Ameren Missouri
2025 IRP Annual Update
Appendix B

Prepared for:

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Ameren Missouri HVDC Transmission Facilities Benefits Analysis

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CRA Project No. D100873

Ameren Illinois RTO Cost-Benefit Study

Disclaimer

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1. Executive Summary

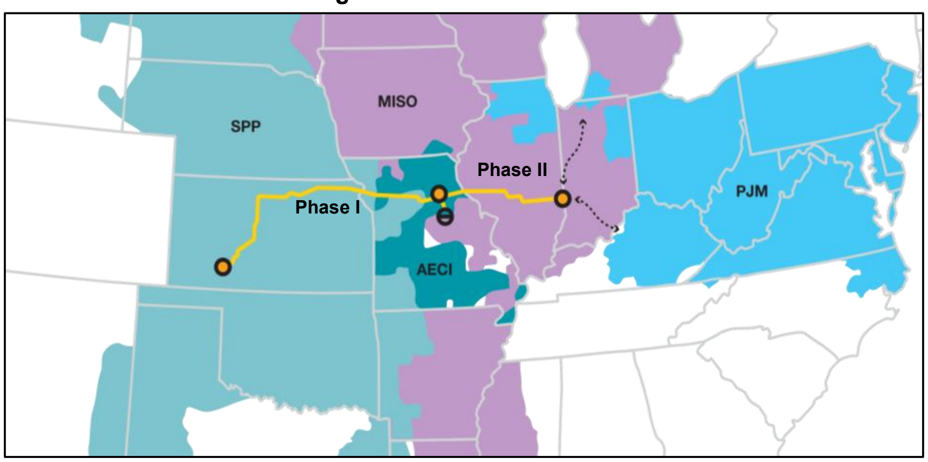
On behalf of Ameren Missouri and as directed by the Missouri Public Service Commission[1], Charles River Associates (CRA) conducted an analysis of the reliability, resiliency and operational benefits of high voltage direct current (HVDC) transmission facilities connecting to the Ameren Missouri service territory (MISO Zone 5). For the purpose of the benefits analysis, CRA modeled Phase I of the Grain Belt Express (GBX) project which according to GBX's most recent Missouri PSC filings is planned to provide 1,500 MW of transmission capacity between Western Kansas and MISO Zone 5 beginning in 2029.[2] CRA's analysis identified benefits in the form of reduced energy, resource adequacy, and resource costs enabled by access to Kansas wind and solar resources in lieu of MISO alternatives. While this report only studies the benefits of GBX and similar HVDC transmission facilities, it is intended to provide a basis for Ameren Missouri to compare HVDC costs and inform future investment decisions.

1.1. Study Methodology

Two different cases were analyzed over a 12-year period from 2029-2040:

1. "*Reference Case"* – where GBX is not modeled*,* and
2. *"HVDC Case"* – where Phase I of GBX (Figure 1) is operational starting in 2029[3]

Figure 1: GBX Phase I and II



1 On October 30, 2024, the Missouri PSC directed Ameren Missouri to weigh the reliability, resiliency and operational benefits of HVDC transmission facilities in the Order approving the stipulation and agreement and granting certificate of convenience and necessity (CPCN) under Docket EA-2024-0237.

2 According to the amended CPCN filing for GBX under Docket EA-2023-0017, Phase I of GBX plans to provide a 2500 MW connection between Western Kansas and Missouri of which 1500 MW will be delivered to MISO Zone 5 and 1000 MW to Associated Electric Cooperative Incorporated (AECI). Phase 2 of GBX is expected to provide another 2500 MW of transmission capacity between Kansas and PJM, but was not modeled as the benefits analysis focuses on Ameren Missouri.

3 A recent update by Invenergy projects that GBX Phase 1 construction will commence in 2026 and be complete by 2029.

In the *Reference* Case it is assumed that Ameren Missouri is limited to renewable resources in MISO Zone 4 and Zone 5. However, in the *HVDC Case,* 1,800 MW of Illinois wind and 600 MW of Missouri solar are replaced by an equivalent amount (based on ICAP) of GBX resources located in Western Kansas. The GBX portfolio is subject to a 1,500 MW line limit with the assumption that any excess renewable generation is sold into the SPP market at spot prices.

CRA's benefit analysis assumes that Ameren Missouri secures rights to one-third of the GBX Phase I portfolio and transmission capacity (600 MW KS Wind, 200 MW KS Solar, 500 MW line limit) with the remainder distributed to other entities in MISO Zone 4 and Zone 5. While the full GBX Phase I portfolio and transmission capacity are modeled by CRA, benefits attributed to Ameren Missouri are based on its one-third allocation.

To quantify the benefits between *HVDC Case* and *Reference Case*, highly regarded industry standard models were used to complete the study. CRA analyzed impacts to Ameren Missouri using the zonal capacity expansion and production cost modeling software Aurora, while reliability and resiliency assessments were performed using CRA's in-house reliability model AdequacyX.[4]

1.2. HVDC Benefits

The benefits enabled by GBX for Ameren Missouri are summarized in Table 1. As shown, net benefits of the *HVDC Case* relative to the *Reference Case* from 2029 to 2040 are $266.9 million (2025 net present value).[5]

Table 1: 2029-2040 GBX Benefits

(2025 NPV in millions of dollars)[6]

	Ameren Missouri
1. Energy Trade Benefits	117.7
2. Resource Adequacy Benefits	16.3
3. Resource Cost Savings	132.9
Total Benefits	266.9

As listed in Table 1, the key cost/benefit components assessed in this study are: 1. Energy Trade Benefits; 2. Resource Adequacy Benefits; and 3. Resource Cost Savings. Each category is discussed in further detail below.

<u>1. Energy Trade Benefits</u> are the reduction in energy costs incurred by Ameren Missouri enabled by GBX transmission capacity and paired generic Kansas wind and solar resources. The renewable resources that are assumed to be connected to GBX are also assumed to have higher capacity factors compared to MISO alternatives, putting downward pressure on

4 AdequacyX utilizes industry best practices for probabilistic Monte Carlo-based loss of load studies. It has been used in IRP proceedings and other resource adequacy studies across the country including NIPSCO, Wisconsin Power and Light, and Interstate Power and Light.

5 Assumes a 6.96% discount rate.

6 Net Present Value (NPV) figures are all in 2025$

zonal energy costs and operational costs for Ameren Missouri resources. Additionally, excess energy from GBX resources above the transmission transfer limit is assumed to be sold into SPP at spot prices, driving additional revenue for Ameren Missouri. Overall, Energy Trade Benefits for Ameren Missouri in the *HVDC* Case result in a benefit of $117.7 million over the 2029-2040 period.

2. Resource Adequacy Benefits represent the improved reliability contributions of GBX resources relative to MISO alternatives. CRA's modeling shows a reduction in loss of load expectation (LOLE) and expected unserved energy (EUE) in the *HVDC Case.* To quantify resource adequacy benefits CRA assigned a value of lost load (VOLL) to the reduction in EUE achieved in the *HVDC Case*. Overall, Resource Adequacy Benefits for Ameren Missouri in the *HVDC Case* result in a benefit of $16.3 million over the 2029-2040 period.[7]

3. Resource Cost Savings are the difference in assumed costs between Kansas wind and solar resources relative to MISO alternatives. Bids received by Ameren Missouri identify an approximate 10% equivalent capital cost savings for Kansas resources relative to Missouri and Illinois. Resource Cost Savings for Ameren Missouri in the *HVDC Case* are $132.9 million over the 2029-2040 period.

2. Introduction and Background

On October 30, 2024, the Missouri PSC issued an order in Docket No. EA-2024-0237 approving the negotiated Stipulation and Agreement filed by Ameren Missouri, Staff, MECG, Renew Missouri, and Grain Belt in addition to granting a CPCN for the 800 MW Castle Bluff Project. As part of the Stipulation and Agreement, Ameren Missouri was directed to weigh the reliability, resiliency and operational benefits of HVDC transmission facilities themselves, including but not limited to those outlined in Section 6 of Guidehouse Study: *Grain Belt Express (GBX): Resilience and Reliability Values.*[8] Having in-depth experience in resource planning and cost-benefit studies, Ameren Missouri engaged CRA to lead the HVDC Transmission Facilities Benefits Analysis as directed by the Missouri PSC.

Charles River Associates

CRA has a long history of working on cost-benefit assessments. CRA recently worked on the Ameren Illinois MISO vs. PJM cost-benefit study performed at the directive of the Illinois Commerce Commission (ICC). CRA's RTO analysis work dates back more than a decade, including work for East Kentucky Power Cooperative (decision to join PJM in 2012) and Entergy and Cleco (decision to join MISO in 2011). Moreover, the company, and the staff assigned to this engagement, possess extensive experience in capacity expansion, resource adequacy, and cost-benefit analysis, which are core components of this analysis. For instance, CRA has reviewed and refined MISO and SPP cost-benefit frameworks for regional transmission planning processes. CRA has also performed market modeling, portfolio modeling, and resource adequacy assessments for several MISO, PJM, and SPP investor-owned utilities including AEP, NiSource, Alliant, Liberty, Entergy, FirstEnergy, Dominion, and Duke. Lastly, CRA has performed commercial and regulatory diligence on a number of transmission

7 Resource adequacy benefits can be measured by reducing the risk of load shedding as measured by risk metrics, like Loss of Load Expectation (LOLE) or Expected Unserved Energy (EUE) (FERC Benefit 2A) or reducing the reserve margin/capacity needs (FERC Benefit 2B). While both approaches are discussed in this report – CRA quantified Resource Adequacy Benefits under Benefit 2A.

8 Exhibit 11, Schedule AP-2, Section 6 in Docket No. EA-2023-0017.

mergers and acquisitions processes, including FERC rate-regulated and merchant HVDC and HVAC transmission assets.

Below is a list of relevant cost-benefit and transmission engagements CRA has participated in:

- 2011 Entergy Cost Benefit Analysis (SPP, MISO)
- 2011 ATSI Cost Benefit Analysis (MISO, PJM)
- 2012 EKPC RTO Membership Assessment (PJM)
- 2020: SEEM RTO Study (Southeast US)
- 2023 Ameren Illinois Cost Benefit Study (MISO and PJM)
- 2023/2024: MISO Benefits Framework Assessment for Regional Planning Process
- 2021-2024: Transmission Diligence Engagements in multiple ISO markets
- 2024/2025: SPP Benefits Framework Assessment for Regional Planning Process

More recently, the CRA team has used similar analytical approaches and modeling tools in conducting several Integrated Resource Plans (IRP) for electric utilities across the United States.

3. Benefits Analysis

CRA assessed three different categories of benefits for the Ameren Missouri HVDC Transmission Facilities Benefits Analysis: Energy Trade Benefits, Resource Adequacy Benefits, and Resource Cost Savings.

3.1. Energy Trade Benefits

3.1.1. Model Overview

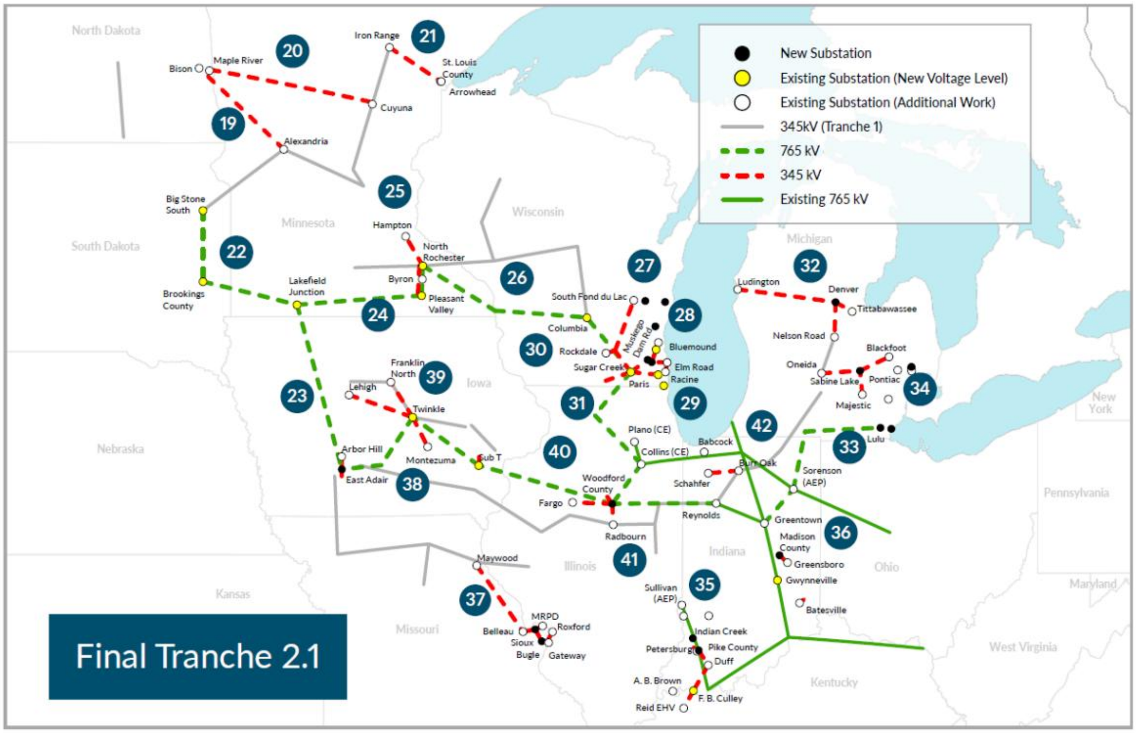
CRA's market projections are based on a fundamental analysis of portions of the Eastern Interconnection market (MISO, SPP, PJM, SERC) from January 2025 through December 2040. For the energy market modeling, CRA deployed the Aurora[9] electricity market model to develop a fundamental forecast of market prices. Aurora is a detailed capacity expansion and production costing model that simulates operation of the electric power system taking into account zonal transmission topology. The Aurora model determines commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the zonal price for each generator and load area. CRA has extensive experience with the Aurora model and currently leverages it for all market modeling and utility portfolio modeling engagements.

CRA's market analysis is performed at the zonal level, focusing on price formation in regions with persistent and significant transmission congestion, rather than at every individual node within the system, accounting for interzonal transfer capability limits based on MISO's local resource zones (LRZs). CRA's analysis considered existing and planned transfer capabilities across MISO zones, particularly Long Range Transmission Planning (LRTP) Tranches 1 and

9 The Aurora model is commercialized by Energy Exemplar and is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation; https://www.energyexemplar.com/aurora

2.1 projects (Figure 2), expected to be completed in the 2028 to 2034 period. Actual realized prices will differ at the nodal level within these zones, and changes in local transmission topology plus changes in local supply and demand dynamics could significantly alter nodal pricing dynamics over time. However, the zonal approach evaluates the expected long-term trends at major pricing hub levels over a long-term analysis horizon.

Figure 2: MISO LRTP Tranche 1 and 2.1 Approved Projects

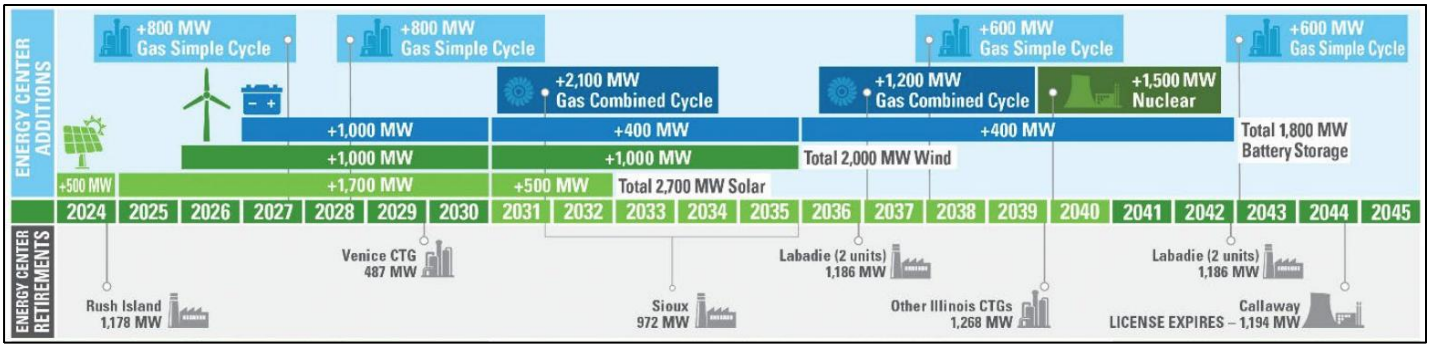


To model future resource mixes across MISO, SPP, and PJM, CRA relied on the Aurora model to perform the capacity expansion analysis. Aurora's Long Term Capacity Expansion (LTCE) functionality provides an analytical framework to account for policy measures, market rules, and changes in fundamental market drivers. This model uses a recursive optimization process to identify the set of resources with the highest and lowest market values to produce an economical capacity expansion and retirement schedules.

This licensed model is set up to perform regional, long-term capacity expansion analysis for MISO, SPP, and PJM, simultaneously; and to forecast hourly zonal price and economic dispatch using hourly demand. Aurora also includes individual resource operating characteristics in a transmission constrained system representing the Eastern Interconnect. Market inputs for the Aurora model include fuel prices, emission prices, demand, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options.[10] Resource additions and retirements from Ameren Missouri's 2025 Preferred Resource Plan (Figure 3) were also included in the Aurora model.

Zonal energy prices are derived from the dispatch cost of the last unit in a zone needed to serve its net load. Dispatch costs are determined by fuel costs, variable O&M costs, and the costs of emissions allowances. By increasing energy trade, additional low-cost generation from GBX resources leads to lower dispatch costs, resulting in cost savings.

Figure 3: Ameren Missouri's 2025 PRP Resource Timeline



3.1.2. HVDC Modeling

Benefits gained from Kansas solar and wind generation enabled by GBX are evaluated under two cases: the *Reference Case* considering current trajectory of MISO without the GBX line, and the *HVDC Case* considering the inclusion of GBX Kansas resources in MISO. The *Reference Case* uses CRA internal load forecasting and capacity expansion results for MISO, SPP, and PJM, which include considerable load growth from data centers and generation buildout necessary to meet these growing energy needs. The *HVDC Case* on the other hand includes GBX with a line capacity of 1,500 MW paired with 1,800/600 MW of Kansas wind/solar respectively.

To establish a proper comparison between resources gained in the *HVDC Case* and what is in the planned buildout for MISO in the *Reference Case*, GBX resources are offset by subtracting the equivalent amount of wind and solar resources from MISO Zone 4 and Zone 5.[11]

CRA modeled GBX resources as the combination of wind and solar generation, capped at the maximum MW transfer limit of the GBX line. Since Ameren Missouri is only pursuing rights to one-third of the GBX MISO capacity, CRA modeled three resource tranches in Aurora composed of 600 MW of Kansas Wind, 200 MW of Kansas Solar, and a 500 MW line limit (Figure 4) – totaling 800 MW of potential generation per tranche. When the sum of solar and

10 CRA subscribes to the Hitachi Energy Velocity Suite – a database that provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model. The database includes approximately 25,000 electricity generating facilities in the contiguous United States (U.S.), Canada, and Baja Mexico. These generating facilities include wind, solar, biomass nuclear, coal, natural gas and oil.

11 Resource offsets between the *HVDC* and *Reference Case* are done on installed capacity (ICAP) terms – i.e. the total 1,800 MW of wind and 600 MW of solar are offset instead of the 1,500 MW GBX line limit.

wind generation exceeds 500 MW in a given hour, GBX resources are capped at 500 MW. Figure 5 captures one tranche of GBX wind and solar output relative to the 500 MW line limit. As shown, certain days in this example month (August) have excess generation above the line limit – particularly in the morning and evening hours.

Figure 4: GBX Generation Breakdown per Tranche

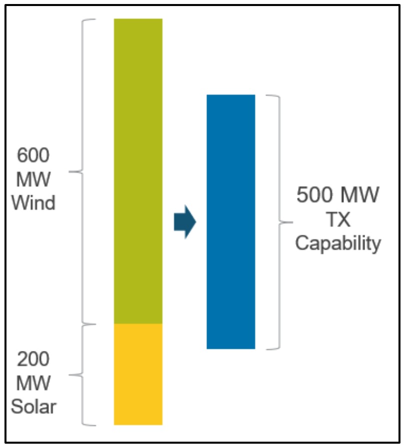
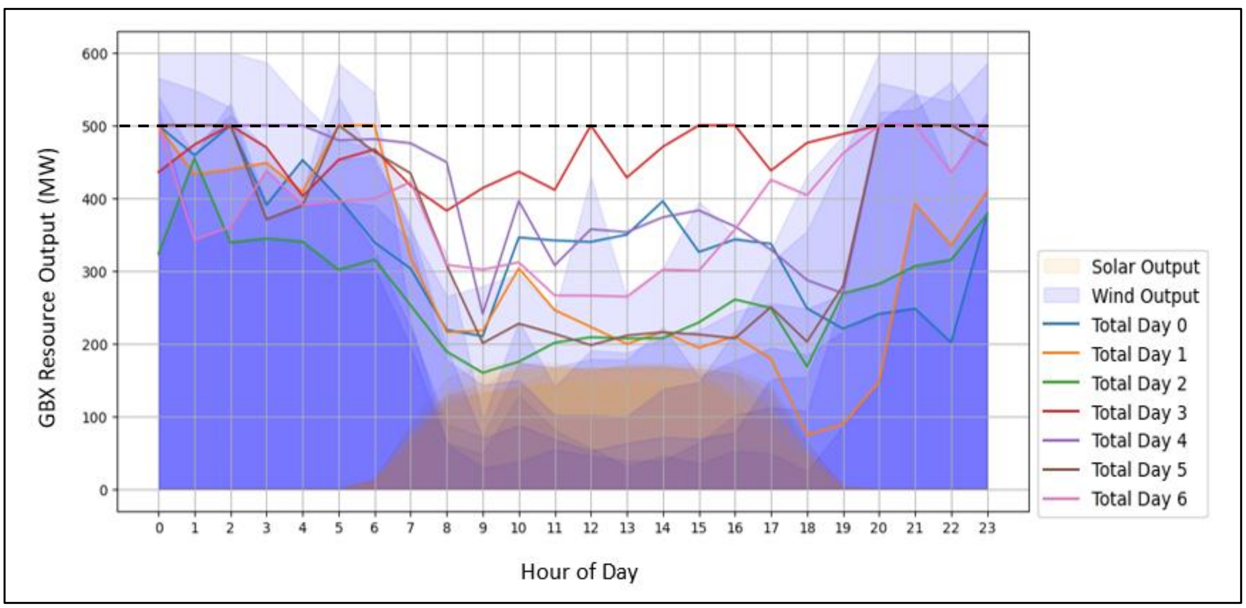


Figure 5: GBX Wind + Solar Generation Capped at Line Limits (August)



3.1.3. Energy Trade Benefit Results

In this study, energy trade benefits are quantified by calculating, at every hour, the difference in energy purchases, dispatch costs, and excess GBX energy sales between the *Reference* and *HVDC* cases for Ameren Missouri.

Table 2 summarizes the results of the energy trade benefit analysis. As discussed, superior capacity factors of GBX resources result in lower energy costs for MISO Zone 5 and lower dispatch costs for Ameren Missouri resources ($98.3M benefit). Additionally, excess GBX resource sales into SPP ($19.4M benefit) further improve net benefits relative to the

Reference Case. When combined, the *HVDC* Case results in a net present value of $117.7M in energy trade benefits.

Table 2: Energy Trade Benefit Results (2029-2040)

Year	Ameren Missouri Energy Trade Benefits ($ millions)
2029	13.5
2030	15.7
2031	16.2
2032	14.9
2033	15.4
2034	17.0
2035	15.9
2036	13.7
2037	20.7
2038	17.1
2039	21.3
2040	14.8

3.2. Resource Adequacy Benefits

3.2.1. Methodology

One of the potential benefits of GBX is the ability to improve resource adequacy of the system. Per FERC Order 1920, this reliability benefit (listed as the second of seven benefits) can be measured in two ways: reducing the risk of load shedding as measured by risk metrics, like Loss of Load Expectation (LOLE) or Expected Unserved Energy (EUE) (Benefit 2A) or reducing the reserve margin/capacity needs (Benefit 2B).[12]

CRA evaluated the potential reliability benefits of GBX – and subsequent access to wind and solar resources in Kansas and potential access to excess energy in the wider SPP market during emergencies – using both, LOLE and EUE, approaches. This analysis was performed using AdequacyX, CRA's Monte Carlo-based resource adequacy model. This model simulates a wide range of correlated wind, solar, load, and outage shocks to assess the likelihood of an event with insufficient generating capacity to meet demand across the system, subject to physical infrastructure limits. Reliability assessments in AdequacyX, as with other reliability models, are run over a single year – for the benefits analysis, CRA conducted AdequacyX runs for both the *Reference Case* and *HVDC Case* across three target years: 2030, 2035, and 2040 – representing the full 2029-2040 forecast horizon. Further details on this model are included in the appendix.

12 Federal Energy Regulatory Commission. *E1* | RM21-17-000.

The risk of shedding load due to insufficient deliverable generation is measured using LOLE[13] and EUE.[14] LOLE measures the expected number of days per year with at least one outage event; EUE measures the expected total energy (MWh) not served. From this analysis, the capacity accreditation of various resources can be quantified using MISO's Direct Loss of Load approach (discussed in further detail below).

Simulated Portfolio

AdequacyX simulated load-shedding risk across all of MISO Zone 5, since risk is pooled within each Zone and across the broader MISO footprint. Accordingly, the full 1,500 MW GBX line capacity and associated Kansas resources (1,800 MW of wind generation and 600 MW of solar generation) were modeled as entering Zone 5. CRA assumes outages and benefits are shared proportionally to the energy share of each load-serving entity in each Local Resource Zone (LRZ). As such, Ameren Missouri would be exposed to the entire Zone 5 LOLE risk and a share of the Zone 5 EUE risk proportional to its share of total energy consumed in Zone 5. CRA assumes Ameren's energy share of Zone 5 is 96% prior to 2032 and 97% thereafter.

To evaluate the potential resource adequacy benefits of GBX, CRA modeled the *Reference Case* not including the GBX line and Kansas-based resources, but considered equivalent new solar and wind resources, in the MISO footprint, contracted to deliver energy and capacity to MISO. In the GBX counterfactual, CRA simulated the impact on the reliability of Zone 5 if these resources were moved outside the MISO footprint and instead built in Kansas.

To accurately assess the reliability benefits of the GBX line, it is critical that Kansas-based resources are modeled as *alternative* wind and solar resources, not as additional resources. This is because Ameren Missouri is only required to meet the capacity target set by MISO. As such, it would contract with either MISO-based resources or Kansas-based resources to meet its capacity and energy needs. It would not pursue both resources if capacity obligations are met by one or the other. Thus, CRA assumes that, if GBX comes online, it would displace equivalent nameplate capacity of MISO-based resources due to the absence of an offtaker.

As with the Energy Trade Benefits, the Resource Adequacy assessment models two scenarios for potential displacement of MISO-based wind resources. In the *Reference Case*, Zone 5 contracts with an 1,800 MW Illinois-based wind resource (assuming new wind technology) and a 600 MW Missouri solar resource to meet its capacity and energy needs. Ameren Missouri receives only one-third of these resources in meeting its energy and capacity needs (under the assumption Ameren Missouri receives a 500 MW allocation of GBX) but still benefits from the energy physically entering LRZ 5. In the *HVDC Case*, these resources are removed from the MISO footprint, and an 1,800 MW Kansas-based wind resource and 600 MW Kansas-based solar resource are added to the system via GBX.

In the AdequacyX model, any excess generation from within MISO and SPP is available to help other zones within those systems, subject to line limits. In the scenarios that simulate GBX in service, CRA also assumed that any excess generation in SPP could support MISO and be delivered on GBX and other transmission links and vice versa. CRA understands that the ability of the GBX line to accommodate bi-directional flow or access the wider SPP market

13 Loss of load expectation measures the likelihood of a day in a given year having at least one event where firm load demand cannot be met due to insufficient generating resources. LOLE does not account for the magnitude or duration of these load shedding events or the occurrence of multiple events on a given day.

14 Expected unserved energy measures the average portion of firm energy demand which cannot be served due to insufficient generating resources.

is not yet settled. However, this analysis assumed both to provide an upper-bound estimate of the reliability benefits from the GBX line.

Benefit 2A: Increased Reliability with the Same Nameplate Portfolio

Using the Benefit 2A approach, CRA simulated the reliability risks to Zone 5; the reliability benefit of GBX was quantified as the change in LOLE and EUE relative to the baseline. The financial benefit of improved reliability, shown in Equation 1, was quantified as the reduction in EUE between the *Reference* and *HVDC cases* multiplied by the Value of Lost Load (VOLL). CRA assumed a VOLL of $10,000 per MWh of load shedding – in line with recent FERC approval for MISO.[15,16] Ameren Missouri's share of the reliability benefit created by GBX is scaled relative to its share of the energy consumed in Zone 5.

Equation 1: GBX Reliability Benefit 2A

$$GBX\ Reliability\ Benefit = Ameren\ \%\ Zone\ 5 * VOLL * (EUE_{Reference} - EUE_{HVDC})$$

Benefit 2B: Meeting Capacity Obligations with Less Installed Capacity[17]

An alternative approach to quantifying resource adequacy benefits is the Benefit 2B approach, which simulates the reduction in capacity need, under the same portfolio concept. These benefits are alternatives to each other, not additional benefits. Using the Benefit 2B approach, CRA simulated the potential reduction in installed capacity that is enabled by connecting to Kansas resources with a different capacity accreditation than an equivalent MISO-based resource. As a result of the change in resource accreditation, Zone 5 and Ameren Missouri could need fewer resources, as measured by nameplate capacity, to meet capacity needs.

Ameren Missouri operates within MISO and is required to meet the capacity obligations set by MISO. Options include developing native resources, entering into power purchase agreements, or obtaining additional capacity via the MISO capacity auction. Ameren Missouri must follow MISO's rules when ascribing capacity accreditation to its generating resources. As such, CRA used the accreditation rules defined by MISO when assessing the potential capacity contribution of GBX and MISO-native resources – the Direct Loss of Load (DLOL) methodology. MISO received FERC approval to implement DLOL and plans to implement it in Planning Year 2028-2029.[18]

DLOL measures the contribution of various technologies during tight margin hours (i.e., hours where load demand is closest to or exceeds the available generation to serve it) in a given season. MISO assigns a seasonal class-wide value to each resource class based on the average contribution of each technology class during tight margin hours identified using computer simulation models.

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15 Value of lost load is theorical price that a customer would pay to avoid interruption. VOLL is highly dependent on assumptions about customer behavior and the time of the outage, magnitude of the outage, and duration of the outage. True VOLL is unknown and often treated as a single, estimated value.

16 On April 4, 2025, FERC gave MISO authority to set its VOLL as high as $10,000/MWh.

17 Benefits under 2B are calculated using DLOL framework currently published by MISO and approved by FERC. CRA recognizes MISO is reviewing accrediation methodoliges for HVDC resources which may be subject to change in the future including potential accrediation of the HVDC line itself.

18 Federal Energy Regulatory Commission. *Order Accepting Proposed Tariff Revisions*, Docket No. ER24-1638-000. Issued October 25, 2024.

After three years of operation, each individual unit's performance is adjusted based on its *actual* performance during tight hours (known as Tier 2 hours) and typical operation (known as Tier 1 hours) in each season, with a greater weight placed on the former to reward generators for contributing during periods of grid stress. The measure of each unit's real-time performance in each season is called the Intermediate Seasonal Accredited Capacity (ISAC). After three years in operation, a unit's seasonal capacity accreditation is adjusted based on its ISAC values. It can receive higher or lower seasonal ratings than other generators in its resource class. This final adjusted capacity rating, known as the Seasonal Accredited Capacity (SAC), is shown in Equation 2. Because of this unit-specific correction, high-performing units relative to their peers can achieve a higher capacity accreditation.[19]

Due to the strong wind and solar potential in Kansas, Kansas-based wind resources could achieve higher ISAC values than comparable MISO resources, particularly during summer months. As a result, these higher-accredited Kansas resources could reduce the size of MISO-based resources required for Ameren and other Zone 5 entities to meet their capacity obligations.

Equation 2: MISO DLOL Accreditation

$$SAC = Nameplate * DLOL_{class} \frac{ISAC}{ISAC_{class}}$$

Critically, MISO is currently refining its approach to DLOL. It is not yet clear how resources outside of the MISO footprint will be accredited or how the impact of line limits will be simulated in the DLOL framework. For this study, however, CRA assumed that MISO will apply the standard DLOL framework to out-of-footprint resources, and that these resources can count toward meeting Ameren Missouri's seasonal capacity obligation. Accordingly, Kansas-based resources were credited with both the base MISO seasonal class value and a unit-specific ISAC adjustment (after three years of operation).

The benefit of the GBX resources is measured by the reduction in the seasonal unforced capacity obligation due to access to highly accredited Kansas-based resources. Ameren Missouri's tightest season is winter. Accordingly, CRA focused the impact to capacity obligation during winter months due to the ISAC values of Kansas-based resources, relative to equivalent MISO-based resources. The potential reduction in installed capacity is given in the equations below.

Equation 3: UCAP Reduction

$$UCAP\ Reduction = \frac{ISAC_{GBX} - ISAC_{Reference}}{ISAC_{Class}} DLOL_{Class} ICAP_{GBX}$$

Equation 4: ICAP Reduction

$$ICAP\ reduction = \frac{UCAP\ Reduction}{DLOL_{Reference}}$$

Reliability Benefits of Kansas-based Resources

Strong capacity factor relative to legacy MISO resources
Kansas-based resources are assumed to offer several advantages relative to legacy MISO-

19 Midcontinent Independent System Operator (MISO). Resource Accreditation White Paper, Version 2.1. March 2024.

based resources. First, Kansas has strong wind potential. In 2023, the U.S. Energy Information Administration (EIA) reported that wind farms in Kansas achieved an average capacity factor of 36.9%, comparable to or exceeding many states in MISO (37.6% for Iowa, 32.6% for Missouri, and 33.3% for Illinois).[20]

These values, however, reflect the capacity factor of the existing fleet, rather than new turbine technology. Improvements in wind generator technology — particularly increased turbine efficiency and access to higher hub heights — have steadily raised capacity factors. According to the 2024 Land-Based Wind Market Report, the average hub height of land-based wind turbines has increased by 5% since 2022 and by 83% since 1998−1999.[21] As a result, new wind projects in high-resource states, such as Kansas and Iowa, can now regularly achieve capacity factors in the 40–50% range. This is a meaningful improvement over legacy resources which typically had capacity factors in the 30–40% range.[22] New wind projects in high-wind parts of MISO, particularly Iowa, can also achieve similar performance.

Kansas also has relatively strong potential for solar resources relative to the states within northern MISO. According to the EIA, its average solar capacity factor, 24%, is higher than states within the northern MISO footprint (22.7% for Iowa, 21.5% for Missouri, and 22.9% for Illinois).[23]

Steady Summer Performance

In addition to generally strong wind generation, Kansas wind performs better during the summer months, relative to equivalent MISO-based resources. Wind generation in the Upper Midwest, Upper Plains, and Lower Plains typically slows in summer. As a result, MISO assigns the lowest Direct Loss of Load (DLOL) values for the wind generators during this season, relative to other seasons of the year.[24] This seasonal dip is critical because many MISO regions remain summer-peaking and face their tightest margins during the summer months – Ameren Missouri is an exception though as its system is winter constrained due to gas supply constraints.

By contrast, Kansas wind resources exhibit a smaller summer slowdown and steadier month-to-month performance. This means Kansas resources can provide more generation during MISO's most constrained summer periods.

However, Kansas-based resources may have worse performance than MISO-based resources in the winter months. Wind farms in the northern portion of MISO often experience their peak performance in winter, while Kansas based resources typical have their best months in the shoulder seasons.

20 U.S. Energy Information Administration. "Capacity Factors and Usage Factors at Electric Generators: Total (All Sectors), 2023"

21 Lawrence Berkeley National Laboratory. *Land-Based Wind Market Report: 2024 Edition.*

22 *Id.*

23 U.S. Energy Information Administration. "Capacity Factors and Usage Factors at Electric Generators: Total (All Sectors), 2023"

24 Midcontinent Independent System Operator, Inc. *LOLE Modeling Enhancements: Storage Modeling*.

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Figure 6 and Figure 7 illustrate this point: while all sample sites experience summer reductions, the Kansas site shows the smallest decline and the most stable monthly profile.

Figure 6: Sample Monthly Capacity Factors for Kansas Wind Resources

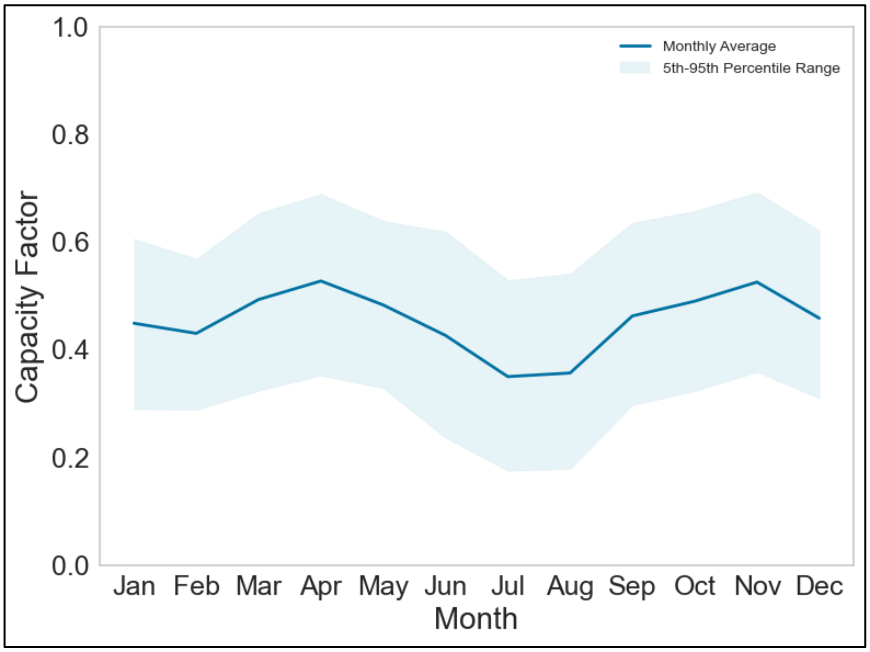
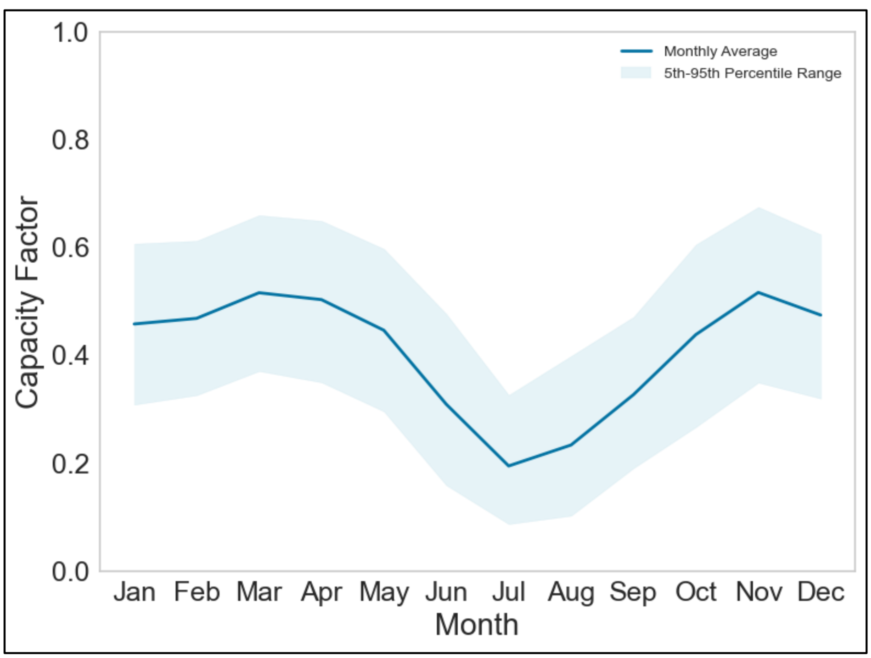


Figure 7: Sample Monthly Capacity Factors for Illinois Wind Resources



Increased geographic diversity
Kansas-based resources also enhance the geographic diversity of the MISO fleet. By tapping into a wider range of weather systems, Kansas-based resources provide a hedge against correlated renewable lulls across the MISO footprint. Greater diversity reduces the risk that wind and solar resources in multiple regions underperform simultaneously, thereby improving overall system adequacy. As discussed above, Kansas-based resources also have complementary patterns in generation relative to MISO-based resources: Kansas wind is strongest in the shoulder seasons, while MISO-wind is strongest in the winter. Wind farms in both regions experience summer slowdowns, but Kansas's slowdown is markedly less than much of MISO's. Additionally, Kansas-based solar resources also continue later into the evening hours since they are physically further to the west than MISO-based resources. This can provide more solar energy during increasingly tight hours in MISO after the sun has set.[25]

3.2.2. Resource Adequacy Benefit Results

VOLL / Benefit 2A Approach

CRA quantified the benefits of GBX and resulting access to Kansas-based wind and solar resources by evaluating the reduction in reliability risk (Benefit 2A approach). CRA found that displacing Missouri/Illinois-based resources with higher capacity factor Kansas based resources could reduce reliability risks. The annual reliability results are shown in Table 3. Change in LOLE and EUE as well as AdequacyX study year VOLL benefits are captured for Ameren Missouri. Assuming a VOLL of $10,000, linear interpolation between the study years, a discount rate of 6.96%, and assuming that Ameren Missouri comprises between 96-97% of Zone 5, CRA found the resource adequacy benefit for Ameren Missouri to be $16.3M net present value**.**

Table 3: LOLE, EUE, & VOLL Benefits

	LOLE (days/year)		EUE (MWh)		VOLL Benefits
Study Year	***Ref. Case***	***GBX Case***	***Ref. Case***	***GBX Case***	**Million $**
2030	0.51	0.30	672	302	3.5
2035	0.1	0.06	148	69	0.8
2040	0.25	0.17	864	541	3.1

While GBX resources do drive resource adequacy improvements in terms of LOLE and EUE, the VOLL benefits are relatively small as the *Reference Case* already starts from a strong reliability position, leaving little room for improvement in the *HVDC Case.* Alternatively, resource adequacy benefits enabled by GBX can also be evaluated by potentially reducing Ameren Missouri resource capacity obligations as discussed below.

Capacity Reduction / Benefit 2B Approach

CRA also assessed the potential benefits of GBX and the resulting access to Kansas-based wind and solar resources by evaluating the reduction in capacity needs (Benefit 2B

25 MISO. *Planning Year 2025–2026 Loss of Load Expectation Study Report*.

approach). CRA computed the ISAC values for each of the relevant portfolios of wind and solar resources. The ISAC represents the weighted-average contribution of each portfolio during typical and tight-margin hours. ISAC values were estimated from the AdequacyX simulations, but in reality, would be computed using actual operations and would vary year-to-year.

The key variation between the portfolios is seasonal performance in wind generation and the resulting impact on the estimated ISAC value. The estimated ISAC value for each of the potential wind locations is shown in Table 4.

Table 4: ISAC Values for Potential Wind Resources

Season	Legacy MISO	New IL	New KS
Winter	0.24	0.52	0.48
Spring	0.20	0.50	0.46
Summer	0.18	0.22	0.36
Fall	0.18	0.33	0.44

All new wind resources in Illinois and Kansas would have significantly higher ISAC values due to the adoption of state-of-the-art wind generation technology. As a result, new Illinois and Kansas wind would receive a capacity accreditation higher than the existing MISO fleet. However, due to varying seasonal patterns, a Kansas-based wind resource would perform worse in winter and spring relative to an Illinois-based resource, but the Kansas-based resource would perform better in the summer and fall.

While MISO as a whole is typically summer constrained and would benefit from improved Kansas-based wind, Ameren Missouri's tightest season is winter and would see slightly less capacity benefits relative to Illinois wind.

Critically, evaluating the capacity differences of wind resources alone does not fully capture the benefit of the GBX line, since it does not consider the interactions of the portfolio as a whole (i.e. wind & solar) or the impact of line limits on the ability of the Kansas-based resources to contribute to resource adequacy in MISO. To this end, CRA performed a similar analysis for the ISAC of the entire portfolio (Table 5).

Table 5: ISAC Values for Potential Portfolios

Season	1,800 Legacy Wind + 600 Legacy Solar (Legacy MISO)	1,800 IL Wind + 600 MO Solar (*Reference Case*)	1,800 KS Wind + 600 KS Solar (*HVDC Case*)
Winter	0.20	0.39	0.34
Spring	0.17	0.37	0.33
Summer	0.13	0.18	0.27
Fall	0.15	0.27	0.31

Based on these portfolio ISAC values, CRA also computed the resulting difference in the unforced capacity requirement between the various portfolio concepts (Legacy MISO and *Reference Case)* and GBX Kansas-based portfolio (*HVDC Case)*. These capacity differences are reported in both the winter and summer seasons, which are typically the binding seasons for meeting capacity obligations in MISO. The capacity savings are reported for Ameren Missouri only, assuming that it receives one-third of the capacity accreditation of the GBX resources.

Table 6: Reduction in Unforced Capacity Requirement (UCAP) for Ameren Missouri Due to GBX Resources

Season	1,800 Legacy Wind + 600 Legacy Solar (Legacy MISO)	1,800 IL Wind + 600 MO Solar (*Reference Case*)
Winter	99 MW	-36 MW
Summer	78 MW	50 MW

Relative to legacy MISO resources, a shift to wind and solar resources based in Kansas, substantially reduces the need for local capacity. This is primarily due to the adoption of state-of-the-art wind technology and the relative strength of the Kansas wind and solar resources. However, when compared to similar new technologies in the MISO footprint, the benefit of a Kansas-based fleet is less marked. The shift to a Kansas-based fleet actually *increases* the need for winter capacity. This is because new MISO-based wind resources have stronger winter performance relative to their Kansas counterparts. On the other hand, the shift to a Kansas-based fleet decreases the need for summer capacity relative to MISO-based portfolios. This is due to the higher summer wind speeds in Kansas as compared to states in the MISO footprint.

The net benefit for Ameren Missouri under the Benefit 2B approach is unconclusive as Ameren Missouri experiences a worse capacity position in the winter, but an improved capacity position in the summer. Quantifying the potential benefit is speculative as it would require transparency of seasonal capacity prices over the 2029-2040 forecast period to calculate summer benefits and winter costs. Additionally while MISO is currently summer constrained[26], electrification and weather-dependent capacity is expected to concentrate future risk in the winter[27] further complicating the benefits analysis. For these reasons, CRA used VOLL/Benefit 2A to quantify resource adequacy benefits enabled by GBX resources in the *Reference Case.*

3.3. Resource Cost Savings

To identify resource cost assumptions for MISO resources, CRA relied on LevelTen Energy's[28] wind and solar PPA data for Zone 4 and 5 resources, anchoring the analysis in

26 MISO is currently summer constrained as seen by the Planning Resource Auction (PRA) results for the 2025-26 planning year.

27 MISO Attributes Roadmap. December 2023.

28 LevelTen Energy operates one of the largest renewable energy marketplaces in North America, aggregating wind and solar PPA transaction data from project developers and buyers to provide market-based price benchmarks.

market bid data[29] rather than cost estimates. Of note, LevelTen wind and solar PPA data likely lags real-time market conditions as changing federal incentives in the One Big Beautiful Bill Act are still being processed by renewable developers.

Using the LevelTen market PPA prices, CRA backed out a hurdle rate to derive the implied levelized cost of energy (LCOE) for each resource and used an internal LCOE model to back-calculate corresponding capital costs for wind and solar in each region. Resulting capital cost estimates for Illinois wind and Missouri solar were validated against other regional utility planning estimates to ensure directional alignment.

Confidential bids received by Ameren Missouri indicate an average 10% capital cost savings between Illinois/Missouri and Kansas renewables. CRA applied this 10% discount to Illinois and Missouri capital costs derived from LevelTen data to estimate Kansas resource costs.

Table 7: Wind/Solar Capital Cost Assumptions (2025$)

Region	Resource	Cost ($/kW)
MO	Solar	2,540
IL	Wind	2,107
KS	Solar	2,286
KS	Wind	1,896

Capital costs savings for GBX resources allocated to Ameren Missouri (600 MW Wind and 200 MW Solar) were amortized over 20 years using a 6.96% discount rate resulting in an annual savings of $12.9M/$5.2M for Kansas wind and solar resources respectively. Overall, resource cost savings enabled in the *HVDC Case* total $132.9M NPV over the 2029-2040 study period.

4. Overall Benefit Analysis Results

Shown in Table 8 are the overall net benefits between the *HVDC Case* and the *Reference Case* using the components discussed in Section 3. As shown, the overall net benefit to Ameren Missouri is $266.9 million (2025 net present value) over the 2029-2040 study period.

29 Current PPA prices available from LevelTen represent bids from developers but are not representative of actual transacted projects. Absent cost data from transacted renewable projects, LevelTen data serves as a close proxy.

Table 8: 2029-2040 GBX Benefits

	Ameren Missouri
1. Energy Trade Benefits	117.7
2. Resource Adequacy Benefits	16.3
3. Resource Cost Savings	132.9
Total Benefits	266.9

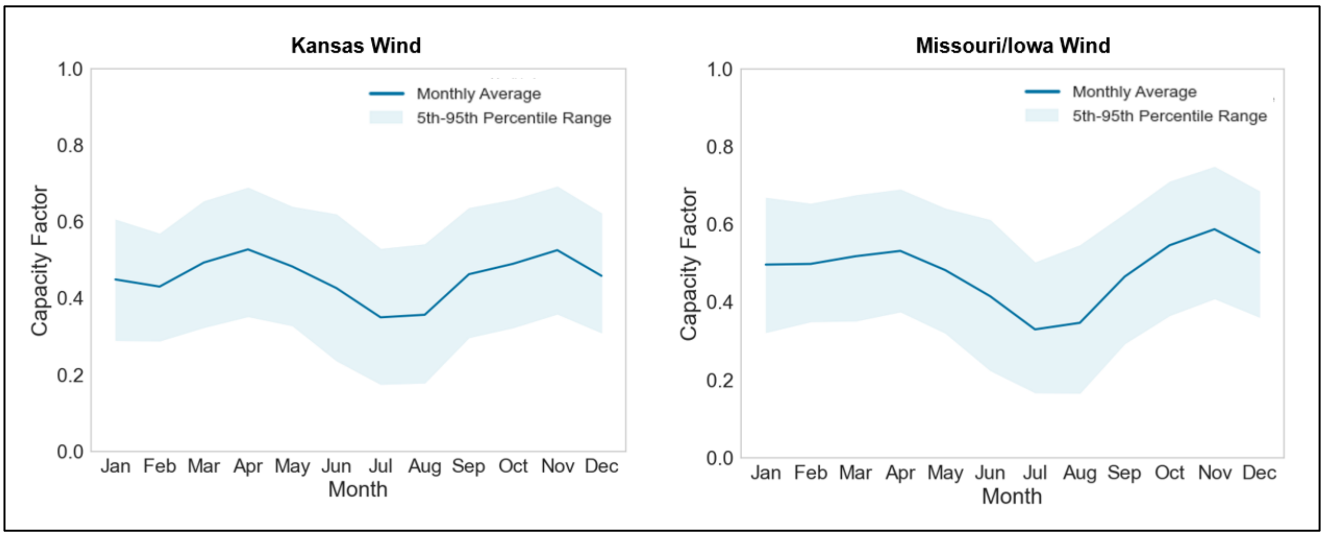
5. Sensitivity Analyses

5.1. Northern Missouri / Iowa Wind Comparison

CRA also explored a sensitivity in which it is assumed that Ameren Missouri can access high value MISO-based wind resources due transmission investments from the MISO Long-Range Transmission Planning Tranche 2.1.[30] In this sensitivity, Zone 5 can access 1,800 MW of wind resources near the Missouri/Iowa border and 600 MW of Missouri-based solar resources. Ameren Missouri also only contracts with one-third of these resources but still benefits from the physical interconnection in the system. In this counterfactual, these resources are removed and replaced with the 1,800 MW Kansas-based wind resource and 600 MW Kansas-based solar resource is added to the system via the GBX line.

This sensitivity is particularly interesting from a resource adequacy perspective as wind near the Missouri/Iowa boarder more closely matches wind shapes in Kansas (Figure 8).

Figure 8: Comparison of Kansas vs Missouri/Iowa Wind



30 Midcontinent Independent System Operator, Inc. *MTEP24 Full Report*. October 1, 2024.

Table 9 captures the LOLE and EUE comparison between Missouri/Iowa wind and GBX resources in Kansas.

Table 9: Resource Adequacy Results with Missouri/Iowa Wind

Study Year	LOLE (days/year)		EUE (MWh)		VOLL Benefits (costs)
	MO/IA Wind+Solar	*GBX MO/IA Sensitivity*	*MO/IA Wind+Solar*	*GBX MO/IA Sensitivity*	Million $
2030	0.29	1.53	251	1827	(15)

The above result is partially caused by GBX line limits. In simulations, the power produced by the Kansas-based solar and wind resources met or exceeded the 1,500 MW line limit during 41% of hours. As a result, an average of *823.7 GWh* could not be delivered on the GBX line. This excess energy could be sold into SPP but is not available to contribute to the resource adequacy of Zone 5. In contrast, the Missouri-based resources had better interconnection with the wider MISO market. When MISO resources exceed local delivery constraints, excess energy could be delivered to other MISO zones or stored in MISO-based storage resources.

The key insight from this sensitivity is to evaluate geographic renewable resource availability options during resource planning. Resource adequacy results from the *Reference Case* show that GBX resources have superior reliability contributions relative to Illinois Wind and Missouri Solar. However, the opposite is true in the sensitivity case where a combination of Missouri/Iowa wind and Missouri solar provide superior resource adequacy benefits relative to GBX resources assuming MISO transmission capacity is made available.

5.2. HVDC Line Limit Impact on Resource Adequacy

As noted above, the MISO assumed GBX line limit of 1,500 MW was met during 41% of hours with a Kansas portfolio of 1,800 MW of wind and 600 MW of solar (Figure 9). To evaluate the impact of line limits on resource adequacy, CRA evaluated a scenario where line limits were relaxed.

Figure 9: GBX Wind/Solar Output with Line Limit

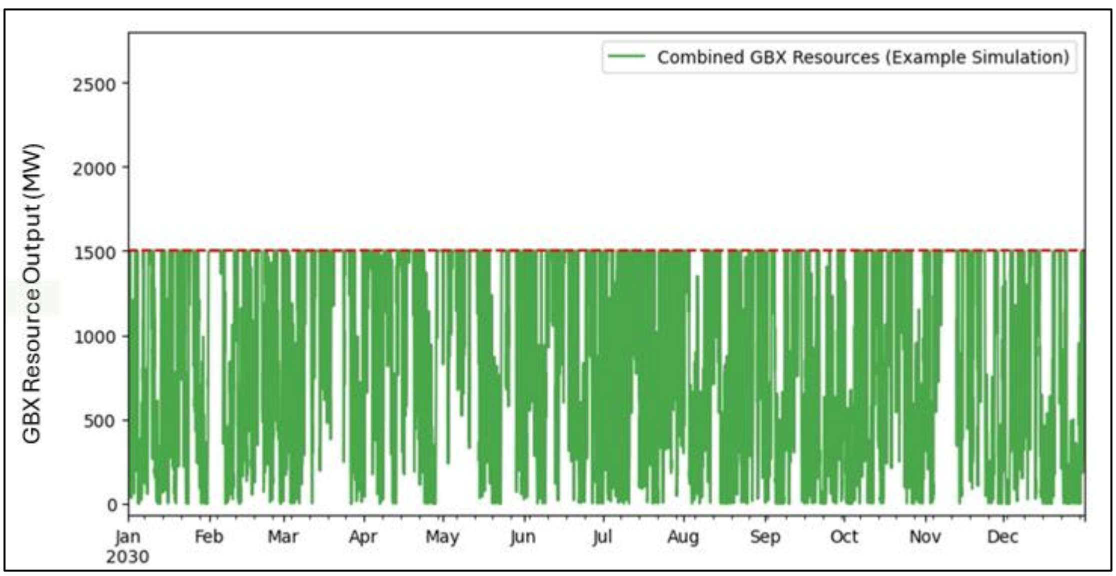


Table 10 shows modest improvements for ISAC values when line limits are relaxed. This result further reinforces the competitive nature of local or transmission rich renewable resources relative to those with transmission limits. As Ameren Missouri considers future resource planning decisions, it is important to evaluate the impact (or lack thereof) transmission limits on available renewable resources.

Table 10: ISAC Comparison with No GBX Line Limit

Season	1,800 IL Wind + 600 MO Solar (*Ref Case*)	1,800 KS Wind + 600 KS Solar (*GBX Case*)	1,800 KS Wind + 600 KS Solar (*No Line Limit*)
Winter	0.39	0.34	0.38
Spring	0.37	0.33	0.38
Summer	0.18	0.27	0.29
Fall	0.27	0.31	0.35

6. Qualitative Considerations

6.1. HVDC System Restoration and Ancillary Service Capabilities

In accordance with the Commission's directive, CRA conducted a literature review and evaluation of the reliability, resiliency, and operational benefits of HVDC transmission facilities, with specific reference to the GBX as outlined in Exhibit 11, Schedule AP-2, Section 6.[31] This review confirms that the findings presented in the exhibit are supported by both a growing body of external research and real-world use cases, confirming that HVDC infrastructure, particularly those utilizing Voltage Source Converter (VSC) technology, offers substantial system-wide advantages across multiple transmission planning regions.

1. Value of System Restoration Capabilities

As outlined in Exhibit 11, Schedule AP-2, Section 6.1, the Grain Belt Express (GBX) project offers an effective approach to system restoration through the use of Voltage Source Converter (VSC) HVDC technology. The exhibit highlights that GBX's converter stations, located in Kansas, Missouri, and Indiana, potentially enabling interconnection with four balancing authorities (SPP, AECI, MISO, and PJM), allowing the project to function as a black-start resource independent of local generation, fuel storage, or weather conditions.[32] The exhibit cites successful black-start operations using VSC HVDC in the Kristiansand–Tjele link (Norway–Denmark) and the NYPA–Quebec HVDC tie during the 2003 blackout as precedents.

CRA's review confirms that GBX's VSC HVDC technology will indeed provide black-start capabilities, supporting independent energization of the grid. Other real-world examples of black start capabilities in HVDC include Caithness–Moray HVDC Link (UK), which demonstrated black-start capability and enabled energization of AC networks without

31 Exhibit 11, Schedule AP-2, Section 6 in Docket No. EA-2023-0017.

32 Assuming bi-directional flow is available to and from all balancing authorities.

synchronous generation, while Caprivi Link (Namibia) enabled black-start of isolated AC systems operated in grid-forming mode during restoration events.[33] These examples are among many that demonstrate the ability of HVDC systems to energize portions of the grid without relying on synchronous generation – a capability GBX could potentially deliver. Additionally, Brattle Group's 2023 report on the operational and market benefits of HVDC to system operators also notes that VSC HVDC systems can provide black-start services and can be operated remotely and do not require onsite generation or fuel, which contributes to cost-effectiveness in restoration scenarios.[34] Similarly, EPRI's HVDC restoration study, conducted in collaboration with the UK National HVDC Centre, also emphasizes the strategic value of VSC HVDC systems in system recovery scenarios. The report highlights HVDC's ability to operate in island mode, provide voltage and frequency control during restoration, and support energization of AC networks in regions with low inertia and vulnerability to extreme weather and fuel supply disruptions.[35] GBX's VSC HVDC technology may be able to provide these same capabilities, reinforcing its contribution to dynamic reliability and restoration capabilities for the regional grid.

2. Unique HVDC Reliability Values

Section 6.2 of Exhibit 11 details the reliability benefits of VSC HVDC systems, emphasizing their ability to provide ancillary services traditionally supplied by synchronous generators. GBX's converter stations are designed to deliver electronically controlled active and reactive power in real time, accurate to the millisecond, which is critical as inverter-based resources (IBRs) replace legacy generation. CRA's review confirms as a VSC HVDC line, GBX will be able to provide independent and flexible active and reactive power control, which improves power quality and avoids overloads on AC networks.[36] Academic studies and operational experience demonstrate that VSC HVDC systems can independently control voltage and reactive power, supporting grid stability in weak or stressed networks.[37]

The exhibit's Section 6.2 also outlines additional operational benefits of GBX's HVDC infrastructure, including voltage and frequency control, dynamic voltage support, emergency power modulation, and damping of electromechanical oscillations. These capabilities align with both real-world VSC HVDC deployments and academic studies.[38] Notably, MISO's Renewable Integration Impact Assessment (RIIA) studies highlight several of these functionalities for VSC-based HVDC technology, which GBX would bring to the region.[39] External literature, including IEEE's survey on HVDC-based oscillation damping (Elizondo et al., 2018), also confirms VSC HVDC's ability to significantly improve system resilience. More recent research (P. B. Garcia-Rosa et al., 2023) shows that VSC HVDC systems can

33 Power Engineering International. 2011. "Modern HVDC Solution Provides Vital African Link - Power Engineering International." Power Engineering International. December 2011.

34 Battle Group, "The Operational and Market Benefits of HVDC to System Operators."

35 EPRI Report: Coordination of AC Protection Settings during Energization of AC Grid from a VSC HVDC Interconnector Project.

36 MISO Planning Advisory Committee "VSC HVDC Technology Attributes for the Future Power System", May 2023,

37 Sood, Vijay K. HVDC and FACTS Controllers: Applications of Static Converters in Power Systems.

38 Brattle Group, "Market and Operational Benefits of HVDC Transmission", February 2025.

39 MISO's Renewable Integration Impact Assessment (RIIA) 1 Contents. February 2021.

emulate synthetic inertia and provide fast frequency response, helping to stabilize low-inertia grids such as those with high renewable penetration. [40]

Brattle's 2023 report on operational and market benefits of HVDC also highlights some of the above-mentioned benefits, along with other benefits not explicitly highlighted in the exhibit, such as AC phase balancing, AC Harmonics, which are important to power quality support, and grid-forming operation under weak grid conditions – all of which GBX will be able to deliver.[41]

While CRA was able to confirm the benefits outlined in Exhibit 11, Schedule AP-2, Section 6, quantifying these benefits was not performed as part of this study. These qualitative benefits are likely smaller compared to the main benefits identified in Section 3 – however if benefits quantified in this study relative to GBX costs are on the margin, recommend Ameren Missouri pursue further analysis to quantify HVDC system restoration and ancillary service capabilities.

6.2. Resiliency Analysis

Another criteria CRA used to evaluate each portfolio's robustness is its performance under extreme events. While the AdequacyX model incorporates extreme weather shocks in some scenarios, expected unserved energy (EUE) only measures the average amount of energy not served in a given year. As such, it does not fully communicate the range of possible load shedding outcomes. To better understand the behavior of the tail risk, CRA also examined the energy not served during the most severe events.

Specifically, CRA employed two additional risk metrics:

- Conditional Value at Risk (CVaR) of unserved energy (90%) — the average total annual unserved energy among only the worst 10% of scenarios. CVaR highlights the tail-end outage risk and shows how portfolios perform under extreme stress.
- Average outage event size — the mean size of a load-shedding event, but only across hours with non-zero unserved energy. This provides insight into the severity of outages when they do occur.

As shown in Table 7, the GBX portfolio in the *HVDC Case* has lower values for both metrics across all years, indicating better resilience to extreme conditions relative to the *Reference Case*.

Table 11: Resiliency Metrics

Study Year	CvaR (90%) Energy (MWh)		Outage Size (MW)	
	Ref. Case	***GBX Case***	***Ref. Case***	***GBX Case***
2030	5,373	2,796	162	82
2035	1,476	686	89	39
2040	7,442	5,105	300	176

40 M. A. Elizondo et al., "Interarea Oscillation Damping Control Using High-Voltage DC Transmission: A Survey," in IEEE Transactions on Power Systems, vol. 33, no. 6, pp. 6915-6923, Nov. 2018.

41 Battle Group, "The Operational and Market Benefits of HVDC to System Operators."

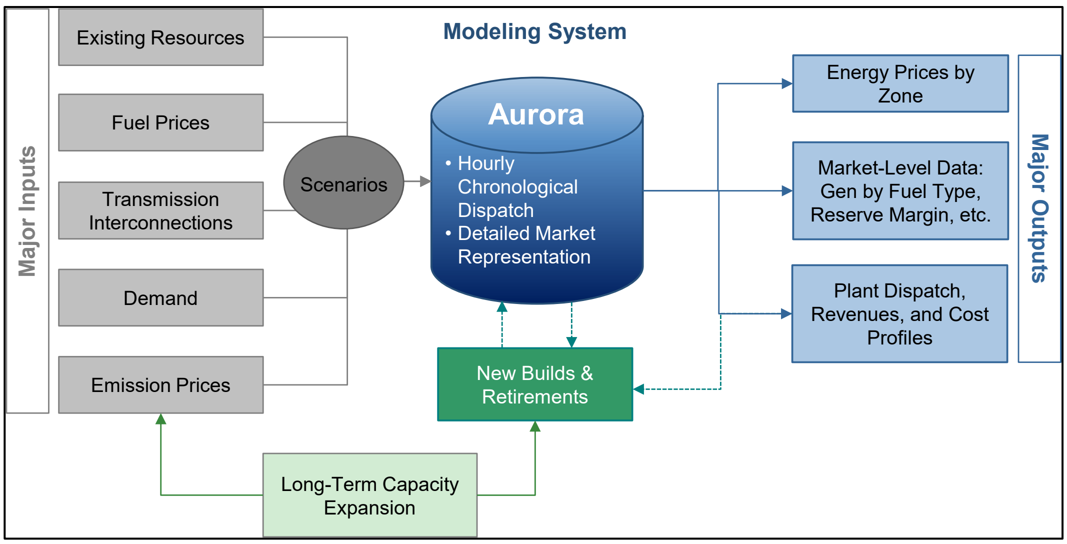
7. Conclusions

Based on the analysis performed and its assumptions, GBX would create significant value for Ameren Missouri in the form of Energy Trade Benefits, Resource Adequacy Benefits, and Resource Cost Savings. However, the benefits must be balanced against the investment costs which CRA has not analyzed in this report. Further, as shown in the sensitivity analysis, if Ameren Missouri can access superior wind resources in Northern Missouri and Iowa, the benefits created by GBX are reduced. Ultimately this analysis provides a basis for Ameren Missouri to compare potential benefits relative to costs of GBX and inform future investment decisions that are in the best interest of Missouri ratepayers.

Appendix A: Aurora

Aurora is a chronological, hourly dispatch model that represents all major pricing zones across North America, including in ERCOT. The model requires inputs for supply resources (and all associated operational parameters), fuel prices, transfer capabilities between zones, demand, and emission prices. It is run in hourly, chronological format and produces energy prices for each zone along with plant-level dispatch, energy revenues, and variable cost profiles for relevant assets in the market. The key model architecture is shown in Figure 10.

Figure 10: Aurora Model Architecture

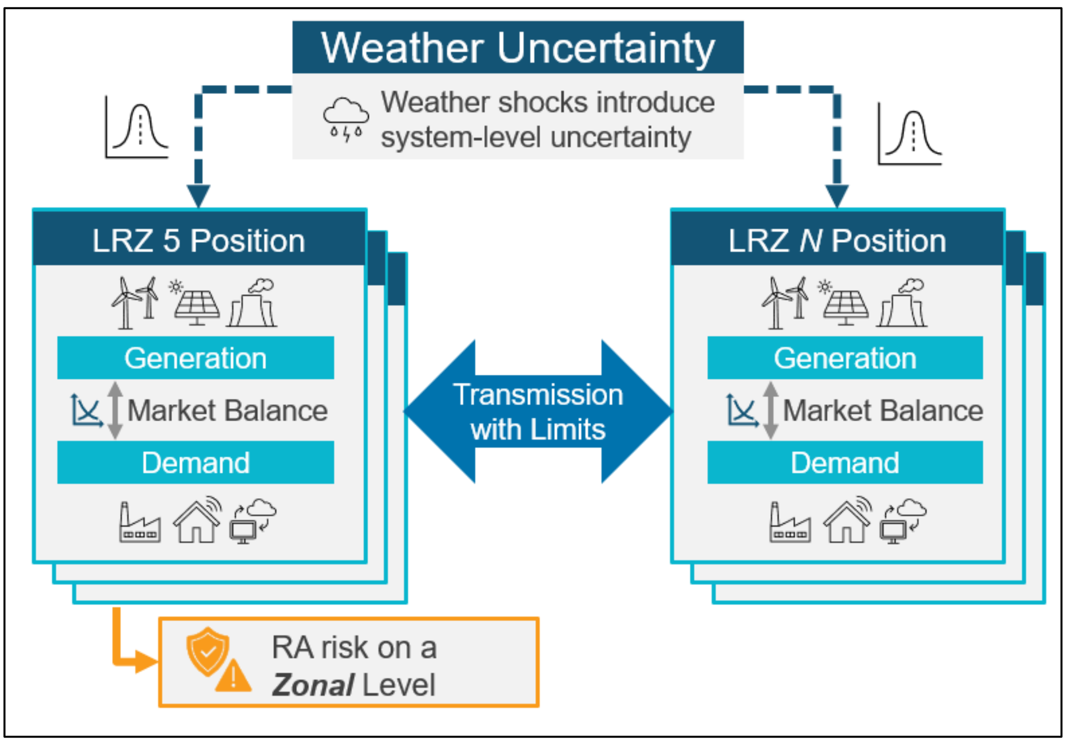


Ameren Illinois RTO Cost-Benefit StudyAmeren Illinois RTO Cost-Benefit StudyAmeren Illinois RTO Cost-Benefit Study

Appendix B: AdequacyX

AdequacyX is a CRA proprietary resource adequacy model. It focuses on physical ability to meet electricity demand, subject to weather variability and physical infrastructure limits. It simulates emergency conditions, rather than typical economic operation. Similar to other models used in the broader resource adequacy space, AdequacyX uses Monte Carlo simulations to generate a large number of wind, solar, load, and outage shocks that capture a full range of possible outcomes. Critically, these iterations are correlated with each other and correlated across hours. This captures wide-area and long-duration events. AdequacyX also captures the impact of cold-weather induced generator outages and the uprates/derates that occurs with generation due to temperature conditions. AdequacyX assumes that each LRZ focuses on meeting its demand first. Any excess capacity is sent to zones to minimize or eliminate load shedding, subject to transmission limits. If any shortfalls remain, batteries are discharged to cover them, subject to energy limits. Any remaining capacity is used to charge battery resources, subject to energy limits. The model's structure is show in Figure 11.

Figure 11: AdequacyX Structure

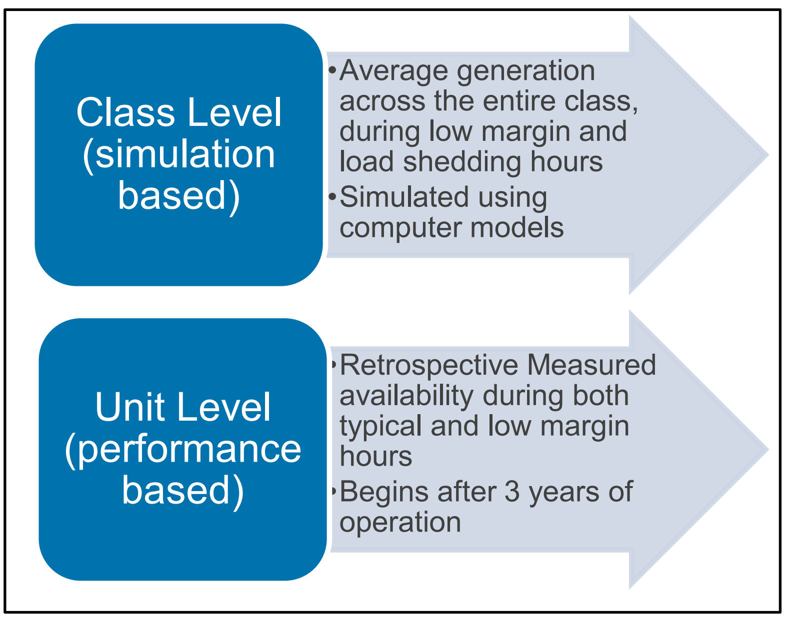


Appendix C: MISO Direct Loss of Load Methodology

The Direct Loss of Load (DLOL) methodology measures the contribution of given resources during low margin hours. MISO received permission from FERC to implement DLOL in Planning Year 2028-2029.[42] It accounts for the contribution of class-wide contribution by generator type during simulated tight margin hours, and the individual performance of each individual unit during tight hours in operation (Figure 12). The former is measured using advanced, Monte Carlo computer simulations which model the behavior of a large number of potential load, wind/solar generation, and thermal generator outage outcomes. Across these simulations, the average availability of a given generators class is measured during the low margin and load shedding hours. This represents the class level direct loss of load rating for each generator technology.

The latter is measured using a weighted average of a unit's real-time availability during normal hours (Tier 1) and the tightest margin hours (Tier 2). This represents a blend of a unit's day-to-day availability – driven more by capacity factors and/or forced outage rates – and operations during extreme event.[43]

Figure 12: DLOL Methodology for Accrediting Resources



To educate stakeholders on potential class DLOL ratings, MISO has published indicative, non-binding values. To CRA's knowledge and at the time of this study, the most recent values

42 Federal Energy Regulatory Commission. Order Accepting Proposed Tariff Revisions, Docket No. ER24-1638-000.

43 Midcontinent Independent System Operator (MISO). Resource Accreditation White Paper, Version 2.1. March 2024.

were published in April 2025.[44] It is important to note that these values are preliminary and will evolve based on changes in selected resources across the MISO footprint and as MISO refines in modeling methodology in response to stakeholder feedback. MISO has given particular emphasis to the simulation of storage dispatch decisions (i.e., 'early' versus 'blended' versus 'even loss'), which has a non-trivial impact on the resulting accreditation assigned to storage resources.

44 Midcontinent Independent System Operator, Inc. *LOLE Modeling Enhancements: Storage Modeling*. RASC Item 8, April 9, 2025.