LRTP Tranche 2 Business Case Metrics Methodology Whitepaper

October 1, 2024

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1 Purpose

The LRTP business case documents the analysis of benefits to demonstrate that sufficient value is provided by the transmission investment in excess of costs to justify recommendation of the portfolio for approval by the MISO Board of Directors. The business case includes a discussion of the various metrics selected and analyzed to quantify the economic and reliability benefits.

2 Scope of Work Effort

The LRTP Business case workstream is responsible for defining the benefit metrics and developing the appropriate methodology needed to calculate the value in support of the overall LRTP objectives. Since the objectives of the multi-value-planning process is dependent on the drivers of the need for investment, the applicability of specific benefit metrics and approach used must be evaluated with each planning cycle (i.e., there is no standard set of metrics and methodologies that can be universally applied).

The development of benefit metrics and hence the quantification of value is largely dependent on the assumptions of the future state of the system which occurs in the Futures development at the beginning of the planning process. Therefore, the business case metrics development begins during the Futures process to ensure that the metrics are aligned with the drivers of the transmission investment and that metrics can be evaluated for feasibility under the current assumptions. Metric selection and evaluation require that assumptions are clearly defined, and that work is progressing on the Futures models and scope of reliability and economic analysis. Furthermore, metrics must be vetted with stakeholders to demonstrate the validity of the assumptions and methods used and seek their input and support for the approach.

The number of benefits may vary but should be comprehensive to demonstrate that benefits are broadly spread to customers in a manner roughly commensurate with costs and the value provided to stakeholders exceeds the total portfolio costs to be eligible for regional cost sharing as required by the MISO Tariff.

Benefits are calculated using the applicable Future scenarios covering a range of possible future outcomes that reflect the member plans and goals. The Tranche 2 portfolio is intended as a least-regrets transmission plan that will provide reliable performance while supporting Future 2A energy needs. Benefits are evaluated using assumptions defined in the Future 2A resource plan to demonstrate that the transmission investment delivers benefits that are in excess of costs to customers across the Midwest subregion. Benefits analysis is also performed using Future 1A scenario to demonstrate robustness of benefits for a range of outcomes.

Once the project selection process has been completed and portfolio is established, the benefit analysis is performed to capture the financial value calculated when LRTP projects are included in the analysis. Analysis findings are compiled into a comprehensive data set to provide documented details of the calculations. Additionally, the business case narrative is created to detail the

assumptions, development process, and summary of findings contained in the business case and included as an appendix to the MTEP report

3 Stakeholder Engagement

After assessing the applicability of benefits, the business case team will define methodologies for the initial set of benefit metrics to begin exploring the level of value expected. The LRTP team will then establish stakeholder outreach on an appropriate cadence to share significant findings and seek input on the validity of the methods and results. MISO will seek to address stakeholder questions and concerns, including incorporating modifications to the proposed benefit metric methods. It is important to MISO that Stakeholders voices are given ample opportunity to be heard and are adequately represented in the collaborative planning process.

MISO staff will prepare meeting materials to summarize proposals and findings and make supporting materials available for Stakeholder meetings.

MISO staff will provide detailed work materials (including models, input data analysis results) to stakeholder with appropriate levels of access for their examination and independent validation of results.

MISO will provide opportunity to review and provide comment on the draft business case report content via the MTEP Report process and formally respond to comments before presenting the report for Board of Directors review.

Supporting materials will be finalized only after Board of Directors approval and will be publicly posted as part of the MTEP materials.

4 Benefit Metrics

4.1 Avoided Capacity Cost

The Avoided Capacity Cost (ACC) metric reflects the capital cost savings from the increase in transmission capability provided by LRTP, enabling access to resources over the wider MISO footprint. The benefit assesses the change in loss of load expectation (LOLE) to determine the adjustment in MISO-wide reserve requirement to meet the LOLE target with and without the LRTP portfolio. The addition of LRTP results in an increase in transfer capability across the footprint that makes more resource capacity available to meet the capacity requirements and reduces the need for investment in additional resources. The change in reserve requirement is applied to an EGEAS capacity expansion model in order to identify the amount and composition of the additional resources that would be needed without LRTP. The costs of these additional resources reflect the benefit of ACC. Since the ACC benefit occurs concurrently in a system with LRTP as the Capacity Savings from Reduced Losses (CSRL) benefit, the reserve requirement deltas reflecting the impact of each are combined and added to the original Series 1A reserve

requirement for incremental expansions to Future 2A and 1A. The incremental expansions quantify the value of both benefits in terms of the costs of additional resources beyond the original Future 2A and 1A expansions. The methodology described for combined reserve requirement, EGEAS expansion analysis, and benefit calculation are identical for both benefits.

The methodology applies familiar concepts of zonal transmission analysis to represent a simplified transmission model in the capacity analysis. This adopts a similar framework to the typical resource adequacy analysis and employs probabilistic loss of load expectation (LOLE) methods to determine the amount of capacity needed to meet the 1 day in 10 years LOLE target. The main distinction in the benefits analysis is that it computes the change observed when additional transmission is modeled. Thus, the metric does not seek to establish resource adequacy requirements but captures the impact of transmission changes on the outcome of the LOLE assessment.

Key Inputs/Model Assumptions

Transmission Adequacy and Reliability Assessment (TARA) is the analysis software used to perform Capacity Import Limit (CIL)/Capacity Export Limit (CEL) studies (transfer limit studies). The Future 2A 20-year out CIL and CEL calculations were determined on a seasonal basis using the following power flow cases assumptions:

> The 2042 summer peak, winter peak, and average load core power flow models[1] are used to reflect the seasonal variation in CIL/CEL.
>
> Base cases used for transfer limit analysis use the Future 2A 2042 summer peak, winter peak, and average load reliability power flow models without LRTP transmission.
>
> Change cases for transfer limit analysis use the Future 2A 2042 summer peak, winter peak, and average load reliability power flow models with LRTP transmission facilities in service.
>
> Base and change cases will also be built from the Future 1A 2042 summer peak, winter peak, and average load reliability power flow models for establishing robustness of benefits in a lower bookend scenario.

PLEXOS is the software used to perform the probabilistic loss of load expectation (LOLE) analysis to calculate change in planning reserves when transmission constraints are included[2]. The following list includes the key modeling assumptions:

> PLEXOS models are based on Future 2A scenario resources and include Future 1A scenario for evaluating benefit robustness.
>
> Probabilistic analysis includes evaluation of 14 weather years (2007-2021; excluding 2013) for synchronized load and renewable generation profiles.

[1] See details in Reliability Study Whitepaper
[2] See planning reserve assumptions under copper sheet conditions in Series 1A Futures Report

Hourly simulations with 150 samples to reflect probabilities of forced outages, including temperature-dependent correlated outages.

Planned maintenance is also accounted for using maintenance rates and maintenance frequency.

EGEAS software is used to perform the capacity expansion analysis. Resource expansion models are based on the Future 2A scenario and include Future 1A scenario for evaluating the robustness of benefits. The methodology described in this section applies to evaluation of Future 1A as well as Future 2A.

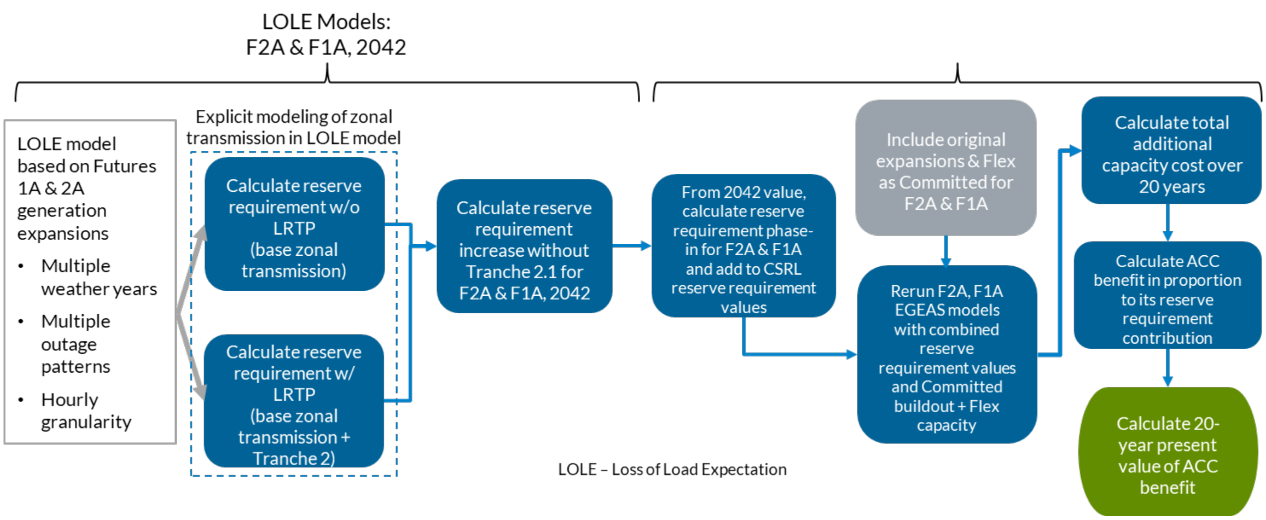


Figure 1 - Process for calculation of Avoided Capacity Cost benefits

Analysis Steps

Step 1 – Capacity Import Limit (CIL)/Capacity Export Limit (CEL) analysis

CIL/CEL analysis is based on transfer capability study that uses linear power flow methods to evaluate how much power can be transported on the transmission network before a transmission limit is reached. The transfers are simulated as shifts in power between defined source/sink subsystems. CIL/CEL specifically examines the limits to transfers into and out of the Local Resource Zones from participating resources.

CIL/CEL transfer capability analysis is performed on 2042 summer peak, winter peak, average load base cases without LRTP. Transfers are simulated for import and exports for LRZ 1-7 and generation redispatch is applied to determine valid limiting constraints and establish the base case CIL and CEL values for each zone LRZ 1-7 for each season.

Transfer capability analysis is then repeated on the 2042 summer peak, winter peak, average load base cases with LRTP using the same approach to establish the CIL/CEL values for LRZ 1-

7 for each season. These CIL/CEL values are, in general, expected to be higher since the addition of LRTP transmission will increase transfer capability.

Step 2 - LOLE/reserve requirement analysis

Probabilistic analysis is used to assess availability of resources and calculate the loss of load expectation as a threshold for determining additional capacity needs. This LOLE metric serves as a common frame of reference for measuring the change in reserve requirements due to the changes in CIL/CEL.

The LOLE analysis is performed using the seasonal CIL/CEL values without LRTP portfolio to compute the LOLE for the modeled resources, and an incremental amount of perfect capacity (or load) is then added until the 0.1 d/y annual LOLE is reached[3]. The same analysis is repeated using the seasonal CIL/CEL values with LRTP portfolio to determine the incremental amount of capacity needed to reach the 0.1 d/y annual LOLE and the difference is calculated as the capacity savings. It is the difference that reflects the impact of LRTP transmission – the absolute amount of capacity addition needed to meet the 0.1 d/y annual LOLE target is not relevant to the benefit calculation.

The transfer limits between the LRZ 8-10 are neglected and the Midwest-to-South regional directional transfer (RDT) constraint is enforced between the Midwest and South subregions in the LOLE model. This guarantees that the reserve requirement assumptions are consistent between the base and change cases.

The value of reserve requirement is calculated as

Reserve requirement ICAP % = (Highest Seasonal ICAP + ICAP Adjustment to meet LOLE target - Highest Seasonal System Peak Demand) / Highest Seasonal Peak Demand

This aligns with the method MISO used to yield the 18.05% reserve requirement for the Series 1A Futures: taking the highest seasonal installed capacity (ICAP) reserve requirement (Winter 2023-2024) less the highest seasonal System Peak Demand (Summer 2023) and dividing by the highest seasonal System Peak Demand (Summer 2023).[4]

Example Only; Placeholder Values	**Without Tranche 2**	**With Tranche 2**
MISO System SUMMER Peak Demand (MW)	250,000	250,000
WINTER ICAP (MW)	500,000	500,000
WINTER Adjustment to ICAP (MW)	5,000	-10,000
WINTER ICAP PRMR (MW)	505,000	490,000
PRM ICAP	102.0%	96.0%
Illustrative PRM ICAP Change:	**6.00%**	

Illustrative

Figure 2 - Example calculation of ACC reserve requirement

[3] Seasonal LOLE targets are also applied to the cases.
[4] See Series 1A Futures Assumption Book

Following the calculation method above, the difference in calculated reserve requirement values with and without the LRTP portfolio determines the additional ACC reserve requirement value applied in the EGEAS capacity expansion analysis.

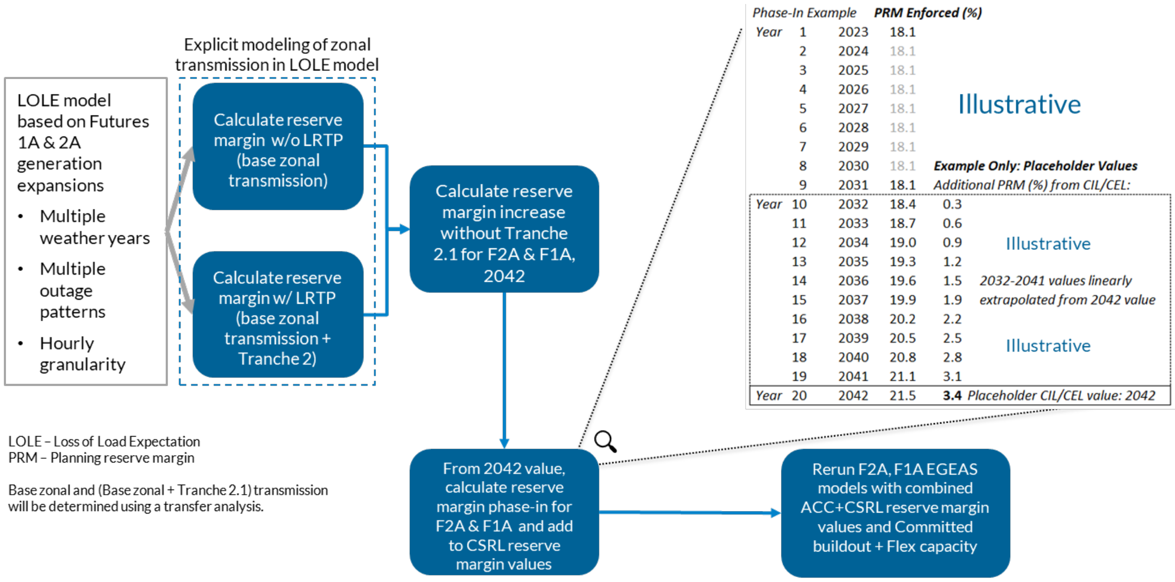


Figure 3 - Process for calculation of ACC reserve requirement and benefits

Step 3 – Calculate combined reserve requirement for ACC + CSRL reserve requirement for EGEAS expansion analysis

As mentioned in the introduction to this benefit, the EGEAS capacity expansion utilizes one reserve requirement value to reflect concurrent ACC and CSRL benefits of LRTP. The reserve requirement deltas of ACC and CSRL are combined to obtain one total reserve requirement delta, which is added to the original Future 2A reserve requirement of 18.05%.[5] This methodology described in this step and following are identical for both ACC and CSRL benefits.

[5] See Series 1A Futures Report

Combined | **Avoided Capacity Costs** | **Capacity Savings from Reduced Losses**

Illustrative

Phase-In Example			*PRM Enforced (%)* (Combined)	Total PRM Δ:	*PRM Enforced (%)* (Avoided Capacity Costs)	Additional PRM (%) from CIL/CEL:	*PRM Enforced (%)* (Capacity Savings from Reduced Losses)	Additional PRM (%) from reduced losses:
Year	1	2023	18.05		18.1		18.1	
	2	2024	18.05		18.1		18.1	
	3	2025	18.05		18.1		18.1	
	4	2026	18.05		18.1		18.1	
	5	2027	18.05		18.1		18.1	
	6	2028	18.05		18.1		18.1	
	7	2029	18.05		18.1		18.1	
	8	2030	18.05		18.1		18.1	
	9	2031	18.05		18.1		18.1	
Year	10	2032	20.94	2.89	19.5	1.5	19.5	**1.4** Reduced losses value: 2032
	11	2033	21.20	3.15	19.7	1.7	19.5	1.5
	12	2034	21.46	3.41	19.9	1.9	19.6	1.5
	13	2035	21.72	3.67	20.1	2.1	19.7	1.6
	14	2036	21.98	3.93	20.3	2.3	19.7	1.7
	15	2037	22.25	4.20	20.5	2.4	19.8	1.8
	16	2038	22.51	4.46	20.7	2.6	19.9	1.8
	17	2039	22.77	4.72	20.9	2.8	19.9	1.9
	18	2040	23.03	4.98	21.1	3.0	20.0	2.0
	19	2041	23.29	5.24	21.3	3.2	20.1	2.0
Year	20	2042	**23.55**	**5.50**	21.5	**3.4** CIL/CEL value: 2042	20.2	**2.1** Reduced losses value: 2042

Example Only: Placeholder Values (Avoided Capacity Costs)

2032-2041 values linearly extrapolated from 2042 value

Example Only: Placeholder Values (Capacity Savings from Reduced Losses)

Interim values linearly interpolated from 2032, 2042 values

Final portion of Total PRM Δ: **62%** ACC   Final portion of Total PRM Δ: **38%** CSRL

Figure 4 - Process for calculation of Combined ACC + CSRL reserve requirement and relative contributions

Step 4 – EGEAS expansion analysis

The EGEAS capacity expansion analysis applies the reserve requirement to reflect the additional capacity requirements to meet the resource adequacy needs. The base Future 2A resource expansion used seasonal data from the 2023-24 Planning Year reserve requirement Analysis to establish a reserve requirement value of 18.05%, applied throughout the study period.

For this benefit, an additional capacity expansion is performed using built-in capacity from the original F2A expansion, and an increased reserve requirement value produced by adding the combined ACC and CSRL delta to the original 18.05% figure. Since the Future 2A scenario is based on copper sheet expansion, it reflects a less constrained system with the assumption that transmission expansion will occur. Thus, the change in reserve requirement will reflect an increase that occurs with a more constrained transmission system (i.e., transmission limitations reduce the availability of resources, driving the need for more installed capacity).

The reserve requirement delta is added to the base reserve requirement of 18.05% and applied in a new EGEAS run. Since the value is based on analysis of the 2042 study and reserve requirement is assumed constant until LRTP portfolio is in service in 2032, it is gradually phased in starting in year 10 and increased to the full amount in year 20 of the benefit period. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the model as committed capacity.

To incorporate Future 2A model-built and flex units, the additional EGEAS capacity expansion takes two steps. First, from the F2A expansion, model-built capacity is added as committed

resources, matching capacity, resource type, and timing from the F2A expansion. Next, F2A flex capacity is added, representing proxy resources of 29 GW committed capacity with annual energy output reflecting the maximum need assessed by PROMOD, four hours a day, 26 days per year.

Step 5 – Allocate ACC and CSRL benefits

With the built-in F2A resources, the revised reserve requirement yields an additional capacity expansion. The total capital costs for these additional resources represent cost savings over 20 years. The benefit of these avoided costs is ascribed to ACC and CSRL in proportion to their contribution to the total reserve requirement delta in 2042.

In the illustrative example, of the total reserve requirement delta in 2042 of 5.5%, ACC contributes 3.4% and CSRL contributes 2.1%. The proportion of ACC and CSRL in the total example reserve requirement delta is 62% and 38% respectively, so if the total additional costs were $10 billion, the calculation would realize an Avoided Capacity Cost benefit of $6.2 billion.

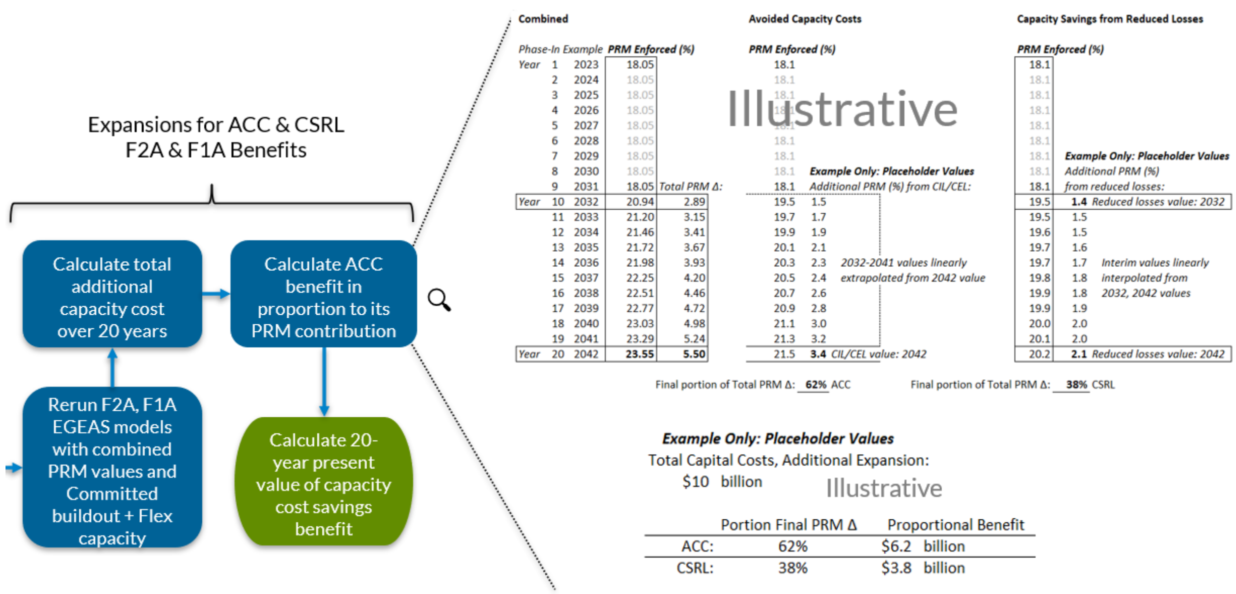


Figure 5 - Process for calculation of ACC benefit

4.2 Capacity Savings from Reduced Losses

The Capacity Savings from Reduced Losses benefit captures the impact of adding transmission capacity that reduces the effective impedance of the system and redistributes flows to decrease system losses. The adoption of more widely dispersed and remote resources in the future will cause power to flow extensively and over longer distances on the transmission network, producing significant power losses. These losses, occurring during the period with highest capacity

requirements, contribute to the need for additional capacity investment. In modeling system requirements for capacity expansion modeling, losses are included in the load forecast data and are held constant when evaluating avoided capacity cost benefits (i.e., the benefit metric does not account for the change in losses with and without LRTP transmission). Capacity Savings from Reduced Losses (CSRL) captures an incremental benefit where LRTP transmission reduces losses in the peak capacity period.

The methodology applied in the calculation of the Capacity Savings from Reduced Losses examines change in losses observed in the reliability power flow models that reflect the various seasonal loading conditions. These reliability power flow cases model both without-LRTP topology (higher losses) and with-LRTP topology (lower losses). The change in losses is calculated using the power flow models that correspond to the season with the peak capacity requirements that determine the capacity investment needed to meet Future F2A needs. For Future 2A expansion, the winter season was determined to have the highest capacity requirements.

The modeling of incremental losses in the EGEAS expansion will be reflected in a reserve requirement adjustment to introduce the additional requirements in the resource expansion. While reserve requirement itself is not a function of system losses, it simply serves as mechanism to capture the effects of losses by introducing additional requirements for capacity. Since the CSRL benefit occurs concurrently in a system with LRTP as the Avoided Capacity Cost (ACC) benefit, the reserve requirement deltas reflecting the impact of each are combined and added to the original Series 1A reserve requirement for incremental expansions to Future 2A and 1A. The incremental expansions quantify the value of both benefits in terms of the costs of additional resources beyond the original Future 2A and 1A expansions. The methodology described for combined reserve requirement, EGEAS expansion analysis, and benefit calculation are identical for both benefits.

Key Inputs/Model Assumptions

PSSE analysis software will be used to calculate losses in the reliability power flow models.

The 2042 summer peak, winter peak, average loading core power flow models[6] are used to estimate the seasonal variation in system losses.

Base cases for loss calculations use Future 2A 2032 winter peak and 2042 winter peak reliability power flow models without LRTP transmission.

Change cases for loss calculations use Future 2A 2032 winter peak and 2042 winter peak reliability power flow models with LRTP transmission facilities in service.

Base and change cases will also use Future 1A 2032 winter peak and 2042 winter peak reliability power flow models for establishing robustness of benefits in a lower bookend scenario.

[6] See details in Reliability Study Whitepaper

EGEAS capacity expansion software will be used to perform a supplemental resource expansion

Resource expansion models are based on the Future 2A scenario and include Future 1A scenario for evaluating the robustness of benefits. The methodology described in this section applies to evaluation of Future 1A as well as Future 2A.

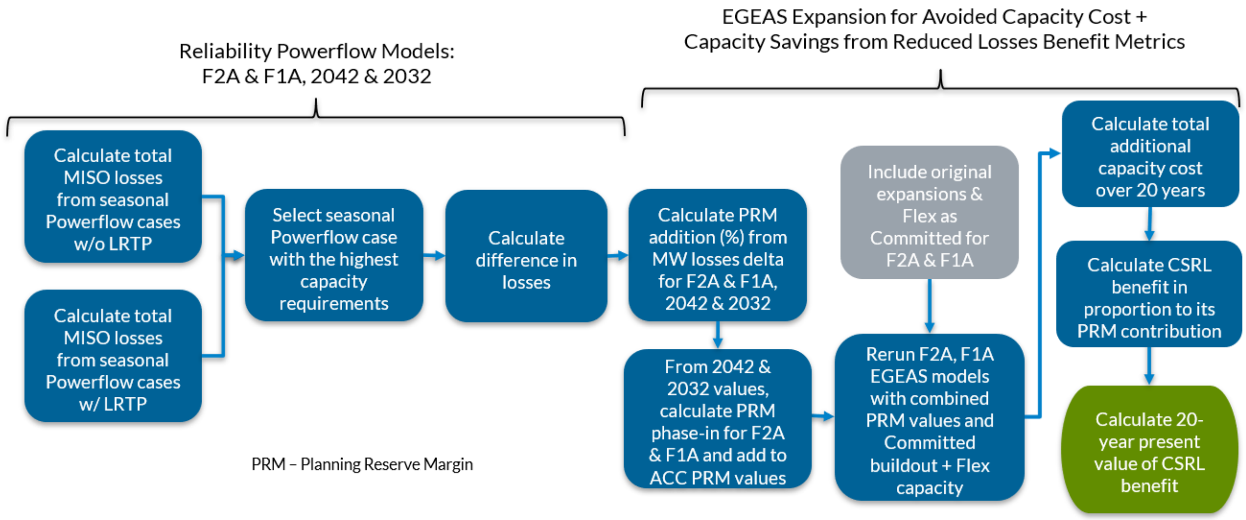


Figure 6 - Process for calculation of Capacity Savings from Reduced Losses benefits

Analysis Steps

Step 1 – Calculate CSRL reserve requirement bookend values from losses data

MISO Midwest system losses for the four core power flow cases (average load, light load, summer peak, and winter peak) are computed for both base case (without LRTP) and change case (with LRTP) topology for years 2032 and 2042. The period with peak season capacity requirements (from Futures capacity analysis) is selected as the season used to calculate losses.

For the selected case, the system losses (MISO Midwest) are computed for both base case (without LRTP) and change case (with LRTP) topology for year 2032 and the difference is calculated. The change in losses from the base case is established for year 2032, as a percentage of the case's total system load. For the selected season, the system losses (MISO Midwest) are then computed for both base case (without LRTP) and change case (with LRTP) topology for year 2042 and the difference is calculated. The change in losses from the base case is established for year 2042, as a percentage of the case's total system load.

F2A 2042 Illustrative Example

Illustrative

	Placeholder Values	Placeholder Values	Placeholder Values	Placeholder Values	Placeholder Values	Placeholder Values	Placeholder Values	Placeholder Values
Placeholder Values	**Avg Load 2042**		**Light Load 2042**		**Summer Peak 2042**		**Winter Peak 2042**	
System Scope		MISO Classic		MISO Classic		MISO Classic		MISO Classic
2042 PRM Delta		1.67%		2.00%		0.33%		1.00%
2042 Loss Reduction (MW)		1,000		900		300		900
Row Labels (MW)	without T2 proj **Losses Average Load 2042**	with T2 proj **Sum of v3_LOSSES_AVE42**	without T2 proj **Losses Light Load 2042**	with T2 proj **Sum of v3_LOSSES_LL42**	without T2 proj **Losses Summer Peak 2042**	with T2 proj **Sum of v3_LOSSES_SUM42**	without T2 proj **Losses Winter Peak 2042**	with T2 proj **Sum of v3_LOSSES_WIN42**
MISO CLASSIC	4,800	3,800	4,300	3,400	4,300	4,000	5,500	4,600
		RL, MISO Classic		RL, MISO Classic		RL, MISO Classic		RL, MISO Classic
Reduced Losses		1,000		900		300		900
	2042 AVG		2042 L-L		2042 SUM		2042 WIN	
Total Load by Model		MISO Classic (MW) **60,000**		MISO Classic (MW) **45,000**		MISO Classic (MW) **100,000**		MISO Classic (MW) **90,000**

Figure 7 - Example calculation of CSRL reserve requirement

Step 2 – Interpolate CSRL reserve requirement for intervening years

Using the 2032 and 2042 calculated loss percentages, a linear curve is created to reflect the increase in annual losses over the 2032-2042 period. The percentage of the total system load for reduced losses in 2032 and 2042 is expressed as additional reserve requirement for these years. The 2032 and 2042 values serve as bookends, which are interpolated to yield the additional CSRL reserve requirement for the intervening years (2033-2041). In this way, the increase in annual losses expressed as additional reserve requirement for the 2032-2042 period is represented.

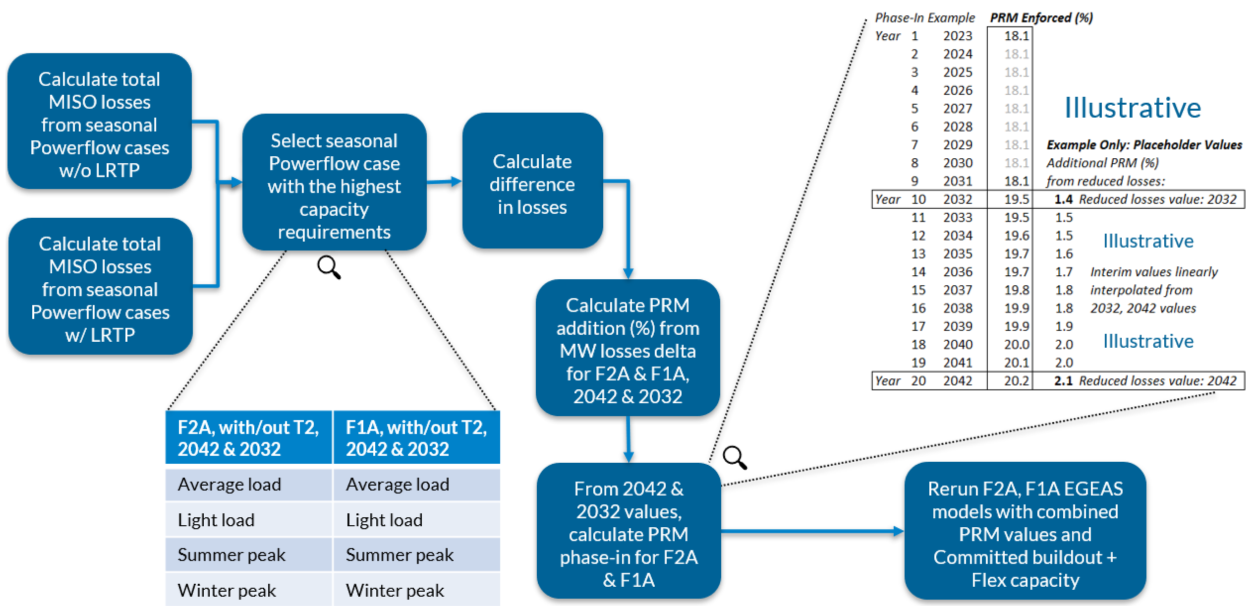


Figure 8 - Process for calculation of CSRL reserve requirement and benefits

Step 3 – Calculate combined reserve requirement for ACC + CSRL reserve requirement for EGEAS expansion analysis

As mentioned in the introduction to this benefit, the EGEAS capacity expansion utilizes one reserve requirement value to reflect concurrent ACC and CSRL benefits of LRTP. The reserve requirement deltas of ACC and CSRL are combined to obtain one total reserve requirement delta, which is added to the original Future 2A reserve requirement of 18.05%.[7] This methodology described in this step and following are identical for both ACC and CSRL benefits.

Illustrative

Combined

Phase-In Example			***PRM Enforced (%)***	
Year	1	2023	18.05	
	2	2024	18.05	
	3	2025	18.05	
	4	2026	18.05	
	5	2027	18.05	
	6	2028	18.05	
	7	2029	18.05	
	8	2030	18.05	
	9	2031	18.05	*Total PRM Δ:*
Year	10	2032	20.94	2.89
	11	2033	21.20	3.15
	12	2034	21.46	3.41
	13	2035	21.72	3.67
	14	2036	21.98	3.93
	15	2037	22.25	4.20
	16	2038	22.51	4.46
	17	2039	22.77	4.72
	18	2040	23.03	4.98
	19	2041	23.29	5.24
Year	20	2042	**23.55**	**5.50**

Avoided Capacity Costs

PRM Enforced (%)		
18.1		
18.1		
18.1		
18.1		
18.1		
18.1		
18.1		
18.1	***Example Only: Placeholder Values***	
18.1	*Additional PRM (%) from CIL/CEL:*	
19.5	1.5	
19.7	1.7	
19.9	1.9	
20.1	2.1	
20.3	2.3	*2032-2041 values linearly*
20.5	2.4	*extrapolated from 2042 value*
20.7	2.6	
20.9	2.8	
21.1	3.0	
21.3	3.2	
21.5	**3.4**	*CIL/CEL value: 2042*

Final portion of Total PRM Δ: **62%** ACC

Capacity Savings from Reduced Losses

PRM Enforced (%)		
18.1		
18.1		
18.1		
18.1		
18.1		
18.1		
18.1	***Example Only: Placeholder Values***	
18.1	*Additional PRM (%)*	
18.1	*from reduced losses:*	
19.5	**1.4**	*Reduced losses value: 2032*
19.5	1.5	
19.6	1.5	
19.7	1.6	
19.7	1.7	*Interim values linearly*
19.8	1.8	*interpolated from*
19.9	1.8	*2032, 2042 values*
19.9	1.9	
20.0	2.0	
20.1	2.0	
20.2	**2.1**	*Reduced losses value: 2042*

Final portion of Total PRM Δ: **38%** CSRL

Figure 9- Process for calculation of Combined ACC + CSRL reserve requirement and relative contributions

Step 4 – EGEAS expansion analysis

The EGEAS capacity expansion analysis applies the reserve requirement to reflect the additional capacity requirements to meet the resource adequacy needs. The base Future 2A resource expansion used seasonal data from the 2023-24 Planning Year reserve requirement Analysis to establish a reserve requirement value of 18.05%, applied throughout the study period.

For this benefit, an additional capacity expansion is performed using built-in capacity from the original F2A expansion, and a reserve requirement value that is adjusted to the new value established by results of the probabilistic analysis. Since the Future 2A scenario is based on copper sheet expansion, it reflects a less constrained system with the assumption that transmission expansion will occur. Thus, the change in reserve requirement will reflect an increase that occurs with a more constrained transmission system (i.e., transmission limitations reduce the availability of resources, driving the need for more installed capacity).

[7] See Series 1A Futures Report

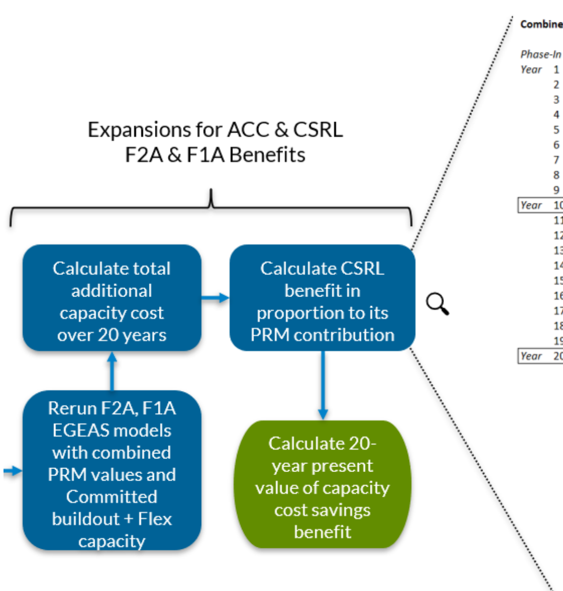
The reserve requirement delta is added to the base reserve requirement of 18.05% and applied in a new EGEAS run. Since the value is based on analysis of the 2042 study and reserve requirement is assumed constant until the LRTP portfolio is in service in 2032, it is gradually phased in starting in year 10 and increased to the full amount in year 20 of the benefit period. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the model as committed capacity.

To incorporate Future 2A model-built and flex units, the additional EGEAS capacity expansion takes two steps. First, from the F2A expansion, model-built capacity is added as committed resources, matching capacity, resource type, and timing from the F2A expansion. Next, F2A flex capacity is added, representing proxy resources of 29 GW committed capacity with annual energy output reflecting the maximum need assessed by PROMOD, four hours a day, 26 days per year.

Step 5 – Allocate ACC and CSRL benefits

With the built-in F2A resources, the revised reserve requirement yields an additional capacity expansion. The total capital costs for these additional resources represent cost savings over 20 years. The benefit of these avoided costs is ascribed to ACC and CSRL in proportion to their contribution to the total reserve requirement delta in 2042.

In the illustrative example, of the total reserve requirement delta in 2042 of 5.5%, ACC contributes 3.4% and CSRL contributes 2.1%. The proportion of ACC and CSRL in the total example reserve requirement delta is 62% and 38% respectively, so if the total additional costs were $10 billion, the calculation would realize a Capacity Savings from Reduced Losses benefit of $3.8 billion.



Year		Year	Combined PRM Enforced (%)	Total PRM Δ	ACC PRM Enforced (%)	Additional PRM (%) from CIL/CEL	CSRL PRM Enforced (%)	Additional PRM (%) from reduced losses
Year	1	2023	18.05		18.1		18.1	
	2	2024	18.05		18.1		18.1	
	3	2025	18.05		18.1		18.1	
	4	2026	18.05		18.1		18.1	
	5	2027	18.05		18.1		18.1	
	6	2028	18.05		18.1		18.1	
	7	2029	18.05		18.1		18.1	
	8	2030	18.05		18.1		18.1	
	9	2031	18.05		18.1		18.1	
Year	10	2032	20.94	2.89	19.5	1.5	19.5	1.4
	11	2033	21.20	3.15	19.7	1.7	19.5	1.5
	12	2034	21.46	3.41	19.9	1.9	19.6	1.5
	13	2035	21.72	3.67	20.1	2.1	19.7	1.6
	14	2036	21.98	3.93	20.3	2.3	19.7	1.7
	15	2037	22.25	4.20	20.5	2.4	19.8	1.8
	16	2038	22.51	4.46	20.7	2.6	19.9	1.8
	17	2039	22.77	4.72	20.9	2.8	19.9	1.9
	18	2040	23.03	4.98	21.1	3.0	20.0	2.0
	19	2041	23.29	5.24	21.3	3.2	20.1	2.0
Year	20	2042	**23.55**	**5.50**	21.5	**3.4**	20.2	**2.1**

Example Only: Placeholder Values

Total Capital Costs, Additional Expansion:

$10 billion

Illustrative

	Portion Final PRM Δ	Proportional Benefit
ACC:	62%	$6.2 billion
CSRL:	38%	$3.8 billion

Figure 10 – Process for calculation of Capacity Savings from Reduced Losses benefit

4.3 Congestion and Fuel Savings

The congestion and fuel savings reflect production cost savings that are achieved through a more economically efficient dispatch enabled by regional transmission, which reduces congestion and provides access to lower-cost generation. Production cost analysis uses hourly (8760) chronological security constrained unit commitment and economic dispatch, adhering to a wide variety of operating constrains and respecting N-1 contingency[8] conditions. Production cost savings calculations compare the reference case dispatch using a model without the LRTP transmission portfolio to a change case dispatch that incorporates the LRTP transmission portfolio. The addition of LRTP transmission decreases the loading (congestion) on the pre-existing network, alleviating several thermal constraints that would otherwise necessitate dispatch of higher-cost resources and facilitates access to lower-cost generation. The difference in production costs between the reference case and change case is thus captured as a benefit provided by the LRTP portfolio.

The Adjusted Production Cost[9] (APC) methodology employed by MISO is valuable to understand the economic efficiency of energy production and transmission across the system. It essentially measures the costs associated with serving load, but it considers the dynamic nature of energy transactions within MISO, such as buying and selling energy among companies.

When companies within MISO can dispatch lower-cost generation, purchase cheaper energy from within the system, or sell excess generation to neighboring companies, it results in a reduction of APC, which translates to APC Savings. This reduction can occur due to factors like reduced transmission congestion, which allows low-cost generation to be more freely dispatched.

MISO's production cost models do incorporate Production Tax Credits[10] (PTC) for applicable resources into the security constrained unit commitment and economic dispatch; however, the associated tax revenue received by the applicable resources are not reflected in the APC savings value shown for the transmission portfolio.

[8] November '23 LRTP Workshop Flowgate Identification Presentation
[9] MISO Adjusted Production Cost Calculation White Paper
[10] MISO Series 1A Futures Report - Inflation Reduction Act

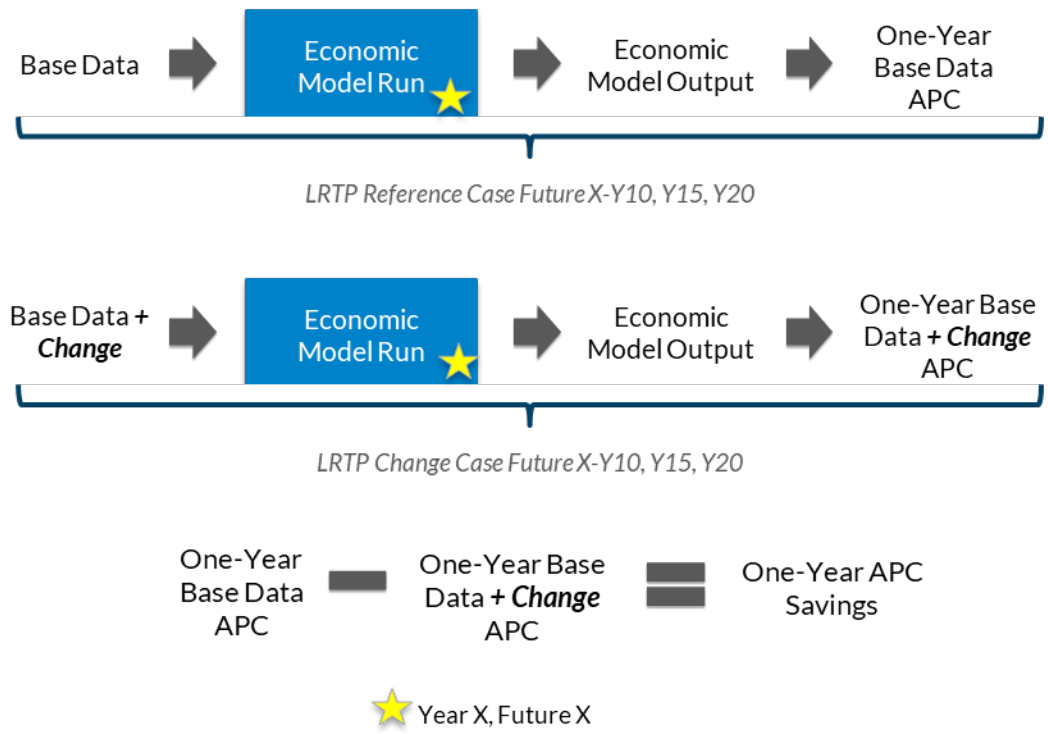


Figure 11 – Process for calculating adjusted production costs to assess Congestion and Fuel Savings benefit

Key Inputs/Model Assumptions

Promod production cost simulation software is used to evaluate the production cost savings attributed to LRTP.

The 2042 summer peak, winter peak, average loading core power flow models[11] are used to estimate the seasonal variation in system losses.

The reference case uses economic models that contain the available Future 2A resources in years 2032, 2037 and 2042 and network topology without LRTP transmission.

The change case uses economic models that contain the available Future 2A resources in years 2032, 2037, and 2042 and network topology with LRTP transmission.

Reference and change cases will also examine Future 1A resources in years 2032, 2037 and 2042 with and without LRTP transmission.

Analysis Steps

Step 1

> Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of adjusted production costs (by zone) without LRTP

[11] See details in [Reliability Study Whitepaper]

transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of adjusted production costs (by Cost Allocation Zone) with LRTP transmission for the three study years.

Step 2

For the three study years, the difference in adjusted production costs with and without LRTP transmission is calculated to produce an annual savings. These yearly values are then used to interpolate or extrapolate annual values for the remaining years within the benefit period.

Year	Depreciation Factor	Calculated APC savings	Annual APC Savings	PV Savings
2032	100.0%	Simulated Value	Simulated Value	$ PV Savings
2033	93.4%		Interpolated Value	$ PV Savings
2034	87.2%		Interpolated Value	$ PV Savings
2035	81.4%		Interpolated Value	$ PV Savings
2036	76.0%		Interpolated Value	$ PV Savings
2037	71.0%	Simulated Value	Simulated Value	$ PV Savings
2038	66.3%		Interpolated Value	$ PV Savings
2039	61.9%		Interpolated Value	$ PV Savings
2040	57.8%		Interpolated Value	$ PV Savings
2041	53.9%		Interpolated Value	$ PV Savings
2042	50.4%	Simulated Value	Simulated Value	$ PV Savings
2043 – 2069	...		Extrapolated Value	$ PV Savings

Figure 12 – Annual values of APC savings are interpolated from the year 10, 15 and 20 simulated values

			Reference Case APC	Change Case APC	Simulation APC Savings	APC Benefit Savings	PV Benefit Savings (2032 dollars)
Year	Depreciation Factor	Value Source	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest
2032	100.0%	**Simulated Value:**	**3,500,000,000**	**3,150,000,000**	**350,000,000**	**350,000,000**	**350,000,000**
2033	97.1%	Interpolated				367,000,000	356,310,680
2034	94.3%	Interpolated				384,000,000	361,956,829
2035	91.5%	Interpolated				401,000,000	366,971,805
2036	88.8%	Interpolated				418,000,000	371,387,586
2037	86.3%	**Simulated Value:**	**4,350,000,000**	**3,915,000,000**	**435,000,000**	**435,000,000**	**375,234,821**
2038	83.7%	Interpolated				448,000,000	375,192,947
2039	81.3%	Interpolated				461,000,000	374,835,187
2040	78.9%	Interpolated				474,000,000	374,179,977
2041	76.6%	Interpolated				487,000,000	373,244,949
2042	74.4%	**Simulated Value:**	**5,000,000,000**	**4,500,000,000**	**500,000,000**	**500,000,000**	**372,046,957**
2043	72.2%	Extrapolated				518,333,333	374,455,028
2044	70.1%	Extrapolated				533,333,333	374,069,269
2045	68.1%	Extrapolated				548,333,333	373,388,318
2046	66.1%	Extrapolated				563,333,333	372,429,697
2047	64.2%	Extrapolated				578,333,333	371,210,160
2048	62.3%	Extrapolated				593,333,333	369,745,717
2049	60.5%	Extrapolated				608,333,333	368,051,671
2050	58.7%	Extrapolated				623,333,333	366,142,639
2051	57.0%	Extrapolated				638,333,333	364,032,580
						20 Year Benefit Savings	7,384,886,819

Figure 13 – Example 20-year present value calculation of Congestion and Fuels Savings benefit

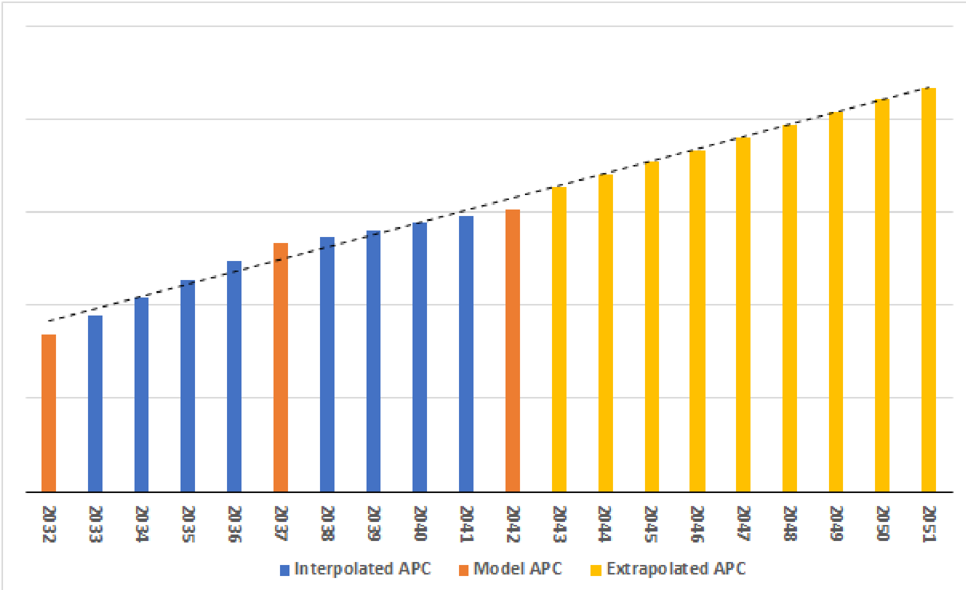


Figure 14 – Example chart of annual Congestion and Fuels Savings benefit over 20-year period

4.4 Energy Savings from Reduced Losses

Energy Savings from Reduced Losses captures the lower production costs that result from the addition of transmission facilities that reduces the overall system losses. Transmission losses that are produced by flow of power across the transmission network contribute to the energy requirements and increase the overall costs of energy to customers. As the resource fleet transitions to utilize more dispersed generation in remote areas of the footprint, losses increase with the more extensive use of the transmission network and transport of power over longer distances further increasing energy costs.

The addition of new transmission facilities provides additional transmission capacity and lowers the effective system impedance which will result in a decrease in real system losses. These real losses are modeled as constant values within the load profiles used in the standard production cost simulations. Thus, production cost savings generally do not capture the incremental benefits of reduced losses provided by the addition of new transmission elements. The production cost model case can be modified to reflect the reduction in losses, estimated from the power flow cases and applied to the demand in the change case which includes the new transmission. The Adjusted Production Costs (APC) savings can be calculated using a reference and change case model pair with base case losses in the reference case and the change case reflecting the estimated reduction in losses. The difference between those two APC values will be the APC savings from reduced losses resulting from the transmission expansion.

MISO's standard production cost models use a loss calculation mode in PROMOD called "single-pass" which assumes the inclusion of transmission losses in the demand profiles. This mode does not calculate or update the magnitude of loss energy during simulation. It only uses a linearization of the model topology to estimate the sensitivity of the model to losses for the purpose of identifying the LMP Loss component. Thus, to reflect a change in actual loss energy, the demand profiles themselves must be modified. There is a different loss calculation mode in PROMOD called "full losses" which updates and calculates losses based on model topology in each hour of the simulation. MISO has historically, and for this study, has chosen not to use this mode for two reasons. The first is that "full losses" requires significantly more processing time on top of an already multi-day processing timeline. Secondly, to establish an equivalent baseline model, transmission losses must be netted out of both the reference and change cases, which would require development of a complex new methodology to make the required adjustments. The method MISO has adopted is the more straight-forward to understand "single pass" method, which maintains consistency with the methodology used for baseline economic models.

Key Inputs/Model Assumptions

PROMOD production cost simulation software is used to evaluate the production cost savings from avoided loss energy attributed to LRTP transmission.

The 2042 summer peak, winter peak, average loading core power flow models are used to estimate the seasonal variation in system losses.

The reference case uses economic models that contain the available Future 2A resources in years 2032, 2037 and 2042 and network topology without LRTP transmission.

The change case uses economic models that contain the available Future 2A resources in years 2032, 2037, and 2042 and network topology with LRTP transmission.

A baseline set of reference and change case models, as described above, will be used to identify Adjusted Production Cost (APC) savings with standard fixed loss assumptions that are included in model loads and no loss value calculation.

A second set of reference and change case models will be used to calculate APC savings in the reduced-losses case. This pair will include the same reference cases as above, but with modified versions of the change case where loss energy reductions have been netted out of the modeled demand. That set of models will be used to identify APC savings when loss energy reductions are considered.

The APC savings due to reduced loss energy can be calculated from the increment in APC savings observed using the baseline change case and the APC savings observed using the loss energy reduction change case.

$$\begin{aligned} &APC\ Savings\ from\ Reduced\ Loss\ Energy \\ &\qquad = (Baseline\ Reference\ Case\ APC - Reduced\ Loss\ Energy\ Change\ Case\ APC) \\ &\qquad - (Baseline\ Reference\ Case\ APC - Baseline\ Change\ Case\ APC) \end{aligned}$$

Reference and change cases will also be developed with Future 1A resources in years 2032, 2037 and 2042 with and without LRTP transmission for establishing robustness of benefits in a lower bookend scenario.

Analysis Steps

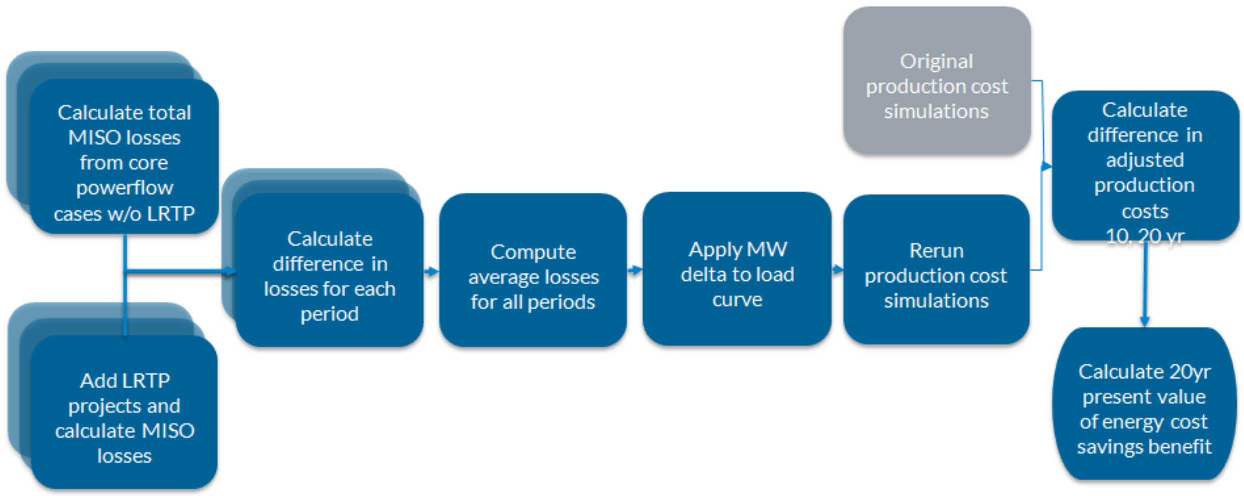


Figure 15 - Process for calculation of Energy Savings from Reduced Losses benefit

Step 1

The value of base case losses is computed by averaging the real system losses for the MISO Midwest subregion using the four core 2032 base case power flow models and the four core 2042 base case power flow models. The value of change case losses is computed by averaging the real system losses for the MISO Midwest subregion using the four core 2032 change case power flow models and the four core 2042 change case power flow models. The difference in losses are calculated with and without LRTP transmission for each of the four core models for years 2032 and 2042. The loss reduction values are averaged across all the core models for each of the years 2032 and 2042 and compared to the average demand in the MISO Midwest subregion in the PROMOD reference cases, to yield an average percentage of load to be used as a scaling factor. The percentage of load for 2037 is interpolated from the calculated values for years 2032 and 2042.

Step 2

Load profiles in change case economic models for 2032, 2037 and 2042 are scaled down using the loss reduction percentages to reflect the reduced loss component. Production cost simulations are run to produce annual values of APC (by Cost Allocation Zone) that account for the reduced losses with LRTP transmission included. The production cost simulations are repeated using the 2032, 2037 and 2042 reference case economic models to determine the annual values of adjusted production costs. The difference in APC between the change case containing the additional loss component and the reference case without the reduced losses provides the total APC savings when reduced loss energy is applied. The APC savings attributable to reduced loss energy can be found by netting out the APC savings from the baseline Reference and Change case (same as the value for the Congestion and Fuel Savings metric) from the APC savings from the reduced energy loss change case.

$$\begin{aligned} &APC\ Savings\ from\ Reduced\ Loss\ Energy \\ &\qquad = (Baseline\ Reference\ Case\ APC - Reduced\ Loss\ Energy\ Change\ Case\ APC) \\ &\qquad - (Baseline\ Reference\ Case\ APC - Baseline\ Change\ Case\ APC) \end{aligned}$$

Step 3

For the three study years (2032, 2037, and 2042), the annual production cost savings from reduced losses are used to interpolate or extrapolate annual values for the remaining years within the benefit period.

Year	Depreciation Factor	Calculated Net APC savings	Annual Net APC Savings	PV Savings
2032	100.0%	Simulated Value	Simulated Value	$PV Savings
2033	93.4%		Interpolated Value	$PV Savings
2034	87.2%		Interpolated Value	$PV Savings
2035	81.4%		Interpolated Value	$PV Savings
2036	76.0%		Interpolated Value	$PV Savings
2037	71.0%	Simulated Value	Simulated Value	$PV Savings
2038	66.3%		Interpolated Value	$PV Savings
2039	61.9%		Interpolated Value	$PV Savings
2040	57.8%		Interpolated Value	$PV Savings
2041	53.9%		Interpolated Value	$PV Savings
2042	50.4%	Simulated Value	Simulated Value	$PV Savings
2043 – 2069	…		Extrapolated Value	$PV Savings

Figure 16 - Annual values of APC savings for Energy Savings from Reduced Losses metric are interpolated from the year 10, 15 and 20 simulated values

			Baseline APC Savings	APC Savings w/ Reduced Losses	Energy Savings from Reduced Losses APC Savings	APC Benefit Savings	PV Benefit Savings (2032 dollars)
Year	Depreciation Factor	Value Source	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest
2032	100.0%	**Simulated Value:**	**350,000,000**	**385,000,000**	**35,000,000**	**35,000,000**	**35,000,000**
2033	97.1%	Interpolated				36,700,000	35,631,068
2034	94.3%	Interpolated				38,400,000	36,195,683
2035	91.5%	Interpolated				40,100,000	36,697,181
2036	88.8%	Interpolated				41,800,000	37,138,759
2037	86.3%	**Simulated Value:**	**435,000,000**	**478,500,000**	**43,500,000**	**43,500,000**	**37,523,482**
2038	83.7%	Interpolated				44,800,000	37,519,295
2039	81.3%	Interpolated				46,100,000	37,483,519
2040	78.9%	Interpolated				47,400,000	37,417,998
2041	76.6%	Interpolated				48,700,000	37,324,495
2042	74.4%	**Simulated Value:**	**500,000,000**	**550,000,000**	**50,000,000**	**50,000,000**	**37,204,696**
2043	72.2%	Extrapolated				51,833,333	37,445,503
2044	70.1%	Extrapolated				53,333,333	37,406,927
2045	68.1%	Extrapolated				54,833,333	37,338,832
2046	66.1%	Extrapolated				56,333,333	37,242,970
2047	64.2%	Extrapolated				57,833,333	37,121,016
2048	62.3%	Extrapolated				59,333,333	36,974,572
2049	60.5%	Extrapolated				60,833,333	36,805,167
2050	58.7%	Extrapolated				62,333,333	36,614,264
2051	57.0%	Extrapolated				63,833,333	36,403,258
						20 Year Benefit Savings	738,488,682

Figure 17 - Example 20-year present value calculation of Energy Savings from Reduced Losses benefit

4.5 Reduced Transmission Outage Costs

Reduced Transmission Outage Costs captures incremental savings that more fully reflect the effects of congestion under actual operating conditions. Congestion and fuel savings benefits apply conservative modeling of system conditions that reflect an intact transmission network. Throughout the year there are typically numerous planned and forced transmission outages that occur with varying degrees of overlap. These facility outages remove available transmission capacity from the system, increase the loading on remaining in-service facilities, and contribute to congestion. The addition of LRTP transmission unlocks additional value by relieving the additional congestion attributed to typical planned and forced outage schedules.

Analysis of outage impacts requires running multiple production cost runs that capture the effects of varying outage patterns. To synthesize sets of planned and forced equipment outages that are used in the calculation of impacts, the methodology relies on historical outage data rather than predictive analytics and uses probabilities of outage classes rather than actual historical outage schedules. These outage sets include modeled transmission lines and transformers of different voltage classes and uses historical outage rates to randomly select outages to be included. Forced outages are generated by performing 365 random draws of outages with daily duration., Planned outages are generated by performing 12 random draws of outages with monthly duration. These outage events are compiled to represent generic outage schedules over the course of a year. This process is repeated to create several outage profiles that are used in production cost simulations to develop an average APC savings value that captures "typical" outage impacts.

Key Inputs/Model Assumptions

Outage statistics are derived from a facility outage dataset used in a [2019 MISO study] to examine how modeling assumptions for generation and transmission outages impact long term reliability needs assessments.

PROMOD production cost simulation software is used to evaluate the production cost savings attributed to LRTP transmission.

The reference case uses economic models that contain the available Future 2A resources in years 2032, 2037 and 2042 and network topology without LRTP transmission.

The change case uses economic models that contain the available Future 2A resources in years 2032, 2037, and 2042 and network topology with LRTP transmission.

Reference and change cases will also be developed with Future 1A resources in years 2032, 2037 and 2042 with and without LRTP transmission for establishing robustness of benefits in a lower bookend scenario.

Analysis Steps

Step 1

Outage probabilities are calculated using an outage dataset compiled by MISO in 2019. This outage data was previously used to examine outage impacts on the annual MTEP studies and reflect 5 years of Control Room Outage Window (CROW)[12] outage records from years 2014-2019. Modeled transmission branches and transformers are tabulated and assigned outage probabilities based on the outage type, equipment type, and voltage class. A random draw is performed for each of the 365 days of the year to establish the facilities expected to be forced out of service for that day resulting in an annual profile of generic outages that are to be reflected in the production cost model. Similarly, a random draw is performed for each of the 12 months of the year to establish the facilities expected to be forced out of service for that month resulting in an annual profile of generic outages that are to be reflected in the production cost model. The annual profile is repeatedly generated to yield 10 possible sets of outages.

Step 2

Each outage set is applied to the reference case and production cost simulations are executed using the 2032, 2037 and 2042 reference case economic models and to produce annual values of APC (by Cost Allocation Zone) without LRTP transmission for the three study years. The outage schedules are applied to the change case and production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of APC (by Cost Allocation Zone) with LRTP transmission for the three study years. The production cost analyses are performed for each of the 10 sets of outages and the average annual production cost savings

[12] CROW is the outage schedule management system used by MISO operations for coordination of facility outages.

Step 3

For each of the three study years (2032, 2037, and 2042), the difference in APC with and without LRTP is calculated to produce an annual savings that captures the effects of the randomized sets of planned and forced outages. For each of the three study years, the production cost savings are averaged across the 10 outage simulation runs to reflect annual savings for a typical year of outages.

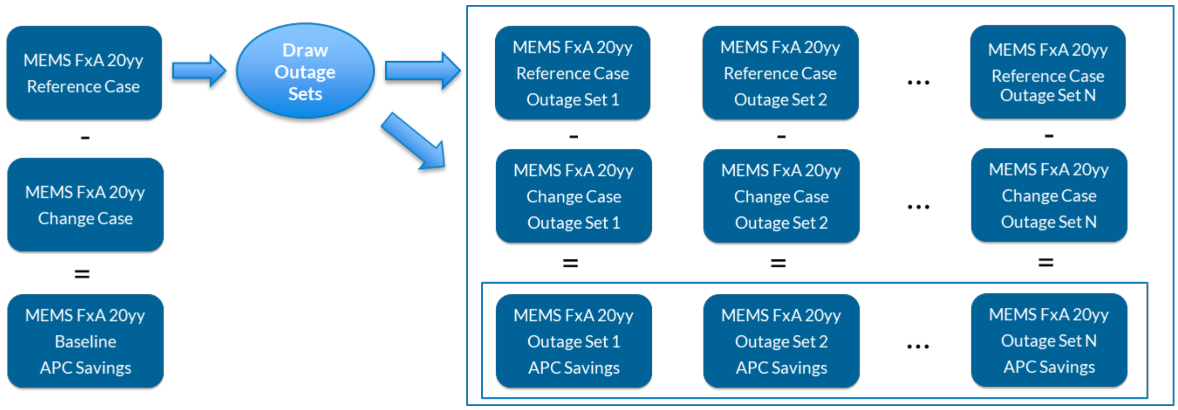


Figure 18 – Process for calculation of Reduced Transmission Outage Costs benefit

Step 4

For each of the three study years the base APC from the congestion and fuel savings benefit calculations is subtracted from the value of annual production costs calculated with the outage impacts to produce an incremental value of production cost savings attributed to the effects of planned and forced transmission outages.

$$Reduced\ Transmission\ Outage\ Costs = \frac{\sum_n Outage\ Set\ n\ APC\ Savings}{N} - Baseline\ APC\ Savings$$

Step 5

For the three study years (2032, 2037, and 2042), the annual production cost savings from outage impacts are used to interpolate or extrapolate annual values for the remaining years within the benefit period.

Year	Depreciation Factor	Calculated Net APC savings	Annual Net APC Savings	PV Savings
2032	100.0%	Simulated Value	Simulated Value	$PV Savings

2033	93.4%		Interpolated Value	$PV Savings
2034	87.2%		Interpolated Value	$PV Savings
2035	81.4%		Interpolated Value	$PV Savings
2036	76.0%		Interpolated Value	$PV Savings
2037	71.0%	Simulated Value	Simulated Value	$PV Savings
2038	66.3%		Interpolated Value	$PV Savings
2039	61.9%		Interpolated Value	$PV Savings
2040	57.8%		Interpolated Value	$PV Savings
2041	53.9%		Interpolated Value	$PV Savings
2042	50.4%	Simulated Value	Simulated Value	$PV Savings
2043 – 2069	...		Extrapolated Values	$PV Savings

Figure 19 - Annual values of APC savings for Reduced Transmission Outage Costs metric are interpolated from the year 10, 15 and 20 simulated values

			Baseline APC Savings	Average APC Savings w/	Reduced Transmission Outage Costs APC Savings	APC Benefit Savings	PV Benefit Savings (2032 dollars)
Year	Depreciation Factor	Value Source	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest	MISO Midwest
2032	100.0%	**Simulated Value:**	**350,000,000**	**385,000,000**	**35,000,000**	**35,000,000**	**35,000,000**
2033	97.1%	Interpolated				36,700,000	35,631,068
2034	94.3%	Interpolated				38,400,000	36,195,683
2035	91.5%	Interpolated				40,100,000	36,697,181
2036	88.8%	Interpolated				41,800,000	37,138,759
2037	86.3%	**Simulated Value:**	**435,000,000**	**478,500,000**	**43,500,000**	**43,500,000**	**37,523,482**
2038	83.7%	Interpolated				44,800,000	37,519,295
2039	81.3%	Interpolated				46,100,000	37,483,519
2040	78.9%	Interpolated				47,400,000	37,417,998
2041	76.6%	Interpolated				48,700,000	37,324,495
2042	74.4%	**Simulated Value:**	**500,000,000**	**550,000,000**	**50,000,000**	**50,000,000**	**37,204,696**
2043	72.2%	Extrapolated				51,833,333	37,445,503
2044	70.1%	Extrapolated				53,333,333	37,406,927
2045	68.1%	Extrapolated				54,833,333	37,338,832
2046	66.1%	Extrapolated				56,333,333	37,242,970
2047	64.2%	Extrapolated				57,833,333	37,121,016
2048	62.3%	Extrapolated				59,333,333	36,974,572
2049	60.5%	Extrapolated				60,833,333	36,805,167
2050	58.7%	Extrapolated				62,333,333	36,614,264
2051	57.0%	Extrapolated				63,833,333	36,403,258
						20 Year Benefit Savings	738,488,682

Figure 20 - Example 20-year present value calculation of Reduced Transmission Outage Costs benefit

4.6 Reduced Risks from Extreme Weather Impacts

Reduced risks from extreme weather impacts reflects the value of reducing the risk of unserved energy during periods of expected supply deficiency attributed to extreme weather conditions. The growing penetration of renewable resources, in combination with correlated outages in thermal resources and higher than expected load levels, will increase the risk of supply disruptions due to extreme weather and resulting in more unserved energy. Reduced risks from extreme weather impacts use probabilistic analysis to examine the amount of expected unserved energy observed in the worst intervals. Limited transmission capacity restricts access to resources that are needed to cover capacity shortfalls that can result in greater unserved energy. Transmission

expansion increases transfer capability to expand capacity deliverability that reduces the amount of unserved energy.

The Reduced Risks from Extreme Weather Impacts metric applies familiar probabilistic methods used for resource adequacy assessment but focuses on the tails of the risk distribution (i.e. intervals with the highest Expected Unserved Energy [EUE]). This analysis of conditional value at risk (CVaR) recognizes the reliability benefits of transmission investment that must be planned and built to address more extreme risks in a future with high levels of uncertainty and variability in the generation resources. A threshold for CVar is used to calculate benefits of transmission based on the distribution of extreme unserved energy events seen in the results. The methodology incorporates zonal transmission constraints based on CIL/CEL analysis, similar to the ACC methodology, and assesses hourly loss of load risk over a sample set that includes 14 years of weather data. The expected unserved energy metric is used to capture both the duration and magnitude of the loss of load events as a measure of the benefit. The addition of LRTP transmission increases CIL/CEL and delivers benefits by reducing EUE for the top 20 percent of EUE hours which is monetized using the Value of Lost Load (VOLL).

Key Inputs/Model Assumptions

TARA is the analysis software used to perform Capacity Import Limit (CIL)/Capacity Export Limit (CEL) studies (transfer limit studies).

The 2042 summer peak, winter peak, average loading core power flow models[13] are used to reflect the seasonal variation in CIL/CEL.

Base cases used for transfer limit analysis apply the Future 2A 2042 summer peak, winter peak, average loading reliability power flow models without LRTP transmission.

Change cases apply the Future 2A 2042 summer peak, winter peak, average loading reliability power flow models with LRTP transmission facilities in service.

Base and change cases will also be built from the Future 1A 2042 summer peak, winter peak, and average loading reliability power flow models for establishing robustness of benefits in a lower bookend scenario.

Plexos is the software used to perform the probabilistic loss of load expectation (LOLE) analysis.

Plexos models are based on Future 2A scenario resources and include Future 1A scenario.

Probabilistic analysis includes evaluation of 14 weather years (2007-21) for load and renewable generation profiles.

Hourly simulations with 200+ samples to reflect probabilities of thermal forced outages.

[13] See details in Reliability Study Whitepaper

Analysis Steps

Step 1 – Capacity Import Limit (CIL)/Capacity Export Limit (CEL) analysis (similar to the Avoided Capacity Cost metric)

CIL/CEL analysis is based on transfer capability study that uses linear power flow methods to evaluate how much power can be transported on the transmission network before a transmission limit is reached. The transfers are simulated as shifts in power between defined source/sink subsystems. CIL/CEL specifically examines the limits to transfers into and out of the Local Resource Zones from participating resources.

CIL/CEL transfer capability analysis is performed on 2042 summer peak, winter peak, average peak base cases without LRTP transmission. Transfers are simulated for import and exports for LRZ 1-7 and generation redispatch is applied to determine valid limiting constraints and establish the base case CIL and CEL values for each zone LRZ 1-7 for each season.

Transfer capability analysis is then repeated on the 2042 summer peak, winter peak, average loading base cases with LRTP transmission using the same approach to establish the valid CIL/CEL values for LRZ 1-7 for each season. These CIL/CEL values are expected to be higher since the addition of LRTP transmission will increase transfer capability.

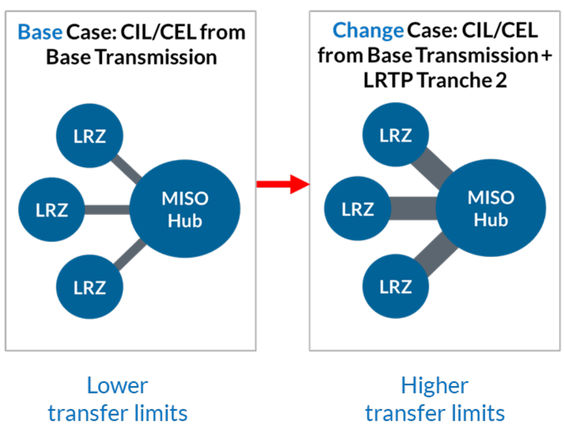


Figure 11 - Additional transmission capacity improves transfer capability to increase zonal import/export limits

Step 2 - LOLE/reserve requirement analysis

Probabilistic analysis is used to assess availability of resources and calculate the hourly unserved energy using 14 years of weather data. The intervals with highest Expected Unserved Energy (EUE), including voluntary load shedding, are selected and the hours of unserved energy in those intervals are summed to quantify the benefit. The financial value,

which will be applied from year 10, when LRTP transmission is enabled in the planning horizon, and be adjusted based on the CVaR target[14], is calculated by the following equation:

$$\text{Economic Value} = \left(\sum_{n=1}^{H} EUE\right) * VOLL$$

Where

EUE is Expected Unserved Energy (MW) in hour n

H is total hourly intervals

VOLL is the Value of Lost Load ($3,500 - $10,000MW/hr)

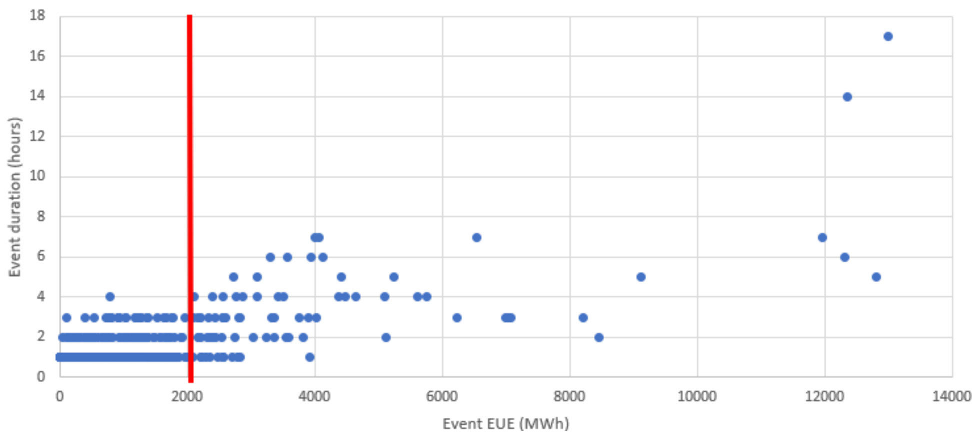


Figure 12 - Analysis of expected unserved energy focuses on the “tails” of the event distribution

For example, a CVaR(80) threshold can be chosen based on the distribution of loss of load events and the cluster of events that are considered "tails" or "outliers", as illustrated in the above figure. The CVaR(80) represents the 20% “worst” events from an energy perspective and these are characterized by more than 2,000 MWh of energy unserved and 4-hour durations.

[14] For a CVaR(80), the benefit is applied to year 0, 5, 10, 15, 20 in the 20-yr NPV calculation.

Example Calculation (Illustrative)			VOLL=$3,500/MWh		VOLL=$10,000/MWh	
Period	Year		EventMW*VOLL	Present Value (low)	EventMW*VOLL	Present Value (high)
0	2032		$54,678,267	$54,678,267	$156,223,620	$156,223,620
1	2033			$0		$0
2	2034			$0		$0
3	2035			$0		$0
4	2036			$0		$0
5	2037		$61,863,440	$43,902,243	$176,752,686	$125,434,981
6	2038			$0		$0
7	2039			$0		$0
8	2040			$0		$0
9	2041			$0		$0
10	2042		$69,992,804	$35,249,965	$199,979,441	$100,714,185
11	2043			$0		$0
12	2044			$0		$0
13	2045			$0		$0
14	2046			$0		$0
15	2047		$79,190,434	$28,302,882	$226,258,382	$80,865,377
16	2048			$0		$0
17	2049			$0		$0
18	2050			$0		$0
19	2051			$0		$0
Total 20yr PV (2032$)				**$162,133,357**		**$463,238,162**

Figure 23 - Example 20-year present value calculation of Reduced Risk from Extreme Weather Impacts benefit

4.7 Decarbonization

Decarbonization benefits relate to avoided CO_2 emissions that result from the more efficient dispatch of lower-cost resources. Production cost simulations are used to economically dispatch resources with respect to availability and subject to transmission constraints and establish the hourly dispatch of resources over 8760 annual hours. The dispatch of lower-cost, non-emitting renewable resources avoids CO_2 emissions for the generation fleet. As transmission congestion occurs on the system, dispatchable, carbon-emitting resources are needed to manage system flows and can displace the carbon-free renewable energy, leading to higher levels of CO_2 emissions. The addition of LRTP transmission alleviates congestion, allowing dispatch of more renewable energy that provides benefits through avoided carbon emissions.

Analysis of decarbonization relies on the emissions data produced by the Adjusted Production Cost (APC) analysis used for the base Congestion and Fuel Savings benefit metric.

Key Inputs/Model Assumptions

PROMOD production cost simulation software is used to evaluate the production cost savings attributed to LRTP.

The reference case uses economic models that contain the available Future 2A resources in years 2032, 2037, and 2042 and network topology without LRTP transmission.

The change case uses economic models that contain the available Future 2A resources in years 2032, 2037, and 2042 and network topology with LRTP transmission.

The difference in CO_2 emissions between the change and reference cases in years 2032, 2037, and 2042 quantifies the avoided carbon emissions inputs for this benefit.

Reference and change cases will also be built for Future 1A resources in years 2032, 2037, and 2042 with and without LRTP transmission for establishing robustness of benefits in a lower bookend scenario. The methodology described in this section applies to evaluation of Future 1A as well as Future 2A.

In addition to the avoided CO_2 emissions, the other key inputs are the prices MISO uses to calculate this benefit. Updating inputs from Tranche 1, this benefit considers updated values for Minnesota Public Utility Commission requirements,[15] as well as new federal values related to the Social Cost of Carbon[16] and the 45Q tax credit. As part of the Inflation Reduction Act, the 45Q tax credit[17] for carbon sequestration increased to $85. This value establishes the Federal price, the lower value in the range for this benefit.

2022 Minnesota legislation requires the Public Utility Commission to consider the values from the final EPA Report on the Social Cost of Greenhouse Gases from 2023 in its evaluation and selection of resource options in all proceedings, including resource plans and certificates of need. This value of $249/metric ton establishes the MN PUC price, the higher value in the range for this benefit.

Analysis Steps

Step 1

Production cost simulations are run using the 2032, 2037, and 2042 reference case economic models and to produce annual values of CO_2 emissions (by Cost Allocation Zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of CO_2 emissions costs (by Cost Allocation Zone) with LRTP transmission for the three study years.

Step 2

For the three study years (2032, 2037, and 2042), the difference in CO_2 emissions with and without LRTP is calculated to produce an annual reduction in CO_2 emissions. These yearly values are then used to interpolate or extrapolate annual values for the remaining years within the benefit period.

The values for the interim years between 2032, 2037, and 2042 are interpolated by taking the difference between those simulated values and distributing among the number of interim years. Since PROMOD reports emissions data in short tons, the study year and interpolated values are multiplied by 0.91 to convert to metric tons.

The post-2042 annual values are extrapolated by taking the last year-over-year difference (YOY Δ) as a percentage, and the last year's rate of change as a percentage. The last year's rate of change

[15] https://www.revisor.mn.gov/bills/text.php?number=SF4&version=latest&session=ls93&session_year=2023&session_number=0
[16] https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf
[17] https://sgp.fas.org/crs/misc/IF11455.pdf

in avoided emissions as a percentage is held constant, and repeats throughout the extrapolated period. An illustrative example is provided below.

Example Only: Placeholder Values				0.907185		
Study Year	Tons CO_2 Avoided	T2	Tons CO_2 Avoided	Metric Tons CO_2 Avoided	YOY Δ	YOY Rate Δ
2032	10,000,000	2032	10,000,000.00	9,071,847.00		
2037	7,000,000	2033	9,400,000.00	8,527,536.18	-6.00%	
2042	6,000,000	2034	8,800,000.00	7,983,225.36	-6.38%	0.38%
		2035	8,200,000.00	7,438,914.54	-6.82%	0.44%
		2036	7,600,000.00	6,894,603.72	-7.32%	0.50%
		2037	7,000,000.00	6,350,292.90	-7.89%	0.58%
Illustrative		2038	6,800,000.00	6,168,855.96	-2.86%	-5.04%
		2039	6,600,000.00	5,987,419.02	-2.94%	0.08%
		2040	6,400,000.00	5,805,982.08	-3.03%	0.09%
		2041	6,200,000.00	5,624,545.14	-3.13%	0.09%
Example Only: Placeholder Values		2042	6,000,000.00	5,443,108.20	-3.23%	0.10%
		2043		5,262,037	-3.33%	0.10%
		2044		5,081,685	-3.43%	0.10%
		2045		4,902,392	-3.53%	0.10%
		2046	Illustrative	4,724,482	-3.63%	0.10%
		2047		4,548,267	-3.73%	0.10%
		2048		4,374,039	-3.83%	0.10%
		2049		4,202,076	-3.93%	0.10%
		2050		4,032,637	-4.03%	0.10%
		2051		3,865,966	-4.13%	0.10%
	Y20	2052		3,702,286	-4.23%	0.10%
		2053		3,541,803	-4.33%	0.10%
		2054		3,384,707	-4.44%	0.10%
		2055	Illustrative	3,231,167	-4.54%	0.10%
		2070		1,417,749	-6.05%	0.10%
		2071		1,330,569	-6.15%	0.10%
	Y40	2072		1,247,408	-6.25%	0.10%

Figure 24 – Example calculation of carbon emissions interpolated from the year 10, 15 and 20 production cost simulations.

Step 3

The annual CO_2 emissions reductions are then monetized by applying carbon prices. For the LRTP Tranche 2 benefits analysis these values are established by two sources. The high-end value is established by the state of Minnesota legislation referencing the federal Social Cost of Carbon defined by EPA's 2023 final technical report, while the low-end value is determined by the 45Q federal tax credit.

	Federal	**MN PUC**
2024$/metric ton	$85	$248.67

Figure 25 – Decarbonization benefit uses Federal and Minnesota PUC carbon costs to provide a range of value.

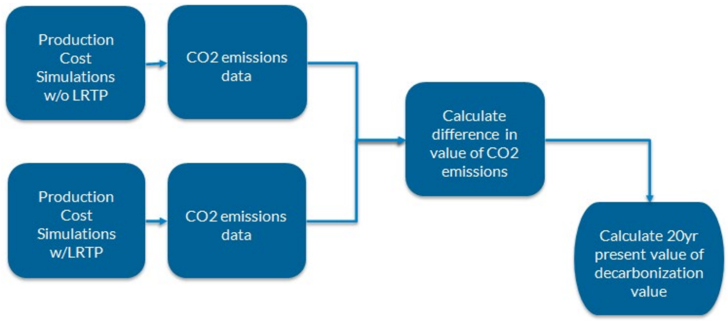


Figure 26 - Process for calculation of Decarbonization benefit

4.8 Avoided Transmission Investment

Avoided transmission investment is the capital cost savings that comes from elimination of age and condition replacement projects that would not be needed because of shared right-of-way with LRTP projects. The construction of LRTP projects along the same route as the existing facilities would require installation of new structures and hardware to support both the new circuit as well as the existing circuit and eliminates the need to replace the aging facility later resulting in avoided costs. The LRTP project scoping will identify opportunities to co-locate the new projects along the routes of existing facilities. These selections are then evaluated for replacement cost except where Transmission Owners have determined that the facilities are ineligible for age and condition replacement due to recent construction or rebuild. Costs are estimated using high level cost estimates derived from the current MISO Transmission Cost Estimation Guide.

Key Inputs/Model Assumptions

Both the reference case and change case contain the same future resources and assumptions of load and dispatch.

Final portfolio is developed after LRTP projects are identified through reliability and economic analysis of performance with and without the LRTP facilities using base case and change cases developed for Future 2A 2032 and 2042 summer peak, winter peak, average loading and light loading conditions.

Final portfolio is evaluated with Future 1A 2032 and 2042 summer peak, winter peak, average loading and light load conditions for establishing robustness of benefits in a lower bookend scenario.

Analysis Steps

Step 1

1. Evaluate LRTP project requirements and potential use of existing right-of-way. Detailed facility scoping will be performed to determine details of line configuration needed for cost estimation
2. Existing facilities that reside in path of LRTP project will be identified and line mileage estimates compiled.
3. Facility scoping calls will be conducted with Transmission Owners to verify feasibility of reusing existing right-of-way, verify existing line details, and to determine if an exclusions should apply for age and condition projects due to recent upgrades.

Example Calculation (illustrative)			
Facility Name	**Location (CAZ)**	**KV**	**Quantity/Miles**
Station A –Station B	1	345kV	85
Station C –Station D	2	161kV	54
Station E –Station F	3	138kV	47

Figure 27 - Example tabulation of line mileage for facilities with co-located LRTP projects.

4. High level cost estimates will be applied to the remaining age and condition replacement facilities using line mileage and rebuild costs to quantify the costs for transmission investment that would be avoided by the LRTP portfolio.

Example Calculation (illustrative)			
Facility Improvement Type	**Unit Cost($M)**	**Quantity/Miles**	**Cost ($M)**
Transmission line Replacement =345kV (per mile)	$3.20	85	$272.00
Transmission line Replacement <345kV (per mile)	$1.90	101	$191.90
Transmission double-ckt line Replacement (per mile)	$2.60	0	
		Total	**$463.90**

Figure 28- Example calculation of replacement costs for Avoided Transmission Investment benefit.

Replacement projects are assumed to be needed prior to the end of the 20 year LRTP study period and capital costs occur in five annual installments prior to the assumed 2042 in-service date.

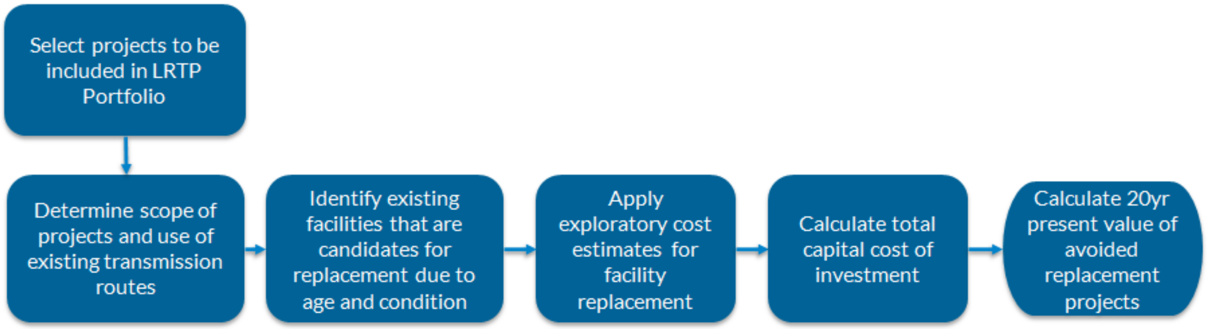


Figure 29- Process for estimating costs for Avoided Transmission Investment benefit.

Example Calculation (illustrative)			
year	New Investment ($M)	Nominal Annual Cost ($M	PV Annual Cost
2032	...	...	...
...	...	...	...
2038	$131.10	$18.16	$12.03
2039	$131.10	$36.05	$22.31
2040	$131.10	$53.67	$31.00
2041	$131.10	$71.02	$38.31
2042	$131.10	$88.09	$44.37
2043	0	$86.73	$40.79
...	...	...	...
2051	0	$75.87	$20.61
20 year present value			**$415.67**

Figure 30 - Example 20-year PV calculation of Avoided Transmission Investment benefit.

4.9 Mitigation of Reliability Issues

The mitigation of reliability issues benefit metric reflects the value that results from alleviating thermal/voltage/stability issues that present a risk of unserved load. These reliability issues are identified through the reliability studies performed to assess system performance with respect to the industry standards and planning criteria of our members. These studies apply deterministic analysis to assess need for transmission reinforcements and to evaluate the most effective regional transmission solutions. The remediation of issues by LRTP projects represents value provided by the transmission investment that can be financially quantified. The method for quantifying the benefit focuses on the thermal/voltage violations found in the analysis that are

alleviated by LRTP transmission and identifies the amount of residual risk of load shedding after applying other available mitigation measures. Where redispatch does not eliminate the violations, there is a remaining risk of unserved load without LRTP portfolio which must be resolved to meet planning requirements. The amount of unserved load can be quantified by analyzing the load curtailment needed to return the equipment within applicable limits. Thus load shedding is used as a measure of reliability risk rather than an operating action to resolve issues. The difference in load curtailment determined with and without the LRTP transmission is captured as the reliability benefit included in the business case.

Key Inputs/Model Assumptions

Annual renewable resource availability from Futures dataset (Zones 1-7) for years 2032 and 2042 are used to establish dispatch limitations based on available renewable resource capacity and hours.

TARA analysis software will be used to calculate benefits of mitigation of reliability issues.

The 2032 and 2042 summer peak, winter peak, average loading, and light load core power flow models[18] are used to perform redispatch and load shedding analysis for the benefit calculations.

Base cases use the Future 2A 2032 and 2042 summer peak, winter peak, average loading and light load reliability power flow models without LRTP transmission.

Change cases use the Future 2A 2032 and 2042 summer peak, winter peak, average loading and light load reliability power flow models with LRTP transmission facilities in service.

Base and change cases will also be built from the Future 1A 2032 and 2042 summer peak, winter peak, average loading and light load reliability power flow models for establishing robustness of benefits in a lower bookend scenario.

TARA setup – generation/load redispatch rules/limits

TARA software is used to perform redispatch to first mitigate loading issues to the extent possible and then perform load shedding to eliminate any residual overload. A two-pass process is intended 1) to ensure that load shedding for NERC Category P1, P2 and P7 contingencies is only applied after adjusting for the range of renewable availability in the hours represented by the study models and 2) to eliminate possible overlapping of benefit with adjusted production cost analysis that optimizes generation dispatch to manage transmission congestion and minimizes production costs which are used to capture congestion and fuel savings benefits.

Reliability redispatch monitors BES facilities in the MISO Midwest subregion as well as tie lines to adjacent entities and examines branch loading for system intact (N-0) conditions at normal limits and safe loading limits and contingency (N-1, N-2) conditions at emergency limits.

[18] See details in Reliability Study Whitepaper

Contingencies evaluated in constraint monitoring include planning events developed with members for the MTEP22 model topology as shown below :

NERC Category P1, P2, P7	included
NERC Category P3, P4, P5, P6	not included

Analysis of benefits from mitigation of reliability issues uses the reliability study models that typify a practical set of conditions to sufficiently analyze and identify potential reliability concerns. Study cases that are used to assess reliability performance and identify reliability issues are further analyzed to establish value of mitigating reliability issues and include at a minimum the four core study models for 2032 and 2042 as well as other study cases used for reliability analysis. Each study case is derived from a core model that is representative of a number of hours of the year that reflect a range of load and generation dispatch patterns (see LRTP Tranche 2 Reliability Study Whitepaper). Renewable dispatch for each core study model is set to a fixed level that is determined by a range of renewable availability that occurs in a typical planning year.

The calculation of benefits applies generation dispatch parameters that provide some flexibility in dispatch of renewable resources for hours where availability exceeds the modeled dispatch level where the amount to available dispatch is determined average headroom for those hours. For the remaining hours, renewable resources are limited to allow down-only redispatch. Thus two generation dispatch scenarios are evaluated for each of the study cases. Generation redispatch rules are applied to resources by type as indicated in table below.

Where additional study cases are used to identify reliability violations, the core model from which the study case is derived will be used to determine applicable hours represented by the adjusted dispatch of the study case. The applicable hours of the core study model will be reduced accordingly.

Generation Dispatch Rules		
Resource Type	**Generation Dispatch Scenario**	
	Renewable Availability > Model Dispatch	**Renewable Availability < Model Dispatch**
Thermal	P1:Up/Down, P2/P7:Fixed	P1:Up/Down, P2/P7:UpOnly(reduced limit)
Renewable	Up/down	Down only
Hydro	P1:Down only, P2/P7: Fixed	P1:Down only, P2/P7:Fixed
Battery	P1:If on, Down only, P2/P7:Fixed	P1:If on, Down only , P2/P7:Fixed
Nuclear	Fixed	Fixed
Flex	P1:Up/Down, P2/P7:Fixed	P1:Up/Down, P2/P7:Fixed
Other (DR, Load etc)	Fixed	Fixed

Figure 31 – Limitations on generation re-dispatch by resource type

Generation Redispatch
In the first pass generation redispatch security constrained reliability dispatch (SCRD) is performed that seeks to minimize the amount of generation that is adjusted to address thermal overloads while respecting generator limits.

Objective

Minimize (MWnew - MWinitial)
subject to: Gen: Pmin < Pgen < Pmax
where Pmax = thermal capacity, renewable availability
Tx: MVAloading <= MVAlimit

Contingencies included

NERC Category P1, P2, P7
(NERC Category P3, P4, P5, and P6 contingencies are not included due to duplication or complex implementation of mitigating actions)

Generation dispatch parameters used in first pass

Precontingent redispatch for contingency constraints
Costs/Penalties;
Generators: $50/MW
Loads: Excluded
Transmission Constraints: $1000/MW

Generation redispatch is used to recognize that study models reflect a single renewable dispatch scenario from a range of dispatch conditions. Applying generation redispatch for P1 contingencies also ensures that there is no overlap where redispatch mitigation is included in economic dispatch for congestion and fuel savings benefits.

Load Redispatch
In the second pass load redispatch, reliability based dispatch (SCRD) is performed that seeks to minimize the amount of load that is curtailed to address remaining overloaded constraints

Objective

Minimize (MWnew-MWinit)
subject to: Loads: 0 < Pload<Pinitial
Tx: MVAloading <= MVAlimit

Contingencies included

NERC Category P1, P2, P7
(NERC Category P3, P4, P5, P6 contingencies are not included due to duplication or complex implementation of mitigating actions)

Load shedding/dispatch parameters used in second pass:

Corrective load redispatch to avoid remaining overloads

i.e. LoadShedMW = sum (max($BusMW_b$)) where BusMW is the amount of load shedding for each contingency

Costs/Penalties;

Generators: Excluded
Loads: $10/MW
Transmission Constraints: $1000/MW

Analysis Steps

Step 1

Include all monitored and NERC Category P1, P2 and P7 contingent facilities from the 2032 and 2042 reliability analysis in the first pass generation redispatch.

Step 2

For the hours represented by 2032 and 2042 summer peak, winter peak, average loading, light load study cases, the hourly resource availability (Zones 1-7) is analyzed to determine the number of hours where renewable generation availability is in excess of or is below the renewable dispatch modeled in the study case. One dispatch scenario is created to allow renewables to be adjusted in the up/down direction for hours with excess capacity, and a second scenario is created that limits renewables to downward only dispatch for hours without excess availability. For the hours of excess availability, the average excess renewable capacity is calculated and divided by the total renewable nameplate/pmax contained in the model (zones 1-7) to compute a percentage of nameplate that is used to establish generation maximum dispatch limits that are applied to the models before running the redispatch routine. Renewable energy targets are also summed across the hours represented by the study models to apply limits on the number of hours permitted for displacement of renewables with the increased dispatch of thermal generation. This enforces the renewable energy production levels that are established by the Futures expansion.

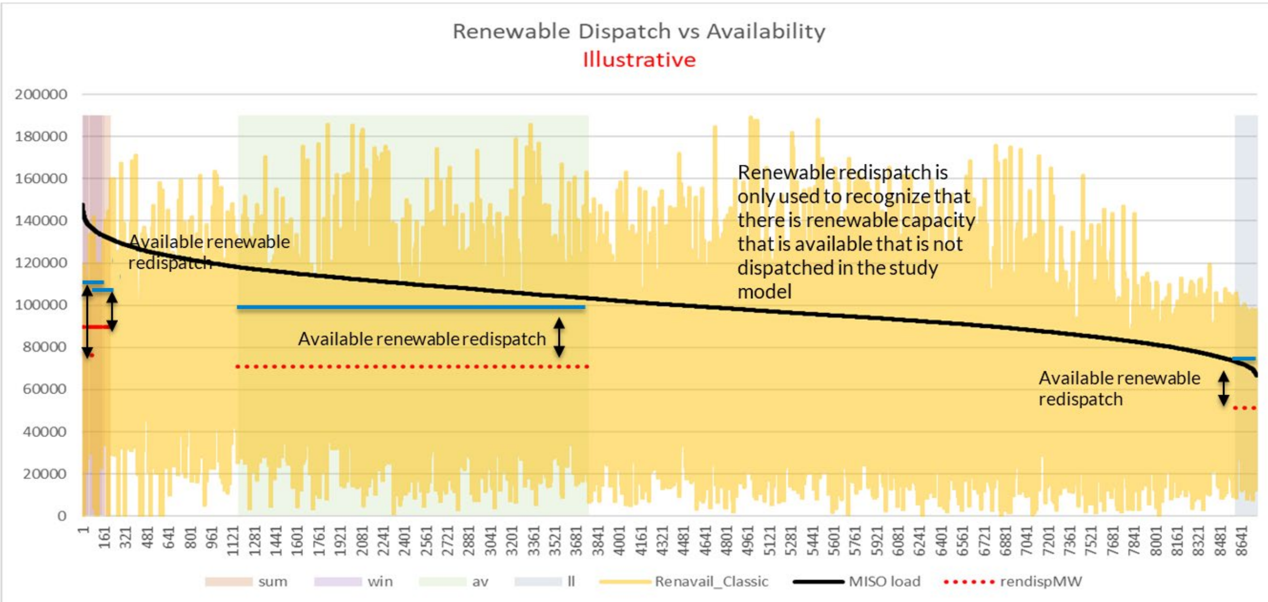


Figure 32 – Example plot of renewable availability used to determine dispatch limits on renewable resources for study scenarios

Example Calculation (illustrative)				
Renewable Resource Availability				
2024	sum peak	win peak	avg loading	light load
total hours	135	49	2612	162
Hours with higher Renewable availability	48	17	1250	76
Hours with lower Renewable availability	87	32	1362	86
Average excess renewables	106092	107005	99042	74951
2042_renewable_nameplate*	216600	216600	216600	216600
%nameplate	43.60%	42.10%	42.60%	29.50%

Figure 33 - Example tabulation of hours of renewable availability for study scenarios

Step 3

The first pass applies generation redispatch for NERC Category P1, P2 and P7 contingencies to alleviate overloading first before resorting to load redispatch.

For hours with excess renewable availability

The base case study models without LRTP transmission, which include at a minimum the 2032 and 2042 sum peak, win peak models, are analyzed in TARA using security constrained reliability redispatch (SCRD) with available renewable headroom applied to mitigate the thermal violations for NERC Category P1, P2 and P7 contingencies.

The resulting study case is saved with the adjusted redispatch applied to be used in the second pass load redispatch analysis.

For hours without excess renewable availability:

The base case study models without LRTP, including at a minimum the 2032 and 2042 summer peak, winter peak, average loading and light load models, are analyzed in TARA using security constrained reliability redispatch (SCRD) with renewable dispatch limited in downward direction to mitigate the thermal violations for NERC Category P1, P2 and P7 contingencies.

The resulting study case is saved with the adjusted redispatch applied to be used in the second pass load redispatch analysis.

Step 4

Compare reliability analysis results from the 2032 and 2042 study models and compile a list of issues that were resolved by the LRTP portfolio to include as monitored and contingent facilities.

Step 5

For hours with excess renewable availability:

The second pass reliability redispatch (SCRD) is executed to include only load participation in pre-contingent redispatch for NERC Category P1, P2 and P7 contingencies. This second pass monitors facilities where overloads were resolved by LRTP and calculates the amount of load reduction needed to alleviate any remaining overloaded facilities after initial generation redispatch. For each study scenario, the aggregate load redispatch amount is calculated and multiplied by hours with excess renewable availability to quantify the amount of avoided risk of load shedding provided by the LRTP portfolio.

For hours without excess renewable availability:
The second pass reliability redispatch (SCRD) is executed to include only load participation in pre-contingent redispatch for NERC Category P1, P2 and P7 contingencies. This second pass monitors facilities where overloads were resolved by LRTP and calculates the amount of load reduction needed to alleviate any remaining overloaded facilities after initial generation redispatch. For each study scenario, the aggregate load redispatch amount is calculated and multiplied by hours without excess renewable availability to quantify the amount of avoided risk of load shedding provided by the LRTP portfolio.

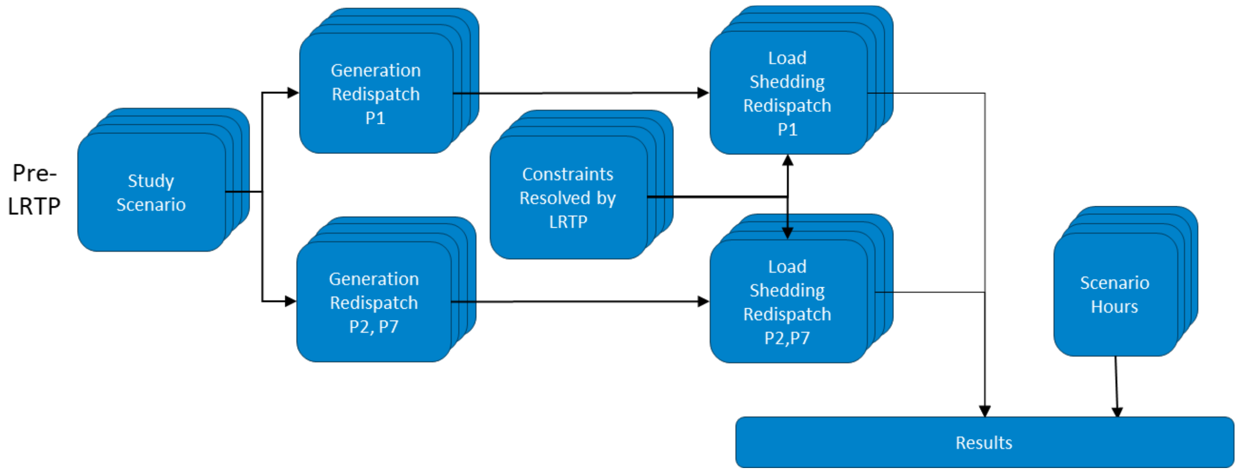


Figure 34 - Process for analyzing Mitigation of Reliability Issues benefit.

Step 6 *Determining the financially quantified value of the benefit*

For all base case study cases, the identified issues and the aggregate load redispatch amount are tabulated for each study scenario. The total load shedding is then multiplied by the relevant number of hours for that scenario to obtain the amount of load shedding (MWh) avoided. This total value is multiplied by the Value of Lost Load (VOLL) to obtain the financial value of the benefit of mitigation of reliability issues.

$$\text{Benefit} = \sum_1^n LoadShedMW * VOLL$$

Where

n = dispatch scenario/season

LoadShedMW = amount of load redispatch for each study scenario

VOLL = Value of Lost Load ($3,500/MWh - $10,000/MWh)

Benefits are accrued on a one time basis for each of the study years (2032 and 2042) and issues identified in the earlier 2032 study year are excluded from consideration in the later 2042 study year. Any reliability issues that are identified are assumed to be mitigated and pose no further risk in the later years.

Example calculation (illustrative)									
Model	Redispatch Scenario	Monitored	Contingency	Pre-overload %	Pre-MW Relief Required	Buses	Sum of Max Load Shed MW	Scenario Hours	MWh Benefit
2032sum	up/down	St A- St B	P1_Ctg1	115%	16MW	bus-a bus-b	124	48	5,952
2032avg	up/down	St C - St D	P1_Ctg2	124%	32MW	bus-c bus-d bus-e	46	420	19,320
2032avg	down-only	St E - St F	P1_Ctg3	107%	20MW	bus-f bus-g bus-h bus-i	295	1362	401,790
2032avg	down-only	St G - St H	P2_Ctg4	109%	18MW				
							Load Shedding MWh		427,062

Figure 13 - Example tabulation of results and calculation of Mitigation of Reliability Issues benefit

Example Calculation (Illustrative)				
Period	Year	Unserved Energy (MWh)	EventMW*VOLL	Present Value
0	2032	427,062	$1,821,167,524	$1,821,167,524
1	2033			
2	2034			
3	2035			
4	2036			
5	2037			
6	2038			
7	2039			
8	2040			
9	2041			
10	2042	270,000	$1,473,877,488	$742,278,151
11	2043			
...	...	...	...	...
19	2051			
Total 20yr PV (2032$)				$2,563,445,675

Figure 36 – Example calculation of 20-year present value of Mitigation of Reliability Issues benefit.

5 Distribution of Benefits

The multi-value planning process provides regional transmission investment that addresses the need for reliable and economic energy delivery. Costs for the LRTP portfolio are recovered from customer load in the MISO Midwest Subregion on a pro-rata energy usage basis and are allocated

in a manner that is roughly commensurate with benefits. Benefit distribution by cost allocation zone is used only to demonstrate that overall benefits are broadly spread to customers throughout the subregion. While all cost allocation zones will receive sufficient benefits provided by the LRTP portfolio, the benefits are not expected to be distributed uniformly across the zones. Distribution of benefits to the cost allocation zones is based on the method used to quantify the benefit and is specified in the table below.

Benefit Metric	Allocation Method
Avoided Capacity Costs	Determined based on load ratio share
Capacity Savings from Reduced Losses	Determined based on load ratio share
Congestion and Fuel Savings	Determined by zone based on PROMOD results
Reduced Transmission Outage Costs	Determined by zone based on PROMOD results
Energy Savings from Reduced Losses	Determined by zone based on PROMOD results
Reduced Risks from Extreme Weather Impacts	Determined based on load ratio share
Avoided Transmission Investment	Determined by zone based on location of upgrade
Mitigation of Reliability Issues	Determined by zone based on location of violations
Decarbonization	Determined based on load ratio share

Figure 37 - Table of distribution of benefits

6 Reference Case and Change Case Model Assumptions

The LRTP business case is designed to reflect the outcome of the collaborative multi-value planning process that supports the regional planning needs of MISO members. As a regional transmission provider MISO is responsible for developing an appropriate regional transmission plan that will enable our members to achieve the resource plans that meet their future goals and energy needs. The resource assumptions that have been agreed upon in the collaborative Futures development process serve as the reference point for the transmission planning process and are used to establish the base assumptions used for determining the benefits attributed to transmission investment. Additionally, members receive benefits relying on MISO regional transmission planning process to enable more efficient capacity planning decisions in developing their resource plans. Benefit metric calculations capture value by examining the impact of LRTP

transmission on these future system needs, including load and resource assumptions to identify the value MISO customers receive from making the investment in the transmission.

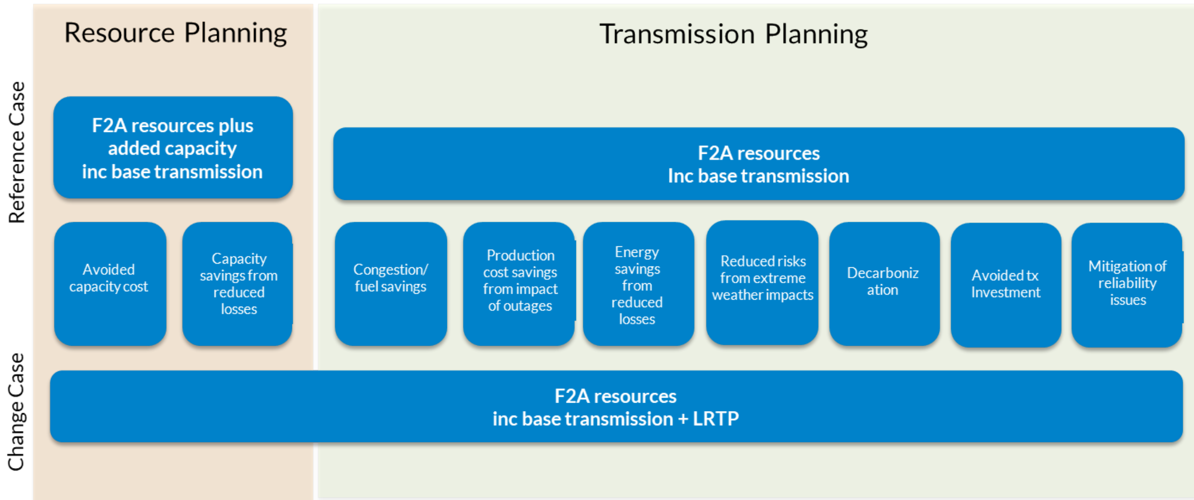


Figure 38 - Transmission planning metrics reflect resource assumptions defined in the Futures scenarios while capacity related metrics reflect resource planning decisions that are used to develop Futures scenarios

7 Version History

Date Revised	Comments
6/6/2024	Original version
9/10/2024	Revised terminology for reserve requirements, added clarifying language on use of demand response for unserved energy calculation, revised VOLL, updated examples for consistency with process and current assumptions, added more details on generation participation in redispatch and load shedding calculation.
9/23/2024	Revised section 4.9 example tables to provide more detail and updated terminology describing the load shedding method applied.
10/1/2024	Revised section 4.6 to align description with the CVar threshold.