LRTP Tranche 2
Benefit Metrics Development

Energy Savings from Reduced Losses, Reduced Risks from Extreme Weather Impacts, and Mitigation of Reliability Issues

April 26, 2024

Purpose & Key Takeaways

Purpose

Review the methodologies for Energy Savings from Reduced Losses, Reduced Risks from Extreme Weather Impacts, Mitigation of Reliability issues

Key Takeaways

- Multiple benefit metrics are used to capture total value and demonstrate broad benefits across MISO Midwest Subregion
- Metrics are included to reflect value of transmission in supporting reliability and flexibility in the future with more uncertainty in resource availability
- MISO will be seeking formal stakeholder feedback on the proposed benefit metrics methodologies

Multiple metrics are being considered to capture the broad value transmission provides across the MISO Midwest Subregion

Prior Discussion	• Reduced risks from extreme weather impacts (Mar '23, Aug '23) • Capacity savings from reduced losses (Mar '23, Mar '24) • Resource Adequacy savings (Aug '23) – removed from Tranche 2 • Decarbonization (Mar '23, Aug '23) • Avoided transmission investment (Mar '23) • Congestion and fuel savings (Jan '24) • Reduced transmission outage costs (Mar '24) • Avoided capacity costs (Mar '24) • Mitigation of resource variability – removed from Tranche 2
Current Discussion	• Energy savings from reduced losses • Reduced risks from extreme weather impacts • Mitigation of reliability issues
June '24*	• Final refinements and conclusion of metrics development

*tentative

( ) – links to presentations at previous LRTP workshops covering benefit metric

Energy Savings from Reduced Losses

New transmission reduces flows on existing wires and can reduce transmission energy loss rates

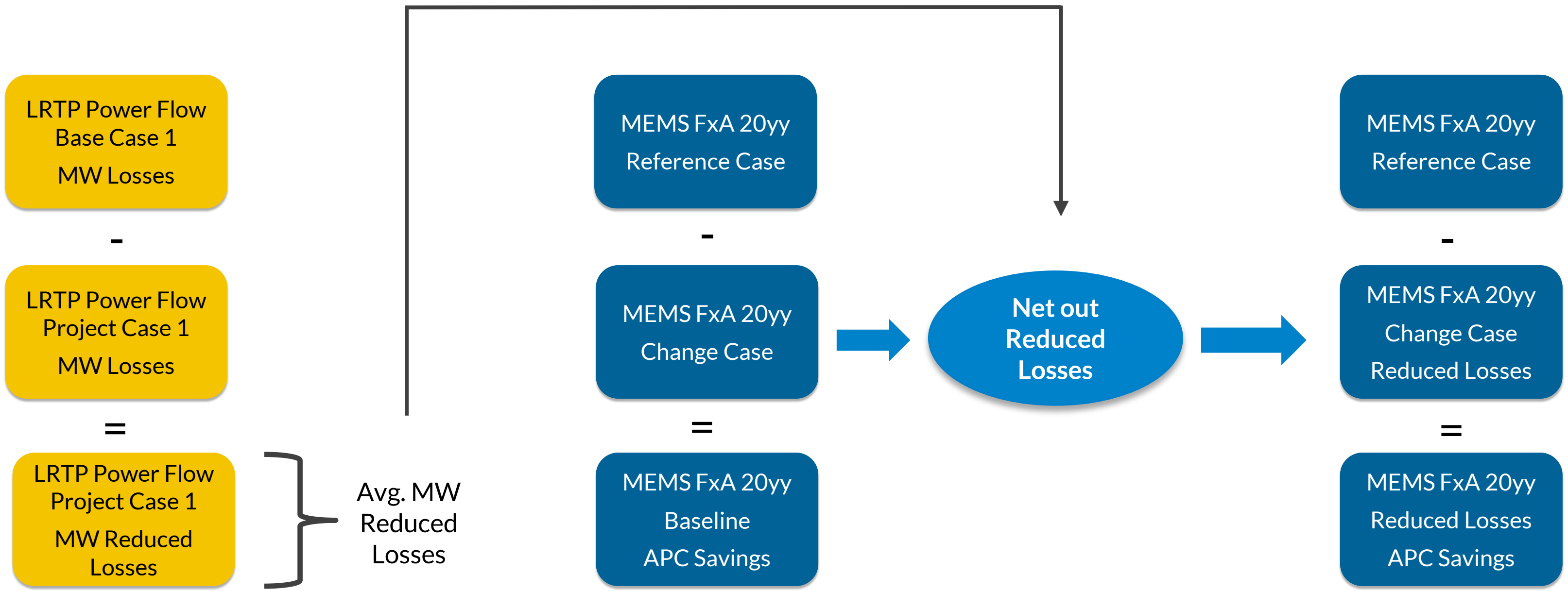
- Tranche 2 portfolio adds network paths that redistribute flows and reduces energy requirements due to lower system losses
- Reducing losses results in lower operating and production costs
- MISO's standard production cost models incorporate transmission losses into fixed demand profiles
  - This means that loss energy values are not actively computed based on topology or dispatch
- The aggregate impact of reducing loss energy may be identified by measuring the incremental impact to Adjusted Production Cost (APC) when estimated loss reductions are netted out of demand
- This metric only quantifies reductions to production costs and does not quantify capital costs
  - PROMOD performs production cost simulations and does not evaluate resource expansion
  - The Capacity Savings from Reduced Losses metric calculates effective capital cost reductions and does not include operating costs

Changes to real losses can be calculated using power flow cases, and applied to production cost models as a reduction in demand

- Transmission losses calculated for each of the power flow cases with and without prospective LRTP transmission
- The MW difference in losses attributed to new transmission will be averaged and used to calculate an annual reduction in loss energy
- The reduction in loss energy will be applied to reduce modeled demand proportionately across the affected region of the system (MISO Midwest) in the Change case
    - e.g. (400 MW avg. Loss Reduction) * (8,760 hrs/yr) = 3,504,000 MWh / yr Loss Reduction
        - (3,504,000 MWh / 600,000,000 Demand & Losses MWh) = 0.584 % Reduction*

* Illustrative example calculation based on approximation of regional demand

Energy Savings from Reduced Losses – APC Savings due to reduction in loss energy



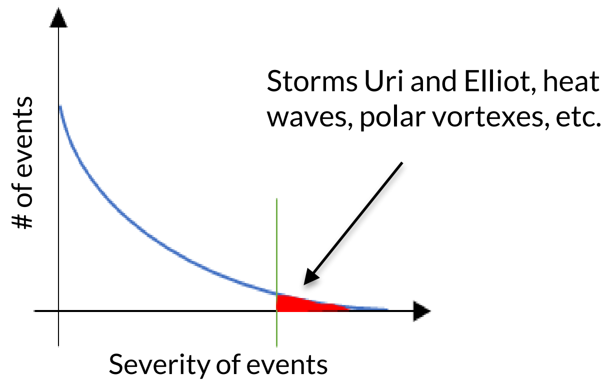
$$\mathit{Energy\ Savings\ from\ Reduced\ Losses} = \mathit{Reduced\ Losses\ APC\ Savings} - \mathit{Baseline\ APC\ Savings}$$

Reference Case: An unmodified base PROMOD case
Change Case: The same Change Case used in other value metrics, where new prospective transmission has been added to the Reference Case
MEMS FxA 20yy: MISO Economic Model Series, Future FxA, Year 20yy

Reduced Risks from Extreme Weather Impacts

The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events

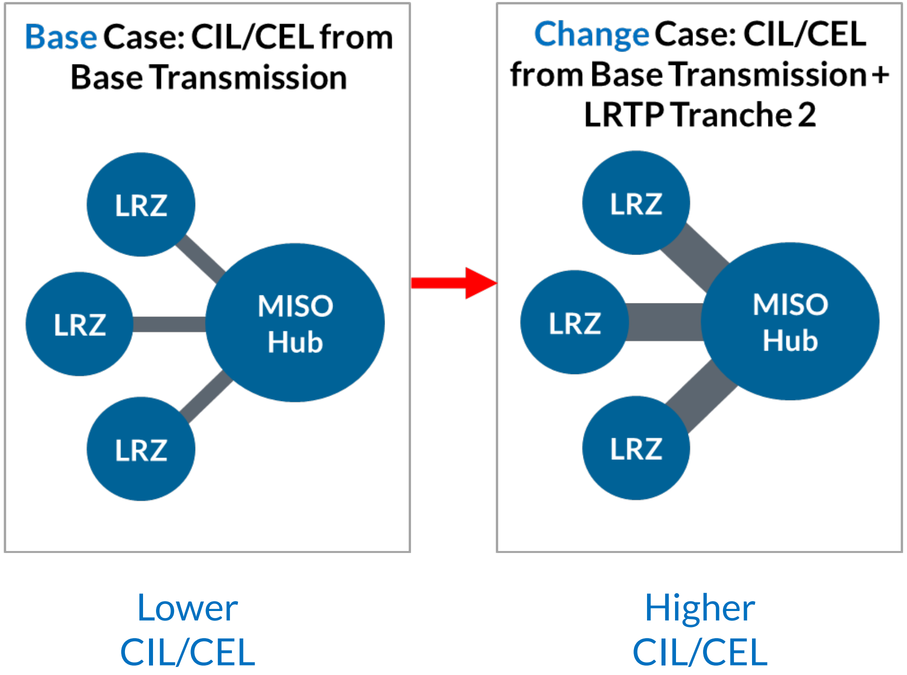
- This benefit accounts for the duration and magnitude of loss of load events during extreme weather conditions (e.g., Storm Uri, 2014 and 2019 Polar Vortex)
  - Adding transmission capacity increases import/export limits which enables access to capacity across the footprint
  - Access to larger pool of capacity reduces the magnitude of loss of load events during extreme weather conditions
- Reduced severity of events under extreme cases are additional benefits that are not explicitly reflected in metrics like LOLE
  - The LOLE metric is a counting metric (e.g., 1 day-event), whereas EUE captures both magnitude and duration (e.g., 700 MWh)
  - LOLE is an expected value (e.g., long-term average), whereas this metric focuses on the most "severe" system conditions



Illustrative distribution of risk

LOLE - Loss of Load Expectation

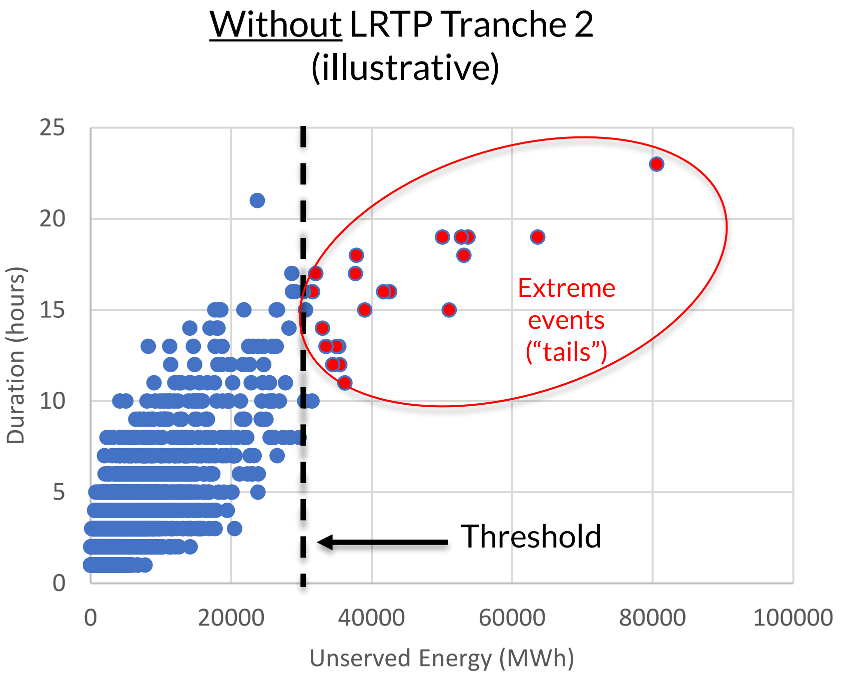
The reduced risk from extreme weather impacts leverages LOLE modeling and incorporates a simplified representation of transmission constraints at the zonal level

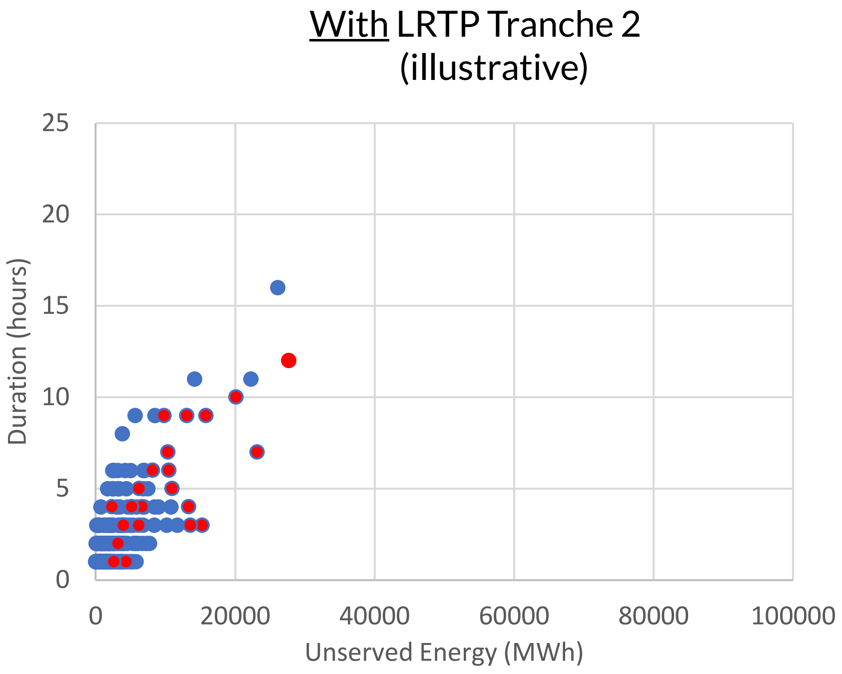


- Simplified representation of transmission constraints at the zonal level are based on seasonal capacity import (CIL) and export limits (CEL)
- Multi-area LOLE modeling, in alignment with the ACC benefit method
- Benefits are attributed to greater EUE without Tranche 2
  - EUE w/o Tranche 2 > EUE w/ Tranche 2
- Economic value is determined by multiplying the delta EUE (*during the most severe events*) with the value of loss of load (VOLL)
  - (ΔEUE) x (VOLL)

ACC – Avoided Capital Cost; LOLE – Loss of Load Expectation; LRZ – Locational Resource Zone; CIL – Capacity Import Limit; CEL – Capacity Export Limit

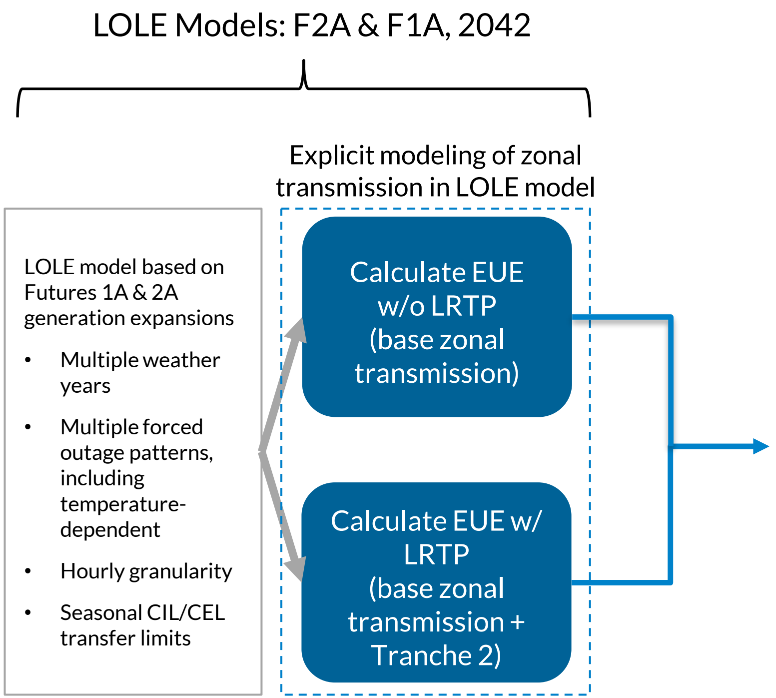
The total number of the most severe events will be determined by analyzing the "tails" of the EUE distribution without Tranche 2





The red dots represent days with EUE that overlap in both bases.
This approach keeps same days in the benefit calculation to isolate changes in EUE from any change in LOLE.

The process starts with a transfer analysis, followed by LOLE simulations, and finishes with the ΔEUE benefit calculation



Calculate ΔEUE for F2A & F1A, 2042 (illustrative)

Day	Weather Year	Sample	Case w/ LRTP – Unserved Energy (MWh)	Case w/o LRTP – Unserved Energy (MWh)	Change in Unserved Energy (MWh)	Include in benefit calculation?
Jul-1	2007	44	5	15	10	✗
Sep-3	2009	27	10	20	10	✗
Sep-2	2010	103	**0**	50	N/A	✗
Jan-3	2014	13	5	30	25	✓
Aug-29	2014	49	15	30	15	✓
July-30	2019	3	**0**	10	N/A	✗
Dec-9	2019	35	15	25	10	✗
Feb-10	2021	24	10	40	30	✓
Jul-30	2013	50	1	3	2	✗
…			Rest of days			…
ΔEUE (total)					**70**	

Benefit = (70 MWh) x (3,500 $/MWh) = $245,000

*The "sample" EUE (daily) is calculated by adding up the total unserved energy for every hour within a day. N/A represents event-days that don't overlap between the two cases and are neglected in the benefit calculation to avoid overlaps with the avoided capital cost (ACC) benefit.

Mitigation of Reliability Issues

Transmission capacity is essential to addressing reliability risks from future fleet evolution

- Reliability benefits are a significant part of the value provided by transmission because the additional transmission reduces risk of service interruption
- The role of transmission is critical to support delivery of energy from resources that are more widely spread throughout the footprint
- With greater uncertainty and variability of future resources, transmission capacity provides robustness and flexibility necessary to compensate for declining dispatchable resources traditionally used to manage reliability risks

MISO's LRTP planning process recognizes the value of reliability

- LRTP / MVP portfolio must meet one of three criteria to be eligible for regional/subregional cost sharing
- LRTP applies Criterion 3 that includes a component of reliability benefits

"A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs…"

Criterion 3 : $$\frac{Benefit_{econ} + Benefit_{rel}}{Cost_{tx}} \geq 1.0$$

While transmission benefits can readily be demonstrated in the mitigation of reliability issues (thermal/voltage issues) , they typically are not financially quantified in MVP benefit-cost analysis

$$\frac{Benefit_{econ} + \cancel{Benefit}_{rel}}{Cost_{tx}} \geq 1.0$$

Note: LRTP Tranche 1 introduced a reliability metric for avoided risk of extreme weather impacts

Transmission planning proactively addresses performance requirements to avoid risks that return reliability benefits

ECONOMIC BENEFITS

Reflect a savings enabled by choosing a more cost-effective option

- A lower cost alternative delivers savings to customers
- For example, APC savings are realized when transmission investment reduces congestion to allow lower cost dispatch of resources
- Economic metrics do not fully capture physical risks (contingencies, DC solution, unresolved constraints, etc.)

RELIABILITY BENEFITS

Reflect the value of mitigating risks of unserved load with transmission investment

- System performance requirements are established by planning criteria and industry standards to reduce risk of unserved load, e. g., planning standards, storm hardening criteria
- Specific thermal and voltage criteria are defined for acceptable system performance
- Reliability benefits can be defined by quantifying the amount of preventive load shedding needed to address expected violations of performance criteria

Reliability benefits reflect the value of avoided risk of unserved load as a consequence of meeting planning objectives

- Regional transmission projects focus on goals and reliability for the long-term horizon versus solving near term issues that are highly dependent on local conditions
- Transmission reinforcements alleviate reliability violations which can otherwise result in unserved load
- Reliability benefits can be quantified using the avoided risk of unserved load determined in the long-term planning study which reasonably reflects the value of uninterrupted service for customers
  - Value of Lost Load (VOLL) is used to monetize benefits of preserving load
  - VOLL is established as a market price of energy that customers are willing to pay to avoid interruption of load

Avoided risk of unserved load is calculated based on rules defined in planning criteria and monetized to reflect reliability value

- The measure of reliable performance is based on meeting established planning criteria
- Reliability value is determined by the thermal/voltage violations that are mitigated
  - Contingency violations must be addressed proactively – cannot rely on post-contingent corrective action to fix an issue
  - Redispatch is proactively applied to relieve an overload (pre-contingent) for NERC Category P1 contingencies[1]
  - No redispatch is applied for NERC Category P2/P7 contingencies[1]
- Reliability benefit can be measured by examining the amount of load shedding required to alleviate violation
  - Load shedding is not an appropriate mitigation action but is a mechanism to quantify the relief needed to address violation
  - Value is determined by calculating the unserved load that would be avoided by the transmission investment

Benefit = LoadShedMW x hrs x VOLL

where *hrs = # risk hours represented by study case*

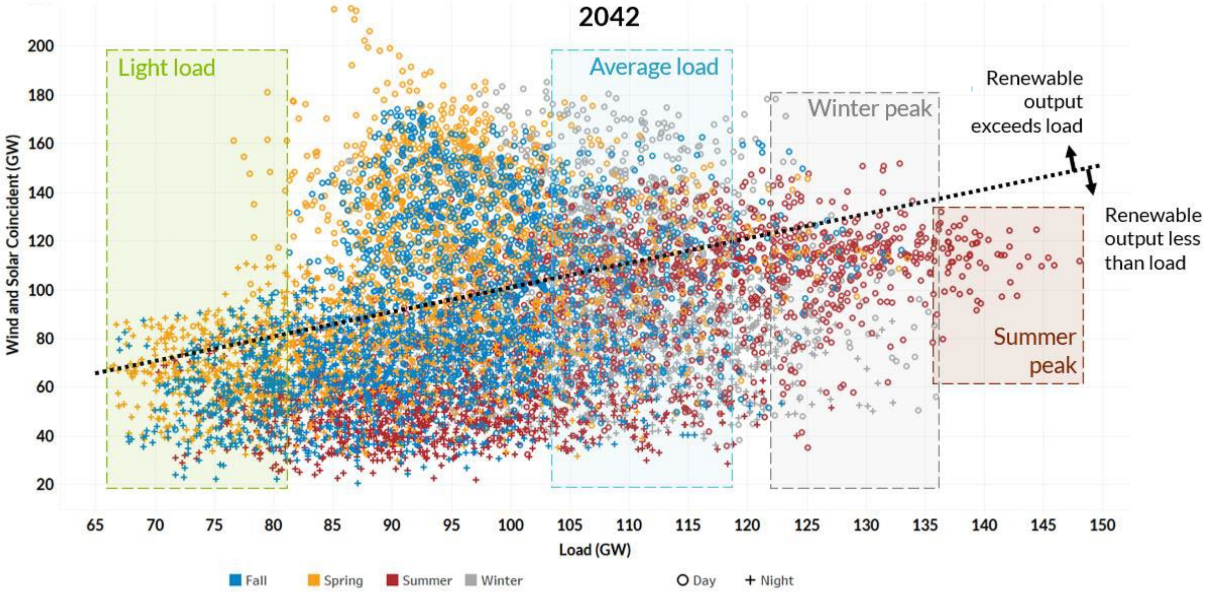
VOLL = range($3,500/MWh[2], $25,000/MWh[3])

[1]NERC TPL-001-5.1 Transmission Planning Standard ,
[2]U nder review,[3]IMM 2022 State of the Market recommendation

Study scenarios represent conditions over multiple hours of the year and are used to examine and quantify load shedding risk

Hours of unserved load are determined by examining the dispatch and load distribution associated with each model scenario

- Model scenarios represent a subset of annual conditions
- Load shedding hours correspond to hours represented by the study scenario in the annual load distribution



A two-step process is used to perform reliability redispatch to mitigate issues and identify residual overloading that would require load shedding

Generation dispatch rules/limitations

- *Generation dispatch limitations are applied to respect resource characteristics and availability*
  - Renewable redispatch will reflect availability of renewables in the hours represented by the study scenario
    - Re-dispatch includes headroom of renewable resources for all hours where renewable availability exceeds current dispatch modeled in study case
    - Re-dispatch for all remaining hours will limit renewables in downward direction
  - Batteries: if on, dispatchable in downward direction
  - Generation redispatch includes thermal resources
    - Must respect member renewable targets – limit on hours of redispatch
- *Load shedding for unresolved overloads*
  - If any unresolved constraints exist, load shedding amount is calculated based on load redispatch with only loads participating
- *Non convergence*
  - Unsolved contingencies that are resolved by LRTP are further analyzed to identify the amount of load shedding to resolve issues

Generation redispatch is used first to alleviate constraint loading and reduce the need for residual load shedding

- Objective - minimize amount of generation redispatch to address an overload subject to constraints (transmission limits, dispatch limits, etc.)
  - *Minimize:*
    - (MWnew-MWinitial)
  - *Subject to:*
    - Gens: Pmin < Pgen < Pmax where Pmax = thermal capacity, renewable availability
    - *Tx:* MVAloading <= MVAlimit

- Contingencies included
  - *P1:* Included in generation redispatch
  - *P2, P7:* Not included in generation redispatch
  - *P3, P4, P5, P6:* N-1-1, N-2 Not included; complex implementation

- Generation dispatch parameters
  - Pre-contingent generation redispatch – respect N-1 constraints
  - Generation cost is uniform
    - Generators: $50/MW
    - Loads: Excluded
    - Tx Constraints: $1000/MW

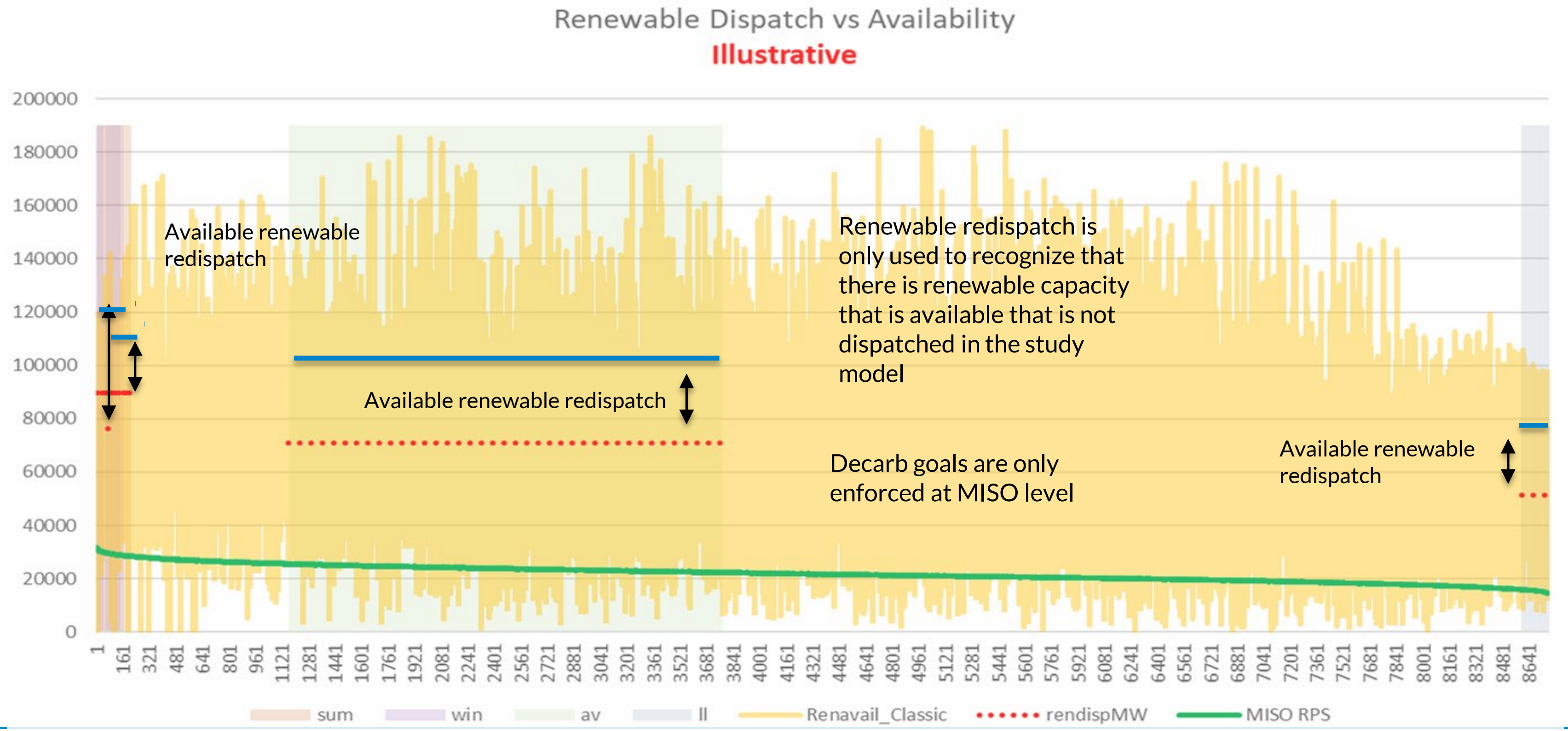
Load shedding analysis uses reliability redispatch to identify load shedding needed to relieve remaining constraints

- Objective - minimize the amount of load redispatch to address any unresolved overloads subject to constraints (transmission limits, dispatch limits, etc.)
  - *Minimize:*
    - (MWnew-MWinit)
  - *Subject to:*
    - Loads: 0 < Pload
    - *Tx:* MVAloading <= MVAlimit

- Contingencies Included
  - *P1, P2, P7:* Included in load redispatch
  - *P3, P4, P5, P6:* N-1-1, N-2 Not included; complex implementation

- Load redispatch parameters
  - Pre-contingent load redispatch – remaining overloads
  - Generation cost is uniform
    - Generators: Excluded
    - Loads: $10/MW
    - Tx Constraints: $1000/MW

Generation redispatch limitations are determined by available renewables and RPS goals within the hours represented by the study scenario



Renewable redispatch limitations are determined by hours where renewable availability exceeds modeled dispatch

2032 *(Illustrative)*

- Maximum of 543 out of 2286 hours where renewables can be dispatched up (may provide additional energy for decarbonization goals)
- Remaining 1743 hours do not include dispatch of renewables in up direction (number of hours limited if decarbonization goals cannot be met)

2032 *(Illustrative)*	summer peak	winter peak	average load	light load
Total hours	104	54	1,997	131
Hours with higher renewable availability	18	7	473	45
Hours with lower renewable availability	86	47	1,524	86
Average excess renewables	73,357	75,461	81,564	58,251
2032_ren_nameplate*	147,400	147,400	147,400	147,400
Percentage nameplate	49.8%	51.2%	55.3%	39.5%

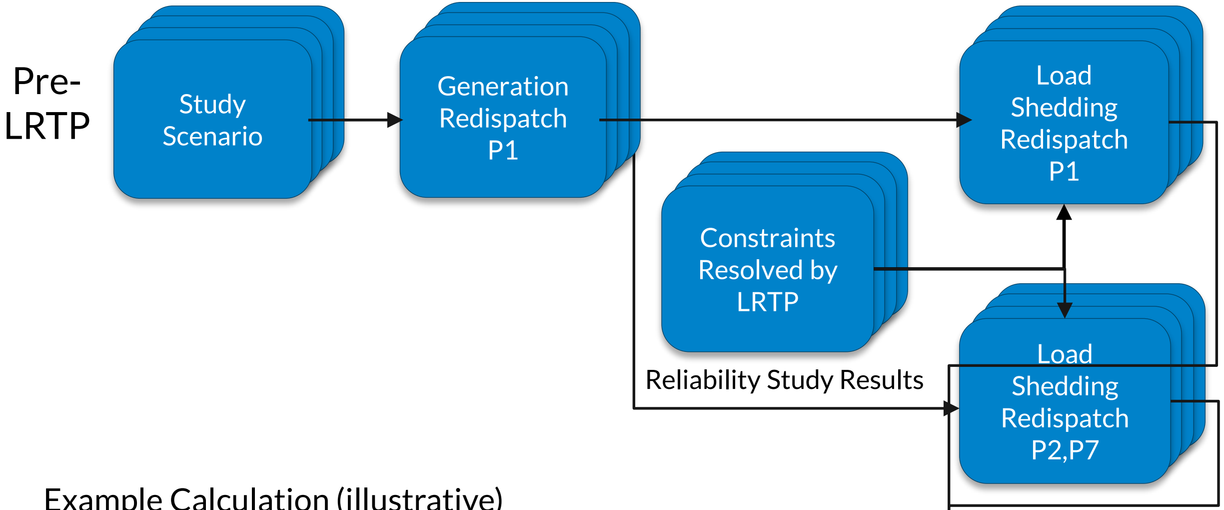
2042 *(Illustrative)*

- Maximum of 1391 out of 2958 hours where renewables can be dispatched up (may provide additional energy for decarbonization goals)
- Remaining 1567 hours do not include dispatch of renewables in up direction (number of hours limited if decarbonization goals cannot be met)

2032 *(Illustrative)*	summer peak	winter peak	average load	light load
Total hours	135	49	2,612	162
Hours with higher renewable availability	48	17	1250	76
Hours with lower renewable availability	87	32	1362	86
Average excess renewables	106,092	107,005	99,042	4,951
2032_ren_nameplate*	216,600	216,600	216,600	216,600
Percentage nameplate	49.0%	49.4%	45.7%	34.6%

*From Supplemental Model Information_v2_12_21_23.xlsx

Redispatch and load shedding are used to identify load shedding risk



Reliability dispatch is used for:

- Pre-contingent redispatch for mitigation of thermal issues
- Pre-contingent load shedding to determine amount of unserved load that would maintain loading within limits

Example Calculation (illustrative)

Model	Redispatch Scenario	Monitored	Contingency	Pre-Overload %	Pre-MW Relief Required	Pre-Load Shed	Post-Loading %	Post-MW Relief Required	Post-Load Shed	Scenario Hours	MWh Benefit
2042sum	Updown	A- B	P1_Ctg 1	115%	16MW	24MW	95	0	0	48	1,152
2042avg	Updown	C-D	P1_Ctg 2	124%	32MW	46MW	97	0	0	1250	40,000
2042avg	Uponly	E-F	P1_Ctg 3	107%	10MW	18MW	100	0	0	1362	24,516
2042avg	---	G-H	P2_Ctg 4	109%	18MW	25MW	98	0	0	2612	65,300

MISO is requesting formal feedback on benefit metrics discussed today

- MISO is requesting formal stakeholder feedback on benefit calculation methodologies for:
  - Energy Savings from Reduced Losses
  - Reduced Risks from Extreme Weather Impacts
  - Mitigation of Reliability Benefits
- Due by May 10, 2024, using the stakeholder feedback tool
- Metrics development discussions will continue at upcoming LRTP workshops:
  - June 2024 (tentative)
    - Review revised methods and finalize metrics development

Questions?

LRTP Website

[Long Range Transmission Planning (misoenergy.org)]

LRTP Help Center

[Help Center (misoenergy.org)]

Appendix

Illustrative example

- Modeling assumptions:
  - 14 weather years
  - 5 samples per weather year (illustrative purposes only)
- Find change in unserved energy between cases for all days, for each weather year and sample, that had unserved energy in the case **with** LRTP
  - Excludes days with unserved energy in the case without LRTP that did not align with unserved energy days in the case with LRTP (prevents overlap with ACC metric)
- Estimated annual prevented unserved energy due to Tranche 2:
  - Total Change in Unserved Energy/ (Samples x Weather Years)
  - 195 MWh/(5 samples x 14 weather years) = 2.79 MWh

Example results – illustrative purposes only

Day	Weather Year	Weather Conditions	Sample	Case w/ LRTP – Unserved Energy (MWh)	Case w/o LRTP – Unserved Energy (MWh)	Change in Unserved Energy (MWh)
Jul-1	2007		4	5	15	10
Sep-3	2009		2	10	20	10
Sep-2	2010		1	**0**	50	N/A
Jan-3	2014		3	5	30	25
Aug-29	2014		4	15	30	15
Jun-15	2016		1	20	40	20
July-30	2019		3	**0**	10	N/A
Dec-9	2019		5	15	25	10
Feb-10	2021		3	5	40	35
Feb-10	2021		4	20	50	30
Feb-11	2021		5	30	70	40
					Total Change in Unserved Energy (MWh) =	**195**

Deterministic analysis directly aligns the calculation of value with the reliability analysis results

- Probabilistic and deterministic methods have merit but achieve different objectives

- Probabilistic simulations can evaluate impact of random contingency events to calculate hours of unserved energy
  - Hourly
  - Requires transmission outage performance data
  - Computationally intensive especially if dispatch is also incorporated
  - Treats load shedding as post contingent corrective action – reactive
  - Does not adequately represent reliability planning objectives for proactive solutions
  - Requires adequate reflection of true outage costs

- Deterministic analysis more closely aligns with planning analysis results
  - Scenarios are representative snapshots of conditions
  - Direct application of load shedding analysis to the identified reliability issues
  - Requires analysis of distributions of dispatch and system conditions
  - Can account for application of other mitigation steps before applying load shedding
  - Pre-emptive load shedding to address violations reflects cost of meeting reliability criteria