
**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

**IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY
FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES**

**STAFF MEMORANDUM
SUPPORTING SETTLEMENT STIPULATION**

DOCKET EL25-024

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation (Settlement) of April 24, 2026, between Staff, and Northern States Power Company dba Xcel Energy (Xcel or Company) in the above-captioned matter. Steve Wegman (Intervenor) has signed a concurrence to the Settlement.

BACKGROUND

On June 30, 2025, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase revenues for electric service from customers in its South Dakota retail service territory by approximately \$43.6 million annually or approximately 15.0%. A typical residential electric customer using 756 kWh per month would see an increase of \$20.56 per month or 18.66% under Xcel's proposed rates.

Xcel's proposed increase was based on a historical test year ended December 31, 2024, adjusted for what Xcel believed to be known and measurable changes, a 10.3% return allowance on common equity, and a 7.56% overall rate of return allowance on rate base.

Xcel's last base rate increase application was filed on June 30, 2022¹. Xcel states² that since that time, it has made significant investments in its distribution system in South Dakota, its generation facilities, and the transmission system, and has also replaced aging technology and fleet assets and invested in service centers. In addition, general economic trends, such as inflation, have increased Xcel's costs of operating its business. Xcel states a rate increase is necessary in order to continue to make investments in its system that will allow it to continue to provide safe, reliable, efficient energy into the future.

The Commission officially noticed Xcel's filing on July 3, 2025, and set an intervention deadline of September 17, 2025. On July 21, 2025, the Commission issued an Order Assessing Filing Fee; Order Authorizing Executive Director to Enter into Consulting Contracts. On September 22, 2025, Steve Wegman, of Sioux Falls, South Dakota, filed a Petition to Intervene on his own behalf. On October 9,

¹ See Docket EL22-017

² See Public Rate Increase Notice

2025, the Commission issued an Order Granting Late Filed Intervention to Mr. Wegman. On December 1, 2025, Xcel filed a Notice of Intent to Implement Interim Rates effective on and after January 1, 2026.

Commission Staff propounded 12 sets of formal discovery requests to Xcel. Within the 12 sets of discovery requests there were approximately 300 total formal discovery requests, with approximately 800 total requests when including all the subparts. In addition, Staff conveyed numerous informal requests to Xcel. There were also numerous phone calls and meetings between Staff and Xcel personnel seeking additional and clarifying information.

Settlement discussions between Staff and Xcel (jointly, the Parties) commenced on February 9, 2026. Thereafter, the Parties held additional settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in Xcel's filing. Ultimately, the Parties reached a comprehensive agreement on Xcel's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns.

Mr. Wegman participated in settlement discussions on February 12, 2026. Upon reaching a settlement in principle with Xcel, Staff provided a copy of the settlement stipulation to Mr. Wegman and Mr. Wegman indicated he was in agreement. Mr. Wegman signed a concurrence to the settlement stipulation on April 24, 2026.

OVERVIEW OF SETTLEMENT

Staff's revenue requirement determination is the result of a comprehensive analysis of Xcel's filing and information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that did not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in Xcel's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some positions were modified, and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues. Staff believes the settlement is based on sound regulatory principles and avoids additional costly and unnecessary litigation.

The Parties agree Xcel's net revenue deficiency is approximately \$25,601,000, justifying an approximate 9.5% increase in retail revenues. When the revenues associated with the rider projects being rolled into base rates of approximately \$19,312,000 are considered, it results in a total base revenue deficiency of approximately \$44,913,000. Additionally, the Parties agree that Xcel will continue the Infrastructure Rider (IR) with conditions as discussed below. The revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of Xcel's South Dakota jurisdictional revenue requirement.

The revenue increase by rate schedule is shown on Staff Exhibit____(JMR-2), Schedule 2³. The total revenue impact summary is shown on Staff Exhibit____(JMR-2), Schedule 1⁴. Staff Exhibit____(JMR-2), Schedules 2-1 through 2-4 reflect the settlement base rates for each rate schedule. The comparison

³ Excludes test year revenues associated with items remaining in the Transmission Cost Recovery Rider, Infrastructure Rider, and Demand Side Management.

⁴ Includes the test year revenues associated with items remaining in the Transmission Cost Recovery Rider, Infrastructure Rider, and Demand Side Management.

between present and settlement rates and resulting bill impacts for the Residential Service rate schedules is shown on Exhibit___(JMR-2), Schedule 3.

STAFF OVERVIEW OF BASE RATE SETTLEMENT

Staff's settlement revenue requirement determination begins with total Company test year costs for the 12 months ended December 31, 2024, and allocates those amounts to the South Dakota retail jurisdiction. Staff then adjusted the December 31, 2024, test year results for known and measurable post-test year changes. Staff Exhibit___(EJP-1), Schedule 3 illustrates Staff's determination of Xcel's *pro forma* operating income under present rates. Staff Exhibit___(EJP-2), Schedule 2 illustrates Staff's calculation of Xcel's South Dakota retail rate base, and Staff Exhibit___(EJP-1), Schedule 2 and Staff Exhibit___(EJP-2), Schedule 1 summarize the positions. Staff Exhibit___(EJP-1), Schedule 1 summarizes Staff's determination of Xcel's revenue deficiency and total revenue requirement to be collected through base rates.

Below is a brief discussion of the issues that Staff identified in the case and Staff's view of the resulting settlement of each issue. Unless otherwise noted, all changes discussed below are changes from the Company's filed position. Attachment A provides a summary of the changes made to the Company's filed case compared to the settlement.

RATE BASE AND OPERATING INCOME ADJUSTMENTS

Advertising – Xcel proposed an adjustment to remove advertising expenses that should not be recovered from ratepayers. The settlement accepted this removal and removed additional advertising costs which do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. This additional adjustment reduces operating expense and the revenue deficiency by approximately \$41,000.

Dues: Professional Associations – Xcel proposed an adjustment to remove approximately \$36,000 of association dues. The settlement accepted this adjustment and removed additional association dues expense that did not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. The effect of this additional adjustment reduces operating expenses and the revenue deficiency by approximately \$133,000.

Aviation – The Company proposed an adjustment to remove 50% of aviation expenses. The settlement accepts this adjustment.

Customer Deposits Expense – The Company proposed an adjustment to recover approximately \$3,000 of interest paid on customer deposits. This treatment is consistent with past rate cases, and the Settlement accepts this adjustment.

Economic Development Donations – Xcel proposed an adjustment to add approximately \$50,000 to its recoverable Economic Development Donations. Xcel has had an economic development recovery program in place since the early 1990s and does not propose any changes to their plan. Xcel records all economic development donation expenses below the line as they are incurred. This adjustment removes some expenses from the test year to reflect the recoverable portion of the 50/50 split of \$100,000 in expenses related to economic development donations, excluding labor. The settlement accepts this adjustment.

Employee Expense – Xcel proposed an adjustment to remove approximately \$25,000 in employee expense that it determined is inconsistent with the Company’s guidelines in its Employee Expense Policy or were identified as generally not being needed for the provision of utility service. The Settlement accepts this adjustment.

Foundation Admin – The Company proposed an adjustment to remove 100% of Foundation Administration expenses. The settlement accepts this adjustment.

Incentive Pay – Similar to the settlement in Docket EL22-017, the Company proposed to recover Annual Incentive Plan (AIP) expenses capped at 20% of employees’ base pay and proposed an adjustment removing all test year expenses above that cap. The total AIP amount sought for recovery is \$1,131,143.⁵ Consistent with past Commission precedent, Staff supports recovery of AIP costs. The Settlement accepts the Company’s proposed adjustment. As a safeguard, Staff negotiated a settlement provision requiring the Company to refund customers if actual aggregate AIP payments are less than the amounts included in rates.

Incentive: Long Term Removal – The Company proposed an adjustment to remove all Long-Term Incentive (LTI) compensation expenses, approximately \$720,000, from the test year and made separate adjustments to propose adding back various components of LTI compensation expenses. The settlement accepts this adjustment.

Time Based LTI – The Company proposed an adjustment to include expenses related to the Time Based long-term incentive compensation of approximately \$400,000. Retaining key employees by offering an incentive for remaining with the Company is beneficial to ratepayers by not requiring the Company to retrain key employees due to turnover. The settlement accepts this adjustment.

Late Payment – The Company proposed an adjustment that eliminates test year late payment revenue in lieu of using actual payment collection days in the cash working capital calculation, where, per statute, a 20- day period is used. The cash working capital adjustment does not account for late payments, only on time payments. Therefore, it is appropriate for Xcel to retain the late payment fees collected in the test year and to not include them in the revenue requirement. This is consistent with past ratemaking treatment. The settlement accepts this adjustment and also allows Xcel to increase the late payment fee in the tariff from 1% to 1.5%.

Pension: Non-Qualified SERP – The Company proposed an adjustment of approximately \$3,000 to remove non-qualified pension expense based on actuarial information provided by Willis Towers Watson and allocated using data derived from SAP. The methodology is consistent with prior rate cases. The settlement accepts this adjustment.

South Dakota Pay As Go – The Company proposed an adjustment to reflect the Commission’s requirement to recover OPEBs on a pay-as-you-go basis rather than accrual accounting, converting test year expense from accrual to cash basis. The adjustment results in an increase to administrative and

⁵ This figure represents South Dakota’s portion of the test year (2024) AIP, net of rate case adjustments and interchange offsets. Source: EL25-024 SDPUC-07-004_Attachment A, Excel cell H40 (decimals must be extended to reflect entire dollar figure).

general expense of approximately \$84,000. The methodology is consistent with prior rate cases. The settlement accepts this adjustment.

SD PI EPU Deferral - The Company proposed an adjustment to reflect amortization of the Prairie Island Extended Power Uprate (EPU) deferral, representing the South Dakota jurisdictional share of abandoned plant costs. The adjustment is based on the methodology approved in the Company's prior rate case and results in an increase to amortization expense of approximately \$365,000. The settlement accepts this adjustment.

Bad Debt – The Company proposed to calculate the uncollectible rate based on test year SD net write-offs and test year SD retail revenues and apply the calculated uncollectible rate to the incremental test year SD deficiency as proposed. The Company also proposed to include the difference between the allocated bad debt and SD test year net write-offs. This settlement uses a three-year average of SD Billed Revenue and SD net write-offs to come up with the uncollectible rate. The uncollectible rate is then applied to the adjusted SD test year revenues as calculated in Staff's cost of service. The difference between the actual per books bad debt expense and the calculated bad debt expense is then determined to adjust test year bad debt expense. The uncollectible rate is also applied to the incremental revenue deficiency as determined in this settlement. The adjustment then totals the adjusted test year bad debt expense and the incremental bad debt expense. This adjustment decreases operating expenses and the revenue deficiency by approximately \$443,000.

Credit Card AutoPay – The Company proposed to eliminate the \$1.80 per transaction processing fee paid by customers to a third-party vendor when a customer chooses to pay their electric bill with a credit or debit card. In order to eliminate this fee, Xcel proposed to increase operating expense by \$480,000 to recover the third-party vendor costs from all ratepayers. The settlement rejects this adjustment, reducing operating expenses and the revenue deficiency by \$480,000.

SD Decommissioning – The Company proposed an adjustment to reflect an approximate \$1.1 million reduction in the nuclear decommissioning accrual, relative to the amount set in Docket EL22-017. The primary driver of the reduction in this accrual are the proposed life extensions of the Company's nuclear plants. Specifically, the accrual set in Docket EL22-017 assumed Monticello (2040), Prairie Island 1 (2033) and Prairie Island 2 (2034) estimated retirement dates, whereas the proposed accrual in the instant proceeding assumes estimated retirement dates of Monticello (2050), Prairie Island 1 (2053) and Prairie Island 2 (2054). The settlement accepts the Company's proposed adjustment regarding the nuclear life extensions, but rejects the portion of the nuclear decommissioning accrual related to the Prairie Island Indian Community (PIIC) payments⁶. This adjustment reduces the accrual and the revenue deficiency additionally by approximately \$95,000.

Depreciation Study: Transmission, Distribution, and General (TD&G) – Depreciation is a system of accounting that distributes the cost of assets, less net salvage, over the estimated useful life of the assets in a systematic manner. The Company proposes revisions to remaining lives, net salvage rates, retirement curves, and, correspondingly, depreciation rates for its plant-in-service. In addition, the Company proposes a reserve reallocation based on theoretical reserve calculations. This reallocation shifts depreciation reserve balances among accounts within functional groups to better align book reserve with expected asset lives and net salvage characteristics. The service lives of the Company's assets remained largely unchanged, while net salvage rates increased. The Company also corrected an

⁶ See Prairie Island Indian Community (PIIC) Deferral section.

error in the development of the proposed depreciation rate for Account 390 – Structures and Improvements. The correction results in a decrease to the proposed depreciation expense of approximately \$31,000 for the South Dakota jurisdiction. The Company’s proposed changes result in a net increase to South Dakota jurisdictional depreciation expense of \$1.843 million. This settlement reduces depreciation by approximately \$28,000 and increases rate base by approximately \$11,000. This adjustment reduces the revenue deficiency by approximately \$27,000.

Dues: Chamber of Commerce – Xcel proposed to include approximately \$14,000 in Chamber of Commerce dues in its cost of service. Staff concluded that dues paid to Chamber of Commerce organizations do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. Therefore, the Settlement rejects this adjustment, reducing operating expenses and the revenue deficiency by approximately \$14,000.

EOL Nuclear Fuel Update – The Company proposed an adjustment to reflect updated end-of-life (EOL) nuclear fuel accruals based on revised fuel cost assumptions, remaining plant lives, and modeling performed using specialized software. The updated accrual results in a decrease in power production expense of approximately \$32,000. The settlement accepts this adjustment.

Foundation and Other Donations – Xcel proposed an adjustment to include in its cost of service certain donations paid to charitable organizations the Company feels are appropriate to include in base rates. The settlement rejects this adjustment, reducing operating expenses and the revenue deficiency by approximately \$125,000.

Environmental Long-Term Incentive (LTI) – The Company proposed an adjustment to include approximately \$388,000 related to environmental long-term incentive compensation. The environmental goals that govern these payouts are, according to responses received in discovery, “not based on laws, regulations, or orders in South Dakota...”⁷ Rather, these goals are related to Xcel’s belief that its “proactive approach” to a transition to “carbon-free electricity” is “cost-effective and will result in a more reliable system than if the Company were to take a more reactive approach.”⁸ Staff does not believe South Dakota customers should pay incentive compensation tied to the achievement of environmental goals that are mandated by neither the federal nor the state government. The settlement rejects this adjustment.

Remaining Life – In addition to the depreciation study, the Company proposed plant-specific remaining life adjustments for certain production facilities. Staff and the Parties addressed each of these adjustments individually in settlement, as described below. A small portion of the Sherco 3 early plant retirement adjustments was included in the Remaining Life adjustment. The settlement did not accept the accelerated retirement of Sherco 3 as discussed in more detail below. This adjustment decreases operating expenses by approximately \$560,000 and increases rate base by approximately \$261,000. This adjustment decreases the revenue deficiency by approximately \$536,000.

Remaining Life - ITC – The Company proposed a flow-through adjustment to reflect changes in Investment Tax Credit (ITC) amortization associated with updated remaining lives. In its initial filing, the Company proposed a reduction to total income tax expense of approximately \$26,000. This amount was subsequently revised during settlement to an increase of approximately \$10,000 to reflect the

⁷ Response to SD-PUC-03.10

⁸ Id.

remaining lives ultimately agreed to in settlement. This adjustment increases operating expenses and the revenue deficiency by approximately \$36,000.

Remaining Life – King – The settlement accepts this adjustment. For more detail, see the “Baseload Resources” section below.

Remaining Life – Monticello Life Extension – The settlement accepts this adjustment. For more detail, see the “Baseload Resources” section below.

Remaining Life – Prairie Island Life Extension – The settlement accepts this adjustment. For more detail, see the “Baseload Resources” section below.

Remaining Life – Sherco 3 – Staff rejected the proposed shortening of the remaining life for Sherco Unit 3 for purposes of calculating depreciation expense in the instant proceeding. For more detail, see the “Baseload Resources” section below. This adjustment decreases operating expenses by approximately \$1,092,000 and increases rate base by approximately \$509,000. This adjustment decreases the revenue deficiency by approximately \$1,047,000.

Storm Damage – The Company proposed an adjustment to normalize storm damage expense based upon a five-year average of actual expense for the time period of 2020 through 2024, consistent with past rate case settlements. The settlement accepts this adjustment.

Vegetation Management – The Company proposed an adjustment to normalize vegetation management expense based upon a five-year average of actual expense for the time period of 2020 through 2024, consistent with past rate case settlements. The settlement accepts this adjustment.

NOL Tax Reform ADIT ARAM – The Company proposed an adjustment to reflect amortization associated with the Tax Cuts and Jobs Act (TCJA), consistent with the amortization level approved in Docket No. GE17-003. The adjustment is amortized over 23 years and results in an increase to amortization expense of approximately \$331,000. The settlement accepts this adjustment.

Prairie Island Indian Community (PIIC) Deferral – The Company proposed to recover costs associated with settlement payments made to the Prairie Island Indian Community (PIIC) related to the Prairie Island nuclear generating plant (PINGP). The proposed payments consist of annual payments made to the PIIC as well as an annual cost per cask stored.

Specifically, the Company sought two adjustments related to these payments. For historical costs, Xcel utilized a three-year amortization period and requested an increase to amortization expense of \$397,000. For “known and measurable” costs, the Company sought a \$604,000 increase to power production expense, which it calculated as the sum of the fixed payment to the PIIC and the required per-cask payment multiplied by the projected number of casks.

Staff rejects the Company’s proposal to include PIIC payment-related costs in South Dakota jurisdictional revenue requirements. This adjustment reduces power production expense by approximately \$604,000,

reduces amortization expense by approximately \$397,000⁹, and reduces rate base by approximately \$992,000. This adjustment decreases the revenue deficiency by approximately \$1,083,000.

Rate Case Expense – Xcel proposed to amortize its original estimate of rate case expenses over the next three years and remove the 2024 rate case expense included in the test year. The Settlement accepts the proposed three-year amortization period, the 2024 removal, and updates rate case expenses based on actual costs incurred. Rate case expenses reflected in the settlement total approximately \$720,000. Expenses are based on actual expenses incurred to date through February 2026. The Settlement provides for the rate base inclusion of one-half of the amortizable costs in rate base, representing the average unamortized balance over the three-year period. This adjustment decreases amortization expense by approximately \$201,000 and increases rate base by approximately \$360,000. This adjustment reduces the revenue deficiency by approximately \$169,000.

Rider: Infrastructure Rider – The Company proposed to move into base rates all in-service projects that are currently being recovered in the rider. The IR adjustment removes all revenues and costs from the cost of service for two capital projects with phased in-servicing and PTCs that will continue cost recovery in the rider after the implementation of final rates. The other projects that will remain in the IR do not have any revenue requirement impacts in the test year, therefore no rider removal is necessary for those projects. The adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the pro forma year revenue requirements. The settlement accepts this adjustment.

Rider: TCR – The Company proposed to move into base rates all in-service projects that are currently being recovered in the rider. The TCR adjustment removes all revenues and costs from the cost of service for the MISO Regional Expansion Criteria and Benefits (RECB) and one capital project with phased in-servicing that will continue cost recovery in the rider after the implementation of final rates. The ongoing projects that will remain in the TCR do not have any revenue requirement impacts in the test year therefore no rider removal is necessary for those projects. The adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the pro forma year revenue requirements. The settlement accepts this adjustment.

Capital Known & Measurable – The Company proposed an adjustment to reflect the 2026 revenue requirements for capital projects that went into service (or were proposed to go into service) in late 2024, 2025, and 2026. The proposed adjustments reflect the incremental revenue requirement for 2026, compared to the revenue requirement, if any, already included in the 2024 test year. Xcel's adjustment included 16 categories of projects, with a total of 129 projects included.

The settlement excludes all projects with in-service dates after December 31, 2025, as these projects were not used and useful at the time interim rates went into effect. Of the 129 projects Xcel proposed to be included in the adjustment, 31 projects were removed due to projects not being in-service. The settlement also removes the costs associated with four projects¹⁰ Staff identified as operating income producing¹¹, costs for a solar garden portal¹² given SD customers are not paying for the energy produced

⁹ A reduction of approximately \$95,000 related to the PIIC payments is incorporated in the nuclear decommissioning expense adjustment.

¹⁰ These projects were proposed as part of the Distribution Operations category.

¹¹ Projects that increase revenues or reduce expenses.

¹² This project was proposed as part of the Technology Services category.

by Minnesota community solar gardens, and the costs of the Envis Switching Station upgrades¹³ as [Begin Confidential] [REDACTED] [End Confidential] is responsible for paying all costs directly associated with these upgrades.

During discovery, Xcel provided 9 additional projects¹⁴ to be included that were in-service as of December 31, 2025, but were not included in the initial filing. During settlement discussions, Staff and Xcel agreed to include two additional project categories for projects placed in-service in 2024 and 2025 that were not already included in the capital known and measurable adjustment. A total of 431 additional projects were added to the adjustment for these two additional categories. While the individual project amounts were less than the projects initially proposed, cumulatively the revenue requirements associated with these additions resulted in a significant amount that staff could support for settlement purposes from a known and measurable perspective.

The settlement adjustment also reflects the impact of the settlement rate of return on the calculation of interchange revenues.

The effect of this adjustment reduces rate base by approximately \$19,043,000. This also reduces operating revenues by approximately \$85,000 and increases depreciation expense by approximately \$416,000. The net impact of these changes on the revenue deficiency is a decrease of approximately \$1,144,000.

Staff notes the settlement capital known and measurable adjustment includes recovery of the Sherco Solar I and Sherco Solar II projects, as proposed by Xcel. See the “New Resource Additions” section below.

Early Coal Retirement – Staff proposed an adjustment to account for early retirements for certain projects and resource choices for certain projects. For more detail, see the “STAFF ANALYSIS OF RELEVANT RESOURCE DECISIONS” section below. This adjustment decreases operating expenses and the revenue deficiency by approximately \$2,262,000.

Excess Liability Insurance – Xcel proposed an adjustment to excess liability insurance costs to reflect policy premium increases effective during and post test year. The Company’s proposal annualized the impact of the policy renewal effective in October 2024 and included the increase associated with the anticipated policy renewal effective November 2025. Staff revised the adjustment to more accurately reflect the annualization of the October 2024 increase and the actual increase effective November 2025. The settlement reflects this revised adjustment, decreasing operating expenses and the revenue deficiency by approximately \$59,000.

Property Tax – The Company proposed to include in its cost of service forecasted incremental increases in property taxes for 2026. This settlement reflects an adjustment to include actual, known property taxes to be paid in 2026. This adjustment decreases operating expenses and the revenue deficiency by approximately \$510,000.

¹³ This project was proposed as part of the Transmission category.

¹⁴ These projects included in the following categories: Distribution Operations II, Energy Supply II, Monticello Nuclear Generation II, and Technology Services II.

Wage Adjustment – The Company proposed to increase wages by 3.0% in 2025 and 3.0% in 2026 for both union and non-union labor. Union wages are set in contract and are effective January 1 of each year. Non-union wages are effective in March of each year. The settlement accepts the 2025 and 2026 increase of 3% for non-union and accepts the 2025 3% increase for union workers. The settlement also revises this adjustment to include the following:

1. Annualized 2024 non-union test year amount to fully reflect March 2024 increase.
2. No 2026 union increase. At the time of the settlement the 2026 union increase was not known.

This adjustment decreases operating expenses and the revenue deficiency by approximately \$263,000.

Net Operating Loss – The Company proposed an adjustment to reflect updated net operating loss levels. The NOL is calculated within the Company’s cost of service model as a secondary calculation that is driven by the revenues, expenses, capital structure, and other inputs reflected in the pro forma year. The adjustment reflects the change from test year to pro forma levels and results in a reduction to total tax expense of approximately \$195,000. Staff reviewed the Company’s approach and supporting workpapers and the settlement accepts this adjustment.

Interest Synchronization – The Settlement synchronized the tax deduction for interest expense with the weighted cost of long-term debt and the historic test year rate base as adjusted for known and measurable changes. While the methodology is the same, Staff’s model calculates interest synchronization in one step whereas the Company’s model calculates interest synchronization for each adjustment individually¹⁵.

Cash Working Capital – The Company’s proposed rate base included an allowance for cash working capital based on a lead-lag analysis. A lead-lag analysis examines the timing of the Company’s receipt of service revenues from customers in relation to the Company’s payment of expenses to vendors and employees. Staff carefully examined Xcel’s revenue lag and expense lead day determinations and made the following modifications, which are consistent with Staff adjustments in prior rate cases:

1. Revised the expense lead days for interchange expense, payroll, and incentive compensation;
2. Included separate lead days for vacation pay, depreciation, deferred federal income tax, investment tax credit, gross receipts tax, and interest on long term debt;
3. Revised revenue lag days to decrease interchange and retail revenue lag days; and
4. Revised expenses per day to incorporate into the lead-lag analysis the impacts of Staff’s recommended adjustments to pro forma operating expenses.

These modifications decreased rate base by approximately \$11,029,000. The impact to the revenue deficiency is a decrease of approximately \$981,000.

Tax Collections Available – The Company experiences a timing difference between receipt of funds for sales taxes and employee withholding taxes and when the Company remits those funds to the taxing authorities. The settlement includes a rate base adjustment to reflect the cash flow-related benefit it receives due to this timing difference. Since these forms of tax collection do not flow through the Company’s income statement, they are not part of the traditional lead lag study and are thus addressed

¹⁵ All individual adjustments with a rate base component have an operating income impact from removing interest sync from the Company filed position to the settlement position given Staff’s model moves all interest synchronization impacts to a cumulative adjustment.

separately with this adjustment. The adjustment results in a decrease to rate base of approximately \$748,000 and a reduction to the revenue deficiency of approximately \$66,000.

Other Working Capital – The settlement reflects a more recent 13-month average for materials and supplies, fuel inventory, prepayments, and customer advances. This adjustment decreases rate base by approximately \$1,028,000, resulting in a decrease in the revenue deficiency of approximately \$91,000.

Removal of DSM Costs and Revenues – Staff proposed an adjustment to remove DSM costs and revenues from the test year. This adjustment removes approximately \$1,093,000 in revenues and approximately \$1,093,000 in expenses. The net effect of this adjustment is no change to the revenue requirement.

Land Sale – Staff proposed an adjustment to remove from test year rate base the 13-month average associated with three land sales that occurred during the test year. The effect of this change reduces rate base by approximately \$10,000, resulting in a decrease in the revenue deficiency of approximately \$1,000.

[Begin Confidential] [REDACTED]
[REDACTED] [End Confidential]

Other Revenues and Expenses – [Begin Confidential] [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED] [End Confidential] This adjustment increases operating revenue by approximately \$53,000, and increases operating expense by approximately \$3,000, resulting in a \$50,000 decrease in the revenue deficiency.

EV Removal – The settlement reflects an adjustment to remove test year expense by the Customer and Utilities Innovations department that support future developments in potential electric vehicle programs. Xcel stated there is no on-going benefit to South Dakota customers related to these expenses. This removal decreases the revenue deficiency by approximately \$23,000.

Jurisdictional Cost of Service and Demand Allocator Update – Staff reviewed the Company’s jurisdictional allocation factors, including customer, demand, and energy allocators, as part of evaluating the reasonableness of the proposed jurisdictional revenue requirement. These allocators are used to assign system costs among Minnesota, North Dakota, and South Dakota and therefore directly influence the level of costs recovered from South Dakota customers.

As an initial matter, a comparison of the Company’s current allocation factors to those utilized in the 2021 test year indicates that, in general, the allocators have remained relatively stable over time, with only modest shifts in jurisdictional shares. Across most allocators, Minnesota’s share has declined slightly, South Dakota’s share has increased modestly, and North Dakota’s share has remained relatively consistent. These changes are incremental in nature and do not reflect a fundamental change in allocation methodology, but rather a gradual evolution in underlying system characteristics.

The Company's discovery responses indicate that these trends are primarily driven by differences in energy usage patterns across jurisdictions. Specifically, the Company explained that Minnesota has experienced relatively greater reductions in both peak demand and overall energy consumption, in part due to the effects of energy conservation programs, while South Dakota's usage has declined more slowly. As a result, South Dakota's relative share of system demand and energy has increased over time, with North Dakota remaining comparatively stable. The observed changes in the allocation factors are consistent with this explanation, as the directional shifts in demand, energy, and composite allocators all reflect a modest reallocation of costs from Minnesota to South Dakota.

With respect to demand-related allocations, the Parties agreed to update the Company's demand allocator from the test year (2024) to 2025 levels. The demand allocator is a key driver of jurisdictional cost assignment, particularly for production-related expenses, and therefore has a meaningful impact on South Dakota's allocated share of system costs. The updated 2025 demand allocator reflects a continuation of the same trend observed in the historical data—namely, that South Dakota's share of demand-related allocations has increased over time, while Minnesota's share has declined and North Dakota's has remained relatively stable.

The Company indicated that this trend is consistent with differences in energy usage patterns across jurisdictions, including the impact of energy conservation efforts in Minnesota that have reduced both peak demand and overall energy consumption relative to other jurisdictions. The Parties find this explanation to be reasonable and consistent with the observed changes in the allocation factors.

The updated allocator reflects the most current available data and results in an increase to South Dakota jurisdictional power production expense of approximately \$1.335 million. Based on the information provided and for purposes of settlement, the Parties agreed that use of the 2025 demand allocator is reasonable and accepted its application in the determination of South Dakota jurisdictional revenue requirements. This adjustment increases the revenue deficiency by approximately \$1,335,000.

STAFF ANALYSIS OF RELEVANT RESOURCE DECISIONS

Staff reviewed the Company's resource-planning support for the decisions presented in this rate case, including the 2020 and 2024 integrated resource plans, the June 2020 update, supporting testimony, additional discovery, and technical analysis prepared for Staff. In general, the Company's resource planning studies reflect accepted industry planning tools and a broad review of new-resource options. While the review identified study-design and modeling limitations that reduce the confidence in certain long-term portfolio conclusions, those do not affect the findings of prudence on resources presented in this case. South Dakota does not pre-approve resource plans, and the prudence inquiry in this docket is therefore whether the specific decisions at issue were reasonable when made and remained reasonable as conditions evolved.

Based on that review, Staff concluded that the retirement of Allen S. King is supportable, but the record does not adequately support the accelerated retirement decisions for Sherco Units 1 and 2 and does not presently support accelerated retirement of Sherco Unit 3. The practical significance of Staff's Sherco findings is straightforward. If Sherco Units 1 and 2 had not been committed to early retirement, the replacement resources at issue in this case would not yet have been required and presented before the Commission.

At the same time, however, the system-planning and procurement process has materially progressed: Sherco 2 has already retired, Sherco 1 is planned to retire in 2026, Sherco Solar 1 is in service, additional solar projects are under development, and the short-term PPA extensions have already been executed. Staff therefore approached settlement with the dual objective of preserving meaningful customer protection while also establishing a workable path for recovery of resources that are now part of the Company's near-term system plan and will provide future benefit to South Dakota customers.

Baseload Resource

The baseload resources at issue fall into two categories: coal units the Company has retired or plans to retire on an accelerated schedule, and nuclear units the Company proposes to continue operating through extended depreciation lives. Commentary is provided for each of these resources:

Allen S. King

Staff's review supports the reasonableness of the planned King retirement. Although the Company did not provide a formal engineering condition assessment for the unit, the record supports the conclusion that King is situated differently from the Sherco units. King is a single-unit station, is the oldest remaining unit of its size still in operation in the United States and appears to have persistently weak operating economics and reliability relative to its firm capacity value. On balance, Staff concluded that retirement of King was reasonably supported and that it is appropriate to align King's depreciation with the Company's planned 2028 retirement.

Sherco Units 1 and 2

Staff reached a different conclusion with respect to Sherco Units 1 and 2. Staff finds that the retirement of these units was voluntarily accelerated without regulatory obligation even as the units still provided economic benefit to customers and had remaining useful life.

During the 2009 to 2013 period, the Company was aware that additional environmental compliance obligations could eventually affect the units, including the potential need for SCR controls under the evolving regional haze framework. In response, the Company performed a 2013 Life Cycle Management Study to evaluate the future of the units under stringent compliance assumptions. That study did not support immediate retirement. Rather, it concluded that continued operation remained economically favorable relative to retirement alternatives and that it was prudent to preserve optionality until greater environmental regulatory certainty emerged. Early versions of the 2016 Upper Midwest Resource Plan reflected that same general approach assuming continued operation through 2030.

However, during finalization of the 2016 resource plan the Company elected to commit to accelerated retirement dates for Sherco Units 1 and 2 without corresponding justification on either a technical or economic basis for this change of course and also despite the Minnesota Pollution Control Agency (MPCA) providing direct comments that it would be reasonable to make a determination during its next resource planning cycle. The Company instead moved from preserving flexibility to making a voluntary commitment that was later incorporated into MPCA air permits and thereby became binding upon the utility.

Subsequent Company resource analyses, including the 2021 Encompass Update to the 2020-2034 Upper Midwest IRP, show positive individual unit economics for Sherco 1 and Sherco 2 when considering the financial value of accredited generating capacity they provide. However,

even as the costs of new resources have risen, construction timelines have extended, and customer growth has accelerated, the Company's prior decisions have excluded the possibility of extension.

For those reasons, Staff concluded that the accelerated retirement decision for Sherco Units 1 and 2 was not prudent when made. That conclusion is central to Staff's settlement position because it means South Dakota customers should not bear the full economic consequences of replacement capacity being advanced to fill a need created by those earlier retirement commitments.

Sherco Unit 3

Staff also remains concerned with the proposed accelerated retirement of Sherco Unit 3. The current record does not provide sufficient technical, economic, or regulatory evidence to demonstrate that Sherco 3 must be retired in 2030. Unlike Units 1 and 2, Sherco 3's retirement is farther out and is not attributed to the need for the new resources brought in this rate case.

Sherco 3 remains well within the age range of a substantial portion of the operating coal fleet, and peer-unit evidence generally supports the continued viability of similarly situated units. From an economic perspective, Sherco 3 continues to provide comparatively low-cost accredited capacity when environmental externalities are excluded and when measured against the avoided cost of new accredited generating capacity.

As Sherco 3 is not scheduled to retire until 2030, the Parties agreed to leave its current depreciation rate unchanged and to reserve their respective rights regarding whether a future revenue requirement adjustment may be warranted and, if so, in what amount. Staff believes that treatment is appropriate. It avoids prematurely resolving an issue for which the current record does not justify accelerated cost recovery while preserving the Parties' positions for a future proceeding.

Monticello and Prairie Island

With respect to Monticello and Prairie Island, Staff finds it reasonable to adjust the depreciation lives of those units in alignment with continued operation and life extension. While analysis of the units' individual economics indicates higher cost than certain new resource alternatives, that fact alone does not negate the importance of the units to the NSP system under current conditions. The present planning environment is shaped by accelerated load growth, tighter resource adequacy conditions, and uncertainty regarding the timing and execution of replacement resources. These resources continue to provide critical support to the NSP transmission system as other baseload units are retired. Staff also acknowledges the benefits of fuel-diversity, reliability, and regulatory-risk mitigation in maintaining these nuclear resources in the portfolio. Accordingly, Staff does not oppose the Company's proposed treatment of Monticello and Prairie Island in this settlement, including extension of Monticello to 2050 and Prairie Island to 2053 and 2054.

Settlement Treatment of Accelerated Sherco Retirements

As the Sherco units and the replacement resources differ materially in size, timing, operating profile, useful life, and energy contribution, Staff did not view a simple one-for-one substitution as the appropriate ratemaking remedy in this docket. Instead, Staff sought a practical proxy that would reflect,

at the revenue-requirement level, the adverse economic effect of the imprudent Sherco retirement decisions on South Dakota customers.

The settlement accomplishes that objective in two ways. First, the Parties agreed to an immediate \$2.3 million reduction to the Company's test year revenue requirement attributable to Sherco 2. That reduction applies through December 31, 2030, and provides a direct customer offset tied to Staff's finding that Sherco 2 was retired earlier than the record justified. The amount is tied to an evaluation of the annual net economic benefits that the facility would have otherwise provided, while also considering the additional capital costs that otherwise would have been required to maintain the unit. The 2030 date corresponds to when the Company reasonably anticipated SCR emissions controls would have been required for the units and thus making continued operation economically unfeasible. The date was also supported by the 2013 Life Cycle Management Study and initial versions of its 2016-2030 Upper Midwest IRP prior to Company deciding on accelerated retirement.

Second, the settlement establishes a mechanism for an additional reduction associated with Sherco 1. That reduction will be determined when the Company seeks recovery, likely through the Infrastructure Rider, of a future capacity resource(s) that replaces Sherco 1. At that time, the Parties may present their respective positions regarding the amount of the reduction. In Staff's view, this structure is reasonable because it recognizes the timing relationship between Sherco 1's retirement and future replacement capacity while avoiding speculation regarding resources that are not yet before the Commission.

Taken together, these provisions do not purport to calculate with precision every long-term economic effect of the Sherco decisions. They do, however, provide meaningful and administrable customer protection tied directly to the findings Staff was prepared to advance.

New Resource Additions

Provided that the settlement includes customer protections addressing the adverse economic effects of the accelerated Sherco retirements, Staff believes it is reasonable to evaluate the new resource additions in the context of resulting actual capacity and energy needs. The relevant question is whether the replacement resources are a necessary and efficient response to those needs.

Sherco Solar 1-3

The recovery of Sherco Solar 1, 2, and 3 is reasonable. These projects were identified through the Company's least-cost planning with reasonable assumptions regarding accredited capacity ratings, cost, and performance of the assets. These resources make efficient use of existing Sherco-area transmission capability and interconnection rights, reducing development risk and avoiding the uncertainty of new queue positions via the generator replacement process. In addition, the projects were competitively procured and priced. Taken together, those factors support a finding that the Sherco Solar projects are a reasonable and efficient means of meeting a portion of the NSP system's near-term capacity needs.

PPA Extension of Manitoba Hydro

The Manitoba Hydro extension is reasonable as a near-term bridge resource. The extension preserves access to capacity and energy from an existing supplier during a period in which the NSP system faces near-term capacity needs and resource adequacy compliance risk. It also provides a practical short-term solution while longer-term replacement resources continue to be developed. Given its limited term, Staff finds the Manitoba Hydro extension to be a reasonable and efficient response to current system needs.

PPA Extension of Cannon Falls

Staff likewise believes the Cannon Falls extension is reasonable as a short-term capacity resource. The extension preserves 357 MW of existing capacity through 2028 and helps address the NSP system’s near-term capacity needs while longer-term resources are developed. Its limited duration and continuation of an existing arrangement make it an efficient bridge solution that helps mitigate resource adequacy risk without committing customers to a new long-life asset. On that basis, Staff finds the Cannon Falls extension to be a reasonable component of the overall settlement.

COST OF CAPITAL AND RATE OF RETURN

In its initial filing, the test-year ending December 2024 capitalization was 46.79 percent Long-Term Debt and 53.21 percent Common Equity. In discovery, Staff requested information to update the capital structure through October 2025, resulting in capitalization ratios of 46.06 percent Long-Term Debt and 53.94 percent Common Equity.

Staff evaluated the 53.94 percent equity ratio against the equity ratios of companies in Xcel’s rate of return proxy group with the same BBB+ bond rating as Xcel and concluded that a reasonable equity ratio was in the range of [Begin Confidential] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [End Confidential]

Staff and Xcel agreed to an overall rate of return on rate base of 7.01 percent. The reduction in the overall rate of return reduces the revenue deficiency by approximately \$8,628,000.

REVENUE DEFICIENCY

Staff Exhibit ___(EJP-1), Schedule 1 calculates the net revenue deficiency, including gross receipts tax, as \$25,601,000. When the revenues associated with the projects being rolled into base rates from the TCR and IR of approximately \$19,312,000 are considered, it results in a total base revenue deficiency of approximately \$44,913,000.

RATE DESIGN ISSUES

The Parties agree in principle on all issues regarding rate design and the class revenue distribution. The settlement position reached between Staff and Xcel is discussed below.

Weather Normalization – The Company’s filed “per books” retail revenues were based on weather normalized sales. Staff independently evaluated Xcel’s weather-normalization adjustment for its sales and revenues. Although Staff used a different methodology, the results were comparable, and therefore, the settlement accepts Xcel’s weather-normalized sales and revenues.

Class Cost of Service/Spread of the Increase – The Parties have come to an agreement on all issues regarding rate design and class revenue distribution. In its filed case, the Company presented a class

cost of service study (“CCOSS”) and supporting rate design proposals. The CCOSS is a 2024 embedded cost study that functionalizes, classifies, and allocates plant and expenses among customer classes based on cost-causation principles. The study reflects updated cost, load, energy, and customer data, including weather-normalized sales, and applies methodologies that are generally consistent with those used in prior South Dakota proceedings, with certain refinements to distribution classification and minimum system analyses.

The Company’s proposed class revenue apportionment begins with the class cost responsibilities identified in the CCOSS and then moderates movement toward cost to account for rate continuity and customer bill impacts. As filed, the Company proposed a partial movement toward cost for each class rather than full movement to indicated cost levels in a single proceeding.

Staff reviewed the Company’s CCOSS and rate design proposals and, based on that review, the Parties agreed to an approach for purposes of settlement that resolves issues related to class revenue distribution and rate design. The resulting allocation of the revenue requirement among the customer classes is reflected in Staff Exhibit ___ (JMR-1), Schedule 2. This approach maintains a reasonable relationship between class cost responsibility and revenue assignment while providing a practical and balanced outcome for rate implementation.

Rate Design (Residential Customer Service Charge) – With respect to residential rate design, the Company proposed to simplify the existing structure by adopting a single, uniform customer charge applicable to all Residential customers, replacing the prior differentiated charges, and proposed a uniform customer charge of \$11.00. During discovery, application of an alternative allocation approach (i.e., the Basic Customer method) produced a residential customer charge level of \$8.62.¹⁶ In light of these results, and in an effort to arrive at a reasonable and administratively practical outcome, the Parties agreed to a uniform residential customer charge of \$10.00 per month. This agreed-upon level reflects a rounded, whole-dollar figure that falls between the levels indicated by the differing approaches while preserving a simplified and consistent rate structure.

STAFF OVERVIEW OF INFRASTRUCTURE RIDER SETTLEMENT

The Infrastructure Rider was first established in Docket EL12-046. The settlement approved in Docket EL14-058 continued the Infrastructure Rider, allowing recovery of specific capital additions, with the opportunity to request inclusion of additional projects annually. In Docket GE17-003, Staff and the Company stipulated to allowing the Company to only seek Infrastructure Rider recovery of new wind generation projects and the costs of terminating certain biomass power purchase agreements going forward. The Infrastructure Rider continued in this form until the rate case filing, Docket EL22-017.

The settlement approved in Docket EL22-017 included several projects with opportunity for Xcel to request inclusion of additional projects beginning in 2024, with the condition that the individual project revenue requirements be \$250,000 or greater on a South Dakota jurisdictional level. The EL22-017 settlement also established that wind production tax credits (PTCs) would be credited through the Infrastructure Rider instead of the fuel clause.

In the current settlement, the Parties agree that Xcel may propose to include in the infrastructure rider projects, excluding blanket projects, with an annual South Dakota revenue requirement of at least

¹⁶ See response to SD-PUC-11-001, Att. B.

\$100,000 and that do not produce offsetting cost savings and that are not required for the provision of service to new customers or increase load for existing customers.

The Parties also agree that the Infrastructure Rider will be updated as a result of this rate case for Xcel to recover the deferred 2024 and 2025 cost recovery for Sherco Solar 1 and 2. The Infrastructure Rider rates including recovery of these costs will be determined in Docket EL25-033.

OTHER ISSUES

Rate Moratorium – The Parties agree that Xcel shall not file any rate application for an increase in base rates which would go into effect prior to January 1, 2029.

Implementation of Rates – The tariffs shown on Exhibit A attached to the Settlement are proposed to be implemented for service rendered on or after July 1, 2026. Customer bills will be prorated so that usage prior to that date is billed at the interim rates and usage on and after that date is billed at the new rates.

Interim Rate Refund – Interim rates were implemented on January 1, 2026. Approval of the Settlement will authorize a rate increase less than the interim rate level. The Company agreed to refund customers the difference between interim rates and new rates collected, during the period January 1 through June 30, 2026. As part of the refund, Xcel will include interest, calculated by applying 7% annual interest to the average refund balance for each month that interim revenues were collected. Attached to the Settlement is the Company’s Interim Refund Plan. As mentioned above, the interim rate refund includes a netting of the Infrastructure Rider revenue requirements for January – June 2026.

[Begin Confidential] [REDACTED]

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 - [REDACTED]

- [REDACTED]
- [REDACTED]
- [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [End Confidential]

RECOMMENDATION

The Commission is the state entity that has been tasked by the legislature under SDCL Chapter 49-34A, to regulate utility companies in the state. This regulation includes determining just and reasonable rates under SDCL 49-34A-6, for Xcel Energy and the other five investor-owned utility companies providing electric service in the state. The Commission is also required under SDCL 49-34A-8 to “give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its total current cost of furnishing such service, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.”

After reviewing the filing, Staff believes the settlement finds a balance between providing Xcel Energy with an increase they are eligible for under the law in order to provide safe and reliable electric service, along with a reasonable profit and ensures customers are not being charged unfair or excessive rates.

Staff recommends the Commission approve the settlement for the reasons stated in this memo.