MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	May 23, 2019	Agenda Item 5**
Company	Northern States Power Company, d/b/a Xcel Energy	
Docket No.	**E-002/M-17-797**	
	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	

Issues

1. Should the Commission approve or modify Xcel Energy's proposed rate of return used for determining the Transmission Cost Recovery 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 request for cost recovery of the ADMS Distribution-Grid Modernization project?
4. Should the Commission approve or modify Xcel Energy's 2017 and 2018 revenue requirements for the projects eligible for cost recovery through the Transmission Cost Recovery Rider?
5. Should the Commission approve or modify Xcel Energy's request to modify its Transmission Cost Recovery Tariff, 2016 True-up and Tracker Balance report, adjustment factors, and customer notice?

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✓ **Relevant Documents**	**Date**
Xcel Energy - Petition	November 8, 2017
Minnesota Department of Commerce, Division of Energy Resources - Comments	April 2, 2018
Minnesota Office of Attorney General - Comments	April 2, 2018
Xcel Energy – Reply Comments	May 14, 2018
Xcel Energy – Supplemental Reply Comments	May 25, 2018
Xcel Energy – Second Supplement to Reply Comments	July 16, 2018
Commission Notice of Comment Period	February 22, 2019
Minnesota Department of Commerce, Division of Energy Resources – Response Comments	March 4, 2019
Xcel Energy – Reply to Response Comments	April 11, 2019

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I. Statement of the Issues

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II. Introduction and Background

A. Introduction

Generally, a public utility may not change its rates without undergoing a rate case in which the Commission comprehensively reviews the utility's costs and revenues. However, the Legislature has created exceptions to this general policy, a utility may implement a rider to expedite recovery of certain costs not reflected in the company's current base rates.

Under Minnesota (Minn.) Statute (Stat.) section (§) 216B.16, subdivision (subd.) 7b, the transmission-cost recovery statute[1] the Commission may but is not required to authorize a "tariff mechanism" that allows a utility to recover, through a rider, the Minnesota jurisdictional costs of:

- new transmission facilities that the Commission has approved through a certificate of need or under the state transmission plan; and
- charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator (MISO) to benefit the utility or the integrated transmission system.

The Commission has established the Northern States Power Company d/b/a Xcel Energy (Xcel Energy or the Company) Transmission Cost Recovery (TCR) rider, referred to as a transmission cost adjustment mechanism, as Xcel Energy's mechanism to recover these costs.

The 1997 Legislature enacted the Renewable Energy Statute, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with utility investments or costs to comply with renewable energy mandates. The 2005 Legislature enacted the Transmission Statute, authorizing the Commission to approve, modify

[1] A copy of Minn. Stat. § 216B.16, subd. 7b is located in an attachment to these briefing papers.

or reject a tariff mechanism for an automatic adjustment of charges for costs associated with eligible utility investments in transmission facilities and, in 2008, amended this statute to allow inclusion of certain regional transmission facilities' costs, as determined by MISO.

The Commission's November 20, 2006 *Order* in Docket No. E-002/M-06-1103 approved Xcel Energy's TCR Rider tariff, which combined recovery of eligible projects under the Renewable Statute and the Transmission Statute in one annual automatic adjustment mechanism.

Since 2006, the Company's TCR Rider mechanism has been modified several times to allow recovery of additional costs subsequently authorized by the Minnesota Legislature. The Commission's March 20, 2008 *Order* in Docket No. E-002/M-07- 1156 approved recovery of greenhouse gas infrastructure costs incurred for the replacement of circuit breakers that contain sulfur hexafluoride (SF6). The Commission's June 25, 2009 *Order* in Docket No. E-002/M-08-1284 approved recovery of Regional Expansion Criteria and Benefits (RECB) revenues and costs. In 2013, the Transmission Statute was modified to allow TCR Rider eligibility of projects located in other states that have been approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by MISO to benefit the utility or integrated transmission system.

During the 2015 legislative session, the Transmission Statute was further modified to allow for the cost recovery of facilities and planning investments that support grid modernization efforts. Such projects must be certified by the Commission under Minn. Stat. § 216B.2425 in order to be eligible for rider recovery. Xcel Energy's first Biennial Grid Modernization Report was submitted on November 1, 2015 in accordance with Minn. Stat. § 216B.2425, subd. 2. The Commission certified the Company's ADMS grid modernization project through the Biennial Report proceeding in its June 28, 2016 *Order* in Docket No. E-002/M-15-962. This is Xcel Energy's first TCR rider proceeding filed subsequent to that *Order*, so the Company requested cost recovery of the certified ADMS grid modernization project in this *Petition*.

In the past, Xcel Energy has categorized all reports and calculations associated with project costs and revenue requirements in three groups: (1) Transmission Statute projects; (2) Renewable Statute projects; and (3) Greenhouse Gas projects. In this filing, the Company added a fourth group for Distribution-Grid Modernization projects. While those projects are authorized for recovery under the transmission cost recovery statute, Xcel Energy believes this type of project is distinct from transmission projects and believes the additional category (i.e. the fourth grouping of projects) can aid in review. Although Xcel Energy tracks costs separately by project covered by one statute or the other, it has been the Company's past practice in TCR petitions to request approval for recovery of the total costs under a single recovery mechanism, the TCR rider. This specific *Petition* includes only Transmission Statute projects and Grid Modernization-Distribution projects.

With the filing of the instant *Petition*, Xcel Energy proposed to set new TCR Adjustment Factors beginning January 2, 2018. As has been the case in past TCR dockets, the Company has asked to true-up the difference between the revenues they will continue to collect under the current TCR Adjustment Factors with the revenue requirements the Commission approves in the instant *Petition*.

B. Background

1. 15-891 Docket

In Xcel Energy's most recent TCR rider in Docket No. G-002/M-15-891 (15-891 Docket), Xcel Energy requested approval of its 2015 true-up report and 2016 TCR revenue requirements.

In the 15-891 Docket *Order*, dated January 17, 2017 the Commission approved Xcel Energy's 2015 true-up report tracker balance of approximately $8 million and 2016 TCR revenue requirements in the amount of approximately $78.4 million and authorized recovery of actual 2016 costs through the TCR rider and revised adjustment factors with the following modifications:

- Approved historical ADIT costs and agreed that the various parties should work together to develop and submit a PLR request to the IRS.
- Allowed Xcel Energy to recalculate the TCR adjustment factors at the completion of its then pending rate case.

2. 17-797 Docket (this docket)

In the instant *Petition*, Xcel Energy requests Commission approval of the TCR Rider combined revenue requirements for 2017 and 2018 of approximately $109.5 million and the corresponding TCR adjustment factors. The Minnesota Department of Commerce, Division of Energy Resources (Department) and the Minnesota Office of the Attorney General – Residential Utilities and Antitrust Division (OAG) filed comments discussing a number of issues. They are:

- Rate of Return on Investment;
- Prorated Accumulated Deferred Income Taxes;
- Revenue requirements for seven transmission projects:
- Cost recovery for the Advanced Distribution Management System (ADMS);
- Recovery of its net MISO Regional Expansion Criteria and Benefits (RECB) charges;
- Recovery of 2016 true-up carryover balance resulting from under-collections in prior years;
- TCR adjustment factors;
- Potential implementation of carrying charge; and
- Tariff sheets and customer notices.

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 seven ongoing TCR rider projects that have been previously approved by the Commission in prior TCR proceedings.[2] The Company also requests Commission approval of the

[2] Xcel Energy's projects are more fully discussed in Attachments 1 and 1A of the *Petition*.

ADMS grid modernization project as eligible for TCR rider recovery. Xcel Energy requests approval of a combined revenue requirement for 2017 and 2018 of approximately $109.5 million. In determining the 2017 and 2018 revenue requirements, the Company proposed using an ROE of 10.00 percent.

According to Xcel Energy, the responsibility for the TCR rider revenue requirement is allocated to customer classes consistent with how responsibility for the Company's demand (capacity) costs are allocated according to its demand allocation factors approved in Xcel Energy's most recent electric rate case (Docket No. E-002/GR-15-826).

The proposed TCR adjustment factors by customer class along with existing factors are shown in Xcel Energy's petition (shown below).[3]

Table 1: Current and Proposed TCR Adjustment Factors

	2016 Approved	2017-2018 Proposed (annualized)
Total TCR Revenue Requirements	$80,525,828	$109,549,879
Residential Rate/kWh	$0.003503	$0.004645
Commercial Non-Demand/kWh	$0.003384	$0.004102
Demand /kW	$1.017	$1.274

The proposed TCR adjustment factors are higher due to the combined effects of increased TCR annual revenue requirements, prior year's under-recovery, and proposed ROE.

IV. Discussion of Issues

A. Rate of Return

1. Background

Minn. Stat. § 216B.16, Subd. 7b. **Transmission Cost Adjustment**. Allows for recovery the Minnesota jurisdictional costs of certain new transmission facilities, facilities and planning investments that support grid modernization efforts and certain MISO charges associated with regionally planned transmission projects. As for the specific rate of return, Minn. Stat. § 216B.16, Subd. 7b (b)(6) states:

> allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest.

The current ROE was established in Docket No. E-002/GR-15-826, Xcel Energy's most recent rate case (15-826 Docket). In its *Order* dated June 12, 2017, the Commission approved the Stipulation of Settlement allowing "…Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%) for settlement purposes…"[4] In its *Order* approving the *Settlement*,

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[3] Xcel Energy *Petition* at 13.

[4] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for*

the Commission made clear that the authorized ROE that Xcel Energy was authorized to represent was not binding on future proceedings that involve ROE, stating:

> Because the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings, if future circumstances suggest that a lower ROE is appropriate in other contexts, parties will be free to assert an alternative ROE at that time.[5]

In the current *Petition*, Xcel Energy proposed to use 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 15-826 Docket, with a proposed update only to the Company's ROE. Specifically, rather than the 9.20 percent ROE authorized (for representational purposes) by the Commission in the 15-826 Docket, the Company proposed an ROE of 10.00 percent. The Company used Concentric Energy Advisors (Concentric), to perform a cost of equity analysis and determine the appropriate ROE. The results ranged from a low of 8.19 percent for the Discounted Cash Flow (DCF) method to a high of 10.78 percent for the Capital Asset Pricing Model (CAPM).

The Department and the OAG responded to the Company's proposal and provided their own recommendations as discussed below.

Regarding the cost of equity, all three parties recommended that the Commission follow the standards established in (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U. S. 695 (1923) ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"). These decisions explain that utility regulators must set rates that permit the utility the opportunity: (1) to attract capital at reasonable terms; (2) to maintain its credit rating and ensure its financial integrity; and (3) to provide a return commensurate with returns on investments having comparable risks. These rates get developed, in significant part, by setting an appropriate overall cost of capital for the utility, equal to the cost of each capital component (both debt and equity) multiplied by the percentage that the component comprises the overall capital of the utility.

2. Department Comments

The Department disagreed with Xcel Energy's proposed ROE, and instead proposed the Commission authorize an ROE of 8.99 percent.[6]

Electric Service in the State of Minnesota, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 10, OP 2 at 68 (June 12, 2017).

[5] *Id.* at 22.

[6] Department *Comments* at 13. The Department revised its recommendation to 8.59 percent in its *Response Comments*.

a. Methods to Determine Cost of Common Equity

The Department stated that there are a number of analytical methods that can be used to calculate a reasonable cost of equity. The methods used by the parties are:

i. Discounted Cash Flow Model

The DCF model, is a market-oriented method that requires the determination of the appropriate dividend yield and the appropriate growth rate to be used in this analysis. If annual dividends grow at a constant rate over an infinite period, the required rate of return on common equity capital can be estimated with the following formula:

The expected (required) rate of return on equity =
the expected dividend yield + the expected growth
rate in dividends.

A variation of the DCF model is the Two Growth Rate DCF (TGDCF). This model is sometimes used when an analyst thinks the short-term earnings growth rate may be either unusually low or unusually high and is not expected to be sustained. To the degree that such growth rates may not be sustainable in the long-run, the TGDCF method accommodates two different growth rates: short-term and sustainable, long-term growth rates.

ii. Capital Asset Pricing Model

The CAPM defines risk as the relationship of a security's returns with the market's returns. The basic premise of CAPM is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta ("β"). The CAPM is expressed as follows:

$$K = r_f + \beta\ (r_m - r_f)$$

Where:

K = the required rate of return on the stock in question;
β = Beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market portfolio.

The Department states that, while the CAPM is theoretically sound, its use as a method to estimate a company's cost of equity raises some difficult analytical issues. These include determining 1) the appropriate beta, 2) the appropriate riskless asset, and 3) a reasonable estimate of the required return on the market portfolio. Because of these issues, the Department does not use the results of its CAPM analysis directly to determine the required return on equity. Rather, the CAPM analysis is used only to assess and check the reasonableness of the results of its DCF analyses.

iii. Risk Premium Analysis

The Risk Premium Analysis (RPA) is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt. The cost of equity is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last-in-line in any claim on the corporation's assets and earnings. This model often assumes a relatively stable relationship (delta) over time between the cost of long-term debt and equity.

b. Flotation Costs

Flotation costs are the costs of issuing new shares of common stock. Due to issuance costs, the price paid by an investor for a new share is higher than the price received by the company issuing the new share. As a result, in order to meet investor's required rate of return, the company must earn a higher percentage return on its stock issuance proceeds than investors require on their investments. For example, if a company issues $1 million worth of new common stock, and incurs flotation costs of four percent, the company will receive only $960,000 from the issuance. If the company's equity investors' require a 10 percent annual return on their initial investment of $1 million, the company must generate $100,000 per year on the proceeds from its stock issuance in order to compensate the new stockholders. In order to generate a return of $100,000 per year on net proceeds of $960,000, the company must earn an annual return of 10.42 percent ($100,000 / $960,000 = 0.1042). If the company earns only a 10.00 percent rate of return, it will generate only $96,000 per year, and thus investors would not receive their required return.

Flotation costs are permanent, meaning that an adjustment is required for flotation costs incurred for all past issuances; otherwise investors will not receive their required return. Flotation costs have long been explicitly included in the company's cost of debt issued in the past, and the same principle applies to the company's common equity.[6]

The DCF model (as well as the CAPM) measures the required return on the value of shareholders' equity holdings (i.e. the 10 percent in the example above), not the required return on a company's net proceeds from stock issuances. Thus, if the DCF ROE estimate is applied directly without an adjustment for flotation costs, Xcel Energy would not earn returns high enough to satisfy the expectations under which its investors purchased stock. A flotation cost adjustment corrects this problem.

The dividend yields of the companies in the Department Proxy Groups must be adjusted by dividing them by 1-F, where F is the percentage of flotation costs. The Department used the same estimate of F as it used in the 2016 Rate Case, 2.85 percent.[7] Adjusting for flotation costs increased the DCF cost of equity estimates by 8-10 basis points.

c. Department Recommended Return on Equity

The Department used a weighted average of its mean two-growth DCF results for its Proxy Groups. The Department argues that the DCF model is a fair, market-oriented method that uses current, relevant information to allow NSPM to compete sufficiently and fairly in the capital markets and thus the DCF results should be used to determine the reasonable rate of return on common equity capital for NSPM. The Department noted that the Commission has a long history of relying principally on the DCF method to determine a reasonable return on equity for public utilities. The DCF method allows one to calculate investors' likely expectations of the cost of equity capital for NSPM based on the rates of return of comparable companies. Because the purpose of this proceeding is to estimate the required rate of return for NSPM's electric operations, the Department assigned more weight to the electric proxy group's (EPG's) DCF result than the combination proxy group's (CPG's). However, because the companies in the CPG are primarily engaged in the provision of retail electric services, the CPG's DCF result has significant analytical value.

Consistent with past practice, the Department assigned weights of 60 percent and 40 percent to the mean average TGDCF results for the EPG and CPG, respectively.

Table 2: Calculation of Recommended ROE

Model	Mean Average Two-Growth DCF ROE Estimate	Weights	Weighted ROE
EPG	8.80%	60.00%	5.28%
CPG	9.28%	40.00%	3.71%
Recommended ROE			8.99%

These weights produce a final ROE estimate for Xcel Energy of 8.99 percent, including flotation costs. The Department recommends that the Commission approve an ROE of 8.99 percent for use in the Company's TCR rider, as well as any other riders filed before the Company concludes its next electric rate case.

3. OAG Comments

The OAG argues that Xcel Energy's proposed ROE is not commensurate with the risks of investments recovered through riders like the TCR. The OAG recommends that the Commission establish a return for the Company's TCR rider based on Xcel Energy's cost of long-term debt of 4.30 percent. The OAG also considered an ROE of 2.30 percent, which is the average yield on two-year Treasury bonds. The OAG did not present the results of traditional DCF, CAPM, or Risk Premium models to estimate the cost of equity for Xcel Energy's TCR rider.

a. Risk profiles of Riders compared to General Rate Cases

The OAG argues 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 argues 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 provided the following example, if a utility makes an investment outside of a test year (or if Xcel Energy makes an investment that is not included in its current MYRP), it will not be able to recover any of the related costs until its next rate case is complete. There is the risk of significant negative cash flows related to the timing of up-front investments, and additional risk because it is never certain whether a regulator will allow the costs to be recovered. In the case of an investment that is eligible for rider recovery, then the initial recovery of that investment will be nearly immediate and far more certain than if the utility (investor in the project) had to wait until a future rate case for cost recovery.

The OAG continues by stating that the difference becomes even more significant for rider investments that have already been certified by the regulator before the investments are made. For many riders, investments that are recovered through the rider have already been certified or reviewed in some format by the regulator. This significantly reduces the risk of future disallowance. These certifications significantly reduce business risk compared to investments recovered through base rates, which are normally not pre-approved or reviewed by regulators until they are presented in a rate case proceeding.

Rider investments have a fundamentally different risk profile than investments recovered in base rates. Rider investments have lower business risk (because of reduced regulatory risk) and lower cash flow risk (because of both the nearly immediate recovery of cost and the certainty that there will be full recovery of the revenue requirement, including the cost of capital). These characteristics are very different from the risks for rate base investment, and that means that a different ratemaking analysis and approach is warranted to determine what return would be "commensurate with returns on investments in other enterprises having corresponding risks."

b. Calculation of Appropriate Return

Rather than selecting a single type of debt security to provide a comparison to TCR investments, the OAG argues that the most reasonable analysis is to compare a range of debt securities. The OAG argues that one of the primary factors impacting the return on debt securities is the length of maturity. "To determine which debt securities have risks that are comparable to rider investments, it is necessary to consider the intended "length" of rider investments. In other words, how long should investments remain in a rider before they are rolled into base rates?"[7]

The OAG notes there are several theories on how to answer this question and comparing those theories to different types of debt securities can help the Commission create a range of debt security returns to compare to the TCR rider. The OAG suggest the following process:[8]

> **Creating A Floor**
>
> One theory about the "length" of rider investments is that they should be rolled into base rates at the first opportunity. This treatment would be consistent with traditional ratemaking policy. Xcel has been filing rate cases relatively frequently, and taking advantage of multi-year rate plans, indicating that the time between rate cases is relatively small. Applying this theory to Xcel would suggest that its rider investments should be rolled into base rates very quickly, perhaps in as little as one or two years after the investments are made. This would indicate that debt securities with maturities of one or two years would provide a reasonable comparison. In other words, a debt security with a maturity of one or two years would be relevant when considering the TCR rider, when assuming that TCR investments should be rolled into base rates after only a year or two. The return on a two-year Treasury currently is approximately 2.3 percent. This provides a reasonable floor for the range of debt security returns.
>
> In addition to the 2.3 percent two-year Treasury, it is also valuable to keep in mind the utility's cost of short-term debt, and the cost of its available lines of credit. These sources of financing may also be reasonable comparisons to rider investments because the utility can achieve full recovery of its costs of investment in a relatively similar length as the repayment terms of these financing sources.
>
> **Creating A Ceiling**
>
> In order to provide a complete range of comparable debt security returns, it is also necessary to establish a ceiling. As explained previously, a floor was established in based upon a theory that riders should be rolled into base rates as quickly as possible [sic]. In contrast, the ceiling should be established via consideration of the longest reasonable amount of time during which it would make sense to recover an investment through a rider. In general, it is not appropriate to recover long-term investments through riders over their entire lifespan. Investments should be rolled into base rates at some point. Consistent with that reasoning, the ceiling for a rider return should not exceed the cost of the utility's longest-lived form of debt financing—its long-term debt [approximately 4.3 percent].

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[7] OAG *Comments* at 15.

[8] *Id*. at 16-17 (Citations Omitted).

c. Other Jurisdictions

The OAG points out that in 2011 the state of Iowa concluded a rulemaking that determined that the "cost of debt" was the most appropriate rate of return for gas utilities' infrastructure-related capital investment riders.[9] Specifically, the OAG stated:

> The 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 rulemaking involved a debate between the utility, the regulator, and consumer advocates over the appropriate rate of return to set for capital investment riders. On one end, utilities advocated for a rate of return set at the weighted average cost of capital from the utility's most recent rate case. On the other end, the Iowa Office of Consumer Advocate ("OCA") recommended that no return be allowed for rider recovery at all. The OCA argued that allowing utilities a return on rider-related capital spending would weaken a utility's incentive to contain costs and would unduly benefit utility shareholders.
>
> The Iowa Utilities Board ultimately chose a middle ground in 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. <u>This reduced risk of under recovery should be reflected through a lower return on the investment recovered through the automatic adjustment mechanism.</u> 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.
>
> Applying this reasoning to Xcel's TCR rider would support setting the return at the long-term cost of debt.[10]

d. OAG Recommend Return on Equity

The OAG argued that the Commission has the authority to set a return for the TCR rider that is consistent with the public interest, and it must set a return that will produce just and reasonable rates. In doing so, the Commission must ensure that the return is "commensurate with returns on investments in other enterprises having corresponding risks." If there is any

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[9] *Id*. at 21.

[10] *Id*. at 21-22.

doubt about whether the TCR return is comparable to other investments of similar risk, the Commission must resolve that doubt in favor of ratepayers.

To satisfy these requirements, the OAG recommended that the Commission set the return for Xcel Energy's TCR rider at the Company's cost of long-term debt, which is approximately 4.3 percent. The OAG argued that the risks of Xcel Energy's rider investments are not comparable to the risks of its base rate investments, or the general risk of other utility companies that would make up a traditional proxy group. For these reasons, the risk profile of TCR investments is best compared to the risks of debt securities, and specifically, a reasonable range of debt securities to consider would span from a floor at the cost of two year Treasuries, to a ceiling based on Xcel Energy's cost of long-term debt. Because of the particular circumstances of this proceeding, the OAG stated, it would be reasonable to set the return at the ceiling of that range, based on the Company's cost of long-term debt of 4.3 percent. In reaching this decision, the Commission can follow a path that has already been made by other regulatory Commissions, including the Iowa Utilities Board.

4. Xcel Energy Reply Comments

In its *Reply Comments*, Xcel Energy argued the Company's proposed 10 percent ROE is consistent with ROEs recently authorized for integrated electric utilities in other jurisdictions. Xcel Energy points out that data from SNL Financial shows the average authorized ROE for integrated electric utilities from January 2017 through March 2018 was 9.78 percent and that the Department's recommendation "is lower than the bottom of the range of authorized ROEs in all 50 rate case decisions involving integrated electric utilities in other jurisdictions."[11]

Additionally, Xcel Energy continued its argument that the DCF model understates the return on equity under current market conditions because the dividend yield component of the DCF is being suppressed by the low interest rate environment, which has been characterized by the Federal Energy Regulatory Commission (FERC) as "anomalous". Xcel Energy pointed to recent FERC decisions bolstering its argument that the Commission should not solely rely on the DCF model in determining an appropriate ROE, as the Department does, but rather "consider the results of alternative risk-premium based models, such as the Risk Premium analysis and the CAPM, in order to determine where, within the range of reasonable DCF results, to set the authorized ROE for transmission companies."[12] Xcel Energy also cites decisions from the Pennsylvania Public Utility Commission (PPUC) and the Missouri Public Service Commission citing similar guidance as the FERC.

As for the OAG recommendation of an authorized ROE of 4.30 percent based on Xcel Energy's weighted-average long-term debt, Xcel Energy argued that such a return is not just and reasonable and does not meet the threshold established in the *Hope* and *Bluefield* decisions for a fair return.

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[11] Xcel Energy *Reply Comments* at Attachment B page 5 of 19.

[12] *Id*. at Attachment B page 7 of 19.

Additionally, Xcel Energy argued that the OAG's recommendation does not take into consideration the risks associated with equity ownership, including the risk that dividends are not guaranteed to shareholders. Furthermore, Xcel Energy argued the OAG's recommendation is not consistent with the way in which Xcel Energy finances the transmission projects included in the TCR rider. Specifically, the Company finances TCR investments using a mix of equity and debt and therefore it is not reasonable to set Xcel Energy's authorized ROE for the TCR rider based on long-term debt costs because the Company is using both equity and debt to finance these large transmission projects. The TCR rider's purpose is to allow Xcel Energy to recover the costs (including financing costs) associated with these types of projects before they are placed into service and added to rate base in a future rate case.

As for the decision of the Iowa Utilities Board (IUB) in Docket No. RMU-11-0002, which the OAG claimed supported its use of a long-term debt cost as the equity return for a rider, Xcel Energy noted that the Iowa decision was issued in a 2011 rule making docket for gas distribution utilities, in which the question arose as to the appropriate return for an infrastructure replacement cost rider for gas utilities.

Xcel Energy argued that Minnesota statutes related to the TCR rider provide the necessary precedent for the Commission; and it is not necessary to look to rules for Iowa gas distribution utilities as precedent. As discussed in the *Petition*, the Commission's determination of the appropriate rate of return for the TCR rider looks to the ROE allowed in the Company's last general rate case, unless the Commission determines that a different rate of return is in the public interest.[13] In this instance, the Order establishing the authorized rate of return for Xcel Energy's last general electric rate case was issued on June 12, 2017, when the Company's ROE was set at 9.20 percent as part of a negotiated settlement. In its decision approving the settlement, the Commission stated that "the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings" and that "parties will be free to assert an alternative ROE at that time."[14] On that basis, Xcel Energy presented an updated cost of equity analysis in support of its recommendation. The OAG's recommended ROE based on long-term debt costs for Xcel Energy is not just and reasonable, and should be disregarded by the Commission.

5. Department Response Comments

The Department provided an updated recommendation based on recent market data and responded to Xcel Energy's reply comments. The Department recommended that the Commission approve an authorized ROE of 8.59 percent. Additionally, the Department continued its recommendation that the ROE established in the instant proceeding be used in all proceedings that require an ROE for the Company's electric operations until Xcel Energy concludes its next rate case, at which time a new authorized ROE would be established.

[13] Minn. Stat. § 216B.16, subd. 7b (b)(6).

[14] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 22 (June 12, 2017).

a. Updated DCF Analysis

As described in *Comments*, the Department developed two proxy groups, one comprised of companies assigned a Standard Industrial Classification (SIC) code of 4911: Electric Services (the Electric Proxy Group, or EPG), and one comprised of companies with a SIC code of 4931: Electric and Other Services Combined SIC (the Combination Proxy Group, or CPG).

The Department updated its proxy group screening analysis and performed constant growth and two-growth DCF analyses on the two updated proxy groups using recent stock prices, dividends, and long-term earnings growth rate forecasts. Table 3 below summarizes the Department's updated constant and two-growth DCF analyses' results for the EPG and CPG.

Table 3: Updated Constant Growth and Two-Growth DCF Analysis Results Includes Flotation Adjustment

Model	Mean Low ROE	Mean ROE	Mean High ROE
Constant Growth DCF Results			
EPG	7.61%	8.21%	8.88%
CPG	8.63%	9.22%	9.82%
Two-Growth DCF Results			
EPG	7.47%	8.09%	8.80%
CPG	8.75%	9.34%	9.94%

b. Updated CAPM Analysis

The Department also updated its CAPM analysis using more recent data to estimate the risk-free rate, the required market return, and beta.

The Department's CAPM estimate of the cost of equity for the EPG, including a 10 basis point adjustment for flotation costs, is 9.71 percent. The Department's CAPM estimate of the cost of equity for the CPG, including a flotation cost adjustment, is 9.59 percent.

Therefore, the Department concluded that its CAPM results when compared with the DCF results for the EPG and CPG proxy groups confirm the reasonableness of its DCF results.

c. Updated Recommended ROE

Consistent with past practice, the Department assigned weights of 60 percent and 40 percent to the mean average two-growth DCF results for the EPG and CPG, respectively, to derive a final ROE recommendation.

Table 4: Department's Updated Recommended ROE

Model	Mean Average Two-Growth DCF ROE Estimate	Weights	Weighted ROE
EPG	8.09%	60.00%	4.85%
CPG	9.34%	40.00%	3.74%
Recommended ROE			8.59%

d. Response to Xcel Energy's Reply Comments

i. Authorized Returns on Equity for other Integrated Electric Utilities

In its *Reply Comments*, the Company noted that the Department's recommended ROE from its Comments was lower than all authorized ROEs authorized in state jurisdictions from January 2017 through March 2018. The Department argued that the Company asserted, without support, that those decisions are relevant. As discussed below, the majority of the authorized ROEs from January 2017 through March 2018 are not relevant to the Commission's determination of a reasonable authorized ROE.

The Department stated that Figure 1 on page 5 of Attachment B of the Company's *Reply Comments* summarizes the ROEs authorized in 34 rate cases for vertically integrated electric utilities from January 2017 to March 2018. Of those 34 rate cases, 23 were resolved via settlements, and 11 were fully-litigated and determined by a state commission. The Department argued that ROEs determined by negotiated settlement agreements may not reflect unbiased assessments of the utilities' cost of equity and therefore cannot reasonably be used as reference points in determining a reasonable ROE for Xcel Energy.

In addition, even for the 11 fully-litigated ROEs, the Department stated that the Company provided no discussion of the factors considered by the state Commissions in determining the ROEs, whether the factors considered align with factors generally considered by the Minnesota Public Utilities Commission, or whether there are any utility-specific factors that do or do not apply to Xcel Energy. For example, one of those 11 is the ROE authorized by the Minnesota Public Utilities Commission for Otter Tail Power Company (Otter Tail) in its most recent rate case. In that case, the Commission considered several factors, including Otter Tail's small size, its history of completing large projects under budget, and its customer satisfaction rankings, that are not relevant to the Xcel Energy. Another of those 11 ROEs is an ROE authorized by Nevada's Public Utilities Commission that includes an ROE incentive for "critical facilities", which is also not relevant to Xcel Energy.

The Department concluded by arguing that, to the extent any of the authorized ROEs are relevant, they reflect other Commission's assessments' of capital market conditions at that time. The Commission has current market data and financial model results based on that data available to it in the record in this Docket and can consider and assess that information directly, rather than indirectly through the assessments of other regulators.

ii. Determinations of other Commissions

Xcel Energy in its *Reply Comments*, reiterated its concern from its *Petition* that current capital market conditions, particularly historically low interest rates, are artificially inflating utility stock prices and causing the DCF model to understate utilities' costs of equity. The Company noted that the FERC and two other state utilities commissions have reached similar conclusions.

In response, the Department reiterated the response it provided in its *Comments*. First, given that the low interest rates that the Company asserts are depressing utility stock prices and DCF ROE estimates have persisted for several years, it is no longer reasonable to describe them as "anomalous." Second, reasonable investors would not hold an investment if they believed that it is likely to perform poorly. Thus, if investors expected interest rates to rise and utility stock prices to fall as a result, they would sell their stock holdings and bid the price of the stock down until it reaches a point at which the expected return meets investors' required return.

Therefore, Investors' expectations of interest rates are fully embedded in current stock prices, and no additional adjustments, either direct or indirect, intended to reflect investor expectations are necessary.

6. Xcel Energy Reply to Department Response Comments

Xcel Energy continued to recommend an authorized ROE of 10 percent and submitted its own revised analysis in response to the Department's *Response Comments*, shown in Table 5 below.

Table 5: Summary of Xcel Energy ROE Results

	9/30/2017	1/31/19
DCF Model – 90-day average stock price		
Constant Growth	8.19%	8.74%
Risk Premium		
30 Yr. U.S. Treasury	10.41%	10.22%
Moody's A-rated Utility Index	10.36%	10.16%
CAPM		
Value Line Beta	10.78%	10.62%
Bloomberg Beta	9.52%	9.35%
Expected Earnings	Not filed	10.79%
Mean of All Methods (not including Expected Earnings)	9.85%	9.82%
Mean of All Methods (including Expected Earnings)	N/A	9.98%

Additionally, Xcel Energy continued to argue that comparison of authorized ROE's from other jurisdictions is appropriate because Xcel Energy competes for capital both within the Company and in the overall investment market. If the Company is placed at the low end of the authorized ROE's, both within Xcel Energy and the market as a whole, investments in Minnesota become a less attractive option. For this reason, Xcel Energy argued that ROE's in other jurisdictions are certainly relevant to this proceeding, as they provide a useful comparison that can assist the Commission it its decision-making process.

Finally, Xcel Energy continued to oppose the Department's recommendation for the Commission to require the ROE established in the instant proceeding be used in all proceedings that require an ROE for the Company's electric operations until Xcel Energy concludes its next rate case, at which time a new authorized ROE would be established.

7. Staff Analysis

In determining the appropriate ROE for a rider docket the Commission has a different statutory directive and starting point than in a general rate case. Staff thinks it is important to start from the directive in the statute applicable to this proceeding which states:

> allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest; [15]

The current ROE was established by Commission Order on June 12, 2017, in the 15-826 Docket. In its *Order* dated June 12, 2017, the Commission approved the Stipulation of Settlement allowing "…Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%)

[15] Minn. Stat. § 216B.16, subd. 7b (b)(6).

for settlement purposes…"[16] In its *Order* approving the *Settlement*, the Commission made clear that the ROE that Xcel Energy was authorized to represent was not binding on future proceedings that involve ROE, stating:

> Because the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings, if future circumstances suggest that a lower ROE is appropriate in other contexts, parties will be free to assert an alternative ROE at that time.[17]

Historically, approval of a revised ROE has been confined to Xcel Energy's Gas Utility Infrastructure Cost (GUIC) riders.[18] Primarily, this was due to the length of time that had transpired since the Company's most recent natural gas general rate case (09-1153). The instant *Petition* is the first time that staff is aware that Xcel Energy requested an updated rate of return for an electric rider.[19] The table below lists the Commission approved ROE's in the Company's last natural gas rate case and subsequent GUIC riders.

Table 6: Historical ROE's in Xcel Energy GUIC Riders

Docket No.	Authorized ROE (%)
09-1153 (rate case)	10.09
14-336 (GUIC rider)	10.09[20]
15-808 (GUIC rider)	9.64
16-891 (GUIC rider)	9.04
17-787 (GUIC rider)	TBD

In the instant docket, both Xcel Energy and the Department provided full ROE analyses discussing areas of capital market conditions, proxy group selection, and cost of equity models. In its analysis, the OAG distinguished between the risk profile discussed in a general rate case and the risk profile of the current docket and argued that a typical rate case ROE analysis should not apply and therefore recommended an ROE factor for the instant *Petition* based on Xcel Energy's long-term cost of debt.

Regarding the cost of equity, all three parties recommended that the Commission follow the standards established in (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U. S. 695 (1923) ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"). These decisions explain that utility regulators must set rates

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[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 10, OP 2 at 68 (June 12, 2017).

[17] *Id.* at 22.

[18] Staff notes that updating the ROE is an issue in the current GUIC proceeding (Docket No. G-002/M-17-787) as well.

[19] Xcel Energy also requested a higher ROE in the Renewable Energy Standards rider filed on November 17, 2017 (Docket No. E-002/M-17-818.

[20] Staff notes that the Commission revised the approved capital structure in this docket.

that permit the utility the opportunity: (1) to attract capital at reasonable terms; (2) to maintain its credit rating and ensure its financial integrity; and (3) to provide a return commensurate with returns on investments having comparable risks.

As discussed above, 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."[21] However, the settlement also approved a revenue deficiency recommended by the Department which is understood by staff to have been calculated using the Department recommended ROE of 9.06 percent. [22] 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*.

Staff also notes, that in its most recent Xcel Energy rider ROE decision, at its meeting on April 25, 2019, involving Xcel Energy's proposed revisions to its Lighting Tariff and LED options, the Commission required the Company to use a 9.06 percent ROE rather than the 9.20 percent in the calculation of the rates in this rider.[23]

The table below lists the various recommended ROE's in the current docket.

Table 7: Recommended ROE's in this TCR docket

	ROE Recommendation (%)
Xcel Energy	10.00
Department - Initial	8.99
Department - Revised	8.59
OAG	4.30[24]

The Commission may also want to consider its ROE decisions in recent electric rate cases in its evaluation of Xcel Energy's request in this proceeding. The table below shows the Commission authorized ROE from the three most recent electric rate cases.

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

[22] *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.

[23] In the Matter of Xcel Energy's Petition for Approval of Lighting Tariff Revisions to Include Light Emitting Diode (LED) Options, Docket No. E-002/M-18-729, order pending.

[24] It is staff's understanding that the OAG's recommendation is to establish the rate of return at the Company's long term cost of debt. If so, the actual ROE would need to be calculated based on the Commission's order in this docket. Therefore, staff includes the 4.30 percent as an illustrative figure.

Table 8: Authorized ROE in recent Electric Rate Cases

	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%

The only ROE decision the Commission has to make at this meeting is the decision about Xcel Energy's ROE for the TCR rider. Both the Company and Department agreed to use the ROE established for the TCR rider as the ROE to be used for the RES rider which is also scheduled for the May 23rd agenda meeting. Xcel Energy's GUIC rider involves its gas utility and will be determined separately.

In addition, the Commission may wish to consider how it will handle future rider ROE requests as they are becoming more common and consume a considerable amount of time. One option is the establishment of a minimum time period that must pass from the conclusion of a general rate case before the utility is able to request a different ROE in a rider proceeding. Staff notes that Xcel Energy requested an updated ROE in the instant *Petition* less than five months after issuance of the final Order in the 15-826 Docket.[25] Staff believes that there must be a clear and convincing rationale for the Commission to deviate from the authorized ROE established in the most recent rate case especially in this proceeding where less than five months had elapsed.

Staff concludes that a minimum period of three years from the final order in its most recent rate case is an appropriate amount of time. This would strike the appropriate balance between the utility being able to meet its financial needs and the efficient use of regulatory resources.

In the alternative, the Commission could request Xcel Energy discuss the establishment of a minimum time period in its upcoming rate case. This will allow for a full discussion of the merits of the proposal and development of a complete record.

The Commission may wish to query the parties regarding staff's proposal at its May 23, 2019, agenda meeting.

[25] Xcel Energy also requested a higher ROE in the Renewable Energy Standards rider filed on November 17, 2017 (Docket No. E-002/M-17-818).

8. Decision Alternatives

1. Approve Xcel Energy's proposed return on equity of 10.00 percent. [Xcel Energy]

2. Approve the Department's proposed return on equity of 8.99 percent [Department initial position]

3. Approve the Department's proposed return on equity of 8.59 percent. [Department revised position]

4. Approve the OAG's proposed return of 4.30 percent. [OAG]

5. Determine that no party has convinced the Commission to alter the currently authorized rate of return established in Xcel Energy's most recent electric rate case (Docket No. E-002/GR-15-826).

    a. 9.20 percent (as represented to the investment community)
    b. 9.06 percent (used to calculate revenue requirement and set rates)

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

6. Adopt the Department's recommendation requiring Xcel Energy to use of the ROE determined in the present docket in all electric dockets filed by the Company that require an ROE until the Commission issues an order in the Company's next rate case authorizing a different ROE. [Department]

    and/or

7. Establish a policy requiring a minimum period of three years from the date of the final Order in Xcel Energy's most recent electric rate case before the Company may request a revision to the rate of return in a future TCR rider. [Staff]

    and/or

8. Require Xcel Energy to address the issue of establishing a policy requiring a minimum period of time to pass from the final order of its most recent rate case before the Company is allowed to request revision to its established rate of return in any subsequent rider petition. [Staff]

B. Prorated Accumulated Deferred Income Taxes

1. 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 its early years, 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, and 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.[26]

ADIT proration has proven to be controversial in the context of riders. Most riders, including Xcel Energy's TCR 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.[27]

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. In the instant petition, Xcel Energy and the Department disagree whether ADIT proration is necessary for the TCR true-up.

2. Xcel Energy

In its *Petition*, the Company provided actual ADIT for the January – June 2017 time period and forecasted ADIT balances for July 2017 through December 2018. Xcel Energy noted that it had been working with the Department to resolve the ongoing ADIT proration issue and that it would continue to work with the Department and other stakeholders towards a reasonable resolution and will update the calculations, as needed.

3. Department Comments

The Department stated that its position is unchanged from Xcel Energy's previous TCR docket (E-002/M-15-891) where the Department stated:

> Based on our review of IRS Section 1.167(l)(h)(6), the Department concludes that the ADIT issue is simply a timing issue. Once actual non-

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

[27] 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).

> prorated ADIT balances are known in the following year, they should replace the forecasted prorated ADIT balances in the beginning-of-year and end-of-year average ADIT balance calculations for true-up purposes.
> …
> Based on the above, the Department recommends that the Commission require Xcel to replace its forecasted prorated ADIT balances with actual non-prorated ADIT balances in its beginning-of-month and end-of-month average calculations for true-up purposes in future [Transmission Cost Recovery] TCR Rider filings. Alternatively, the Commission could require Xcel's riders to be based solely on historical costs, as Xcel acknowledges that the issue applies only in cases with forward-looking rates.

The Department recommended that the Commission either: (1) allow the Company to include prorated ADIT balances in its forecasted test-year revenue requirement calculations, but require it to replace its forecasted prorated ADIT balances with actual non-prorated ADIT balances in its beginning-of-month and end-of-month average calculations for true-up purposes in future TCR dockets, or (2) require the Company to implement the adjustment factors, based on actual non-prorated ADIT balances, approved in this Docket on or after January 1, 2019. Doing so would render the rate adjustment factors historical, eliminating the need to prorate ADIT balances.

4. Xcel Energy Reply and Supplemental Reply Comments

In three sets of *Reply Comments*, Xcel Energy addressed the issue of pro-rated ADIT and ultimately proposed a new methodology in which it treats each month in the test period as an individual test period. The new methodology was discussed in the Company's *Supplemental Reply Comments*, based on advice the Company received from Deloitte Tax Services (Deloitte). Deloitte provided the following recommendations:[28]

> 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.

In Table 9 below, Xcel Energy summarized the reduction of the revenue requirements for ADIT proration.[29]

Table 9: Reduction in Prorated ADIT

Amounts in dollars ($)	**2018**	**2019**
ADIT Proration As-filed	$627,974	$241,014
ADIT Proration Refined (Deloitte method)	$198	$227
Difference	($627,776)	($240,787)

[28] Xcel Energy Supplemental *Reply Comments* at 2.

[29] *Id*.

Xcel Energy noted that it made a similar proposal in its Gas Utility Infrastructure Cost (GUIC), Renewable Energy Standard (RES), and State Energy Policy (SEP) rider petitions. The Company argued that the benefits of the Deloitte approach is that it allows Xcel Energy to maintain a forecast period, minimizes impacts to customers, and is compliant with IRS normalization rules. Using this methodology, the overall revenue requirement impact of ADIT proration would be approximately $150 per year.

5. Department Response Comments

The Department recommended that the Commission reject Xcel Energy's proposed methodology as needlessly complex, difficult to monitor, and unnecessary to preserve the significant deferred tax benefits associated with using accelerated depreciation for tax purposes. The Department recommended that the Commission require the Company to calculate rates that do not reflect any ADIT proration and implement rates one day after the test period being analyzed. Thus, rates implemented after January 1, 2019, do not need to include (and therefore should not include) any proration of forecasted ADIT balances.

6. Xcel Energy Reply to Department Response Comments

Xcel Energy noted that the test period for the instant petition has ended and agrees with the Department 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.

Additionally, Xcel Energy stated because the test period has elapsed it does not believe that any decision regarding ADIT proration is necessary in this proceeding.

7. Staff Analysis

The first in-depth ADIT discussion in a rider first occurred 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.

Since that time, the ADIT proration issue has been a disputed issue in many other dockets with differing results. Table 10 below provides a list of dockets with Commission decisions.

Table 10: ADIT Proceedings

Company	***Docket No.***	***Proceeding***	***Outcome***
Xcel Energy	G-002/M-18-692	Gas Utility Infrastructure Charge (GUIC)	Ongoing
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
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 (Current Docket)
Xcel Energy	G-002/M-17-787	Gas Utility Infrastructure Charge (GUIC)	Ongoing
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,[30] 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."***[31] (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

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

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

> 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."[32] (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.

8. Decision Alternatives

9. Allow Xcel Energy to implement its TCR rider factor effective January 1, 2018, and authorize the Company to recover its ADIT proration as proposed in the Initial *Petition*.

10. Allow Xcel Energy to implement its TCR rider factor effective January 1, 2018, and authorize the Company to recover its ADIT proration, calculated by Deloitte Tax Service, as proposed in Xcel Energy's May 25, 2018, *Supplemental Reply Comments*.

11. Require Xcel Energy to implement its TCR rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department, Xcel Energy-this docket only)

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

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

C. ADMS Cost Recovery Authorization and Approval

1. Background

As part of the instant petition, Xcel Energy requested recovery of its ADMS Project costs.

Previously, on June 28, 2016, the Commission had certified, under certain conditions and assumptions, that Xcel Energy's ADMS Project was consistent with new statutory language - that the project was a necessary investment to modernize Xcel Energy's distribution grid. Table 11 below, gives a timeline related to the ADMS project.

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[32] *Id*.

Table 11: ADMS Timeline

Date	Action	Document Link
July 1, 2015		2015 Session Law
October 30, 2015	Xcel Energy files for certification of ADMS and Belle Plaine Battery Project	201511-115454-01
May 18, 2016	Staff Briefing Paper on ADMS Approval	20165-121484-01
June 28, 2016	Commission Order Approving ADMS Project	20166-122702-01
November 8, 2017	Xcel Energy's Petition for ADMS Project TCR Rider Recovery	201711-137240-01

The ADMS Project was the first distribution and grid modernization project to: 1) request and receive grid modernization/distribution certification and 2) seek cost recovery under the TCR rider.[33]

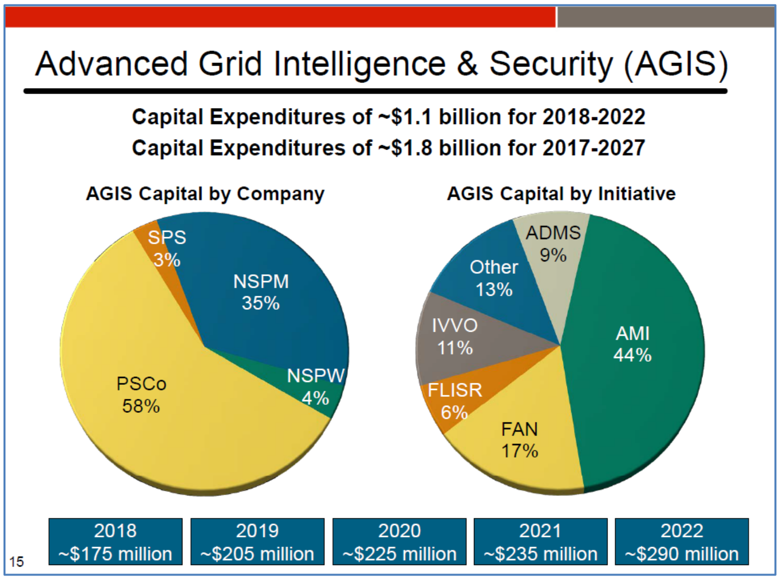
Background information on ADMS project generally, how it was characterized in the October 30, 2015 request for certification (2015 ADMS Certification Petition), details of the Commission's 2016 approval (2016 ADMS Certification Order), and the context under which the ADMS Project was certified are discussed in more detail below.

2. Framing of Issue for Commission Consideration

This ADMS Project is the first distribution grid modernization project to be certified by the Commission and the first to request rider recovery, therefore, this petition is renewing a question raised at the time of certification - how and where the Commission intends to, generally, review distribution and grid modernization project costs, benefit, and interdependencies with other projects. This section outlines issues the Commission should consider as it reviews this request.

[33] The Commission certified Xcel Energy's Time-Of-Use Pilot as a grid modernization project in docket M-17-775 on August 7, 2018 however the TOU pilot program has not been submitted for recovery. (Doc. ID: 20188-145582-01).

Figure 1: Xcel's AGIS Capital Expenditures

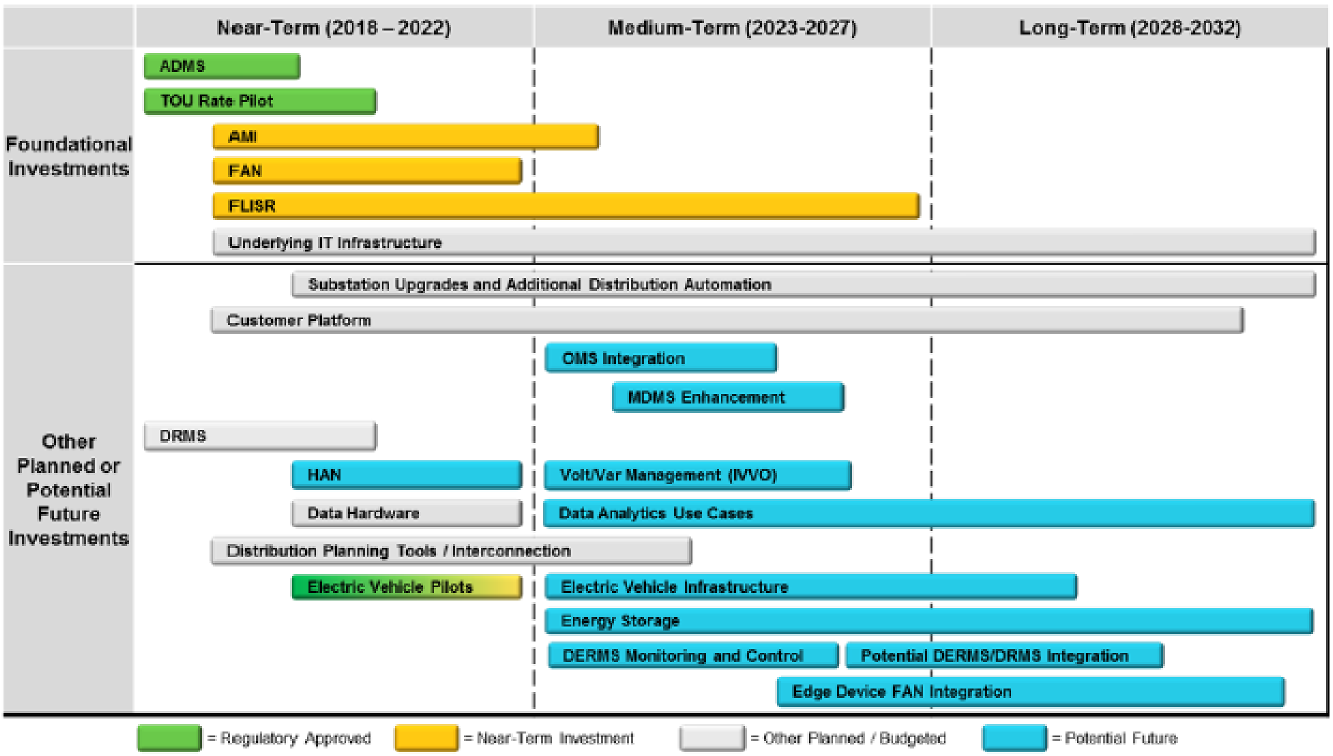


It is known that Xcel Energy will have additional, and significant, distribution and grid modernization-related investments (beyond the ADMS Project) coming in the near term (through 2027).[34] Xcel Energy's Advanced Grid Intelligence and Security initiative (AGIS) is described in detail throughout Xcel Energy's 2018 Integrated Distribution Plan (IDP) filing.[35] Xcel Energy's IDP explains that the AGIS initiative will encompass multiple components, but as a subset of its AGIS, Xcel Energy's Field Area Network (FAN), Fault Location Isolation Service Restoration (FLISR), and Advanced Metering Infrastructure (AMI) capital and O&M costs are anticipated to be between $632 and $822 million (not including ADMS).[36] Xcel Energy's Cost Benefit section of that filing are included to this paper as Attachment B.

The investments and technologies that Xcel Energy is pursuing (through its AGIS and other initiatives) are significant, non-traditional (but becoming less so industry-wide[37]) and are in part why the Commission initiated its Grid Modernization investigation and IDP processes.[38] See Xcel Energy's AGIS 15-year outlook from its 2018 IDP:[39]

[34] See OAG *Comments*, Exhibit 2.
[35] Xcel Energy's 2018 IDP, November 1, 2018 including page 234 which provides a 15-year view (graphic representation) of the AGIS Initiatives.
[36] *Id*. at 148.
[37] See DTE Testimony that provides a list of utilities actively implementing ADMS as of 2016, PDF at 323.
[38] See Commission Order Approving Integrated Distribution System Planning Requirements for Xcel Energy, August 30, 2018 at 3.
[39] Xcel's 2018 IDP, November 1, 2018 at 234.

Figure 2: Xcel's Advanced Grid Initiatives 15-Year View



The grid modernization investments have the potential to redefine the services and value Xcel Energy provides to customers as well as create new value that may need to be passed back or shared with ratepayers.

Filings to date in the IDP docket and the grid modernization proceeding have provided the Commission and staff with 1) a thorough and comprehensive understanding of Xcel Energy's existing distribution system, 2) an overview of the plan for Xcel Energy's future modernized system, 3) information about how the distribution system will (generally) interact with new resources, hardware, software, data, and planning tools, and 4) a high-level, theoretical and conceptual view of the potential utility and customer benefits these new technologies could unlock.

However, the *IDP* does not provide a business case, or cost-benefit analysis, needed to ensure that the costs are reasonable and in the public interest, as argued by Xcel Energy.[40] This is an area of dispute in the IDP docket; Xcel noted that the *IDP filing* is not the place for an in-depth analysis of costs – the place for that analysis will be the requests for cost recovery [like here, with ADMS] when costs are certain and the customer strategy is known.[41] [42]

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[40] Docket 18-251, Xcel *Reply Comments*, March 25, 2019, p. 5-8.

[41] *Id.*

[42] Staff notes that there are differing levels or types of cost-benefit analyses (CBAs) conducted in relation to utility grid infrastructure investments – while traditionally, standard CBAs have been used, it is discussed by Xcel and others that potentially a different form – either a business case, or least-cost,

Due to the nature, size, and interrelatedness of the ADMS Project, and coming projects, it may be appropriate for the Commission to pause and consider whether it has the information and understanding it needs before approving rider cost recovery of the ADMS Project through the TCR Rider, either for the $27 million certified in 2016 or the $69.1 million updated estimate. Additionally, the Commission may want to provide Xcel Energy additional direction on what may be sought for future cost requests beyond ADMS.

The Commission will need to determine whether the ADMS cost recovery request:

1) is sufficient to meet the expectations of the Commission based on the ADMS certification order and record;
2) rises to the level of detail needed to ensure that costs and value have been comprehensively articulated and quantified (to the extent practicable);
3) ensures that the grid modernization investments live up to their promised benefits; and,
4) properly delineates overlapping or interdependent costs and benefits.

Staff believes more stakeholder input is may be needed on this issue, either for the ADMS petition or generally in order to provide additional guidance to Xcel for future requests.

At a high-level, the current information provided on the ADMS Project could be found lacking either for the incremental increase in ADMS Project costs (from what was certified, from $27 to $69 million), but the Commission will want to consider whether there is sufficient information for recovery of the costs up to $27 million.

In review of the ADMS Project TCR Rider Petition, it may be unclear which components (applications) of the ADMS Project are included in the costs (discussed further below), what future associated ADMS Project costs Xcel Energy anticipates, and the expected life of the project - among other issues. Xcel Energy had noted in its 2015 certification filing that thorough detail would be provided in this cost recovery filing.[43]

These concerns were not raised during the comment period for the TCR Rider by other stakeholders. However concerns relating to these same issues were raised by stakeholders during the 2015 ADMS Project Certification Request docket (issues like: what certification meant, what level of information was needed to allow for certification and subsequent rider recovery, and requests for rulemaking) and in the Xcel IDP docket.[44] Xcel anticipates holding a pre-filing stakeholder-only meeting prior to filing its 2019 IDP on cost benefit analyses for grid

best-fit model may be more reasonable. Regardless, staff does not believe that any analysis has been conducted yet sufficient to deem costs in the public interest.

[43] Xcel Energy's 2015 Request for Certification, November 1, 2018, at 14, 19, and 24 (Doc. ID: 201511-115454-01)

[44] See Docket M-15-962, Initial (January 4, 2016) and Reply Comments (February 22, 2016) by DOC DER, OAG-RUD, EFCA, etc.; See Docket M-18-251, Comments from CUB,

modernization investments, however that will likely only pertain to investments that are not certified or seeking cost recovery.[45,46]

Last, staff has concern that if a grid modernization investment component or value is not itemized or outlined at this stage (or earlier) ensuring that ratepayers are later provided with the equal share of the benefits or system savings (and not simply associated costs) and ensuring that costs are not double recovered for multiple projects, will be difficult. Valuation of grid modernization investments, delineation of costs of different components, (and allocation of costs across operating companies) is difficult and is an emerging industry topic; regardless, it is important to ensure ratepayers are obtaining reasonable value from Xcel Energy's investments.

As Xcel notes in their reply comments on the IDP filing, "the ultimate analysis for grid modernization investments will likely need to involve a number of tools that balance tangible and intangible benefits with required and desired capabilities."[47]

Options to proceed through these issues are included below.

3. Background, Statute and Rules on Grid Modernization Certification and Rider Recovery

Similar to other rider recovery process steps, a distribution grid modernization project must first be deemed as a rider-eligible project (certification) and second, following its eligibility determination, the utility (Xcel Energy) can seek approval to seek recovery of costs through a rider.

Eligibility, or certification, under the distribution grid modernization provision (under the Biennial Transmission Projects Statute) requires the utility to demonstrate that the grid modernization/distribution system project is necessary to modernization the distribution system (Minn. Stat. 216B.2425 Subd. 2 (e) and Subd. 3).[48] No rules on this statute have been promulgated.[49]

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[45] See Docket M-15-962.

[46] See Docket M-18-251.

[47] Xcel Reply, p. 9, 2018 IDP, Docket M-18-251

[48] Xcel Energy's next Biennial Transmission Project Report/Grid Modernization Report is due November 1, 2019. Xcel Energy has noted in filing in other dockets (specifically its Integrated Distribution Plan (IDP) filed on November 1, 2018, Docket 18-251) that it intended to file for certification of its Advanced Metering Infrastructure (AMI) investments either through the Grid Modernization filing and TCR recovery option (Minn. Stat. 216B.2425) or as part of its next rate case (also expected on November 1, 2019).

[49] Several parties (Department, OAG) advocated for the Commission to initiate a rulemaking on this topic in Docket 15-962.

Minn. Stat. 216B.2425 Subd. 2(e) and Subd. 3, states:

Subd. 2 (e) [Biennial Transmission Projects Report filing Requirements] … a utility operating under a multiyear rate plan … shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

Subd. 3. Commission approval. By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. The commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is:

(1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers;
(2) needed, applying the criteria in section 216B.243, subdivision 3; and
(3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.

In 2015, at the same time as the Legislature amended Minn. Stat. 216B.2425 to add distribution-planning provisions, it amended Minn. Stat. 216B.16, subdivision 7b,[50] to allow for rider recovery of the above mentioned distribution costs. As amended, subdivision 7b permits rider recovery of three types of distribution costs:

- Jurisdictional costs, net of associated revenues, of new distribution facilities that are certified as a priority project under section 216B.2425;
- Costs associated with distribution planning required under section 216B.2425; and
- Costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the Commission under section 216B.2425.[51]

4. 2015 ADMS Certification Petition – October 20, 2015 (Docket 15-962)

Xcel Energy filed for certification of the ADMS Project on October 30, 2015.[52] Xcel Energy noted that the ADMS Project was part of a building block approach (AGIS) it intended to

[50] Minn. Stat. § 216B.16, subd. 7b, allows utilities to seek approval to recover certain transmission costs between rate cases through an "automatic annual adjustment" mechanism, or rider.
[51] Minn. Stat. § 216B.16, Subd. 7b(b)(5).
[52] The Battery Storage Project was denied, for reasons discussed below.

implement to modernize its distribution system. The building block approach is graphically represented in Xcel Energy's IDP filing made on November 1, 2018.[53]

In the original 2015 ADMS Certification Petition, Xcel Energy explained the scope of the ADMS Project:

> As we work to implement ADMS, we currently plan to deploy the short-term applications at each of our operating companies starting with Public Service Company of Colorado (PSCo) in 2017, NSP-MN and NSP-WI in 2018, and Southwestern Public Service Company (SPS) in 2019. Our initial roll out will encompass the following installations, analysis, and training: [54]
>
> - unbalanced state estimation,
> - fault location prediction,
> - fault location, isolation and service restoration,
> - integrated volt/VAr optimization,
> - distributed energy resource monitoring,
> - study mode and engineering analysis, and
> - operator training simulator.

Xcel Energy further noted that:

> …new ADMS functionality would be added in future years, on an as-needed basis and as software functionality improves with future software versions. Potential new functions to be added in the future include but are not limited to:
>
> - switch order management,
> - outage management systems,
> - distributed energy resource management,
> - integration to demand response, and
> - mobility applications.

Xcel Energy noted that its cost estimate (at the time of the October 30, 2015 filing) was:

> $9 million per year in 2016, 2017, and 2018 to implement the initial roll out of ADMS with additional funding necessary for added functionality after these years. These initial cost estimates are based on preliminary vendor cost estimates and industry partner experience. We will submit more thorough documentation along with our cost recovery request next fall upon certification of this project.

At the time of certification, both the OAG and the Department argued that Xcel Energy had not made a prudent showing that either project was necessary, cost-effective, and/or in the public interest. Fresh Energy and the Minnesota Center for Environmental Advocacy (MCEA) argued

[53] Xcel Energy's 2018 IDP, November 1, 2018.

[54] These implementation dates have been modified and are currently set for 2019-2020 per the IDP.

that the Commission should take a high-level view of project certifications and simply view the projects on whether they make a more efficient use of the distribution grid. Both Fresh Energy and MCEA argued that the ADMS project should be certified, but Xcel Energy should be required to provide more information on the ADMS project including what additional functions it could entail, how it could allow for greater penetration of distributed energy resources, and a detailed business case and roadmap for ADMS.

Xcel Energy argued in response to these comments that the Commission should not delay a decision on whether to certify the ADMS, and it should look to how it certifies transmission projects for rider inclusion, in that the Commission determines whether the project meets the statutory requirements and whether the project would be eligible for cost recovery. Xcel Energy noted that its preliminary cost estimates of the ADMS should not prevent the project from being certified since the Commission would retain oversight of the project costs through the annual TCR Rider process.[55] Additionally, in response to several parties' concerns that its proposal did not contain enough information about incremental costs, Xcel Energy indicated that such levels of detail were more appropriate for its cost recovery filing.[56]

Additionally, in its reply conclusion, Xcel Energy argued:

> Given the unique circumstances surrounding this first request, we propose to update the cost estimates and provide any additional analysis requested by the Commission as part of our October 1, 2016 TCR petition. We request that the Commission reserve judgment on the appropriate cost levels until they are presented with our final budget and implementation plan in the October 1 filing.[57]

5. June 28, 2016 ADMS Certification Order[58] and Conditions (Docket 15-962)

In its 2016 ADMS Certification Order, the Commission approved Xcel Energy's proposal for its ADMS project, explaining the basis for its decision. [59] The Commission summarized its approval of the ADMS project as follows[60]:

> Xcel Energy described ADMS as a collection of software applications designed to monitor and control the entire electric distribution network efficiently and reliably. The Company anticipates that the core ADMS software will offer three main functions: distribution network modeling, distribution supervisory control and data acquisition (SCADA), and unbalanced load flow and network topology processing.

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[55] 15-962 Xcel Energy *Reply Comments*, February 22, 2016, at various. (Doc. ID: 20162-118540-01).
[56] *Id.* at 17-18. (Doc. ID: 20162-118540-01).
[57] *Id.* at 23. (Doc. ID: 20162-118540-01).
[58] Commission Order Certifying ADMS Project under Minn. Stat. § 216B.2425 and Requiring Distribution System Study, June 26, 2016. (Doc. ID: 20166-122702-01).
[59] The Commission also denied the Belle Plaine battery project due to lack of a showing that 1) the project was a 'necessary' grid modernization project and 2) that the information learned from the project could not be simply obtained from the company through similar Colorado-based projects.
[60] June 28, 2016 *Order*, at 5.

> Xcel Energy stated that ADMS would contribute to grid modernization by allowing the Company to:
>
> - Visualize the current state of the network, providing system operators with greater network awareness;
> - Obtain an improved awareness of distributed energy resources' influence on the grid;
> - Respond more quickly and accurately to outages, optimize distribution voltages, and improve power quality;
> - Provide access to real-time and near-real-time data to control-room operators;
> - Accurately model all elements in the network for better load forecasting, fault-location prediction, energy-loss reduction, and equipment-failure prevention; and
> - Support short- and long-term load forecasting for network planning and an extensive training simulator.
>
> Xcel Energy is already working to implement ADMS and plans to complete the project in 2018. The Company estimates that the ADMS initiative will cost $9 million per year in 2016, 2017, and 2018.

Additionally, the Commission noted:[61]

> Finally, several parties expressed concern over the preliminary nature of Xcel Energy's cost estimate. The Commission clarifies that its decision to certify the ADMS project does not imply any decision regarding recovery of the project's costs. The Commission's decision represents only a finding that the project is consistent with the requirements of section 216B.2425. Any rider recovery of costs associated with the project will be determined in response to a petition for rider recovery of those costs under Minn. Stat. § 216B.16, subd. 7b. At that time, Xcel Energy will have the burden of establishing the prudence of the costs it requests to recover through the TCR Rider.

6. 2017 ADMS Project TCR Rider Petition (17-797) and Xcel Energy Recap of 2015 Petition (15-962)

In the 2017 TCR Rider Petition, Xcel Energy characterizes their 2015 ADMS Project Certification Filing estimate as follows:

> As noted in our 2015 certification request, we provided an initial cost estimate of $27 million for 2016, 2017, and 2018 (plus an additional amount of unquantified funding beyond those years) based on preliminary vendor estimates and industry partner experience. Due to the timing of the new legislation authorizing us to file for certification of grid modernization projects on June 13, 2015 and the required statutory filing date of November 1, 2015, we were unable to prepare and submit a thorough budget estimate at that time and committed to submit a more

[61] ADMS Certification *Order* at 9.

thorough request and documentation at the time of our request for actual cost recovery. Since that time, we have spent significant time and resources researching and developing our plans and as a result we not provide more detail to support our cost recovery request. The ADMS budget was developed using an extensive process in which information was collected from other utilities, industry experts, consultants and rigorous sourcing process.

7. ADMS Project TCR Rider Petition – Overview and Staff Discussion

a. Overview of ADMS Project Request and Cost

In the ADMS Project TCR Rider Petition, Xcel Energy is seeking recovery of their ADMS Project through the TCR rider and the requested amount to be recovered from Minnesota is $69.1 million across the span of 10 years (through 2025).[62,63]

The total system-wide cost for the ADMS is $208.9 million (including Colorado and New Mexico operating territories).[64,65] Xcel Energy noted in the TCR Rider Petition that $4.4 million for the ADMS Project was already included in the multi-year rate plan revenue requirement and therefore was removed from the 2016 TCR Rider Petition.[66]

In the 2017 certification request (of FLISR and TOU pilot) Xcel Energy responded to a staff IR on the amounts of certain projects recovered through its past MYRP and current TCR requests, the following summary (and correction, in red-line) was provided.[67] The Commission should confirm with Xcel and the Department of Commerce whether the amount currently being recovered in base rates in the multi-year rate case is $4.4 million or $6.6 million per year.

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[62] Xcel Energy *Petition* at Attachment 1A, pg. 22 of 24.
[63] *Id*. at Attachment 1A, pg. 1 of 24
[64] *Id*. at Attachment 1A, pg. 22 of 24.
[65] Staff notes that Xcel Energy did not provide an explicit statement in its 2015 ADMS Project Certification Petition on whether the $27 million for the ADMS Project was MN-alone, NSP-MN/WI or otherwise.
[66] See Xcel Energy *Petition* at 23, and Attachment 4A.
[67] Xcel Energy Response to Staff IR: (Doc. ID: 20183-141224-01)

Figure 3: Staff IR – Xcel Estimated AGIS Costs (2018-2027) State of Minnesota Table

Estimated AGIS Capital Costs (2018-2027) – State of Minnesota
(millions)
Note: See Supplement below for explanation of redline updates

AGIS Program	Total Cost*	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Notes
ADMS	~~$43.4 (2016–2022)~~ ~~$24.5 (2023–2025 Forecast)~~ $69.1	$~~22.6~~18.8 (costs through 2018; additional TCR recovery may be sought at a later date)	~~$2.3~~ $6.6	N/A	The Company will seek recovery of remaining costs for ADMS through the TCR Rider or base rates, as appropriate at the given time.
FLISR	$65.3	Expect to submit request post-certification	$2.3	N/A	N/A
FLISR - FAN	$64.1		N/A **	N/A	N/A
TOU Pilot	$7.6	Expect to submit request post-certification	N/A	N/A	N/A
TOU Pilot – FAN	$3.0		$8.9 **	N/A	N/A
AMI	TBD	Expect to submit request post-certification	N/A	N/A	N/A
AMI - FAN	TBD		N/A	N/A	N/A
AGIS - Other	$20.4 (2018-2022)	Expect to submit request post-certification	$19.7	N/A	Five-Year Forecast

Note: Costs included in total and rate case columns for ADMS include assumed internal labor expenses; however, TCR rider recoveries exclude internal labor costs in order to follow proper rider recovery requests.
* Amounts include internal labor and therefore may not match cost recovery requests where internal labor is excluded.
** At the time of the Company's MYRP filing, FAN costs were not specifically allocated to FLISR or the TOU Pilot. The allocation between the two initiatives was determined at the time of the Company's grid modernization certification request. Both the TOU Pilot and FLISR will benefit from the FAN WiMAX infrastructure included in the MYRP.

b. GIS Data Collection

Of the ADMS Project total costs, as shown in Table 12, $31 million is attributable to GIS data collection.

Table 12: Xcel's Project Capital Budget Summary (Dollars in Millions, on a MN basis)

	Pre-2016	2016	2017	2018	2019	2020+	Total
Labor	2.1	2.7	6.3	6.8	10.1	1.4	29.4
Software	0.0	0.0	1.9	1.3	0.0	0.0	3.2
GIS	0.0	0.0	0.1	0.4	1.5	28.9	31.0
Sub-total	2.1	2.7	8.3	8.5	11.6	30.3	63.5
Hardware	0.0	0.0	3.1	2.3	0.2	0.0	5.6
TOTAL	2.1	2.7	11.4	10.8	11.8	30.3	69.1

As noted in the TCR Rider Petition, Xcel Energy is participating in a National Renewable Energy Lab (NREL) study to (as staff interprets) determine the optimal configuration of the ADMS system either using various levels of field measurements as inputs to the models *or* extensive field data collection. This work is being conducted to determine how the ADMS system can be optimized and at the lowest effort and cost. As noted in the petition:[68]

> The parties also held discussions to evaluate the functionality of the Schneider Electric ADMS along with field measurements to identify the trade-offs between measurement density and impedance model improvement needs, and determine if more field measurements decrease the necessity for extensive field data collection. If so, what types of data and feeder locations may not need field data collection.

As further noted in the Attachment to the Petition[69]:

> Subtask 3.3 – Analyze the results: In this task, NREL will provide an ADMS model/application matrix heat map (shown in Figure 2) to show where additional field monitoring devices could potentially reduce the need for GIS data collection. A few iterations of possible field measurement locations will be identified in discussion with Xcel Energy and the impact will be evaluated against different impedance model improvement levels to generate a tradeoff Matrix as shown in Figure 2. Heat maps will be provided for IVVO performance metrics.

It appears, from staff's understanding that this NREL study may find a method in which the GIS data collection costs could be minimized. Xcel Energy notes in the attachment that estimates from a data collection service in Colorado was used for reference and then extrapolated for the entire service territory to determine the GIS data collection costs. [70] Further detail about that estimate, including the extrapolation calculation may be useful to further justify the cost. Also, information on the breakdown of the GIS costs, what specific data is being collected, what other non-ADMS related project or initiatives could or will derive value from the GIS data, whether the NREL study could assist in minimizing the largest component of the ADMS Project costs, or other information on how the GIS cost was calculated (or may be 'contingency in nature') may be useful to understand the largest cost portion of the ADMS costs.

c. Internal Labor, Hardware, and O&M Costs

Xcel Energy noted that the costs do not include internal labor (only external consultant labor) and do not include hardware costs of $5.6 million (which will be recovered in a later rate case).[71,72] Xcel Energy:

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[68] Xcel Energy *Petition* at Attachment 1A, Appendix A, pg. 1 of 8.
[69] *Id*. at Attachment 1A, Appendix A, pg. 6 of 8.
[70] *Id*. at Attachment 1A, pg. 21 of 24.
[71] *Id.* at Attachment 1A, pg. 19 of 24.
[72] *Id*. at Attachment 1A, pg. 22 of 24.

> The total Xcel Energy Company-wide ADMS investment is estimated to be approximately $208.9 million over several years. The State of Minnesota portion is approximately $70 million, with an expected in-service date of 2020. We have included in this request the O&M costs related to the software maintenance agreement which are firm, external costs related to grid modernization necessary for the functionality of this project. As we describe in more detail in Attachment 1A, we engaged in an RFP process to find a vendor suited to our needs, and worked closely with Schneider Electric, our chosen vendor, to manage costs while not sacrificing the quality of the installed product.[73]

The Minnesota allocation of on-going operations and maintenance costs are expected to be $1.9 million per year [staff assumes through 2025]. This is noted to include external software support and maintenance, hardware support, wide-area network costs and internal labor supporting the application and technical infrastructure.[74]

Table 13: Minnesota Project O&M Summary (Dollars in Millions, MN Basis)

	2016	2017	2018	2019	2020+
Labor – Distribution and Internal Support	**0.0**	**0.0**	**0.0**	**0.3**	**5.9**
Training & Communications	**0.0**	**0.0**	**0.1**	**0.1**	**0.6**
I/T Hardware Support and Network	**0.0**	**0.0**	**0.0**	**0.1**	**1.4**
Software Maintenance Agreements	**0.0**	**0.0**	**0.1**	**0.4**	**5.5**
TOTAL	**0.0**	**0.0**	**0.2**	**0.9**	**13.4**

Staff does not have additional information to discuss on this section, other than to outline what appear to be additional (greater than $27 and $69.1 million) project costs.

d. Included Components (Applications) of the ADMS Project Costs

As noted by Xcel Energy in the instant *Petition*: [75]

> ADMS is a software platform that provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists the control room, field operating personnel, and

[73] Xcel Energy *Petition* at 8.

[74] Staff notes that the Field Area Network (FAN) and associated Wi-Max and Wi-Sun communication systems have not come before the Commission for either grid modernization certification or rate recovery. However, Xcel has an existing wide-area network (WAN) it describes in its 2018 IDP Filing:" The current WAN is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers as well as satellite backup facilities." (Xcel IDP, Docket 18-251, pg. 129.)

[75] Xcel Energy *Petition*, Attachment 1A, pg. 2 of 24

> engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated network model and maintaining advanced applications which provide the Company with greater visibility of an increasingly complex electric distribution grid. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and smart grid technology executions with the enhanced network model to provide load flow calculations everywhere on the grid that accurately adjusts with changes in grid topology. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid which enables multiple performance objectives to be realized over the entire grid.

In the TCR Rider Petition Xcel Energy provides an overview of the core ADMS software which includes: distribution network modeling, distribution SCADA, and a load flow, state estimation, and network topology processor. Xcel Energy notes that these five functionalities are foundational to the ADMS platform and all advanced applications of ADMS facilitate through them.[76]

In the 2015 certification filing, Xcel Energy had noted that the initial roll out of grid modernization foundational elements would be:[77]

- **Unbalanced State Estimation** – we will install on 10+ feeders which will use telemetry on feeders to improve load flow result accuracy. As telemetered devices are added to the grid, State Estimation applies the new telemetry to the load flow calculations to improve load flow results on grid segments where no telemetry exists.
- **Fault Location Prediction (FLP)** – we will install on 10+ feeders which will predict/provide a probability where a fault is located on a feeder.
- **Fault Location, Isolation and Service Restoration (FLISR)** – we will install on 10+ feeders which will intelligently control automated devices in response to a 13 feeder or substation level outage to isolate and restore customers in an automated manner. This will also provide various switching sequences (where relevant automation is not present) to control center operators in response to a substation or feeder level outages to optimize the outage response using awareness of the current state of the grid.[78]
- **Integrated Voltage & VAr Optimization (IVVO)** – we plan to implement on feeders where the system model is complete and able to maintain the same operational functionality as the SmartVAR system. This operational functionality maintains its efficacy as feeder topologies change with network model changes. We have no plans to implement the voltage reduction feature of IVVO at this time.
- **Distributed Energy Resource Monitoring (DERM)** – this will provide improved awareness of DER impacts to power-flow on the grid.

[76] *Id*. at Attachment 1A, pg. 3 of 24

[77] Xcel Energy's 2015 Request for Certification, November 1, 2018, at 13-14 (Doc. ID: 201511-115454-01).

[78] Staff notes that the Commission rejected Xcel Energy's request for FLISR certification in Docket 17-776. See Order Approving Pilot Program, Setting Reporting Requirement, and Denying (FLISR) Certification Request, August 7, 2018. (Doc. ID: 20188-145592-01).

- **Study Mode & Engineering Analysis** – we will perform an analysis on all distribution substations and all feeders which will provide an opportunity to analyze grid performance relative to real-time and historic grid operating conditions.
- **Operator Training Simulator** – we will install on all distribution substations and all feeders which will provide a system that enables Distribution Operators to be trained in a simulated, but realistic environment that reflects and simulates normal and emergency operating conditions using a representation of the existing distribution grid.

In the 2017 TCR *Petition*, Xcel Energy provided a Bubble Diagram Table in Attachment 1A, Appendix B, which correlates general grid modernization terms to discrete Schneider Software Items:[79]

Table 14: Bubble Diagram – Schneider Software Terms vs. Common Terms

Core Applications	
General Term	*Schneider Software Item*
Distribution Network Modeling	Network Model
Impedance Calculation	
Network Topology Processor	Topology Analyzer
	Temporary Elements
	Tracing
	Dynamic Equipment Rating
D-SCADA	Switching Validation
	Volt/Var Optimization
	Voltage Reduction
	Basic Switching Management (SOM)
Unbalanced Load Flow	Load Flow
Unbalanced Load Allocation	Load Profile Generator
Short Term Applications	
General Term	*Schneider Software Item*
Unbalanced State Estimation	State Estimation
Integrated Volt & VAr Optimization	Closed Loop VVO
	Volt/Var Optimization
	Model Readiness
Fault Location Prediction	Fault Location
Fault Location Isolation and Service Restoration	Closed Loop FLISR
	Integrated FLISR
	Element Isolation
	Supply Restoration
	Return to Normal State
	Basic Switching Management (SOM)
Study Mode and Engineering Analysis	Fault Calculation
	Snapshot

[79] Xcel Energy *Petition*, Attachment 1A, Appendix B, pg. 1 of 2. The ADMS platform was purchased from Schneider Electric.

	Playback
	Thevenin Equivalent
DER Monitoring	DG Monitoring
	Electric Vehicle Monitoring
Operator Training Simulator	DMS Advanced Simulation
	Dispatcher Training Simulator
Historical Information Storage and Reporting (HSIR)	Historical Trending
	Snapshot
	Playback
Medium-Term and Long-Term Applications	
General Term	*Schneider Software Item*
Network Planning	Capacitor Placement
Contingency Analysis	Contingency Analysis
Switching, Analysis, Planning and Execution	Work Order Management (WOM)
Mobility – Maps, Switch Management, etc.	
Forecasts of Load and Distributed Generation	Near-Term Load Forecast
	Short-Term Load Forecast
	Medium-Term Load Forecast
	Long-Term Load Forecast
Outage Management System	Core OMS
	OMS Reliability Analysis
Protection Coordination	Relay Protection
	Protection Coordination
Integration to Demand Response	Load Management (Demand Response)
	Customer Connection
Load Shedding	Load Shedding
Load Relief Load Balancing	Network Reconfiguration
	Load Relief
	Phase Balancing
Not Identified in Bubble Diagram	Large Area Restoration

In the instant *Petition*, Xcel Energy does not itemize which modules were purchased or are included in the ADMS costs of $69.1 million. However, staff understands these software applications to be modular and to have discrete prices, Xcel Energy's 2018 IDP:

> Xcel Energy has already purchased the IVVO module in ADMS and will test it as part of the initial ADMS deployment. In addition to the operating system and communication network, there are four principal utility field equipment components of IVVO: (a) capacitors, (b) secondary static VAr compensators (SVCs), (c) voltage sensing devices, and (d) Load Tap Changers (LTC). Voltage sensing devices placed at strategic points on the distribution system enable IVVO systems to operate the most effectively. While these may be unique devices, using AMI meters where available is a cost-effective solution. For this reason, the Company intends to use bellwether AMI meters as its primary voltage sensing device in

> Minnesota. To maximize the benefit of an IVVO program, a significant cost of implementation is replacing/upgrading LTCs with the controls to do full Conservation Voltage Reduction (CVR) as existing LTCs on the distribution system are not capable of accepting IVVO commands from an ADMS. This would be a significant cost in Minnesota. ….[80]
>
> …As such, we do not believe that the benefits of CVR are significant enough to justify the cost of implementing IVVO in the near term beyond our existing SmartVAr program. However, we see value in developing its voltage management capabilities – particularly as the level of DER in our service are increases over the period covered by this Roadmap. The current plan is to complete the various projects that will enable IVVO (e.g., ADMS, FAN, AMI) and monitor other indicators (such as the results of the roll-out of IVVO in Colorado and DER penetration levels in Minnesota) to determine the appropriate time to make this investment. We will also test IVVO functions (including CVR) in Minnesota as a part of its in-servicing of the ADMS software.[81]

Staff is unclear of the cost of the IVVO module (or other modules purchased) and to what extent any module will be utilized on the system or in what time frame. Additionally, there are Schneider software application functions that have been mentioned in the 2015 ADMS Certification request, 2018 IDP, and 2017 TCR Rider ADMS Petition that do not fall discretely into the core application or short-term application sections of the bubble diagram (so staff cannot assume 'all core applications have been purchased and are implemented without additional cost'). Various software applications listed in the categories (core, short, or long-term) are noted in these various filings as being [in staff's terminology]: partial roll-out, purchased but in test phase, not purchased, utilized by NREL in its ADMS work for Xcel Energy (staff assumes these have been purchased), or are in need of further investments (i.e. FAN, AMI, etc.) to fully utilize. More information on the cost, timeline, connected needs (among other pieces of information), and customer versus utility costs and benefits, would likely be beneficial to the Commission and stakeholders – and provide clarity when considering the incremental costs or business cases for the FAN, AMI, FLISR, etc).

e. Life of the ADMS Project

Xcel Energy discusses O&M and Service Life of the project in terms of the depreciation life and notes that "The ADMS project components will have either a 9 or 10 year life depending on the outcome of the pending depreciation docket." Xcel Energy notes it has budgeted for both capital and O&M labor for the engineering and support expenses anticipated to maintain and operate the system.[82]

It is unclear to staff what the technical (not just depreciated) expected life of the ADMS Project is, when it would need to be replaced, what the cost of potential system upgrades may be, or

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[80] Xcel Energy's 2018 IDP, at 166.
[81] *Id*. at 169.
[82] Xcel Energy *Petition*, at 22 of 24.

what the costs of additional features may be (however, those costs may be unknown at this time).

f. Cost Benefit Analysis or Business Case

As noted above, grid modernization investments have the potential to redefine the services and value Xcel Energy provides to customers as well as create new value that may need to be passed back or shared with ratepayers.

To date, Xcel Energy has not yet filed a comprehensive business case, or cost-benefit analysis, that ensures that the costs are reasonable and in the public interest and the benefits can be internalized and returned or at least shared with ratepayers. The Commission will need to determine whether the information provided to date on ADMS is sufficient for cost recovery. Staff acknowledges that quantifying qualitative, mostly external benefits is difficult, and in some instances not possible. However, there has been no quantification of any benefit regarding any portion of the ADMS project, only narrative and qualitative discussion. Other utilities have quantified some benefits of an ADMS investment, [83] however, as for most grid modernization investments, the analyses are combined with other initiatives to improve the foundational elements cost benefit ratio.

The Commission could deem the ADMS project as so foundational to unlocking future benefits that any attempt at a stand-alone ADMS cost-benefit or business case analysis would not be worth the effort. For example, the California Public Utilities Commission found that an analysis discretely separating the benefits of individual grid modernization components in isolation to be infeasible:

> To determine the cost effectiveness of each grid modernization investment, the IOUs would need to identify the driver of the investment and isolate the value of its contribution to enabling DER growth. We find this infeasible, given the multiple, interrelated functions of grid modernization investments.[84]

With the large pending investments, staff believes it may be reasonable to provide additional guidance to Xcel Energy and stakeholders on what level of business case or cost benefit analysis should be provided (beyond the narrative Xcel Energy has provided to date). Additionally, with the limited party comment in this docket, combined with the (contested) cost-benefit discussions occurring in relation to Xcel Energy's 2018 IDP, this may need to be a broader conversation. Staff again highlights that as part of the 2018 IDP comment period, Xcel Energy noted that it would hold a 'focused stakeholder' workshop (as part of its 2019 IDP) to discuss a

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[83] See DTE Testimony before the MI PSC, PDF pg. 323, See National Grid GMP Presentation, Rhode Island PSC, slides 42-52. Companies noted to have installed ADMS or have pending authorizations: HydroOne, PECO, PPL, Ameren, Centerpoint Energy, Oncor, Georgia Power, Florida Power and Light, United Illuminating, Duke Energy, San Diego G&E, Alabama Power, Consumers Energy, Electricity Northwest, Seattle City Light, Tacoma Power, Oklahoma G&E, Execelon.

[84] CPUC Decision, 14-08-013 - Decision on Track 3 Policy Issues, 18-03-023, March 26, 2018, at 24.

cost-benefit framework for grid modernization investments for use in the IDP.[85] However, discussions occurring with the 2019 IDP cost benefit questions are geared toward certification requests and preliminary IDP cost-benefit analysis, those discussions will not answer the questions before the Commission on the ADMS recovery petition nor provide guidance for the level of cost-benefit analysis needed at the cost recovery stage for future grid modernization investments.

Last, the Department of Energy, DSPx Report, Volume III: Decision Guide, outlines core steps to take when determining value of a grid modernization investment,[86] essentially agreeing on objectives, identifying grid functions, etc. Xcel Energy has largely outlined several of these steps in its 2018 IDP, including future potential functionalities and uses, however, how those measures will be tracked over time, and correlated with investment costs and resulting benefits, or how they are translated to a cost recovery request has not been articulated.

Figure 3: DSPx - Summary of Decision Process Diagram

[85] See Xcel Energy's *Reply Comments*, 2018 IDP, pg. 5. (Doc. ID: 20193-151529-01). However, to date, some of the IDP stakeholder meetings were advertised to only stakeholders than commented in Xcel's 2017 grid modernization filing and therefore stakeholder participation may be limited. See Xcel's 2019 IDP Stakeholder Plan, April 8, 2019 (Doc. ID: 20194-151758-01).

[86] DOE - DSPx Volume III: Decision Guide , p. 82

8. Decision Alternatives

The Commission has a wide range of options before it:

13. Approve the $27 million under the TCR Rider as certified by the Commission in 2016.

14. Approve the $69.1 million under the TCR Rider as petitioned.

15. Table TCR cost recovery for all portions of the ADMS Project until a more thorough cost benefit analysis or business case is provided by Xcel Energy for the ADMS Project.

16. Table TCR cost recovery for all portions of the ADMS Project until a more thorough cost benefit analysis or business case is provided for interrelated grid modernization investments.

17. Table TCR cost recovery for all of the incremental (above $27 million) costs until a more thorough cost benefit analysis or business case is provided.

18. Solicit stakeholder input on content requirements for a cost benefit analysis or business case proposal for grid modernization cost recovery requests from Xcel Energy.

19. Require a ratepayer impact assessment for implementation of ADMS.

20. Require a ratepayer impact assessment for implementation of all pending grid modernization investments.

21. Deny Xcel's entire request for TCR cost recovery for ADMS without prejudice.

Under alternatives 13 or 15, the Commission could outline additional parameters or clarifications to Xcel Energy on what it should provide for this case and/or future cases.

Staff has drafted, but not eFiled, an outline of information that may be used as a straw proposal to solicit stakeholder feedback on what information should be included in request for cost recovery (Alternative #18).

D. Two-Way Carrying Charge

In its *Petition*, Xcel Energy proposed the creation of a two-way carrying charge on tracker balances beginning January 1, 2019 to account for "the potential misalignment of the time a rate is effective compared to the revenue requirements intended for recovery."[87] A two-way carrying charge would result in ratepayers paying interest on under-collected balances, and the Company paying interest on over-collected tracker balances. Xcel Energy also stated that, if a two-way carrying charge were implemented, "[a]ll parties would have some motivation to match the recovery period with the test period so as to

[87] Xcel Energy *Petition* at 14.

minimize the magnitude of a carrying charge…."

1. Department Comments

The Department noted that the Commission considered this issue in a previous Otter Tail TCR proceeding.[88] In its March 10, 2014 Order, the Commission stated on page nine:

> In Otter Tail's last renewable energy rider docket, the Commission requested that the Company explain, in its next rider filing of any type, why the inclusion of a carrying charge imposed on a rider tracker account balance is justified. The Company responded to the Commission's request in this docket by stating that a rider reflects either an over- or under-recovery of the tracker balance and the carrying charge provides symmetrical treatment in both circumstances.
>
> Having considered the issue, the Commission will not allow the Company to add a carrying charge to the tracker balance for its transmission cost recovery rider and its renewable resource cost recovery rider. While the Company's observation about symmetrical treatment is true, it does not go to the heart of the issue. As discussed above, the TCR rider and the renewable resource cost recovery rider are extraordinary cost-recovery mechanisms adopted to expedite the construction of critically needed infrastructure.
>
> They offer unique advantages over traditional ratemaking treatment. For example, they permit cost recovery—including recovery of the authorized rate of return—to begin with construction, instead of when the facilities are placed into service. And both riders permit cost recovery to begin before the facilities' costs have been fully scrutinized in a rate case. The additional advantages of a carrying charge are therefore unnecessary either to ensure fairness or to act as an incentive.
>
> For all these reasons, the Commission will not permit carrying charges on either rider. [Footnote omitted]

Based on the Commission's reasoned decision in that docket, the Department recommended that the Commission deny the Company's request.

[88] Docket No. E-017/M-13-103

2. Xcel Energy Reply Comments

Xcel Energy continued to support its proposal stating that the issue it addressed with a carrying charge is neither one of fairness nor incentive, as discussed in the Otter Tail Order, but one of customer impact. The Company stated that it has observed that evaluation periods have lengthened, and that carryover balances have been increasing in size as a result. The Company is concerned that these larger carryover balances create significant volatility in rider rates, and stated that a carrying charge is a tool that may help reduce this volatility by encouraging a better match between rider test periods and rate implementation periods.

3. Department Response Comments

The Department stated that it understands Xcel Energy's reasons for proposing a carrying charge in this Docket are different from the reasons discussed in the Otter Tail Order; nonetheless, the Department believes the Commission has given ample consideration to implementing carrying charges and determined not to include them. Further, the Department noted that the increases in evaluation times are due in large part to the increasing size and complexity of certain riders, and implementing a carrying charge will likely not result in reduced evaluation periods. Rather, carrying charges likely will simply add to the revenue requirements and exacerbate the problem the Company has identified. Therefore, the Department recommends the Commission deny the Company's request

4. Decision Alternatives

22. Approve Xcel Energy's request for implementation of a two-way carrying charge. [Xcel Energy]

23. Deny Xcel Energy's request for implementation of a two-way carrying charge. [Department]

E. MISO Revenue Requirements

1. Background

The TCR statute allows rider recovery of charges billed under a federal tariff associated with other transmission expansions being constructed in the MISO region by other utilities. Xcel Energy projected the MISO Tariff Schedule 26 and 26A expenses to be $141.5 million and expects the expenses to be offset by $142 million in Schedule 26 and 26A revenues.[89] The revenues are associated with regional rate recovery of NSP System project investments. The forecast results in an estimated negative revenue requirement of approximately $501,319 million for the total NSP system which results in an estimated negative revenue requirement of approximately $368,171 after allocation based on the MISO load share ratio to Minnesota.[90]

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[89] Xcel Energy *Petition* at 15.

[90] Xcel Energy did note that further adjustments may be necessary pending the outcome of the vacated Order 531 and a second compliant period. The Company committed to keeping the Commission informed of any additional outcomes of these MISO ROE proceedings at the FERC.

2. Department Comments

The Department noted that Xcel Energy excluded the interest component of the ROE from refund amounts it is proposing to recover from ratepayers via the TCR because the Company does not consider interest income or expense to be MISO RECB activity. Had Xcel Energy included the interest component of the ROE refund amounts, its TCR revenue requirements would have been higher by approximately $0.5 million. The Department requested that the Company provide further explanation of its reasons for excluding the interest component from its TCR revenue requirements.

3. Xcel Energy Reply Comments

Xcel Energy stated that interest related to the MISO ROE resettlement was recorded as interest expense (on the cumulative over-collection of revenue requirements) and not transmission expense or transmission revenue. The Company also stated that "actual interest expenses and revenues are typically not included in ratemaking. Instead, the ratemaking mechanisms rely on the cost of capital applied to the particular scope of the mechanism to determine the appropriate interest to recognize."[91]

4. Department Response Comments

The Department disagreed with the Company's assertion that FERC-mandated interest payments associated with the ROE refunds are comparable to interest expense associated with the cost of capital. The Department noted that Minn. Stat. § 216B.16, subd. 7b(b)(2) "allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects," net of "revenues received by the utility and by amounts the utility charges to other regional transmission owners." The statute does not distinguish between the specific types of charges and revenues incurred pursuant to a federally approved tariff, and therefore the Department concluded that the interest component of the ROE refund should be included in Xcel Energy's TCR revenue requirements.

5. Xcel Energy Reply to Department Response Comments

Xcel Energy continued to oppose the Department's position that the interest component of the MISO ROE refund should be included in the TCR revenue requirements. The Company does not believe the Department's proposal is appropriate treatment from an accounting perspective and noted that inclusion of the interest will actually increase the TCR revenue requirement. Xcel Energy reiterated a statement from its *Reply Comments* that "[t]he Company's actual interest expenses and revenues are typically not included in ratemaking. Instead, the ratemaking mechanisms rely on the cost of capital applied to the particular scope of the mechanism to determine the appropriate interest to recognize."[92]

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[91] Xcel Energy *Reply Comments* at 6.

[92] *Id*.

6. Staff Analysis

Typically, MISO charges included in the TCR are accounted for on an "all in" basis. The Department's recommendation to include the $501,319 ($368,171, Minnesota Jurisdiction) revenue requirement impact, although detrimental to ratepayers, is consistent with previous TCR-related expense recovery recommendations (i.e., the "all in" method). While Xcel Energy is correct in stating that interest is not usually a recoverable expense because it is taken into account in the capital structure, Staff views the interest included in the capital structure to be interest related to financing activities such as bonds', lines of credit's or loans' interest. Staff does not consider the MISO interest to be related to financing activities; therefore, Staff agrees with the Department that, in this instance, interest should be included as part of the revenue requirement.

7. Decision Alternatives

24. Allow Xcel Energy to exclude the interest component of the ROE refunds from the TCR rider revenue requirements. [Xcel Energy]

25. Require Xcel Energy to include the interest component of the ROE refunds in the TCR rider revenue requirements. [Department]

F. Revenue Requirements and TCR Adjustment Factors

In its *Petition*, Xcel Energy provided the following table showing the proposed revenue requirements and TCR Adjustment Factors.

Table 15: Current and Proposed TCR Adjustment Factors[93]

	2016 Approved	2017-2018 Proposed
Total Revenue Requirements	$80,525,828	$109,549,879
Residential Rate/kWh	$0.003503	$0.004645
Commercial Non-Demand/kWh	$0.003384	$0.004102
Demand /kW	$1.017	$1.274

In *Supplemental Reply Comments*, Xcel Energy updated the information to account for:

- Changes resulting from the Tax Cuts and Jobs Act (TCJA);
- Actual revenues through March 2018 to provide more recent tracker information;
- 2019 sales forecast to illustrate a revised rate calculation over 12 months beginning July 1, 2018;
- A more recent ADMS forecast to ensuring no hardware costs are included, as discussed in the Company's *Reply Comments*;

[93] Xcel Energy *Petition* at 13.

- Updated ADIT proration methodology, including the removal of ADIT proration from the 2017 revenue requirements as that test period has ended.

The following table summarizes the total effect of the updates listed above on the TCR revenue requirements:

Table 16: Updated TCR Revenue Requirement

($ millions)	2018	2019
As-filed	$ 109.5	$ 90.5
Updated	98.1	88.4
Difference	(11.4)	(2.1)

Incorporating the updates to the ADIT proration and other updates listed above changes the proposed rates. Assuming a July 1, 2018 implementation date and recovery over 12 months, the 2018 residential TCR Rider adjustment factor decreases from $0.004645 per kWh in the initial *Petition* to $0.004178 per kWh. This results in a reduction of approximately $0.32 per month for an average residential customer compared to the rate shown in the initial *Petition*.

1. Department Response Comments

The Department recommended that the Commission approve recovery of the 2018 revenue requirements and cost allocations presented in Xcel Energy's May 25, 2018 Supplemental Reply Comments, modified to reflect:

(1) an ROE of 8.59 percent;
(2) interest associated with the FERC ROE adjustment of $0.5 million; and
(3) ADIT calculated without pro-rationing.

Additionally, the Department recommended that the Commission deny the Company's request to recalculate its rate adjustment to collect the approved 2018 revenue requirement over the remaining months of 2018, as 2018 is now over. Instead, the Department recommended that the Commission require Xcel Energy to calculate its final rider rates using the approved 2018 revenue requirement and the billing determinants reflected in the Company's May 25, 2018 *Supplemental Reply Comments*, with no adjustment for the delayed implementation date.

2. Staff Analysis

As the Department discussed in its Response Comments the 2018 test period has ended. In addition, Staff notes that all of the proposed revenue requirements discussed above were based on various assumptions (e.g., ROE, ADIT, Implementation date) that either are no longer appropriate or may change based on the Commission's Order. In its initial *Petition*, Xcel Energy proposed to recalculate its Adjustment Factors via a compliance filing based on the Commission's decision. Staff notes that the Commission dealt with a similar issue on Xcel Energy's previous TCR filing (15-891) by requiring the Company to file a compliance filing reflecting the Commission's decision and updating the forecasted numbers within 10 days of the date of the Order.

3. Decision Alternatives

26. Require Xcel Energy to submit a compliance filing updated to reflect the Commission's decisions in the Order and updating the forecasted numbers with actual numbers within ten days from the date the Commission's Order is issued. [Xcel Energy, Department]

27. Require Xcel Energy to submit a compliance filing updated to reflect the Commission's decisions in the Order and updating the forecasted numbers with actual numbers within thirty days from the date of the Commission's Order is issued.

G. Tariff Sheet and Customer Notice

1. TCR Rider tariff

Xcel Energy updated its TCR Rider tariff sheet reflecting the proposed TCR Adjustment Factors by customer class. The tariff provides that the TCR Adjustment Factors are included in the Resource Adjustment and that factors will be applied to customer bills subsequent to Commission approval. The Company also proposed the following administrative updates:

- Add references to distribution-related costs that are now eligible for inclusion in the TCR rider;
- Remove references to the Street Lighting class;
- Remove duplicate references to the Commission.

The Department reviewed the proposed changes to the TCR Rider tariff and concluded they are reasonable.[94]

2. Proposed Customer Bill Message

Xcel Energy plans to provide notice to customers regarding the change in the TCR Adjustment Factors reflected in their monthly electric bill. The Company's proposed updated language is to be included as a message on the customers' bill the month the TCR Adjustment Factors are implemented:

This month's Resource Adjustment includes a decrease in the Transmission Cost Recovery Adjustment (TCR) which recovers the costs of transmission and distribution investments, including delivery of renewable energy sources to customers. The TCR portion of the Resource Adjustment is $0.004645 per kWh for Residential Customers; $0.004102 per kWh for Commercial (Non-Demand) customers; and $1.274 per kW for Demand billed customers.

Xcel Energy stated that it will work with the Department and Commission Staff if there are any suggestions to modify this proposed customer notice. The Department did not comment on the Company's proposed customer notice.

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[94] Department *Comments* at 18.

3. Staff Comments

Typically, the Commission requires that the utilities' proposed notices be approved by the Commission's Consumer Affairs Office (CAO); therefore, the Commission may want to instruct the Company to work with the CAO on its proposed bill message.

4. Decision Alternatives

28. Instruct Xcel Energy to work with the Commission's Consumer Affairs Office on the proposed costumer bill message. [Xcel Energy]

29. Take no action.

H. 2016 True-Up and Tracker Balance

Xcel Energy's *Petition* described two adjustments reflected in its 2016 tracker balance that were not reflected in its January 23, 2017 Compliance Filing in Docket No. E-002/M-15-891. One related to updated jurisdictional allocators approved in the Company's most recent rate case, and the other was described in Xcel Energy's *Petition* as an update for a December 2016 true-up. In its *Comments*, the Department asked the Company to explain the need for this second adjustment.

In *Reply Comments*, Xcel Energy explained that the January 23, 2017 Compliance Filing included an estimate of costs and revenues for December 2016, not actuals, and the true-up simply corrected for the difference between the estimate and actuals. The Department concluded that this explanation is reasonable.

V. Decision Options

Rate of Return

1. Approve Xcel Energy's proposed return on equity of 10.00 percent. [Xcel Energy]

2. Approve the Department's proposed return on equity of 8.99 percent [Department initial position]

3. Approve the Department's proposed return on equity of 8.59 percent. [Department revised position]

4. Approve the OAG's proposed return of 4.30 percent. [OAG]

5. Determine that no party has convinced the Commission to alter the currently authorized rate of return established in Xcel Energy's most recent electric rate case (Docket No. E-002/GR-15-826).

    a. 9.20 percent (as represented to the investment community)
    b. 9.06 percent (used to calculate revenue requirement and set rates)

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

6. Adopt the Department's recommendation requiring Xcel Energy to use of the ROE determined in the present docket in all dockets filed by the Company that require an ROE until the Commission issues an order in the Company's next rate case authorizing a different ROE. [Department]

    and/or

7. Establish a policy requiring a minimum period of three years from the date of the final Order in Xcel Energy's most recent electric rate case before the Company may request a revision to the rate of return in a future TCR rider. [Staff]

    and/or

8. Require Xcel Energy to address the issue of establishing a policy requiring a minimum period of time to pass from the final order of its most recent rate case before the Company is allowed to request revision to its established rate of return in any subsequent rider petition. [Staff]

Prorated Accumulated Deferred Income Taxes

9. Allow Xcel Energy to implement its TCR rider factor effective January 1, 2018, and authorize the Company to recover its ADIT proration as proposed in the Initial *Petition*.

10. Allow Xcel Energy to implement its TCR rider factor effective January 1, 2018, and authorize the Company to recover its ADIT proration, calculated by Deloitte Tax Service, as proposed in Xcel Energy's May 25, 2018, *Supplemental Reply Comments*.

11. Require Xcel Energy to implement its TCR rider effective January 1, 2019, thereby eliminating the need to prorate ADIT. (Department, Xcel Energy-this docket only)

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

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

ADMS Cost Recovery

13. Approve the $27 million under the TCR Rider as certified by the Commission in 2016.

14. Approve the $69.1 million under the TCR Rider as petitioned.

15. Table the TCR recovery of all portions of the ADMS Project until a more thorough cost benefit analysis or business case is provided for the ADMS Project.

16. Table the TCR recovery of all portions of the ADMS Project until a more thorough cost benefit analysis or business case is provided for interrelated grid modernization investments.

17. Table the TCR recovery of the incremental (above $27 million) until a more thorough cost benefit analysis or business case is provided.

18. Solicit stakeholder input on content requirements for a cost benefit analysis or business case proposal for grid modernization cost recovery requests from Xcel Energy.

19. Require a ratepayer impact assessment for implementation of ADMS.

20. Require a ratepayer impact assessment for implementation of all pending grid modernization investments.

21. Deny the entire TCR Recovery of ADMS without prejudice.

Two-way Carrying Charge

22. Approve Xcel Energy's request for implementation of a two-way carrying charge. [Xcel Energy]

23. Deny Xcel Energy's request for implementation of a two-way carrying charge. [Department]

MISO Revenue Requirement

24. Allow Xcel Energy to exclude the interest component of the ROE refunds from the TCR rider revenue requirements. [Xcel Energy]

25. Require Xcel Energy to include the interest component of the ROE refunds in the TCR rider revenue requirements. [Department]

Revenue Requirements and TCR Adjustment Factors

26. Require Xcel Energy to submit a compliance filing updated to reflect the Commission's decisions in the Order and updating the forecasted numbers with actual numbers within ten days from the date the Commission's Order is issued. [Xcel Energy, Department]

27. Require Xcel Energy to submit a compliance filing updated to reflect the Commission's decisions in the Order and updating the forecasted numbers with actual numbers within thirty days from the date of the Commission's Order is issued.

Tariff Sheet and Customer Notice

28. Instruct Xcel Energy to work with the Commission's Consumer Affairs Office on the proposed costumer notice. [Xcel Energy]

29. Take no action.

Minn. Stat. § 216B.16 Subd. 7b.Transmission cost adjustment.

(a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:

(1) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or new transmission or distribution facilities that are certified as a priority project or deemed to be a priority transmission project under section 216B.2425;

(2) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system; and

(3) charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;

(2) allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;

(3) allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system;

(4) allows the utility to recover costs associated with distribution planning required under section 216B.2425;

(5) allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under section 216B.2425;

(6) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(7) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(8) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(9) allocates project costs appropriately between wholesale and retail customers;

(10) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(11) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;

(2) a schedule for implementation of applicable projects;

(3) the utility's costs for these projects;

(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

Xcel's Cost Benefit Assessment in the 2018 Integrated Distribution Plan

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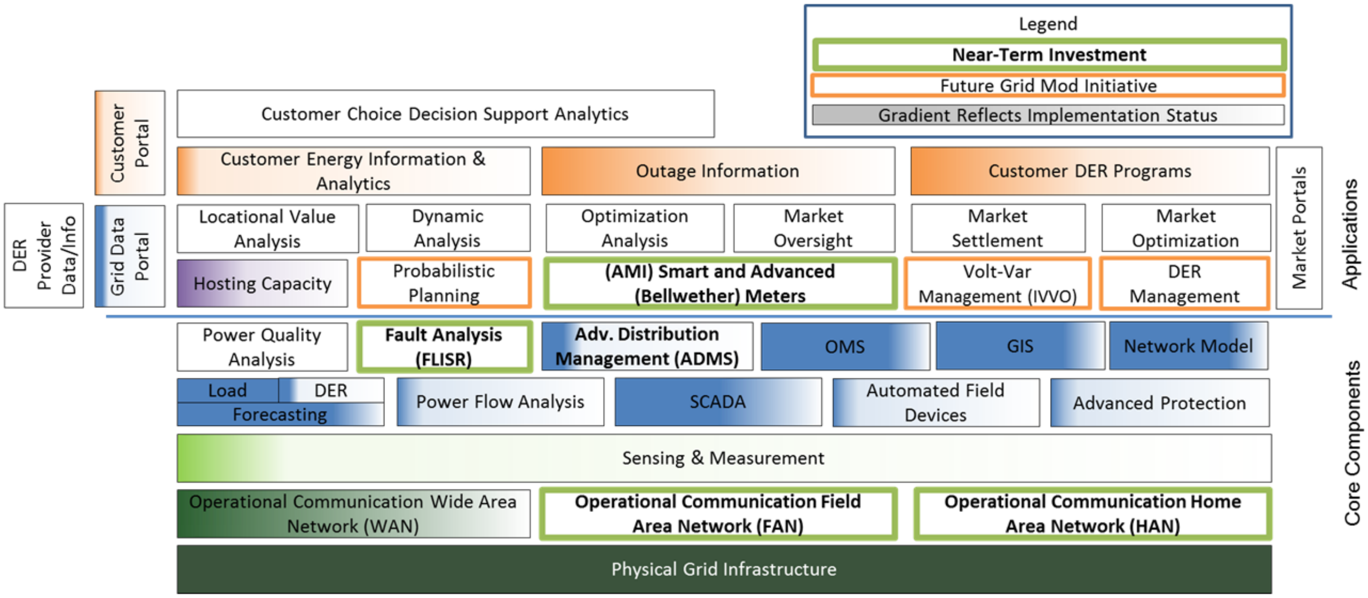
Figure 48: Estimated Status of AGIS Implementation



H. Cost Benefit Analysis

Though we have done a significant amount of development work, we are still in the planning stages of AMI, FAN and FLISR and are not yet seeking cost recovery or certification of these investments, we have conducted a high level cost benefit analysis (CBA) for purposes of this filing. Since we have not yet finalized our customer and data strategy, we have not yet finalized our planned investments or costs, so the estimates used in building this CBA are preliminary. The CBA is intended to provide a point of reference and considerations when evaluating these holistically. Generally, we evaluate investments such as these on a "least-cost best-fit" basis to meet the identified need- meaning that the selected investments are those that provide the highest value to customers and the needs of the distribution system when considering *both* the costs and the value of being offered by the projects in light of the identified needs. In other words, these decisions are not based entirely on CBA results- the benefits of our AGIS investments are not limited to quantifiable items; they will also improve our customers' overall experience and help achieve broader energy goals.

We currently estimate that the total capital and O&M costs for AMI, FAN, and FLISR is between $632 and $822 million. While these projects are in the early phases of planning, these costs were identified on the basis of benchmarking, internal expertise, and appropriate contingency. Further, these costs are offset by benefits, such that we estimate a range of benefit-to-cost ratios of approximately 0.50-0.80 for AMI (of which FAN is a component) and 2.50-3.00 for FLISR, with a total quantitative benefit-to-cost ratio somewhere between .70- 1.10. These analyses only compare quantifiable projected benefits, such as O&M and capital expenditures savings. By definition, these analyses do not capture other benefits that cannot be quantified, such as customer satisfaction, improved power quality, human health and safety, the secondary effects of lost productivity, business, consumables on customers due to electric outages or possible future capabilities like wire-down detection.

Some of the AMI benefits include:

- Reduction in manual meter reading expenses,
- Reduction in bad-debt write-off
- Reduction in okay on arrival trips associated with outages
- Costs savings from remote disconnect capability
- Reduction in labor associated with estimated bills
- Savings from reduction in call volume
- Outage management efficiency
- Reduced outage duration
- Reduced field trips for voltage investigations
- Savings from reduction in theft

Some of the FLISR benefits include:

- Customer Minutes Out- CMO Savings
- Patrol Time Reduction
- Real time grid visibility and control

Certainly balancing the costs and benefits of any given investment is an important consideration, which we do not discount. However, it is not the only consideration. From a policy perspective, the importance of the unquantifiable benefit of advancing the distribution grid are difficult to overstate. Safety, reliability, and customer satisfaction are key to our role as a public utility. A more automated, transparent grid supports greater customer and employee safety. Similarly, without the advanced technologies associated with the AGIS initiative, the Company will not be able to keep up with industry trends regarding reliability, as measured by SAIDI. Nor can utilities keep up with greater customer demand for DER without investing in the advanced grid technologies necessary to support these resources—in particular EVs, as AMI would give us insight to adoption and charging issues allowing us to effectively manage EV integration and potentially extract additional value. In addition, giving customers choice and control over their energy usage by providing greater data to customers; giving customers greater input into the types of energy they use by supporting DER; and empowering customers to make good choices about their impact on the environment are important pieces of both building customer satisfaction and managing electric demand.

We recognize that it is difficult to put a numeric value on future opportunity and non-monetary benefits, and that evaluating these possibilities can be a challenge. However, the trends in the utility industry and the efforts of other states to advance their distribution grids verify the importance of bringing utilities' distribution grids into the future. Along these lines, our legacy AMR system that was installed in the mid-1990s under a services agreement will no longer be supported by our vendor after the early-2020s. Further, they plan to discontinue support for AMR technology entirely in the mid-2020s, like many other vendors, around the time our current service agreement will end. Without AGIS, we would otherwise be behind in managing to customer standards, supporting DER, employing current technologies, meeting reliability goals and expectations, and fully capturing DSM opportunities.

X. CUSTOMER AND OPERATIONAL DATA MANAGEMENT

The proliferation of sensor technology and AMI is producing new and voluminous data for utilities. As this data becomes more available, utilities are faced with the challenge of leveraging it to improve the customer experience and capture additional value streams, while managing data security and privacy concerns. As discussed above, we are still working through our overall customer and data management strategy as these are critical components of ensuring we optimize these grid modernization investments for our customers. However, our strategy planning is evolving and we have made great progress thus far. Our data strategy work to-date (summarized in Figure 49 below) considers three types of data and their associated uses: a) customer data and two types of system data, b) operational data, and c) planning data.

In this Section, we discuss each of these types of data and what the Company envisions for the future use of data, from both customer and Company perspectives. Among other things, this Section addresses the specific requirement for the five-year Action Plan set forth above related to its customer data and grid data management plan.