STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Vice Chair
Matt Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factors

DOCKET NO. E-002/M-17-797

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL

The Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") respectfully submits these comments in response to the Transmission Cost Recovery Rider filing of Northern States Power Company ("Xcel" or "the Company").

These Comments address only the return that should be applied to the Transmission Cost Recovery ("TCR") rider, and the OAG takes no position on other issues at this time. The statute authorizing Xcel's TCR rider, Minnesota Statutes section 216B.16, subdivision 7b, authorizes the Commission to establish a return that is "consistent with the public interest." One of the primary legal requirements for a return to be consistent with the public interest is that it must be "commensurate with returns on investments in other enterprises having corresponding risks."[1] The analytical tools used to establish a return in general utility rate cases do not produce a return that is commensurate with the risks of investments recovered through riders like the TCR. For that reason, the Commission should apply new methods, and establish a return for Xcel's TCR rider that is based on the Company's cost of long-term debt.

[1] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

I. LEGAL STANDARD FOR RETURN ON EQUITY.

The statute authorizing Xcel's TCR rider is Minnesota Statutes section 216B.16, subdivision 7b. It provides that the Commission must "allow[] 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."[2] And, as with all rates charged by utilities in Minnesota, the Commission must ensure that the rates charged through the TCR rider are "just and reasonable."[3] There is significant legal guidance on what factors the Commission must consider in determining what return will be consistent with the public interest and result in just and reasonable rates. After reviewing these factors, described below, if there is *any* doubt about what would produce a just and reasonable rate, the Commission is required by law to resolve that doubt in favor of ratepayers.[4]

Two United States Supreme Court cases establish the factors that the Commission must review when setting returns for regulated utilities: *Bluefield Water Works* and *Hope Natural Gas Co*. In *Bluefield*, the Supreme Court established a lower bound for utility returns, holding that "[t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."[5] In *Hope*, the Court established an upper bound, holding that the return "should be commensurate with returns on investments in other enterprises having corresponding risks."[6]

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[2] Minn. Stat. § 216B.16, subd. 7b(b)(6).
[3] Minn. Stat. § 216B.03 ("*Every rate* made, demanded, or received by any public utility . . . *shall be just and reasonable*.") (emphasis added).
[4] *Id.* ("*Any* doubt as to reasonableness should be resolved in favor of the consumer.") (emphasis added).
[5] Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923).
[6] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

Together, these two cases instruct the Commission to review three factors when setting utility returns. The first two factors are focused on ensuring that the utility has the financial support to continue providing service to customers. According to the Supreme Court, the return should "assure confidence in the financial soundness" of Xcel, and "maintain and support its credit," so that the utility can continue to provide safe and reliable service.[7] These factors must be balanced against the third factor, which is the Supreme Court's requirement that a utility's return should be "commensurate with returns on investments in other enterprises having corresponding risk," and no higher.

One of the key inquiries in any determination about an allowed rate of return, then, is what type of investments are subject to "corresponding risk," and the expected return of those corresponding investments. These Comments demonstrate that the risk of Xcel's investments recovered through the TCR rider is very different than the risk of its other investments, and that investments of similar risk must receive a much lower return than the return "authorized" in the Company's last rate case.[8] Using the analysis provided by the Supreme Court, the return paid for those TCR investments should be lower as well.

II. THE RISK ASSOCIATED WITH CAPITAL INVESTMENTS RECOVERED THROUGH RIDERS IS LOWER THAN THE RISK OF OTHER UTILITY INVESTMENTS.

According to the United States Supreme Court, the Commission is required to set utility returns at a level that is "commensurate with investments in other enterprises having corresponding risks."[9] In a general rate case, this process typically involves selecting other

[7] Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923).
[8] No ROE was authorized in Xcel's last rate case, but the Commission permitted Xcel to represent to its shareholders that its ROE was 9.20 percent.
[9] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

comparable utilities to develop a proxy group that has similar risk. This section will demonstrate that the risks for investments recovered through riders, like the TCR, are not comparable to the risks of general utility operations, and a different approach should be used to identify "corresponding risk." Section II.A will provide a definition of different types of risk that the Commission should consider. Section II.B will explain why the risks of rider investments are not comparable to the risks of investments recovered through base rates. Section II.C will demonstrate that some specific characteristics of Xcel's TCR rider proposal further reduce the already-low risk of rider investments. Finally, section II.D will summarize the conclusions made throughout Section II.

A. RISK DEFINITION AND EXPLANATION.

Before continuing, it is important to define the concept of "risk," because it can be understood in many different ways. Risk, in the context of the cost of capital, can be defined as "the degree of uncertainty (or lack thereof) of achieving future expectations at the times and in the amounts expected."[10] Three types of risk are particularly relevant for consideration in this docket. Business risk is the uncertainty inherent in day-to-day business operations, such as the possibility that revenue could decline. Utilities face business risk related to the uncertainty of sales, and uncertainty about whether regulators will allow recovery of their investments when they are between rate cases.

Financial risk is the risk that is related to the utility's capital structure, such as the possible volatility associated with adding debt to the capital structure. All else equal, an investment financed with more debt is riskier, and an investment financed with less debt is less

[10] SHANNON P. PRATT & ROGER J. GRABOWSKI, COST OF CAPITAL 71 (5th ed. 2014)

risky because of the fixed costs associated with debt. Increased financial risk (e.g. increased debt) essentially magnifies the underlying business risk.

Investors' primary focus, however, is on underlying cash flow risk. Cash flow risk is the risk that cash flows do not occur at the expected time and in the expected amount. Both business risk and financial risk contribute to cash flow risk. Investors will require different returns depending on the level of cash flow risk, because they want compensation for the possibility that the investment does not generate money as expected, when expected. The more uncertain an investor is about an investment's likely cash flows, the riskier it is. Conversely, the more certain an investor is about how much cash flow will be generated, and when it will be generated, the less risky it is.

B. THE RISK OF RIDER INVESTMENTS IS MUCH LOWER THAN BASE RATE INVESTMENTS.

The risk of investments recovered through riders is lower than the risk of investments that are recovered through base rates. Both business risk and cash flow risk are very low compared to investments recovered through base rates because recovery of the rider revenue requirement is virtually guaranteed. It may be useful to first consider how utility investments are recovered in a traditional rate case to more clearly see how rider recovery poses fundamentally lower risk.

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. In fact, it would be relatively unusual, and likely coincidental, if a utility earned the exact revenue requirement calculated in a rate case. 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.[11]

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 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.[12] This stands in stark contrast to investments that may only be recovered in base rates.

For example, if a utility makes an investment outside of a test year (or if Xcel 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. If the utility selects 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 investment had to wait until a future rate case.

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

[11] While Xcel's full decoupling program is, to some extent, a true-up of the top-line (revenue) portion of its business, the bottom line (profit) portion is not trued-up at all. Deviations in bottom line profit are tolerated by the utility, and its investors, in return for the allowed ROEs that are included in rates approved by regulators.

[12] The OAG observes that temporary under-collection could theoretically occur 50 percent of the time if utilities target exactly one dollar of recovery for each dollar of the revenue requirement and if actual recovery is normally distributed. Additionally, under-collection will be seasonal to the extent that recovery is volumetric.

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."[13] In addition to these generally applicable differences between rider and base rate investments, which would hold for any IOU in Minnesota, there are unique features of Xcel's TCR rider that could serve to reduce the risk to the utility even further.

C. SPECIFIC CHARACTERISTICS OF XCEL'S TCR RIDER FURTHER REDUCE ITS RISK COMPARED TO BASE RATE INVESTMENTS.

There are at least three reasons why Xcel's TCR rider further reduces risk compared to other possible rider structures. First, Xcel has requested a two-way carrying charge "because of the potential for a misalignment of the time a rate is effective compared to the revenue requirements intended for recovery."[14] If approved, this two-way carrying charge will reduce risk for the TCR rider by compensating for cash flow timing differences (e.g. under-collection).[15] Xcel confirmed the risk elimination in its response to OAG Information Request 203: "[s]hould an under-collection occur, the Company would be protected for its time value of money through

[13] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).
[14] Xcel's Petition at 14.
[15] *Id.*

an interest charge."[16] Xcel also explained that the two-way carrying charge would be "calculated on a monthly balance."[17] As it stands, Xcel is guaranteed that it will be allowed to true-up the TCR rider at the end of the year, but there is still some risk of under-collection during the course of the year. Calculating a carrying charge on the monthly balance as Xcel has requested would essentially eliminate the impact of that risk.

The concept of "time value of money" suggests that money has a different value depending on when the cash flow occurs—money that comes later is not worth as much as it is today. To provide a simple example, assuming a five percent interest rate, $105 on January 1, 2019 is equivalent to $100 on January 1, 2018.[18] If the investor was comfortable that the interest rate fairly compensated for the underlying risk, it would not care whether it was paid $100 in 2018 or $105 in 2019.

By paying Xcel interest if it under-collects on a monthly basis, Xcel's proposed two-way carrying charge would accomplish a similar result for the TCR rider. In other words, if this change is implemented, it would essentially mean that Xcel should no longer care whether it under-collects on a monthly basis from the TCR rider. The combination of rider recovery and monthly interest would thus allow Xcel to make TCR investments at an extremely low risk, and it would be very different from how base rate investments are handled. If utilities are allowed to recover the rate of return on subsequent true-ups of any under-collected amounts, the utility's risk is essentially eliminated—it is unclear whether there would be any real investment risk at that point. A two-way carrying charge mechanism *could* be in the public interest, but only if its

[16] OAG Information Request 203, OAG Exhibit 1.
[17] *Id.*
[18] $105 = $100 * (1 + 5%)

risk-reducing properties are reflected by a reduced rate of return as described in these Comments.[19]

The second risk reducing feature in Xcel's TCR rider is its proposal to recalculate the rider "to recover the 2017–2018 revenue requirements over the remaining months of 2018 in order to match 2018 cost recovery with the eligible 2018 costs."[20] The OAG agrees that this approach is reasonable, but it is also important to note that it further reduces the risk of the TCR rider because it would lead to a higher rider rate, and thus further reduce the risk of temporary under-collection this year and in future years because the rider rate remains in place until it is changed by the Commission.

Finally, Xcel has spread the risks of many of the TCR investments among other utilities, thus defraying the risk to Xcel. In its Petition, the Company explained that "[a]n investment of approximately $1.8 billion for all of the projects would be difficult for any one utility to undertake. By collaborating with a number of other regional utilities, the Company is able to successfully spread its risks and balance its costs."[21] These specific TCR investments have even further reduced risks because their burden is shared with other utilities.

In combination, these characteristics further demonstrate that the risks of TCR investments are lower than the risk of base rate investments—and even lower than a generic rider. The next question thus becomes what an appropriate approach should be for establishing a return in this proceeding.

[19] If the rate of return is set using the Commission's traditional methods, the OAG does not support the two-way carrying charge.
[20] Xcel's Petition at 13.
[21] Xcel's Petition, Attachment 1, at 3.

D. THE RISK OF TCR INVESTMENTS IS NOT COMMENSURATE WITH THE RISK OF BASE RATE INVESTMENTS, AND A DIFFERENT APPROACH IS REQUIRED.

In a general rate case, the Commission reviews a proxy group and various financial models to find a return that is commensurate with investments of similar risk. The risk of rider investments is not comparable to the overall risk level of utilities, because the utilities primarily recover investments through base rates with much higher levels of risk than through the TCR rider.

One of the primary factors in establishing utility returns is to ensure that they are "commensurate with returns on investments in other enterprises having corresponding risks."[22] To summarize the findings contained in this section: TCR investments are far less risky than investments that are recovered through base rates. Xcel's cost recovery is essentially guaranteed, and is not subject to a rate case. It has essentially no risk of under-recovery because of the annual true-up, and even that risk would be eliminated by its proposal for a two-way carrying charge. And it has very little risk of regulatory disallowance, because costs recovered through the TCR rider have already been approved or certified by the Commission. These characteristics demonstrate that the risks of the TCR rider are not commensurate or corresponding with the risks of investments recovered through base rates in a general rate case. Investments recovered through Xcel's TCR rider bear far less risk, and, according to the analysis of the United States Supreme Court, that means they should earn a lower return than base rate investments. The next step of the analysis is to determine the appropriate return for this level of risk.

[22] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

III. THE RISKS OF THE TCR RIDER ARE COMMENSURATE WITH THE RISK OF DEBT SECURITIES.

As explained in Section I, the Commission has the authority to set a return for the TCR rider that is "consistent with the public interest"[23] and that will produce "just and reasonable rates."[24] In order to satisfy those requirements, the United States Supreme Court requires the Commission to establish a return that is "commensurate with returns on investments in other enterprises having corresponding risks."[25] Section II demonstrates that the traditional methods for establishing a regulated rate of return for calculating base rates are not reasonable in this instance, because the risks of investments that are recovered through riders are not comparable to the risks of base rate investments. In order to establish a return that is consistent with the public interest and will produce just and reasonable rates, different investments with corresponding risks must be used for comparison.

Section III will demonstrate why the level of risk for investments in Xcel's TCR rider is comparable to debt securities, and why the Commission should establish a return equal to NSPM's cost of long-term debt for the TCR rider in this case. Section III.A will provide general information about debt securities. Section III.B will explain that the risk of rider investments is comparable to the risk of debt securities. Section III.C will quantify a range of returns based on debt securities. Section III.D will explain why a return based on the utility's cost of long-term debt is reasonable for this case.

A. GENERAL INFORMATION ABOUT DEBT SECURITIES.

Debt securities include many types of investments. The United States Treasury issues many types of debt securities, which are generally referred to as Treasuries. Corporations can

[23] Minn. Stat. § 216B.16, subd. 7b(b)(6).
[24] Minn. Stat. § 216B.03.
[25] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

also issue debt securities, and they come in many forms as well. The primary characteristic of these securities are the predictable cash flows that they present to a potential investor. In general, debt securities provide investors with (1) guaranteed interest payments on a specific schedule; (2) a guarantee that the entire principal amount (i.e. the loan) is repaid to the investor at the maturity date; and (3) protection in the form of priority in the event of bankruptcy. For example, a corporate bond could provide the bondholder with guaranteed interest payments on January 1 every year, with a further guarantee that the entire amount of the bond will be paid off on a specific date.

Debt securities come in many forms, with variance in the terms and conditions. The most significant characteristics for the purposes of these Comments are the maturity (i.e., duration or length) of the security and the built-in return (i.e., the coupon rate). Differences in these terms contribute to the overall risk profile of the security. For example, longer-lived Treasuries generally provide a higher return than shorter-term Treasuries to account for the increased risk of the longer maturity period.

Securities issued by the U.S. Treasury Department are considered to be the lowest risk investments available in the United States.[26] In comparison, corporate bonds are seen as more risky than U.S. Treasury securities, and thus often have a higher return, all else equal. The reason that corporate bonds are riskier is even though the risk of default on a corporate bond is low, it is still higher than the risk of the United States government defaulting on its debt obligations. The yield spread between corporate bonds and U.S Treasuries can be understood to represent the different levels of risk between the investments. As a whole, despite the variance

[26] There are two companies with AAA credit ratings (Johnson and Johnson, and Microsoft), but they do not have the degree of liquidity associated with Treasuries.

in terms and conditions, the risk profile of debt securities compares favorably to the risk profile of rider recovery.

B. THE RISK OF TCR INVESTMENTS IS COMPARABLE TO THE RISK OF DEBT SECURITIES.

The risks of investments recovered through the TCR rider and debt securities are comparable because they share important characteristics that are *not* shared by equity investments. Compared to equity investments, cash flows from both debt securities and riders are relatively predictable. Equity securities do not include any guaranteed cash flows. For example, shareholders that own stocks of Microsoft only receive cash when its board of directors decides to pay dividends. The same is true for other equity investments. While many corporations, including utilities, pay dividends regularly, they are under no obligation to do so, and the shareholders have no inherent right to receive dividend payments. In contrast, an investor holding a corporate bond has a legal right to expect payments on the bond on specific dates that were agreed to at the outset, *and* the right that the investment will be paid in full on a specific date.

Cash flows for investments recovered through a rider are much more comparable to the certainty of the cash flows provided to debt securities than the uncertain, non-guaranteed (risky) cash flows associated with equity securities. Investments recovered through the TCR rider are essentially guaranteed full recovery on a yearly basis, and, if Xcel's requested two-way carrying charge is approved, it would be compensated financially for any delay in the true-up. This certainty of the amount and timing of recovery is comparable to the guarantees provided by debt securities. It is reasonable to compare investments that have similar levels of cash flow risk because, as discussed above, cash flow risk is the primary focus of investors in the market. The

cash flow risk of TCR investments is thus commensurate with and comparable to the cash flow risk of debt securities, not equity investments.[27]

Rider investments share other characteristics with debt securities. One benefit of holding debt (instead of equity) is that debt holders are generally receive priority over equity holders in the event of bankruptcy. This protection in the event of business failure is a significant benefit. One of the reasons equity investments typically require greater returns is because equity investors are aware that debt holders will have priority in the event of bankruptcy. Similarly, one benefit (to utilities) of riders is the ability to get a project or projects pre-approved or certified from the Commission prior to commencement of the project. This provides the utility significant protection against the risk of disallowance. In general, base rate investments do not receive pre-approval from the Commission; the utility must make the investments and hope that regulators will agree that they were prudent. Bankruptcy preference for debt securities is thus comparable to certification for rider investments because both provide protection against the risks of loss that are not available to equity investments or base rate investments.

Another characteristic that rider investments and debt securities share is their insulation and separation from a firm's long-term strategy and the impacts of the general economy. Equity investors hold what is essentially an infinite claim of partial ownership in a business, and the share price of their investments relies significantly on (1) market opinions about the direction of the firm, whether that direction is good or bad, and (2) opinions about the general economy. Debt investors, on the other hand, are largely insulated from these long-term factors. Once a debt security is issued, there are commitments about the length of maturity and when payments

[27] *See* Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

will be made, commitments that are far less likely to be impacted by the direction of the firm or opinions about the general economy.

This separation is similar to the way that rider investments are separated from the broad spectrum review that a utility receives in a general rate case. When the Commission reviews rider investments, the analysis is typically limited to the specific issues in a rider and often do not incorporate the moving pieces of the utility's larger business. To some extent, base rate investments are comparable to equity investments because they require a review and understanding of the utility's entire business, while rider investments and debt securities are, to some extent, partitioned from the larger business operations. In combination, these characteristics demonstrate that risk/reward relationship of debt securities is more commensurate than equity securities with the risk/reward of investments recovered through riders. The next question is how to determine which particular debt securities most resemble the risk profile of rider recovery.

C. A RANGE OF DEBT SECURITIES PROVIDES A REASONABLE COMPARISON TO INVESTMENTS RECOVERED THROUGH THE TCR RIDER.

Rather than selecting a single type of debt security to provide a comparison to TCR investments, the most reasonable analysis is to create a range of debt security returns that can be compared. 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?[28] There are several theories on how to answer this question. Comparing those theories to different

[28] At which point they would be entitled to earn the full rate of return authorized for the utility's base rates.

types of debt securities can help the Commission create a range of debt security returns to compare to the TCR rider.

1. 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 is approximately 2.3 percent currently.[29] 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.

2. 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

[29] U.S. DEP'T OF THE TREASURY, Daily Treasury Yield Curves, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/default.aspx (last accessed Apr. 1, 2018).

theory that riders should be rolled into base rates as quickly as possible. 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.

Consider the debt holdings of Xcel Energy—on December 31, 2017 Xcel Energy Inc.'s capitalization included approximately $25 billion in long-term debt, with approximately $19 billion due *after* 5 years, with the remaining approximately $6 billion due *within* five years.[30] Xcel explains its "Manageable Debt Maturities" at slide 27 of a recent investor presentation.[31] For NSPM specifically, it explained at page 54 of its most recent 10-K that:

> In 2017, NSP-Minnesota issued $600 million of 3.6 percent first mortgage bonds due Sept. 15, 2047. In 2016, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046. During the next five years, NSP-Minnesota has long-term debt maturities of $300 million due in both 2020 and 2022, respectively.[32]

With the recent $600 million issuance, NSPM's current long-term debt totals $5 billion, has a weighted average time to maturity of approximately 18 years, and has a weighted average coupon rate of approximately 4.3 percent.[33]

[30] XCEL ENERGY, INC., U.S. SECURITIES & EXCH. COMM'N 2017 FORM 10-K at 77.
[31] OAG Exhibit 2 (Xcel's East Coast Investor Meetings February 27–28, 2018)
[32] NORTHERN STATES POWER CO., U.S. SECURITIES & EXCH. COMM'N 2017 FORM 10-K at 54.
[33] Xcel's petition states that its 2018 cost of long-term debt is 4.77 percent. Xcel's Petition, Attachment 10. It appears that this cost of debt was drawn from Xcel's recent rate case settlement—in other words, the "2018 cost of long-term debt" in the Petition is based on an estimate that is several years old, and does not incorporate the more recent issuances, which have driven the cost down.

Xcel's long-term debt, with a weighted average maturity of 18 years, is a reasonable comparison to the risks of its TCR investments when considering the greatest length of time that an investment would be allowed to remain in a rider before being rolled into base rates. Given the Commission's prior decisions on riders, and the fact that Xcel will be operating under a series of MYRPs, it is unlikely that any investments will be recovered through a rider for more than 18 years. For that reason, it is reasonable to use the 4.3 percent long-term debt rate as a ceiling for the comparable debt security range. Because the time to maturity of financing is generally intended to approximate the duration of the investment, 4.3 percent would actually be a conservative ceiling in this case.[34]

The analysis above suggests that a range between the two year Treasury rate, 2.3 percent, and Xcel's 4.3 percent cost of long-term debt, provides a range of debt security returns that are commensurate with the risks of Xcel's rider investments.[35]

D. IN THIS PROCEEDING, A RIDER RETURN CONSISTENT WITH XCEL'S COST OF LONG-TERM DEBT WOULD BE A REASONABLE AND CONSERVATIVE RESULT BECAUSE IT BALANCES THE INTENT OF RIDERS WITH THE RISKS OF TCR INVESTMENTS AND IS CONSISTENT WITH THE PUBLIC INTEREST.

Within the range described above, a reasonable and conservative return for this proceeding is the ceiling, or a return equal to NSPM's cost of long-term debt. There are several reasons why setting a return at the high point of the range is reasonable in this proceeding.

First, establishing a return using debt securities, rather than the methods that are typically applied in a rate case, would be a change. From that perspective, it would be reasonable to be conservative and select a result from the high point of the range.

[34] It is worth pointing out that the Company's cost of long-term debt is significantly higher than the current yield on 30-year Treasuries.

[35] The Commission could select a return outside of this range if it seeks to incentivize utilities to change their behavior. For example, the Commission could incentivize utilities to avoid the use of riders by selecting a rate of return at or below the level of the two year Treasury. In contrast, it could encourage utilities to use riders rather than base rates by providing a return that is greater than the cost of long-term debt.

Second, the Commission has not yet expressed a preference for how long-term investments should be recovered through riders. If, at some point, the Commission indicates that rider investments should be rolled into base rates quickly, then it may be reasonable to select a different point within the range described above. Absent that indication, the cost of long-term debt is a reasonable balance against the public policy goals for the use of riders. One reason to permit utilities to use riders is to assist during periods of significant investment.

Third, Xcel's cost of long-term debt provides a factual basis upon which the Commission can base a decision. Xcel clearly has access to capital at those rates, and, given the certainty of the amount of recovery for rider investments, it is reasonable to tie the return on those investments to the cost of financing investments with similar characteristics. Because investment recovery through riders is generally intended for a period of approximately two years or more and rider risk is clearly much lower than the risk associated with base rates, the cost of long-term debt will provide a reasonable return for this case.

The risks of investments recovered through riders like the TCR are commensurate with the risks of debt securities. Specifically, a debt security range extending from the two-year Treasury rate of 2.3 percent to Xcel's cost of long-term debt rate of 4.3 percent provides a reasonable range of comparison for the risks of Xcel's TCR investments. Within that range, for this proceeding, the most reasonable and comparable return is Xcel's cost of long-term debt—4.3 percent.

In addition to the requirement that returns be should be "commensurate with returns on investments in other enterprises having corresponding risks,"[36] the U.S. Supreme Court has established other requirements that must be fulfilled when setting the return for utility

[36] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

investments. The next section will demonstrate that a return based upon debt securities fulfills these requirements.

IV. A RETURN ON EQUITY BASED ON DEBT SECURITIES FOR THE TCR RIDER WOULD SATISFY ALL THREE HOPE AND BLUEFIELD CONDITIONS.

As described in Section I, the United States Supreme Court has established three factors that must be fulfilled when setting a return for utility investments. The return must (1) "assure confidence in the financial soundness" of the utility;[37] it must (2) "maintain and support its credit" so that the utility has access to capital;[38] and it must be (3) commensurate with returns on investment in other enterprises having corresponding risks."[39] The prior sections have demonstrated that a return based on debt securities, and specifically Xcel's cost of long-term debt, would be commensurate with other investments having corresponding risks. This section will demonstrate that a return at that level would assure confidence in the financial soundness of investments recovered through this TCR rider and in Xcel's Minnesota electric utility overall, and that the Minnesota electric utility would continue to have sufficient access to capital to ensure the continuation of safe and reliable service.

Riders like the TCR were originally developed to provide cash to utilities during the times when they invest significantly more than usual in long-term capital projects because they are not yet "used and useful." Because assets cannot generally be placed into rate base until they are used and useful, riders provide a way for utilities to collect cash earlier than they would otherwise be allowed, to offset cash outflows for projects that are still under construction and are not included in AFUDC or CWIP in a general rate case. Because riders essentially provide

[37] Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923).
[38] *Id.*
[39] *Id.*; Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

unearned cash to utilities on the assumption that they will finish the project and eventually place it into rate base when it is used and useful, these riders contribute to the financial soundness and creditworthiness of the utility, whether the rider-recovered investment is allowed a return or not. Providing more cash to a company generally contributes to its financial soundness and creditworthiness compared with removing cash from a company. Allowing a return equal to the cost of long-term debt likely provides more cash than necessary for the utility to finance its rider investment projects until its next general rate case, so the resulting extra cash further contributes to the financial soundness and creditworthiness of both its rider investments and the utility in general. Because rider-recovered investments are not intended to comprise a significant portion of utility revenue or return, their relative impact on the overall utility should be, by definition, relatively insignificant.

V. ANOTHER REGULATORY COMMISSION HAS REACHED A SIMILAR CONCLUSION REGARDING RIDER RATE-OF-RETURN.

At least one other regulatory commission has set utility returns based on the principles described above. In Iowa, a 2011 rulemaking determined that the utility's cost of debt was the most appropriate rate of return for gas utilities' infrastructure-related capital investment riders.[40] 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."[41]

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,

[40] *In Re: Capital Infrastructure Investment Automatic Adjustment Mechanism for Rate-Regulated Natural Gas Utilities*, Iowa Util. Board Docket No. RMU-2011-0002, ORDER ADOPTING RULE (Oct. 13, 2011).
[41] 199 IAC 19.18(3)(c). The cost of debt is defined as the "cost of debt from the utility's most recent general gas or electric rate review proceeding . . . ." 199 IAC 19.18(3)(b)(3).

utilities advocated for a rate of return set at the weighted average cost of capital from the utility's most recent rate case.[42] On the other end, the Iowa Office of Consumer Advocate ("OCA") recommended that no return be allowed for rider recovery at all.[43] 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.[44]

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.[45]

Applying this reasoning to Xcel's TCR rider would support setting the return at the long-term cost of debt.

The Board has also recently approved rider recovery at the cost of debt in a proceeding in which a gas utility requested recovery of costs associated with the replacement of farm tap

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[42] *In Re: Capital Infrastructure Investment Automatic Adjustment Mechanism for Rate-Regulated Natural Gas Utilities*, Iowa Util. Board Docket No. RMU-2011-0002, ORDER ADOPTING RULE at 30–34 (Oct. 13, 2011).
[43] *Id.* at 29.
[44] *In Re: Capital Infrastructure Investment Automatic Adjustment Mechanism for Rate-Regulated Natural Gas Utilities*, Iowa Util. Board Docket No. RMU-2011-0002, OCA STATEMENT OF POSITION at 3 (Jun. 23, 2011).
[45] *In Re: Capital Infrastructure Investment Automatic Adjustment Mechanism for Rate-Regulated Natural Gas Utilities*, Iowa Util. Board Docket No. RMU-2011-0002, ORDER ADOPTING RULE at 34–35 (Oct. 13, 2011) (emphasis added).

lines.[46] In that case, the company proposed three alternatives for cost recovery. First, it proposed including costs in a rider-like mechanism authorized under Iowa Rule 19.18.[47] The company later withdrew this recommendation. Second, the utility proposed placing the full costs of each replaced line in a regulatory asset account, with deferred cost recovery and an 11.45 percent carrying charge.[48] Third, the company proposed a recovery mechanism similar to one it had in place for the recovery of costs associated with energy efficiency.[49]

The Board ultimately selected the company's first proposal, which was to recover costs via a rider with a return based on a cost of debt of 4.4 percent. Despite the company's objections, the Board determined that this was "the most reasonable and just way to recover authorized capital costs prior to [the company's] next general rate case" and that "all automatic adjustment mechanisms are intended in part to reduce regulatory lag," but that "complete elimination of regulatory lag is not a policy the Board has previously endorsed" and it chose not to do so in that case.[50] Further, the Board's order stated that "[u]sing the current cost of debt reflects the Board's intent when it approved [a prior rider closely resembling the current one] that it was not intended to displace the need for all future rate cases," but rather that "allowing utilities to earn a return of their investment as well as a return on their investment equal to the cost of debt significantly reduces the effects of regulatory lag and provides substantial incentive to utilities to move forward with implementation of such safety-related projects."[51]

Throughout the Board's rulemaking and subsequent application of the rule, it has become clear that the Board views capital infrastructure riders as having risks that are distinct and

[46] *In Re: Black Hills/Iowa Gas Utility Company, L.L.C. d/b/a Black Hills Energy*, Iowa Util. Board Docket No. SPU-2015-0039, TF-2015-0352, FINAL DECISION AND ORDER at 8 (Apr. 20, 2017).
[47] *Id.* at 8.
[48] *Id.* at 8–9.
[49] *Id.* at 9.
[50] *Id.* at 10.
[51] *Id.*

different from investments that are recovered through base rates. Although the Iowa Board's rulemaking and subsequent cases involve natural gas utilities, the similarities outweigh the differences in regard to their applicability to the circumstances in this docket. In both instances, the utility regulator had to grapple with the differences in risk between rate cases and riders. The Iowa Board weighed these considerations and determined that the risks associated with rider recovery are fundamentally different than traditional base rate recovery of capital costs. The Minnesota Commission should do the same in this docket.

One significant difference between the Iowa example and Xcel's situation in Minnesota is Xcel's request for a multiyear rate plan. For the reasons described below, Xcel's current multiyear rate plan, which is intended in part to reduce the risk faced by the utility, is another reason that the return granted for the TCR Rider should be significantly reduced.

VI. IN ADDITION TO ESTABLISHING A RETURN COMMENSURATE WITH OTHER INVESTMENTS OF SIMILAR RISK, A RETURN BASED ON XCEL'S COST OF LONG-TERM DEBT WOULD PRODUCE OTHER PUBLIC POLICY BENEFITS.

The existence and structure of Xcel's current multiyear rate plan ("MYRP") significantly reduces the risk faced by the utility and is another reason that the return allowed in the Company's capital cost riders should be set at a much lower level than Xcel requests. In short, in addition to satisfying the legal requirement that the return be similar to the return on investments with similar risk, a return set at Xcel's cost of long-term debt would address several other policy concerns stemming from the use of riders during Xcel's MYRP. This section will first briefly introduce the concept of MYRPs. This will be followed by a discussion of how the allowance of such a mechanism alters the risk faced by the utility. Finally, this section will show how awarding capital cost riders with built-in guaranteed returns that match or exceed the returns built into base rates through the MYRP can harm the public interest.

A. THE STRUCTURE OF A MULTI-YEAR RATE PLAN.

In a traditional rate case, a utility's base rates remain static between general rate cases. This increases the risk that prudent utility costs will increase without a commensurate increase in revenue, otherwise known as regulatory lag.[52] There are several regulatory tools that are designed to reduce the regulatory lag faced by a utility, such as a forecasted test year and cost trackers and riders. Minnesota's regulatory structure uses both of these tools. Recently, a new regulatory tool was introduced to Minnesota that will allow utilities to reduce regulatory lag even further.

The MYRP as a regulatory tool is based upon the premise that without one, utilities will file continuous rate cases because of growing costs and declining growth in sales.[53] The filing of continuous rate cases causes an increase to regulatory costs for the utility, other parties, regulators—and ultimately ratepayers. But the "biggest" benefit from MYRPs comes from the utility's opportunity to increase base rates each year, which increases revenue.[54]

There are three main components to a MYRP.[55] The first component is the starting rate base or revenue amount that is typically determined using a forecasted or historical test year. The second component is the step-wise increases to base rates that may be determined by forecasts or increases tied to industry indices. Finally, the third component is the duration of the MYRP.

There are also a number of additional components that can be added to a MYRP in order to balance risk between the utility and ratepayers. For example, MYRPs can increase

[52] Regulatory lag can benefit utilities during times of high sales growth and/or declining costs, but this scenario creates a ratepayer risk that the utility is over-earning.
[53] Ken Costello, Nat'l Reg. Research Inst. Report No. 16-08, *Multiyear Rate Plans and the Public Interest* 16 (Oct. 2016).
[54] *Id.* at 17. The OAG acknowledges that Xcel's current base rate shape, which was determined via black box settlement, does not include a base rate increase for one of the four years.
[55] *Id.* at 20–21.

productivity and the incentive for utilities to contain costs. In theory, these benefits are achieved in two ways. First, the extended time between the filing and litigation of a rate case allows utility managers to turn their focus toward the utility operation itself, thus increasing productivity. Second, and relatedly, any increase to productivity should lead to cost savings, which the utility is able to retain during the duration of the MYRP. In a separate docket, the OAG has recommended that the Commission develop performance mechanisms designed to measure the cost containment performance of Xcel during its MYRP.[56] The actual realization of the theoretical benefits of MYRPs, however, depends in large part on the design of the MYRP itself and on the interactions between regulators and the utility during the plan years on issues that impact utility incentives.

Xcel is currently operating in the third year of a four-year MYRP, which is the first of its kind in Minnesota. The Company filed this case in 2015 and the final four-year base rate shape is the result of a settlement agreed to by some of the intervening parties and ultimately approved by the Commission.[57] The settlement was a "black box" settlement, meaning that the underlying revenue requirements cannot be derived on an issue-by-issue basis. Similarly, the settlement contained a provision allowing Xcel to represent a return on equity of 9.20 percent to investors, even though this number had no ties to the final, settled revenue requirement.[58] The next section will describe how Xcel's settled MYRP has impacted its cost riders and how this runs counter to the public interest.

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[56] *In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and Potentially, Incentives for Xcel Energy's Electric Utility Operations*, MNPUC Docket No. E002/CI-17-401, OAG INITIAL COMMENTS at 62–64 (Dec. 21, 2017).

[57] *See generally In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MNPUC Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT (Aug. 16, 2016).

[58] The OAG recommended an ROE of 8.14 percent in the case. *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MNPUC Docket No. E002/GR-15-826, OAG INITIAL BRIEF at 168 (Nov. 30, 2016).

B. COST RECOVERY RIDERS AND MYRPS.

A capital rider like the TCR Rider is another way for utilities to reduce the level of risk they face by allowing the utility's revenue to more closely track the prudent costs it incurs. Capital cost trackers can be used in MYRPs to address extraordinary levels of spending or surges in spending over the plan years.[59] The inclusion of capital riders in MYRPs, however, weakens the incentive of the utility to contain its costs during the plan years.[60] In fact, the Commission has stated that cost riders alone substantially erode "meaningful and binding incentives to control costs."[61] Allowing riders in combination with MYRPs may exacerbate the concerns.

For this and other reasons, the Commission has ordered utilities to "seize" opportunities for administrative efficiencies in their MYRP proposals by ordering utilities to "consolidat[e] as many of [the existing riders] as practical in the most reasonable manner available."[62] This directive is especially applicable to those costs that are "continuing" and "predictable."[63] The design of the partial settlement in Xcel's 2015 rate case and the Company's filing in this docket demonstrate the prescience of the Commission's 2013 MYRP Order.

In its initial filing in the 2015 rate case, the Company deflected the Commission's directive to incorporate existing riders into base rates by pointing to an amendment to the MYRP statute and arguing, essentially, that the amended statute did not prevent a utility from using

[59] Mark Newton Lowry, J. Deason, M. Makos, & L. Schwartz, U.S. Dep't of Energy Grid Modernization Laboratory Consortium, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* 4.3 (Jul. 2017).
[60] *Id.*
[61] Minn. Pub. Util. Comm'n, *Utility Rates Study* 7 (Jun. 2010).
[62] *In the Matter of the Minnesota Office of the Attorney General—Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, MNPUC Docket No. E,G-999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS at 8 (Jun. 17, 2013).
[63] *Id.*

riders during a MYRP.[64] This issue came to the Commission as an integral part of the settlement that was reached between Xcel and several other parties. The settlement allowed three TCR Rider projects to remain in the rider instead of in base rates and it limited the Company to the use of "only" the 26 existing cost riders during the course of the MYRP.[65]

The existence of riders alongside a MYRP is not, as the Company has asserted, part of a "complementary" or "healthy" approach to ratemaking.[66] Rather, the existence of riders, and the expedited cost recovery (with a return) that they feature, represents a significant reduction in the risk faced by the utility. This is especially true for a rider like the TCR Rider, where costs are continuing and predictable, rather than extraordinary or outside of the utility's control. Put simply, the presence of the TCR Rider in Xcel's portfolio weakens Xcel's incentive to contain costs.[67]

The next section will describe several policy implications of this conclusion.

C. ESTABLISHING A DEBT RETURN FOR THE TCR WOULD PARTIALLY MITIGATE SEVERAL PUBLIC POLICY CONCERNS.

There are at least three public policy concerns that may be partially mitigated when a debt return is applied to riders. First, allowing a rider to have a return equal to the return on base rates creates a perverse incentive for the utility to focus on investments that can be recovered through the rider rather than what investments will best serve ratepayers. A utility should not be

[64] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* MNPUC Docket No. E002/GR-15-826, DIRECT TESTIMONY OF AKASH CHANDARANA at 62 (Nov. 2, 2015).
[65] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* MNPUC Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT at 7 & ATTCH. 3 (Aug. 16, 2016).
[66] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* MNPUC Docket No. E002/GR-15-826, DIRECT TESTIMONY OF AKASH CHANDARANA at 62 (Nov. 2, 2015).
[67] *See In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and Potentially, Incentives for Xcel Energy's Electric Utility Operations,* MNPUC Docket No. E002/CI-17-401, EXPERT OPINION OF DR. MARK N. LOWRY at 36 (Dec. 21, 2017) (noting that the existence of Xcel's TCR Rider during the MYRP weakens the incentive to contain costs, even with the current design of the TCR Rider).

allowed to request a return for a rider that is equal to the return established in its most recent rate case, especially if that utility is operating under a MYRP. A rider return greater than the base rate return is not consistent with the public interest or with the regulatory compact and should not be considered. Allowing a rider return equal to a base rate return would incentivize utilities to keep as many costs as possible outside of base rates and in existing riders. Doing so allows utilities to increase the certainty of recovery of those items, since rider mechanisms typically allow for complete cost recovery and reduce any delay relative to traditional rate case recovery. It also increases the likelihood that a utility will over-recover, since it will be virtually guaranteed cost recovery of costs that are subjected to a higher return than costs included in base rates. It would also incentivize utilities to litigate the return for each rider proceeding. One of the benefits of a MYRP was supposed to be a reduced regulatory burden. This benefit will not happen if the Commission has to resolve rate of return litigation for each of Xcel's riders, every year.

Second, awarding a debt return will address concerns about the ongoing presence of riders during the MYRP. One of the benefits of the MYRP is that it should incentivize the utility to control costs until it can file another rate case. This incentive is significantly reduced when the utility can put many types of costs into riders. Instead of focusing on cost containment, the utility will be incentivized to spend money that can be recovered through riders. In addition to being similar to investments with comparable risks, a debt return for the TCR rider would mitigate this concerning incentive, while still allowing the utility both return of and a return on its prudent investments.

Third, the combination of risk reduction from riders and risk reduction from the MYRP is a powerful advantage for utilities that should be reflected in the way their returns are calculated.

Both riders and the MYRP work to reduce risks for utilities. The MYRP itself is a risk-mitigation tool for utilities, especially when additional risk mitigation tools like revenue decoupling are included. It would not be reasonable, or appropriate under the *Hope* and *Bluefield* standards, to set returns using the same analytical methods that are applied in a general rate case proceeding. Awarding a debt return for the TCR rider would, to some extent, mitigate the concerns about this significant reduction in risk by also working to control costs for ratepayers and design appropriate investment incentives for the utility.

VII. SUMMARY AND CONCLUSION.

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."[68] If there is any doubt about whether the TCR return is comparable to other investments of similar risk, the Commission must resolve that doubt in favor of ratepayers.[69]

To satisfy these requirements, the Commission should set the return for Xcel's TCR rider at Xcel's cost of long-term debt, which is approximately 4.3 percent. These Comments demonstrate that the risks of Xcel'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. The specific characteristics of Xcel's TCR rider, including its proposal for a two-way carrying charge, further reduce its risks compared to base rate investments. For these reasons, the risk profile of TCR investments is best compared to the risks of debt securities, and

[68] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).
[69] Minn. Stat. § 216B.03.

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's cost of long-term debt. Because of the particular circumstances of this proceeding, it would be reasonable to set the return at the ceiling of that range, based on Xcel's cost of long-term debt of 4.3 percent.[70] In reaching this decision, the Commission can follow a path that has already been made by other regulatory Commissions, including the Iowa Utilities Board. Further, establishing a return for the TCR rider based on the cost of debt would also address several public policy concerns related to using riders during Xcel's MYRP.[71]

[70] As described above, this cost of long-term debt was taken from Xcel's most recent jurisdictional annual report, but the OAG is open to discussion about whether a different long-term cost of debt figure is more appropriate.

[71] The Commission may want to consider whether it would be reasonable to apply its decision on the return for the TCR rider to Xcel's other electric riders in order to maximize regulatory efficiency, as it did recently with Xcel's natural gas riders. The OAG takes no position on the question at this time.

For these reasons, the Commission should set the return for Xcel's TCR rider at 4.3 percent.

Dated: April 2, 2018

Respectfully submitted,

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FOR THE OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

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Xcel Energy
Docket No.: E002/M-17-797
Response To: Office of the Attorney General Information Request No. 203
Requestor: Ryan Barlow
Date Received: March 6, 2018

Question:
Reference: Petition page 14

The Petition states that "[the Company] request[s] of a two-way carrying charge starting January 1, 2019."

Define, Explain, and Quantify the requested two-way carrying charge.

Provide at least two hypothetical scenarios illustrating (1) an under-recovery scenario and (2) an over-recovery scenario.

Explain all benefits (1) for ratepayers and (2) for shareholders of the requested two-way carrying charge.

Response:
The two-way carrying charge would apply interest to the true-up balance, whether the balance is an over-collection or an under-collection.

Factors that might lead to under-recovery include actual costs being higher than forecast, actual sales being lower than forecast, and a timing mismatch of rate implementation compared to the test period especially if annual revenue requirements are increasing due to phased-in eligible investment. In the hypothetical example below, the initial rate is delayed by two quarters in the Test Year 1 and left in place for three periods in Test Year 2. At the end of two test years, a significant true-up balance exists that is more than half of the full year of revenue requirements for Test Year 2, thereby adding a significant amount to the presumed Test Year 3 rate. For ease of illustration, the example assumes a 10% interest rate applied annually, though in practice the interest would be calculated on the monthly balance.

Under-Recovery Example	Year 1				Year 2			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Forecasted and Actual Revenue Requirements	$100	$100	$100	$100	$150	$150	$150	$150
Forecasted and Actual Sales	1000	1000	1000	1000	1000	1000	1000	1000
Forecasted Rate	$0.10	$0.10	$0.10	$0.10	$0.15	$0.15	$0.15	$0.15
Rate in Effect	--	--	$0.10	$0.10	$0.10	$0.10	$0.10	$0.15
True-up Balance	$100	$200	$200	$200	$270	$320	$370	$370
Interest (10% for ease of calc)				$20				$37
Total True-Up Balance				$220				$407

Factors that lead to over-recovery include actual costs being less than forecasted, sales being higher than forecasted, and a timing mismatch of rate implementation compared to the test period especially if annual revenue requirements are declining through depreciation. In the example below, actual revenue requirements are less than forecast in Year 1 and Year 2. At the end of two test years, a significant true-up balance exists that is more than half of the full year of revenue requirements for Test Year 2, thereby significantly skewing the presumed Test Year 3 rate.

	Year 1				Year 2			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Forecasted Revenue Requirements	$100	$100	$100	$100	$150	$150	$150	$150
Forecasted Sales	1000	1000	1000	1000	1000	1000	1000	1000
Rate in Effect	$0.10	$0.10	$0.10	$0.10	$0.15	$0.15	$0.15	$0.15
Actual Revenue Requirements	$75	$75	$75	$75	$125	$125	$125	$125
Actual Sales	1250	1250	1250	1250	1250	1250	1250	1250
True-up Balance	($50)	($100)	($150)	($200)	($283)	($345)	($408)	($470)
Interest				($20)				($47)
Total True-up Balance				($220)				($517)

In both examples, if eligible revenue requirements continue for several more years, the large true-up balances combined with timing mismatches between the rate implementation and the test period can create a yo-yo effect with the implemented rate and lead to customer bill volatility, even though the revenue requirements are relatively flat.

Ratepayers and shareholders would see similar benefits. All parties would have some motivation to match the recovery period with the test period so as to minimize the magnitude of a carrying charge, assuming equal likelihood of an under- or over-collection. The motivation of better matching should lead to smaller true-ups and

therefore less bill volatility. Additionally, both the Company and customer are compensated through interest when they are owed money. Should an under-collection occur, the Company would be protected for its time value of money through an interest charge. Should an over-collection occur, the ratepayers would be protected for their time value of money through an interest credit. The longer the mismatch between the test period and the recovery period, the more interest would accrue.

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Title:	Director of Revenue Analysis
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Telephone:	612-330-6646
Date:	March 16, 2018

Leading the Transition

East Coast Investor Meetings

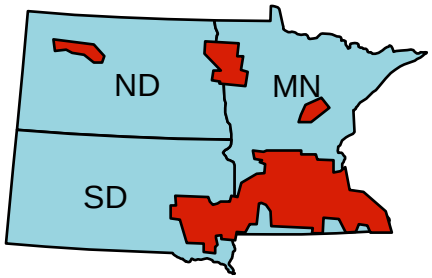
February 27-28, 2018

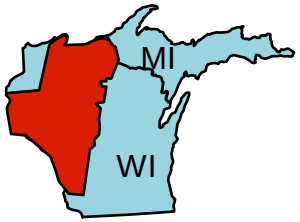
Exhibit 2

Safe Harbor

Except for the historical statements contained in this presentation, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2018 earnings per share guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in Xcel Energy’s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017, and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) to obtain financing on favorable terms; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by Xcel Energy; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors. See note 7 in our 2017 year end earnings report for more information about our use of non-GAAP numbers and a reconciliation of ongoing earnings to GAAP earnings.

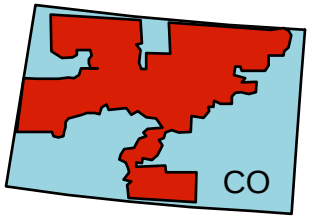
Diversified, Regulated, Leading Utility





NSPM
2016 Rate Base: $9.9 billion
2017 Ongoing EPS: $1.01
2018-2022 Cap Ex: $7.8 billion

NSPW
2016 Rate Base: $1.3 billion
2017 Ongoing EPS: $0.16
2018-2022 Cap Ex: $1.3 billion

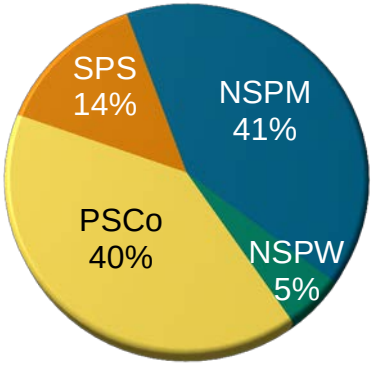


PSCo
2016 Rate Base: $9.4 billion
2017 Ongoing EPS: $0.94
2018-2022 Cap Ex: $6.2 billion

SPS
2016 Rate Base: $3.4 billion
2017 Ongoing EPS: $0.30
2018-2022 Cap Ex: $3.9 billion

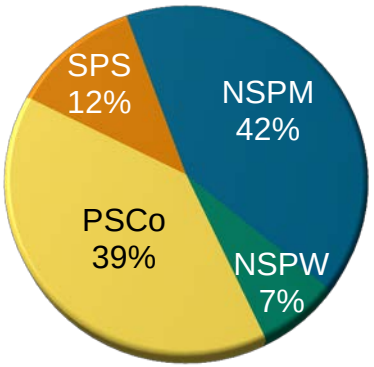
- Industry-leading, regulated electric and natural gas utility
- Leading utility renewable platform (as of YE 2017)
  - ~6,700 MW of wind
  - ~700 MW-AC universal scale solar
  - ~700 MW-DC community & private solar
- Attractive total return
  - Dividend yield of ~3.4%
  - Dividend growth objective of 5-7% annually
  - EPS growth objective of 5-6% annually
  - “A” rated secured credit profile

2016 Rate Base



$24 billion

2017 Ongoing EPS



$2.30/share

Cap Ex estimates do not include yet-to-be-allocated capital reductions totaling an estimated ~$500 million on a consolidated company basis

Translating Strategic Priorities to Growth

Lead the Clean Energy Transition

- Investment in wind, solar and related transmission
- Carbon reduction:
  - Achieved 30% in 2016
  - Projected 45% by 2021
  - Projected 60%+ by 2030

Enhance Customer Experience

- Investment in enhanced security, reliability, and automation
- Storage/EV enablement
- Lower SAIDI/SAIFI
- Top quartile satisfaction

Keep Bills Low

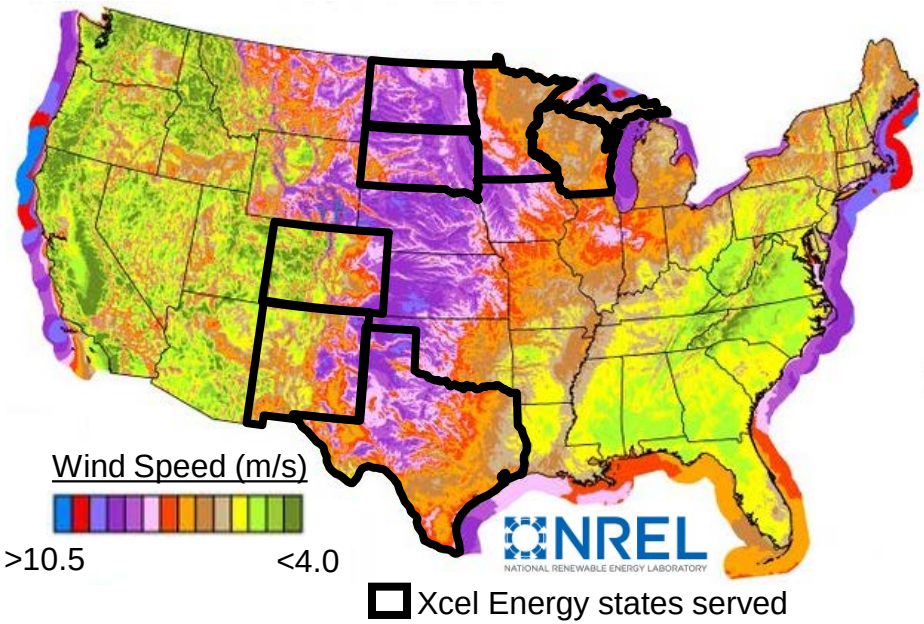
- Steel for fuel = savings
- Economic development
- Flat O&M
- Average bill increase at or below inflation

Stakeholder Alignment

Five-year Capital: $18.5 - $20.0 billion
Rate Base CAGR: 6.5% - 7.0%

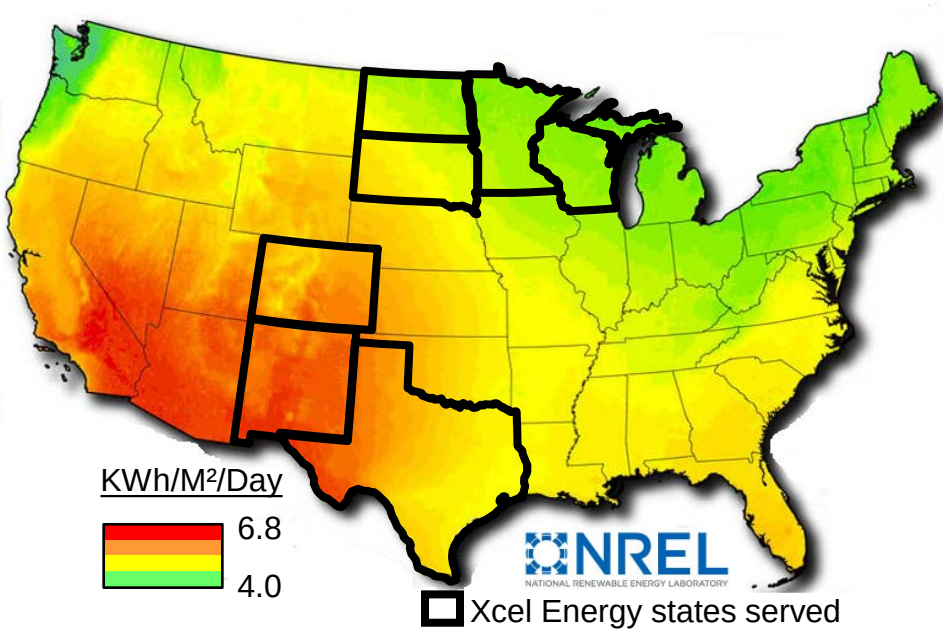
Advantaged Geography

Wind Resource – Annual Average Wind Speed
(at 100 meters)



This map was created by the National Renewable Energy Laboratory for the U.S. Department of Energy with data provided by AWS TruePower, but includes modifications by Xcel Energy.

Solar Resource – Photovoltaic



This map was created by the National Renewable Energy Laboratory for the U.S. Department of Energy, but includes modifications by Xcel Energy.

Wind	Capacity Factor
NSPM	~50%
PSCo	~45%
SPS	~50%

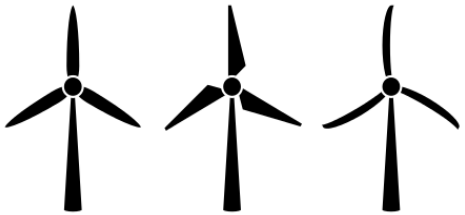
Large-scale Solar	Capacity Factor
NSPM	~22%
PSCo	~30%
SPS	~34%

Steel for Fuel

Capital recovery costs offset by lower fuel and O&M costs and tax credits

3,680 MW of new wind by 2021 (83% owned)

Rush Creek
Blazing Star 1 & 2
Lake Benton
Foxtail
Hale
Sagamore
Dakota Range
Crowned Ridge
Freeborn
630 MW of PPAs



High efficiency wind:
- Displaces coal and natural gas fuel
- Significant customer savings

Lower Fuel Costs

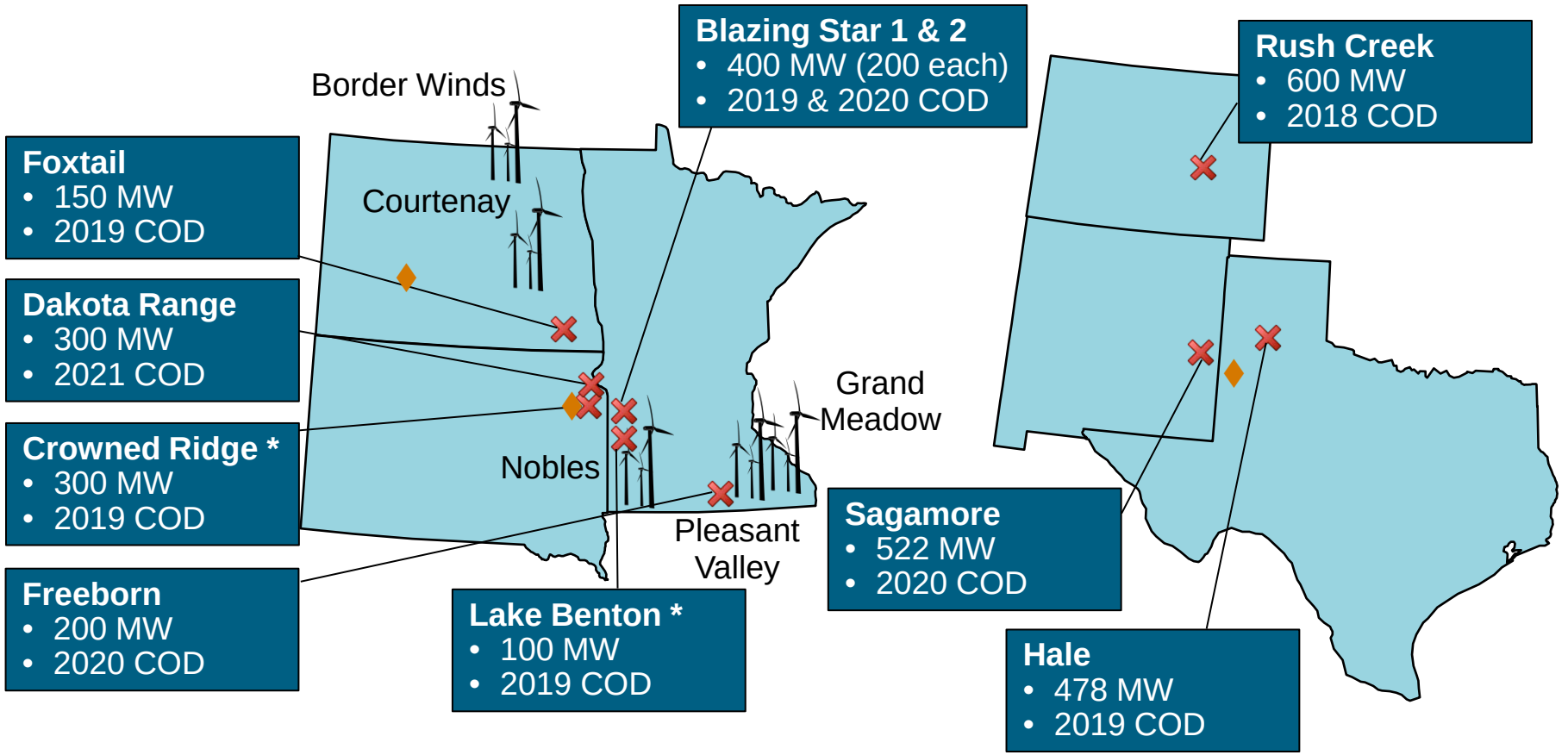
Lower O&M

Capture PTC

Lower Emissions

Economic, zero-emission energy enabled by:
- High wind capacity factors in our states
- Supportive regulatory environment
- Production tax credit

Accelerating Renewables



= Operational owned facilities totaling ~850 MW

= Proposed owned facilities totaling ~3,050 MW

= Proposed PPAs totaling ~630 MW

* = Build-own-transfer

SPS Wind Proposal

1,230 MW Proposal

Sagamore
- Self-Build
- 522 MW
- 2020 COD
- New Mexico

Hale
- Self-Build
- 478 MW
- 2019 COD
- Texas

Bonita
- PPA
- 230 MW
- 2019 COD
- Texas

Total capital investment of ~$1.6 billion

Settlements in principle reached in Texas and New Mexico

ALJ recommended against interim recovery in NM, which is critical to project

Commissions expected to rule on proposal in 2018 Q1

Significant customer savings

Colorado Energy Plan (CEP)

- Early retirement of 660 MW of coal generation:
  - Comanche 1 (325 MW) by 2022
  - Comanche 2 (335 MW) by 2025
- New renewable proposal:
  - Targeted ownership: 50% renewables; 75% natural gas and/or storage
  - Up to 1,000 MW of wind
  - Up to 700 MW of solar
  - Up to 700 MW of natural gas and/or storage
  - Potential capital investment of up to $1.5 billion, based on a preliminary estimate. Capital investment may be lower due to renewable pricing and asset composition selected through RPF process.
- Commission decision anticipated in summer 2018

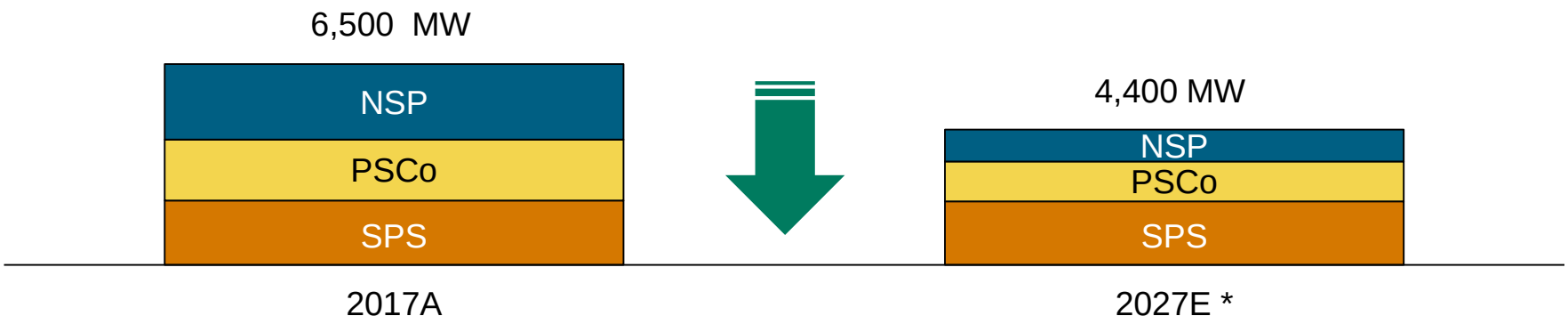
No increase in customer bills

Reducing carbon emissions by ~60%, by 2026 from a 2005 baseline

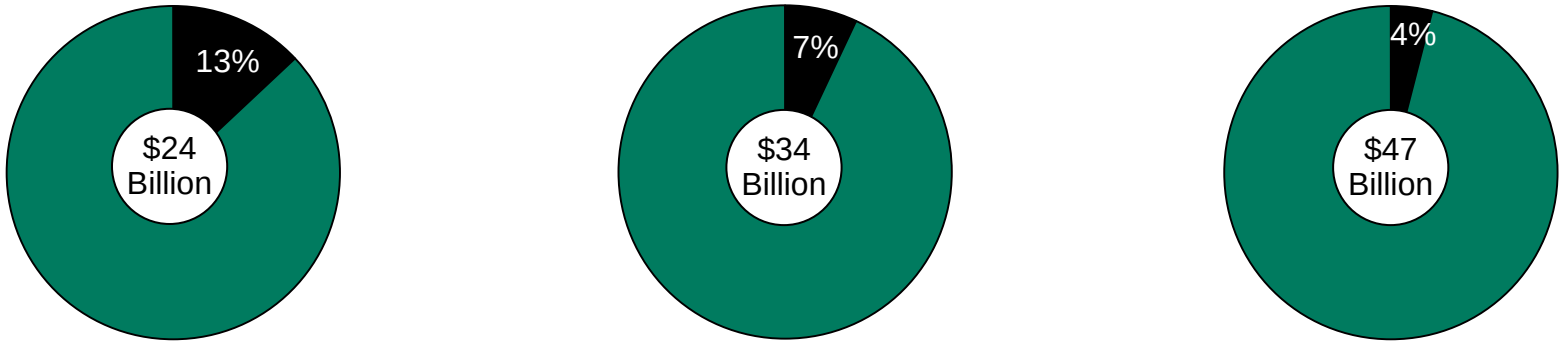
Increasing renewables to ~55% of energy mix by 2026

Lead the Clean Energy Transition

Declining Coal Capacity



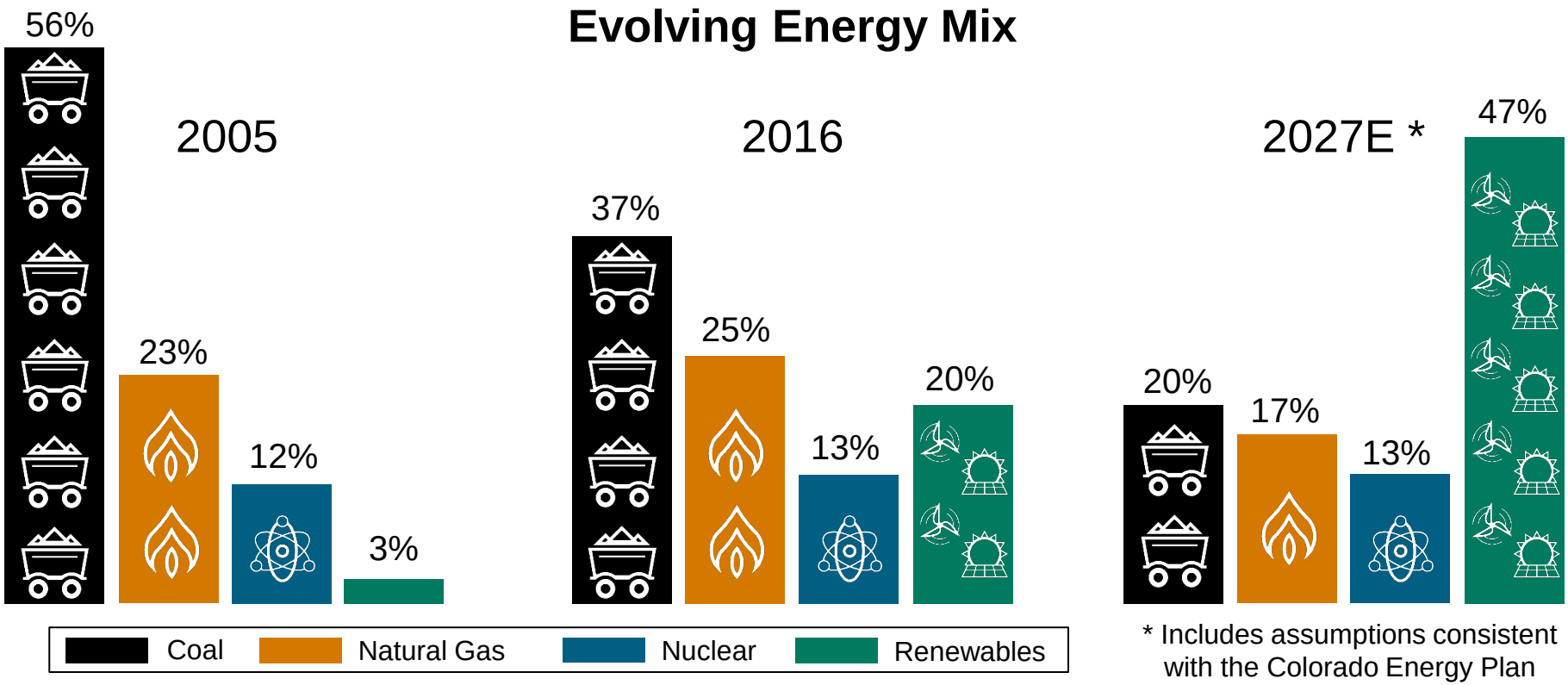
Declining Coal Investment in Rate Base



* The 2027 forecast includes assumptions consistent with the Colorado Energy Plan

** The 2027 rate base number is hypothetical and applies a 6.5% CAGR to the 2022 rate base forecast

Lead the Clean Energy Transition



Carbon Reduction

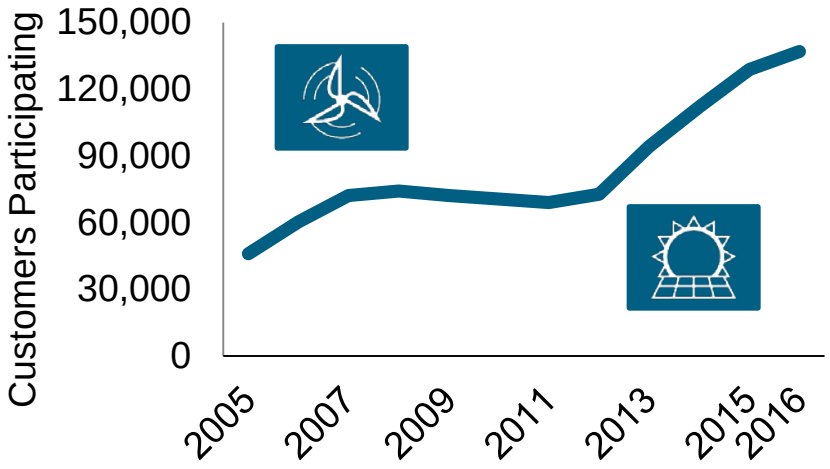
2005-2016 Achieved	2005-2021 On-track	2005-2030 Projected
30%	45%	60%+

Enhance Customer Experience

	Cleaner, More Reliable Energy	A Better Customer Experience	More Ways to Save Money
Customer Value	▪ Integrate renewables ▪ Improve reliability	▪ Timely, relevant information ▪ Integrate new technologies ▪ Efficient, self-serve options	▪ Ability to track and adjust energy usage ▪ New pricing plans
Operations Value	▪ Improves response times ▪ Remote configuration & outage isolation ▪ Monitoring and controlling	▪ Enhances outage notification ▪ Improves access to customer usage data ▪ Faster customer intervention capability	▪ Reduces outage duration ▪ Increases operational efficiency ▪ Data to support billing

Enhance Customer Experience

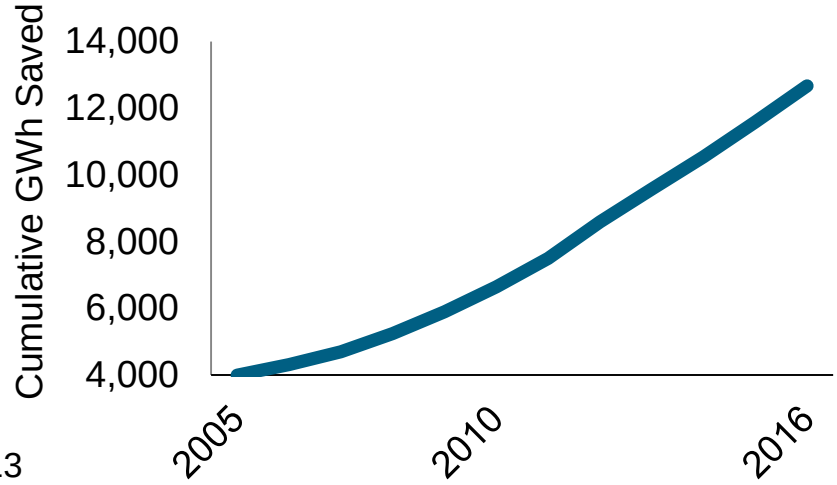
Renewable Energy Programs



Providing innovative renewable choice products

- Solar*Rewards®
- Windsource®
- Solar*Rewards Community®
- Solar*Connect Community®
- Renewable*Connect®

Energy Efficiency Programs



More than 150
efficiency and rebate programs
that annually save one TWh of electricity

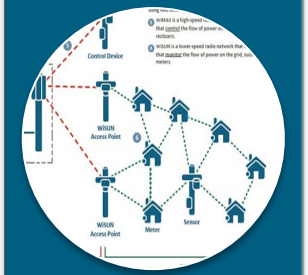
Advanced Grid Intelligence & Security (AGIS)

Strengthen the grid so our customers view Xcel Energy as their long-term energy solutions provider

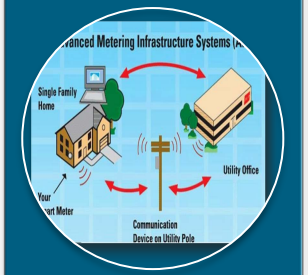
Advanced Distribution Management System (ADMS)

Fault Location, Isolation, and Service Restoration (FLISR)

Integrated Volt-VAr Optimization (IVVO)



Field Area Network (FAN)



Advanced Meter Infrastructure (AMI)

Emerging Technologies

Technology Suite – Enabling Customer Experience, Choice, Control & Enhancing Grid Operability

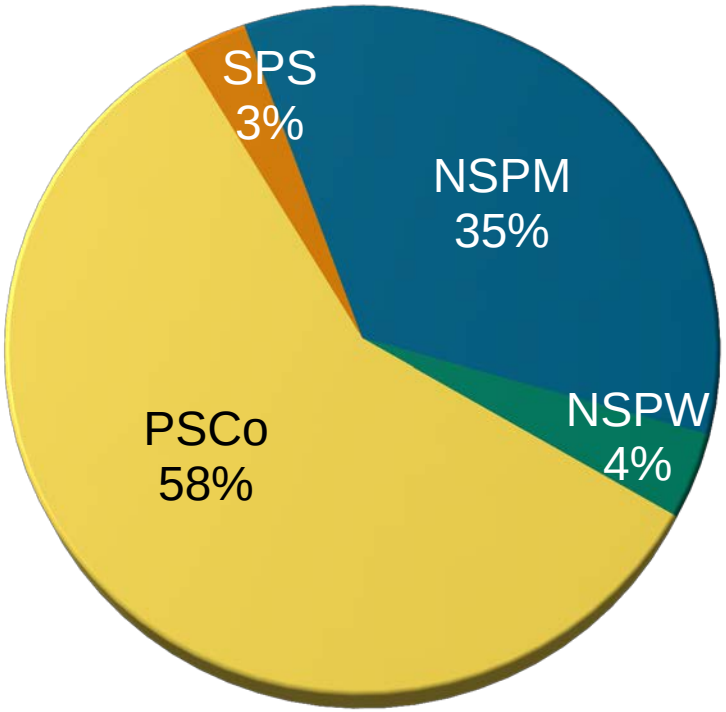
Security and Data Solutions

Advanced Grid Intelligence & Security (AGIS)

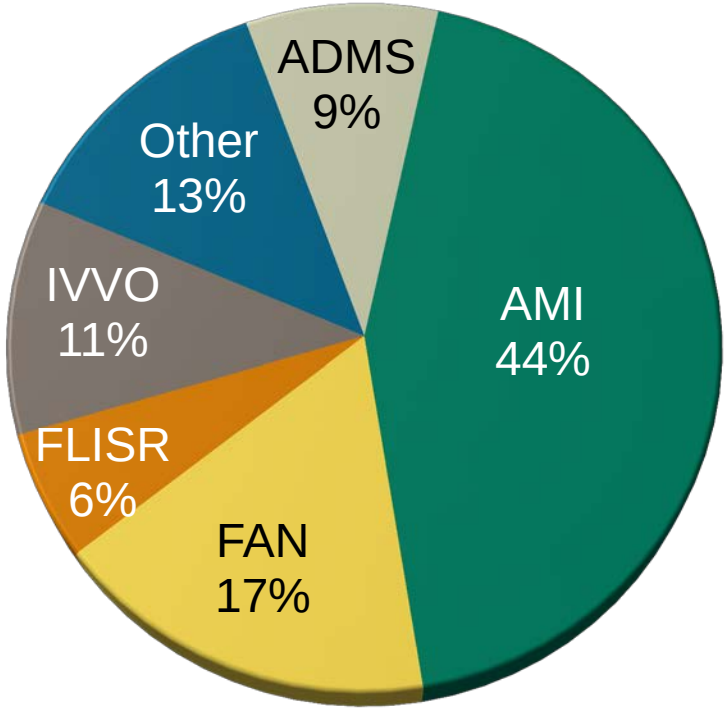
Capital Expenditures of ~$1.1 billion for 2018-2022

Capital Expenditures of ~$1.8 billion for 2017-2027

AGIS Capital by Company



AGIS Capital by Initiative

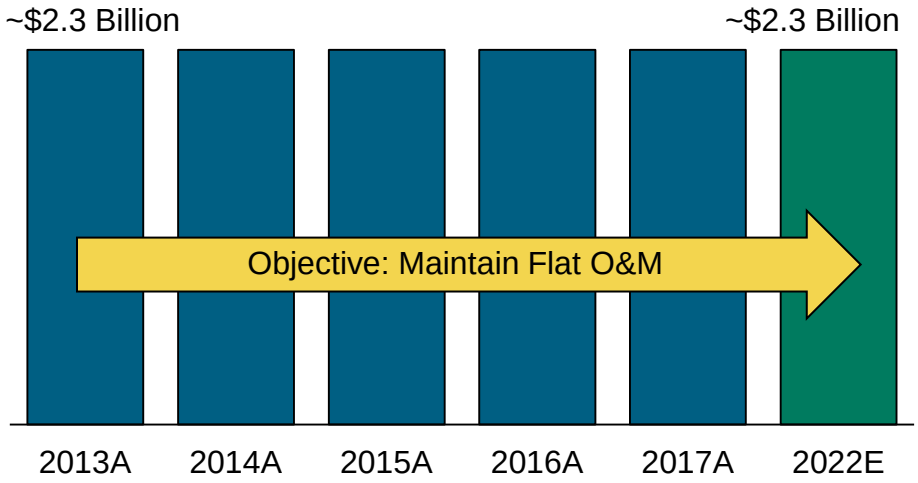


2018	2019	2020	2021	2022
~$175 million	~$205 million	~$225 million	~$235 million	~$290 million

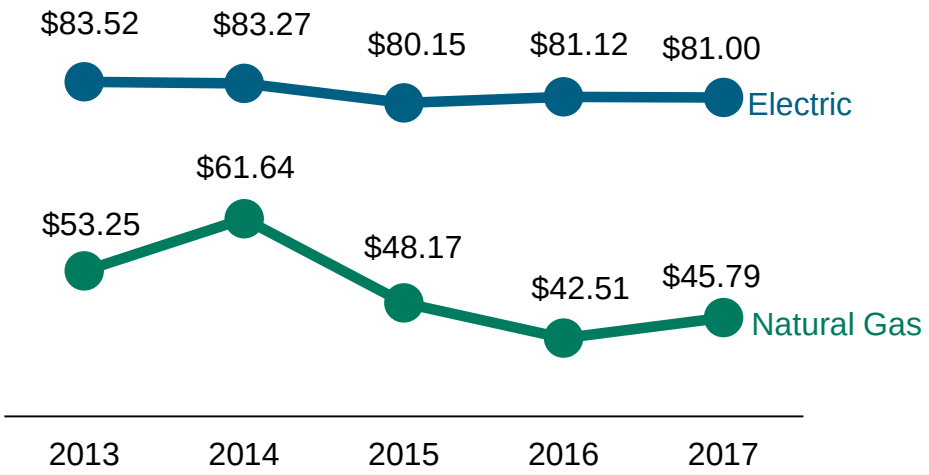
Keep Bills Low

- Productivity Through Technology
- Continuous Improvement
- Commercial Excellence
- Steel for Fuel
- Workforce Transition
- Generation Flexibility

O&M Cost Management

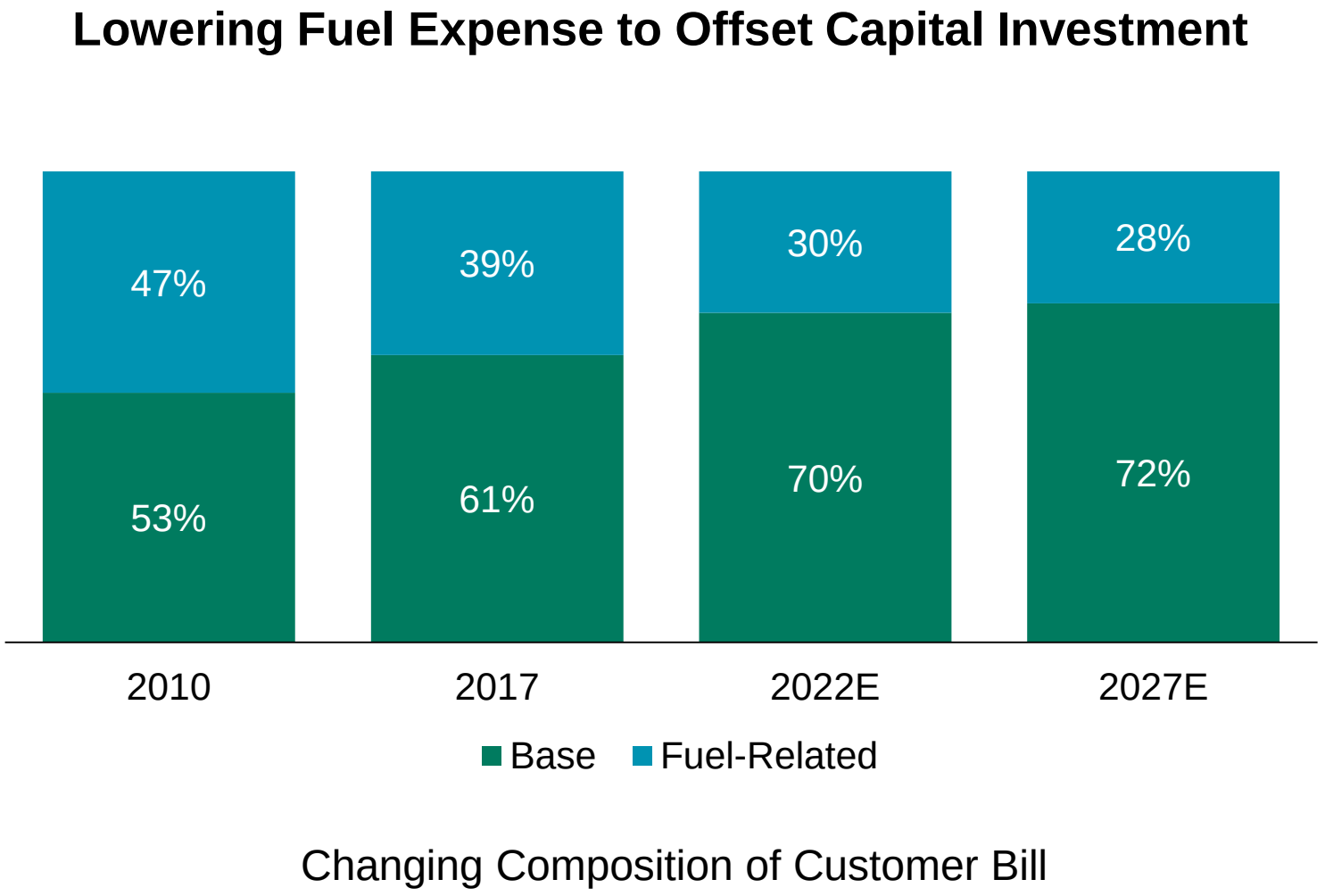


Xcel Energy Declining Residential Bills



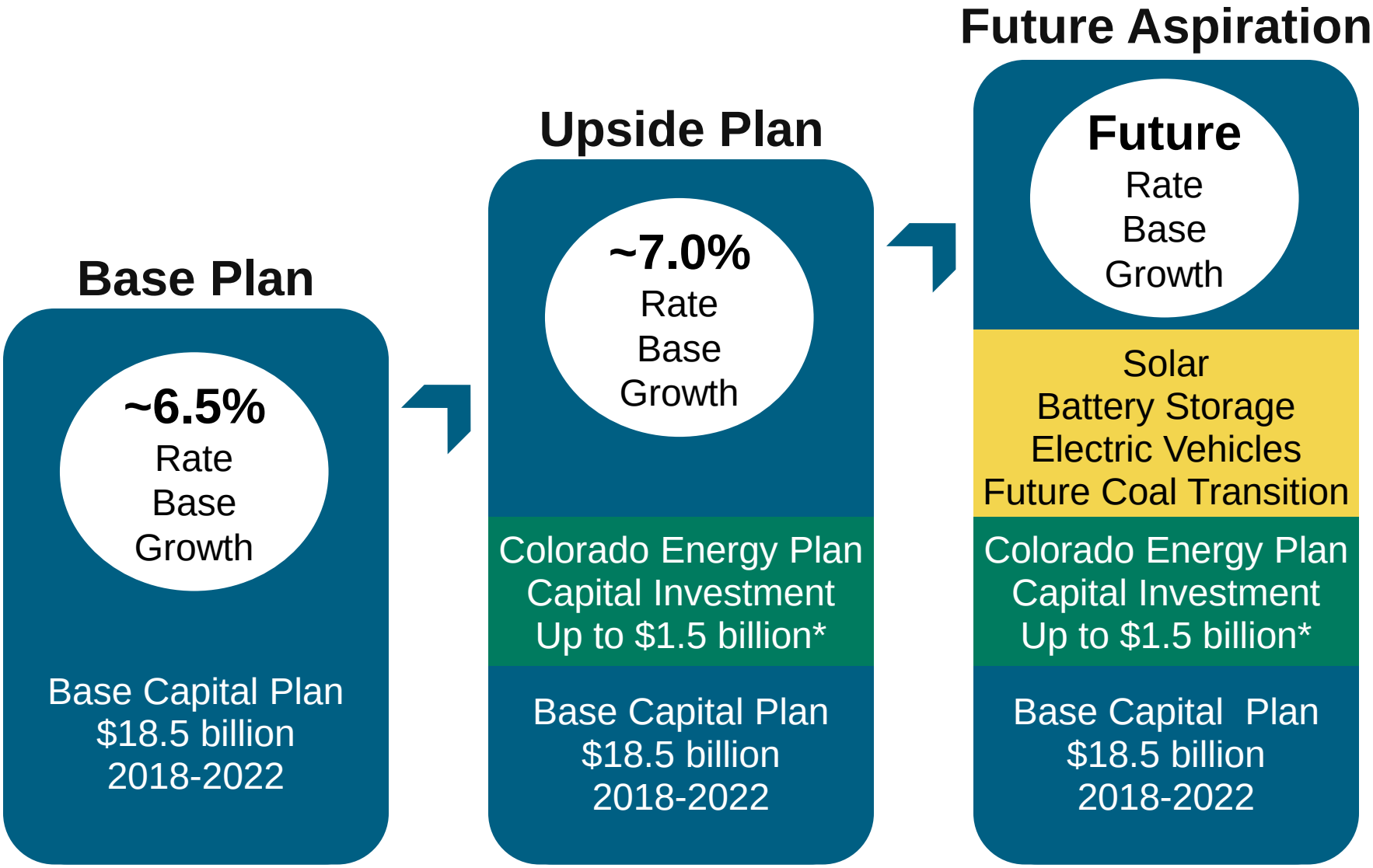
Source: SNL data for retail electric sales
Figures included are annual average of monthly bills

Keep Bills Low



Changing Composition of Customer Bill

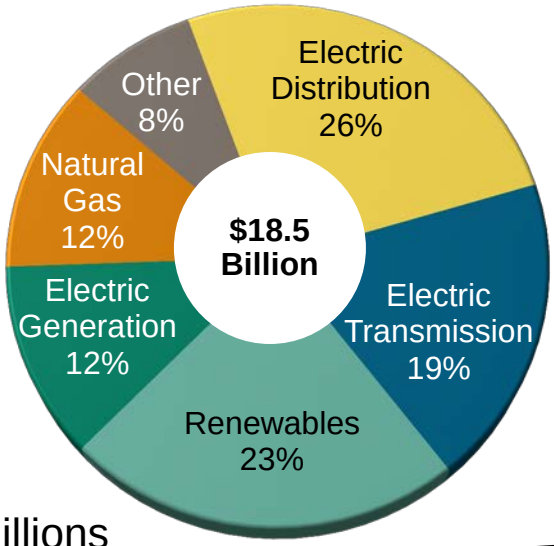
Executing on Investment Plan



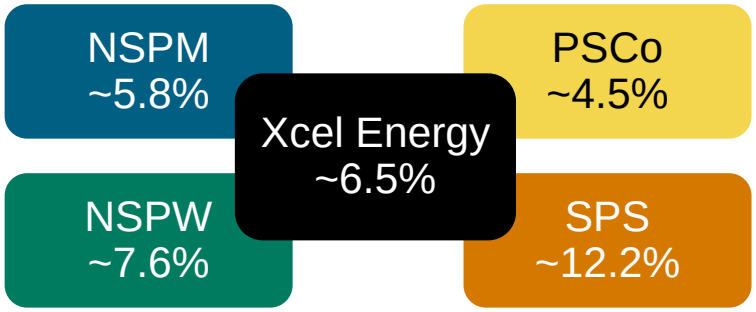
* Based on a preliminary estimate. Investment may be lower due to RFP pricing/selection.

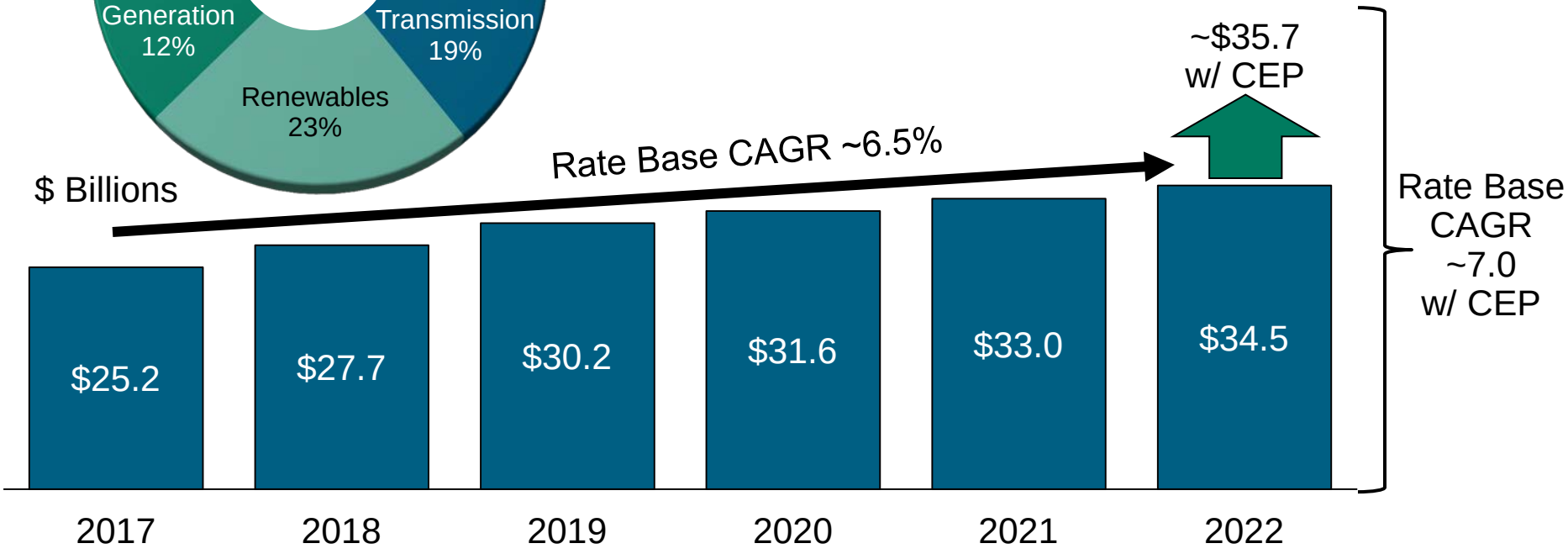
Investing in Infrastructure

Base Capital Expenditures 2018-2022



Rate Base CAGRs 2017-2022

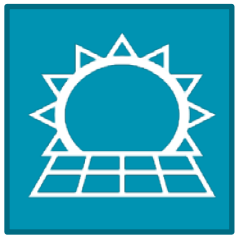




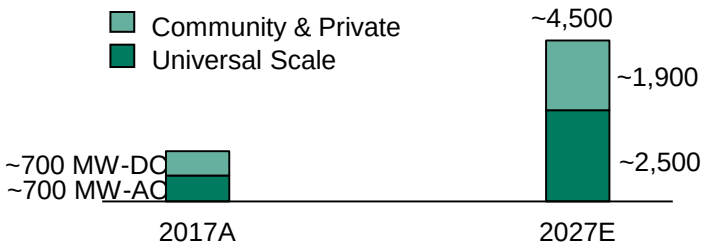
Base capital includes SPS wind & Dakota Range proposals, but does not include CEP, which could increase capital by up to $1.5 billion, based on a preliminary estimate. Investment may be lower due to RFP pricing/selection.

Future Investment Opportunities

Solar

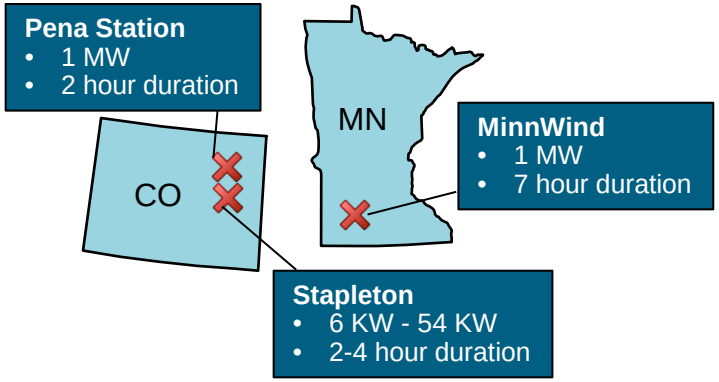


Xcel Energy Solar Capacity (MW)



- ❑ Universal solar approaching “grid parity”
- ❑ Increasing need for capacity
- ❑ Renewable*Connect and other programs providing customer choice
- ❑ Xcel Energy investing in its first CSG in Minnesota (~25 MW DC)

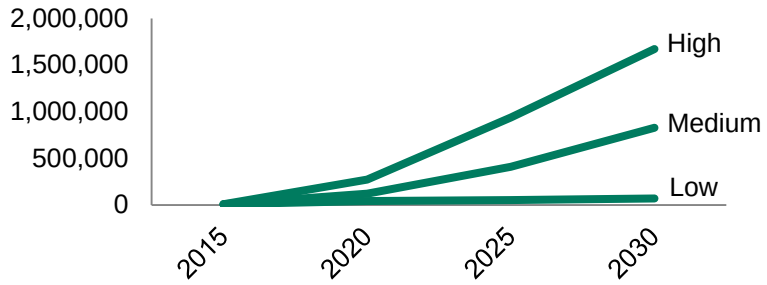
Battery



- ❑ Storage costs declining in the future
- ❑ Battery storage pilot programs underway in Colorado and Minnesota
- ❑ Improved system reliability
- ❑ Increased renewables utilization
- ❑ Potential investment opportunity

Electric Vehicles

Projected # of EVs in Xcel Energy Territories



- ❑ U.S. EVs and hybrid market:
  - ~650,000 EVs today
  - Potential of 8 million EVs by 2025
  - Up to 10 GW of incremental demand
- ❑ Xcel Energy potential opportunities:
  - Additional sales (~3 MWh per EV/year)
  - System upgrades to manage new loads
  - Potential investment in charging stations

Tax Reform

- **Beneficial to our customers**
- **Estimated to be mildly accretive to long-term earnings**
- **No change to 2018 EPS guidance or long-term EPS growth rate objective**
- **Will work with regulators on customer refunds and preservation of credit ratings**

Potential Tax Impacts
Assuming no Regulatory Actions

- Lowers revenue requirements ~$400 million
- Lower tax shield on holding company debt: earnings drag of ~$20 million
- Higher rate base CAGR for same Cap Ex
- One-time, non-cash write-off of deferred tax and credits of $23 million in 2017

Potential Regulatory Options
for Tax Savings and Credit Ratings

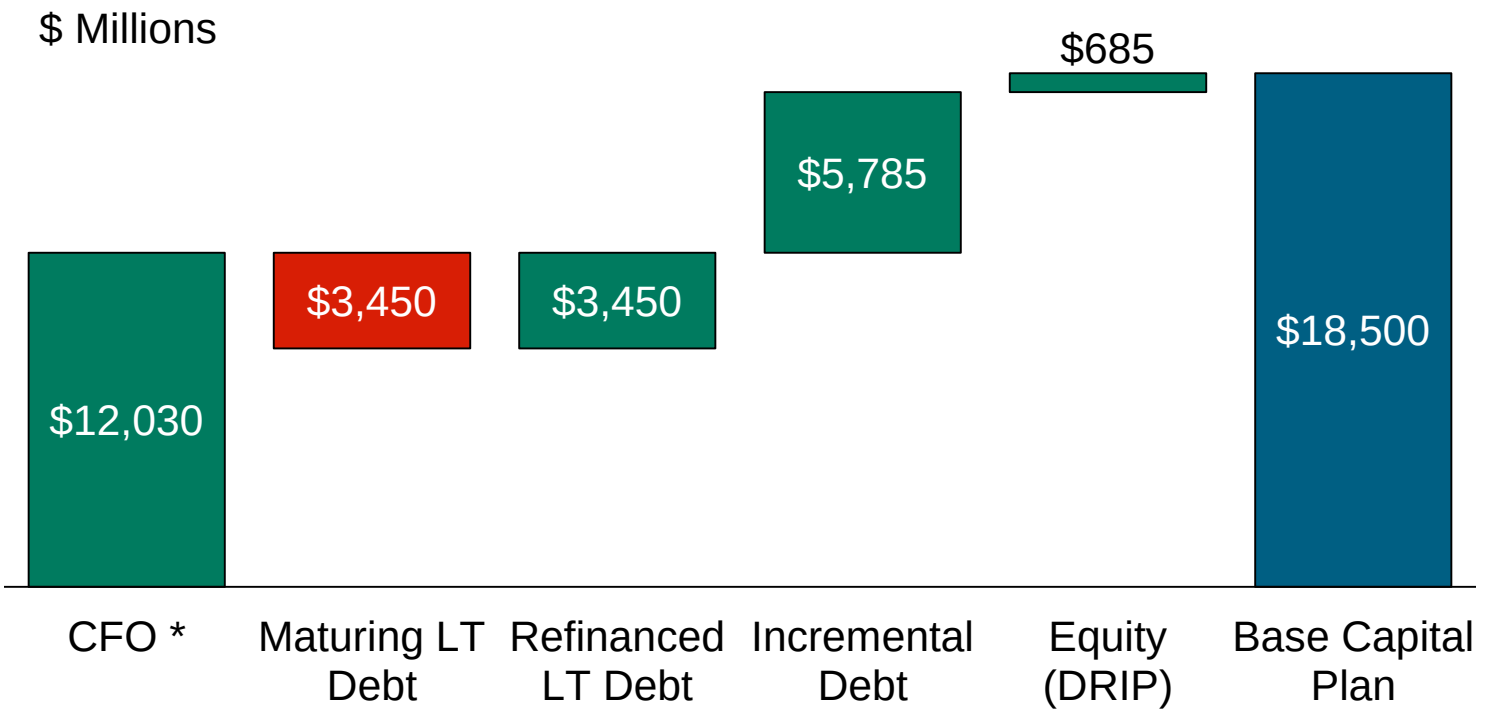
- Accelerate asset depreciation
- Increase equity ratios
- Modify capital investment
- Avoid or defer future rate cases
- Fund certain long-dated obligations
- Customer refunds

Actions to mitigate impact on credit ratings:

- Reduce capital expenditures by ~$500 million
- Issue up to $300 million of incremental equity beyond DRIP/benefits

Modest Financing Needs

Base Capital Financing Plan 2018-2022



* Cash from operations is net of dividend & pension funding

Financing plans are subject to change

Maintaining Strong Credit Metrics

	2018	2019	2020	2021	2022
FFO/Debt	~17%	~18%	~18%	~18%	~18%
Debt/EBITDA	4.7x	4.7x	4.8x	4.8x	4.7x
Equity Ratio	~42%	~41%	~40%	~40%	~40%
Hold Co Debt/Total Debt	23%	23%	23%	23%	22%

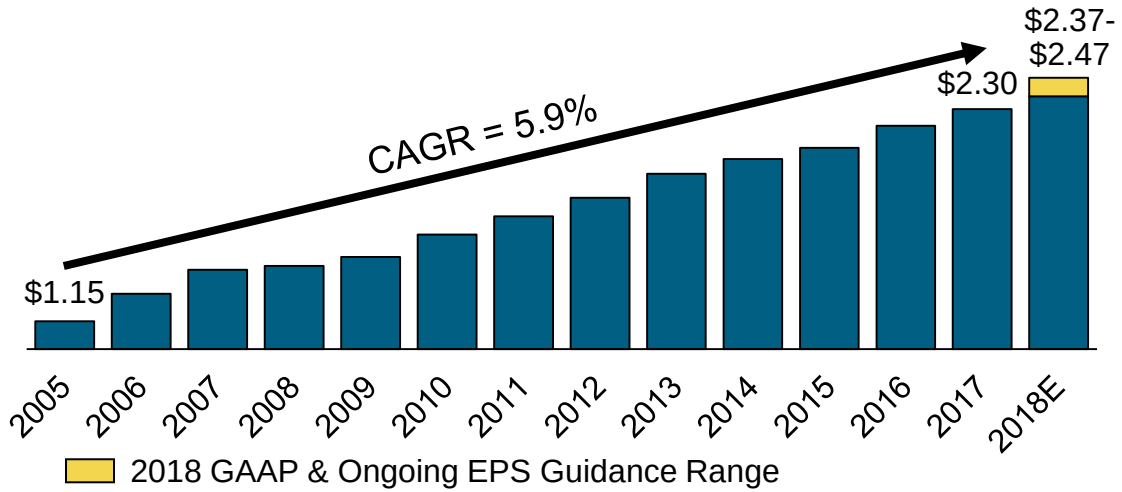
	Moody's	S&P	Fitch
Xcel Energy Unsecured	A3	BBB+	BBB+
NSPM Secured	Aa3	A	A+
NSPW Secured	Aa3	A	A+
PSCo Secured	A1	A	A+
SPS Secured	A2	A	A-

Credit metrics reflect base capital forecast

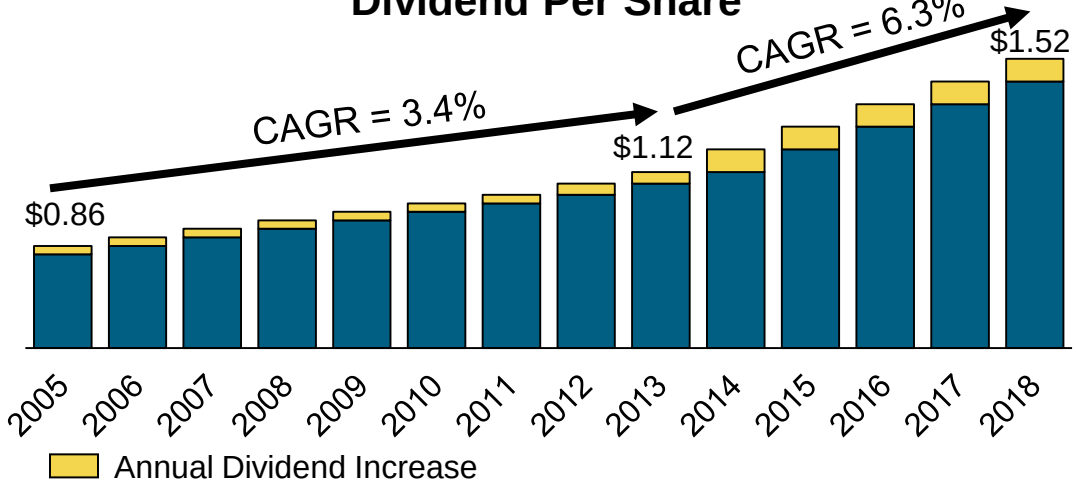
Credit metrics do not reflect rating agency adjustments

Proven Track Record

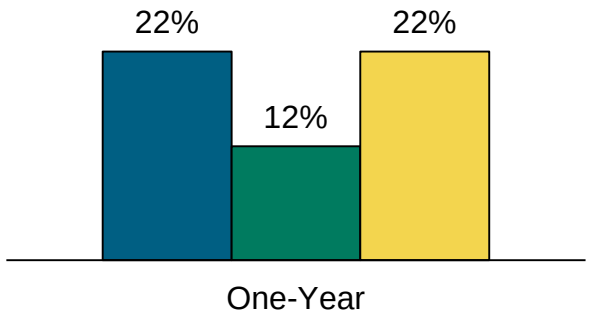
Ongoing Earnings Per Share

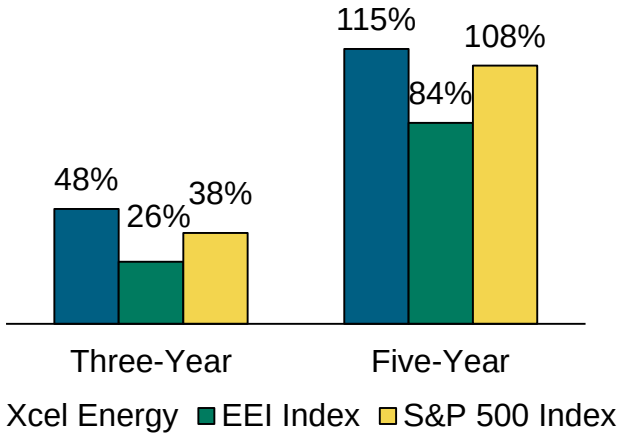


Dividend Per Share



Total Shareholder Return





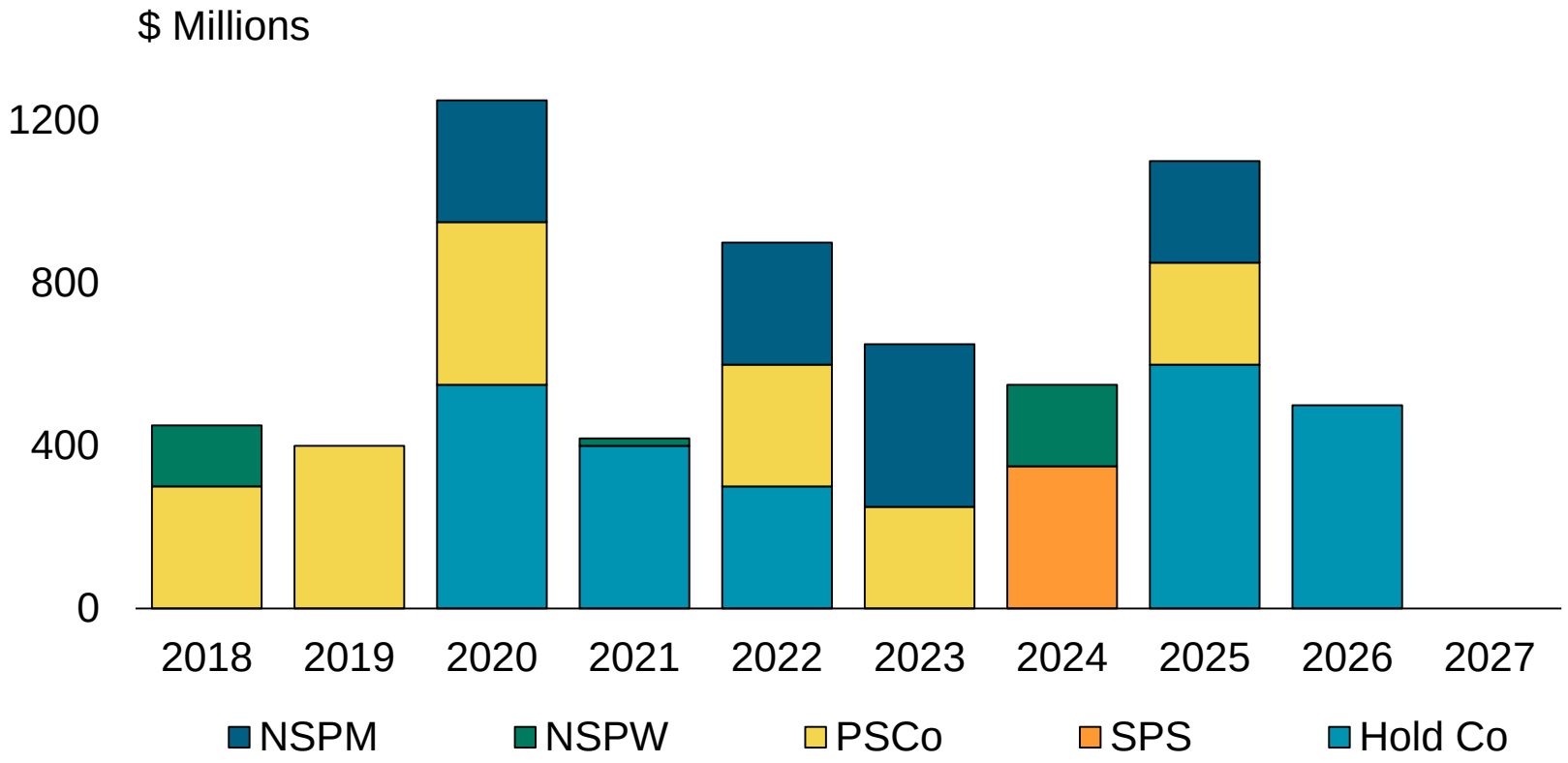
Periods ended December 31, 2017

Proven Track Record
Delivering on Financial Objectives

EPS Guidance		
2005	Achieved	✓
2006	Achieved	✓
2007	Exceeded	✓
2008	Achieved	✓
2009	Achieved	✓
2010	Achieved	✓
2011	Achieved	✓
2012	Achieved	✓
2013	Achieved	✓
2014	Achieved	✓
2015	Achieved	✓
2016	Achieved	✓
2017	Achieved	✓

Appendix

Manageable Debt Maturities



Lowered weighted average coupon from 5.6% to 4.3% over past 5 years

Financing Plan

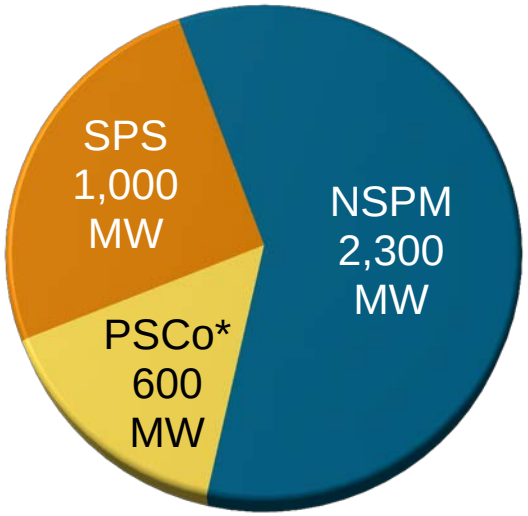
Issuer	Security	Amount (millions)	Timing
Hold Co	Senior Unsecured	$750	2018
NSPM	First Mortgage Bonds	$300	
NSPW	First Mortgage Bonds	$200	
PSCo	First Mortgage Bonds	$750	
SPS	First Mortgage Bonds	$350	
Xcel Energy plans to issue ~$300 million of incremental equity, in addition to $385 million of equity issued through the dividend reinvestment program/benefit programs during the five year forecast time period			

Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

Steel for Fuel

Cost effective renewables: Emission reductions - significant customer savings

Projected Owned Wind Capacity by Company by 2021 *



* Does not include proposed Colorado Energy Plan (CEP)

Project	Capacity	State	Estimated Completion	Regulatory Status
Rush Creek	600 MW	CO	2018	Approved
Freeborn	200 MW	MN	2020	Approved
Blazing Star 1	200 MW	MN	2019	Approved
Blazing Star 2	200 MW	MN	2020	Approved
Lake Benton	100 MW	MN	2019	Approved
Foxtail	150 MW	ND	2019	Approved
Crowned Ridge	300 MW	SD	2019	Approved
Dakota Range	300 MW	SD	2021	Pending
Hale	478 MW	TX	2019	Pending
Sagamore	522 MW	NM	2020	Pending
Total New Ownership *	**3,050 MW**			
Existing Ownership	850 MW	NSP	In service	
Grand Total *	**3,900 MW**	By 2021		

Base Capital Expenditures by Function

$ Millions

	2018	2019	2020	2021	2022	Total
Electric Distribution	$750	$810	$870	$1,110	$1,380	$4,920
Renewables	$1,410	$1,860	$880	$270	$0	$4,420
Electric Transmission	$770	$540	$570	$860	$980	$3,720
Electric Generation	$520	$370	$290	$520	$530	$2,230
Natural Gas	$460	$400	$410	$420	$510	$2,200
Other	$400	$250	$240	$280	$340	$1,510
Estimated Capital Reduction	($100)	($100)	($100)	($100)	($100)	($500)
Total	**$4,210**	**$4,130**	**$3,160**	**$3,360**	**$3,640**	**$18,500**

Base capital includes SPS wind & Dakota Range proposals, but does not include CEP, which could increase capital by up to $1.5 billion, based on a preliminary estimate. Capital investment may be lower due to RFP pricing/selection.

The estimated capital reduction of ~$500 million will be allocated to function and company at a later date.

Base Capital Expenditures by Company

$ Millions

	2018	2019	2020	2021	2022	Total
NSPM	$1,370	$1,910	$1,450	$1,590	$1,500	$7,820
PSCo	$1,650	$1,020	$950	$1,150	$1,410	$6,180
SPS	$1,020	$1,140	$710	$470	$540	$3,880
NSPW	$250	$250	$240	$280	$290	$1,310
Other *	$20	($90)	($90)	($30)	$0	($190)
Estimated Capital Reduction	($100)	($100)	($100)	($100)	($100)	($500)
Total	**$4,210**	**$4,130**	**$3,160**	**$3,360**	**$3,640**	**$18,500**

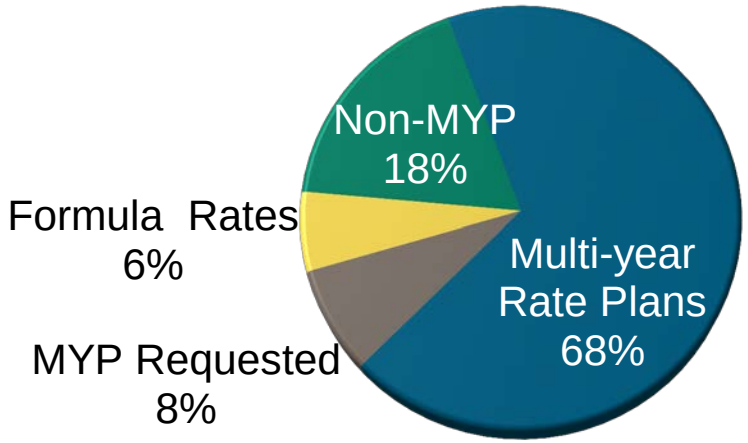
Base capital includes SPS wind & Dakota Range proposals, but does not include CEP, which could increase capital by up to $1.5 billion, based on a preliminary estimate. Capital investment may be lower due to RFP pricing/selection.

* Primarily reflects intercompany transfers for safe harbor wind turbines

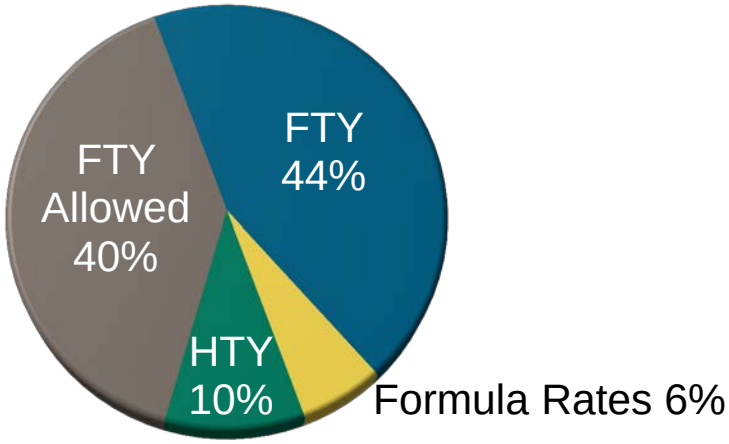
The estimated capital reduction of ~$500 million will be allocated to function and company at a later date.

Improving the Regulatory Framework

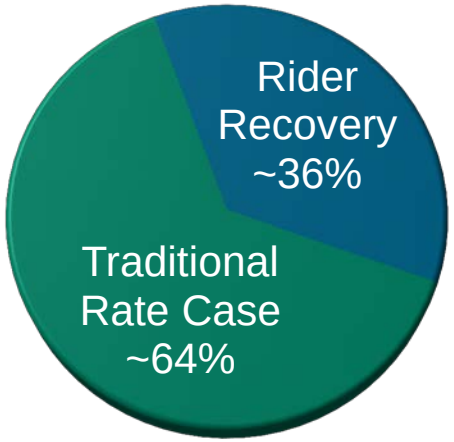
Rate Base Covered by MYP



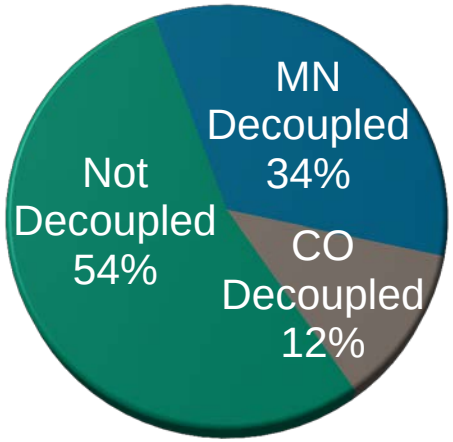
Rate Base Recovered Under Forward Test Year (FTY)



Cap Ex Eligible for Recovery by Rider



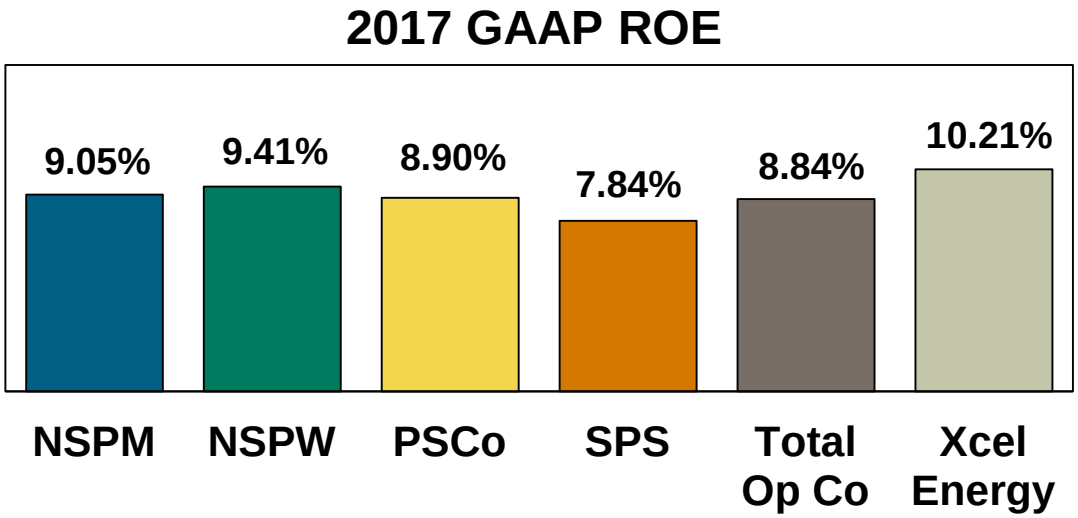
Retail Electric Sales Covered by Decoupling

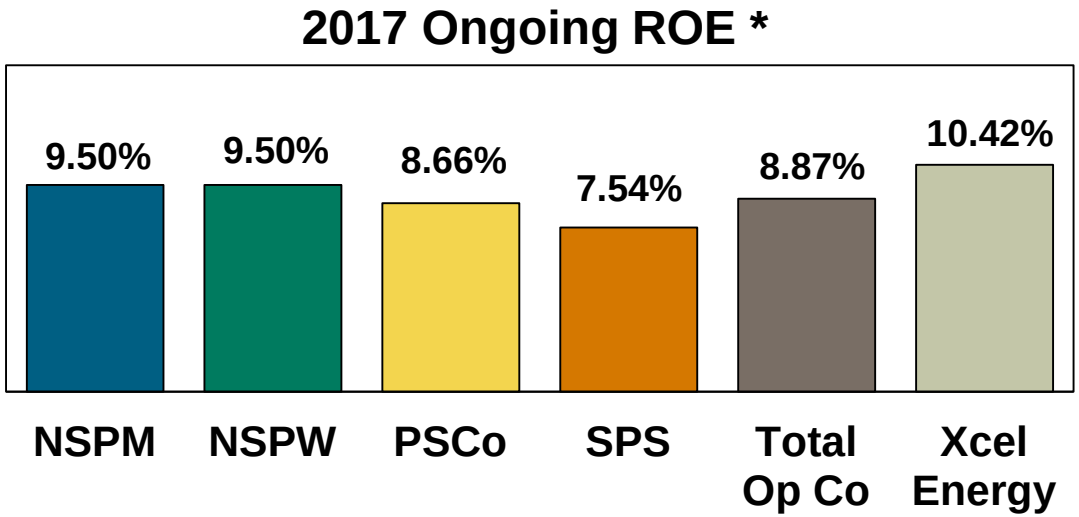


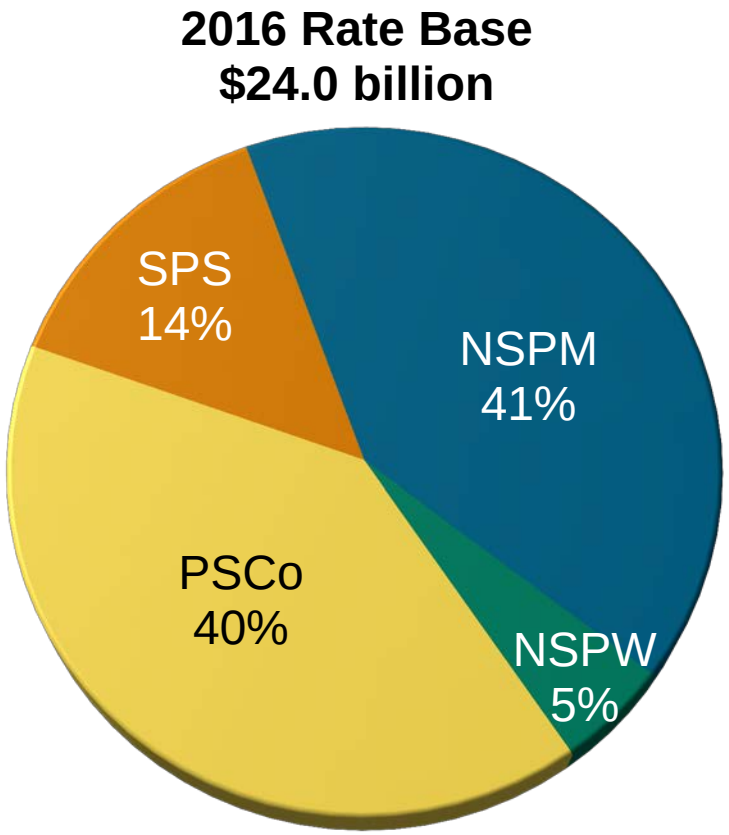
Improving the Regulatory Framework

	NSPM	NSPW	PSCo	SPS
Multi-year rate plans	✓		✓	
Forward test year	✓ MN & ND	✓	Allowed	✓ NM Allowed
Interim rates	✓		Allowed	
Fuel recovery mechanism	✓	✓	✓	✓
Capacity recovery mechanism			✓	
Renewable rider	✓ MN & ND		✓	
Transmission rider	✓		✓	✓ TX
Distribution recovery mechanism	✓ MN		Proposed	✓ TX
Decoupling	✓ MN		✓	
Pension deferral mechanism	✓ MN		✓	✓
Property tax deferral / true-up	✓ MN		✓	

ROE Results – GAAP & Ongoing Earnings







* Ongoing earnings exclude an estimated one-time, non-cash, income tax expense of approximately $23 million recognized upon the enactment of the TCJA

Regulatory vs. Authorized ROE – 2016

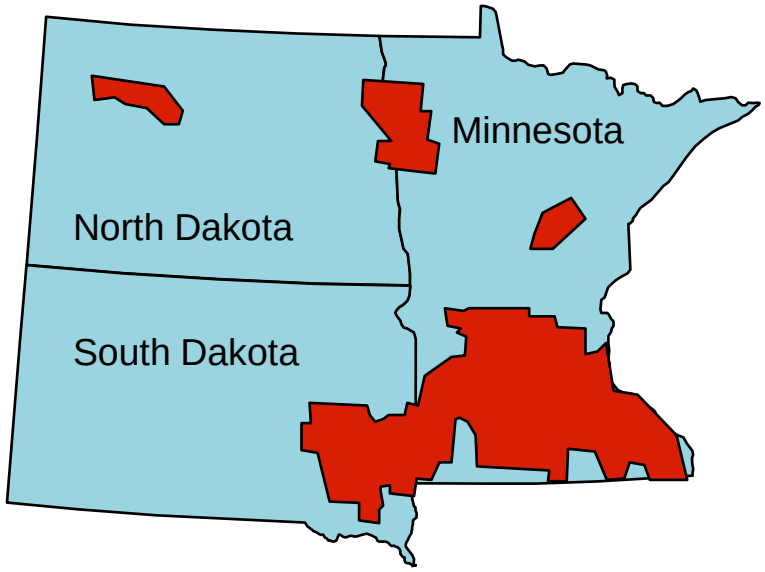
OpCo	Jurisdiction	Rate Base ($ millions)	Authorized ROE	W/A Earned ROE	Regulatory Plan
NSPM	MN Electric	$8,251	9.20%	9.35%	2016-2019 MYP
	MN Natural Gas	506	10.09	8.12	
	ND Electric	540	10.00	9.60	2013-2017 MYP
	ND Natural Gas	53	10.75	6.00	
	SD Electric	590	Blackbox	8.91	2015-2017 MYP
PSCo	CO Electric	6,927	9.83	9.22	2018-2021 MYP Filed
	CO Natural Gas	1,920	9.50	7.34	2018-2020 MYP Filed
	PSCo Wholesale	532	*	*	
SPS	TX Electric	1,763	9.70	7.44**	2017 Rate Case Filed
	NM Electric	786	9.96	6.34**	2017 Rate Case Filed
	SPS Wholesale	868	***	***	
NSPW	WI Electric	1,118	10.00	9.27	2017 Rate Case Filed
	WI Natural Gas	108	10.00	5.62	2017 Rate Case Filed
	MI Elec. & Nat. Gas	31	10.10(e); 10.20(g)	7.07	

* The authorized ROE for PSCo transmission & production formula = 9.72%

** Actual ROE, not weather-normalized

*** The transmission ROE = 10.50% and production formula ROE = 10.00%

NSP-Minnesota Profile

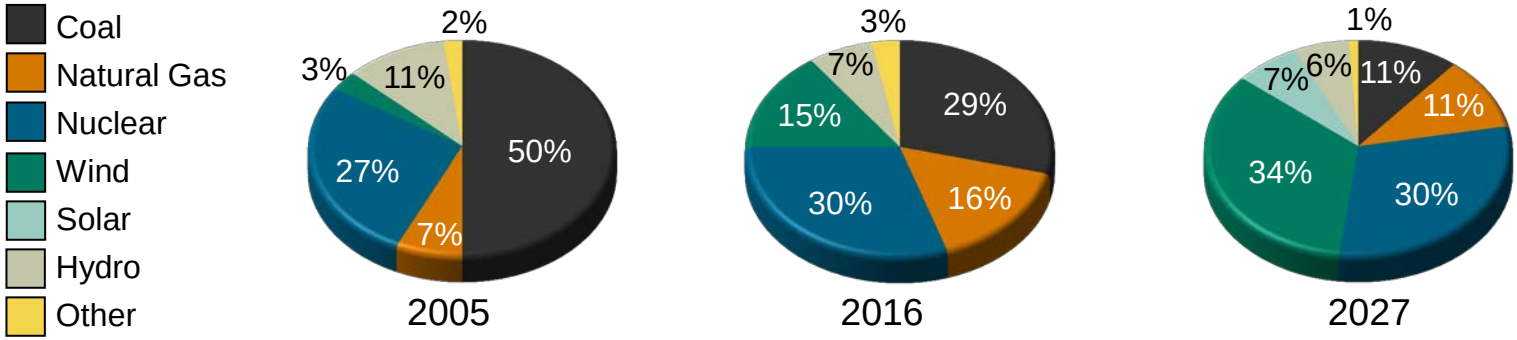


Electric – Retail	Natural Gas – Retail
1.5 million Customers	514,000 customers
34 million MWh	79 million MMBtu

2017 Financials	GAAP	Ongoing
Net Income	$490 million	$514 million
Assets	$17.9 billion	
ROE	9.05%	9.50%
Equity Ratio	52.5%	

Credit Ratings (Sec./Unsec.)	
Fitch	A+ / A
Moody's	Aa3 / A2
S&P	A / A-

NSP System Energy Mix



NSPM Capital Expenditures by Function

$ Millions

NSPM	2018	2019	2020	2021	2022	Total
Renewables	$400	$1,170	$520	$270	$0	$2,360
Electric Distribution	$250	$230	$300	$480	$600	$1,860
Electric Generation	$340	$190	$170	$310	$290	$1,300
Electric Transmission	$140	$90	$220	$280	$340	$1,070
Other	$140	$130	$140	$130	$140	$680
Natural Gas	$100	$100	$100	$120	$130	$550
Total*	**$1,370**	**$1,910**	**$1,450**	**$1,590**	**$1,500**	**$7,820**

The NSPM base capital plan includes the Dakota Range 300 MW wind proposal

* Does not include NSPM's allocation of yet-to-be-determined capital reductions totaling an estimated ~$500 million on a consolidated company basis

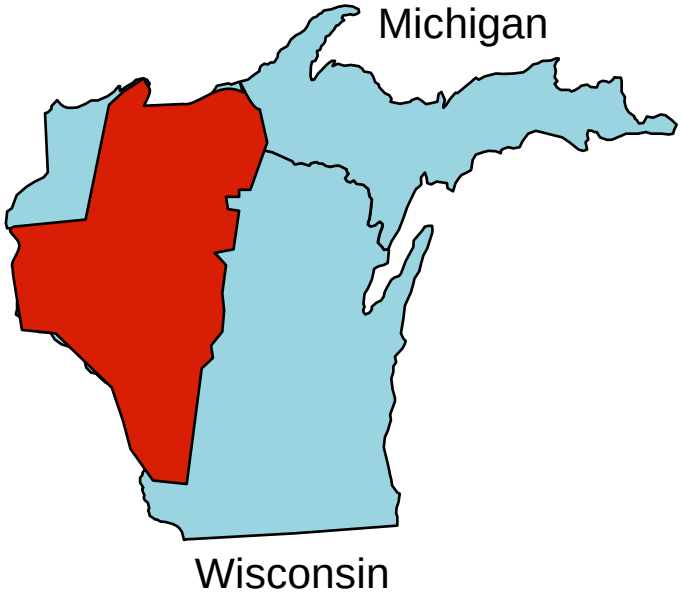
Minnesota Recovery Mechanisms

- Forward test year with interim rates
- Transmission rider
- Renewable energy rider
- Gas infrastructure rider
- Environmental improvement rider
- DSM incentive mechanism
- Fuel clause adjustment
- Electric decoupling/sale true-up for all classes (2016-2019)
- Multi-year rate plan legislation
  - Allows for multi-year plans for up to five years
  - Recovery of capital investments
  - Recovery of O&M expenses
  - Recovery of early plant closure costs
  - Recovery of grid modernization through transmission rider
  - Interim rates for the first two years of a multi-year rate plan

North Dakota & South Dakota Recovery Mechanisms

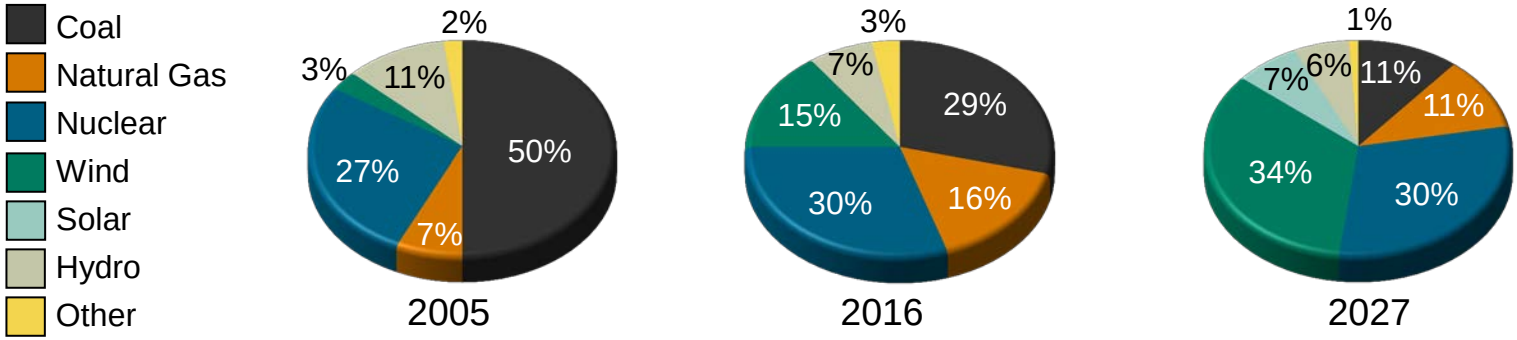
- Forward test year with interim rates (ND)
- Historic test year (SD)
- Environmental rider (ND & SD)
- Transmission rider (ND & SD)
- Renewable energy rider (ND)
- Infrastructure rider for capital projects (SD)
- Fuel clause adjustment (ND & SD)

NSP-Wisconsin Profile



Electric – Retail	Natural Gas – Retail	
259,000 Customers	114,000 customers	
7 million MWh	16 million MMBtu	
2017 Financials	**GAAP**	**Ongoing**
Net Income	$79 million	$80 million
Assets	$2.6 billion	
ROE	9.41%	9.50%
Equity Ratio	53.2%	
Credit Ratings (Sec./Unsec.)		
Fitch	A+ / A	
Moody's	Aa3 / A2	
S&P	A / A-	

NSP System Energy Mix



NSPW Capital Expenditures by Function

$ Millions

NSPW	2018	2019	2020	2021	2022	Total
Electric Transmission	$110	$100	$100	$140	$140	$590
Electric Distribution	$60	$80	$80	$80	$90	$390
Other	$40	$30	$30	$30	$30	$160
Natural Gas	$20	$20	$20	$20	$20	$100
Electric Generation	$20	$20	$10	$10	$10	$70
Total*	**$250**	**$250**	**$240**	**$280**	**$290**	**$1,310**

* Does not include NSPW's allocation of yet-to-be-determined capital reductions totaling an estimated ~$500 million on a consolidated company basis

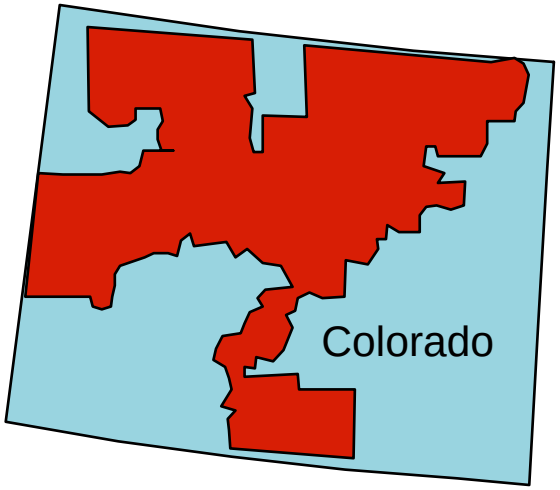
Wisconsin Rate Case

- NSPW filed a Wisconsin electric & natural gas rate case in May 2017
  - Requested electric rate increase of $24.7 million (3.6%)
  - Requested nat. gas rate increase of $12.0 million (10.1%)
  - ROE of 10.0% and equity ratio of 52.53%
  - Rate base of ~$1.2 billion (electric) and $138 million (nat. gas)
  - Based on 2018 forward test year
- PSCW Staff recommended rate increases of $10.9 million (electric) and $9.9 million (natural gas)
- Commission decision anticipated in December 2017
- New rates expected to be effective January 2018

NSPW Recovery Mechanisms

- Forward test year (WI and MI)
- Biennial rate case (WI)
- Annual electric fuel plan with reconciliation (WI)
- Purchased gas adjustment (WI)
- Gas cost recovery mechanism (MI)
- Power supply cost recovery (MI)

PSCo Profile

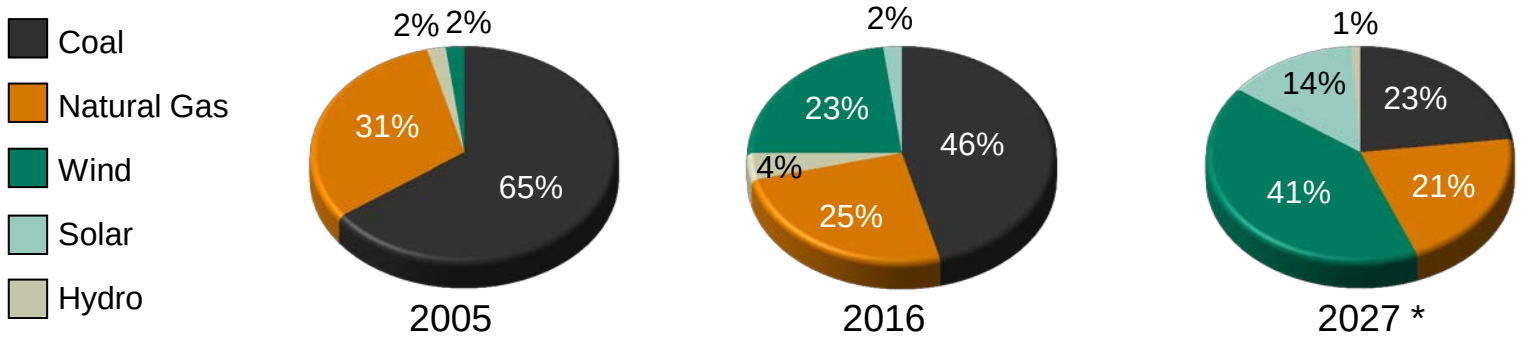


Electric – Retail	Natural Gas – Retail
1.5 million customers	1.4 million customers
29 million MWh	126 million MMBtu

2017 Financials	GAAP	Ongoing
Net Income	$494 million	$481 million
Assets	$16.0 billion	
ROE	8.90%	8.66%
Equity Ratio	55.8%	

Credit Ratings (Sec./Unsec.)	
Fitch	A+ / A
Moody's	A1 / A3
S&P	A / A-

PSCo Energy Mix



* Includes assumptions consistent with the Colorado Energy Plan

PSCo Capital Expenditures by Function

$ Millions

PSCo	2018	2019	2020	2021	2022	Total
Electric Distribution	$340	$390	$380	$420	$500	$2,030
Natural Gas	$340	$280	$290	$280	$360	$1,550
Electric Transmission	$200	$100	$100	$190	$240	$830
Other	$170	$140	$120	$110	$130	$670
Electric Generation	$100	$110	$60	$150	$180	$600
Renewables	$500	$0	$0	$0	$0	$500
Total*	**$1,650**	**$1,020**	**$950**	**$1,150**	**$1,410**	**$6,180**

Base capital includes SPS wind & Dakota Range proposals, but does not include CEP, which could increase capital by up to $1.5 billion, based on a preliminary estimate. Capital investment may be lower due to RFP pricing/selection.

* Does not include PSCo's allocation of yet-to-be-determined capital reductions totaling an estimated ~$500 million on a consolidated company basis

Colorado Multi-Year Natural Gas Rate Case

($ Millions)	2018	2019	2020	Total
New Revenue Request	$63	$33	$43	$139
PSIA revenue conversion to base rates	0	94	0	94
Total	$63	$127	$43	$233
Projected YE Rate Base ($ Billions)	$1.5	$2.3	$2.4	

- PSCo filed a Colorado natural gas multi-year rate case in June 2017
  - Requested a natural gas rate increase of $139 million over 3 years
  - Requested an ROE of 10.0% and equity ratio of 55.25%
  - Includes transfer of $94 million of PSIA rider - no impact on customer bills
  - Rate base in 2019 reflects the roll-in of capital associated with the PSIA rider
- Interim rates, subject to refund, were implemented on January 1, 2018
- Commission decision expected in March or April 2018
- Tax reform expected to be addressed in the rate case or a separate proceeding

Colorado Multi-Year Electric Rate Case

($ Millions)	2018	2019	2020	2021	Total
New Revenue Request	$74	$75	$60	$36	$245
CACJA & TCA revenue	133	0	0	0	133
Total	$207	$75	$60	$36	$378
Projected YE Rate Base ($ Billions)	$6.8	$7.1	$7.3	$7.4	

- PSCo filed a Colorado electric multi-year rate case in October 2017
  - Requested an electric rate increase of $245 million over 4 years
  - Requested an ROE of 10.0% and equity ratio of 55.25%
  - Transfer of CACJA & TCA riders will not impact customer bills
- Interim rates, subject to refund, will be effective on June 1, 2018
- Procedural schedule:
  - Supplemental direct testimony – April 16, 2018
  - Answer testimony – May 31, 2018
  - Rebuttal and cross-answer testimony – July 10, 2018
  - Hearings – August 21-31, 2018
  - Decision anticipated by the end of 2018
- Tax reform expected to be addressed in the rate case or a separate proceeding

Colorado Recovery Mechanisms

- Ability to file multi-year requests
- Ability to file either historic or forward test years
- Purchased capacity cost adjustment
- Clean Air Clean Jobs Act rider (forward looking)
- Transmission rider (forward looking)
- Natural gas pipeline integrity rider
- Renewable energy rider
- DSM incentive mechanism
- Energy cost adjustment
- Natural gas cost adjustment
- Decoupling for residential and non-demand SC&I classes

SPS Profile

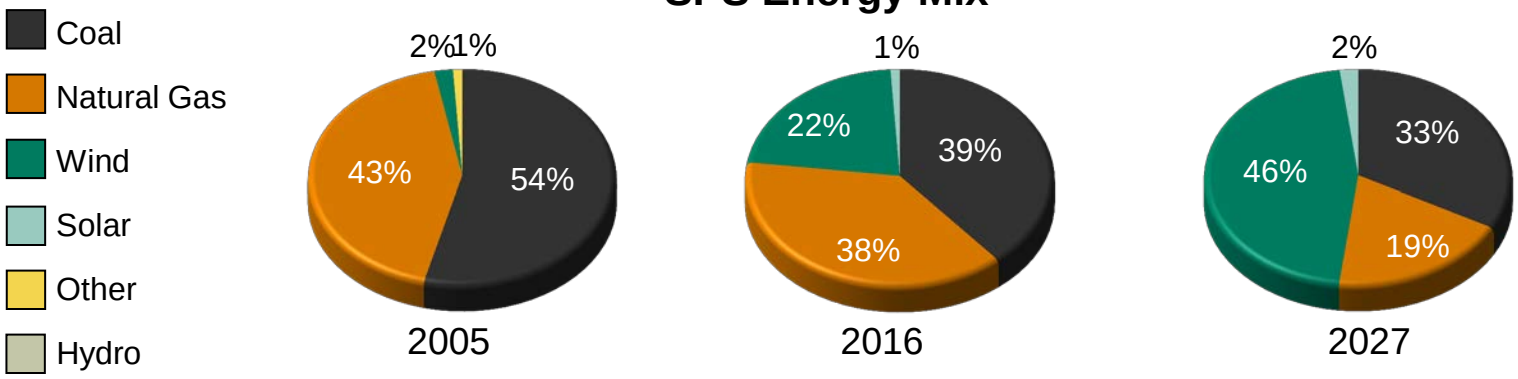
Electric – Retail
390,000 customers
19 million MWh

2017 Financials	GAAP	Ongoing
Net Income	$159 million	$153 million
Assets	$5.9 billion	
ROE	7.84%	7.54%
Equity Ratio	53.8%	

Credit Ratings (Sec./Unsec.)

Fitch	A- / BBB+
Moody's	A2 / Baa1
S&P	A / A-

SPS Energy Mix



SPS Capital Expenditures by Function

$ Millions

SPS	2018	2019	2020	2021	2022	Total
Renewables	$510	$690	$360	$0	$0	$1,560
Electric Transmission	$320	$250	$150	$250	$260	$1,230
Electric Distribution	$100	$110	$110	$130	$190	$640
Electric Generation	$60	$50	$50	$50	$50	$260
Other	$30	$40	$40	$40	$40	$190
Total*	**$1,020**	**$1,140**	**$710**	**$470**	**$540**	**$3,880**

The SPS base capital plan includes the 1,000 MW wind proposal

* Does not include SPS' allocation of yet-to-be-determined capital reductions totaling an estimated ~$500 million on a consolidated company basis

Texas Electric Rate Case

- In August 2017, SPS filed a Texas electric rate case
  - Requested a net electric rate increase of $55 million (5.8%)
  - ROE of 10.25% and equity ratio of 53.97%
  - Electric rate base of ~$1.9 billion
  - Based on a historic 12-month ended June 30, 2017 test year
- Tax reform expected to be addressed in the rate case
- Procedural schedule:
  - Intervenor testimony – February 22, 2018
  - PUCT Staff testimony – March 1, 2018
  - PUCT Staff and intervenor cross-rebuttal testimony – March 22, 2018
  - SPS rebuttal testimony – March 23, 2018
  - Hearings – April 10-20, 2018
  - Commission decision – third quarter 2018
  - New rates expected to be effective retroactive to January 2018

New Mexico Electric Rate Case

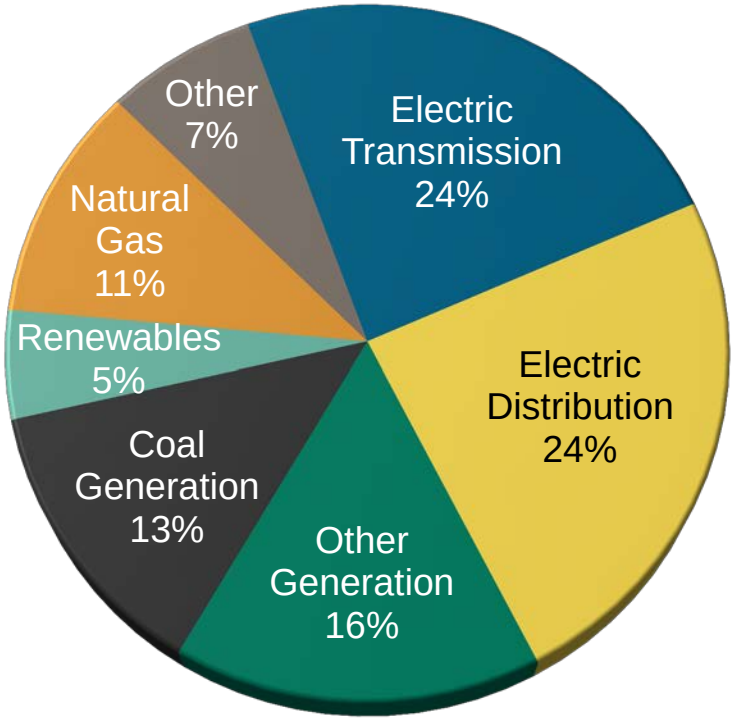
- In October 2017, SPS filed a New Mexico electric rate case
  - Requested an electric rate increase of $43 million
  - ROE of 10.25% and equity ratio of 53.97%
  - Electric rate base of ~$885 million
  - Based on a historic test year ended June 30, 2017
- Tax reform expected to be addressed in the rate case
- Procedural schedule:
  - Staff and intervenor testimony – April 13, 2018
  - SPS rebuttal testimony – May 2, 2018
  - Hearings – May 15-25, 2018
  - Commission decision and implementation of final rates anticipated in the second half of 2018

SPS Recovery Mechanisms

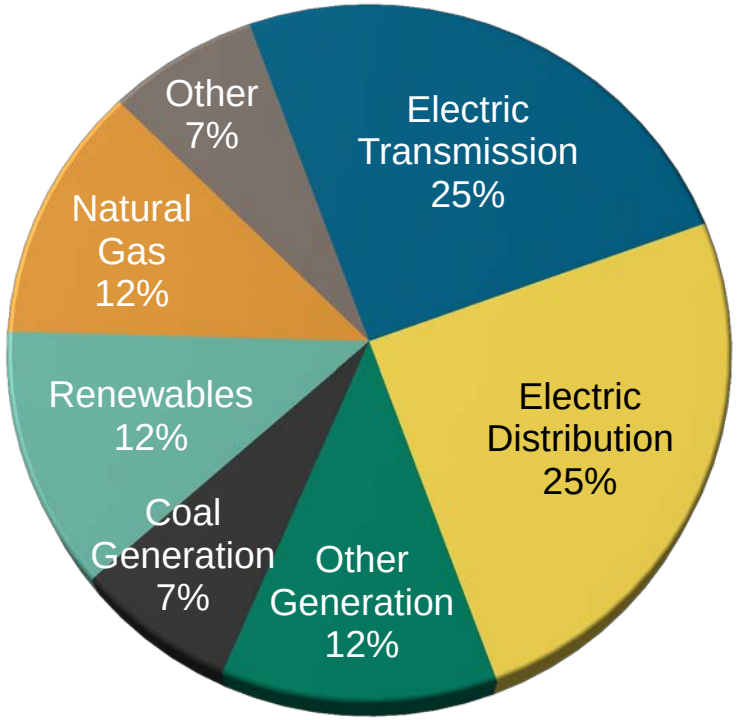
- Historic test year (TX)
- Ability to file forward test year (NM)
- DSM incentive mechanism (NM)
- Fuel clause adjustment (TX/NM)
- Purchase Capacity Cost Recovery Factor (TX)
- Transmission Cost Recovery Factor (TX)
- Distribution Cost Recovery Factor (TX)
- Texas legislation passed in 2015 that reduces regulatory lag

Changing Composition of Rate Base

2016 Actual Rate Base
$24.0 billion



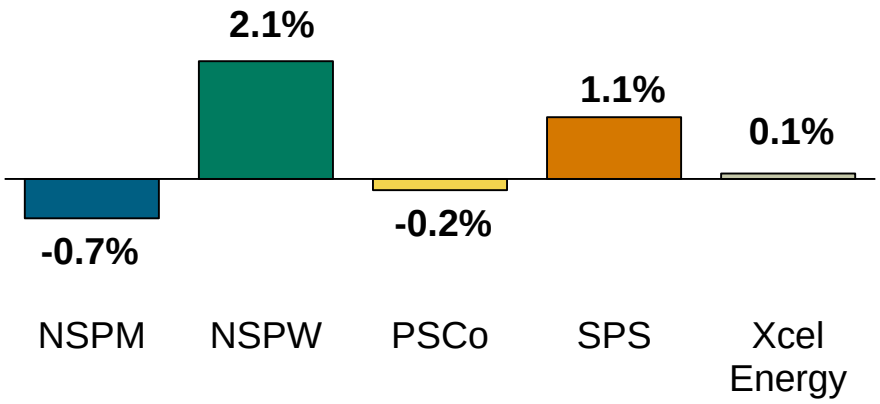
2022 Projected Rate Base
$34.5 billion



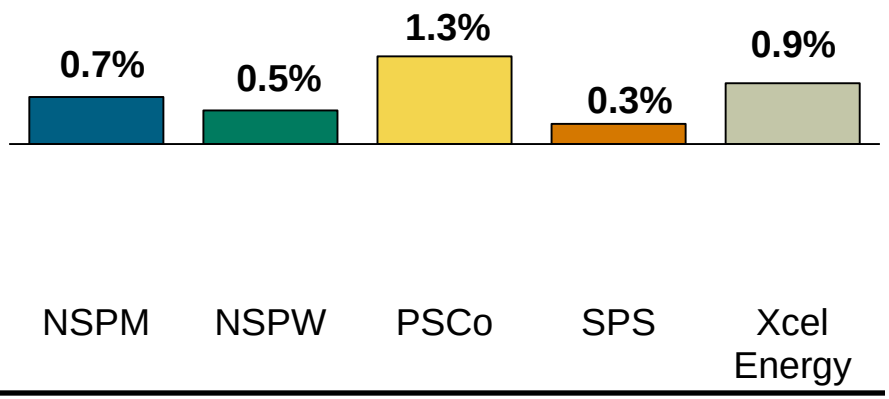
Base capital includes SPS wind & Dakota Range proposals, but does not include CEP, which could increase capital by up to $1.5 billion, based on a preliminary estimate. Capital investment may be lower due to RFP pricing/selection.

Economic, Sales, and Customer Data

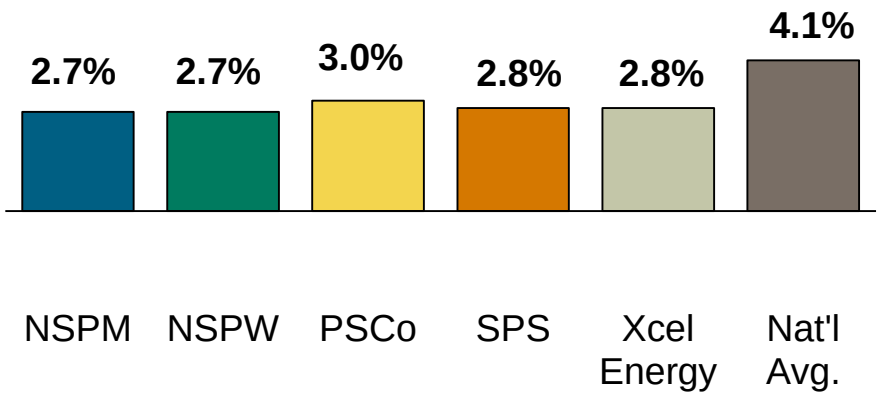
2017 W/A Electric Sales Growth
(adjusted for leap day)



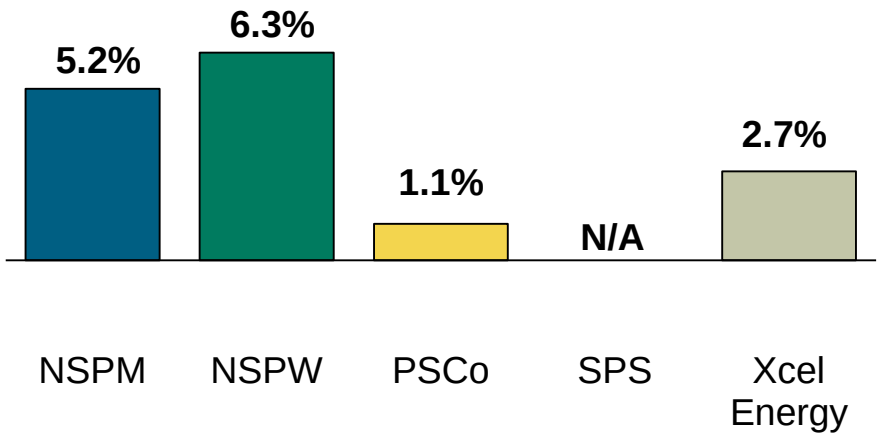
2017 YoY Electric Customer Growth



December Unemployment



2017 W/A Nat. Gas Sales Growth
(adjusted for leap day)



Reconciliation: Ongoing EPS to GAAP EPS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Ongoing EPS	**$1.15**	**$1.30**	**$1.43**	**$1.45**	**$1.50**	**$1.62**	**$1.72**	**$1.82**	**$1.95**	**$2.03**	**$2.09**	**$2.21**	**$2.30**
PSRI-COLI	0.05	0.05	(0.08)	0.01	(0.01)	(0.01)	-	-	-	-	-	-	-
Prescription Drug Tax Benefit	-	-	-	-	-	-	-	0.03	-	-	-	-	-
SPS FERC Order	-	-	-	-	-	-	-	-	(0.04)	-	-	-	-
Loss on Monticello LCM/EPU Project	-	-	-	-	-	-	-	-	-	-	(0.16)	-	-
Impact of Tax Cuts and Jobs Act	-	-	-	-	-	-	-	-	-	-	-	-	(0.05)
Cont. Ops	1.20	1.35	1.35	1.46	1.49	1.61	1.72	1.85	1.91	2.03	1.94	2.21	2.25
Discont. Ops	0.03	0.01	-	-	(0.01)	0.01	-	-	-	-	-	-	-
GAAP EPS	**$1.23**	**$1.36**	**$1.35**	**$1.46**	**$1.48**	**$1.62**	**$1.72**	**$1.85**	**$1.91**	**$2.03**	**$1.94**	**$2.21**	**$2.25**
Amounts may not sum due to rounding													

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the company and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

STATE OF MINNESOTA

OFFICE OF THE ATTORNEY GENERAL

LORI SWANSON
ATTORNEY GENERAL

SUITE 1400
445 MINNESOTA STREET
ST. PAUL, MN 55101-2131
TELEPHONE: (651) 296-7575

April 2, 2018

Mr. Daniel Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: ***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***
MPUC Docket No. E-002/M-17-797

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matter please find Comments of the Minnesota Office of the Attorney General – Residential Utilities and Antitrust Division.

By copy of this letter all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

Joseph A. Dammel
JOSEPH A. DAMMEL
Assistant Attorney General

(651) 757-1061 (Voice)
(651) 296-9663 (Fax)

Enclosure

AFFIDAVIT OF SERVICE

Re: ***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***
MPUC Docket No. E-002/M-17-797

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on 2nd[h] day of April, 2018, I e-filed with eDockets ***Comments of the Office of the Attorney General – Residential Utilities and Antitrust Division*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 2nd day of April, 2018

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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