their LTIIPs compared to the original projections.	

Rhode Island	• In 2010, the Rhode Island General Assembly passed legislation to amend Chapter 39-1 of the Rhode Island General Laws to allow the Rhode Island PUC to approve revenue decoupling and infrastructure investment tracking mechanisms. • As a result of this legislation, National Grid utilizes an Infrastructure Safety and Reliability Plan (ISR) which replaced its existing Accelerated Replacement Program (ARP). This program began April 2011 and funds both replacement of leak prone mains and bare steel, high pressure services. The plan also includes funds for system reliability, mandated programs and special projects and includes a fully-reconciling rate mechanism designed to recover actual and anticipated capital investments as reflected in the approved ISR spending plan. • In its FY 2015 Gas Infrastructure Safety and Reliability Plan (ISR) (Docket No. 4474), the Commission authorized the company to target 70 miles of main per year, which would reduce the time frame for removal of leak prone pipe to approximately 20 years. The company had replaced 50 miles in FY 2014.	Rhode Island General Laws: Title 39, Chapter 39-1, Section 39-1-27.7.1 Docket No. 4474 (National Grid)
South Carolina	• In 2005, South Carolina passed the Natural Gas Rate Stabilization Act (RSA), which was designed to reduce fluctuations in customer rates by allowing for more efficient recovery of the costs regulated utilities incur in expanding, improving and maintaining natural gas service infrastructure. • In lieu of a general rate case, Piedmont Natural gas and SCE&G have filed annual base rate updates since 2005 pursuant to the RSA. The annual rate update enables the Company to earn a return on actual plant investments made thru the prior March 31st.	Natural Gas Rate Stabilization Act
Tennessee	• In April 2013, Tennessee enacted legislation which provides for alternative regulatory methods to allow for public utility rate reviews and cost recovery for investments in infrastructure replacement and expansion in lieu of a general rate case. In particular, the measure allows the Tennessee Regulatory Authority (TRA) to approve cost recovery mechanisms to recoup operational expenses and/or capital costs associated with infrastructure replacement that is necessary to comply with federal and state safety requirements and/or ensuring reliability. • Piedmont Gas utilizes this rider. • In May of 2015, Atmos Energy received approval from the Tennessee Regulatory Authority to implement an Annual Review Mechanism, which will allow the company to adjust its rates annually to reflect higher capital investment and higher O&M costs relating to infrastructure replacement and other factors.	Public Chapter No. 245 (HB 191) Docket No. 1400146 (Atmos Energy)
Texas		

	• In 2003, the Texas Legislature passed SB 1271 which established the Texas Gas Reliability Infrastructure Program (GRIP). • GRIP allows a gas utility that has filed a rate case within the previous two years to file a tariff or rate schedule that provides for an interim adjustment in its monthly customer charge or initial block rate in order to recover the cost of investment changes, which could include the replacement of aging infrastructure or expansion of infrastructure. • In 2011, the Texas Railroad Commission adopted a comprehensive pipeline safety rule that requires all state natural gas distribution companies to survey their pipeline distribution systems for the greatest potential threats for failure and make replacements. The rule allows for the recovery of costs of such programs via a deferral mechanism. • Atmos Energy, CenterPoint Energy and Texas Gas Service utilize portions of these mechanisms. • On August 25, 2015 the Texas Railroad Commission (RRC) adopted a settlement in CenterPoint Energy's base rate case. The agreement provides that a 10% ROE with a 54.5% equity capital structure is to be used for prospective adjustments under any interim rate adjustment mechanisms that recognize new capital investment, including the company's Gas Reliability Infrastructure Program.	Senate Bill 1271, Establishing the Gas Reliability Infrastructure Program 16 TAC Chapter 8- Pipeline Safety Regulations (2011)
Utah	• In 2010, the Utah Public Service Commission authorized Questar Gas to implement a three-year pilot Infrastructure Replacement Adjustment (IRA) mechanism to track and recover the costs associated with the replacement of high pressure natural gas feeder lines between rate cases.	Docket No. 09-057-16
Virginia	• In 2010, Virginia enacted the SAVE (Steps to Advance Virginia's Energy Plan) Act. The law allows utilities to petition the Virginia State Corporation Commission for a separate rider to recover a return on certain investments, including natural gas facility replacement projects that enhance safety and reliability, or have the potential to reduce greenhouse gas emissions by reducing system integrity risks; Atmos Energy, Columbia Gas Virginia, Virginia Natural Gas and Washington Gas utilize the rider. • On November 28, 2011, The Virginia State Corporation Commission approved the SAVE plan and rider of Columbia Gas of Virginia. The plan permits Columbia to spend $20 million each year with the flexibility to vary this amount up to 5% above or below the projected level of plan investment in any year. The approved plan runs through December 31, 2016. • On July 25, 2014 The Virginia State Corporation Commission authorized Virginia Natural Gas to recover costs associated with the replacement of up to $105	Code of Virginia: 56-603, 56-604 (Implementation of SAVE Act) PUE-2010-000871 (Washington Gas) PUE-2012-00096 (Washington Gas) PUE-2015-00017 (Washington Gas) PUE-2012-00012 (Virginia Natural Gas) PUE-2011-00049 (Columbia Gas of Virginia)

million of infrastructure during the five-year term (2012-2016) of its SAVE Plan. The Company intends to spend up to $25 million annually with the total investment over the five-year term of the SAVE Plan capped at $105 million. Costs are recovered through a rider ("Rider E" or "SAVE Rider") on customers ‘bills as authorized by the SAVE Act.

- On February 6, 2015 Washington Gas Light Company (WGL) filed an application with the Commission for approval of amendments to its SAVE Plan, which the Commission first approved in Case No. PUE-2010-000871 ("Approved SAVE Plan") and modified in its Order Approving Amended SAVE Plan in Case No . PUE-2012-00096. In this Application for an amended SAVE Plan, WGL proposed to increase its Virginia SAVE Plan expenditures for the period January 1, 2015, to December 31, 2017 ("Period") by approximately $75.2 million, for a total of $194 .4 million for the Period, for the expansion of the scope of certain of its approved SAVE Plan programs and implementation of new programs. This plan was approved on June 5, 2015.

- WGL plans to expand its pre-1975 Plastic Service Replacements program, and the Copper Service Replacement program to include all services in each of these categories. The Company also proposed to add two new distribution system replacement programs.

    - Program 8 - a Meter Set Survey and Remediation Program - will address the replacement of piping if certain conditions are discovered during the meter set survey, the replacement of shallow main that is occasionally discovered, and the replacement of gauge lines for medium pressure main-line valves.

    - Program 9 – a Meter Set Survey Technology Implementation Program - will automate the Company's manual processes by constructing-a data model and technology solution that will provide integration with a range of work management systems, document management systems, and mapping systems.

    - This filing also calls for the approval of an additional one 1 per year of bare steel replacement on top of the company’s currently-approved 25 mile per year pace and .7 miles per year of cast iron replacement on top of the company’s current 13.3 mile per year pace.

- In December of 2015, Virginia Natural Gas asked the State Corporation Commission to approve a plan to further accelerate its replacement of aging infrastructure. Since 2012, the company has installed 155 miles of new main line and more than 9,000 new service lines to customers, replacing aging connections, and expects to finish work on another nine miles of main line and 600 service lines by the end of the year. The proposed plan aims to replace the final 23 miles of cast

	iron pipe in the company's system, as well as 293 miles of bare steel main. If approved, this proposal would authorize the company to invest $30 million in 2016 and $35 million a year from 2017 to 2021, up to a maximum of $210 million. • On March 17, 2016, The Virginia State Corporation Commission (SCC) approved an expansion of Virginia Natural Gas' (VNG) infrastructure modernization program. Under the newly-approved plan, VNG plans to invest $30 million in its Steps to Advance Virginia's Energy (SAVE) program in 2016 and up to $35 million annually after that to replace more than 200 miles of aging pipeline infrastructure through 2021. Since 2012, Virginia Natural Gas has invested about $82 million in replacing more than 160 miles of pipeline with modern materials. • The SCC stated that it would require VNG to provide a list of completed projects during the preceding calendar year, a list of planned projects for the current calendar year and details about what the projects address. This list is to be filed annually in January.	
Washington	• In December 2012, the Washington UTC issued a policy statement aiming to enhance safety and modernize and update the state's pipeline system. • In November 2013, the UTC approved the the plans of Avista Corporation, Puget Sound Energy Inc., Cascade Natural Gas Corporation and Northwest Natural Gas Company. The plans involve the replacement of hundreds of miles of older "elevated risk" pipes with plastic pipe. • As an incentive, the UTC permitted these utilities to recover costs annually instead of waiting for future formal rate proceedings. The companies are also required to update their modernization plans every two years.	Docket No. PG-120715 (12/31/2012)
West Virginia	• In its January 2015 base rate filing, Mountaineer Gas proposed an infrastructure replacement program to increase reliability and enhance safety by enabling the more timely cost recovery for eligible infrastructure improvements. The proposed program would cover investments to eliminate bare steel mains and services with the highest leakage rates and other infrastructure replacements. This enhanced investment will accelerate overall safety and reliability improvements by reducing system integrity risks due to corrosion, equipment failures, material failures, and the impact of natural forces, and it will reduce customer service outages through replacement of higher-risk pipeline segments. Investment currently in rate base (or that would be included in rate base in this rate case), or that would increase revenue by directly connecting new customers to the system, would be ineligible. • The program would be funded through a rate mechanism, which would be implemented beginning on January 1, 2017, and the Company would commit to invest at least $12,800,000 in qualifying infrastructure	SB 390 Docket No. 15-0003-G-42T (Mountaineer Gas) Docket No. 15-1600-G-390P (Dominion Hope) Docket No. 15-1256-6-390P (Mountaineer IREP)

	replacement each year for the succeeding three years. The Company wishes to formalize this program under the Commission's direction and to accelerate its investment in this important component of its system. • On February 3, 2015, the West Virginia Senator Charles Trump (R) filed SB 390. This bill provides that natural gas utilities may file with the commission, an application for a multi-year comprehensive plan for infrastructure replacements, upgrades and extensions. Subject to commission review and approval, a plan may be amended and updated by the natural gas utility as circumstances warrant. • Following commission approval of its infrastructure program, a natural gas utility shall place into effect rates that include an increment that recovers the allowance for return, related income taxes, depreciation and property tax expenses associated with the natural gas utility's estimated infrastructure program investments for the upcoming year, net of contributions to recovery of those incremental costs provided by new customers served by the infrastructure program investments, if any, ("incremental cost recovery increment"). In each year subsequent to the order approving the infrastructure program and an incremental cost recovery increment, the natural gas utility shall file a petition with the commission setting forth a new proposed incremental cost recovery increment based on investments to be made in the subsequent year, plus any under-recovery or minus any over-recovery of actual incremental costs attributable to the infrastructure program investments, for the preceding year. This bill was signed into law on March 24, 2015 and will take effect on June 11, 2015. • On September 30, 2015, Dominion Hope Gas filed for approval of its Pipeline Replacement and Expansion Program (PREP). PREP is consistent with SB 390's objectives of replacing, upgrading, extending and expanding the Company's natural gas pipeline infrastructure to provide continued and enhanced, efficient, safe and reliable gas service to its current base, including to new customer bases in unserved or underserved areas of West Virginia. • PREP features two separate replacement initiatives. The first is a 50-year program to accomplish the following goals: o Replace bare steel distribution mains; o Replace unprotected, ineffectively coated steel distribution mains; o Replace unprotected bare steel services; o Enhance or upgrade system facilities; and o Replace aged gas measurement and regulation equipment • The second replacement initiative is the company's proposal to prospectively replace existing gas sales service customer' piping (CSP) if it is found to be bare steel in the course of associated mainline replacements	

	or when the time comes in the future to replace that customer-owned CSP due to its age or condition. • Costs associated with PREP would be eligible for recovery through an annual rate surcharge. • On July 31, 2015, Mountaineer Gas Company (MGC) filed for approval of an Infrastructure Replacement and Expansion Program (IREP). On October 9, 2015, the parties in this proceeding filed a Joint Stipulation and Agreement for Settlement (Joint Stipulation). In the Joint Stipulation, the parties recommended that the Commission authorize a total 2016 revenue increase of $565,758, using the customer class allocation determined in above-referenced rate proceeding. The IREP rate component for IS and LGS customers will also be expressed as a fixed customer charge, as opposed of the volumetric calculation that MGC had proposed in its IREP Application. The parties asserted that this change would not affect other rate schedules. The parties also agreed that the IREP rate component would not apply to customers who receive service under one or more special contracts filed with the Commission. The Commission approved the Joint Stipulation on December 23, 2015. • On February 4, 2016, the West Virginia Public Service Commission approved a Joint Stipulation and Agreement for Settlement that provides for a Pipeline Replacement and Expansion Program (PREP) and a PREP cost recovery component to the base rates of Hope Gas (Dominion Hope). The Commission modified the Joint Stipulation as it relates to the filing of quarterly reports as part of a pilot program. The approved Stipulation reflects the parties' agreement to a 2016 projected PREP capital investment of approximately $20.5 million. The approved agreement allows Dominion Hope to collect a total 2016 revenue increase of $862,014 using the customer class allocations and rate of return on equity determined in Dominion Hope's last base rate proceeding. The company's initial filing separated proposed projects into 3 categories. Categories 1 and 3 were approved. • Category 1 projects -- The largest category of proposed capital investment, these projects will replace and upgrade aged infrastructure, including distribution mains, service lines and appurtenant facilities. When individual PREP projects are completed Dominion Hope will prepare a work order package that contains the same information that was approved in the Mountaineer SB 390 proceeding: the materials used (type and amount), unit prices, work force used (internal or contracted), total project cost, construction period and duration, project in-service date and related details. These packages will be available to Commission Staff and the Consumer Advocate Division for auditing purposes. • The Commission also approved the parties request for approval of a three-year pilot program in which Category 3 projects - Dominion Hope's repair, replacement and installation of customer service piping. These projects will also be included in the capital investment for PREP	

	cost recovery. The pilot program will begin March 1, 2016, and end December 31, 2018.	
Wyoming	• On August 4, 2016, the Wyoming Public Service Commission approved a Pipeline Safety and Integrity Mechanisms (PSIM) for Black Hills Energy (BHE). The PSIM will allow BHE to recover its investment for nine specific projects utilizing the PSIM and would increase its natural gas utility revenue by $42,511 for the period of August 1, 2016, through March 31, 2017. • The PSIM is designed to recover the PSIM Revenue Requirement associated with the investments in pipeline infrastructure approved in Docket Nos. 30003-62-GA-14 and 30005-187-GA. Until such time as these infrastructure investments are included in base rates, but no later than March 31, 2021, PSIM costs will be recovered from customers using a PSIM charge applied to all customers' monthly bills. The PSIM will be calculated annually using the actual and forecasted capital costs and operating expenses for the just ending calendar year and forecasted Dth billing determinants by customer class, except for the calculation to be used to determine the first PSIM rates effective with usage on or after August 1, 2016. • The Company will make a PSIM filing with the Commission annually by December 31st of each year. The PSIM filings will: 1) reflect the additional investment in pipeline replacement costs that have been, or that are anticipated to be completed, during the current year; 2) true-up to actual costs the investment costs and related revenue requirement from the amount in the previous year's PSIM, and 3) true-up the revenue collected from customers to the amount, reflecting the prior year's trued-up investment. The PSIM applies to all natural gas rate schedules for all classes of service authorized by the Wyoming Public Service Commission	DOCKET NO. 30003-66-GA-15

Certificate of Service

I, Carl Cronin, hereby certify that I have this day served copies or summaries of the foregoing documents on the attached list(s) of persons.

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

xx electronic filing

Docket No. G002/M-15-808
Docket No. G002/GR-09-1153
Xcel Energy Miscellaneous Gas Service List

Dated this 1st day of November 2016

/s/

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Carl Cronin

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