MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	May 23, 2019	Agenda Item 7**

Company Northern States Power Company d/b/a Xcel Energy

Docket No. **G-002/M-17-787**

In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider True-up Report for 2017, the Forecasted 2018 Revenue Requirements, and Revised Adjustment Factors.

Issues

1. Should the Commission approve or modify Xcel Energy's proposed rate of return used for determining the Gas Utility Infrastructure Cost Rider revenue requirements?

2. Should the Commission approve or modify Xcel Energy's proposed proration for Accumulated Deferred Income Taxes?

3. Should the Commission approve or modify Xcel Energy's proposed 2018 Gas Utility Infrastructure Cost Rider revenue requirement and adjustment factor?

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ *Relevant Documents*	**Date**
Xcel Energy Initial Petition	November 1, 2017
Xcel Energy Supplement to Petition – Updated Revenue Requirement	March 27, 2018
Commission – Notice of Comment Period	May 2, 2018
Xcel Energy – Supplemental Comments	May 29, 2018
Minnesota Office of Attorney General Comments	June 29, 2018
Minnesota Department of Commerce Comments (Non-Public)	July 3, 2018
Xcel Energy Reply Comments (Non-Public)	July 27, 2018
Minnesota Department of Commerce Response Comments (Non-Public)	December 6, 2018
Xcel Energy Reply to Department of Commerce Response Comments	December 17, 2018

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I. Statement of the Issues

- Should the Minnesota Public Utilities Commission approve or modify Xcel Energy's proposed rate of return used for determining the Gas Utility Infrastructure Cost Rider revenue requirements?

- Should the Minnesota Public Utilities Commission approve or modify Xcel Energy's proposed proration for Accumulated Deferred Income Taxes?

- Should the Minnesota Public Utilities Commission approve or modify Xcel Energy's proposed 2018 Gas Utility Infrastructure Cost Rider revenue requirement and adjustment factor?

A number of issues discussed in these briefing papers are typically addressed in general rate case proceedings rather than annual rider compliance filings but due to the length of time since the Company's last rate case and the complexity of the issues in the instant *Petition*, they arise here. Some of these issues are:

- Rate of Return
- Sales Forecast

II. Introduction and Background

A. Introduction

Northern States Power Company d/b/a Xcel Energy (Xcel Energy or the Company) is seeking approval of its updated Gas Utility Infrastructure Cost (GUIC) Rider to be in effect through March 31, 2019. The Company requested that it be allowed to recover its forecasted 2017 GUIC revenue requirement of approximately $23.22 million,[1] subject to actual cost true-up. Xcel Energy's GUIC recovery includes expenditures for integrity management programs and deferred costs.[2]

Integrity Management Programs were introduced pursuant to the Pipeline Safety Improvement Act, passed by the U.S. Congress in 2002. The law directed the U.S. Department of Transportation to promulgate rules to address integrity programs for gas transmission lines. A Transmission Integrity Management Program (TIMP) is a prescriptive risk-based program with

[1] Xcel Energy initially requested $27.5 million in its November 1, 2017 filing but filed a supplement to its *Petition* on March 27, 2018, reflecting updated revenue requirement due to the Commission's Order in Docket No. G-002/M-16-891, the Tax Cuts and Jobs Act (TCJA) and other updates. Subsequently, the Company revised its request to $23.22 million in its July 27, 2018 *Reply Comments*.

[2] In Xcel Energy's most recent general rate case (Docket No. G-002/GR-09-1153), the Company was authorized an annual rate increase of $7.3 million, or 1.27 percent, to collect a total annual revenue requirement of approximately $592.9 million. Of this $592.9 million, at least $429 million was for the recovery of purchased gas costs. As a percentage of non-gas costs, Xcel Energy's $7.3 million rate increase was approximately 4.5 percent per year.

the objective to improve pipeline safety; gas transmission operators are required to assess the health and condition of a utility's gas transmission assets, and evaluate and prioritize repairs to mitigate the risks and threats.

In 2009, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) published the final Distribution Integrity Management Program (DIMP) rule establishing integrity management requirements for gas distribution pipeline systems. The DIMP rules are intended to help gas distribution utilities identify, prioritize, and evaluate risks, identify and implement measures to address risk, and validate the integrity of their gas distribution system.

In 2005, the Minnesota Legislature enacted Minnesota (Minn.) Statute (Stat.) section (§) 216B.1635, the *Recovery of Gas Utility Infrastructure Costs* statute (GUIC statute), permitting gas utilities to file petitions for a rate schedule to recover certain costs of GUIC-defined projects. In 2013, the GUIC statute was amended which, in part, expanded both the definition of GUIC projects and the eligible rider-recoverable costs.[3]

Prior to the GUIC statute amendments, the Minnesota Public Utilities Commission (Commission) granted Xcel Energy deferred accounting for incremental TIMP/DIMP initiatives and for its sewer and gas line conflict-remediation program required by the Minnesota Office of Pipeline Safety (MNOPS).[4] In its January 27, 2015 *Order* (Docket No. G-002/M-14-336), the Commission approved the commencement of a five-year amortization recovery of these deferred costs through the GUIC Rider.

B. Background

1. 14-336 Docket

In Xcel Energy's inaugural GUIC petition, Docket No. G-002/M-14-336 (14-336 Docket), Xcel Energy requested approval of a new tariffed rate rider to recover Gas Utility Infrastructure Costs under Minn. Stat. § 216B.1635. On January 27, 2015, the Commission issued its *Order Approving Rider with Modifications*. A subsequent Commission Order in the 14-336 Docket, issued on April 10, 2015, denied the request for reconsideration from the Office of the Attorney General – Residential Utilities and Antitrust Division (OAG).

In the 14-336 Docket, the Commission approved Xcel Energy's proposed GUIC rider with the following modifications:

[3] A complete copy of Minn. Stat. § 216B.1635 is located in an attachment to these briefing papers.

[4] See Docket Nos. G-002/M-10-422 and G-002/M-12-248, respectively.

- a reduced overall rate of return, calculated using the capital structure and cost of debt from Xcel Energy's then pending electric rate case[5] and the cost of equity from its last natural gas rate case;[6]

- a rate design that allocates responsibility for the GUIC rider revenue requirement according to the revenue apportionment approved in Xcel Energy's last natural gas rate case;[7] and

- an effective date as of the date of the January 27, 2015 order, with final rate-adjustment factors calculated to recover 2015 revenue requirement over the remaining months of 2015.

The 14-336 Docket *Order* also required Xcel Energy to submit, sixty days in advance of its next annual GUIC filing, information on what it believes the appropriate rate of return should be for the coming year. Xcel filed this information on September 2, 2015.

2. 15-808 Docket

In Xcel Energy's 2015 true-up report and request for 2016 forecasted revenue requirement and revised adjustment factor, in Docket No. G-002/M-15-808 (15-808 Docket), Xcel Energy requested approval of its 2015 true-up report and 2016 GUIC revenue requirements along with implementation of a new Federal Code Mitigation project and a request to modify the effective period of the GUIC rider factor to be in place through March 31st, rather than December 31st.

In the 15-808 Docket *Order*, the Commission approved Xcel Energy's 2015 true-up report and 2016 GUIC revenue requirements and revised adjustment factors with the following modifications:

- approved an overall rate of return of 7.34 percent;

- required Xcel Energy to develop specific metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and provide stakeholders the opportunity for meaningful involvement; and

- required Xcel Energy to include specific information about each individual project in future GUIC Rider filings 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.

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[5] Docket No. E-002/GR-13-868.

[6] Docket No. G-002/GR-09-1153.

[7] *Id*.

3. 16-891 Docket

In Xcel Energy's 2016 true-up report and request for 2017 forecasted revenue requirement and revised adjustment factor, in Docket No. G-002/M-16-891 (16-891 Docket), Xcel Energy requested approval of its 2016 true-up report and 2017 GUIC revenue requirements.

In the 16-891 Docket Order, the Commission approved Xcel Energy's 2016 true-up report and 2017 GUIC revenue requirements and revised adjustment factors with the following modifications:

- Approved an overall rate of return of 7.02 percent;
- Denied Xcel Energy's proposed Accumulated Deferred Income Tax (ADIT) proration for the forecasted year and determined that the 2017 GUIC Rider must not be effective prior to January 1, 2018;
- Disallowed Quality Assurance/Quality Control related costs as duplicative services;
- Continued to require Xcel energy to discuss, with other parties, proposed performance metrics and ongoing evaluation of reporting requirements in future GUIC proceedings; and
- Continued to require Xcel Energy to include specific information about each individual project in future GUIC Rider filings 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.

4. 17-787 Docket (this docket)

In the instant petition, Xcel Energy requests Commission approval of the 2017 true-up report and 2018 GUIC revenue requirements and revised adjustment factors. The Minnesota Department of Commerce, Division of Energy Resources (Department) and the OAG filed comments discussing a number of issues. The issues addressed are:

- Rate of Return on Investment
- Prorated Accumulated Deferred Income Taxes
- Sales Forecast
- Data Gaps
- GUIC Project Cost Allocation Between Minnesota and North Dakota
- Project Costs Proposed for Inclusion in GUIC Recovery Rider
- Review of Contracts, Work Orders, and Invoices
- GUIC Rider Schedules
- Compliance Filing, True-up Report, Tracker Balances, and Carrying Charge
- Tariff Sheet and Customer Notice
- Performance Metrics

The following sections of these briefing materials provide in more detail the positions and comments of the parties.

III. Xcel Energy's Initial Petition

Xcel Energy has nine ongoing GUIC projects, three are TIMP-related and six are DIMP-related.[8] In determining the 2018 GUIC revenue requirement, Xcel Energy proposed using a rate of return (ROR) of 7.52 percent, which is based on a proposed ROE of 10.00 percent.

According to Xcel Energy, responsibility for the GUIC rider revenue requirement is allocated to customer classes consistent with how responsibility for the Company's revenue requirement was apportioned in Xcel Energy's most recent natural gas rate case, in docket 09-1153.

The proposed 2018 GUIC factors by customer class along with existing factors are shown in Xcel Energy's petition (shown below).[9]

Table 1: Proposed 2018 GUIC Adjustment Factors
($ per therm)

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

The proposed 2018 GUIC factors are higher due to the combined effects of increased GUIC annual revenue requirements and prior year (2017) under-recovery. The increasing revenue requirements correlate with the accumulation of GUIC capital investments (rate base).

With TIMP and DIMP combined, the table below summarizes Xcel Energy's overall projected annual and year-to-date (YTD), GUIC capital expenditures and each year's projected GUIC revenue requirements, inclusive of deferred costs, through the year 2022:

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[8] Xcel's projects are more fully discussed in Attachment C (TIMP) and Attachment D (DIMP) of the *Petition*.

[9] *Petition* at 37.

Table 2: Projected GUIC Capital Expenditures & Revenue Requirements 2015 - 2022 ($ 000s)			
	Capital Expenditure*		
Year	Annual	YTD	Rev. Req.^
<2015		$ 21,952	
2015	$ 30,873	$ 52,825	$ 12,503
2016	$ 31,551	$ 84,376	$ 16,147
2017	$ 21,895	$ 106,271	$ 22,865
2018	$ 45,528	$ 151,799	$ 27,478
2019	$ 60,721	$ 212,520	$ 34,856
2020	$ 47,013	$ 259,533	$ 34,767
2021	$ 48,209	$ 307,742	$ 40,570
2022	$ 48,055	$ 355,797	$ 46,713

* Source: Petition, page 22, Table 2
^ Source: Petition, Attachment N

The lower revenue requirement in 2020, as compared to 2019, is due to the conclusion of the recovery of deferred costs (five-year amortization) and the anticipated completion of the gas and sewer line investigation project in 2019.[10] The revenue requirement then increases in 2021 with additional TIMP and DIMP capital related revenue requirements.

Xcel Energy proposed a customer notice billing message using the same language approved in its prior GUIC docket, which is included on page 39 of its *Petition*. Xcel Energy stated its willingness to work with Department and Commission staff if modifications are suggested.

IV. Discussion of Issues

A. Resolved Issues

1. Filing Requirements

The Department's *Comments* concluded that Xcel Energy's *Petition* omitted a report of the costs and salvage value associated with the existing infrastructure replaced or modified as required by Minn. Stat. § 216B.1635, Subd. 4 (2)(iii). The Department requested that the Company file the required information in its *Reply Comments* and recommended that the Commission direct Xcel Energy to include such reporting in future GUIC Rider petitions.

Xcel Energy acknowledged the omission and subsequently provided the required

[10] Xcel Energy *Petition* Attachment J.

information in Attachment A to its *Reply Comments*. The Company's *Reply Comments* explained how it quantified the information reported in its Attachment A, given that the retired assets had already been removed from its accounting system.[11]

The Department concluded that Xcel Energy's *Reply Comments* reasonably satisfy this filing requirement. However, because this information is integral in developing and evaluating the reasonableness of requested rider recovery amount, the Department recommends that the Commission put the Company on notice that any future GUIC filings lacking statutory filing requirements will be subject to rejection.

2. Incremental Costs

In *Comments* the Department noted per Minn. Stat. Section 216B.1635, the GUIC Rider must include only the *incremental* costs associated with GUIC projects. In addition, the Department pointed out that the Company's proposed rate base, depreciation expense and property tax amounts for rider recovery were not adjusted to reflect only incremental costs, therefore, the Department, recommended that the Commission direct Xcel Energy to do so.[12]

In its *Reply Comments*, Xcel Energy acknowledged that the GUIC projects *replace* existing assets, therefore made adjustments to rate base, depreciation and property tax in order to reflect only the incremental costs of the GUIC projects in its recovery request. Collectively, Xcel Energy's calculated adjustments reduced the annual GUIC Rider revenue requirement by $481,000 as shown in Table 2 on page 6 of Xcel Energy's *Reply Comments.*

The Department concluded that this issue is now resolved and recommended that Xcel Energy continue the practice of isolating only the incremental costs in future GUIC Rider cost recovery petitions.

3. GUIC Project Depreciation Rates[13]

The Department, in its *Comments*, recommended that Xcel Energy incorporate and apply the recent Commission-approved depreciation factors (Docket No. E,G-002/D-17-581), when calculating GUIC projects' depreciation in the instant *Petition*.[14]

In *Reply Comments* Xcel Energy agreed and included a revision to its proposed revenue requirements.[15] The Company calculated that the new depreciation rates reduced its proposed

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[11] Xcel Energy *Reply Comments* at 3-5.

[12] Department *Comments* at 13-18.

[13] The issue of non-GUIC depreciation expense impacts is discussed in section IV.B.13 of these briefing papers.

[14] Department *Comments* at 17.

[15] Xcel Energy *Reply Comments* at 7, Attachment B.

rider revenue requirement by approximately $540,000; however, the final impact arising from use of newly approved depreciation rates may change based on the Commission's Order in this matter.

In *Response Comments* the Department concluded that this issue had been resolved.[16]

4. Non-Minnesota Costs

The Department expressed concern regarding capital costs that cannot be traced back to a specific contract and Xcel Energy's inability to demonstrate that all of the costs requested for recovery were for projects performed in Minnesota. Both of these issues are discussed in sections IV.B.4 and IV.B.9 of these briefing papers. The issue here deals with two work orders related to work completed in Colorado which were incorrectly identified as Minnesota-related work and subsequently included in the Company's initial GUIC revenue requirement. These two work orders were discovered as a result of Xcel Energy's response to Department Information Request No. 62 where the Company agreed to remove the work orders from its requested revenue requirement. The revenue requirement impact from these projects were approximately $213 in 2017 and $465 in 2018.[17] Xcel Energy's revised revenue requirement included in the Company's *Reply Comments* reflects this change. During a further review of these invoices, the Company discovered additional invoices for work completed outside of Minnesota totaling $336.30 in costs. Xcel Energy stated that it removed these additional costs from its revised revenue requirement.[18]

5. Recovery Period

Xcel Energy proposed to recover the 2018 GUIC Rider revenue requirements over an 8-month period while the Department recommended a 12-month recovery period, consistent with the Commission's prior decision in the 16-891 Order. In *Reply Comments*, Xcel Energy did not oppose the Department's recommendation.[19]

6. GUIC Rider Schedules, Tariff Sheets, and Customer Notices

In *Comments*, the Department requested that, going forward, Xcel Energy work to put historical and projected revenue requirements, rates, and recoveries within a single tracker for each year.[20] The Company agreed, and stated it would provide an updated format in its next GUIC Rider.[21]

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[16] Department *Response Comments* at 7.

[17] Xcel Energy *Reply Comments* at 15.

[18] *Id*.

[19] Xcel Energy *Reply Comments* at 23.

[20] Department *Comments* at 36-37.

[21] Xcel Energy *Reply Comments* at 24.

The Department also requested that, if any changes were approved to the proposed 2018 GUIC Rider revenue requirement, Xcel Energy make a compliance filing within 10 days of the written order date. The Company agreed to do so, and also stated that it could provide a similar filing and customer bill insert within 10 days of any rate changes.

In *Response Comments*, the Department thanked the Company and indicated its support for this course of action.[22]

B. Disputed Issues

1. Rate of Return

a. Background

Minn. Stat. § 216B.1635, subdivision (Subd.) 6. *Rate of return*. states:

> 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.

In its January 27, 2015, *Order*, in the 14-336 Docket the Commission discussed the issue of the appropriate cost of capital for the GUIC projects. In its *Order*, the Commission found that updating the cost of debt for GUIC investments was consistent with the public interest. In addition, the Commission stated that the ROE was likely lower than what was authorized in Xcel Energy's last natural gas rate case; however, the record in the 14-336 Docket did not provide a basis of support for the Commission to adjust the ROE at that time. Updating Xcel's cost of debt resulted in a rate of return of 7.56 percent in the 14-336 Docket.

The Commission *Order* stated:

> In future GUIC filings the Commission will expect to see information on Xcel's current capital structure, cost of debt, and cost of equity. To that end, the Commission will require Xcel, 60 days in advance of its next annual GUIC filing, to submit information on what it believes the appropriate rate of return should be for the coming year. Based on this information, the parties can recommend, and the Commission can set, an updated rate of return for the GUIC rider if appropriate.

In Ordering Paragraph (OP) 9 of its August 18, 2016, *Order*, in the 15-808 Docket, the Commission approved a capital structure of 52.50 percent equity, 45.61 percent long-term debt, and 1.89 percent short-term debt. In OP 10, the Commission approved an ROE of 9.64 percent, a cost of long-term debt of 4.94 percent, a cost of short-term debt of 1.12 percent and an overall ROR of 7.34 percent.

[22] Department *Response Comments* at 8.

In OP 2 of its February 8, 2018, *Order*, in the 16-891 Docket, the Commission approved the same capital structure, cost of long-term debt and cost of short-term debt as the Commission approved in the 15-808 Docket, in addition, the Commission approved a 9.04 percent cost of common equity (ROE) which resulted in an overall authorized rate of return of 7.02 percent.

In the current *Petition*, Xcel Energy proposed the same capital structure, cost of long-term debt and cost of short-term debt to develop its proposed ROR as the Commission approved in the 16-891 Docket, with a proposed update only to the Company's ROE. Specifically, rather than the 9.04 percent ROE authorized by the Commission in Xcel Energy's prior GUIC rider, the Company proposed an ROE of 10.00 percent and an authorized ROR of 7.52 percent.

The Department and the Office of the Attorney General responded to the Company's proposal and provided their own recommendations as discussed below.

b. Department Comments

The Department opposed Xcel Energy's proposal of a 7.52 percent ROR and instead supported maintaining the current authorized ROR of 7.02 percent, as approved in the 16-891 Docket. The Department states that maintaining the overall ROR would adopt the Commission's past policy of using the same capital structure and ROR on debt from previous years, a policy that has worked well and which the Company supports. The only difference from prior years would be that this policy would be extended to the ROR on common equity, keeping the overall ROR unchanged. This slightly altered policy would make the ROR aspect of the GUIC Rider consistent with how the ROR is applied to general rates, in which the ROR is not updated year to year. Further, this approach would make the GUIC Rider more consistent with other rates and streamline regulatory review. As a result, the Department concluded that maintaining the overall ROR from year to year is in the public interest.

c. OAG Comments

The OAG recommended that the Commission set the rate of return at the utility's most recent cost of long-term debt (4.94 percent) established in the GUIC rider. The OAG argued that Xcel Energy's long-term cost of debt more reasonably matches the risk the Company faces in its Rider petitions.

The OAG argued that the risk of investments recovered through riders is lower than the risk of investments recovered through base rates. In a traditional rate case, investments are placed into rate base and recovered through base rates. Cash flows related to those investments are incorporated into the utility's revenue requirement only after a utility files a rate case. Assuming that the investments are allowed into rate base (and thus incorporated into base rates), the cash flows related to these investments are not guaranteed and fluctuate from year to year. Cash flow deviation (either under- or over-recovery) is an expected and well-understood part of utility ratemaking. Any deviation is generally not trued-up annually, which means that there may be significant volatility in when, and how much, cash flow is received from year-to-year.

In comparison, the revenue requirement for rider investments is fully trued-up each year. While it is likely that utilities will over- or under-recover rider investments month-to-month, on an annual basis the OAG argued that there is zero risk of under-recovery because of the true-up mechanism. While investors receive no guarantees of recovery for investments recovered in base rates, investors are guaranteed a full recovery of rider investments. The only real risk is that of a temporary under-collection that will be corrected in no more than one year. This stands in stark contrast to investments that may only be recovered in base rates.

The OAG noted that natural gas utilities have two choices when deciding how to address infrastructure investment: (1) file general rate cases or (2) file capital cost recovery rider. Across the state, some utilities have opted to file more frequent rate cases whereas Xcel Energy has opted to file a succession of GUIC rider filings. The OAG continued by stating that the Commission could look to a neighboring state for guidance on how to address infrastructure riders in a way that balances the interests of ratepayers and the utility.

The OAG referenced a 2011 rulemaking proceeding by the Iowa Utilities Board addressing its own infrastructure rider process. Specifically, the OAG stated:

> This rulemaking set out to "allow rate-regulated natural gas utilities to implement an automatic adjustment mechanism for recovery of eligible capital infrastructure investment costs." The resulting rule, 199 Iowa Administrative Code 19.18(476), allows natural gas utilities to recover "amount[s] limited to annual depreciation plus a return on the undepreciated balance based upon the cost of debt."
>
> The record from the rulemaking evinces the push-pull of the various stakeholders regarding the appropriate return to establish for the rider investments. Utilities advocated for a rate of return set at the weighted average cost of capital from the utility's most recent rate case. Consumer advocates recommended that no return be allowed for rider recovery at all. The Iowa Utilities Board ultimately chose a middle ground by establishing a rider rate of return set at the cost of debt. The Board explained its reasoning as follows:
>
> "There is a reduced risk for the utility if there is a mechanism for recovery of capital infrastructure investment between general rate cases. The utility will be receiving a return on and return of investment prior to the inclusion of that investment in regular rate base. This is money the utility would not otherwise receive. This reduced risk of under recovery should be reflected through a lower return on the investment recovered through the automatic adjustment mechanism. The board has chosen the cost of debt from the utility's last rate case to reflect this reduced risk, rather than to try and establish what the actual reduced risk would be for each utility and each investment, as that process would be time- consuming and expensive, thereby undercutting the purpose of the automatic adjustment."

For the reasons discussed above, the OAG recommended that the Commission balance the interest of ratepayers with the utility by following the Iowa approach and adopting a rate of return for Xcel Energy's current GUIC rider at the Company's long-term cost of debt.

d. Xcel Energy Reply Comments

Xcel Energy asserts that its proposed 10 percent ROE is reasonable because of the change in market conditions over the intervening year, including successive increases in interest rates by the Federal Reserve and a corresponding increase in government and corporate bond yields.

In addition, the Company argued that the OAG's position is not consistent with how the Company finances projects included in the GUIC Rider. GUIC projects involve a mixture of equity and debt capital and therefore it is not reasonable to set the Company's ROE for the GUIC Rider based on long-term debt costs when the Company is using both equity and debt to finance GUIC projects.

Finally, Xcel Energy noted that the GUIC statute establishes that, for GUIC projects, the appropriate return should be set at the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest. In the Company's 2017 GUIC Rider filing the Commission determined that the appropriate ROE should be set at 9.04 percent, which resulted in an ROR of 7.02 percent.[23] The OAG's recommended ROR is a significant reduction in overall ROR from what the Commission recently established in its 2017 Order.

e. Department Response Comments

The Department continued to support its recommendation that the Commission maintain the current authorized ROR of 7.02 percent, as approved in the 16-891 Docket. The Department noted that while certain market conditions may vary between yearly GUIC filings, it is not an appropriate or necessary use of Company, Department, or Commission resources to analyze and update the GUIC Rider ROR every year. Nor does the GUIC statute require such annual analyses. Instead, the GUIC statute directs the Commission to set the ROR at the level approved in the Company's last rate case, unless the Commission determines that a different rate is in the public interest. The Department supported the Commission's requirement for Xcel Energy to update the ROR in 2016 in its Order in Docket No. G-002/M-14-336, which required the Company to file ROR information for the 2016 GUIC Rider. It was logical to update the GUIC ROR in 2016 because a significant amount of time had elapsed since the Company's rate case, accompanied by a significant change in market conditions. Xcel Energy again filed ROR information in 2017 (Docket No. G002/M-16-891), although that year it was not required by the Commission. The Department provided an extensive review of the 2017 information and recommended an updated rate of return.

Nonetheless, it is not a reasonable use of limited regulatory resources to provide annual updates of rates of return on numerous rider petitions that are filed by Xcel Energy and other utilities. Given that the Commission only recently determined the ROE in the 2017 GUIC Rider, the Department recommends that the Commission use that most recently established ROE.

[23] Docket No. G-002/M-16-891.

Keeping the 2018 GUIC ROR at the approved 2017 levels is a more efficient use of party resources, is consistent with the GUIC statute, and allows for consistency with other riders and within the GUIC. The Department further concludes that the Company has not demonstrated how changing the ROR from the level set by the Commission for Xcel Energy's 2017 GUIC would be in the public interest.

Therefore, the Department continues to recommend that the Company maintain its ROR as the currently approved in the 2017 GUIC Rider.

f. Staff Analysis

In 2013, the GUIC statute was amended, and of the several amendments, one expanded the definition of GUIC projects to include,

> "*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*" [Minn. Stat. § 216B.1635 Subd. 1(c)(2)].

Another amendment expanded the list of eligible recoverable GUIC costs by adding "*any incremental operation and maintenance costs"* [Minn. Stat. § 216B.1635 Subd. 4].

The statute's expansion of the basis for and the type of work that qualifies as a GUIC project, thus as a rider-recoverable cost, to the extent it is incremental, can provide jurisdictional utilities additional latitude in their O&M budgeting, which in turn, mitigates compromising its earnings potential and other operational expenditures. For instance, of Xcel Energy's projected 2018 calendar year GUIC activity costs, [24] O&M expense composes approximately 26 percent of the estimated 2017 activities' revenue requirements.[25] The majority of the Company's GUIC O&M expense arises from the ongoing gas and sewer line conflict investigation project which is expected to be completed in 2019.[26]

Xcel Energy put forth a full cost of capital analysis similar to that which would be done for a general rate case. The Department and OAG did not. Staff notes that the Commission has a different statutory directive and starting point in this proceeding than in a rate case. Staff thinks it is important to start from the directive in the statute applicable to this proceeding which states "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

[24] Absent prior years' deferrals and true-ups.

[25] *Petition* at 23. The incremental O&M expense and capital-related revenue requirements projected total $4.9 million and $18.5 million, respectively. As noted in *Petition* Attachment C, page 4, and Attachment D, page 3, the capital-related revenue requirements consist of debt and equity return on rate base, property taxes, current and deferred taxes, and book depreciation.

[26] *Petition* Attachment D.

determines that a different rate of return is in the public interest."

No party is recommending that the return on investment (ROR or weighted average cost of capital) from the last natural gas rate case, 8.28 percent, be used in this docket. In the 14-336 Docket, the Commission found a different return on investment, 7.56 percent, to be more appropriate. That return was based on the cost of equity of 10.09 percent from Xcel's last gas rate case, Docket 09-1153, combined with the capital structure and cost of debt from Xcel's last electric rate case, Docket 13-868. In Xcel Energy's most recent GUIC proceeding (16-891 Docket), the Commission approved an updated rate of return, 7.02 percent. Although the Statute allows for application of the return on investment from the last rate case, parties have not discussed that option, instead, the discussions started from the ROR approved in the 16-891 Docket, which had an overall ROR of 7.02 percent.

The parties agree that the Commission could determine that a different rate of return is in the public interest. However, they do not agree on how that rate should be determined and what the rate should be. For clarification, the tables below provide a history of how the GUIC cost of capital has progressed to the current proposals and identifies where the differences and modifications can be found:

Table 3: Rate of Return Based on 09-1153
(Xcel Energy's last natural gas rate case)

	Capital Structure	Cost	Weighted Cost
Long-term Debt	46.74%	6.36%	2.973%
Short-term Debt	0.80%	1.36%	0.011%
Common Equity	52.46%	10.09%	5.293%
Rate of Return	**100.00%**		**8.277%**

Table 4: Rate of Return Authorized in 14-336
(Xcel Energy's 1st year of the GUIC rider)

	Capital Structure	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.249%
Short-term Debt	1.89%	0.67%	0.013%
Common Equity	52.50%	10.09%	5.297%
Rate of Return	**100.00%**		**7.559%**

Table 5: Rate of Return Authorized in 15-808
(Xcel Energy's 2nd year of the GUIC rider)

	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%**

Table 6: Rate of Return Authorized in 16-891
(Xcel Energy's 3rd year of the GUIC rider)

	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%	9.04%	4.75%
Rate of Return	**100.00%**		**7.02%**

Table 7: Xcel Energy - Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with New ROE)

	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%	**10.00%**	5.25%
Rate of Return	**100.00%**		**7.52%**

Table 8: Department - Proposed Rate of Return, this docket
(Based on 16-891 Decision)

	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%	**9.04%**	4.75%
Rate of Return	**100.00%**		**7.02%**

Table 9: OAG Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with New ROR and Calculated ROE)[28]

	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%	**5.09%**	2.67%
Rate of Return	**100.00%**		**4.94%**

When determining an appropriate ROE, the Commission may want to consider its overall decision in this proceeding, including cost recovery, and how its decision differs from that in a rate case proceeding. The ROE authorized in a rate case is not guaranteed, rather it is a cost used to establish rates and is at risk. If a company underperforms, its ROE will suffer.

Depending on the Commission's decision in this proceeding, the ROE may be guaranteed. Minn. Stat. 216B.1635, Subd. 4 allows a 'rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs' that include a 'rate of return, income taxes on the rate of return'. As further noted in the Subd. 4, this is a petition for approval of a rate schedule to recover costs outside of a general rate case. Depending on the rate schedule approved and the interpretation of whether there is a true-up for those costs, the authorized return may not be at risk. In such a situation, because the ROE is not at risk, the ROE should be lower to reflect the lower risk.

Staff also notes that the instant *Petition* was filed on November 1, 2017. Approximately four and a half months prior the Commission approved an ROE in Xcel Energy's electric rate case (Docket No. E-002/GR-15-826) [29] in that case, the Commission approved a settlement which allowed "Xcel Energy to represent its authorized ROE as nine and two-tenths (9.20%) for settlement purposes in this rate case proceeding.[30] The settlement also approved a revenue deficiency recommended by the Department which it is understood by staff to have been calculated using the Department recommended ROE of 9.06 percent. [31] Thus, the most recently approved Xcel Energy electric general rate case contains an ROE which is significantly lower than the ROE put forth by the Company in the instant *Petition*.

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[28] The OAG's proposal did not contain a recommended capital structure or recommended ROE. However, the OAG's recommendation does refer to the utility's "cost of long-term debt" and its comments do not discuss any changes to the currently approved capital structure. Thus, Staff uses the current GUIC approved capital structure from the 16-891 Docket to calculate the necessary ROE to arrive at the OAG's recommended 4.94 percent ROR. The table is Staff's attempt at structuring the OAG's recommendation into a format similar to that put forth by the Department and Xcel Energy and implies an ROE of 5.09%.

[29] See the Commission's *Findings of Fact, Conclusions, and Order*, dated June 12, 2017.

[30] See *Stipulation to Settlement* dated August 16, 2016 at 6.

[31] *Id*. at 5. In addition, Ms. O'Connell from the Department also made a similar statement during the Commission's May 4, 2017 agenda meeting.

The Commission may also want to consider its own ROE decisions in recent natural gas rate cases in its evaluation of Xcel Energy's request in this proceeding. There were two decisions in natural gas rate cases with 2018 test years.

Table 10: Authorized ROE for Natural Gas Rate Case Decisions with 2018 test year

	Date Filed	Test-Year	Main Order Date	Authorized ROE
CenterPoint Energy Docket No. G-008/GR-17-285	Aug. 2, 2017	FY 2018	Jul. 20, 2018	9.21%[32]
Minnesota Energy Resources Docket No. G-011/GR-17-563	Oct. 13, 2017	CY 2018	Dec. 26, 2018	9.70%

The following table contains the ROEs this commission has awarded to electric utilities either just prior or just after the filing of the instant *Petition.*

Table 11: Authorized ROE for recent Electric Rate Case Decisions

	Date Filed	Test-Year	Main Order Date	Authorized ROE
Xcel Energy (multiyear rate plan) Docket No. E-002/GR-15-826	Nov. 2, 2015	2016 - 2019	Jun. 12, 2017	9.20%
Otter Tail Power Docket No. E-017/GR-15-1033	Feb. 16, 2016	2016	May 1, 2017	9.41%
Minnesota Power Docket No. E-015/GR-16-664	Nov. 2, 2016	2017	Mar. 12, 2018	9.25%

Also, of interest and related to its request for a higher authorized ROE and higher earnings, Xcel Energy has several requests pending in Commission dockets for calendar year 2018. Besides the instant *Petition* Xcel Energy submitted almost identical requests in two other rider petitions, the Xcel Energy-Electric Transmission Cost Recovery (TCR) rider petition,[33] and the Renewable Energy Standards rider petition[34] at approximately the same time. In all three proceedings, Xcel Energy includes a report from a consultant hired by the Company that recommended the 10.00 percent ROE. In all three petitions, in these separate dockets, Xcel Energy stated the following:

[32] Staff notes that the proceeding was the subject of a settlement where an authorized ROE was not litigated however, this figure was calculated based on the settled rate of return of 7.12 percent and various cost of capital ratios.

[33] In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factors, Docket No. E-002/M-17-797, *Petition*, at 11.

[34] In The Matter Of The Petition Of Northern States Power Company For Approval Of The Renewable Energy Standard Rider Revenue Requirements For 2017 And 2018 And Revised Adjustment Factors, Docket No. E-002/M-17-818, *Petition*, at 12.

> The Company believes it would be helpful for the Commission to issue a procedural schedule that allows for an evaluation of the Company's proposed ROR and supporting analysis, as well as an evaluation of any analysis provided by parties which support their recommendations in an efficient manner. The Company recommends that all intervening parties provide their analysis of the Company's recommended ROE and ROR in their initial comments, which the Company will respond to in their reply comments. After that, the Commission should only allow for additional ROE and ROR analysis to enter the record, up to the point where the Commission takes up consideration of the filing, if changing market conditions necessitate additional analysis.[35]

Staff also notes that in its Annual Jurisdictional Reports (AJR) for Xcel Energy's gas utility has reported the following earned ROEs for 2014, 2015, 2016, and 2017.

Table 12: ROE for Current Year Normalized for Weather (including CIP incentives)

	2014	2015	2016	2017
Xcel-Gas	10.62%	11.04%	9.47%	9.85%

The only ROE decision the Commission has to make at this meeting in this docket is the decision about Xcel Energy's ROE for the GUIC rider for 2018.

g. Decision Alternatives

8. Approve Xcel Energy's proposed capital structure for this rider with a return on equity (ROE) of 10.00 percent and a rate of return (ROR) of 7.52 percent. (Xcel Energy)

Xcel Energy - Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with New ROE)

	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%	**10.00%**	5.25%
Rate of Return	**100.00%**		**7.52%**

[35] In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2017, Revenue Requirements for 2018, and Revised Adjustment Factors, Docket No. G-002/M-17-787, *Petition*, at 42.

9. Approve the Department's capital structure with an ROE of 9.04 percent and an ROR of 7.02 percent (Department)

Department - Proposed Rate of Return, this docket
(Based on 16-891 Decision with same ROE)

	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%	**9.04%**	4.75%
Rate of Return	**100.00%**		**7.02%**

10. Continue with the current capital structure and approve the OAG's recommended ROR of 4.94 percent and an ROE of 5.09 percent. (OAG)

OAG Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with new ROR and calculated ROE)

	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%	**5.09%**	2.67%
Rate of Return	**100.00%**		**4.94%**

11. Approve the Department's capital structure with an ROE of 8.59 percent and an ROR of 6.78 percent (Department's TCR Recommendation)

Department - Proposed Rate of Return, TCR docket
(Based on 16-891 Decision with updated ROE)

	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%	**8.59%**	4.51%
Rate of Return	**100.00%**		**6.78%**

2. Prorated Accumulated Deferred Income Taxes

a. Background

For financial accounting and ratemaking purposes, public utilities depreciate assets using straight-line depreciation. Under straight-line depreciation, an assets value decreases by an equal amount each year over its useful life.

For federal tax purposes, however, most utilities depreciate assets using accelerated depreciation. Under accelerated depreciation, an asset loses value more quickly during the early years of its life, allowing for greater deductions and lower income taxes in these years.

The difference between the tax a utility pays under accelerated depreciation and the tax that it would have paid under straight-line depreciation is known as accumulated deferred income tax (ADIT). ADIT represents the prepayment of a utility's income taxes by its ratepayers. Many regulatory agencies, including this Commission, require utilities to deduct ADIT from the rate base on which they earn a return, reducing the revenue requirement charged to ratepayers.

Internal Revenue Service (IRS) rules specify how utilities are to calculate the amount of the ADIT rate-base offset. In particular, when a utility used a "future period" to determine the amount of federal income tax to include in rates, the IRS requires that the utility prorate projected accruals to ADIT to adjust for the period of time that these amounts are expected to be in the ADIT account.[36]

ADIT proration has proven to be controversial in the context of riders. Most riders, including Xcel Energy's GUIC rider, are implemented through a rate adjustment that is calculated using forecasted costs. The IRS has expressed in private letter rulings (PLR) its view that, to the extent that a rate is based on forecasted costs, it reflects a "future period," and the associated ADIT accruals must be prorated.[37]

However, another feature of most riders is that any over- or under-recovery relative to actual costs is trued up at the end of the year after the forecasted test period is over. In the instant petition, Xcel Energy and the Department dispute whether the ADIT component of the GUIC rider true-up must be prorated.

b. Department Comments

The Department objected to Xcel Energy's use of a forecast period and the inclusion of prorated ADIT in the rider filing. The Department's recommendation is that the Company implement the new rider rate one day following the test period, January 1, 2019.

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[36] 26 C.F.R. § 1.167(l)-1(h)(6)(ii).

[37] A PLR is a statement issued by the IRS at the request of a taxpayer that interprets and applies tax laws to the taxpayer's represented set of facts. With limited exceptions, a PLR may not be relied on as precedent by other taxpayers. *See* 26 U.S.C. § 6110(k)(3).

The Department provided additional context to the ADIT proration concept:[38]

> Prorating ADIT is required by the Internal Revenue Service (IRS), as part of normalization requirements for ratemaking, when forecast test periods are used in setting rates and the rates are implemented prior to the end of the test period. The prorated ADIT methodology reduces the credit to rate base for ratemaking purposes that would otherwise occur by using averaging typically applied to other rate base components; thus the prorated ADIT method increases rates charged to ratepayers…
>
> Although this rider is subject to true-ups, an IRS-issued private letter ruling (PLR) on the matter, to an undisclosed utility company, indicated the effect of using prorated ADIT cannot be undone within a rider true-up[39]
>
> [Department-provided footnote]

The Department noted that the IRS has provided a solution to avoid the ADIT proration issue all together. Implementing the rate factor after the test period eliminates the need for ADIT proration.

c. Xcel Energy Reply Comments

Xcel Energy proposed a new ADIT prorate methodology in its reply comments, based on advice the Company received from engaging Deloitte Tax Services (Deloitte). Deloitte provided the following recommendations:[40]

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

Xcel Energy noted that it made a similar proposal in its Transmission Cost Recovery (TCR), Renewable Energy Standard (RES), and State Energy Policy (SEP) rider petitions. The benefits to Deloitte's approach is that it allows the Company to maintain a forecast period, minimize impacts to customers, and remain compliant with IRS normalization rules. Using this methodology, the overall revenue requirement impact of ADIT proration would be $150.

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[38] Department *Comments*, at 19

[39] IRS PLR 201717008 released April 28, 2017, https://www.irs.gov/pub/irs-wd/201717008.pdf at page 14, ordering paragraph 4.

[40] Xcel Energy *Reply Comments* at 22.

Tables 13 and 14, provided by Xcel Energy,[41] demonstrate how the prorate calculation changes between the methodology the Company initially proposed compared to the reply comments in which Xcel Energy engaged Deloitte.

Table 13: ADIT Prorate Calculation – Initial Filing

Line			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
19	Pro-Rate Days	A	335	307	276	246	215	185	154	123	93	62	32	1	
20	Pro-Rate Factor	B = A/365	0.917808	0.841096	0.756164	0.673973	0.589041	0.506849	0.421918	0.336986	0.254795	0.169863	0.087671	0.002740	
22	Deferred Tax Exp	C	156,665	156,665	156,665	156,665	156,665	156,665	156,665	156,665	156,665	156,665	156,665	156,665	1,879,977
23	Prorated Deferred Tax Expense	D = B*C	143,788	131,770	118,464	105,588	92,282	79,405	66,100	52,794	39,917	26,612	13,735	429	870,884
25	Revenue Requirement Factor	E = WACC*(T/(1-T))	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	
27	RR of ADIT Pro-rate	F = D*E	4,361	3,997	3,593	3,203	2,799	2,409	2,005	1,601	1,211	807	417	13	26,416
29	Jurisdictional Allocator	G	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
31	MN Jur RR of ADIT Pro-rate	H = F*G	4,361	3,997	3,593	3,203	2,799	2,409	2,005	1,601	1,211	807	417	13	26,416

Table 14: ADIT Prorate Calculation – Deloitte Methodology

Line No.	TIMP		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	Excel Line Reference on Tab F
3	Pro-Rate Days	A	15	14	15	15	15	15	15	15	15	15	15	15		
4	Pro-Rate Factor	B = A/Days in Month	0.483871	0.500000	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871		
6	Deferred Beg Bal	C	6,977,837	7,056,006	7,134,175	7,212,344	7,290,513	7,368,682	7,446,851	7,525,020	7,603,188	7,681,357	7,759,526	7,837,695		
7	Deferred Tax Exp Activity	D	78,169	78,169	78,169	78,169	78,169	78,169	78,169	78,169	78,169	78,169	78,169	78,169	938,027	*Line No. 21*
8	Deferred Tax End Bal	E=C+D	7,056,006	7,134,175	7,212,344	7,290,513	7,368,682	7,446,851	7,525,020	7,603,188	7,681,357	7,759,526	7,837,695	7,915,864		
9	Average ADIT End Bal	F=(C+E)/2	7,016,922	7,095,091	7,173,259	7,251,428	7,329,597	7,407,766	7,485,935	7,564,104	7,642,273	7,720,442	7,798,611	7,876,780		
11	Deferred Tax Exp Prorated Activity	G=B*D	37,824	39,084	37,824	39,084	37,824	39,084	37,824	37,824	39,084	37,824	39,084	37,824		
12	Deferred Tax End Bal Prorated	H = C+G	7,015,661	7,095,091	7,171,999	7,251,428	7,328,336	7,407,766	7,484,674	7,562,843	7,642,273	7,719,181	7,798,611	7,875,519		*Line No. 7*
14	Revenue Requirement Factor	I= (WACC+(Equity Return*T/(1-T)))/12	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%		
16	RR of ADIT Pro-rate	J = (F-H)*I	10	-	10	-	10	-	10	10	-	10	-	10	71	
18	Jurisdictional Allocator	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		
20	MN Jur RR of ADIT Pro-rate	L = J*K	10	-	10	-	10	-	10	10	-	10	-	10	71	

Line No.	DIMP		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	Excel Line Reference on Tab G
25	Pro-Rate Days	A	15	14	15	15	15	15	15	15	15	15	15	15		
26	Pro-Rate Factor	B = A/Days in Month	0.483871	0.500000	0.483871	0.500000	0.483871	0.500000	0.483871	0.483871	0.500000	0.483871	0.500000	0.483871		
28	Deferred Beg Bal	C	5,442,670	5,530,079	5,617,487	5,704,895	5,792,304	5,879,712	5,967,121	6,054,529	6,141,937	6,229,346	6,316,754	6,404,162		
29	Deferred Tax Exp Activity	D	87,408	87,408	87,408	87,408	87,408	87,408	87,408	87,408	87,408	87,408	87,408	87,408	1,048,900	*Line No. 21*
30	Deferred Tax End Bal	E=C+D	5,530,079	5,617,487	5,704,895	5,792,304	5,879,712	5,967,121	6,054,529	6,141,937	6,229,346	6,316,754	6,404,162	6,491,571		
31	Average ADIT End Bal	F=(C+E)/2	5,486,375	5,573,783	5,661,191	5,748,600	5,836,008	5,923,416	6,010,825	6,098,233	6,185,641	6,273,050	6,360,458	6,447,866		
33	Deferred Tax Exp Prorated Activity	G=B*D	42,294	43,704	42,294	43,704	42,294	43,704	42,294	42,294	43,704	42,294	43,704	42,294		
34	Deferred Tax End Bal Prorated	H = C+G	5,484,965	5,573,783	5,659,781	5,748,600	5,834,598	5,923,416	6,009,415	6,096,823	6,185,641	6,271,640	6,360,458	6,446,457		*Line No. 7*
36	Revenue Requirement Factor	I= (WACC+(Equity Return*T/(1-T)))/12	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%		
38	RR of ADIT Pro-rate	J = (F-H)*I	11	(0)	11	(0)	11	(0)	11	11	-	11	-	11	79	
40	Jurisdictional Allocator	K	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		
42	MN Jur RR of ADIT Pro-rate	L = J*K	11	(0)	11	(0)	11	(0)	11	11	-	11	-	11	79	

By calculating the pro-rate factor on a monthly basis and effectively treating each month as a separate test period, Xcel Energy is able to reduce its $26,416 revenue requirement impact down to $150 ($71 and $79 for TIMP and DIMP, respectively). Xcel Energy also stated that it

[41] Xcel Energy *Reply Comments*, Attachment H

would not use the Commission's decision on this particular docket as a "precedent" when making similar requests in other dockets.

d. Department Response Comments

The Department maintained its recommendation that the rider adjustment be effective one day after the test period, thereby eliminating the need to prorate any ADIT. The Department dismissed Xcel Energy's proposal based on the recommendations of Deloitte. The Department reiterated its position that the monthly test period approach is needlessly complex and that the simple approach is to avoid ADIT proration all together.

The Department also noted that the Commission denied Xcel Energy's request to prorate ADIT in the Company's 2017 GUIC.[42]

> The Commission denies Xcel's proposed accumulated deferred income tax (ADIT) proration for the forecasted year in the instant petition, and instead determines that the Company's 2017 GUIC rider must not be effective prior to January 1, 2018.

e. Staff Analysis

This issue of proration of ADIT in cost recovery riders was first discussed in depth in Xcel Energy's Transmission Cost Recovery Rider in Docket No. E-002/M-15-891 at the Commission's December 8, 2016, agenda meeting. (Previously, the proration of ADIT first arose in Otter Tail Power's 2015 rate case, in Docket NO. E-015/GR-15-1033.)

Since that time the issue of ADIT proration has been a disputed issue in many other dockets with differing results. The table below provides a list of dockets with Commission decisions.

Table 15: ADIT Proceedings

Company	*Docket No.*	*Proceeding*	*Outcome*
Xcel Energy	G-002/M-18-692	Gas Utility Infrastructure Charge (GUIC)	Ongoing/Pending
Minnesota Power	E-015/M-18-375	Renewable Resource Rider (RRR)	Allowed proration due to de minimis amount ($299) – Order issued 11/19/2018
Great Plains Natural Gas Co.	G-004/M-18-282	Gas Utility Infrastructure Charge (GUIC)	Allowed proration – Order issued 02/12/2019

[42] Commission Order issued February 8, 2018 approving rider with modifications in Docket No. G-002/M-16-891

Company	Docket No.	Proceeding	Outcome
Minnesota Energy Resources Corp.	G-011/M-18-281	Gas Utility Infrastructure Charge (GUIC)	Allowed the use of forecasted expenses – Order issued 02/05/2019
Xcel Energy	G-002/M-18-184	State Energy Policy (SEP) Rider	Denied request for forecasted period – Order issued December 21, 2018
Xcel Energy	E-002/M-17-797	Transmission Cost Recovery (TCR) Rider	Ongoing/Pending
Xcel Energy	G-002/M-17-787	Gas Utility Infrastructure Charge (GUIC)	Ongoing (Current Docket)
Xcel Energy	G-002/M-16-891	Gas Utility Infrastructure Charge (GUIC)	Denied proration – Order issued 2/8/2018
Minnesota Power	E-015/GR-16-664	General Rate Case	Final Order issued after test year. Proration required for interim rates. Order issued 3/12/2018
Otter Tail Power	E-017/GR-15-1033	General Rate Case	Final Order issued after test year. Proration required for interim rates. Order issued 5/1/2017
Xcel Energy	E-002/M-15-891	Transmission Cost Recovery (TCR) Rider	Commission Order issued after test year
Xcel Energy	E-002/M-15-805	Renewable Energy Standard (RES) Rider	Issue deferred to current petition.

On June 21, 2018, FERC instituted proceedings to examine the methodology for public utilities to calculate ADIT balances in their projected test years and annual true-up calculations for transmission formula rates.

In the background section of its June 21, 2018 Order,[43] FERC stated the following:

> Under Commission ratemaking policies, income taxes included in rates are determined based on the return on net rate base that is calculated using straight-line depreciation. However, in calculating the actual amount of income taxes due to the Internal Revenue Service (IRS), companies generally are able to take advantage of accelerated depreciation. Accelerated depreciation will usually lower income taxes payable by companies during the early years of an asset's life followed by corresponding increases in income taxes payable during the later years of an asset's life when the depreciation is lower. This means that a company's income taxes owed to the IRS during a period will differ from its income tax expenses used for Commission ratemaking purposes during the same period. The difference between the income taxes received by a company in its rate based on straight-line depreciation and the actual income taxes owed to the IRS by the company are reflected in an ADIT account. Because the resulting balance in an ADIT account effectively provides the company with cost-free capital, the Commission generally requires a company to subtract the ADIT from rate base, thereby reducing customer charges. The reduction to rate base is diminished as the ADIT reverses due to actual taxes owed to the IRS subsequently exceeding the income taxes calculated based on straight-line depreciation***. This method of passing the time value of benefits from accelerated depreciation on to ratepayers throughout the asset's life is referred to as tax normalization.***[44] (emphasis added.)
>
> The depreciation normalization rules of the Internal Revenue Code and the IRS regulations (Normalization Rules) mandate the use of a very specific proration procedure in measuring the amount of ***future test period ADIT*** that can reduce rate base. Section 1.167(l)-1(h)(6)(ii) of the IRS regulations requires that, ***if a utility uses solely a future period (projected test year) to determine depreciation, 'the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period.'*** The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.[45]

[43] June 21, 2018, 163 FERC 61,200; ORDER INSTITUTING SECTION 206 PROCEEDINGS, COMMENCING PAPER HEARING PROCEDURES, AND ESTABLISHING REFUND EFFECTIVE DATE.

[44] *Id*. at 2-3.

[45] *Id*.

(emphasis added.)

The timing of test periods is critical in determining the need for normalization through proration adjustments. Because the test period has already ended (December 31, 2018), if the Commission authorizes Xcel Energy to prorate ADIT using either one of its methodologies, the Company will collect the extra revenue requirements despite the fact that the test period has concluded. Ordering Xcel Energy to use the Department's methodology to order a historical test period resolves the issue of ADIT proration in this docket, but the Commission may wish to clarify which methodology shall be used in future GUIC filings so that this issue does not continue to be disputed.

Xcel Energy Reply Comments Filed in Docket E-002/M-17-797

In the TCR Docket, Xcel Energy filed additional comments on April 11, 2019.

> …the 2018 test period for this TCR Rider proceeding has ended. The Company agrees that this means rates implemented after January 1, 2019 do not need to include proration of forecasted ADIT balances. As such, the Company will update the TCR tracker to remove ADIT proration for the 2018 test period and provide updated schedules as part of a compliance filing in this docket. We do not believe that any decision regarding ADIT proration is necessary in this proceeding.

Xcel Energy did not file similar comments in the current petition. However, the forecast period for this docket has also passed. The Commission may wish to ask the Company at its meeting on May 23rd to explain its current position on ADIT proration in this docket, and, whether it mirrors that of 17-797. Staff notes that the Company's comments in the TCR docket do not indicate a generalized new position regarding the issue of ADIT proration; the Company is merely stating that ADIT proration is a nonissue in that particular docket. The Commission may wish to still address ADIT proration on a going-forward basis in this and other rider dockets.

f. Decision Alternatives

12. Allow Xcel Energy to implement its GUIC rider factor effective January 1, 2018 and authorize the Company to recover $26,416 related to ADIT proration as proposed in the Company's Initial Petition.

13. Allow Xcel Energy to implement its GUIC rider factor effective January 1, 2018 and authorize the Company to recover $150 related to ADIT proration, calculated by Deloitte Tax Services, as proposed in the Company's July 27, 2018 Reply Comments. (Xcel Energy)

14. Require Xcel Energy to implement its GUIC rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department)

    Staff note: the following alternative would be in addition to any of the ADIT alternatives shown above.

15. Require Xcel Energy to utilize the ADIT proration methodology ordered by the Commission in this docket in future GUIC rider docket filings. (Staff)

3. Sales Forecast

a. Background

Xcel Energy uses a sales forecast in its class factors calculation to determine how to apportion the revenue responsibility for the GUIC Rate Adjustment Factor. In the Company's 2017 GUIC, the Commission ordered revisions to Xcel Energy's sales forecast.[46]

> The Commission approves a revised sales forecast based on the Company's regression model results before monthly sales and demand-side management (DSM) adjustments as set forth by the Company in Attachment F of its reply comments for the 2017 GUIC rider.

In Xcel Energy's initial petition, it included a historical adjustment. The Department disputed this inclusion and the Company agreed to remove the historical adjustment, noting that the GUIC order was issued subsequent to Xcel Energy's initial petition. The Department and the Company still disagree on the period to be used in order to establish test revenues for the current docket.

b. Department Comments

The Department stated that Xcel Energy's forecasted sales in the GUIC rider were noticeably lower than the actual sales filed in the Company's Gas Jurisdictional Annual Report (GJAR).[47]

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[46] 16-891 Docket *Order*, ordering paragraph 8.

[47] Department *Comments* at 22.

> In the current GUIC proposal, the Company projects 2018 sales of 89,314,493 dekatherms (Dth) and 2019 sales of 91,556,339 Dth. However, in Xcel's GJAR, the Company reports 2016 actual sales of 97,104,355 Dth and 2017 actual sales of 99,469,703 Dth.

The Department requested that the Company provide a qualitative reason for the lower forecast for 2018.

c. Xcel Energy Reply Comments

In response, Xcel Energy noted that the difference between forecasted volumes and the historical amounts relates to two gas-fired generation facilities that came online and the continued growth of renewables.[48]

> …The primary contributor to higher actual sales in 2016 and 2017 than the forecast in 2018 and 2019 is a decrease in the forecasted sales for the transportation class, particularly the interdepartmental transport class.
>
> The interdepartmental transport class is comprised of gas volumes used for electric generation. The forecast of gas transported for electric generation is an output from the Company's production cost model of anticipated electric dispatch. The forecast of interdepartmental transport sales was developed in July 2017 and predicted that less gas would be used for electric generation during the forecast period than was used in 2016 and 2017 – more than seven million dekatherms less than 2016 actual sales and more than five million dekatherms less than 2017 actual sales. The Department stated a belief that sales may have been underestimated for this forecast, but the forecast was considering an expected decrease in gas transports to our electric generating plants. The decrease in demand at our production facilities is driven partially due to the addition of new gas generation at the Black Dog and Mankato facilities, which operate more efficiently, along with the continued addition of renewable wind and solar generation which reduces the overall gas generation forecast…

Xcel Energy offered to include a discussion of any drivers causing major increases or decreases in sales forecasts compared to actual previous year sales in future filings. However, the Company maintained that its proposed sales forecast in this docket is appropriate.

d. Department Response Comments

The Department acknowledged Xcel Energy's qualitative analysis, however, the Department also stated that there are numerous factors that may affect the dispatch of facilities by the Midcontinent Independent System Operator (MISO). Therefore, the Department continues to request that the Commission require the Company to use the most recent 12 months of actual natural gas sales to allocate the costs across jurisdictions and classes.

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[48] Xcel Energy *Reply Comments* at 19

e. Decision Alternatives

16. Allow Xcel Energy to utilize its 2018-2019 sales forecast to allocate costs across jurisdictions and classes. (Xcel Energy)

17. Require Xcel Energy to use the most recent 12 months of actual natural gas sales to allocate the costs across jurisdictions and classes. (Department)

4. Data Gaps

a. Background

49 CFR § 192.619 states that pipeline operators cannot operate pipelines that exceed a maximum allowable operating pressure (MAOP). The requirements to validate pressure for plastic and steel pipe were first enacted on August 19, 1970. On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which requires the Pipeline and Hazardous Materials Safety Administration (PHMSA) to direct each owner or operator of a gas transmission pipeline and associated facilities to provide verification that their records accurately reflect MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in High Consequence Areas (HCAs). As discussed further in the Department's comments, the records must be traceable, verifiable, and complete in order to meet the validation requirements. Xcel Energy proposed to include costs to address data gaps related to meeting this requirement.

b. Department Comments

The Department expressed concern with the data gaps included in the GUIC. 21 percent of Xcel Energy's transmission pipeline (15.6 miles) cannot meet the MAOP validation standard as required by federal law due to insufficient records.[49]

> …records must be "TVC", that is, (1) traceable (those that can be clearly linked to original information about a pipeline segment or facility), (2) verifiable (those for which information is confirmed by other complementary, but separate, documentation) and (3) complete (those for which the record is finalized as evidenced by a signature, date or other appropriate marking)
>
> [footnote omitted]

The Department questioned whether Xcel Energy had properly acquired, secured, or recorded information about its pipeline system. Federal pipeline safety regulations have been in place since 1970 and the Department believes that the MAOP validation isn't an extraordinary requirement of a pipeline operator.

The Department described the potential solutions for the data gaps.[50]

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[49] Department *Comments* at 23-24.

[50] Department *Comments* at 25.

> Xcel stated that the remedies available to resolve the absence of data is to either conduct pressure tests (at a cost of $150,000 to $2 million per mile), or replace the pipeline (at a cost of $3 million to $8 million per mile). When applying these cost estimates to the Metro Area's 40.5 miles of intermediate pressure distribution pipelines lacking MAOP documentation, the range of Xcel's estimated costs equates to a $6 million to $324 million cost-range problem for the Metro Area lines alone.

Therefore, the Department recommended that the Commission limit the return on the capital costs incurred to remediate the system's MAOP data gaps to Xcel Energy's long-term debt costs or not allowing extraordinary rider ratemaking treatment for projects where the Company lacks sufficient data.

c. Xcel Energy Reply Comments

Xcel Energy responded to the Department's concerns that the Company failed to maintain adequate records.[51]

> The rules that govern MAOP documentation have emerged only within the last few years. These new requirements are significantly more stringent than the rules that were in place when the vast majority of our system was constructed, and the Company could not have reasonably anticipated these new requirements decades before they were adopted. While the Company has always maintained appropriate documentation for its system, the more stringent requirements now in place make it imperative that the Company undertake efforts to reestablish MAOP to meet the new safety requirements. The expenditures requested in this filing are a part of a systematic effort to update records to satisfy PHMSA rules for our transmission pipeline and DIMP requirements for our IP distribution pipeline.

The Company believes the new TVC requirements established in 2012 are sufficiently extraordinary to justify Xcel Energy's request for inclusion in the GUIC since the MAOP validation is required by a federal or state agency.

d. Department Response Comments

The Department agreed that a recent change in 2012 requires pipeline operators to verify their MAOP records and report findings to PHMSA, but MAOP record retention has been a requirement of pipeline operators since 1970. Therefore, the Department argues that unless a pipeline has not been tested since 1970, the Company should be held accountable to maintain that its pipelines are operated within safe operating pressures. The Department maintained its recommendation that the Commission limit the return on any approved MAOP remediation capital costs to debt cost rate or consider disallowing extraordinary rider ratemaking treatment for projects undertaken due to insufficient MAOP data.

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[51] Xcel Energy *Reply Comments* at 8

e. Staff Analysis

PHMSA Advisory Bulletin ADB-2012-06 requires utilities to verify MAOP records. Specifically, the records must be traceable, verifiable, and complete. ADB-2012-06 specifically defines those terms, as follows:[52]

> Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.
>
> Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipe segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by an individual who would have reason to be familiar with the test or inspection.
>
> Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipe segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

49 CFR § 192.619 discusses the maximum allowable operating pressure. Specifically, it states:

> (a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:
>
> (1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§

[52] ADB-2012-06, 77 FR 26823

192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see§ 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12 3/4 inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors [1], segment -		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under § 192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
- Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
- Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in § 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under § 192.620(a).

The Department argued that Xcel Energy has an obligation to maintain MAOP validation records for pipeline installed subsequent to 1970. Therefore, the Department believes PHMSA Advisory Bulletin ADB-2012-06 should be considered as a new reporting requirement for information the Company otherwise should possess. Xcel Energy, however, believes that the specific traceable, verifiable, and complete requirements of PHMSA Advisory Bulletin ADB-2012-06 are more stringent than the record keeping requirements of § 192.619, and therefore, the costs associated with the more stringent requirements or a governmental or regulatory body should be recoverable through the GUIC rider.

f. Decision Alternatives

18. Determine that Xcel Energy has demonstrated MAOP validation costs and costs related to data gaps are prudently incurred and authorize the Company to recover the costs in full. (Xcel Energy)

19. Limit the return on MAOP validation capital costs to the Company's debt cost rate. (Department)

20. Disallow extraordinary rider ratemaking treatment for projects undertaken due to insufficient MAOP data. (Department – Alternate)

5. TIMP – Island Line South Project

a. Background

The Island Line South project is a TIMP-based project described as 1.9 miles of 20-inch natural gas pipeline along the Mississippi River. Originally built in 1952, the pipeline is slated for replacement. Xcel proposed to recover in the GUIC rider planned expenses for in line inspection (ILI) assessment and improvement.

b. Department Comments

The Department disputed the inclusion of the Island Line South project for two reasons. First, the Department argued that Xcel Energy has not justified incurring ILI expenses on a line the Company intends to replace. The Department recommended, at a minimum, that Xcel Energy be directed to exclude the $0.6 million estimated costs of the ILI assessments to be performed on the Island Line South pipeline designated for replacement.

Second, Xcel Energy estimated the costs of pumping water to be approximately $1.7 million, but the actual costs were $3.2 million (an 88% cost overrun). The Department argued that Xcel Energy failed to demonstrate the reasonableness of this cost overrun. Therefore, the Department recommended that the Commission disallow the cost overrun from recovery under the GUIC rider.

c. Xcel Energy Reply Comments

In response, Xcel Energy stated that ILI expenses are part of its TIMP requirement to assess the condition of the pipeline. The information received from this integrity assessment will determine what courses of action are needed to remediate current risks, including making a determination of potential repairs or replacements. Therefore, the Company believes the costs are necessary and reasonable to include in its GUIC rider.

Xcel Energy disagreed with the Department's assertion that ""no utility is entitled to recover cost overruns in a rider." The Company noted that the recovery of costs, whether in rates or in a rider, depends on the prudency of the costs. Xcel Energy also stated that the cost overruns were due to unforeseen weather issues and were prudently incurred.

d. Department Response Comments

In several instances, Xcel Energy indicated that the Island South line is to be replaced under the GUIC rider in 2018, refuting the Company's discussion about ILI expenses being necessary to determine remediation of the line.[53] The Department states:

> First, in an email in which Xcel explained why the Island Line pipeline has different reported lengths under two separate TIMP Projects (1.9 miles under 2017 Transmission Pipeline Assessment program and 1.5 miles under the 2017 Programmatic Replacement/MAOP Validation program), Xcel explained that the 1.5 mile length of work consists of 0.34 miles of pipeline that was replaced in 2017 and that **"the remaining 1.15 miles (6100 feet) of pipeline is slated to be replaced in 2018."**
>
> … Xcel stated that the Island Line project entails construction activity "associated with the replacement of the Montreal Line South and the Island Line South." Xcel quantified the original scope and cost estimate for the **Island Line South replacement** as 1.5 miles at a unit cost of $920 per foot, but updated that amount to be "$1,160 per foot for a total cost of $9.2 million" (of which $3.0 million is anticipated in 2017 with the remaining cost to occur in 2018). The total estimated cost of $9.2 million is attained by multiplying the 7,920 feet (1.5 miles) by the estimated $1,160 cost per foot; thus the project cost reflects replacement of the pipeline… the Island Line project overview description states **"replace 7,900 feet**

53 Department *Response Comments* at 10-11.

> **of 20-inch"** pipe installed in 1952, located in Lilydale extending from Mendota Station to the Pickerel Lake…
>
> [Department emphasis, footnotes omitted]

The Department reviewed Xcel Energy's claim that the record supported the Company's cost overrun. The Department noted the weather-related events and reviewed invoiced work during those times and determined that Xcel Energy only supported $193,282 of cost overruns in the record. The Department requests that the Commission only allow the Company to recover $1.9 million ($1.7 estimated costs and the $0.2 million in supported overruns).

e. Staff Analysis

Minn. Stat. § 216B.1635, Subd. 4 (iv) states that a utility's petition to recover gas utility infrastructure costs outside of a general rate case is subject to "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." The Department reviewed Xcel Energy's invoices and concluded that the Company had only provided support for $0.2 million in cost overruns.[54]

> When comparing the documented $1.9 million total to Xcel's 2016 cost estimate of $1.7 million less the estimated $15,000 internal cost (or a $1,685,000 result), the cost variance between the actual and the estimate is only $193,282 (or approximately $0.2 million).

A qualitative description of work provided by the contractor was provided as an attachment to the Department's public comments. Specific contractor pricing and financial invoices were also provided by Xcel Energy but have been filed as **Trade Secret**. The Company has maintained that the water pumping cost overruns were the result of unforeseen weather and permitting delays due to excess rain and environmental delays due to fledgling eagles and migratory bats in the area.

[54] Department *Response Comments* at 14.

f. Decision Alternatives

21. Determine that the ILI costs related to the Island Line South project are reasonable and necessary and allow Xcel Energy to recover those costs through the GUIC rider. (Xcel Energy)

22. Require Xcel Energy to remove the $0.6 million in ILI assessment costs from its GUIC rider. (Department)

23. Limit Xcel Energy's water pumping recovery costs to the $1.7 million as originally estimated by the Company and the $0.2 million in cost overruns support by the record. (Department)

6. DIMP – Langdon Line Project

a. Background

The Langdon Line project is a DIMP project identified by Xcel Energy as being a high risk line due to the threat severity and its location in a high consequence area. The Company proposed to replace 6 miles of line of varying sizes (6, 8, and 12 inch diameter) installed in 1958 with a single-sized line that could support its ILI technology. For this project, Xcel Energy proposed to use a 12 inch line, estimated to cost $12.5 million, with $11.8 million included in the Company's 2018 GUIC rider.

b. Department Comments

The Department agreed that having no variation in the pipeline size would aid in the use of ILI, however, the Department disputed the size of the line Xcel Energy has selected. In Department Information Request (IR) #31, the Department inquired about the use of an 8-inch pipe. The Company responded that an 8-inch pipe would adequately serve the needs of its customers, but noted that a 12-inch line would allow for the use of ILI equipment on the entire line. The Department researched the equipment and noted that modern robotics allow for pipelines as narrow as 10mm to be inspected and also stated that no government body or regulation requires the use of ILI in its DIMP. Additionally, Xcel Energy has not specifically stated that ILI equipment cannot be used on an 8-inch line. Therefore, the Department concluded that the cost difference between the proposed 12-inch line and the Department's recommended 8-inch line should be removed from the GUIC rider due to the fact that the additional pipe size constitutes a betterment. The difference in cost would be approximately $3.6 million. Should the Company still elect to install a 12-inch line, the Department notes that Xcel Energy could request recovery of the full cost of the pipe in a future rate case.

c. Xcel Energy Reply Comments

Xcel Energy defended its use of ILI technology.[55]

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[55] Xcel Energy *Reply Comments* at 11.

> …When renewing large diameter, IP distribution pipelines operated in densely populated areas, the Company constructs in a manner to facilitate inspection by means of ILI tools in order to monitor for defects that could lead to pipeline failure and leakage. ILI tools allow the Company to inspect lines for multiple threats that include external corrosion, internal corrosion, manufacturing defects, material defects, construction defects and third party damage. Therefore, to reduce the risk from all threat types, ILI is the preferred inspection method for large diameter, IP distribution pipelines.

Xcel Energy also responded to the Department's concern about using a 12-inch pipe. In its response, the Company stated that the rest of the Langdon Line is already a 12-inch pipe and ILI equipment capable of inspecting both 8-inch and 12-inch pipe in a single run is not commercially available. The technology researched by the Department is not practical due to its short battery life.

Lastly, Xcel Energy argued that a larger pipe is not automatically considered to be a betterment. In Docket No. G-002/M-14-336, Xcel Energy received approval to use a uniform 20-inch diameter pipe as opposed to an 18-inch pipe due to engineering efficiency.[56]

> The Commission concurs with Xcel and the Department that the East Metro project will not result in a betterment. Using 20-inch rather than 18-inch pipe is not a betterment because it is the best engineering choice to restore the pipe to its original, safe condition. Had Xcel used 24- or 30-inch pipe, the situation would be different, since it would suggest that the Company was taking advantage of the replacement to increase its capacity. However, 20 inches is the pipe size Xcel routinely uses when replacing its transmission lines. The East Metro project therefore does not go "beyond repair or restoration" and is not a betterment.

Therefore, Xcel Energy requests the Commission find its Langdon Line project costs are reasonable and eligible for recovery under the Company's GUIC rider.

d. Department Response Comments

The Department argued that an 8-inch line would sufficiently allow for ILI tools to be used.[57]

> Xcel argued that use of a 12-inch diameter pipe would allow for ILI to be used on the entire line. However, the Department understands that ILI tools are available for use within 8-inch diameter pipelines as well; the issue with ILI tools is that a single tool cannot inspect continuous lines with variations in diameter of more

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[56] *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 at 11 (January 27, 2015).

(January 27, 2015).

[57] Department *Response Comments* at 15.

> than two inches. Therefore, ILI technology can be used within this six-mile stretch of pipeline whether the uniform diameter installed is 12-inch or 8-inch pipeline.

The Department notes that 8-inch pipe is routinely used in the construction and replacement of Xcel Energy's system and allows for the use of ILI tools. Additionally, in the Lexington to Snelling project, Xcel Energy asserted that a benefit of a shorter 3- mile pipeline replacement project, consisting of both 8-inch and 12-inch pipe, would be made accessible to use ILI tools. Therefore, the Department does not believe Xcel's ILI capabilities would be diminished with the use of an 8-inch line. The Department continues to recommend that the Commission allow the Company to recover only the cost of an 8-inch replacement pipe, thereby reducing Xcel Energy's request in the GUIC rider by $3.6 million.

e. Staff Analysis

Minn. Stat. § 216B.1635, Subd. 1(b)(3) states:

> ["Gas utility infrastructure costs" or "GUIC" means costs incurred in gas utility projects that] 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.

The parties dispute whether the use of a 12-inch line constitutes a betterment or if using the same size pipe as the rest of the Langdon Line results in engineering efficiency and is, therefore, a prudent cost to incur.

Xcel Energy and the Department agreed that the Company could serve its customers and expected load with an 8-inch pipe. There was also agreement that ILI tools could be used on both 8-inch and 12-inch lines, however, the same tools could not be used for a pipe of varying sizes. Therefore, if the Company used an 8-inch pipe for 6 miles, it would be unable to perform an ILI assessment on the entire Langdon Line in a single run. No governmental body or regulation requires the use of ILI tools but the Company argues that these tools are an efficient and effective way to identify potential risks in its pipeline system.

Xcel Energy determined that it would be more efficient to use a single size line for all of the Langdon Line. The Department noted that the Company has made proposals to use varying sized pipe on shorter runs in this proceeding (Lexington to Snelling project, specifically). Also, the Department notes that the vast majority of Xcel Energy's system consists of pipe smaller than 12-inches. Therefore, the Department believes that allowing the Company to use a 12-inch pipe, when an 8-inch pipe provides service at the lowest reasonable cost, would constitute a betterment in violation of the GUIC statute.

f. Decision Alternatives

24. Determine that the replacement of the Langdon Line with a 12-inch pipe does not constitute a betterment and allow Xcel Energy to include all Langdon Line project costs in its GUIC rider. (Xcel Energy)

25. Allow Xcel Energy to only recover the cost of replacing the Langdon Line with an 8-inch pipe and require the Company to remove the excess cost, estimated to be $3.6 million, from its GUIC rider. (Department)

7. DIMP – Lexington to Snelling Project

a. Background

The H005 – Lexington to Snelling project is a 3-mile high-pressure distribution pipeline replacement estimated to cost $4.9 million. The pipeline, originally constructed in 1964, scored as high risk by Xcel Energy's assessment and has a history of leak repairs, most notably caused by material failure, mechanical defects, third party damage and corrosion. Xcel Energy plans for the new pipeline to be constructed in a manner that will allow the use of in-line inspection tools.

b. Department Comments

The Department's concern with the cost recovery of the H005 – Lexington to Snelling project is that the Company relocated approximately 20 services to help facilitate the use of ILI equipment. Xcel Energy estimated the cost of these relocations to be approximately $420,000 of the project's costs. The Department argued that the Company was not required by any governmental body or regulation to relocate the services. Therefore, the Department recommends that these costs be removed from the GUIC rider and only be recovered through a future rate case.

c. Xcel Energy Reply Comments

Xcel Energy maintained that its proposed costs meet the definition of the GUIC statute.[58]

> …the ILI work being undertaken is necessary to comply with DIMP regulations. Further, we believe it is reasonable to design and construct the pipeline in a manner that prevents unnecessary disruption of service. We therefore believe the transfer of services to another section of the system is based on requirements by a federal agency and is permissible under the GUIC statute, which should not be interpreted to require inefficient or disruptive construction or inspection practices…

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[58] Xcel Energy *Reply Comments* at 12.

d. Department Response Comments

The Department does not dispute the reasonableness of undertaking system improvements while concurrently working on GUIC projects but the Department maintains that elective work activity should be kept separate from GUIC-eligible projects for the purposes for cost recovery. Therefore, the Department maintains its recommendation that the costs to relocate the customer services not be included with the GUIC rider but, rather, recovered in a general rate case.

e. Staff Analysis

Minn. Stat. § 216B.1635, Subd. 1(c) provides a definition of the projects eligible for the GUIC:

> (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.

The Department argued that elective work, such as the relocation of services, does not fit the intent of the GUIC statute and should be excluded from the GUIC and recovered in a general rate case. Xcel stated that the movement of these services prevent unnecessary disruptions and is based on requirements by a federal agency.

f. Decision Alternatives

26. Allow Xcel Energy to include all H005 Lexington to Snelling project costs in its GUIC rider, including the costs related to relocating customer services along the existing pipeline. (Xcel Energy)

27. Require Xcel Energy to remove $420,000, the costs related to relocating customer services, from the H005 Lexington to Snelling project. (Department)

8. DIMP/TIMP – Rider Eligibility for Expenditures on Low-Risk Infrastructure Replacement

a. Background

This issue concerns the replacement of low-risk pipeline segments not because they were deemed necessary by any metric but rather the fact that they were located near a GUIC project and were replaced to minimize future disruption to the local community.[59] In response, the Department issued an information request in an attempt to quantify the number of instances

[59] Xcel Energy *Petition* Attachment D2(a) at 2.

and the cost of the low risk pipe segment replacements. The Company responded with an attachment showing ten instances where Xcel Energy replaced some low risk pipe segments for a total cost of $85,000.[60] The Department argued against rider recovery for these segments.

b. Department Comments

The Department expressed concern regarding the elective nature of these expenditures and recommended removal of these costs because the replacement work was elective, not supported by civic/public work requirements, nor required by government regulations.[61]

c. Xcel Energy Reply Comments

Xcel Energy stated lower risk pipe segments that are in the same block as higher risk segments may be replaced as a part of projects to replace high risk segments in order to minimize disruption to the local community. The Company continued by stating efficiencies are achieved by replacing small low-risk segments of pipeline that may exist in a block while contractors are already mobilized and on site to renew the high and medium risk pipeline. First, it avoids the potential for multiple projects over the course of different years on the same block. Second, avoiding multiple projects by replacing all pipe in the area at the same time likely decreases the overall cost of the GUIC initiatives by avoiding multiple digging situations. Xcel Energy maintains its position that the proposed costs are reasonable and the full cost should be included in its GUIC revenue requirement.[62]

d. Department Response Comments

In *Response Comments*, the Department argued that Xcel Energy already receives cost recovery via base rates for capital investment work on its existing system and whether that work is carried out within a GUIC project jobsite is immaterial. The only consideration is whether the costs are eligible for recovery pursuant to the GUIC statute.

e. Staff Analysis

Is the upgrading of lower risk pipe segments when not necessary for completion of a GUIC project allowed by Minnesota Statute? Or, does the replacement constitute a "betterment" as defined in Minn. Stat. § 216B.1635, subd. 1(b)(3) and therefore not eligible for cost recovery via GUIC rider. The GUIC statute states that such betterment is not eligible for GUIC rider recovery "unless the betterment is based on requirements by a political subdivision or 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."[63]

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[60] Xcel Energy response to Department Information Request No. 35, included as Attachment 12 to the Department's *Comments*.

[61] Department *Comments* at 29.

[62] Xcel Energy *Reply Comments* at 12-13.

[63] Minn. Stat. § 216B.1635, subd. 1(b)(3). A complete copy of Minn. Stat. § 216B.1635 is located as an attachment to these briefing papers.

There does not appear to be a dispute concerning the efficiency of upgrading lower risk pipe segments while Xcel Energy is already upgrading higher risk segments on the same block as part of a GUIC project. However, the record does not contain any evidence that the work was required by a governmental body or that a regulation required the upgrading of the lower risk pipe segments. Although Xcel Energy's arguments that its approach is an efficient and effective way to avoid future disruptions may have merit, these projects do not appear to meet the required terms of the statute for cost recovery.

f. Decision Alternatives

28. Allow Xcel Energy recovery of $85,000 in costs incurred on low-risk infrastructure replacement costs. (Xcel Energy)
29. Deny Xcel Energy recovery of $85,000 in costs incurred on low-risk infrastructure replacement costs because they were not required by civic/public work requirements, nor required by government regulations. (Department)

9. Jurisdictionally Unclear Operations and Maintenance (O&M) Costs

a. Background

In a previous GUIC proceeding (16-891 Docket (2017 GUIC)), the Department expressed concerns regarding the contracts, invoices, and work orders related to software costs for Xcel Energy's Pipeline Data Project (PDP). In that proceeding Xcel Energy included software-related DIMP costs of approximately $2 million in its GUIC calculations. According to the Company, these costs related to its Pipeline Data Project, an effort to locate and evaluate Xcel Energy's aging distribution pipelines.

The Department opposed including the full $2 million in the rider for two reasons. First, the Department noted that some of these costs were from a quality-assurance/quality-control (QA/QC) contractor overseeing the work of another contractor that Xcel Energy hired to review old work orders. The Department argued that QA/QC services are "professional services," a cost category already included in the Company's base rates, and should not be included in the GUIC rider.

Second, the Department was unable to verify that all the DIMP software costs Xcel Energy included in its GUIC calculations were attributable to Minnesota, noting that the Company's contract included non-Minnesota operating companies. The Department recommended that the Commission allow Xcel Energy to allocate only a portion of this contract - $444,543 – to its Minnesota ratepayers through the rider.[64]

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[64] The Department calculated this amount in two steps. First, the Department applied the FERC Distribution Gas allocator to determine an amount for Xcel Energy's Minnesota operating company. Then, because the Minnesota operating company includes parts of North and South Dakota, the Department applied a second allocator to approximate the portion of costs attributable only to Minnesota. *See* the Department's March 1, 2017 comments, at 15 in Docket No. G-002/M-16-891.

The Commission concurred with the Department's analysis that Xcel Energy had not fully supported its request to recover $2 million in DIMP software costs through the GUIC rider. The Commission approved the Department recommended $444,543 in DIMP software costs for rider recovery and disallowed all QA/QC-related costs as duplicative costs already included in base rates.

The Commission has consistently treated riders in general, and the GUIC rider in particular, as an extraordinary means of recovering utility costs. There are a number of reasons for this, and one of the most important is that a rider proceeding – in contrast to the contested-case process in a rate case – affords a limited opportunity for rigorous examination of claimed costs.

Minn. Stat. § 216B.1635 permits recovery of GUIC costs outside of a rate case, but Xcel Energy still retains the burden to establish that the costs it seeks to include in the rider are both: (1) attributable to its Minnesota gas operations; and (2) not already reflected in base rates. It is not the Department's or any other stakeholder's responsibility to connect the dots necessary to justify the Company's claimed costs.

b. Department Comments

In the instant proceeding, the Department conducted a three-step jurisdictional inspection of Xcel Energy's contracts, work orders, and invoices. The first step was reviewing the contracts themselves to determine which parties were included in the contracts. The second step involved reviewing the Company's contract-specific cost data provided to the Department. The third step involved auditing invoices and work orders from the Company's data set.

Based on the Department's review, the Department concluded that $2,994,264 of GUIC costs were jurisdictionally unclear and should be reallocated via the same two-step jurisdictional allocation used for software costs in the 16-891 Docket.[65]

c. Xcel Energy Reply Comments

In *Reply Comments*, Xcel Energy stated that it enters into contracts that cover work within multiple jurisdictions but its accounting and work management systems contain functionality that enables the Company to track work by jurisdiction. Xcel Energy stated that "the use of jurisdictional specific work orders within our systems enables the Company to design, estimate, and execute work and ensure that the cost of that work is assigned to the proper jurisdiction. When preparing the revenue requirement request for the GUIC Rider filings, the Company pulls only those work orders that are assigned to Minnesota work."[66]

[65] The Department did not quantify the recommended disallowance in its comments.

[66] Xcel Energy *Reply Comments* at 15.

Xcel Energy provided invoices for the individual O&M charges identified by the Department as "jurisdictionally unclear" and noted that most of the invoices contained the necessary information to determine that the work was taking place in Minnesota.

d. Department Response Comments

The Department reviewed the invoices provided by Xcel Energy and in *Response Comments* agreed that most of the costs appear to be Minnesota specific. The Department concluded that a single invoice in the amount of $6,550 remained jurisdictionally unclear[67] and since the costs focused on software costs and included Xcel Energy affiliates across all of the Company's jurisdictions which was also the issue addressed in the 16-891 docket the Department recommended that the same two-step jurisdictional allocation methodology be used in this case.[68]

e. Decision Alternatives

30. Allow recovery of the entire disputed $6,550 as prudent and eligible for recovery in the GUIC Rider. (Xcel Energy)

31. Require Xcel to follow the two-step allocation process established in the 16-891 Docket and allow recovery of $1,712.74 in jurisdictionally unclear costs from the GUIC Rider.[69] (Department)

32. Disallow the entire $6,550 in jurisdictionally unclear charges from the GUIC Rider.

10. Internal Capitalized Costs

a. Background

Along with reviewing the jurisdictional costs discussed above, the Department also reviewed the capital and O&M costs included for recovery in Xcel Energy's GUIC. The Department determined that $8,276,882 should be excluded from the GUIC.

b. Department Comments

In *Comments*, the Department found that it was only able to perform a jurisdictional review of costs that could be tied back to a specific contract or vendor and concluded that Xcel Energy

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[67] The specific contract can be found in pg. 796 of **Trade Secret** Attachment C of Xcel Energy's response to Department Information request No. 62.

[68] Again, the Department did not quantify the actual amount of disallowance from the two-step jurisdictional allocation process. Thus, staff calculated the Minnesota jurisdictional amount using the two-step process from the 16-891 Docket as $1,712.74 ($6,550 x 29.6370% = $1,941.22 x 88.23% = $1,712.74).

[69] Please see footnote 53.

had not met its burden of proof in demonstrating that $8,276,882 in capital costs were either Minnesota-specific, and incremental to costs already in base rates.[70]

In *Comments*, the Department noted that $8,276,882 in internal capitalized costs could not be traced back to a particular contract. These costs were labeled: Overheads, Cost in Aid of Construction (CIAC), Materials, Other, Transportation, Company Labor Loadings, Company OT Labor, and Company ST Labor. The Department concluded in its *Comments*: "Ultimately, the Department was unable to verify that these costs were actually specific to work performed in Minnesota, or even truly incremental to costs already recovered in base rates."[71] The Department asked Xcel Energy to respond in reply comments how these costs were MN-specific and incremental to costs represented in base rates.

c. Xcel Energy Reply Comments

In *Reply Comments*, Xcel Energy clarified that only $7,787,034 of the approximately $8.3 million identified by the Department was actually included in the GUIC Rider request because $0.5 million in costs with a "Labor" label had been backed out. The Company argued that, aside from this $0.5 million, all non-contract work identified by the Department is GUIC Rider-eligible because the capitalized costs support specific GUIC projects. Xcel Energy stated: "In particular, we note that the remaining costs are directly related to the same projects underlying the $17.4 million in capital costs approved by the Department. In other words, the remaining costs are for materials, CIAC, overhead, and other charges for items that directly support the vendor work for which the Department takes no issue."[72] The Company provided a table demonstrating this concept in Attachment C of its *Reply Comments*, which is reproduced below.

Table 16: 2017 Capital Charges by Work Order

									Internal Labor Capital Costs. Not GUIC Eligible			
Work Order Number	Project Description	Outside Vendor Contract	Overheads	CIAC	Material	Other	Transportation	Subtotal (GUIC Eligible Capital Costs)	Company Labor Loadings	Company OT Labor	Company ST Labor	Total Capital Costs
E.0000002.005	DIMP Service Renewals	$ 1,473,631	$ 389,436	$ (79)	$ 93,452	$ 93	$ 74	$ 1,956,606	$ 1,109	$ 429	$ 4,176	$ 1,962,321
E.0000002.043	NSPM Programmatic Service Repl	724,927	221,449	2,637	50,465	282	6,010	1,005,770	4,830	3,455	14,160	1,028,215
E.0000002.053	NSPM Programmatic Service Repl	5,921	2,055		1,464		2,294	11,733	5,572	3,779	12,072	33,157
E.0000002.056	NSPM Programmatic Service Repl	(935)	841		2,720			2,626		0		2,626
E.0000004.019	TL0206 High Bridge Lateral Rplc	(29,446)	(16,573)		(5,005)	(1)	(32)	(51,057)	(79)	(55)	(204)	(51,394)
E.0000004.048	NSPM Pipe Trans and IMP - Dist FERC Acct	4,029,425	1,085,514		419,755	243,889	301	5,778,884	10,004	7,435	29,015	5,825,338
E.0000004.054	NSPM Install 6"" and 4"" Distr	4,263	4,030		516	247	661	9,717	1,886	86	3,533	15,222
E.0000004.064	Repl 12in Upper55 to SStPaul R	83,158	45,058			129,982	528	258,726	3,128	182	6,345	268,382
E.0000004.075	NSPM Install 6"" and 4"" Distr	1,888	1,098		(333)	3,143		5,796	98			5,894
E.0000007.002	MNGD Main Renewal-MN	4,719,602	1,162,413		103,989	12,453	154	5,998,612	5,634	5,030	14,842	6,024,117
E.0000007.006	Sartell Bridge Replacement	567,593	241,821		7,684	231	(75,703)	741,626	1,469	1,684	3,281	748,060
E.0000007.045	NSPM Programmatic Main Replace	3,786,852	1,264,740		384,104	17,846	(76,739)	5,376,803	5,040	1,674	12,377	5,395,894
E.0000007.053	IP Line Assessments	105,942	30,184			16,563		152,689	4,029	936	8,897	166,550
E.0000007.060	NSPM Programmatic Main Replace	52,225	35,403		25,514	18	6,130	119,290	14,652	7,499	33,337	174,778
E.0000007.067	NSPM Programmatic Main Replace	24,941	6,223		183	175	385	31,908	771	92	2,010	34,780
E.0000008.002	MNGM Main Reinforcement-MN	69,975	65,700		98,845	12,403	3,845	250,768	26,456	21,154	67,394	365,772
E.0000008.050	Emergency Valve Replacement	22,774	7,495		18,615	-	3,430	52,314	4,824	4,564	12,486	74,188
E.0000009.018	High Bridge Lat Replace Dist Reg	2,026	1,284		0			3,310				3,310
E.0000018.041	ASV/REV Installation on High Pr	17,918	17,567		203,445	459	1,093	240,482	6,585	2,629	15,018	264,714
E.0000018.052	NSPM TIMP Mitigation of ILI Re	905,133	42,135		19,297	449	5,526	972,540	8,808	1,441	36,735	1,019,525
E.0000030.001	East Metro Pipe Replac. Proj H		35		1,973	766		2,774				2,774
E.0000030.002	EastMetro Pipe Repla. Proj Dis	572,895	17,366		11,483	1,101	689	603,534	2,540	3,386	10,499	619,958
E.0000030.004	East Metro Pipeline Replacement				(260)			(260)				(260)
E.0010011.003	Programmatic Main Replacement - Mains	103,670	218,579		67,082	725,728		1,115,060	575	540	1,151	1,117,326
E.0010011.004	Programmatic Main Replacement - Services	122,362	101,807		1,033	271,003		496,205				496,205
E.0010011.005	NSPM Install 6" and 4" Dist. Valves	19	6,626		10,057	632		17,334	6,130	6,166	16,557	46,187
	Grand Total	$ 17,366,758	$ 4,952,287	$ 2,558	$ 1,516,080	$ 1,437,464	$ (121,355)	$ 25,153,791	$ 114,062	$ 72,105	$ 303,682	$ 25,643,640

[70] Department Comments at 31-35.

[71] Department *Comments* at 31.

[72] Xcel Energy *Reply Comments* at 14.

d. Department Response Comments

The Department provided the following table summarizing Xcel Energy's Attachment C, above.[73]

Table 17: Department Summary

Outside Vendor Contract	$17,366,758
Overheads	$4,952,287
Cost In Aid of Construction (CIAC)	$2,558
Materials	$1,516,080
Other	$1,437,464
Transportation	$(121,355)
Subtotal Capital Costs (GUIC Eligible)	$25,153,791
Company Labor Loadings	$114,062
Company OT Labor	$72,105
Company ST Labor	$303,682
Total Capital Costs	$25,643,640

The Department stated that it appreciated Xcel Energy's clarification and additional information, and agreed that internal labor costs must be removed from the GUIC. In light of this information, the Department revised its recommendation to support recovery of Materials and CIAC through the GUIC, since it is reasonable to expect that those costs are incremental to the costs recovered in base rates. However, the Department argued that costs for Overheads, Other, and Transportation, a total of $6,268,396, should be removed from the rider since the Company is already recovering representative amounts of these costs in base rates.

As support for its position the Department included a footnote containing a series of Orders where the Commission had not allowed recovery of internal capitalized costs outside of rate cases.[74]

[73] Department *Response Comments* at 23.

[74] For example, the Commission denied recovery of internal capitalized costs in a rider outside of a rate case in the following proceedings:

- *In the Matter of Otter Tail Power Company's Request for Approval of its 2010 Renewable Resource Cost Recovery Adjustment Factor*, Docket No. E-017/M-09-1484, in its Order dated August 27, 2010, the Commission denied Otter Tail Power Company's request to include capitalized labor and internal costs, subject to future true-up if the Commission determined in Otter Tail's then-pending rate case, Docket No. E-017/GR-10-239, that the amount should be included.
- *In the Matter of Xcel Energy's Petition for Approval of Two Proposed Energy Innovation Corridor Projects in the Central Corridor Utility Zone and Deferred Accounting Treatment for Costs Incurred After January 1, 2010*, Docket No. E-002/M-09-1488, the Commission decided not to

The Department went on to cite the following passage from a Commission order addressing an Xcel Energy TCR petition:

> When Xcel employees are involved in the construction of new facilities, the Company treats their salaries as a capital cost rather than an operation and maintenance (O&M) expense. Xcel included approximately $1.5 million of capitalized internal labor costs for recovery in its proposed 2012 TCR rider.
>
> The Department recommends that the Commission exclude these costs from rider recovery because representative amounts are already being recovered from ratepayers through base rates. Xcel argues that none of the capitalized costs being requested for recovery in the 2012 rider were recovered in the base rates established in the Company's 2011 rate case. The Department agrees that the *specific* costs of projects completed after 2011 were not included in the 2011 test year but maintains that a representative amount of capitalized internal labor costs were included in 2012 base rates.
>
> Xcel has not shown that capitalized labor costs are not being recovered through base rates.[75]

The Department is concerned that a utility could expense its employee internal labor in a rate case, then later capitalize that same labor in a rider, thus charging ratepayers for those same internal labor costs twice. The effect is that in base rates, the utility would earn a return *of* this labor as an operating expenses; in the rider, the utility would earn

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determine cost recovery in the rider, sending those issues to Xcel Energy's then-pending rate case, Docket, No. E-002/GR-10-971.

- *In the Matter of Minnesota Power's Petition for Approval of its Transmission Cost Recovery Rider*, Docket No. E-015/M-10-799, the Commission's May 11, 2011 Order required Minnesota Power to exclude internal costs from the rider.
- *In the Matter of Minnesota Power's Petition for Approval of its 2011 Transmission Cost Recovery Rider Factor*, Docket No. E-015/M-11-695, the Commission's May 11, 2011 Order required Minnesota Power to exclude internal costs from the rider. The Commission's subsequent November 12, 2013 Order required Minnesota Power to "continue to exclude internal capitalized costs" from riders.
- *In the Matter of Xcel Energy's Petition for Approval of 2012 Transmission Cost Recovery (TCR), Project Eligibility, TCR Rate Factors, and 2011 True-up*, Docket No. E-002/M-12-50, the Commission's February 7, 2014 Order required Xcel Energy to removed capitalized costs from the rider.
- *In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to April 30, 2014*, Docket No. E-017/M-13-103, the Commission's March 10, 2014 Order required Otter Tail Power to exclude internal costs.

[75] *In the Matter of Xcel Energy's Petition for Approval of 2012 Transmission Cost Recovery (TCR), Project Eligibility, TCR Rate Factors, and 2011 True-up*, Docket No. E-002/M-12-50, Order Approving 2012 TCR Project Eligibility and Rider, Capping Costs, and Modifying 2011 Tracker Report at 5 (February 7, 2014). Footnotes omitted.

both a return *of* this labor as a depreciation expense and a return *on* this rider through a return on rate base. Thus, the Commission correctly disallowed double-recovery of those costs.

The Department points out that in the *Order* for Otter Tail's TCR Rider, the Commission twice made the argument that *any* rider proceeding is an inappropriate place for approving capitalized internal labor costs:

> And the Department is also correct that this docket, like any rider update docket, is not an appropriate vehicle for making the exacting factual distinctions necessary to identify any internal labor costs not already included in base rates.[76]

> Nor does this, or any other rider proceeding, provide the comprehensive evidentiary development required to permit the Commission to make the factual determinations required to classify individual labor-cost accounts as subject to capitalization or expensing.[77]

Similarly, the Department concluded that, in this proceeding, Xcel Energy should not be allowed to recover through the GUIC Rider costs for which a representative amount is already recovered in base rates. Specifically, while the Department does not dispute recovery of Material and CIAC costs in the GUIC Rider, the Department recommends that Overhead, Other and Transportation costs not be recovered in the GUIC Rider, since the Company is already recovering representative amounts for these costs in base rates.

Moreover, although Xcel Energy removed costs labeled Labor, the Company proposes to include Overhead capitalized costs, described as follows:

> Overhead costs include engineering, supervision, general office, and administrative costs that are incurred to ensure the continued proper operation of construction projects, but are costs that cannot be directly assigned to specific projects.[78]

Xcel Energy's description of Overhead costs indicated that there is not a meaningful difference between Overhead and Labor costs. In other words, it seems that the costs of both Labor and Overhead are primarily used to pay for employee work. As such, the Overhead costs in the Company's proposal have the same effect of inclusion of Labor costs in the dockets discussed above: the cost of Xcel Energy's internal employees may have been expensed during the rate case, then capitalized as Overhead GUIC costs. Thus, Overhead costs should not be recovered in the GUIC, to avoid allowing Xcel Energy to recover such costs twice.

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[76] *In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to April 30, 2014*, Docket No. E-017/M-13-103, Order Capping Costs, Denying Rider Recovery of Excess costs, And Requiring Inclusion of All MISO Schedule 26 cost and Revenues in TCR Rider at 6 (March 10, 2014).

[77] *Id*.

[78] Xcel Energy's October 1, 2018, response to Department IR No. 65, page 1.

Similarly, Xcel Energy hasn't shown that the miscellaneous costs under the category of "Other" are incremental to the costs being recovered in base rates. In addition, Transportation costs appear to be duplicative of amounts reflected in base rates.

As a result, the Department recommends that the Commission require Xcel Energy to remove costs of Overhead, Other, and Transportation, totaling $6,268,396, from the GUIC Rider, to the extent that these costs are not already removed through other adjustments.

e. Decision Alternatives

33. Allow Xcel Energy to maintain the capital charges shown in Attachment C of the Company's Reply Comments. (Xcel Energy)

34. Require Xcel Energy to remove the costs of Overhead, Other, and Transportation, totaling $6,268,396, from the GUIC Rider. (Department)

11. Tracker Balance Carrying Charge

a. Background

The concept of a Tracker carrying charge was first discussed in the 14-336 Docket. In its January 27, 2015, Order the Commission denied the recovery of a carrying charge in the GUIC tracker. [79]

b. Department Comments

In *Comments*, the Department pointed out that use of this rider is optional and that the GUIC Rider is an extraordinary rate tool, which permits utilities to begin recovery of eligible costs sooner than its next general rate case, therefore, the Department continues to recommend no carrying charge.

c. Xcel Energy Reply Comments

In *Reply Comments*, Xcel Energy stated that a carrying charge should be considered if a historical test year is used, in order to relieve financial pressures caused by delay in the recovery of costs.[80]

d. Department Response Comments

In *Response Comments*, the Department reiterated its argument that use of a rider provides the utility the certainty of recovering the return earned on its investments (not simply the opportunity to earn the approved return rate), as well as full return of the investments while

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[79] *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 at 12 (January 27, 2015).

[80] Xcel Energy *Response Comments* at 23.

included in the rider mechanism. This certainty that the approved return will be earned should alleviate any financial pressures and eliminate the need for a carrying charge. Finally, the Department argues that the test year period used (historical or future) when setting GUIC Rider rates should be irrelevant, because similar to the approach in setting rates in a general rate case, the test period is not a factor in the approved ROR when determining revenue requirements. For the forgoing reasons, the Department continues to recommend that the Commission adopt no carrying charge for the GUIC Rider.

e. Decision Alternatives

35. Allow a carrying charge in the GUIC tracker account. (Xcel Energy)

36. Deny recovery of a carrying charge in the GUIC tracker account. (Department)

12. Performance Metrics

a. Background

In OP 2 of its August 18, 2016, *Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures* in the 15-808 Docket, the Commission required Xcel Energy to develop metrics and reporting requirements to analyze the appropriateness of the Company's GUIC expenditures. Xcel Energy presented its proposed metrics to the Department and OAG on November 16, 2016 and submitted the proposed metrics in a supplemental filing on January 13, 2017.

In OP 5 of its February 8, 2018, *Order Approving Rider with Modifications* in the 16-891 Docket, the Commission acknowledged that Xcel Energy's proposed metrics were a helpful starting point and ordered Xcel Energy to continue to discuss with other parties, including the Department and OAG, proposed metrics and reporting requirements in future GUIC petitions.

b. Department Comments

The Department reviewed the results of Xcel Energy's metrics and generally concluded that they were reasonable, with one exception. The Department noted that the "DIMP Poor Performing Main Unit Cost" metric had a project (Downtown St. Paul project) which stood apart from all the others in terms of unit costs per foot. The Department noted that because the Company included this outlier project when calculating the standard deviation threshold caused only one project, the outlier itself to appear to be the only project having cost deviations beyond the normal range.[81] The Department stated that Xcel Energy could have excluded the outlier project from its statistical calculations, and as a result, there would have been six additional projects that would have exceeded the cost variation threshold. As a result, the Department requested that the Company provide an evaluation of the additional six projects in reply comments.

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[81] The Downtown St. Paul project unit cost exceeded $325 per foot, whereas all other measured activities were less than $100 per foot.

c. Xcel Energy Reply Comments

In its *Reply Comments*, Xcel Energy included the requested analysis and evaluation of the six projects as Attachment I. In addition, the Company stated that it would set up a future stakeholder meeting in compliance with the Commission's order in the 16-891 Docket.

d. Department Response Comments

In *Response Comments*, the Department acknowledged the revised analysis on the six projects that exceeded the "DIMP Poor Performing Main Unit Cost" metric cost variation threshold. The Department noted that the stakeholder meeting occurred on September 26, 2018, in compliance with the Commission's order in the 16-891 Docket, and stated that it would continue to monitor Xcel Energy's performance metrics in future GUIC filings.

e. Staff Comment

As noted above, the Department acknowledged Xcel Energy's revised analysis on the six projects that exceeded the "DIMP Poor Performing Main Unit Cost" metric cost variation threshold but did not expressly make a recommendation regarding those projects. Thus, staff sought clarification from the Department and confirmed the Department does not recommend disallowance of any cost recovery of the six projects that exceeded the "DIMP Poor Performing Main Unit Cost" metric cost variation threshold, discussed above.

f. Decision Alternatives

37. Find that Xcel Energy has complied with ordering paragraph 5 of the Commission's Order *Approving Rider with Modifications* in the 16-891 Docket requiring Xcel Energy to "continue to discuss with other parties, including the Department and the OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GUIC proceedings."

38. Require that Xcel Energy, the Department, and the OAG continue their discussions regarding the establishment of performance metrics in future GUIC proceedings.

13. Depreciation Impacts from Xcel Energy's Five-Year Study in Docket No. E,G-002/D-17-581

a. Background

On April 26, 2018, at a regularly scheduled agenda meeting, during the discussion regarding the certification of Xcel Energy's five-year depreciation study in Docket No. E,G-002/D-17-581, the Commission directed staff to "prepare and issue a notice for supplemental comments in Xcel's pending 2018 GUIC proceeding, in Docket No. G-002/M-17-787, that requires Xcel to address the gas utility's $6.8 million decrease in depreciation expense and the appropriateness of using a true-up or some other kind of adjustment in the GUIC rider to reflect this decrease in depreciation expense."

On May 2, 2018, the Commission issued a "Notice of Supplemental Comment Period" requesting comments related to Xcel Energy's $6.8 million reduction in annual depreciation expense, starting in 2018, resulting from its depreciation revisions approved in Docket No. E,G-002/D-17-581. The notice requested comments on the following topics:

- Should the commission address the $6.8 million decrease in depreciation expense discussed in Xcel Energy's five-year depreciation study (Docket No. E,G-002/D-17-581) in Xcel Energy's Gas Utility Infrastructure Cost (GUIC) rider petition, in this docket?
- If so, how should the Commission address the decrease in depreciation expense (e.g., with a corresponding adjustment) in the GUIC petition? If not, why not?
- How should the Commission handle similar issues in the future?
- Are there other issues or concerns related to this matter?

On May 29, 2018, Xcel Energy submitted supplemental comments.

On July 3, 2018, the Department submitted its comments.

b. Xcel Energy Supplemental Comments

In *Supplemental Comments*, Xcel Energy stated it fully intends to incorporate the new depreciation rates for GUIC projects in the 2018 GUIC Rider revenue requirements, estimating the impact to be a $540,000 reduction.[82] However, the Company argued that the non-GUIC depreciation impact should be incorporated into a future rate case rather than this proceeding. The Company argued that addressing the full gas utility depreciation impact (including non-GUIC impacts) as a standalone issue in the GUIC Rider would violate the Commission's longstanding policy against single-issue ratemaking and fail to account for the multiple factors that have driven overall increases to its revenue requirement since its 2010 rate case.

Single-Issue Ratemaking

Xcel Energy noted that the vast majority of the depreciation expense change is not related to GUIC-dedicated projects, and incorporating non-GUIC depreciation impacts would significantly expand the scope of the GUIC Rider mechanism beyond its purpose of facilitating cost recovery for projects aimed at gas infrastructure integrity and public safety.

Xcel Energy further argued that addressing this single change in depreciation expense—on its own and without consideration to offsetting cost increases that have occurred since the 2010 Gas Rate Case—would violate the Commission's longstanding and consistent policy against single-issue ratemaking. The Company cited the following Commission statements:

> Granting the parties' request to reopen past rate cases, readjust rates . . . , and require a refund of the adjusted amount would also violate the Commission's longstanding policy against single-issue ratemaking. The Commission consistently

[82] Staff notes the issue of accounting for the change in depreciation expense on GUIC related impacts is discussed previously in section IV.A.3 of these briefing papers.

> confines significant rate decisions to the context of a rate case analysis. Through a full rate case investigation the Commission is best able to judge a particular rate factor against the company's overall financial picture, including revenue requirement, rate base, and rate of return.
>
> [A] readjustment of past rates to account for the SMMPA settlement should not take place without allowing NSP the opportunity to present evidence regarding underrecoveries during the same time. The rate case test year concept is particularly constructed to confine such analysis to the rate case test year itself. In a rate case the parties present their best evidence of the company's costs and recoveries during the set period, with the understanding that under- and overrecovery will occur during test years. The . . . requested rate readjustment would violate the test year concept and related Commission policy against single-issue ratemaking.[83]

Xcel Energy argued that the same is true here. The Company's gas rates were set in its 2010 Gas Rate Case,[84] and since that time, its revenue requirements have increased due to a variety of factors. The increases in costs unrelated to GUIC projects have not been factored into recovery because base rates have not been reset since the 2010 case. Therefore, Xcel Energy does not believe it is appropriate to isolate this single expense decrease outside of a rate case and without consideration given to all of the increases in costs we have experienced over the past eight years.

Xcel Energy notes that Depreciation expense has increased in every year subsequent to 2010 despite the fact that depreciation rates were also changed in 2013, which resulted in lower depreciation rates and lower depreciation before factoring in plant increases during the year. The year-by-year change in Minnesota Jurisdictional Gas Utility Depreciation Expense is illustrated in Table 18 below.

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[83] *In re Northern States Power Company's Petition for Deferred Accounting Treatment for Settlement Payments from SMMPA*, E-002/M-96-1623 (Sept. 17, 1997); see *also In re Petition of Northern States Power Company*, E-002/RP-91-682 (Aug. 17, 1993) ("[T]he Commission generally rejects single issue ratemaking as an inefficient use of resources and a poor substitute for the comprehensive examination of total revenue requirements in a general rate case."); *In re Assignment of an Eligible Telecommunications Carriers,* P-999/CP-98-1193 (October 6, 1999) ("[T]he Commission has traditionally rejected the concept of single issue ratemaking, choosing in the great majority of instances to examine specific cost recovery issues during rate case analysis of overall revenues, expenses, and rate design.").

[84] Docket No. G-002/GR-09-1153.

Table 18
Minnesota Jurisdictional Gas Utility Depreciation Expense
($000)

Year	MN Gas Depreciation Total	GUIC-Related Depreciation	Total W/O GUIC Depreciation	Base Rates Depreciation Expense	Difference
	[a]	*[b]*	*[c]=[a] – [b]*	*[d]*	*[e]=[c] – [d]*
2010	$33,067	-	$33,067	$32,684	$383
2011	34,215	-	34,215	32,684	1,531
2012	34,910	-	34,910	32,684	2,226
2013	35,445	-	35,445	32,684	2,761
2014	37,069	409	36,660	32,684	3,976
2015	38,598	741	37,857	32,684	5,173
2016	40,163	1,590	38,574	32,684	5,890
2017	41,845	2,266	39,579	32,684	6,895

Xcel Energy explained that the increase in annual depreciation since the 2010 Gas Rate Case resulting from normal changes in depreciable plant and the previous change in depreciation rates outstrips the Minnesota jurisdictional decrease approved in 2018, $6.1 million, by approximately $0.8 million. Thus, using an unrelated rate rider mechanism to only incorporate the recently approved change in depreciation expense without incorporating the steady growth and the impact of previously approved changes in depreciation rates is asymmetrical and delivers a skewed view of how depreciation has changed since the time of the 2010 Gas Rate Case. The Company stated this is the reason why there is a well-established policy against single-issue ratemaking and why revenues and expenses must be examined holistically in the context of a rate case test year.

Precedent for Depreciation Rate Change Impacts

Xcel Energy argued that the proper venue to address the depreciation changes for non-GUIC projects is a subsequent rate case which would allow the Commission and interested parties to assess the depreciation change based on test year plant data, and will also allow the depreciation amount to be weighed against all other revenue requirement components in a holistic way. This approach reflects longstanding practice when the approval and implementation of new depreciation rates occurs outside of a rate case test year period. In fact, excluding the most recent changes approved in Docket No. E,G-002/D-17-581, depreciation rates have changed six times for the gas utility since the 2010 Gas Rate Case. And none of these impacts—outside those related to GUIC projects—have yet been incorporated into base rates.

The Company believes that no change is warranted to the Commission's longstanding treatment of depreciation rate change impacts.

c. Department Reply Comments

The Department agreed with Xcel Energy and concluded that the GUIC Rider should not incorporate the study's impact on the non-GUIC projects depreciation expense because doing so would fragment non-GUIC asset recovery, would be single issue ratemaking, and appeared to extend beyond the scope of the GUIC statute.

Fragment Asset Recovery

The Department pointed out that in regulated utility ratemaking, for its plant investments, utilities typically are authorized to earn a return on their investments as well as a return of their investment. Despite the fact that the return on and return of dollars represent two types of costs, these costs are linked and are tied to a common item. (The accumulated "return of" dollars reduce the principal on which the "return on" amount is determined.) In the Department's view, to update a GUIC Rider rate to account for a dollar change in "return of" the non-GUIC common asset without regard to any change in the asset investment-to-date and without updating a tariff rate for any impact such change has on the "return on" dollars, would not be fair or reasonable. Furthermore, to carve out a portion of an asset's particular cost element for cost recovery, in an irregular manner that causes the asset's cost element to be reflected within multiple rate mechanisms established at different points in time, would complicate rate review and regulatory oversight.

Single Issue Ratemaking

The Department explained that the concept of a test year is to establish just and reasonable base rates by reviewing a utility's entire operations at a normal operating level. It is not unusual that from year-to-year costs, sales volumes, or customer counts may vary, either up or down. Nor is it unusual that in a capital-intensive industry, depreciation expense is a material cost. Even so, to include in the GUIC rider a change in one ordinary base rate cost that occurs many years after a rate case, which is not a product of the rider-based activity, and without consideration of other inputs that established the base rate, would disregard the fact that the test-year's purpose and function is to set representative and reasonable rates. Therefore, the Department concluded that to consider inclusion of Xcel Gas' annual depreciation expense changes unrelated to the GUIC projects would be single-issue ratemaking and should not be included in this rider.

However, as previously discussed above in Section III.D.1.b.ii, the Department recommended that the Commission require Xcel Gas' to incorporate the newly approved depreciation rates when determining the depreciation expense for GUIC Rider projects.

Scope of the GUIC Statute

The Department believes that inclusion of changes in depreciation expense stemming from non-GUIC operations would capture changes that are beyond the rider's statutory framework. The Department also noted that the non-GUIC cost changes, in part, could be linked to or are a product of betterments and/or connecting new customers; costs related to these reasons are specifically to be excluded from this rider. In fact, Xcel Energy's average number of customers has grown by approximately 21,000 since its last rate case. Therefore, inclusion of the Company's overall annual depreciation expense does not appear to be supported by Minn. Stat. § 216B.1635. The following are parts of the statute that led the Department to its conclusion.

Section 216B.1635, Subd. 2 states in part:

> 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 referenced Section 216B.1635, Subd. 1, paragraph (c), reads:

> (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.

And Section 216B.1635, Subd. 4 reads:

> 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.

Section 216B.1635, Subd 1(b) provides the definition of gas utility infrastructure costs, which reads:

> (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.

The Department concluded that nowhere does the statute refer to non-GUIC costs; as a result, it would not be appropriate to include changes in non-GUIC costs in the GUIC rider.

d. Staff Analysis

This issue was first raised at the April 26, 2018 agenda meeting in Docket No. E,G-002/D-17-581. In that meeting, the Commission directed Staff to issue a notice of comment period in the current docket to consider addressing, in the GUIC rider, the $6.8 million decrease in depreciation expense discussed in the Company's five-year depreciation study.

Both Xcel Energy and the Department filed comments in agreement that it would not be reasonable to address concerns about general changes in depreciation expense in the GUIC Rider. Particularly, both the Department and Xcel Energy expressed concerns about single issue ratemaking. Addressing depreciation expense in a vacuum doesn't contemplate other mitigating costs or revenues that otherwise would be considered in a general rate case.

Additionally, the depreciation expense in question is largely attributable to non-GUIC projects. Including non-GUIC expenses in a GUIC rider would not only misalign the operation of the rider with legislative intent, but would also complicate regulatory oversight. The Department noted that Xcel Energy has added approximately 21,000 customers since its last rate case. Requiring Xcel Energy to consider depreciation on non-GUIC projects in the GUIC rider, especially considering that the statute explicitly prohibits the Company from including projects that constitute a betterment in the rider, would be inconsistent with the historical application of the statute.

Staff concurs with the comments made by both Xcel Energy and the Department. Concerns with non-GUIC related depreciation expenses, or any expenses for that matter, are properly reviewed and addressed holistically in a general rate case. Just as the Company has the right to file a rate case if it feels it is under earning, the Commission can issue, either on its own motion or at the request of a ratepayer advocate, an order for Xcel Energy to show cause if it feels the Company is overearning and the current rates are unjust or unreasonable.[85] Considering non-GUIC issues in the GUIC docket only when it benefits ratepayers could be seen as unjust for the utility.

[85] See Minn. Stat. §§ 216B.17 and 23.

e. Decision Alternatives

39. Authorize Xcel Energy to only incorporate and apply the reduction in annual depreciation expense from its five-year study (Docket No. E,G-002/D-17-581) pertaining to GUIC projects in the 2018 GUIC rider revenue requirements and to incorporate the non-GUIC depreciation changes in a future general rate case. (Xcel Energy, Department)

40. Require Xcel Energy to incorporate and apply the $6.8 million in Commission-approved reductions in annual depreciation expense from its five-year study (Docket No. E,G-002/D-17-581) in the 2018 GUIC rider revenue requirements.

V. Decision Alternatives

__Resolved Issues__

Filing Requirements

1. Require Xcel Energy to include the reporting required by Minn. Stat. § 216B.1635, Subd. 4 (2)(iii) in all future GUIC rider petitions.

Incremental Costs

2. Require Xcel Energy to include only incremental rate base amounts in its GUIC rider rate base in all future GUIC rider petitions.

GUIC Project Depreciation Rates

3. Approve Xcel Energy's recalculated incremental depreciation expense amount

Non-Minnesota Costs

4. Require Xcel Energy to remove the work that is not Minnesota-specific, as identified by the Company in response to Department IR no. 62

Recovery Period

5. Authorize Xcel Energy to recover the 2018 revenue requirements over the 12 months following the effective date of this Order.

GUIC Rider Schedules, Tariff Sheets, and Customer Notices

6. Require Xcel Energy, in future GUIC filings, to present historical and projected GUIC revenue requirements, rates, and recoveries within a single tracker for each year.

7. Require Xcel Energy to make a compliance filing showing the final rate-adjustment factors and all related tariff changes, within ten calendar days of the date of the Order.

Unresolved Issues

Rate of Return on Investment

8. Approve Xcel Energy's proposed capital structure for this rider with a return on equity (ROE) of 10.00 percent and a rate of return (ROR) of 7.52 percent. (Xcel Energy)

Xcel Energy - Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with New ROE)

	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%	**10.00%**	5.25%
Rate of Return	**100.00%**		**7.52%**

9. Approve the Department's capital structure with an ROE of 9.04 percent and an ROR of 7.02 percent (Department)

Department - Proposed Rate of Return, this docket
(Based on 16-891 Decision with same ROE)

	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%	**9.04%**	4.75%
Rate of Return	**100.00%**		**7.02%**

10. Continue with the current capital structure and approve the OAG's recommended ROR of 4.94 percent and an ROE of 5.09 percent. (OAG)

OAG Proposed Rate of Return, this docket
(Based on 16-891 Decision Updated with new ROR and calculated ROE)

	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%	**5.09%**	2.67%
Rate of Return	**100.00%**		**4.94%**

11. Approve the Department's capital structure with an ROE of 8.59 percent and an ROR of 6.78 percent (Department's TCR Recommendation)

Department - Proposed Rate of Return, this docket
(Based on 16-891 Decision with updated ROE)

	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%	**8.59%**	4.51%
Rate of Return	**100.00%**		**6.78%**

Prorated Accumulated Deferred Income Taxes

12. Allow Xcel Energy to implement its GUIC rider factor effective January 1, 2018 and authorize the Company to recover $26,416 related to ADIT proration as proposed in the Company's Initial Petition.

13. Allow Xcel Energy to implement its GUIC rider factor effective January 1, 2018 and authorize the Company to recover $150 related to ADIT proration, calculated by Deloitte Tax Services, as proposed in the Company's July 27, 2018 Reply Comments. (Xcel Energy)

14. Require Xcel Energy to implement its GUIC rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department)

Staff note: the following alternative would be in addition to any of the ADIT alternatives shown above.

15. Require Xcel Energy to utilize the ADIT proration methodology ordered by the Commission in this docket to be used in all future GUIC rider docket filings. (Staff)

Sales Forecast

16. Allow Xcel Energy to utilize its 2018-2019 sales forecast to allocate costs across jurisdictions and classes. (Xcel Energy)

17. Require Xcel Energy to use the most recent 12 months of actual natural gas sales to allocate the costs across jurisdictions and classes. (Department)

Data Gaps

18. Determine that Xcel Energy has demonstrated MAOP validation costs and costs related to data gaps are prudently incurred and authorize the Company to recover the costs in full. (Xcel Energy)

19. Limit the return on MAOP validation capital costs to the Company's debt cost rate. (Department)

20. Disallow extraordinary rider ratemaking treatment for projects undertaken due to insufficient MAOP data. (Department – Alternate)

TIMP – Island Line South Project

21. Determine that the ILI costs related to the Island Line South project are reasonable and necessary and allow Xcel Energy to recover those costs through the GUIC rider. (Xcel Energy)

22. Require Xcel Energy to remove the $0.6 million in ILI assessment costs from its GUIC rider. (Department)

23. Limit Xcel Energy's water pumping recovery costs to the $1.7 million as originally estimated by the Company and the $0.2 million in cost overruns support by the record. (Department)

DIMP – Langdon Line Project

24. Determine that the replacement of the Langdon Line with a 12-inch pipe does not constitute a betterment and allow Xcel Energy to include all Langdon Line project costs in its GUIC rider. (Xcel Energy)

25. Allow Xcel Energy to only recover the cost of replacing the Langdon Line with an 8-inch pipe and require the Company to remove the excess cost, estimated to be $3.6 million, from its GUIC rider. (Department)

DIMP – Lexington to Snelling Project

26. Allow Xcel Energy to include all H005 Lexington to Snelling project costs in its GUIC rider, including the costs related to relocating customer services along the existing pipeline. (Xcel Energy)

27. Require Xcel Energy to remove $420,000, the costs related to relocating customer services, from the H005 Lexington to Snelling project. (Department)

DIMP/TIMP – Rider Eligibility for Expenditures on Low-Risk Infrastructure Replacement

28. Allow Xcel Energy recovery of $85,000 in costs incurred on low-risk infrastructure replacement costs. (Xcel Energy)

29. Deny Xcel Energy recovery of $85,000 in costs incurred on low-risk infrastructure replacement costs that were not required by civic/public work requirements, nor required by government regulations. (Department)

Jurisdictionally Unclear Operations and Maintenance Costs

30. Allow recovery of the entire disputed $6,550 as prudent and eligible for recovery in the GUIC Rider. (Xcel Energy)

31. Require Xcel to follow the two-step allocation process established in the 16-891 Docket and allow recovery of $1,712.74 in jurisdictionally unclear costs in the GUIC Rider. (Department)

32. Disallow the entire $6,550 in jurisdictionally unclear charges from the GUIC Rider.

Internal Capitalized Costs

33. Allow Xcel Energy to maintain the capital charges shown in Attachment C of the Company's Reply Comments. (Xcel Energy)

34. Require Xcel Energy to remove the costs of Overhead, Other, and Transportation, totaling $6,268,396, from the GUIC Rider. (Department)

Tracker Balance Carrying Charge

35. Allow a carrying charge in the GUIC tracker account. (Xcel Energy)

36. Deny recovery of a carrying charge in the GUIC tracker account. (Department)

Performance Metrics

37. Find that Xcel Energy has complied with ordering paragraph 5 of the Commission's Order *Approving Rider with Modifications* in the 16-891 Docket requiring Xcel Energy to "continue to discuss with other parties, including the Department and the OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GUIC proceedings."

38. Require that Xcel Energy, the Department, and the OAG continue its discussions regarding the establishment of performance metrics in future GUIC proceedings.

Depreciation Impacts from Xcel Energy's Five-Year Study (Docket No. E,G-002/D-17-581

39. Require Xcel Energy to only incorporate and apply the reduction in annual depreciation expense from its five-year study (Docket No. E,G-002/D-17-581) pertaining to GUIC projects in the 2018 GUIC rider revenue requirements and incorporate the non-GUIC depreciation changes in a future general rate case. (Xcel Energy, Department)

40. Require Xcel Energy to incorporate and apply $6.8 million in Commission approved reduction in annual depreciation expense from its five-year study (Docket No. E,G-002/D-17-581) in the 2018 GUIC rider revenue requirements.

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.