ECO Cost-Effectiveness Advisory Committee Summary Report

2027-2029 ECO Program Period

October 31, 2025

COMMERCE DEPARTMENT
ENERGY RESOURCES

Mendota Group

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Executive Summary

The Minnesota Department of Commerce (Department) created the Cost-Effectiveness Advisory Committee (CAC) to act as a forum to discuss how to update components of Energy Conservation and Optimization (ECO) program cost-effectiveness methodologies. This role is consistent with the Department's responsibility to ensure that utilities are systematically and aggressively procuring cost-effective energy savings, and that ECO program evaluations and reporting are accurate.

During the previous CAC update process, major changes were made to ECO's cost-effectiveness tests for the 2024-2026 Triennial Plans, including the adoption of ECO's new primary cost-effectiveness test called the Minnesota Cost Test (MCT). The process cumulated in the Deputy Commissioner's March 31, 2023, Decision (Docket No. E,G999/CIP-23-46).[1]

The current CAC update process, which applies to the upcoming 2027-2029 ECO Triennial Plans, has focused on updating values that are time-based (such as discount rates tied to economic factors), quantifying previously unquantified metrics, and refining the way utilities evaluate their ECO programs and portfolios for cost-effectiveness. Information and resources from the full CAC stakeholder engagement process can be found on the CAC's webpage.[2]

This summary report, prepared by Department Staff and the Mendota Group, summarizes the activities of the CAC from June 3, 2024, to the present. Over the course of a year and a half process, the CAC held eight meetings to discuss updates to ECO's cost-effectiveness methodologies. During Phase 1 of the CAC update process (from June to December 2024), the CAC worked to identify priority updates/changes to the cost-effectiveness impacts. The CAC is now nearing the conclusion of Phase 2 of the process (from February 2025 to present) to update the CAC's identified priority methods and impacts. This report focuses on those aspects of ECO's cost-effectiveness tests that are proposed for modification or update.

By November 17, 2025, Department Staff request the ECO Cost-Effectiveness Advisory Committee's emailed written feedback on the summary report, including:

- Staff would appreciate the committee's feedback on areas support and/or disagreement with the proposed cost-effectiveness methods and impacts outlined in this summary report.

- As this is the near conclusion of the advisory committee update process, Staff do not plan to incorporate feedback related to brand new methodology proposals that have not been discussed by the advisory committee.

- One specific methodology that Staff request the committee's feedback on is the "Utility Performance Incentive" impact's methodology (i.e. the method used to

[1] Deputy Commissioner Decision, "In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities" (Docket Nos. E,G999/CIP-23-46), March 31, 2023. Also referenced in this document as the "March 31, 2023 Decision." https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1

[2] MN Cost-Effectiveness Advisory Committee Webpage: https://mendotagroup.com/mn-cost-effectiveness-ac/

account for that specific impact in cost-effectiveness tests). The complexity of that impact's methodology was brought up as an issue by some committee members, and Staff are interested in proposals that could help simplify the methodology while still accurately accounting for the impact in cost-effectiveness tests. For reference, the "Utility Performance Incentive" impact's methodology description can be found on pages 257-261 of the Deputy Commissioner's March 31, 2023, Decision (Docket No. E,G999/CIP-23-46).[3]

After receiving informal written feedback on this cost-effectiveness summary report, there will be a formal regulatory process leading up to the Department's approval of ECO's 2027-2029 cost-effectiveness methodologies. The anticipated timeline for the formal regulatory process is summarized as follows:

- **January 2026**: The Department intends to issue the Staff Proposed Decision for the 2027-2029 ECO cost-effectiveness inputs on eDockets.
- **February 2026**: Written comment period where stakeholders can submit formal written comments on Staff's Proposed Decision recommendations.
- **March 2026**: The Department's Assistant Commissioner Decision approving the final 2027-2029 ECO cost-effectiveness methodologies for investor-owned utilities. This will mark the conclusion of the 2027-2029 ECO cost-effectiveness update process.

A. Introduction

The CAC acts as a forum to discuss how to update components of ECO's cost-effectiveness impacts and tests. This role is consistent with the Department's responsibility to ensure that utilities are systematically and aggressively procuring cost-effective energy savings, and that ECO program evaluations and reporting are accurate.

Although the CAC does not have formal authority to update the cost-effectiveness tests that utilities use to evaluate their ECO programs, it plays an important role in shaping ECO's technical guidance. For example, the CAC functions similar to the Department's Technical Reference Manual Advisory Committee (TRMAC), which recommends updates to energy efficiency measure technical assumptions.

Historically, the Department gathers feedback from the CAC over the course of a stakeholder engagement process, which includes multiple meeting discussions and feedback on methodology "straw proposals." This feedback then helps inform the proposed cost-effectiveness methodologies recommended in Department Staff's Proposed Decision. When Staff's Proposed Decision is filed on eDockets, interested parties can then provide written comments on the

[3] Deputy Commissioner Decision, "In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities" (Docket Nos. E,G999/CIP-23-46), March 31, 2023. Also referenced in this document as the "March 31, 2023 Decision". https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1

recommendations, and these comments are reviewed and considered in the Department's Final Decision approving ECO's cost-effectiveness methods.

During the previous CAC update process, major changes were made to ECO's cost-effectiveness tests for the 2024-2026 Triennial Plans, including the adoption of ECO's new primary cost-effectiveness test called the Minnesota Cost Test (MCT). The MCT is a dynamic, jurisdiction-specific test that reflects the state's evolving policy goals and helps align utility ECO portfolios with state priorities. The process cumulated in the Deputy Commissioner's March 31, 2023, Decision (Docket No. E,G999/CIP-23-46).[4]

The 2027-2029 CAC process sought to build on these accomplishments by addressing the Deputy Commissioner's March 31, 2023, Decision instructions to Department Staff, quantifying previously unquantified metrics, and refining the way utilities evaluate their ECO program cost-effectiveness.

Department Staff, with technical assistance and facilitation support from the Mendota Group, convened the first meeting of the 2027-2029 CAC on June 3, 2024. During the meeting, Staff outlined their plans and timeline for this iteration of the CAC, namely to hold meetings every other month through the end of 2025, concluding with the Department's Final Decision in Q1 2026. The CAC's key objectives are to:

- Advise on ECO cost-effectiveness priority issues to explore for the 2027-2029 IOU Triennial Plans,
- Discuss how to integrate cost-effectiveness methodology updates,
- Provide input into the Department's Proposed Decision and Final Decision adopting the approved 2027-2029 ECO cost-effectiveness methodologies.

The first CAC meeting also summarized the results from a poll sent to CAC members, which highlighted the greatest interest in reviewing current MCT estimates with possible revisions to the MCT, adding elements to the MCT, discussing the role of Secondary Tests, and updating cost-effectiveness guidance. Staff also tasked the CAC with helping to address Order points from the March 31, 2023, Decision, as follows:

- Order Point 5d: For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.
- Order Point 6c: Gas BENCOST Inputs: Related to the Commodity Cost input, for future triennials, the Deputy Commissioner directs Staff to evaluate if there is an accurate, publicly available data source for Minnesota forecasted natural gas prices as a possible replacement for historical utility PGA costs.
- Order Point 6d: Gas BENCOST Inputs: Related to the Project Lifetime input, as part of the TRMAC, the Deputy Commissioner instructs Staff to revisit measure lifetimes

[4] Deputy Commissioner Decision, "In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities" (Docket Nos. E,G999/CIP-23-46), March 31, 2023. Also referenced in this document as the "March 31, 2023 Decision." https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1

in the next TRM cycle to determine what, if any, adjustments could be made to increase expected lifetime for prescriptive measure assumptions beyond 20 years.

Information and resources from the CAC stakeholder engagement process can be found on the CAC's webpage.[5]

As shown in Table 1 and Table 2, the MCT includes both Utility System Impacts (USIs) and Non-Utility System Impacts (NUSIs) that are used to evaluate utility ECO program cost-effectiveness. This approach is consistent with the National Standard Practice Manual (NSPM). The NSPM recommends that jurisdictions "identify and include the full range of utility system impacts in the primary test, and all BCA (benefit-cost analysis) tests."[6] Utility system refers to the entire system (electric or natural gas) used to provide service to retail customers. In contrast, consistent with the NSPM's guidance, the cost-effectiveness tests should only include those NUSIs that are consistent with the jurisdiction's policy goals.

Table 1 and Table 2 shows the components of the MCT, including those quantified for 2024-2026 Triennials (see the "Quantified" column) and those the 2027-2029 CAC determined should be reviewed for potential updates (see "Review" column). Although the tables separate Societal Impacts from other Non-Utility System Impacts, Societal Impacts are considered a subset of NUSIs.

Table 1 - USIs and NUSIs Considered for Review

Type	Utility	Category	Impact	Quantified?	Values	Review?
Utility System	Electric Utility	Generation	Energy Generation	Yes	Utility-specific	Yes
			Capacity	Yes	$104.17/kW-year	Yes
			Environmental Compliance	No		No
			Renewable Portfolio Standard Compliance	No		No
			Market Price Effects	Yes	1% adder	Yes
			Ancillary Services	Yes	1% adder	Yes
		Transmission	Transmission Capacity	Yes	Utility-specific	Yes
			Transmission System Losses	Yes	Utility-specific	Yes

[5] MN Cost-Effectiveness Advisory Committee Webpage: https://mendotagroup.com/mn-cost-effectiveness-ac/

[6] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1, Spring 2017 (Prepared by The National Efficiency Screening Project), p. 21.

Type	Utility	Category	Impact	Quantified?	Values	Review?
		Distribution	Distribution Costs	Yes	Utility-specific	Yes
			Distribution System Losses	Yes	Utility-specific	Yes
		General	Program Incentives	Yes	Utility-specific	No
			Program Administration Costs	Yes	Utility-specific	No
			Utility Performance Incentives	Yes	Utility-specific	Yes
			Credit and Collection Costs	No		No
			Risk	No		No
			Reliability	No		No
			Resilience	No		No
	Gas Utility	Commodity / Supply	Fuel	Yes	DOC Developed	Yes
			Capacity & Storage	Yes	Utility-specific	No
			Environmental Compliance	Yes	1.40%	Yes
			Market Price Effects	No		No
		Transportation	Transportation	Yes	DOC Developed	No
		Delivery	Delivery	Yes	DOC Developed	No
		General (same as Electric)	(see electric section)			
Non-Utility System	Both	Other Fuels	Other Fuels	Yes	Utility-specific (electric) DOC Developed (gas)	No
Societal	Both	Societal Impacts	GHG emissions	Yes	DOC Developed	No
			Criteria air emissions	Yes	DOC Developed	No
			Other environmental	No		Yes
			Economic and Jobs (Macroeconomic)	No		Yes
			Energy Security	No		No
			Energy Equity	No		No
			Societal Discount Rate	Yes	3.30%	Yes

Table 2 – Current and Proposed Updates to USIs and NUSIs

Type	Utility	Category	Impact	Current 2024-2026 Values	Proposed 2027-2029 Values	Context About Proposed Values
Utility System	Electric Utility	Generation	Energy Generation	Utility-specific	Utility-specific	* Allow electric utilities to continue using IRP data for marginal energy costs. * Marginal energy is the largest component of avoided costs and best to align with values that are associated with IRP process. * Although proprietary, utilities are expected to share the data with entities that sign non-disclosure agreements.
			Capacity	$104.17/kW-year	$81.43/kW-year	* Propose revising the value to MISO's Net CONE for LRZ 1 (from CONE). * Net CONE subtracts revenues the reference plant could earn by participating in MISO's energy and ancillary services markets. * MISO proposed this value for the 2026/2027 Planning Year in an October 15, 2025, filing with FERC.
			Environmental Compliance	Not Quantified	Not Quantified	
			Renewable Portfolio Standard Compliance	Not Quantified	Not Quantified	
			Market Price Effects	1% adder	1% adder	* No new information on which to base change.
			Ancillary Services	1% adder	1% adder	* Electric utilities can propose program-specific avoided ancillary services for programs focused on reliability (e.g., load management)

Type	Utility	Category	Impact	Current 2024-2026 Values	Proposed 2027-2029 Values	Context About Proposed Values
						* Retain 1% portfolio-level factor for all other programs.
		Transmission	Transmission Capacity	Utility-specific	Utility-specific	* Propose to retain values included in 2017 study, and update escalation rates. * Revised estimates require significant utility analysis, and the CAC timeline did not afford sufficient time. * Updates to the T&D values could potentially be estimated as part of a separate study and would apply to the 2030-2032 cost-effectiveness update process. Such a study may consider whether T&D impacts from EE and EFS are symmetrical.
			Transmission System Losses	Utility-specific	Utility-specific	
		Distribution	Distribution Costs	Utility-specific	Utility-specific	
			Distribution System Losses	Utility-specific	Utility-specific	
		General	Program Incentives	Utility-specific	Utility-specific	
			Program Administration Costs	Utility-specific	Utility-specific	
			Utility Performance Incentives	Utility-specific	Utility-specific	* Propose to examine revisions to this cost-effectiveness impact's methodology to try and address calculation complexity challenges.
			Credit and Collection Costs	Not Quantified	Not Quantified	
			Risk	Not Quantified	Not Quantified	
			Reliability	Not Quantified	Not Quantified	
			Resilience	Not Quantified	Not Quantified	
	Gas Utility	Commodity / Supply	Fuel	DOC Developed	DOC Developed	* Use utility-specific PGA values, with the expectation that forecasted data from utility Gas IRPs will be available for 2030-2032.
			Capacity & Storage	Utility-specific	Utility-specific	

Type	Utility	Category	Impact	Current 2024-2026 Values	Proposed 2027-2029 Values	Context About Proposed Values
			Environmental Compliance	1.40%	1.00%	* Updated to 1.0% based on recent data.
			Market Price Effects	Not Quantified	Not Quantified	
		Transportation	Transportation	DOC Developed	DOC Developed	
		Delivery	Delivery	DOC Developed	DOC Developed	
		General (same as Electric)	(see electric section)	(see electric section)	(see electric section)	
Non-Utility System	Both	Other Fuels	Other Fuels	Utility-specific (electric) DOC Provided (gas)	Utility-specific (electric) DOC Provided (gas)	* For Gas, not revise approach for Non-Gas fuel and environmental impacts. * For EFS, incorporate electric T&D and generating capacity impacts. * For Electric, request that electric utilities use BENCOST to model gas components of EFS measures. Electric utilities have asked DOC Staff for additional guidance.
Societal	Both	Societal Impacts	GHG emissions	DOC Developed	DOC Developed	* Calculated based on MN PUC's January 3, 2018, Order in docket number CI-14-643. Gas is incorporated into BENCOST = Environmental Damage Factor.
			Criteria air emissions	DOC Developed	DOC Developed	* NOx, SO2, and PM2.5. Calculated based on MN PUC's January 3, 2018, Order in docket number CI-14-643. Gas is incorporated into BENCOST.
			Other environmental	Not Quantified	Not Quantified	* No change. Determined not to update at this time. Unable to find good source data without conducting a separate study.

Type	Utility	Category	Impact	Current 2024-2026 Values	Proposed 2027-2029 Values	Context About Proposed Values
			Economic and Jobs (Macroeconomic)	Not Quantified	Not Quantified	* Allow utilities to include program-specific values in ECO portfolios.
			Energy Security	Not Quantified	Not Quantified	
			Energy Equity	Not Quantified	Not Quantified	
			Societal Discount Rate	3.30%	3.00%	* Use fixed 3.0% Societal Discount rate based on the 30-year moving average of the real (inflation-adjusted) 10-year Treasury bond rate. * Proposing to fix this rate for future Triennials.

B. Discussion of Proposed Changes

Section B provides details related to the proposed changes and updates and changes to Utility System and Non-Utility System Impacts included in the MCT. The discussion focuses on those impacts that the CAC proposed to add, update, or modify.

1. Utility System Impacts (Electric)

a. Energy Generation

For electric utilities, energy generation refers to the electric energy either avoided by energy efficiency measures or increased by efficient fuel-switching measures. The impact is measured in kilowatt-hours (kWh). In Minnesota, utilities generally use forecasts of "marginal energy" costs from their Integrated Resource Planning (IRP) process or other relevant filings in cost-effectiveness modeling. Utilities update these values with each Triennial filing, and the values apply to all three program years (with escalation rates between years).

In the March 31, 2023, Decision, the Deputy Commissioner directed "Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly."[7]

The 2027-2029 CAC explored ways of addressing the transparency issues, including conducting a deeper analysis of data from the National Renewable Energy Laboratory's Cambium model. A representative from Minnesota's Efficient Technology Accelerator presented their experience with the Cambium model. Based on the presentation and additional analyses of Cambium data, it was determined that, although the data is publicly available, the values did not appear consistent with utility IRP-sourced information and were not sufficiently detailed to represent individual utilities.

To ensure that significant changes in marginal energy values between the latest IRP data and Triennial approval, Staff also proposed requiring that utilities refile their Triennial documents if IRP-based marginal energy values changed above a certain threshold. Utilities expressed strong disagreement with this approach, preferring to use values that are fixed at the time of filing.

Staff propose that utilities continue to use marginal energy data sourced from either their most recent Integrated Resource Plan or other similar filing[8], noting that utilities will continue to allow stakeholders who sign non-disclosure agreements to access the data.

b. Generating Capacity

For electric utilities, generating capacity is the amount of installed capacity (expressed in terms of kilowatts or kW) required to meet the forecasted peak load, which typically includes an additional reserve margin. A utility either needs to build generating capacity or procure it to ensure it has sufficient generating capacity to meet planning requirements. DERs that decrease or increase loads impact generating capacity needs.

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[7] March 31, 2023 Decision, p. 73.

[8] For example, Minnesota Power proposes to use values from their Cogeneration and Small Power Production Tariff because it will be more up-to-date than their IRP.

For the 2024-2026 Triennial, in a departure from previous Triennial filings where electric utilities developed their own generating capacity values, the Department required that utilities use a value based on MISO's Local Resource Zone (LRZ) 1 Cost of New Entry (CONE). This provided a consistent value ($104.17/kW-year) across utilities, was publicly available, and was considered a good proxy for individual utility generating capacity. CONE represents the annualized capital cost of building a new peaking power plant, typically a combustion turbine. It reflects the cost of adding new capacity to meet peak demand and maintain resource adequacy.

For the 2027-2029 Triennial filings, Staff propose to modify the source from the CONE value to the "Net CONE". Net CONE subtracts revenues that the reference proxy plant could earn by participating in MISO's energy and ancillary services markets. Net CONE is more appropriate for cost-effectiveness evaluations of DERs because it reflects the actual cost burden avoided (or incurred) by reducing (or increasing) peak demand.[9] This value is $81.43/kW-year for 2026-2027.[10]

However, as discussed during the CAC's Meeting 7, for resource planning, MISO and utilities are moving towards seasonal peaks or "risk periods". MISO has changed its method of valuing accredited capacity and is using a risk-based method called the direct loss of load approach. The overall threshold that load-serving entities must meet is based on risk periods (when MISO anticipates there won't be much generation available to meet load). Tight periods are called "risk hours".

It is possible that using a flat annual avoided capacity value will understate benefits for measures that reduce summer peak load and overstate benefits for measures that primarily reduce winter or shoulder-season loads (and vice versa for EFS measures). If one, instead, uses MISO's Planning Resource Auction (PRA) results, it's possible to establish month-by-month values. The PRA auction is an annual market mechanism MISO uses to ensure there are enough electricity generation resources available to meet expected peak demand across its footprint. The 2025 auction values can be applied to months based on days per month.[11] The results are as follows:

Table 3 - MISO 2025 Planning Reserve Auction Results by Month

Month	Season	Days	Price North/Central (MW-day)	Price North/Central (kW-month)
January	Winter	31	$33.20	$1.03
February	Winter	28	$33.20	$0.93
March	Spring	31	$69.88	$2.17
April	Spring	30	$69.88	$2.10

9 See: "Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency", Prepared for PJM by The Brattle Group, March 17, 2020, p. 28.

10 See: https://cdn.misoenergy.org/2025-10-15%20Docket%20No.%20ER26-139-000722804.pdf, p. 13.

11 See seasonal values here: https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/misos-planning-resource-auction-indicates-sufficient-resources/

Month	Season	Days	Price North/Central (MW-day)	Price North/Central (kW-month)
May	Spring	31	$69.88	$2.17
June	Summer	30	$666.50	$20.00
July	Summer	31	$666.50	$20.66
August	Summer	31	$666.50	$20.66
September	Fall	30	$91.60	$2.75
October	Fall	31	$91.60	$2.84
November	Fall	30	$91.60	$2.75
December	Winter	31	$33.20	$1.03

The total $/kW-year ($79.07) is slightly lower than the CONE value of $81.43 because the CONE value is a planning value, while the PRA values actual auction results associated with a specific year. The question for CAC members is whether this approach appears preferable to an annual value and, to electric utilities, whether their cost-effectiveness modeling can effectively accommodate this approach.

Gas utilities that implement EFS measures do not currently include generating capacity in their evaluations because the BENCOST model has no place for such inputs (which would be denominated in kW). As a question for all CAC stakeholders, while it would be possible to add a kW component (for EFS, this will be an increase in kW) to BENCOST, and incorporate annual "avoided costs", it would be more challenging to use monthly $/kW-month values. Although monthly values are doable, EFS measure inputs in BENCOST would also require information that specifies the impact profile of individual measures to ensure that the model applies the appropriate calculations. In other words, kW-month values for an air source heat pump, for example, might have positive (savings) values in the summer (due to a more efficient air conditioner) and negative (increased usage) values in the winter and shoulder months.

c. Market Price Effects

In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the electricity demand, they reduce (or increase) the wholesale market prices. This change creates benefits (or costs) for all customers participating in the wholesale market at that time. This effect is sometimes referred to as the demand reduction induced price effect (DRIPE). It's also called the wholesale price suppression effect. As Load Serving Entities (LSEs), Minnesota electric utilities participate in MISO competitive wholesale energy and operating reserves markets. Reductions in utility energy and capacity requirements through energy efficiency and load management, in turn, impact the MISO wholesale electricity and reserves markets as described above.

The proposed value of 1 percent for the 2027-2029 Triennial period for Electric Market Price Effects would remain the same as 2024-2026 Triennials. The value is applied to both <u>energy and capacity values</u> for all years. The 2027-2029 CAC did not review this value for change or updating.

d. Ancillary Services

Ancillary services are those services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves. MISO's three main ancillary services products are regulation, spinning reserves, and supplemental reserves. A DER's net effect on ancillary services depends on its load shape and what the real-time system conditions are at the time of its operation. Even if a DER's operation is not directly in response to a signal to provide ancillary services, it may nevertheless create an impact. A DER that reduces energy consumption would create a benefit by avoiding the average ancillary service price, while a DER that increases usage would create a cost equal to the average price.

The proposed value of 1 percent for the 2027-2029 Triennial period for Ancillary Services would remain the same as 2024-2026 Triennials. The value is applied to generating capacity values for all years. The 2027-2029 CAC did not review this value for change or updating. However, Staff propose to permit electric utilities to propose program-specific values for programs (such as load management) that were anticipated (or designed) to increase reliability and produce ancillary services benefits.

e. Transmission and Distribution

EE DERs reduce loads on the electric transmission and distribution (T&D) systems while EFS DERs tend to increase loads on T&D systems. If these load reductions (or increases) occur during T&D peaks, they can defer/eliminate (EE) required investments or accelerate/trigger (EFS) required investments. The defer/eliminate impacts can be passive, resulting from system-wide efficiency programs, or active, such as non-wires alternatives (NWAs) targeted to specific parts of the utility's (usually distribution) system. Similarly, efforts to stimulate EFS measures on parts of the distribution system (such as programs aimed at eliminating all natural gas service in an area) can have active impacts while generalized EFS programs are passive contributors to load across the utility's system.

Since the 2017-2019 Triennial Plans, electric utilities have used values provided by the 2017 "Minnesota Transmission and Distribution Avoided Cost Study" as approved in the Department of Commerce's July 31, 2017, Decision.[12] The 2027-2029 CAC sought to have utilities update the values from this study or to find alternative, publicly available values to update the 2017 information. For transmission values, Staff considered using MISO network transmission service revenue requirements (as included in utility Attachment O filings); however, these values include all transmission costs and, without a detailed analysis of those costs that should be excluded (for example, costs recovered for prior system investments), this proved not to be a good source. For distribution costs, although Xcel Energy is in the process of conducting a detailed analysis of its system to determine ways that EE, load management, and EFS measures either reduce or increase costs, as of this writing, this analysis is not complete. In addition, the other electric utilities did not believe they could replicate Xcel's analysis for their systems, nor were they able to update their T&D values using the 2017 Study method during the CAC's timeframe.

[12] https://mendotagroup.com/wp-content/uploads/2025/02/Transmission-and-Distribution-Avoided-Cost-Study.pdf

Considering these factors, Staff propose that utilities continue to use 2017 Study values for their 2027-2029 Triennial filings. The exception may be Xcel Energy, which has conducted a detailed analysis of its distribution system and may wish to propose revisions to its distribution system impact values. As Xcel pointed out during CAC meetings, preliminary results indicate that EE, LM, and EFS measures and programs may benefit from either program-specific or program-category-specific (e.g., EE programs, LM programs, EFS programs) values because decreases in load from EE or LM may not create the same avoided distribution costs as EFS adds to distribution costs (values are not symmetrical). This observation underscores the need for additional study of the overall topic, which will not be accomplished before utilities file their 2027-2029 Triennials in June 2026. The values for the individual utilities from the 2017 study follow[13]:

Table 4 - 2017 T&D Study Utility 2027-2029 Values

Year	Xcel Energy		Minnesota Power		Otter Tail Power	
	D	T	D	T	D	T
2027	$8.84	$3.35	$5.06	$0.00	$6.04	$7.73
2028	$9.05	$3.42	$5.19	$0.00	$6.23	$7.96
2029	$9.26	$3.51	$5.32	$0.00	$6.41	$8.20

Gas utilities that implement EFS measures do not currently include T&D capacity in their evaluations because, similar to generating capacity, the BENCOST model has no place for such inputs. Department Staff propose to include T&D values for each electric utility and allow gas utilities to select the utility in whose service territory they expect most EFS projects to happen.

f. Utility Performance Incentives

Minnesota electric and gas utilities can earn shareholder incentives for meeting specific performance metrics. These performance incentives represent a cost associated with the delivery of the DER program. The NSPM recommends that the MCT and relevant secondary tests (Societal Cost Test, Utility Cost Test, and Ratepayer Impact Measure Test) include performance incentives as a cost.

The March 31, 2023, Decision required utilities during the 2024-2026 triennial period to include performance incentives as a cost in cost-effectiveness calculations using a method to avoid circular calculations.[14] Circular calculations arise because the performance incentives use net benefits (calculated as overall avoided costs minus utility administrative costs) and performance incentives impact administrative costs.

Staff did not flag this as an impact that would be revised or updated but are interested in receiving feedback from CAC members on the topic and issues it may pose for electric utilities in calculating portfolio, segment, and program cost-effectiveness. Staff propose to examine

[13] Values for individual utilities were escalated at rates between 2.4 and 3.0 percent. Department Staff propose to update these values based on actual inflation rates during this time period (closer to 3.32%).
[14] See page 258 of the March 31, 2023 Decision.

revisions to this cost-effectiveness impact's methodology to try and address calculation complexity challenges.

2. Utility System Impacts (Gas)

a. Fuel

For gas, fuel refers to the commodity costs avoided by energy efficiency, or EFS measures. In the BENCOST, this value is denominated in $/Dekatherm (Dth). The BENCOST model has historically used a single number for all utilities based on a weighted average of gas utility purchased gas adjustment (PGA) values (for the 2024-2026 Triennial, this period was 11/20 to 10/22). The value for 2024-2026 was $4.52/Dth, with an escalation rate applied based on commodity cost projections from the U.S. Department of Energy's Energy Information Administration Annual Energy Outlook.

In response to the March 31, 2023, Decision's Order Point 6c, the 2027-2029 CAC discussed ways to improve the accuracy of this value (which is based on historical information), possibly by using information from upcoming utility gas IRPs. The plans are anticipated to include natural gas commodity cost forecasts and, therefore, should be better than historical purchased gas costs.[15] The first IRPs are not due to be filed until 2026 (Xcel), 2027 (CenterPoint), and 2028 (Minnesota Energy Resources Corporation). Since ECO Cost-Effectiveness guidance for the 2030-2032 ECO Triennials will be issued in 2029, this should be sufficient time for Xcel and CenterPoint to have available IRP data to include in BENCOST. Great Plains Natural Gas Company and Greater Minnesota Gas are not required to file IRPs.

For the 2027-2029, Staff propose that BENCOST will use utility-specific PGA values (as opposed to a single weighted-average value). Starting with the 2030-2032 Triennial, utilities that do not have IRPs or for whom IRP values are not yet available would continue to use utility-specific PGA values. For EFS calculations, electric utilities would use the most relevant utility PGA value for calculations (e.g., Xcel uses its own gas utility values for its gas service territory and CenterPoint values for Minneapolis; OTP and MP would use the utility for which most projects are anticipated [MERC, CenterPoint, etc.]).

b. Environmental Compliance

Environmental compliance refers to actions electric and gas utilities take to comply with environmental regulations. This can include compliance with federal regulations, like the Clean Air Act, or state and local laws and regulations. However, it is important to ensure that these impacts are not already included in electric or natural gas commodity costs to avoid double-counting. In this context, Environmental Compliance does not include utility system costs associated with greenhouse gases (these are included as a Non-Utility System impact).

For the 2024-2026 Triennials, electric Environmental Compliance costs were set to zero, and the 2027-2029 CAC did not propose changing this value. For gas, the 2024-2026 value was set at 1.40% of the $/Dth Commodity Costs to reflect impacts from the then-proposed regulations to

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[15] "Utilities shall analyze high, medium, and low natural gas price sensitivities in their resource plans" in Order Clarifying and Expanding Framework for Natural Gas Utility Integrated Resource Planning (Dockets No. G-999/CI-21-565; G-008,G-002, G-011/CI-23-117), Minnesota Public Utilities Commission, October 28, 2024.

reduce methane emissions from natural gas transmission and storage facilities (EPA-452/R-23-013).[16] The EPA issued a revised RIA that lowers the economic impact to 1.0%. Therefore, Staff propose using 1.0% of the $/Dth Commodity Cost for 2027-2029.[17] Although it is unclear how this impacts the RIA and its estimate of 1%. With subsequent Triennials and utility use of forecasted gas prices, it is expected that these compliance costs will be priced into forecasts, and the metric will be reduced to 0 (unless it is determined that other Environmental Compliance impacts are identified and priced).

3. Non-Utility System Impacts (Both Electric and Gas)

a. Other Fuels

Other Fuels refers to impacts from fuels that are not provided by the relevant utility. For example, for a natural gas utility, the Other Fuel could be electricity for measures that save or increase (EFS) consumption. For an electric utility, Other Fuels refers to measures that save natural gas, oil, propane, gasoline, or wood (EFS).

BENCOST incorporates Other Fuels in several inputs, namely the Non-Gas Fuel Cost, the Non-Gas Fuel Loss Factor, and Non-Gas Fuel Environmental Damage Factor. As discussed in this document, Staff are considering adding Non-Gas Fuel factors, Generating Capacity, and T&D.

Gas utilities that implement EFS measures use marginal electric energy values in the Non-Gas Fuel Cost input, a value that has historically used a single $/kWh-year value with a fixed escalation rate. This is different from electric utilities, which may use hourly, weekly, or monthly marginal energy forecasts. The BENCOST Non-Gas Fuel Cost input uses the average of Midcontinent Independent System Operator (MISO) daily real-time final market locational marginal prices (LMP) at the Minnesota Hub. For the 2024-2026 Triennium, this value was $0.04414/kWh.

As a change, Staff are considering using a value that is an average of electric utility marginal energy values (to protect data that utilities consider trade secret); however, depending on when this data is available, it may be difficult to align BENCOST values with the values utilities will use in their June 1, 2026, filings. After release of this summary document, Staff will request this data from electric utilities. If this is not workable, the BENCOST model may, again, use MISO data.

The Non-Gas Fuel Loss Factor for the 2024-2026 Triennial was 8.22 percent, a value calculated by taking the average of Minnesota Power, Xcel Energy, and Otter Tail Power's reported 2021 transmission and distribution loss factors and weighting by the utilities' 2017-2019 average retail sales. Staff will be requesting updated values from electric utilities to incorporate into the revised BENCOST. Staff note that utilities include different loss factors for both energy and demand. These different factors would also be applied to the energy and demand-related factors in BENCOST.

[16] The 1.40 percent was based on the EPA's Regulatory Impact Analysis (RIA) which, among other things, estimates the impact on prices from the new rule.
[17] The Trump Administration, on July 31, 2025, issued a revised rule that delays compliance requirements, but it is unclear whether this affects the economic impact analysis.

For electric utilities, Other Fuels refers to natural gas and other fossil fuels. Electric utilities are expected to use BENCOST (or BENCOST proxy values) to evaluate the natural gas portion of EFS measures. In addition, electric utilities are expected to include proposed values for other fuels such as oil, propane, gasoline, and wood in their Triennial filings. Staff intend to develop guidance in the Proposed Decision to ensure consistency between electric utilities.

b. Greenhouse Gas (GHG) Emissions

Societal GHG emissions are "externalities" because they are not included in the cost of electricity and gas. The GHG factors for both electric and gas measures represent the additional cost to society of GHG emissions. The values are typically set by regulatory authorities. Any environmental compliance costs associated with the reduction of GHG emissions that are already included in USIs must be subtracted from this impact to avoid double-counting.

For electric utilities, this value is based on the Minnesota PUC's January 3, 2018, Order in docket number CI-14-643. The "equivalent" value in BENCOST that gas utilities use for EFS measures is BENCOST's Non-Gas Fuel Environmental Damage Factor. The Non-Gas Fuel Environmental Damage Factor represents the long-term "external" cost to society and the environment from the production of electricity. The factor, $0.02536/kWh in the 2024-2026 Triennial, includes damage factors associated with both criteria air emissions and greenhouse gases (GHGs).

The factor is calculated using the median range of the final metropolitan fringe environmental cost values approved by the Minnesota Public Utilities Commission (Commission)[18] for carbon dioxide (CO2), sulfur dioxide (SO2), fine particulate matter (PM2.5), carbon monoxide (CO), nitrogen oxides (NOx), and lead (Pb); along with estimated 2016 emission factor (or factors) for each emission provided by the Environmental Protection Agency[19] and the Minnesota Pollution Control Agency.[20] CO2, Staff used a median value of $25.76/ton in 2020 from the Commission's January 3, 2018 Order Updating Environmental Cost Values for 2024-2026. Staff propose to update this value with the latest available information.

For electric utilities using BENCOST to estimate avoided gas costs, the GHG factor is the Gas Environmental Damage Factor. The factor includes damage factors associated with both criteria air emissions and GHGs. The value for the criteria emissions component is calculated using the high range of the final metropolitan fringe environmental cost values approved by the Minnesota Public Utilities Commission (Commission)[21] for sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), carbon monoxide (CO), nitrogen oxides (NO_x), and lead (Pb), along with estimated natural gas emission factor (or factors) for each pollutant provided by the U.S. Environmental

18 January 3, 2018, Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643.

19 February 15, 2018, Emissions & Generation Resource Integrated Database 2016 (eGRID). Environmental Protection Agency. <https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid>.

20 2016 Permitted Facility Air Emissions Data. Minnesota Pollution Control Agency. <https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data>.

21 January 3, 2018, Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643.

Protection Agency.[22] For the carbon dioxide (CO_2) GHG,[23] Staff used as the starting point the high externality value of $45.16/ton in 2023 from the Commission's January 3, 2018 Order Updating Environmental Cost Values. Staff propose to update this value with the latest available information.

c. Other Environmental

Energy resources can have environmental impacts beyond GHG emissions, including impacts on other air emissions, liquid and solid waste releases, land use, and water use. Societal environmental impacts represent the impacts that occur after compliance with environmental regulations and requirements. Staff's review of recent policy changes indicated that a factor related to DER impacts on water use would be good to include if the value could be quantified. Unfortunately, the CAC could not identify any reliable sources to quantify DER water impacts and the available sources indicated that the value would be very small. Therefore, Staff recommend that Other Environmental continue to have a zero value in the MCT.

d. Economic and Jobs (Macroeconomic)

Economic and Jobs refers to any incremental economic development and jobs provided by DERs. These may come in the form of direct impacts (jobs and economic activity associated with constructing, installing, and operating the energy resource), indirect impacts (jobs and economic activity associated with additional work and revenue that DERs channel to supply chains associated with the direct impacts), and induced impacts (jobs and economic activity created by the re-spending of the newly hired workers who gained employment in the direct or indirect impacts categories).[24]

The CAC sought good sources to estimate ECO program impacts on the economy and jobs, but was unable to find a good source.[25] Although there were studies available, there were concerns about potential double-counting components within other Utility System Impacts, and the need to remove GHG benefits from these estimates GHGs are quantified elsewhere.

In the interest of providing an opportunity to place higher value (according to the MCT) on programs designed to produce direct economic benefits and jobs (beyond those "system-level" jobs program investments create), Staff propose allowing utilities (and alternative filers) to propose impact estimates for programs focused on workforce development or other programs that produce measurable and demonstrable economic development/macroeconomic impacts.

Given feedback from CAC members that utilities tend not to count low-income program benefits in calculations of their performance incentives, the thought is that utilities may not use this approach with low-income workforce programs (because although calculating economic impacts

[22] AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources.
[23] Additional greenhouse gases include: methane, nitrous oxide, and fluorinated gases such as hydrofluorocarbons. The PUC factor focuses on CO_2, the primary greenhouse gas emitted through human activities.
[24] *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, National Energy Screening Project, August 2020, p. 4-22.
[25] In addition, the NSPM cautions about using Economic impact values, indicating that they may be better handled qualitatively or as stand-alone (not incorporated into BCA) analyses.

may increase low-income program cost-effectiveness, these benefits would not be counted in overall portfolio net benefits). Therefore, such programs would likely be better proposed as indirect impact or direct impact (if they also produce energy savings).

e. Discount Rates

Each cost-effectiveness test is designed to analyze ECO investments from a different perspective. This ensures that regulators have a complete picture of who is actually better off and who might be worse off as a result of an ECO investment. For the tests to be meaningful, each test should use the appropriate discount rate that reflects the time value of future benefits from the perspective of the entity who is making the investment.

Discount rates reflect a “time preference" (the relative importance of short and long-term impacts). A higher discount rate gives more weight to short-term benefits and costs relative to long-term benefits and costs, while a lower discount rate gives greater weight to long-term impacts. All cost-effectiveness use discount rates to create a "present value" value stream of costs and benefits.

Societal Discount Rate

Historically, Staff have used an average of the daily (for the relevant year) United States Department of the Treasury’s (Treasury) 20-year Constant Maturity (CMT) Rate to set the Societal Discount Rate. The 20-year CMT rate is the interest rate the U.S. government would pay if it borrowed money for 20 years. For the 2024-2026 Triennial, the selected time period was 1/3/22 to 12/30/22, which set the value at 3.30 Percent. Understandably, this value fluctuates with each Triennial based on prevailing rates.

For the 2027-2029 Triennial, Staff propose to use a fixed real Societal Discount rate equal to 3.0 percent, based on the United States Office of Management and Budget’s (OMB) guidance to Federal agencies on the development of regulatory analysis as required under Section 6(a)(3)(c) of Executive Order 12866, and a variety of related authorities (Circular A-4). OMB adopted the value in 2003, and it stood until 2023, when OMB lowered the value to 2.0 percent. Although recent data suggest lower real returns on government debt, a 3.0% rate remains appropriate based on historical averages, policy stability, international norms, and intergenerational equity. Staff believe that maintaining a consistent discount rate avoids frequent recalibration and supports long-term planning. This value is also consistent with other jurisdictions that have recently adopted Societal Cost tests (California) and new jurisdictional tests (Michigan).

The Societal Discount Rate is used in the Minnesota Cost Test, the Societal Cost Test, and the Participant Cost Test (for residential programs).

Utility Discount Rate

Staff propose continued use of the method (termed the "CIP Utility Discount Rate") adopted in the CIP Gas and Electric Utilities -- 2021-2023 Cost-Effectiveness Review Decision[26] to

[26] *Deputy Commissioner’s Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost Effectiveness Review*, Docket Nos. G999/CIP-18-782, E999/CIP-18-783, February 11, 2020 https://efiling.web.commerce.state.mn.us/documents/%7B00953570-0000-CD23-81EE-524E2CE8A306%7D/download?contentSequence=0&rowIndex=1

calculate the Utility Discount Rates used in the Utility Cost Test, Participant Cost Test (for non-residential programs), and the Ratepayer Impact Measure Test.

For the Participant Cost Test, the Department has historically required that utilities use the Societal Discount Rate for residential programs and the CIP Utility Discount Rate for non-residential programs. There is no proposal to change this approach. The BENCOST model currently only has a field for the Participant Discount Rate with an assumption that utilities will fill in the appropriate rate for the respective customer classes. Staff are considering revising these fields to have separate entries for residential and non-residential program discount rates and is interested in feedback from CAC members.

The Ratepayer Impact Measure Test currently uses the CIP Utility Discount Rate in its calculations. Staff do not propose changes to the RIM Test use of the CIP Utility Discount Rate.

Staff will request data from utilities to update the CIP Utility Discount Rates (which will be renamed "ECO Utility Discount Rates").

For reference, here are the 2024-2026 CIP Utility Discount Rates and after-tax Weighted Average Cost of Capital:

Utility	**CIP Utility Discount Rate**		**WACC (After Tax)**	
	Electric	**Gas**	**Electric**	**Gas**
CenterPoint		5.39%		6.45%
Greater Minnesota Gas		5.61%		6.76%
Great Plains Natural Gas				7.03%
MERC		5.57%		6.70%
Minnesota Power	5.41%		6.47%	
Otter Tail Power	5.61%		6.77%	
Xcel Energy	5.38%	5.34%	6.43%	6.38%

For additional reference, here is a description of the step-by-step process used to calculate the CIP Utility Discount Rate.

1. When the IOUs submit their annual CIP status reports, these filings usually include both utility program admin costs (including rebates they pay to customers) plus estimates of the incremental costs that the participants paid.
2. Staff aggregated all of the CIP cost data across the IOUs, and determined the estimated percentage total CIP costs that are paid by customers (in the form of incremental participant costs)[27] and the percentage of total CIP costs paid by the utilities. Staff's

[27] The gas utility BENCOST results for actual achievements that the utilities submit in their Status reports include the information needed to calculate the estimate of incremental participant costs (Direct participant costs per customer and number of customers), Xcel Electric directly stated its participant customer incremental costs, and Otter Tail and Minnesota Power responded to Staff's request for estimates of their customers' 2017 and 2018

analysis shows that participating customers pay a weighted average of 67 percent of total costs and the utilities pay a weighted average of 33 percent of total costs. See Attachment X tables in Appendix F for more information.

3. Staff calculated that commercial and industrial (C&I) customers pay a weighted average of 54 percent of all incremental participant costs while residential customers pay a weighted average of 46 percent of all incremental participant costs. In the CIP Inputs to BENCOST for Natural Gas Utilities, "Input 11 – Participant Discount Rate" specifies that C&I customers be assigned a participant discount rate equal to the utility's WACC while residential customers are assigned a discount rate equal to the SDR. See Attachment Y table in Appendix F for more information.
4. To calculate the participating component of the new discount rate represented by C&I participating customers, Staff multiplied each individual IOU's WACC percent times 54 percent (C&I Percent of Spending) times 67 percent (Percent of Total CIP Costs that are Participants). The result was a C&I customer participant component of 2.53 percent.
5. To calculate the participating component of the new discount rate represented by residential participating customers, Staff multiplied the SDR of 3.02 percent times 46 percent (Residential Percent of Spending) times 67 percent (Percent of Total CIP Costs that are Participants). The result was a residential customer participant component of 0.93 percent. Since the societal discount rate is the same for each utility, the residential customer participant component did not vary among IOUs.
6. To calculate the utility component of the new discount rate, Staff multiplied the individual utility's WACC percent times 33 percent (Percent of Total CIP Costs Made Up by Utility Costs). The results varied by IOU. See Attachment Z in Appendix F for results.
7. Finally, Staff added the participating customer and utility components for new CIP Utility Discount Rates that ranged from 5.34 percent to 5.79%. See Attachment Z table in Appendix F for more information.[28]

Lastly, below is a table showing calculations for CenterPoint from Attachment Z.[29]

incremental participant costs.

[28] *Deputy Commissioner's Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost Effectiveness Review*, pages 21-22.

[29] *Deputy Commissioner's Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost Effectiveness Review*, Attachment Z, p. 83.

Attachment Z Calculation Tables

	CenterPoint	Values	(1) Participating Customer Component Represented by C&I Participating Customers = AxCxE	(2) Participating Customer Component Represented by Residential Participating Customers = BxDxE	(3) Utility Cost Component = AxF	CIP Utility Discount Rate = (1) + (2) +(3)
			2.33%	0.93%	2.13%	**5.39%**
A	CenterPoint After-Tax WACC	6.45%				
B	Societal Discount Rate	3.02%				
C	C&I Percent of Spending	54%				
D	Residential % of Spending	46%				
E	% of Total CIP Costs that are Participants	67%				
F	% of Total CIP Costs that are Utility	33%				

C. Other Topics

Section C discusses other topics related to cost effectiveness that the 2027-2029 CAC considered.

1. Primary and Secondary Tests

The CAC did not have much discussion on the topic of Primary and Secondary Tests, although members expressed interest in Department guidance on how to use the tests.

Guidance language from pages 89-93 of the March 31, 2023, Decision is provided below. Staff propose to continue using similar guidance regarding the purpose of the primary and secondary cost-effectiveness tests. Staff welcome comments and input from CAC members on this topic.

Minnesota Test as CIP's Primary Cost-Effectiveness Test

a. The Deputy Commissioner approves the MCT as CIP's primary cost-effectiveness test that the gas and electric IOUs shall use to screen their energy efficiency, load management, and efficient fuel-switching programs. The Deputy Commissioner also requires that CIP custom projects should be screened using the MCT as the primary test.

b. The Deputy Commissioner will allow approval of cost-effectiveness at the segment-level, so that the IOUs are responsible for ensuring that each segment, rather than individual program, is cost-effective by CIP standards.

c. The Deputy Commissioner approves the following general guidelines regarding cost-effectiveness and program design decisions:
   i. Cost-effectiveness and program design are separate, but related concepts. Program design and portfolio development involve many considerations;
   ii. Cost-effectiveness evaluations can help inform program design but should not be the primary basis for program design;

iii. Just because a program is cost-effective does not mean that the utility should include it in its portfolio and, by extension, just because a program is not cost-effective does not mean that it should be automatically eliminated; and
iv. It is the utility's responsibility to design a program (including measure mix, incentives, etc.) that is attractive to customers, is deliverable in a practical sense, and (generally) is cost-effective under the primary test used to evaluate programs.

d. Table 23 summarizes the impacts that are part of the new MCT's framework. An * indicates impacts that are currently quantified to estimate cost-effectiveness and should be included in the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT. Impacts that do not have an * symbol are not currently quantified as part of the MCT and/or do not have an approved estimation methodology. These impacts should be assigned a value equal to 0 for the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT.

Table 23. MCT Impacts

Type	Utility	Category	Impact
Utility System	Electric Utility	Generation	Energy Generation*
			Capacity*
			Environmental Compliance
			Renewable Portfolio Standard Compliance
			Market Price Effects*
			Ancillary Services*
		Transmission	Transmission Capacity*
			Transmission System Losses*
		Distribution	Distribution Costs*
			Distribution System Losses*
		General	Program Incentives*
			Program Administration Costs*
			Utility Performance Incentives*
			Credit and Collection Costs
			Risk
			Reliability
			Resilience
	Gas Utility	Commodity / Supply	Fuel*
			Capacity and Storage*
			Environmental Compliance*
			Market Price Effects
		Transportation	Transportation*

<table>
<tr><th>Type</th><th>Utility</th><th>Category</th><th>Impact</th></tr>
<tr><td rowspan="2"></td><td rowspan="2"></td><td>Delivery</td><td>Delivery*</td></tr>
<tr><td>General (same as Electric)</td><td>(see electric section)</td></tr>
<tr><td>Non-Utility System</td><td>Both</td><td>Other Fuels</td><td>Other Fuels</td></tr>
<tr><td rowspan="6">Societal</td><td rowspan="6">Both</td><td rowspan="6">Societal Impacts</td><td>GHG emissions*</td></tr>
<tr><td>Criteria air emissions*</td></tr>
<tr><td>Other environmental</td></tr>
<tr><td>Economic and Jobs (Macroeconomic)</td></tr>
<tr><td>Energy Security</td></tr>
<tr><td>Energy Equity</td></tr>
</table>

Secondary Cost-Effectiveness Tests and Program Design

a. The Deputy Commissioner approves the SCT, UCT, PCT, and RIM as CIP's secondary cost-effectiveness tests.

b. The Deputy Commissioner approves the following approach to primary and secondary cost-effectiveness tests, as presented in Synapse's June 8, 2022 Straw Proposal (see Appendix F):

> The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

c. The Deputy Commissioner approves the following general guidelines regarding the purpose of the secondary tests:
   i. Secondary tests can help to:
      - Inform decisions on how to prioritize programs (based on constraints or objectives).
      - Inform how a program affect different parties (e.g., all customers, host customers, society).
      - Inform decisions regarding marginally cost-effective programs.
   ii. Any impact that is included in more than one test (e.g. avoided energy) should be treated consistently across all the tests (e.g., using the same \$/MWh or \$/Dth value).

iii. When IOUs present cost-effectiveness results in their Triennial Plans and Status Reports, they should:
   - Describe the cost-effectiveness results by program using the Minnesota Test,
   - Describe any key cost-effectiveness issues that were considered in program design, and
   - Describe any programs where secondary tests played a role in decision-making.

d. Table 24 summarizes the impacts that the Deputy Commissioner approves for the MCT's and the secondary tests' frameworks. For 2024-2026 CIP cost-effectiveness analyses using the secondary tests, utilities may include estimates for impacts that are not currently quantified or do not have an approved methodology, but utilities should clearly outline all the assumptions and methodology details regarding how those impacts were estimated as part of their CIP Status Report and Triennial Filings.

Table 24. List of Cost-effectiveness Test Impacts

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
Utility System	Electric Utility	Generation	Energy Generation	x	x	x		x
			Capacity	x	x	x		x
			Environmental Compliance	x	x	x		x
			Renewable Portfolio Standard Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
			Ancillary Services	x	x	x		x
		Transmission	Transmission Capacity	x	x	x		x
			Transmission System Losses	x	x	x		x
		Distribution	Distribution Costs	x	x	x		x
			Distribution System Losses	x	x	x		x
		General	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Utility Revenue Impacts					x
			Credit and Collection Costs	x	x	x		x

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Utility System	Gas Utility	Commodity / Supply	Fuel and Variable O&M	x	x	x		x
			Capacity and Storage	x	x	x		x
			Environmental Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
		Transportation	Transportation	x	x	x		x
		Delivery	Delivery	x	x	x		x
		General (same as Electric	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Non-Utility System	All	Other Fuels	Other Fuels	x	x			
		Participant	Participant Costs		x		x	
			Participant Benefits		x		x	
Societal	All	Societal Impacts	GHG emissions	x	x			
			Criteria air emissions	x	x			
			Other environmental	x	x			
			Economic and Jobs (Macroeconomic)	x	x			
			Energy Security	x	x			
			Energy Equity	x	x			
			Societal Discount Rate	x	x		x	

2. Project Lifetimes

Order Point 6d instructed Staff to revisit measure lifetimes in the next MN Technical Reference Manual (TRM) cycle to determine what, if any, adjustments could be made to increase expected lifetime for prescriptive measure assumptions beyond 20 years. TRM 5.0, which the Department will soon file with the Assistant Commissioners for consideration, extends the maximum effective project useful life to 35 years, for the Residential Envelope – Insulation and Air Sealing measure. Staff plan to modify BENCOST to accommodate EULs up to 50 years.

3. Data Requests

In addition to items in this document for which the Department is requesting feedback, Staff will be sending data requests to utilities for information to include in cost-effectiveness inputs and guidance. Staff anticipate to issue these data requests within two weeks of distributing this report.