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414 Nicollet Mall
Minneapolis, MN 55401

August 13, 2025

—Via Electronic Filing—

Mike Bull
Acting Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: INITIAL COMMENTS
IN THE MATTER OF COMMISSION REVIEW OF UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION
DOCKET NO. E,G999/CI-08-133

Dear Mr. Bull:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments in response to the Minnesota Public Utilities Commission's Notice of Comment issued on July 16, 2025 in reference to the Public Utilities Commission's Review of Utility Performance Incentives for Energy Conservation.

We have electronically filed this document with the Minnesota Department of Commerce, and copies have been served on the parties on the attached service list. Please contact me at (612) 337-2268 or amber.r.hedlund@xcelenergy.com or contact Luke Anderson at luke.anderson@xcelenergy.com or (612) 216-9238 if you have any questions regarding this filing.

Sincerely,

/s/

AMBER HEDLUND
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF COMMISSION REVIEW OF UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION

DOCKET NO. E,G999/CI-08-133

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments in response to the Minnesota Public Utilities Commission's Notice of Comment issued on July 16, 2025, in the above-referenced docket.

The Company appreciates the hard work and consultation by Center for Energy and Environment (CEE), the Department of Commerce, and Fresh Energy (the Joint Proposers) to develop a forward-looking conservation incentive mechanism that seeks to align utility incentives with the programmatic outcomes prioritized by state policy. The Company is particularly appreciative of the effort to revise the Energy Conservation and Optimization (ECO) incentive mechanism earlier in the procedural cycle than has historically been the case. Knowing the design of the mechanism well before Triennial Plans are filed will create more opportunity for utilities to tailor their ECO programming in response to the mechanism, which should result in ECO portfolios that yield good outcomes for both customers and utilities.

The Company supports many aspects of the Joint Proposal, including the proposed mechanism to incentivize natural gas programming. On the electric mechanism, the Company has several proposed additions and enhancements. These proposals are intended to help better align the mechanism with the expected evolution of electric ECO programming given recent and anticipated trends; to provide flexibility for utilities to achieve reasonable incentive outcomes when programs successfully advance state policy goals; and to ensure that cost-effective conservation and efficient fuel-switching (EFS) remain preferred resource choices for utilities regardless of variation in utility service areas and customer makeup. Additionally, we believe these changes will ensure that the financial incentive mechanism continues to incentivize utilities to pursue not only high energy savings, but also those activities which are likely to result in the most customer value and lowest system cost as the electric system transition proceeds and accelerates.

The Company also appreciates that the Joint Proposal appears to be calibrated with an intent to maintain overall incentive results at levels roughly comparable to those awarded by the current mechanism. The Joint Proposal includes estimates suggesting that, when applied to utility achievements in 2024, the proposed mechanism would result in a modest decrease in incentive results, with an estimated total decrease in utility incentives of about 5 percent. However, as noted in the filing, the Joint Proposal seeks to emphasize activity that is not emphasized under the current mechanism (and thus utilities' current portfolios); the Company agrees with the Joint Proposers' statement that "[i]f the Proposed mechanism is approved by the end of 2025, the utilities would have enough notice to adapt plans and refocus resources on programming that fulfills the new metrics."[1] That said, and as we discuss in more detail below, the Company is concerned that for electric energy efficiency (EE) programs, declining avoided costs are likely to result in a considerably lower financial incentive result in the 2027-2029 Triennial. The Company has sought to identify modest changes to the mechanism that, like the Joint Proposal, are intended to provide results generally consistent with recent historical results when achievement is comparable (modulo the specific changes, such as increased emphasis on income-qualified programming, that the Joint Proposal seeks to encourage).

We recommend the Commission approve the multifactored conservation incentive mechanism as follows, and as more fully detailed within these Comments.

- Approve the natural gas incentive mechanism considering symmetry between the differing mechanisms.
- Approve an electric efficient fuel switching mechanism that is explicitly separate from the energy efficient mechanism and that is simpler to administer; and
- Approve the electric energy efficiency incentive mechanism with modifications to:
    1. Increase the maximum total percent of net benefits awarded to 7 percent,
    2. Require utilities to achieve both the first-year savings threshold and the low-income spending threshold to receive an electric energy efficiency

[1] Joint Proposers, *2027–2029 Shared Savings DSM Incentive Proposal*, June 26, 2025, at p. 28.

incentive in any given year,

3. Remove caps on the net benefits that can be achieved from any individual component of the mechanism, and
4. Add a demand savings component, measured in kW savings from permanently avoided demand through energy efficiency.

The remainder of these Comments describe how the Company sees the role of EE and demand-side management (DSM) programming generally in the coming years, highlighting certain trends that are already emerging and likely to continue. The Company will then discuss the Joint Proposal in the context of those trends and offer suggestions for adjustments to the Joint Proposal to help ensure the financial incentive mechanism continues to encourage and reward the activities that create the most long-term value to Minnesota's energy system and all customers.

COMMENTS

I. THE EXPECTED FUTURE OF ELECTRIC DSM IN MINNESOTA

In this section, the Company describes its expectations of the ways that electric DSM will continue to evolve in Minnesota. Some of the trends discussed are already becoming evident, while others can be reasonably expected to emerge in the near future; all of them are important factors to consider in weighing the Joint Proposal. Several of these trends are the direct result of successful achievement of (or progress toward) Minnesota's renewable energy and emissions reduction goals.

A. Avoided Electric Energy Costs

As renewable sources of electricity that do not consume fuel increasingly dominate the state's generation mix, the cost-effectiveness of electric energy efficiency is declining. This is a result not of programs becoming more expensive but of the operating costs to generate electricity declining, meaning that a saved kWh results in a smaller monetary savings to the utility system. There are two primary sources of value for saved electric energy: the monetary cost (predominately fuel) that would otherwise be incurred to generate the electricity, and the greenhouse gas emissions that are avoided by not combusting that fuel.[2]

The transition away from combusted fuels (and in particular combusted fossil fuels) puts downward pressure on both of these sources of value. Writ large, this transition

[2] Electric energy efficiency can also create significant value through avoiding or delaying the need to build new electric generation, but that is a distinct topic which will be discussed below – the focus here is on the value of avoided energy, rather than demand.

has benefited utility customers and the climate. However, we are reaching a point where a significant portion of the electricity saved through energy efficiency would otherwise have been generated from renewable or other zero-carbon resources. With less fuel being used to generate the average kWh, the value of that savings declines. Similarly, generating more electricity from sources that do not emit greenhouse gases means that the average saved kWh will have less climate benefit than it would have in the past, when the generation mix was more reliant on fossil fuels.

The state's Minnesota Test for cost-effectiveness relies heavily on these two sources of value. In 2024, avoided generation costs represented the largest single category of value from the Company's ECO portfolio at over $258 million (37 percent of total benefits and 52 percent of electric system benefits under the MN Test), while avoided electric externalities – predominantly carbon costs – added another $50 million.[3]

The Company's most recent 2024-2040 Upper Midwest Integrated Resource Plan (IRP) continues to increase the fraction of generation coming from non-fuel-using and non-emitting sources. This plan aligns with Minnesota's energy and climate policies and, indeed, the Company's vision; the state's utilities have been leaders in transitioning to non-fossil sources of electricity and are rightly proud of their accomplishments. However, and as the Company pointed out in its 2023 Comments in this docket, "as electric utilities have made and continue to make progress in reducing emissions from electricity generation, the emissions avoided through energy efficiency have and will continue to decline[.]"[4] The same applies to generation cost savings.

To analyze the impact of the energy transition on the avoided costs and net benefits from energy efficiency, the Company applied the marginal energy costs from its recently approved IRP[5] to its 2024 ECO achievement. To do this, the Company utilized the same methodology described in Appendix 1 of the Company's 2024-2026 ECO Triennial[6] to generate updated avoided costs by load shape and lifetime. The Company applied these avoided costs to the program results reported in its 2024 ECO Status Report.[7] The resulting generation cost savings under updated marginal energy costs totaled $191,305,196, compared to the approved 2024 total of

[3] See the Company's 2024 ECO Status Report, filed April 1, 2025, in Docket No. E,G002/CIP-23-92, p. 188.

[4] *Comments* of Xcel Energy in the current docket, filed October 23, 2023, Attachment A, p. A6.

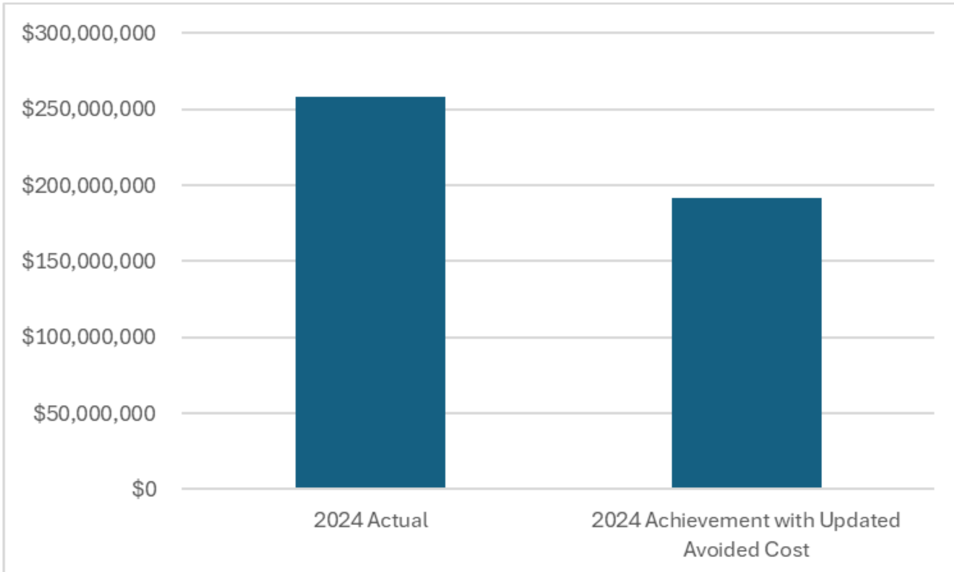
[5] The Company used the EnCompass modeling from the settlement agreement approved by the Commission in its April 21, 2025 Order (Docket Nos. E002/RP-24-67 and E002/CN-23-212).

[6] APPENDIX 1: ELECTRIC UTILITY SYSTEM IMPACTS on page 518 of the Company's compliance filing on January 29, 2024 in Docket No. E,G002/CIP-23-92.

[7] Docket No. G,E002/CIP-23-93.

$258,419,026, as shown in Figure 1. [8]

Figure 1: Declining Value of Saved Electricity



The left column indicates the generation cost savings reported in the Company's 2024 ECO Status Report. The right column shows the cost savings that would result from same level of energy savings, using generation costs derived from the Company's most recent IRP.

This 26 percent reduction in marginal energy cost is not because the cost of fuel is expected to drop into the future, but rather because the continued growth of low-cost renewable generation leads to more hours when these generation sources are on the margin. Because these sources have no fuel cost associated with their energy generation, they are considered to have a $0.00 per MWh marginal cost.[9] The IRP projects that the number of hours in which renewables are on the margin will increase by an order of magnitude over the next 20 years, as shown in Table 1.

[8] There are other sources of value from saved electricity which the Company was not able to compute at this time, partly because the Cost-Effectiveness Advisory Committee that will establish avoided cost methodologies for the 2027-2029 Triennial Plans is still working. However, the value of avoided emissions is likely to follow a similar trajectory to generation costs, because they are both driven by the same underlying trend (an increasing share of renewables). While it is possible that capacity costs may increase, it is unlikely that they will increase enough to offset the significant decline in generation costs.

[9] The March 31, 2023 Decision *In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities* (Docket No. E,G999/CIP-23-46) establishes the avoided cost methodology.

Table 1: Projected Annual Hours when Renewables are the Marginal Generation Resource

Year	Number of Hours	Percentage of Hours
2025	449	5%
2030	2,544	29%
2045	5,022	57%

What this implies for ECO is that (1) energy savings that are cost-effective under the Minnesota Test will become harder to achieve as individual measures and programs become less cost-effective; and (2) at any given level of energy savings, less total net benefit will be created by utility portfolios. Utilities certainly can, and indeed have been, tailoring their ECO programming to drive energy savings at the most fuel- and carbon-intensive times of the day and the year, in order to maximize the benefit of those savings. This should and will continue. However, the structure of Minnesota's legislatively established energy savings goals means that utilities must also strive to achieve a certain level of energy savings regardless of when or where on the system they occur. This means potentially pursuing significantly less cost-effective savings simply to achieve the statutory minimum (and to qualify for an incentive). All the foregoing suggests that Minnesota may be reaching a threshold at which policymakers may need to consider whether annual electric energy savings remains the most effective metric for utility ECO portfolios.

The Company raises these topics to highlight the trends in avoided costs, and to suggest that Commission consider the resulting decline in net benefits when approving a mechanism based on awarding a percent of net benefits to the utility. The same level of achievement might need to result in a higher percent of net benefits awarded in order to give the same dollar value from the incentive.

We also emphasize that, regardless of the Company's avoided costs, energy efficiency is one of the best tools available to customers to manage their energy costs. Moreover, robust energy efficiency programs can play a critical role in supporting the achievement of other energy policy goals, and in reducing other types of costs on the electric system. One of these, the cost of capacity, is discussed in the following section.

B. Importance of Avoided Demand

As the previous section indicated, the source of value of energy efficiency as an electric utility resource is shifting away from first-year energy savings and increasingly toward avoided capacity investments. This includes both generation capacity and transmission and distribution capacity. While the importance of energy efficiency for avoiding or delaying capacity expansions is not a new idea, it is not currently reflected in the statutory requirements for ECO. The Company anticipates that as the value of avoided energy declines, and as new loads continue to connect to the electric grid, avoided demand will become the primary benefit of energy efficiency. The Company believes that the time is right for policy signals – such as the incentive mechanism – to reflect this value and encourage utilities to achieve demand savings in addition to energy savings.

Certainly, the avoided cost of capacity is reflected in cost-effectiveness tests, including the Minnesota Test, and thus in the net benefits achieved by utility programs. However, if the percent of net benefits awarded by the incentive mechanism reflects only saved energy and not demand, it risks creating a distorted value signal to the utility – emphasizing activities which do not necessarily drive the greatest value to the system.

Moreover, some aspects of the value of avoided demand are not possible to reflect in cost-effectiveness tests. Among these are the "preventive benefits" to energy efficiency, through which energy efficiency avoids future costs that are additional to the immediate savings but unknown at the time of the investment in efficiency. For example, investing in building shell measures can reduce heat loss even if no change is made to the building's heating system, immediately reducing annual operating costs for the customer. At some point in the future, the building owner may realize an additional benefit if, when the time comes to replace the heating system (such as when the customer decides to install a heat pump), the improved shell allows the installation of a smaller system than would have been needed with the old, leakier shell. Installing a smaller heat pump saves cost for the customer as well as for the electric system because it will not be able to impose as high a peak load as a larger system.[10] Neither of these future avoided costs can be accurately quantified and included in cost-benefit tests at the time the customer is upgrading the building shell, but they are no less important for that.

[10] See Quinnell, Bohac, *et. al.,* "It's All About the Envelope: Prioritizing Envelope Upgrades for Electrification of Cold Climate Homes," *Proceedings of the 2022 Summer Study on Energy Efficiency in Buildings*, ACEEE (Washington DC, 2022). Among other findings, the authors note that "[m]edian peak loads drop 2 to 2.5 kW […] when the baseline stock is fully weatherized. […] Such reductions of peak load will have a dramatic impact on grid capacity investments for fully electrified and decarbonized space heating in cold climates." (p. 9-178)

Finally, demand savings will continue to be of value even when carbon and fuel costs are entirely[11] eliminated from the electric system. In an all-renewable system, a saved kWh will have very low value to the system, where an avoided peak kW will continue to represent avoided capacity investment.

For these reasons, the Company believes it is both appropriate and important for the ECO incentive mechanism to include a component to focus electric utility efficiency efforts on demand savings in addition to energy savings. The specifics of the Company's proposal are discussed below, but at a high level the Company suggests creating a third component to the multi-factor electric energy efficiency mechanism that would allow an additional percentage of net benefits based on permanently avoided electric demand through energy efficiency.

C. Importance of Efficient Fuel-Switching

With the dramatic and continuing decline in carbon emissions from the electric sector,[12] efficient-fuel switching can allow for the beneficial substitution of electricity for combusted fuels in other sectors. In addition to reducing emissions, replacing fossil fuels with electricity can considerably reduce customer costs in many cases, in both the buildings and transportation sectors.

The combination of a relatively dirty and expensive incumbent fossil fuel with the staggering inefficiency of internal combustion engines means the transportation sector is both the highest-emitting and most wasteful sector of Minnesota's economy – and one particularly ripe for electrification. Transportation emissions are nearly a third of the state's GHG emissions and have declined only about six percent in the last seventeen years.[13] Wasted energy in the transportation sector is the largest single energy end use in the state's economy by a wide margin: wasted transportation energy represented 20 percent of the 1,706 trillion BTU used in the state in 2022, and almost 80 percent of the sector's consumption.[14] Electrifying transportation saves cost for

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[11] Or almost entirely, given the possible exception of nuclear fuel costs.

[12] Minnesota's electric sector emissions declined 50 percent between 2005 and 2022, thanks to continued investments in electric energy efficiency and renewable sources of electricity and the transition away from coal-burning power plants. See Minnesota Pollution Control Agency, *Greenhouse Gas Emissions in Minnesota 2005-2022*, January 2025 (https://www.pca.state.mn.us/sites/default/files/lraq-3sy25.pdf)

[13] *Ibid.*

[14] Lawrence Livermore National Laboratory, "Minnesota Energy Consumption in 2022" (https://flowcharts.llnl.gov/sites/flowcharts/files/styles/orig/public/2025-04/energy-2022-united-states-minnesota.png?itok=RTRhlPvz). Wasted transportation energy was nearly 31 percent higher than the next largest end use.

drivers, reduces emissions, and makes Minnesota more efficient overall.

Increasingly, a similar story is true for other end uses, including space and water heating. Heat pump technologies are now capable of operating at higher efficiencies and over wider temperature ranges, making them economically attractive for many customers even in Minnesota's cold climate. The continued transition away from fossil-fueled electric generation and toward renewables with no fuel cost or carbon emissions will further support this beneficial trend.

Further, the additional electricity sales from electrification can be beneficial to all customers. To the extent that new loads can be served at a cost lower than the incremental revenue they bring the utility, they can put downward pressure on the rates paid by all customers. Again, transportation is particularly attractive in this respect, because vehicle charging predominately occurs off-peak and, in many cases, can be managed to avoid increased electric system costs.[15]

Efficient fuel switching is thus critically important to achieving Minnesota's energy goals. The legislature recognized this by creating the ability for utilities to promote EFS when it passed the ECO Act in 2021, and again in 2024 when it authorized the creation of a financial incentive mechanism for EFS. Through these policies, the legislature has set the table for electric utilities to offer robust EFS programming that makes it easier for customers to choose highly efficient electric options across a variety of end uses, without requiring customers to use (or abandon) any particular technology.

The Company supports an incentive mechanism specific to electric EFS that allows utilities to support policy objectives while emphasizing the rate reduction potential of electrification. While the Joint Proposal is a start in this direction, as described below, the Company suggests further refining the EFS mechanism to focus these efforts more precisely.

II. THE JOINT PROPOSAL

In this section, the Company will discuss the Joint Proposal, highlighting areas that it sees as particularly well-designed or where it has concerns. The first portion of this section will discuss the overall structure of the proposal and then turn to the individual mechanisms for natural gas energy efficiency, efficient fuel switching, and

[15] See, e.g., *Making Electricity More Affordable with Electric Vehicles*, Alliance for Transportation Electrification (July 2025), https://evtransportationalliance.org/wp-content/uploads/2025/07/ATE_Making-Electricity-More-Affordable-with-EVs_FINAL.pdf

electric energy efficiency. In Section III, the Company will provide its recommendations for changes to the proposed mechanism to ensure the mechanism sends appropriate financial and policy signals to utilities.

A. Overall Incentive Structure

The Joint Proposal is designed as a multi-factor mechanism, where utilities can earn a percent of net benefits reflecting their achievement of three important policy goals. These are first-year energy savings and spending on low-income programming for both electric and natural gas programs. The electric and natural gas mechanisms differ in their third component; for natural gas, it is the level of savings achieved from air-sealing and insulation measures, while for the electric mechanism is the third component is net benefits from efficient fuel switching. The Joint Proposal caps the percent of net benefits that can be achieved from each individual component and includes an overall cap on the incentive (as a percent of net benefits) that is equal to the sum of the individual component caps. The Joint Proposal also includes a cap on overall incentives at 20 percent of spending, increasing to 25 percent of spending if the utility achieves sufficient levels of first-year energy savings.

The Company generally supports the change to a multi-factor mechanism. Multi-factor mechanisms can encourage and reward specific outcomes that support state policy within the context of an overall portfolio. The Joint Proposal presents a manageable and relatively straightforward mechanism by focusing on a limited number of metrics and selecting metrics that are generally supported by statute.[16]

However, the Company flags two potential issues for consideration. The Joint Proposal appears to treat electric EFS[17] as a component of the overall electric energy efficiency mechanism. The first issue the Company highlights is that electric EFS is a different sort of program activity from electric energy efficiency and treating it as an element of a multi-factor mechanism may elide the differences. Second, the statute authorizing an incentive mechanism for EFS states "the commission must develop and implement incentive plans designed to promote energy conservation separately from the plans designed to promote efficient fuel-switching."[18] Treating EFS as one of several metrics to incentivize energy efficiency may be inconsistent with this

[16] First-year savings, low-income spending, and electric EFS are all explicitly discussed in statute; the Joint Proposal gives a clear explanation of the importance of air-sealing and insulation, and the Company supports its inclusion.

[17] The Company uses the phrase "electric EFS" to mean "efficient fuel-switching undertaken by an electric utility."

[18] Minn. Stat. § 216B.16, Subd. 6c.

requirement.

Also, the proposal makes an electric utility's EFS incentive contingent upon its energy efficiency achievements. The core determinant of the EFS incentive under the Joint Proposal is the percentage of net benefits achieved by the utility's energy efficiency programming. This makes it more difficult for utilities to maximize their EFS achievement, because estimates of the incentive that will result from EFS will be contingent on expectations of EE achievement. This approach also exacerbates the conflict with the statutory requirement for the EFS incentive mechanism to be separate from the EE mechanism.

The Company supports the proposed spending caps, which are consistent with the caps approved by the Commission for the current mechanism. To ensure separation between the EFS incentive and the EE incentive, the Company below (in Section III) proposes an alternative metric for determining whether the utility's EFS achievement merits the higher spending cap (25 percent of spending).

Finally, the Joint Proposal includes both caps on the percent of net benefits that can be achieved from the individual factors of the multi-factor structure, as well as an overall net benefits cap that is equal to the sum of the individual caps. This is redundant and reduces the benefit of flexibility that a multi-factor mechanism could otherwise offer.

B. Natural Gas Energy Efficiency

The Company supports the Joint Proposal's recommendations for the natural gas mechanism. The trends of declining avoided costs discussed above generally do not apply to natural gas[19]: commodity prices are not expected to decline significantly, and while the Company is undertaking initial exploration of lower-carbon substitutes for natural gas, it will be some time before the average carbon content of the gas delivered to customers begins to materially decline.

The approach of treating efficient fuel switching undertaken by gas utilities essentially the same as energy efficiency savings is appropriate. The three factors proposed as components of the multi-factor mechanism (first-year savings, low-income spending, and savings from air-sealing and insulation measures) are reasonable and the

[19] While the avoided cost associated with natural gas is likely to remain fairly consistent, it is worth noting that the continued transition in electric generation will support both the economics and the climate benefit of efficient fuel switching away from natural gas. The times that heat pumps are the most efficient are generally the shoulder seasons where the Company expects to see the biggest increase in hours in which renewable energy sources are on the margin.

mechanism appears to be calibrated to result in comparable results for the utility when program achievements are comparable to recent history.

C. Electric Efficient Fuel-Switching

The Joint Proposal for an electric EFS mechanism is likewise generally reasonable apart from its connection and overlap with the EE mechanism. By awarding a percent of Minnesota Test net benefits created by the utility's EFS programming, the Joint Proposal would reward utilities for EFS achievements that result in both economic and carbon savings. Multiplying the percent of benefits achieved by the EFS portfolio's Ratepayer Impact Measure (RIM) test ratio creates an additional encouragement for electric utilities to design programs that deliver on the potential of EFS to create downward rate pressure for all customers. As indicated above, the Company does have concern with the Joint Proposal's treatment of electric EFS as a component of the electric EE mechanism. As discussed in more detail below, the Company suggests approval of an electric EFS mechanism that is clearly and explicitly separate from the EE mechanism,[20] and modifying the determination of the base percent of benefits awarded to avoid having EFS results contingent upon EE achievement.

D. Electric Energy Efficiency

The Company appreciates that the Joint Proposal's electric energy efficiency mechanism (like the natural gas mechanism) appears intended to give comparable results when achievement is comparable to recent levels. However, we have concerns that, given the trend in avoided costs discussed above, this intended result may not play out in practice. While the Joint Proposal may award a similar (or even higher) percent of net benefits to the current mechanism, it may nevertheless result in a materially lower incentive given the anticipated decline in net benefits described above.

To illustrate this, the Company calculated the financial incentive it would have received for its 2024 program results under three alternative scenarios: (1) Applying the Joint Proposal and calculating net benefits using actual 2024 avoided costs (the same approach used by the Joint Proposal with a minor correction[21]); (2) Using the

[20] This would mean there would be three separate incentive mechanisms: One for electric efficiency, one for natural gas efficiency (which would include gas EFS programming), and one for electric EFS.

[21] The Company identified a minor error in the Joint Proposal's treatment of the circularity created by including the incentive in the calculation of MN Test net benefits and RIM Test ratio. To correct this, the Company adjusted the incentive calculation using the circular reference methodology that the Department

current incentive mechanism and actual 2024 savings achievements, but calculating net benefits using estimated avoided costs based on the Company's most recent IRP; and (3) Applying the Joint Proposal to 2024 savings achievements with net benefits calculated with avoided costs from the most recent IRP. The results are shown in Table 2 below, in both dollars and percent of net benefits awarded.

Table 2: Incentive Percent of Net Benefits, Total and Percent Change

Line	Scenario Description	Incentive (Percent of Net Benefits)	Incentive (Dollar Amount)	Percent Change from 2024 Actual
1	*2024 Actual*	*3.68%*	*$ 15,133,727*	*0.0%*
2	2024 with Joint Proposal	3.49%	$ 14,769,325*	-2.4%
3	2024 with 2027 Avoided Costs	3.68%	$ 12,507,349	-17.4%
4	2024 with 2027 Avoided Costs and Joint Proposal	3.49%	$ 12,786,145	-15.5%

* Corrected figure per footnote 21.

As Table 2 shows, the decline in avoided costs alone, when applied to the Company's 2024 achievement, drives a 17 percent decrease in the incentive result. This is mitigated slightly by the Joint Proposal: although the percent of net benefits declines from 3.68% to 3.49%, the total incentive increases because the Joint Proposal treats EFS as part of the overall electric EE mechanism. EFS represents just over $900,000 of the total incentive shown in Line 4 above; without EFS, the incentive figure on that line would be $11,874,187 – a 21.5% decrease from Line 1.

Under the Joint Proposal and the current mechanism, the Company would earn a very similar percent of net benefits based on its 2024 achievements. The considerable decline in the incentive amount is driven by the lower avoided costs, and thus lower net benefits, as discussed above. Again, these lower avoided costs are a result of the shift from fossil-fuel-burning to non-fuel-using sources of energy, consistent with state policy and the Company's commitment to the clean energy transition. In other words, lower net benefits from energy efficiency are a natural result of the success of efforts to remove greenhouse gas pollution from the electric sector. But this does not

suggested in Appendix K of the Final Decision issued on March 31, 2023, in Docket No. E,G999/CIP-23-46. The change results in an incentive amount that differs by less than one percent from the figure presented in the Joint Proposal. This circularity is also used in calculation of Line 4. The Company has not included the details of the corrected calculation here but can provide them to interested parties upon request.

mean that utilities deserve a lower ECO incentive as a result. The state's energy savings goals have only increased in recent years, and first-year savings are becoming increasingly difficult to achieve – in part because declining avoided costs also make energy efficiency less cost-effective to pursue. In order to continue to send a signal rewarding successful energy efficiency programs, the Company believes that a higher net benefits cap and a revised calibration of the first-year savings component are both appropriate.

E. Demand Savings Component

As indicated above, the Company believes that adding a factor to reward utility achievement of permanent demand savings will help keep utilities focused on achieving outcomes that are beneficial to the system overall. As the relative value of energy efficiency shifts from avoided energy to avoided demand, the incentive mechanism should likewise shift to ensure that utilities are achieving as much value as possible for customers. A demand savings factor should replace electric EFS as the third component of the electric multi-factor mechanism, and electric EFS should be made a clearly separate and distinct mechanism.

III. COMPANY RECOMMENDATIONS

The Company offers the following recommendations for modifications to the Joint Proposal. These changes are intended to address the issues identified above and ensure that the financial incentive mechanism continues to incentivize utilities to pursue not only high levels of overall energy savings, but those specific activities which are likely to result in the most customer value and lowest utility system cost as the electric system transition proceeds and accelerates. The changes create an added degree of flexibility for utilities to pursue the sources of value that make the most sense for their specific service areas and circumstances while reflecting state policy and the emerging needs of the grid. At the same time, the Company has sought to identify changes which will allow utilities to continue to earn incentives at a level generally consistent with that seen under recent versions of the mechanism, given sufficient achievement and focus on the programmatic outcomes the mechanism emphasizes.

A. Overall Incentive Structure

The Company recommends that the overall structure of the incentive mechanism be revised to ensure that the incentive mechanism for EFS is clearly separate from the mechanism for energy efficiency. This can be achieved by presenting the EFS mechanism as a standalone mechanism, rather than as a factor within the electric EE mechanism, and by removing the EFS mechanism's reliance on electric EE achievement to establish the base percentage of net benefits achieved. In addition, we offer the following feedback and recommendations.

The Company recommends removing the caps on the percent of net benefits that can be earned through individual components of the multi-factor mechanisms, relying instead on an overall cap on net benefits to limit incentive results. The Company also recommends increasing the net benefits cap for the electric EE mechanism to seven percent of Minnesota Test net benefits, to reflect the declining avoided costs from electric EE (this proposal is discussed in more detail below).

The Company understands from discussion with stakeholders that one motivation for the caps on individual components was a concern that utilities would focus entirely on one factor to the exclusion of others – in particular, that they would pursue high levels of first-year savings while only achieving the statutory minimum on low-income program spending. The Company has considered this concern and suggests the following solution: Utilities should not be eligible for any incentive in a year in which they fall below the minimum achievement thresholds for both first-year savings and low-income spending. While the Joint Proposal could not be maximized without achieving statutory requirements (and beyond), it appears to allow a utility to earn an incentive based on one metric even if performance on another is below threshold. Conditioning the entire incentive on achievement of at least threshold performance on both statutory components (first-year savings and low-income spending) would ensure that utilities achieve at least the minimum on those components.

If the Commission believes that requirement does not go far enough to motivate increased effort on low-income spending, another (possibly additional) approach could be to set the overall net benefits cap at the lower of (a) seven percent; or (b) six percent plus the percentage of net benefits earned by the Company's low-income achievement. This would serve to mitigate the impact of declining avoided costs while ensuring that the utility cannot maximize its incentive without a significant effort on low-income programming. To reach the full seven percent of net benefits, the utility would need to achieve at least a full percentage point of net benefits from the low-income component, which could only be achieved by increasing low-income spending to approximately 0.83 percent of residential gross operating revenue (GOR) – more than 35 percent above the statutory minimum and above any of the historical achievements presented in the Joint Proposal.[22]

[22] The highest achievement among electric utilities in recent years was about 0.75% of residential GOR by Minnesota Power in 2024. *Joint Proposal*, p. 11.

The Company supports the proposed spending caps for the energy efficiency mechanisms of 20 percent, increasing to 25 percent with sufficient first-year savings achievement.

B. Natural Gas Energy Efficiency

For symmetry between the natural gas and electric mechanisms, the Company suggests that the Commission consider removing the caps on individual components and rely instead on the overall net benefit cap; otherwise, the Company supports the Joint Proposal's changes to the natural gas mechanism.

C. Electric Efficient Fuel-Switching

To clearly separate the electric EFS mechanism from the electric EE mechanism, the Commission should adopt a different approach to establish the base percent of net benefits. This would also make program management and forecasting simpler for utility staff, who would not need to rely on projected achievement in a different area in order to forecast the likely result of the EFS incentive.

The Company proposes that, instead of basing the percent of net benefits earned by EFS on the percent of net benefits earned by EE, the Commission should simply apply a fixed 5 percent of net benefits. The mechanism would retain the Joint Proposal's multiplication by the RIM ratio and the application to EFS-driven Minnesota Test net benefits.

The Company recommends that the net benefit cap for EFS be set at ten percent. Achieving this level of incentive would require (assuming the Company's proposal to set a fixed base percent of benefits is adopted) that utilities achieve a RIM ratio of at least 2.0, indicating that the additional revenue driven by EFS programs is equal to at least double the cost of the programs (and any additional costs to serve the added load).

For the EFS mechanism, first-year savings are likely not an appropriate metric on which to base the higher level of spending cap. Instead, the Company proposes that the higher spending cap be applied at 25 percent when the utility's EFS portfolio achieves a RIM ratio of 2.0 or higher.

With this approach, utilities would have an incentive to grow their overall EFS portfolios to increase net benefits under the Minnesota Test (which quantifies the key program benefits of reduced customer fuel cost and reduced emissions) and to do so in a manner that delivers on the potential of EFS programming to create downward pressure on electric rates.

D. Electric Energy Efficiency

To compensate for the decline in avoided costs discussed above, the Company proposes more changes to the electric EE mechanism than to the other two mechanisms. Some changes would alter the design of the mechanism, while others address its calibration. The Company also proposes a new component of the mechanism, demand savings achievements, which it discusses in detail below.

1. Changes to the Design

The Company proposes the following changes to the design of the electric EE incentive mechanism:

A. Increasing the maximum total percent of net benefits awarded to 7 percent;
B. Requiring the utility to achieve at least the first-year savings threshold *and* the low-income spending threshold in order to receive an electric EE incentive in any given year;
C. Removing the caps on the percent of net benefits that can be achieved from any individual component of the mechanism; and[23]
D. Adding a demand savings component, measured in kW savings from permanently avoided demand through energy efficiency.

The Company's rationale for B and C are discussed earlier in these Comments. For A, the Company believes that given the anticipated decline in the amount of net benefits due to the continued transition away from fuel-using generation sources, it is important to increase the percent of net benefits awarded in order to prevent an excessive reduction in the dollar value of the incentive. D is discussed below.

2. Changes to the Calibration

The Company proposes changes to the calibration of the electric energy efficiency mechanism which will allow for utilities to better align their programs with the anticipated future drivers of value from energy efficiency. As discussed earlier, the bulk of saved cost in the future is likely to result from avoided demand, rather than energy savings. While Minnesota's statutory requirements continue to primarily emphasize energy savings as a key metric, the Company believes its proposed recalibration can create space for utilities to begin realignment toward demand

[23] As discussed above, a possible alternative would be to remove the component-level caps but require that the overall net benefits awarded can only exceed 6 percent by the number of percentage points earned from the low-income spending component.

savings, without losing sight of the statutory energy savings requirement. The proposed calibration places less emphasis on first-year savings than the Joint Proposal by reducing the savings threshold and growing the percent of benefits awarded for first-year savings more slowly.

Specifically, the Company proposes that the first-year savings component have a reduced achievement threshold of 1.0 percent of sales, rather 1.5 percent. The incentive at that threshold level would be only 0.5 percent of net benefits rather than the 1.0 percent proposed in the Joint Proposal. At savings of 2.2 percent of sales, at which the Joint Proposal awards 4.5 percent of net benefits, the Company's proposal would award 4 percent. Intermediate achievement would be calculated by interpolation, and achievement above 2.2 percent savings would be calculated by extrapolation (rather than capped as in the Joint Proposal). Higher levels of savings would be rewarded with higher percentages of net benefits, subject to the overall cap of 7 percent.[24]

Overall, the resulting incentive function for first-year savings would grow more slowly than under either the current mechanism or the Joint Proposal, as illustrated in Figure 2. At energy savings corresponding to the Company's 2024 achievement (about 1.9% of sales), the Joint Proposal would award 3 percent of net benefits, while the Company's proposal would yield 3.13% and the actual incentive requested for 2024 was 3.68%. This approach would continue to provide meaningful encouragement to pursue higher levels of energy savings achievement but also create opportunity for the Company to pursue other sources of program value – such as low-income programming or demand savings – in order to maximize its incentive.

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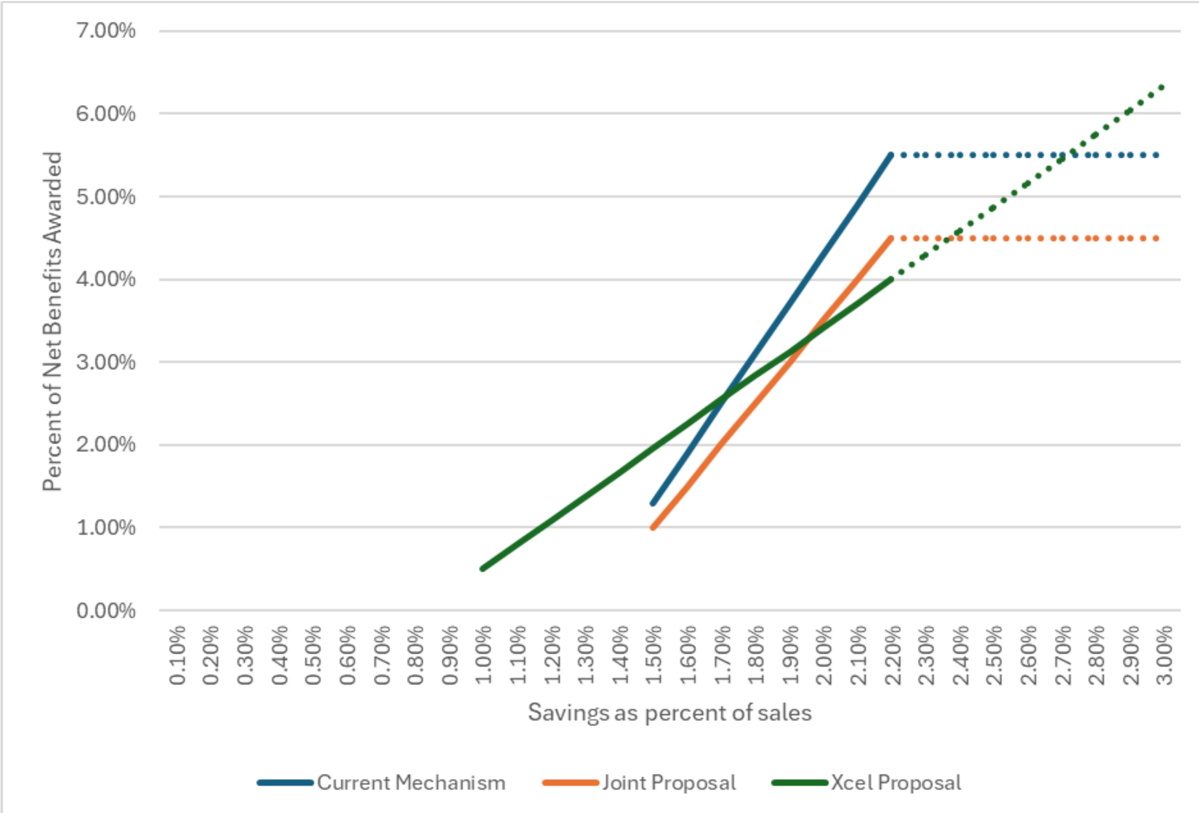
[24] Given the Company's proposals related to caps on individual components, the maximum percentage that could be received for first-year savings would be 6.67 percent (because no incentive could be earned unless the low-income spending threshold is met, which brings 0.33 percent of net benefits), or 6 percent if the Commission adopts the option of increasing the cap above 6 in direct proportion to the percent of benefits earned from the low-income component.

Figure 2: Incentive Functions for First-Year Savings



Dashed lines indicate trajectory beyond the defined calibration points (incentive threshold and 2.2 percent of sales).

The Company proposes a first-year savings threshold of 1.0 percent of sales. Both the current mechanism and the Joint Proposal use 1.5 percent of sales as the threshold, slightly below the default energy savings goal established in statute at 1.75 percent of sales. However, the Commissioner has statutory authority to approve an energy savings goal as low as one percent if the utility requests it and can demonstrate its appropriateness.[25] The Company used the lower 1.0 percent figure as a threshold on that basis.

3. Demand Savings Component

To keep electric utilities focused on pursuing energy efficiency programs and measures which are likely to deliver the most long-term value to the electric system,

[25] MN Stat. 216B.241, Subd. 1c. Paragraph (b) establishes a savings goal of "1.75 percent of gross annual energy sales unless modified by the commissioner under paragraph (c)"; paragraph (c) details the basis on which utilities can request the commissioner make such an adjustment; and paragraph (d) limits the minimum energy savings goal to one percent of sales.

the Company proposes a third component to the electric EE mechanism based on permanently avoided demand. By “permanently avoided demand,” the Company refers to those savings driven by the installation of energy-efficient equipment which reduces the amount of load the customer is able to impose on the system, relative to the counter-factual base case. Excluded from this metric would be demand savings associated with behavioral programming or demand response and load management programs.[26] Those programs, while valuable and particularly helpful for addressing acute grid needs, do not reduce the amount of load the customer is *able* to impose; they simply modify the timing of the load. The Company believes the demand savings component should emphasize more permanent savings.

The Company believes it has developed a methodology for calibrating demand savings achievements that can be used by all of the state’s electric investor-owned utilities. This methodology is described in more detail in Attachment A1, but briefly, it uses the utility’s most recent IRP to estimate the amount of demand savings that could be expected to accompany the amount of energy savings called for in the IRP. That is then used to establish the amount of demand savings that can be expected when energy savings match a given percent of sales. For example, if the utility’s IRP called for 100 MWh of energy savings and this corresponds to one percent of annual sales, and the IRP indicates that 25 MW of demand would be associated with 100 MWh of energy savings, the “1 percent demand goal” would be 25 MW.

In the case of Xcel Energy, this approach results in a “1 percent demand goal” of 50.3 MW and a “2 percent demand goal” of 100.6 MW (based on the Company’s most recent IRP). In 2024, the Company’s demand savings totaled 294.3 MW, of which behavioral and demand response savings represented 195.9 MW, leaving 98.4 MW of demand savings that would be eligible for the demand savings component as proposed here. The Company’s energy savings represented 1.95 percent of sales, suggesting that the programs achieved about (or a little more than) the expected amount of demand savings given the energy savings achieved. This demonstrates that the Company’s approach to determining the demand savings that should accompany a given level of energy savings is reasonable.

The Company proposes that the demand savings component be calibrated such that achievement of the threshold demand savings results in one percent of net benefits awarded, with achievement of the 2.2 percent demand goal resulting in 2.0 percent of

[26] These programs are, and will remain, included in utility energy savings achievements and net benefits calculations – the Company proposes their exclusion only from the calculation of the demand savings component of the incentive mechanism.

net benefits.[27] Intermediate achievement would be calculated through linear interpolation, while achievement above the 2.2 percent demand goal would be calculated by linear extrapolation.

In the Company's view, this approach would help orient electric utilities toward energy efficiency programming that maximizes the demand savings potential of energy efficiency. Given the importance of demand savings in avoiding future system expansion and expense, this is an appropriate and reasonable signal to send. This mechanism would also create opportunity and flexibility as first year energy savings become more difficult to achieve, encouraging utilities to drive value through the timing of those savings even if the total number of saved kWh is lower than in the past.

E. Estimated Incentive

To estimate the impact of the Company's proposed changes to the Joint Proposal, the Company applied its proposed changes and estimated updated avoided costs to its 2024 program achievements. The results are presented in Table 3 below. The electric EFS component was calculated assuming a base 5 percent of net benefits, multiplied by a RIM ratio of 1.5 for a final percent of net benefits of 7.5 percent.

Table 3: Estimated Incentive Results Assuming 2024 Achievement, the Xcel Energy Incentive Proposal, and Updated Electric Avoided Costs

	2024 Actual Incentive		2024 Estimate with Xcel Energy Proposal and Updated Electric Avoided Costs	
	Incentive Amount	Percent of MN Test Net Benefits	Incentive Amount	Percent of MN Test Net Benefits
Electric Energy Efficiency	$15,133,727	3.68%	$18,157,203	5.43%
Electric Efficient Fuel-Switching	N/A	N/A	$1,232,068	7.5%
Natural Gas Energy Efficiency	$4,313,292	4.00%	$4,119,424	3.73%

[27] The Company proposes that the demand savings threshold should match the energy savings threshold, which the Company has suggested should be reduced to 1.0 percent of sales. If the Commission does not adopt the lower energy savings threshold, the demand savings threshold should still match the energy savings threshold (i.e., 1.5 percent) and the Company proposes that the slope of the demand savings incentive function not be changed – it would simply require a higher level of achievement to begin earning.

While Table 3 indicates that the Company's proposal would yield a higher incentive for electric energy efficiency than the 2024 actual achievement, the resulting incentive is nevertheless comparable to the range of incentives approved by the Commission in recent years.

CONCLUSION

The Company appreciates the opportunity to provide these comments on the Joint Proposal. Based on our analysis and the discussion above, the Company summarizes its recommendations below in redline from the Joint Proposal. The redline edits below include the suggestion that the natural gas energy efficiency component-level net benefit caps be removed for consistency with the Company's recommendation for electric energy efficiency.

1. Approve a 2027–2029 Shared Savings DSM Financial Incentive Mechanism with the following provisions:

    A. For all utilities, net benefits are calculated using the Minnesota Test according to the approved 2027–2029 ECO Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, which is expected to be issued by the Department in Q1 2026.

    B. The Societal Discount Rate, as approved in the Department's 2027–2029 ECO Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, is used in the calculation of net benefits to discount for future benefits and costs.

    C. For natural gas <u>energy efficiency</u>:

        a. Allow utilities to begin collecting an incentive for each metric when they reach the following performance levels:

            i. First-year energy savings of 0.7 percent of weather-normalized average retail sales, at which the utility can collect 1.14 percent of portfolio net benefits.

            ii. Insulation and air sealing first-year energy savings of 0.10 percent of weather-normalized average residential retail sales, at which the utility can collect 0.38 percent of portfolio net benefits.

            iii. Low-income spending of 1.0 percent of residential gross operating revenue (GOR), at which the utility can collect 0.38 percent of portfolio net benefits.

        <u>b. A utility may not earn any financial incentive for a year in which</u>

either first-year savings or low-income spending are below the threshold performance level established above.

~~b~~ c. Set metric-specific ~~net benefit caps~~ calibration points at:

i. 3 percent of portfolio net benefits for first-year energy savings, awarded for an achievement of 1.2 percent of weather-normalized average retail sales ~~or higher~~.

ii. 1 percent of portfolio net benefits for insulation and air sealing first-year energy savings, awarded for an achievement of 0.30 percent of weather-normalized average residential retail sales ~~or higher~~.

iii. 1 percent of portfolio net benefits for low-income spending, awarded for an achievement of 2 percent of average residential Gross Operating Revenue ~~or higher~~.

~~c~~ d. Use linear interpolation to award the appropriate percentage of net benefits for performance levels between the achievement threshold and ~~net benefits cap~~ calibration point. Use linear extrapolation to calculate the percentage of net benefits awarded for performance levels above the calibration point.

~~d~~ e. Set a total Net Benefits Cap equal to 5 percent of portfolio net benefits. ~~The total Net Benefits Cap corresponds with maximum achievement in all three metrics.~~

~~e~~ f. Set an Expenditures Cap of 20 percent of total portfolio expenditures, which increases to 25 percent if the utility achieves first-year energy savings of 1.2 percent of weather-normalized average retail sales or higher.

D. For electric ~~utilities~~ energy efficiency:

a. Allow utilities to begin collecting an incentive for each metric when they reach the following performance levels:

i. First-year energy savings of ~~1.5~~ 1.0 percent of weather-normalized average retail sales, at which the utility can collect ~~1~~ 0.5 percent of portfolio net benefits.

ii. Low-income spending of 0.6 percent of residential gross operating revenue (GOR), at which the utility can collect 0.33 percent of portfolio net benefits.

iii. Demand savings equal to the utility's 1.0 percent demand goal (calculated using the utility's most recently approved Integrated Resource Plan), at which the utility can collect 1.0 percent of portfolio net benefits.

b. A utility may not earn any financial incentive for a year in which either first-year savings or low-income spending are below the threshold performance level established above.

~~b~~ c. Set metric-specific ~~net benefit caps~~ calibration points at:

i. ~~4.5~~ 4.0 percent of portfolio net benefits for first-year energy savings, awarded for an achievement of 2.2 percent of weather-normalized average retail sales ~~or higher~~.

ii. 1.5 percent of portfolio net benefits for low-income spending, awarded for an achievement of 1 percent of average residential Gross Operating Revenue ~~or higher~~.

iii. 2.0 percent of portfolio net benefits for demand savings, awarded for an achievement of the 2.2 percent demand goal (calculated using the utility's most recently approved Integrated Resource Plan).

~~c~~ d. Use linear interpolation to award the appropriate percentage of net benefits for performance levels between the achievement threshold and ~~cap~~ calibration point. Use linear extrapolation to calculate the percentage of net benefits awarded for performance levels above the calibration point.

~~d. Calculate the EFS incentive by multiplying EFS net benefits by the EFS Ratepayer Impact Measure (RIM) ratio and the combined net benefits multiplier from the first-year energy savings and low-income spending metrics.~~

e. Set a total Net Benefits Cap equal to ~~6~~7 percent of portfolio net benefits ~~plus 6 percent of EFS net benefits~~.

f. Set an Expenditures Cap of 20 percent of ~~total~~ energy efficiency portfolio expenditures, which increases to 25 percent if the utility achieves first-year energy savings of 2.2 percent of weather-normalized average retail sales or higher.

E. For electric efficient fuel switching:

a. The base percent of net benefits awarded is five percent.

b. The final of net benefits is the lesser of:

i. The base percent of net benefits multiplied by the RIM ratio achieved by the utility's EFS activity; or

ii. ten percent.

c. The percent of net benefits is applied to the total Minnesota Test net benefits from the utility's EFS activity to determine the incentive amount.

d. Set an Expenditures Cap of 20 percent of EFS expenditures, which increases to 25 percent if the utility's EFS portfolio achieves a RIM ratio of 2.0 or higher.

2. Approve the following provisions from the 2024–2026 Shared Savings DSM Financial Incentive Plan for continuation under the 2027–2029 DSM Financial Incentive, as follows:

A. Both electric and gas utilities that have achieved energy savings at or above 1% of retail sales, excluding savings achieved through load management programs, are allowed to count the increased net benefits and energy savings derived from their load management programs that occurred on or after the approval of the Energy Conversation and Optimization Act (May 25, 2021) towards calculating their financial incentive.

B. For the treatment of load management programs that do not result in energy savings,
   a. Calculate net benefits using the Minnesota test and include the net benefits in the total net benefits used to calculate the financial incentive.
   b. Exclude all kW saved from load management programs that existed before May 25, 2021, from the benefits calculation.

~~C. Both electric and gas utilities are allowed to count their expenditures on EFS and load management programs in calculation of their Expenditures Cap.~~

D. CIP-exempt customers shall not be allocated costs for the Shared Savings Incentive Mechanism. Sales to ECO-exempt customers shall not be included in the calculation of utility energy savings goals.

E. If a utility elects not to include a third-party ECO project, the utility cannot change its election until the beginning of subsequent years.

F. If a utility elects to include a third-party project, the project's net benefits and savings will be included in the calculation of the energy savings and will count toward the 1.0 percent savings goal for gas utilities and 1.75 percent savings goal for electric utilities.

G. The energy savings, costs, and benefits of modifications to non-third-party projects will be included in the calculation of a utility's DSM incentive.

H. The costs of any mandated, non-third-party projects (e.g., 2007 Next Generation Energy Act assessments and University of Minnesota Initiative for Renewable Energy and the Environment costs) shall be excluded from the calculation of net benefits and energy savings achieved and incentive awarded.

I. Costs, energy savings, and energy production related to Electric Utility Infrastructure Costs, solar installation, and biomethane purchases shall not be included in energy savings for DSM financial incentive purposes.

3. The new Shared Savings DSM Financial Incentive Plan shall be in effect for 2027–2029 ECO program years.

Dated: August 13, 2025

Northern States Power Company

Attachment A1: Avoided Demand Metric

The Company looked at a few approaches for determining the value of the proposed demand component for the electric incentive based on non-behavioral, non-dispatchable avoided demand. These approaches included:

- Historical generation system energy and demand
- Historical energy efficiency achievement
- Planned energy efficiency in the Company's 2024-2026 Energy Conservation Optimization Plan
- The energy efficiency bundles included in the Preferred Plan in the 2024-2040 Upper Midwest Resource Plan[1] (Integrated Resource Plan or IRP)

The approach that the Company is proposing is to base the avoided demand goal on the IRP. These energy efficiency bundles are based on the projected energy and demand expected considering future changes in the technologies included in the Company's ECO Portfolio and the anticipated adoption of those technologies by program participants. The Company believes this gives the most accurate estimate of the amount of avoided demand that could be expected to accompany the amount of energy savings from energy efficiency called for in the approved IRP.

To model the energy efficiency bundles used in the IRP, the Company developed an energy efficiency load shape based on the load shapes of the various measures included in the bundles. This energy efficiency load shape resulted in the projected demand savings from energy efficiency shown in Table F-6 of the IRP. Dividing the anticipated demand savings by the energy savings yields an estimate of the amount of demand that can be expected to accompany a unit of saved energy. The Company refers to this as the "demand ratio."

In Xcel Energy's case, the demand ratio is 0.000185 MW per MWh.[2] This demand ratio can be calculated by dividing the energy savings in any given year by the demand savings in the same year; it is constant across years because the load shape for energy efficiency was the same in all years of the IRP. For example, in 2027 the IRP calls for a total of 2,221 GWh of energy savings and 410 MW of demand savings (including

[1] 2024-2040 Upper Midwest Resource Plan (Docket No. E002/RP-24-67) Appendix J
[2] The accompanying spreadsheet illustrates this calculation using the figures in Table F-6.

only the approved efficiency bundles 1 and 2); 410 MW divided by 2,221 GWh gives 0.000185 MW per MWh.

The demand ratio will vary between utilities based on their approved levels of energy efficiency and the load shapes used for modeling in their IRP proceedings. Once calculated, however, it can be used to estimate the amount of demand savings that will accompany a given level of energy savings.

By calculating the amount of energy savings that corresponds to a given percent of sales and then multiplying by the demand ratio, we can estimate the amount of demand savings that should accompany energy savings at that percent of sales achievement. For any utility, the demand savings corresponding to 1 percent energy savings (the "1 percent demand goal") can be calculated by multiplying the number of MWh equal to 1 percent of sales by the demand ratio. The table below illustrates this for Xcel Energy.

Table 1: Proposed MW and % of Net Benefits Scale for Xcel Energy

Percent of Sales	MWh Savings	Demand Ratio	Demand Goal (MW)	Percent of Net Benefits
1.00%	272,290	0.0001848	50.320	1.00%
1.10%	299,519	0.0001848	55.352	1.08%
1.20%	326,748	0.0001848	60.384	1.17%
1.30%	353,977	0.0001848	65.416	1.25%
1.40%	381,206	0.0001848	70.448	1.33%
1.50%	408,435	0.0001848	75.480	1.42%
1.60%	435,664	0.0001848	80.512	1.50%
1.70%	462,893	0.0001848	85.543	1.58%
1.80%	490,122	0.0001848	90.575	1.67%
1.90%	517,351	0.0001848	95.607	1.75%
2.00%	544,580	0.0001848	100.639	1.83%
2.10%	571,809	0.0001848	105.671	1.92%
2.20%	599,038	0.0001848	110.703	2.00%
2.30%	626,267	0.0001848	115.735	2.08%
2.40%	653,496	0.0001848	120.767	2.17%
2.50%	680,725	0.0001848	125.799	2.25%

"Demand Goal" is the product of MWh Savings and Demand Ratio. The Demand Goal that corresponds to a given percent of sales is referred to as the "X percent demand goal" and represents the expected demand savings that would accompany energy savings at that percentage. For example, Xcel Energy's 1.7 percent demand goal as calculated on this table would be 85.543 MW. The details showing the calculation of this table can be seen in Attachment A2.

As proposed by the Company, the demand savings component of the incentive would be calibrated such that achieving the 1 percent demand goal (in the table above for Xcel Energy, 50.32 MW) would result in 1 percent of net benefits, while achieving the 2.2 percent demand goal (110.703 MW in the table above) would yield 2.0 percent of net benefits. The Percent of Sales and Percent of Benefits columns would look the same for each utility, while the other columns would reflect each individual utility's percent of sales values (in MWh), Demand Ratio, and Demand Goal (derived from the first two). Additionally, note that the MWh figures above reflect the percent of sales used in Xcel Energy's 2024-2026 Triennial Plan. These would be recalculated using more recent sales in the next Triennial filing, so the Demand Goal will change somewhat from the figures presented here (though the Demand Ratio would not change until a new IRP is approved).

The Company anticipates that other electric utilities should be able to use the energy efficiency requirements and corresponding demand estimates from their own IRPs to produce similar tables to the one above.

CERTIFICATE OF SERVICE

I, Marie Horner, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. **E,G999/CI-08-133 COMMISSION REVIEW OF UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION**

Dated this 13 day of August, 2025

/s/

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Marie Horner
Regulatory Administrator

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25	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	8-133Official
26	Michael	Sachse	michael.sachse@opower.com	OPOWER		1515 N. Courthouse Rd, 8th Floor Arlington VA,	Electronic Service		No	8-133Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						22201 United States				
27	Bruce	Sayler	bruces@connexusenergy.com	Connexus Energy		14601 Ramsey Boulevard Ransey MN, 55303 United States	Electronic Service		No	8-133Official
28	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	8-133Official
29	Jeffrey	Springer	jeff.springer@dairylandpower.com	Dairyland Power Cooperative		3200 East Ave S La Crosse WI, 54601 United States	Electronic Service		No	8-133Official
30	Grey	Staples	gstaples@mendotagroup.com	The Mendota Group LLC		1830 Fargo Lane Mendota Heights MN, 55118 United States	Electronic Service		No	8-133Official
31	Analeisha	Vang	avang@mnpower.com			30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	8-133Official
32	Ethan	Warner	ethan.warner@centerpointenergy.com	CenterPoint Energy		505 Nicollet Mall Minneapolis MN, 55402 United States	Electronic Service		No	8-133Official