APPENDIX B: DEMAND SIDE MANAGEMENT AND DISTRIBUTED RESOURCES

This Appendix of the 2025-2039 Integrated Resource Plan ("2025 Plan") contains information regarding Minnesota Power's (or the "Company") planning and strategies for demand side management ("DSM"), including energy efficiency ("EE") and energy conservation and optimization ("ECO"), along with Residential Time-of-Day ("TOD"), alternative demand side management programs, distributed generation ("DG"), and microgrids. This Appendix is broken into five parts as detailed below.

1. Minnesota Power's EE Resource Alternatives and ECO Strategy;
2. Residential TOD;
3. Alternative Demand Side Management Programs;
4. Distributed Generation; and
5. Microgrids.

A. Part 1: Minnesota Power's EE Resource Alternatives and ECO Strategy

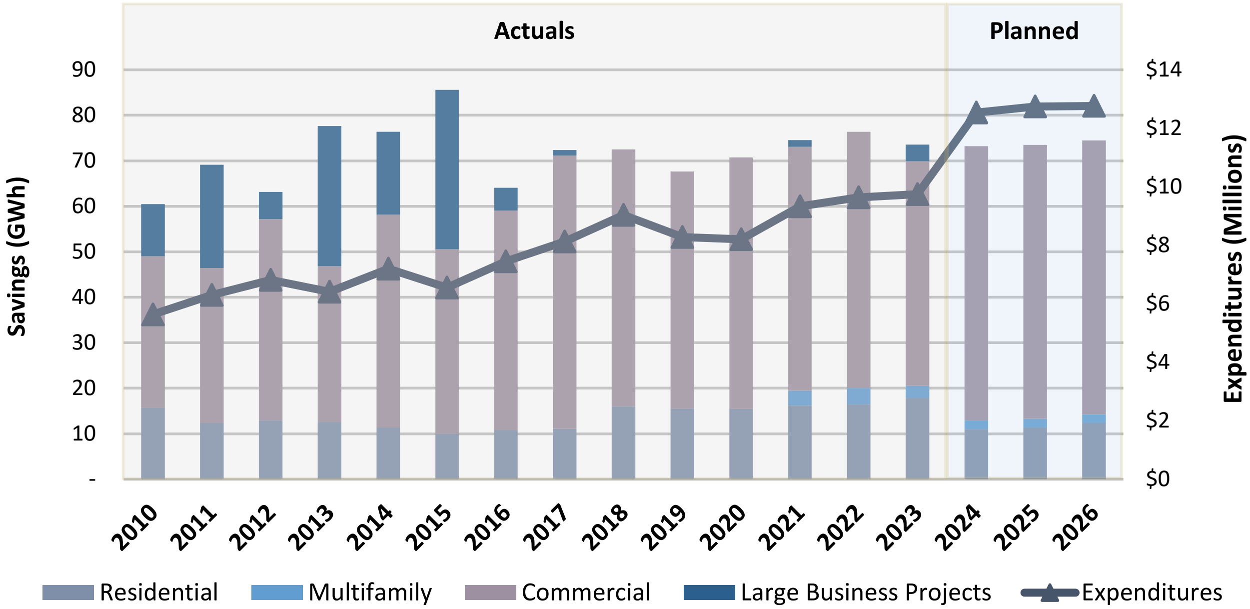
Minnesota Power is committed to providing sustainable energy-efficiency programs, as demonstrated by its strong historical conservation program achievements. Since the Minnesota Next Generation Energy Act of 2007 ("NGEA"), Minnesota Power has been refining and expanding upon its proven conservation program platform to deliver cost-effective savings, customer value, and environmental benefits. The Energy Conservation and Optimization Act of 2021 ("ECO Act") provided a timely pathway for building on core conservation program offerings and expanding those to reach more customers while providing a broader suite of programs and services. Minnesota Power filed its 2024-2026 Triennial ECO Plan on June 30, 2023,[1] and remains dedicated to continuous program improvement. Ongoing conservation initiatives are part of Minnesota Power's broader *Energy**Forward*** resource strategy – a strategy designed to provide a safe, reliable, and affordable power supply while identifying sustainable solutions for compliance with Minnesota's Carbon-Free Electricity Standard. This part of the appendix discusses the development of the Company's energy conservation targets included in the 2024-2026 ECO Triennial Plan filing[2] and the 2025 IRP baseline assumptions, as well as two increased EE alternative resource scenarios.

Figure 1 below reflects historical (first year) savings achievements and the proposed savings goals for 2024-2026, as filed in the latest ECO Triennial Plan. Minnesota Power, together with its customers, community stakeholders, and trade allies, has achieved great success through its energy conservation programs. The Company has delivered energy savings at or above the state's 1.5 percent energy-savings goal since 2010 when the goal went into effect, all while maintaining focus on targeted program objectives – quality installations, informed decisions, EE, and safety. The proposed goal for 2024-2026 and the assumed EE in the baseline forecast, 2.9 percent of sales, reflect the Company's intent to continue achieving significant savings and is well above the state's new ECO goal of 1.75 percent that became effective with the ECO Act.

[1] *Minnesota Power's 2024-2026 Triennial Energy Conservation and Optimization Program Filing*, Docket No. E-015/CIP-23-93, ECO Triennial Compliance Filing (June 30, 2023)

[2] *Minnesota Power's 2021-2023 Triennial Conservation Improvement Program Filing*, Docket No. E-015/CIP-20-476, Petition (July 1, 2020).

Figure 1. Minnesota Power Historical ECO Achievements and 2024-2026 Goals



2025 IRP Baseline Assumptions and the 2024-2026 ECO Triennial

For purposes of both ECO Triennial planning and 2025 IRP modeling, Minnesota Power started with an approach similar to the 2021 IRP. Assumptions used in the 2021-2023 ECO Triennial and the 2021 IRP were developed using the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Minnesota Department of Commerce and led by the Center for Energy and Environment ("CEE").[3] During the study, Minnesota Power worked closely with CEE to update assumptions used in the Minnesota Power specific projections to more accurately capture the Company's specific territory, customer base, and historical experience with energy efficiency programs. Individual program targets and technology contributions were updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years.[4] Subsequently, the 2021 IRP informed the Company's goals for the 2024-2026 ECO plan, which was used as the baseline EE assumption built into the 2025 IRP customer demand forecast. These savings targets are well above the State of Minnesota's 1.75 percent minimum energy-savings goal for ECO,[5] which equates to roughly 45 gigawatt hours ("GWh") on Minnesota Power's system. The Baseline scenario assumes these savings targets will equate to roughly 74 GWh on Minnesota Power's system in 2024-2026. The savings goals in the ECO Triennial Plan and the efficiency levels assumed in the baseline assumptions for the IRP are aggressive, but the Company believes these

[3] *See* Minnesota Department of Commerce, "Minnesota Energy Efficiency Potential Study: 2020-2029," (December 4, 2018), available at https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf.
[4] The process of updating the CEE potential projections and method used to incorporate them into the 2020 load forecast are documented in the Company's AFR2020, included as Appendix A in the 2021 IRP.
[5] Minn. Stat. § 216B.241, subd. 1c(b) ("A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c).The savings goals must be calculated based on the most recent three-year weather-normalized average.").

are achievable. Individual program targets and technology contributions have been updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years. As many of these factors are still evolving, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty.

Summary of Alternative Energy Efficiency Scenarios

Based on the current ECO strategy, and analysis of historical performance and future opportunities, Minnesota Power provided two alternative EE scenarios with additional energy and capacity savings above the Baseline Scenario (built into the base/expected 2024 Annual Electric Utility Forecast Report ("AFR2024") forecast). The Company further developed cost projections consistent with each outlook. The two alternative energy efficiency scenarios evaluated in the IRP analysis are:

1. "High" Scenario: modeled to reflect savings of 3.5 percent of sales, and
2. "Very High" Scenario: modeled to reflect savings of 4 percent of sales.

These scenarios were incorporated in the EnCompass modeling process as supply side alternatives in the capacity expansion plan analysis.

The alternative efficiency scenarios ("High" and "Very High") considered in the IRP analysis begin in the year 2027. These alternatives were not modeled as an option for 2024-2026 due to currently approved savings levels and the limited ability to significantly increase EE above the approved 2024-2026 ECO Triennial Plan. All three EE scenarios assume new program implementation costs (and new savings) each year through 2039. For the purposes of modeling the alternative scenarios in the 2025 IRP, only the additional costs and additional first year MWh/MW savings above the baseline are included. A high-level summary of the baseline EE (assumed in the forecast) and the increased efficiency scenarios modeled in the resource plan are shown in Table 1 and includes the following:

- Percentage of Sales: Represents the level of 2027 savings under each scenario as a percentage of average weather normalized 2020-2022, non-ECO exempt retail sales—the baseline for the 2024-2026 ECO Triennial Plan.[6]
- Energy: Total estimated first year energy savings associated with each scenario for the year 2027.
- Energy Above Base: The additional MWh associated with each scenario in terms of first year savings as compared to the baseline plan (EE assumed in forecast).
- Seasonal Peak: Estimated first year MW demand savings coincident with Midcontinent Independent System Operator ("MISO"). Table 1 below shows summer peak for the year 2027 as an example.
- Summer Peak Reduction Above Base: The additional first year MW demand savings associated with the scenario as compared to the baseline plan.
- Incentives: Program costs directly related to incentivizing customers to install/complete an efficiency measure by covering part or all of the incremental costs associated with implementing the measure.
- Non-Incentives: All other costs incurred by the Company to implement the 2027 EE plan.

[6] In accordance with Minn. R. 7690.1200, 2020-2022 weather-normalized average retail energy sales were used to calculate the minimum electric savings goal for Minnesota Power's 2024-2026 Triennial ECO plan. Effective January 1, 2024, adjusted retail energy sales were approved by the Department of Commerce due to a newly exempt ECO Customer. This equated to 2,555,346,232 kWh, net of ECO exempt customers. Savings as a percent of sales in Table 1 were calculated using this figure.

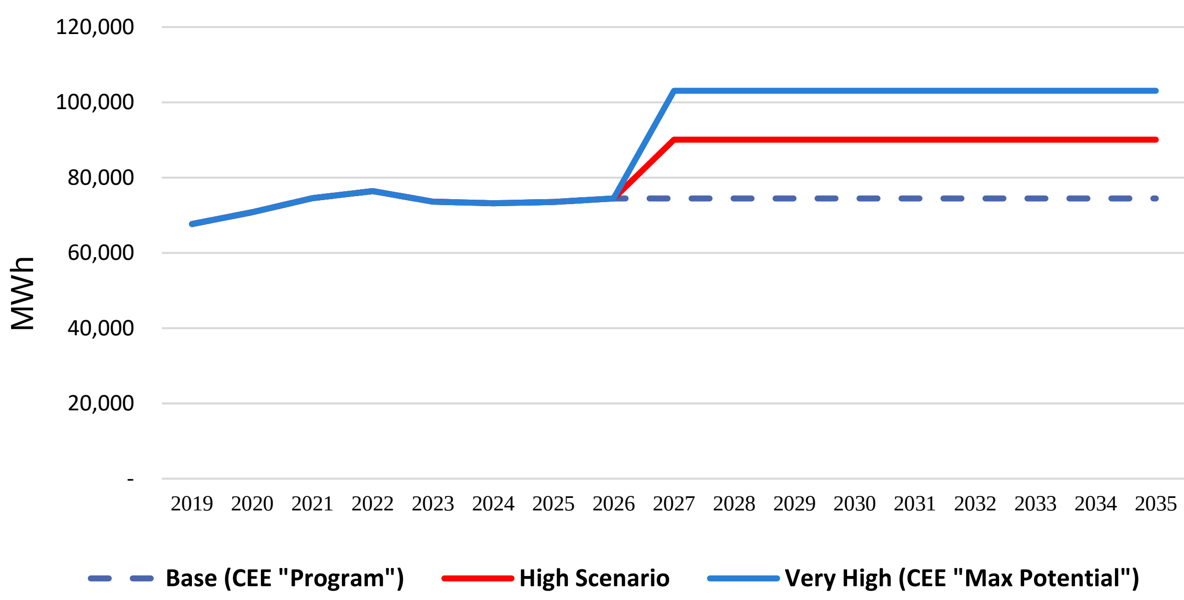
- Total Cost: The estimated total program costs assumed to achieve the level of savings associated with each scenario in the year 2027.
- Total Cost Above Base: The estimated additional spending needed to achieve the incremental savings as compared with the existing plan for the year 2027.

Table 1. Summary of Energy Efficiency Scenarios

		First Year Annual Savings at Generator (Energy: GWh/Peak: MW)				First Year Program Costs (Millions $)			
Scenarios	% of Sales (Rounded)	Energy	Energy Above Base	MP Summer Peak Reduction	Summer Peak Reduction Above Base	Incentives	Non-Incentives	Total Costs	Total Costs Above Base
Base	2.91%	74.5	-	6.8	-	$4.41	$8.15	$12.56	-
High	3.53%	90.1	15.6	8.3	1.5	$14.79	$10.27	$25.06	$12.50
Very High	4.03%	103.1	28.6	9.6	2.8	$32.73	$12.39	$45.12	$32.56

Figure 2 below reflects the first year EE savings (measured at the generator) assumed in each year through 2039 for each of the three scenarios.

Figure 2. 2025 IRP Energy Efficiency Scenarios



Energy Efficiency Scenario Development and Assumptions

As previously noted, Minnesota Power's 2021 IRP was the starting point for developing the 2024-2026 ECO triennial which was used as the Baseline Scenario. The two alternative EE scenarios, which reflect savings levels equivalent to 3.5 percent and 4 percent of eligible sales, were developed by increasing the measure participation assumptions from the baseline scenario proportionally to arrive at the respective savings levels. The costs for the two higher scenarios were developed using a similar approach to the 2021 IRP EE scenarios. Those incentive costs were increased by setting them to a specific percent of incremental costs and adjusting the non-incentive costs to reflect more aggressive levels of program design, delivery, and marketing efforts anticipated to achieve savings beyond the baseline.

Savings Targets and Contribution

Savings contributions by class and technology for the baseline and planning scenarios align with the savings targets assumed in the 2024-2026 ECO plan. They reflect historical patterns, recent experience, and factors that may impact specific measure or class level savings opportunities including policy changes, market penetration, and updates to approved measures and savings calculations as defined in the Technical Reference Manual (“TRM”).[7] Updated avoided costs and net benefit estimates were also taken into account to evaluate changes in cost-effectiveness for various technologies compared to in the past.

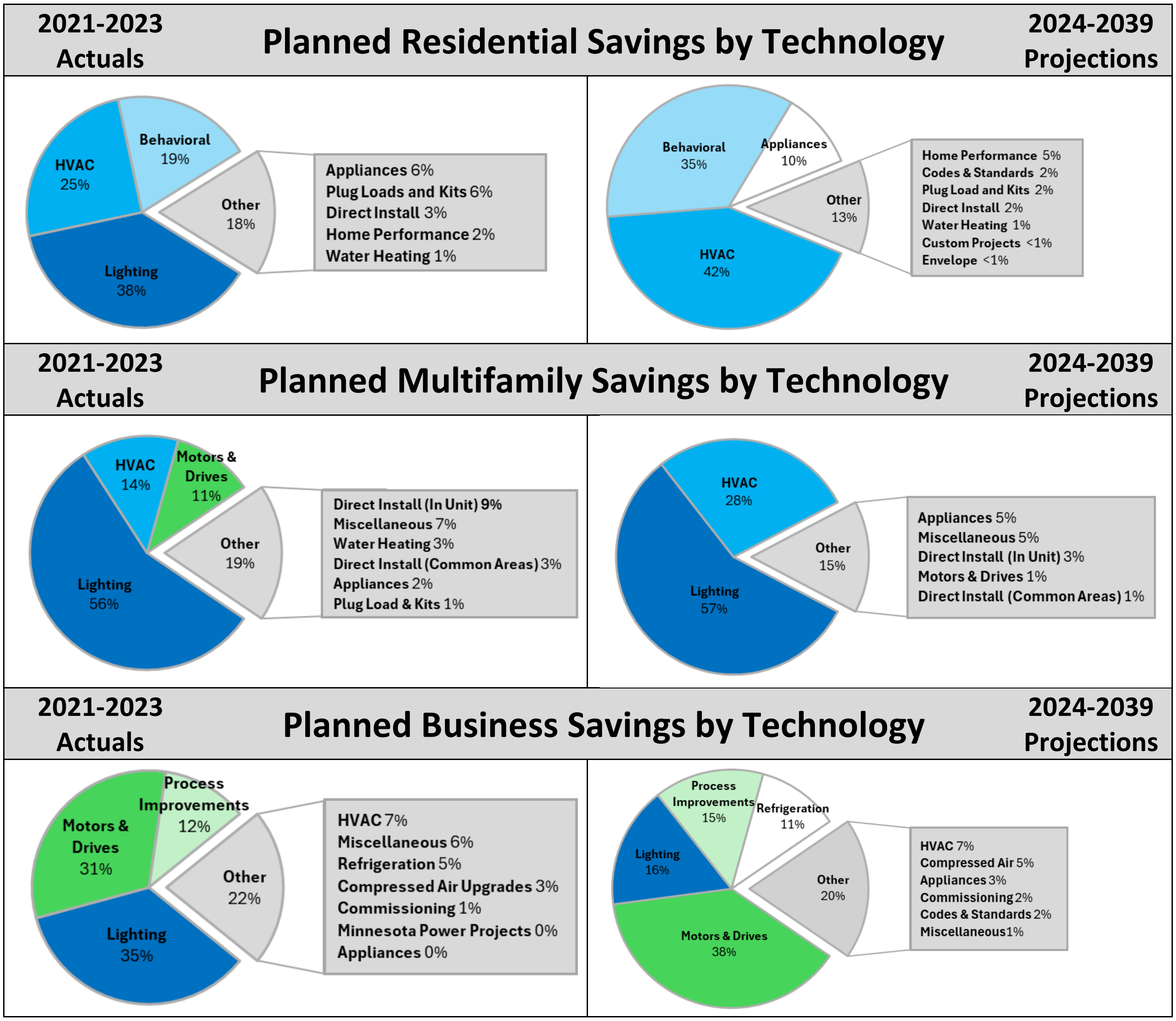
The most significant change to the assumed measure contributions for each EE IRP scenario is the decrease in lighting measures. Minnesota Power updated savings contributions to reflect that new opportunities for lighting savings are significantly less available in residential programs and are diminished in the business program due to changing codes and standards impacting lighting measure baselines and market saturation of commercial and industrial efficient lighting.

Historically, lighting has been a major contributor to all programs requiring a significant shift in measure makeup. For residential, this resulted in a significant shift to heating, ventilation & air conditioning (“HVAC”) savings. For business, this resulted in a noticeable shift away from lighting into other evolving technologies such as motors and heating, ventilation, air conditioning & refrigeration (“HVACR”). The impact of lighting measures on the multifamily customer segment is less predictable as multifamily is a relatively small segment and, historically, projects in this segment were incorporated into the business and residential programs. It was first separated out into its own segment in the 2021-2023 Triennial period and future savings contributions are projected to come from similar technology categories. However, given the size of this segment and the limited pool of participants, actual savings contributions could vary from these assumptions in any given year.

Figure 3 reflects actual savings contributions by technology for the 2021-2023 period and the projected savings contributions by technology for 2024 and beyond. For the alternative savings scenarios (High and Very High), all measures in the Baseline scenario were scaled by the same percentage to achieve the targeted savings levels for each program.

[7] Minnesota Department of Commerce, “State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs,” (Jan. 20, 2020), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0CDC86F-0000-C832-A29A-F7752BF4A0D9}&documentTitle=20201-159365-02.

Figure 3. Planned Savings by Technology



Scenario Cost Development

Cost assumptions were developed for each scenario for 2027 through 2039. For use in the 2025 IRP analysis, the costs associated with the High and Very High scenarios are incremental to the Baseline scenario. Cost assumptions were made for customer incentives and non-incentive costs which include program design, delivery, administration, evaluation, and marketing. For the baseline scenario, budgets from the approved 2024-2026 ECO Triennial Plan were used. For each of the High and Very High EE scenarios, customer incentives were set to a specific percent of incremental costs (where incremental cost is the difference between the cost of the standard efficiency product or action, or sometimes purchasing nothing/taking no action, compared to the cost of the efficient product or action) and non-incentive costs were increased to reflect the elevated level of program design, delivery, and marketing needed to achieve the additional savings.

Baseline Scenario

2027 cost assumptions for the Baseline scenario were developed to serve as the baseline costs against which the costs for the two higher scenarios would be compared. The Company assumed:

- Customer incentives established in the approved 2024-2026 ECO Triennial Plan. The percent of incremental costs assumed here range based on a variety of factors considered during Triennial planning including cost-effectiveness of the measure, market saturation, customer demand, etc.
- Robust program design and marketing.

High Scenario

This represents anticipated costs associated with increasing savings to 3.5 percent of eligible retail sales. The Company assumed:

- Customer incentives are set to at least 50 percent of incremental measure costs. For measures where the baseline incentive is below 50 percent of the incremental cost, the incentive is increased to 50 percent. For measures where the baseline incentive is already above 50 percent of the incremental cost, the incentive cost is assumed to be the same as in the baseline scenario.
- Aggressive program design and marketing.

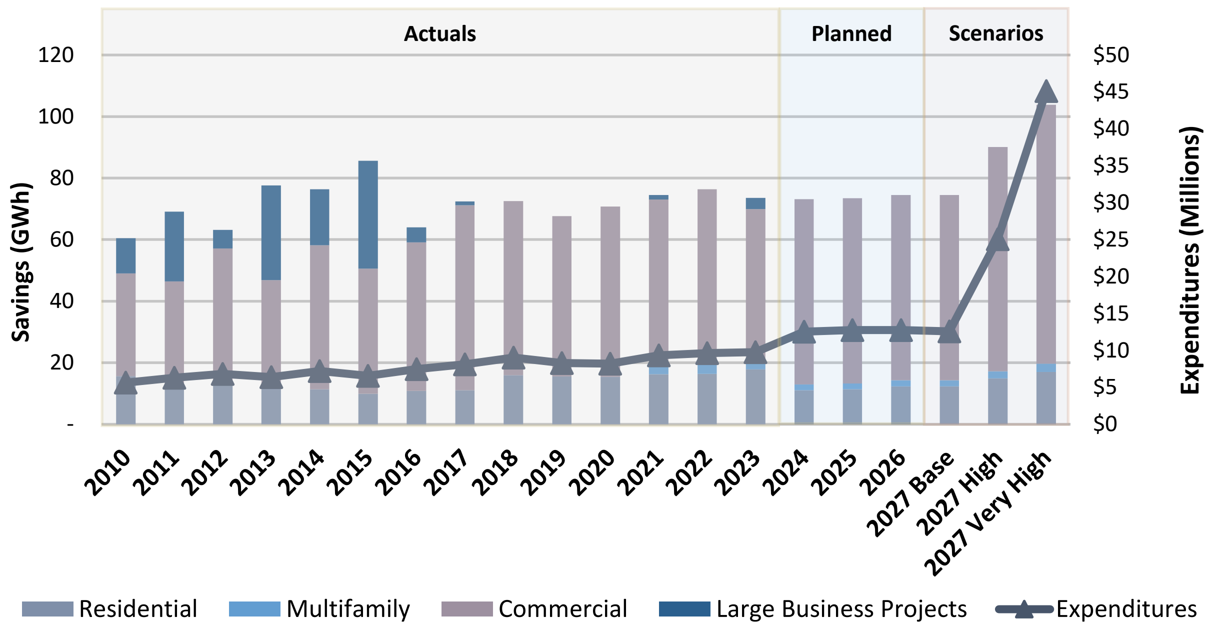
Very High Scenario

This represents the anticipated costs associated with increasing savings to 4 percent of eligible retail sales. The Company assumed:

- Customer incentives are set at 100 percent of incremental measure costs.
- Aggressive program design and marketing.

Figure 4 below expands on the Minnesota Power Historical ECO Performance graph (Figure 1) to include the planned costs and savings for 2024-2026 (as filed in the approved Triennial plan), and 2027 costs and savings as modeled for the Baseline Scenario and two alternative scenarios used in the 2025 IRP analysis:

Figure 4. Historical, Planned, and Modeled CIP Energy Savings (First Year) and Costs

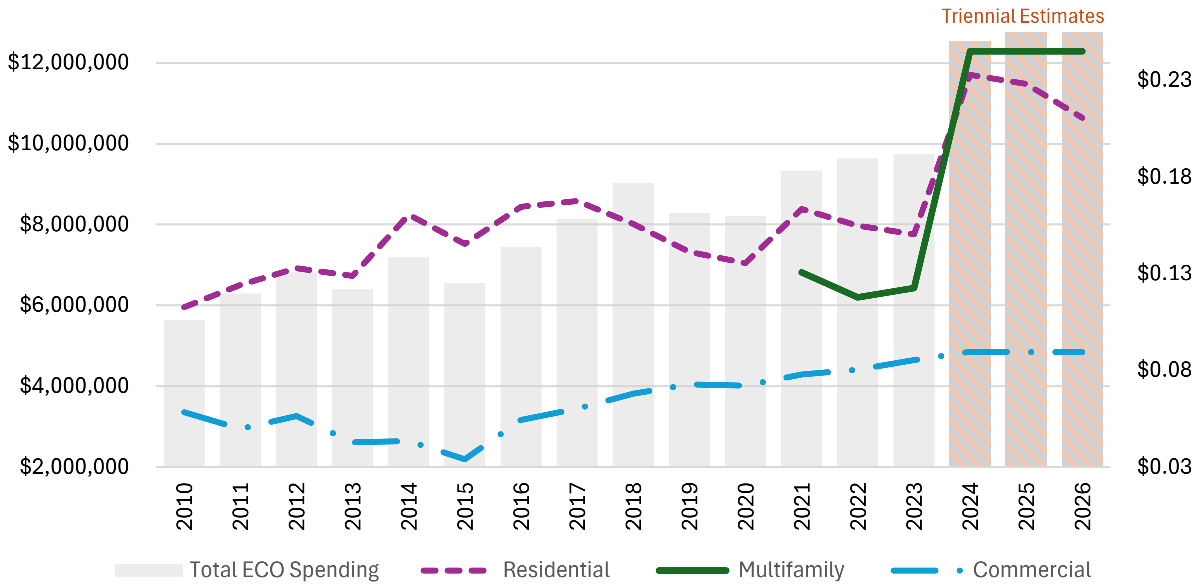


Discussion of Increasing Costs in an Evolving Energy Efficiency Landscape

In developing costs for the 2025 IRP EE scenarios, Minnesota Power started with the budget assumptions approved in the 2024-2026 ECO Triennial filing. Stronger incentive levels and more aggressive program design and marketing will be critical to deliver at the levels discussed in the 2025 IRP. Reduced opportunities for low-barrier measures, changes to measure codes and standards, a changing landscape of market saturation and industry policy, lasting impacts of inflation, and ongoing supply chain and workforce challenges have and continue to impact the need for increased program spending to achieve at or above historical savings levels.

Historical trends show Minnesota Power's overall program costs increasing over time and the Company expects that trend to accelerate. Figure 5 below shows how program costs per kWh have trended over time. Since 2015, commercial and industrial costs per kWh saved have steadily increased and the Company anticipates a significant increase in costs per kWh for the residential and multifamily sectors as well. However, with so many aspects of the energy industry and economy evolving, in order to achieve higher savings goals, the cost per kWh saved will not only continue to trend up, but it will also increase more significantly with higher levels of EE.

Figure 5. Total Spending and Cost per kWh per Program Trending



While Minnesota Power has continued its proven track record of successful program performance, the Company acknowledges that the current energy-efficiency environment is rapidly evolving in ways that will continue to present new challenges. Given that new opportunities for lighting savings are significantly diminished, a transition towards other technologies will be required to maintain savings goals across all programs. Historically, lighting has been one of the most cost-effective and prevalent measures in the ECO portfolio and, in 2023, accounted for nearly 28 GWh in savings (38 percent of total savings). The types of technologies that need to replace these savings are more costly measures that customers may not be as ready (or financially able) to adopt without significant education and incentives to do so. Changing baselines, uncertain economic conditions, high rates of inflation, and workforce constraints will all contribute to Minnesota Power's ability to offer cost-effective, meaningful programs to customers. Increased education and outreach, along with higher rebate levels drive the increase in costs assumed in the 2024-2026 Triennial and 2027 Baseline scenario as compared to the historical costs.

Economic conditions and lasting impacts from the COVID-19 pandemic have affected recent and anticipated program costs in a variety of ways. Increased costs of living for residential customers and higher operating costs for businesses make it more difficult to prioritize energy efficiency investments. Residential customers often must choose between spending money on energy efficiency and other life necessities, both of which have become more expensive. The opportunity cost of updating home appliances or HVAC systems, etc., is greater now than it has been historically. Similarly, commercial customers are facing rising business expenses that impact their ability to spend on energy efficiency measures. To continue achieving high savings levels, Minnesota Power must increase efforts to help customers overcome these financial barriers, while also shouldering higher program delivery costs.

Furthermore, new state and federal policies present both opportunities and challenges for delivering programs that meet customer needs. Specifically, the ECO Act of 2021 and related statute amendments passed during the 2024 legislative session allow for significant expansion of traditional energy conservation programs. While the ECO Act significantly modified the framework for existing utility programs, state and federal energy policies have the potential to be equally as impactful. Minnesota Power continues to work collaboratively with stakeholders to ensure that new state and federal rebate programs are designed and implemented in a way that maximizes benefits to customers and do not unintentionally cannibalize resources. Additionally, the Company is monitoring federal policy changes to better understand potential impacts to program offerings. As these policies evolve, the Company will continue to monitor and anticipate the impacts on ECO programs and related costs.

Scenario Details

The following tables include the plan parameters for each scenario (savings, costs, participation for Baseline, High, and Very High scenarios).

Table 2. Year 2024 Energy and Demand Savings (MISO Summer Peak)

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
Res	**11,622,274**	**14,062,951**	**16,038,738**	**1,214.0**	**1,468.9**	**1,675.3**
Appliances	893,445	1,081,069	1,232,955	252.3	305.3	348.2
HVAC	4,702,513	5,690,040	6,489,468	386.3	467.4	533.1
Envelope	1,031	1,248	1,423	0.1	0.1	0.1
Home Performance	543,097	657,148	749,474	21.9	26.6	30.3
Water Heating	71,555	86,582	98,746	5.9	7.2	8.2
Plug Load and Kits	176,753	213,872	243,920	14.8	17.9	20.4
Direct Install	201,179	243,426	277,626	16.1	19.5	22.2
Behavioral	4,344,777	5,257,181	5,995,793	495.6	599.7	684.0
Codes and Standards	687,923	832,387	949,334	20.9	25.3	28.8
Administrative Costs	0	0	0	0.0	0.0	0.0
Low Income	**722,378**	**874,078**	**996,882**	**67.2**	**81.3**	**92.8**
Appliances	284,474	344,214	392,575	34.1	41.2	47.0
HVAC	223,213	270,088	308,034	14.7	17.8	20.3
Water Heating	103,214	124,889	142,435	8.6	10.4	11.8
Plug Load and Kits	37,967	45,941	52,395	4.2	5.0	5.7
Home Performance	10,972	13,276	15,141	0.4	0.5	0.6
Custom Project	62,538	75,672	86,303	5.3	6.4	7.3
Administrative Costs	0	0	0	0.0	0.0	0.0
Multi-Family Custom	**1,897,574**	**2,296,064**	**2,618,652**	**130.4**	**157.8**	**180.0**
Lighting	1,077,200	1,303,412	1,486,536	41.7	50.4	57.5
Motors and Drives	24,057	29,109	33,199	0.3	0.3	0.4
HVAC	528,397	639,360	729,188	56.7	68.6	78.2
Miscellaneous	84,105	101,768	116,066	0.3	0.3	0.4
Appliances	99,939	120,926	137,915	22.5	27.2	31.0
Direct Install - In Unit	63,336	76,637	87,404	6.8	8.2	9.4
Direct Install- Common Area	20,539	24,852	28,344	2.3	2.7	3.1
Administrative Costs	0	0	0	0.0	0.0	0.0

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
C&I	**60,211,749**	**72,856,216**	**84,150,561**	**5,456.6**	**6,602.5**	**7,661.1**
Lighting	8,464,818	10,242,430	11,681,449	1,232.4	1,491.2	1,700.8
Refrigeration	6,707,469	8,116,038	9,256,308	1,138.7	1,377.8	1,571.4
Motors and Drives	23,108,804	27,961,653	31,890,150	170.8	206.7	235.7
HVAC	4,046,610	4,896,399	5,584,322	561.8	679.8	775.4
Compressed Air Upgrades	2,770,689	3,352,533	3,823,550	302.1	365.5	416.9
Process Improvements	8,985,697	10,872,694	12,400,262	966.3	1,169.2	1,333.4
Appliances	1,599,732	1,935,675	2,207,630	682.6	825.9	942.0
Miscellaneous	852,787	1,031,872	1,176,845	86.5	104.6	119.3
Commissioning	1,126,425	1,362,975	1,554,467	0.0	0.0	0.0
Codes and Standards	2,548,717	3,083,947	4,575,577	315.5	381.7	566.4
Administrative Costs	0	0	0	0.0	0.0	0.0
Indirect	**0**	**0**	**0**	**0.0**	**0.0**	**0.0**
Indirect Program Costs	0	0	0	0.0	0.0	0.0
Grand Total	**74,453,975**	**90,089,309**	**103,804,833**	**6,868.2**	**8,310.6**	**9,609.2**

Table 3. Year 2024 Participation

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Res	**76,701**	**92,809**	**105,849**
Appliances	1,748	2,115	2,412
HVAC	874	1,058	1,206
Envelope	10	12	14
Home Performance	25	30	35
Water Heating	42	51	58
Plug Load and Kits	300	363	414
Direct Install	1,701	2,058	2,347
Behavioral	72,000	87,120	99,360
Codes and Standards	1	2	3
Administrative Costs	0	0	0
Low Income	**2,156**	**2,609**	**2,975**
Appliances	367	444	506
HVAC	380	460	524
Water Heating	607	734	838
Plug Load and Kits	785	950	1,083
Home Performance	2	2	3
Custom Project	15	18	21
Administrative Costs	0	0	0

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Multi-Family Custom	**97**	**117**	**133**
Lighting	32	38	43
Motors and Drives	1	1	1
HVAC	16	19	22
Miscellaneous	4	5	6
Appliances	15	18	20
Direct Install - In Unit	17	21	23
Direct Install - Common Area	13	16	18
Administrative Costs	0	0	0
C&I	**1,269**	**1,535**	**1,753**
Lighting	248	300	342
Refrigeration	157	190	217
Motors and Drives	291	352	402
HVAC	164	198	226
Compressed Air Upgrades	44	53	61
Process Improvements	113	137	156
Appliances	222	269	306
Miscellaneous	10	12	14
Commissioning	19	23	26
Codes and Standards	1	1	3
Administrative Costs	0	0	0
Indirect	**0**	**0**	**0**
Indirect Program Costs	0	0	0
Grand Total	**80,223**	**97,071**	**110,710**

Table 4. Year 2027 Costs

	Base Scenario	High Scenario	Very High Scenario
Residential	**$1,958,077.37**	**$3,043,150.59**	**$5,315,230.58**
Appliances	$118,970.00	$140,969.72	$232,521.72
HVAC	$538,465.00	$1,593,374.00	$3,634,472.88
Envelope	$150.00	$326.70	$745.20
Home Performance	$95,000.00	$95,000.00	$179,986.50
Water Heating	$12,800.00	$20,787.80	$47,416.80
Plug Load and Kits	$9,500.00	$9,500.00	$13,110.00
Direct Install	$16,433.20	$16,433.20	$22,677.82
Behavioral	$35,000.00	$35,000.00	$48,300.00
Codes and Standards	$11,159.17	$11,159.17	$15,399.66
Administrative Costs	$1,120,600.00	$1,120,600.00	$1,120,600.00
Low Income	**$642,992.50**	**$642,992.50**	**$823,333.85**
Appliances	$182,819.50	$182,819.50	$252,290.91
HVAC	$127,797.40	$127,797.40	$176,360.41
Water Heating	$93,645.60	$93,645.60	$129,230.93
Plug Load and Kits	$7,320.00	$7,320.00	$10,101.60
Home Performance	$6,000.00	$6,000.00	$8,280.00
Custom Project	$57,000.00	$57,000.00	$78,660.00
Administrative Costs	$168,410.00	$168,410.00	$168,410.00
Multi-Family Custom	**$465,011.75**	**$549,628.27**	**$828,153.83**
Lighting	$53,556.25	$53,556.25	$92,384.62
Motors and Drives	$1,713.12	$4,200.60	$9,581.52
HVAC	$194,221.94	$194,221.94	$291,959.42
Miscellaneous	$8,528.81	$90,657.85	$206,789.80
Appliances	$12,688.40	$12,688.40	$18,580.09
Direct Install - In Unit	$36,397.50	$36,397.50	$50,228.56
Direct Install - Common Area	$1,905.73	$1,905.73	$2,629.82
Administrative Costs	$156,000.00	$156,000.00	$156,000.00
C&I	**$5,388,111.45**	**$14,602,535.81**	**$29,808,890.51**
Lighting	$572,307.00	$1,516,190.21	$3,458,417.34
Refrigeration	$266,176.00	$1,682,766.61	$3,838,376.73
Motors and Drives	$812,197.00	$3,251,394.30	$7,416,403.53
HVAC	$409,559.00	$1,288,532.44	$2,939,131.84
Compressed Air Upgrades	$49,506.00	$293,713.63	$669,958.37
Process Improvements	$358,483.00	$2,990,051.98	$6,820,283.84
Appliances	$104,440.00	$526,023.77	$1,199,855.88
Miscellaneous	$28,944.00	$267,363.42	$609,853.74
Commissioning	$174,534.00	$174,534.00	$240,856.92
Codes and Standards	$9,965.45	$9,965.45	$13,752.32
Administrative Costs	$2,602,000.00	$2,602,000.00	$2,602,000.00
Indirect	**$4,107,361.00**	$6,227,497.46	$8,347,633.92
Indirect Program Costs	$4,107,361.00	$6,227,497.46	$8,347,633.92
Grand Total	**$12,561,554.07**	**$25,065,804.63**	**$45,123,242.69**

Table 5. Baseline Scenario Cumulative Effects

Year	Admin	Incentives	Total	Yearly				Cumulative			
				kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,133,865.00	$4,407,183.00	$12,541,048.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,154,371.00	$4,412,814.94	$12,567,185.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	37,878	20,586	20,168	222,256,517
2028	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	50,011	26,958	26,487	292,498,595
2029	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	62,108	33,295	32,772	362,438,953
2030	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	74,097	39,540	39,053	432,251,085
2031	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	86,085	45,784	45,334	502,063,217
2032	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	98,053	52,019	51,598	571,757,129
2033	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	109,882	58,170	57,738	640,729,172
2034	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	121,682	64,302	63,852	709,525,474
2035	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	131,856	69,446	68,936	767,877,919
2036	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	142,023	74,585	74,013	826,192,455
2037	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	150,052	78,128	78,165	873,075,338
2038	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	158,384	81,922	82,454	921,623,798
2039	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	166,697	85,705	86,726	970,075,651

Table 6. High Scenario Cumulative Effects

Year	Admin	Incentives	Total	Yearly				Cumulative			
				kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,546,679.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	15,323	8,311	8,246	90,089,309	40,538	22,028	21,599	237,891,852
2028	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	55,327	29,842	29,347	323,763,044
2029	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	70,077	37,621	37,057	409,314,931
2030	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	84,607	45,196	44,658	493,814,538
2031	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	99,136	52,772	52,259	578,314,146
2032	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	113,621	60,317	59,842	662,668,606
2033	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	127,967	67,780	67,301	746,301,196
2034	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	142,280	75,222	74,730	829,733,220
2035	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	154,938	81,657	81,104	902,569,794
2036	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	167,583	88,084	87,465	975,331,553
2037	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	177,749	92,707	92,685	1,034,468,450
2038	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	188,216	97,580	98,040	1,095,262,962
2039	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	198,285	102,162	103,217	1,153,940,114

Table 7. Very High Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,546,679.93	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,561,554.06	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$12,394,643.92	$32,728,598.77	$45,123,242.69	17,607	8,311	9,531	103,804,833	42,822	23,327	22,884	251,607,376
2028	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	59,894	32,439	31,916	351,189,056
2029	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	76,922	41,515	40,907	450,437,197
2030	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	93,639	50,299	49,703	547,885,013
2031	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	110,356	59,083	58,499	645,332,829
2032	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	127,010	67,821	67,276	742,613,700
2033	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	143,526	76,477	75,929	839,172,701
2034	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	160,005	85,109	84,550	935,511,038
2035	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	174,805	92,721	92,095	1,021,131,208
2036	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	189,587	100,322	99,622	1,106,646,686
2037	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	201,614	105,950	105,833	1,176,761,847
2038	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	213,940	111,828	112,178	1,248,528,178
2039	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	225,561	117,188	118,214	1,316,541,301

Summary of Findings

Minnesota Power has a proven track record of successful ECO performance and anticipates continuing this trend into the future, as indicated by the aggressive goals set forth in the 2024-2026 Triennial Plan and assumed in the 2025 IRP baseline forecast. However, the Company acknowledges that the current EE environment is rapidly evolving in ways that will continue to present new challenges. Changing baselines, uncertain economic conditions, evolving policy and incentives, and avoided costs will all affect Minnesota Power's ability to offer cost-effective, meaningful programs to customers. While Minnesota Power continues to build on the successes of its existing programs and adapt to challenges through unique and innovative program offerings and delivery strategies, achieving this higher level of savings through less cost-effective measures will be more resource intensive. Additionally, long-term EE savings require customers to take specific actions year after year, which introduces uncertainty regarding whether these savings will materialize. For these reasons, among others, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty. The Company has done so, while also testing what could be achieved by including alternative scenarios in its IRP analysis.

B. Part 2: Residential TOD

Time-of-Day residential rate impacts are also captured in 2025 IRP scenario planning. The Company's approved Petition for Changes to Minnesota Power's Residential Rate Design[8] included a roughly 2:1 on-peak to super off-peak price ratio, and an on-peak period lasting from 3 p.m. to 8 p.m. on weekdays, which encompasses the most common summer and winter peak times. The rate structure includes time-of-use base energy rates as well as time-of-use fuel and purchased energy adjustments. The associated rate specifications are shown in Table 8.

Table 8. Current TOD Rates ($/kWh) and Hours

	Base Energy Rate	Base Energy Rate + Fuel & Purchased Energy	Weekday Hours	Weekend Hours
Standard (Flat) Rate	$ 0.0940	$ 0.1350	N/A	N/A
On-Peak	$ 0.1307	$ 0.1800	3 pm to 8 pm	N/A
Off-Peak	$ 0.09164	$ 0.1350	5 am to 3 pm; 8 pm to 11 pm	5 am to 11 pm
Super Off-Peak	$ 0.06726	$ 0.0990	11 pm to 5 am	11 pm to 5 am

The approved transition plan consisted of a multi-phased approach to implementing and evaluating the TOD rate. Currently, the Company has completed the first phase of the transition along with an evaluation of the phase's first 12 months. While the first phase focused on operational efficiencies and customer feedback, an analysis of price response was completed as part of the evaluation. Due to the nature of the implementation during this phase, the analysis was limited. The results of this analysis are useful to begin understanding potential long-term impacts of a full roll-out of the TOD rate and were used to develop estimated impacts as part of IRP scenario planning. The Company views these impacts as preliminary and anticipates more refined estimations in the future as later phases of implementation and evaluation with more focus on price response are completed. Due to the preliminary nature of these estimates and the Company still being in the early stages of transitioning to default TOD rates, these impacts are not assumed in the base case.

As part of the February 29, 2024 compliance filing in the residential rate design docket, analysis was completed by third-party consultant Demand Side Analytics ("DSA") to estimate the observed price elasticity using the participant data from Phase I of the transition. As described in Appendix A of the compliance filing:[9]

> This analysis was conducted using a fixed effects model designed to isolate and remove static differences between customer groups, thereby focusing on variations in electricity consumption attributable to the differences in the flat rate and the TOD rate structures.
>
> Equation 3 outlines the specific model utilized estimate the price elasticity. Notably, a temperature coefficient was included to control for variation that can be attributed to

[8] *In the Matter of the Petition for Approval of Changes to Minnesota Power's Residential Rate Design,* Docket No. E-015/M-20-850, Petition (Dec. 1, 2020).
[9] *In the Matter of the Petition for Approval of Minnesota Power's Residential Rate* Design, Docket No. E-015/M-20-850, Compliance Filing at Appendix A at 24 (Feb. 29, 2024).

weather. The customers included in this model were those on the TOD rate and the new customers on the flat rate, starting service after the start of Phase I.

Equation 3 - Price Elasticity Model

$$\ln(kWh_{it}) = \beta_0+\beta_1 \ln(Price_{it})+\beta_2 (TempF_{it})+\alpha_i+\gamma_t+\varepsilon_{ith}$$

Where:

$\ln(kWh_{it})$ is the logged kWh for customer i at datetime t
$\ln(Price_{it})$ is the logged price variable for customer i at datetime t
$TempF_{it}$ represents the temperature in Fahrenheit for customer i at datetime
β_0 is the intercept term.
β_1 is the coefficient for logged price. This value represents the price elasticity
β_2 is the coefficient for temperature, indicating the estimated effects of weather on the dependent variable.
α_i represents the fixed effects for each customer i, capturing unobserved characteristics that are constant over time for a specific customer, but may vary between customers.
γ_t represents the fixed effects for each datetime t, capturing time-specific effects that are constant across all customers but vary over time.
ε_{ith} is the error term for customer i at datetime t

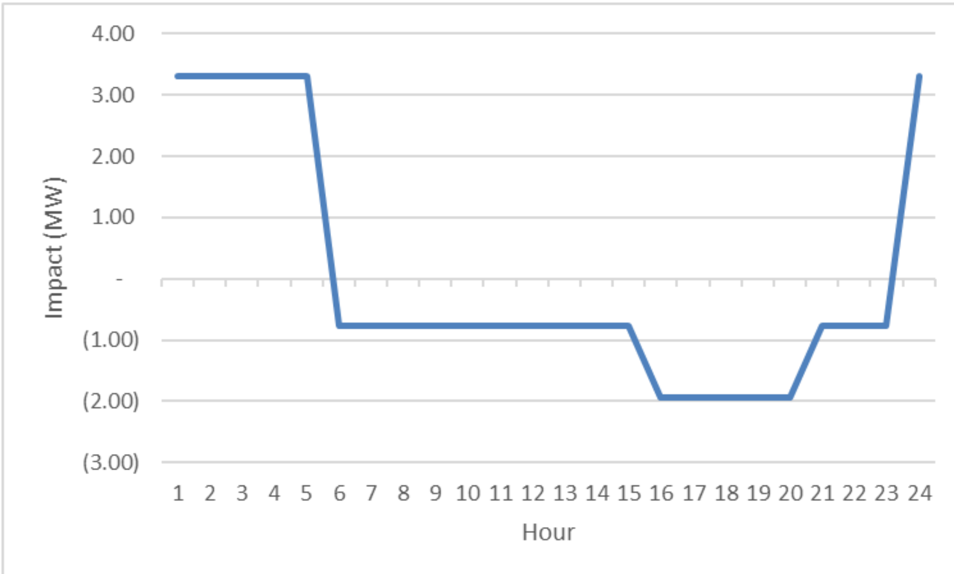
The analysis estimated that participants reduced their load during on-peak periods by 1.88 percent on average. Average impacts during off-peak periods were estimated to be a 0.66 percent reduction in usage and impacts during super off-peak periods were estimated to be a 4.5 percent increase in usage. The super off-peak impact was adjusted such that the total forecasted usage for the residential customer class was net neutral – i.e., the timing of when the usage is occurring is shifted but there is no overall decrease or increase to the forecasted load.

Table 9 below shows the percent kW impacts by TOD period. The on-peak, off-peak, and adjusted super off-peak percent impacts were applied to residential customer use profiles to create the forecasted hourly impacts associated with 100 percent residential customer participation in the TOD rate. The resulting average hourly impact shape is reflected in Figure 6 below.

Table 9. Percent kW Impact by TOD Period

Percent kW Impact			**Adjusted % kW Impact**
On-Peak	Off-Peak	Super Off-Peak	Super Off-Peak
-1.88%	-0.66%	4.50%	3.84%

Figure 6. Average Hourly Impacts from Residential TOD



C. Part 3: Alternative Demand Side Management

Minnesota Power has a very successful demand response program for industrial, residential, and commercial customers that plays an important role in the annual energy and capacity planning for Minnesota Power operations. Today, Minnesota Power has approximately 250 MW of interruptible demand response capability with industrial customers on its system, which is typically procured under one-year contract terms. The 2025 IRP evaluated as alternatives to supply side resources a new enhanced industrial demand response program and two demand response programs for residential and small commercial/industrial customers.

Central air conditioner ("CAC") cycling and electric hot water heater ("HW") demand response programs for residential and commercial customers were screened in the capacity expansion analysis. A demand response program that is expanded to include economic energy curtailments for industrial customers was also screened in the capacity expansion analysis.

Estimates of participation, saturation of CACs in homes and businesses, and anticipated percent of customers called on at any given time indicate a potential of 7.4 MW of capacity reduction for the CAC cycling program. This accounts for cycling the unit off for 15 minutes then on for 45 minutes which allows flexibility for CAC units to keep up with cooling demand while avoiding a post-event rebound period.

The HW program does not assume an on/off cycle during the event and instead would disconnect the HW for the duration of the event. Estimated customer participation and saturation of electric HWs indicates a potential of 4.5 MW of demand reduction.

Both programs require the installation of equipment that allows for the Company to control the CAC or HW load. The total cost of the equipment, labor, and necessary programming is estimated at $400 per participant, in 2024 dollars, based current equipment and labor rates. After this initial cost, ongoing costs include a bill incentive of $30 per participant per year for CAC cycling program customers and $60 per participant per year for HW program customers.

The utility cost of implementing these demand response programs would include, in 2024 dollars, an initial program capital expenditure of $143,000 (approximate) and annual O&M of $72,000 (approximate). This would be needed to support interface and control application software. The initial program cost and annual O&M were allocated between the CAC and HW programs based on participation.

The industrial demand response alternative modeled in the IRP expands Minnesota Power's program for industrial customers to include energy curtailment, along with emergency curtailment – it is referred to as "Product B" in the IRP analysis. This capacity is available in 2028, when the Product C demand response program subscription ends. The Product C program was approved by the Commission in 2021.[10]

Product B includes long-term capacity with economic energy curtailment. This product would offer a meaningful demand payment to customer for the opportunity to utilize their industrial capability for meeting the broader system needs. For this proxy program incorporated into the IRP evaluation there was a $7 per kW-month capacity credit and provides a $30 per MWh energy credit for curtailed energy. These parameters would be refined further when an actual tariff is brought forward with customers.

D. Part 4: Distributed Generation

The 2025 IRP includes assumptions for residential and commercial/industrial adoption of distributed solar generation, these assumptions are what comprises the "Base Case." The forecast methodology for distributed solar adoption and a resulting decrease in Minnesota Power sales are described below for both the Base Case and a Scenario which assumes a more aggressive adoption of distributed generation.

New DG solar installations were projected using the U.S. Energy Information Administration's forecast for distributed solar generation. This outlook for the number of new installs is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installations (i.e., installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company's Base Case forecast assumes about 4,220 new small-scale DG solar installations, adding almost 44,000 kW of nameplate capacity, will be connected to the Minnesota Power grid by 2038 (i.e., installed in years 2024-2038). These new installations would generate about 46,000 megawatt hours ("MWh") per year and reduce sales to residential and commercial sectors by an equivalent amount. The Base Case forecast assumes cumulative capacity expands at an 11 percent compound annual growth rate ("CAGR") from 2023 to 2038.

The Company's Scenario forecast utilizes the same U.S. Energy Information Administration's DG solar generation forecast but with a doubled growth rate. This updated growth rate projects approximately 5,590 new small-scale DG solar installations which adds approximately 58,000 kW of nameplate capacity that will be connected to the Minnesota Power grid by 2038. The new installations would generate almost 61,000 MWh per year of reduced sales to residential and commercial sectors, as shown in Figure 7. The Scenario forecast assumes a 13 percent CAGR from 2023 to 2038.

[10] *In the Matter of the Petition by Minnesota Power for Approval of its Industrial Demand Response Product C Contracts*, Docket No. E015/M-21-28, Order Establishing Pilot Program (Oct. 29, 2021).

Figure 7. Distributed Solar Generation Lost Sales

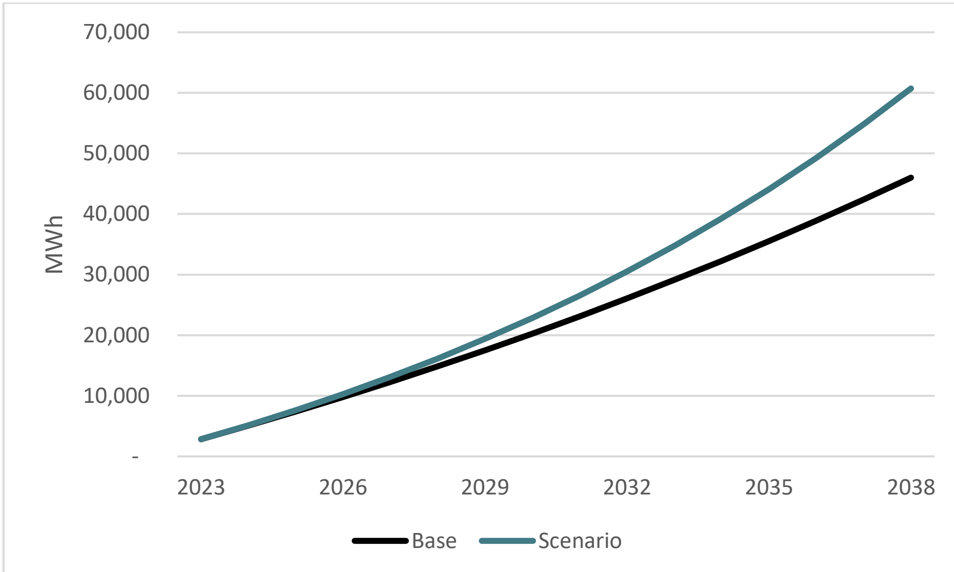
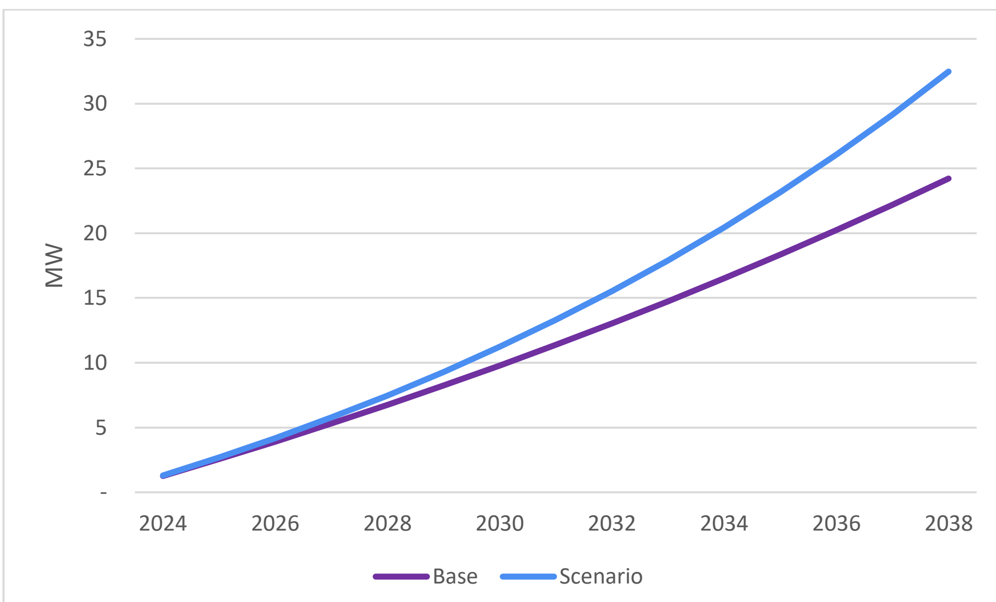


Figure 8. Distributed Solar Generation (Summer Peak)



E. Part 5: Microgrids

Microgrids provide an alternative energy solution for a clean, resilient, and reliable grid. Microgrids also interconnect loads and distributed energy resources to provide electric power when needed either connected or disconnected to the grid. Minnesota Power is exploring the benefits of microgrids, which includes pacing with customer interest. Microgrids are poised to enhance energy sustainability and meet evolving customer demands and Minnesota Power will continue investigating the potential of microgrids on its system.