Schedule AP-2

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Grain Belt Express (GBX): Resilience and Reliability Values

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1. List of Acronyms and Abbreviations

Acronym/Abbreviation	Definition
AC	Alternating Current
ACP	Auction Clearing Price
AECI	Associated Electric Cooperative Incorporated
AEP	American Electric Power
BES	Bulk Electric System
CAISO	California Independent System Operator
CIL	Capacity Import Limit
CONE	Cost of New Entry
CWLP	City, Water, Light & Power
DC	Direct Current
DOE	United States Department of Energy
EIA	Energy Information Administration
ELMP	Extended Locational Marginal Pricing
ERCOT	Electric Reliability of Texas
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
GBX	Grain Belt Express
GW	Gigawatt
HVDC	High Voltage Direct Current
IBR	Inverter-Based Resource
IEEE	Institute of Electrical and Electronics Engineers
IMM	Independent Market Monitor
IPP	Intermountain Power Project
ISD	In-Service Date
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LRR	Local Reserve Requirement
LRTP	Long Range Transmission Planning
LRZ	Local Resource Zone
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt Hours
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
NOI	Notice of Intent
NPV	Net Present Value
NYISO	New York Independent System Operator
NYPA	New York Power Authority

Acronym/Abbreviation	Definition
PJM	PJM Interconnection, LLC
POI	Point of Interconnection
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SIPC	Southern Illinois Power Cooperative
SIUC	Southern Illinois University
SPP	Southwest Power Pool
SRPBC	Sub-Regional Power Balance Constraint
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TCDC	Transmission Constraint Demand Curve
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
VSC	Voltage Source Converters
WECC	Western Electricity Coordination Council

Executive Summary

As an approximately 800-mile high voltage direct current (HVDC) transmission line with points of interconnection to three organized energy markets, the Grain Belt Express (GBX or Project) project has the potential to provide significant and measurable benefits to thousands of residential, commercial, and industrial electric utility customers along its path. Due to ingrained shortcomings of industry standard transmission system planning practices, long-haul interregional transmission projects like GBX require project proponents to estimate customer benefits using methodologies and tools available in the public domain to capture the broad-reaching benefits of a novel interregional transmission project with a breadth of beneficiaries. Through our research and analysis Guidehouse estimated reliability and resilience values potentially generated by GBX which are summarized here. The benefits estimated in this report are intended to be viewed as separate and distinct projections of individual value streams and are not necessarily additive in nature. Rather, the methods used in this report demonstrate different ways of approaching the economic valuation of benefits provided by new interregional transmission assets such as GBX, with GBX as a case study.

Resilience

This report analyzes the potential resilience benefits attributable to the addition of GBX with a focus on mitigated impacts of extreme weather events with results as summarized in Table 1. For the resilience benefit category Guidehouse leveraged two methodologies, the first being MISO's Value of Lost Load (VOLL). This approach approximates the socioeconomic impact of mitigating real time load shed events due to wide scale generation loss during severe winter weather events which recur every three years on average based on existing trends. The second methodology, transfer capacity analysis, applies analysis results published by Grid Strategies in their 2021 report "Transmission Makes the Power System Resilient to Extreme Weather"[11] which quantifies the value of additional transmission transfer capacity as a means to mitigate real time energy prices observed during four recent extreme weather events. Due to the potential for VOLL scenarios and extreme weather events to occur simultaneously or in close succession, these resilience benefits should not be interpreted as additive, but viewed as two different ways of calculating storm resilience benefits generated by interregional transmission resources.

Table 1: Summary of Quantitative Resilience Benefits

Benefit	Benefit Description	Measurement Methodology	Potential GBX Benefits
Mitigation of high energy prices during extreme weather events	Additional transfer capacity between organized markets decreases wholesale energy prices during increasingly frequent extreme weather events	Estimated Locational Marginal Price (LMP) reduction attributable to additional transfer capacity between markets during recent extreme weather events occurring during the 2014-2021 time period	Over the 2014-2021 time period GBX would have mitigated approximately $407.4 million of emergency energy pricing impact to customers in the markets served by the Project
Value of avoided risk of load shedding	Estimates economic value of lost load due to unplanned loss of generation	Application of MISO Long Range Transmission Planning (LRTP) approach to measuring impact of transmission upgrades and Independent Market Monitor (IMM) VOLL unit value	MISO value of avoided risk of load shedding or value of lost load: • 3 year benefit range: $84 million - $552 million • 30 year benefit range of $360 million - $2.37 billion (NPV)

Reliability

Guidehouse assumed that power generation facilities such as wind and solar, most likely paired with some form of firm energy storage resource, will be interconnected to the Project and are capable of delivering capacity through HVDC converter stations located in Kansas, Missouri and Indiana. In addition to the resilience benefits discussed above, the addition of the GBX transmission line and associated interconnected firm power generation facilities enables system operators to more cost effectively meet generation reliability requirements including Loss of Load Expectation (LOLE) thresholds. Guidehouse used two approaches to approximate the Project's contribution to reduced system reliability costs used in generation capacity planning; (1) deferred or mitigated generation capacity investment using avoided Cost of New Entry (CONE) calculations and (2) impact on MISO Planning Resource Auction (PRA) Auction Clearing Prices (ACP). The approximate reliability benefit ranges provided in Table 2 should not be considered additive because the integration of GBX will likely influence a new system equilibrium where there is an observed reduction of local procurement requirements and lower market auction prices due to combined natural market forces that cannot be reasonably uncoupled in an objective way as part of this analysis.

Table 2: Summary of Quantitative Reliability Benefits

Benefit	Benefit Description	Measurement Methodology	Potential GBX Benefits
Reduced generation procurement obligation	Approximates value of mitigated local capacity procurements to satisfy loss of load expectation requirements	Avoided CONE through an increase of transmission system import capacity	Reduced procurement obligations of transmission systems interconnected to GBX: • Annual benefit: $526.4 million • 30 year[1] benefit: $7.638 billion (NPV)
Avoided High Resource Auction Prices	Approximates the ability of GBX to push down annual resource adequacy auction prices by relieving resource scarcity	Analysis of savings generated by reducing auction clearing prices to normal levels	Annual MISO PRA avoided cost range: • Applying a $26.82/MW-day ACP: $346.0 million • Applying a $60/MW-day ACP: $410.9 million

[1] Based on Guidehouse's extensive experience providing transmission rate case analysis and testimony development, a 50 year book life is commonly assumed for high voltage electric transmission assets. Employing a conservative approach, Guidehouse assumed a 30-year asset life for the Project.

Operational Benefits

In addition to our quantitative analysis of reliability and resilience benefits, Guidehouse developed a qualitative description of the operational and reliability benefits the Project provides to system operators and customers, summarized in Table 3. Guidehouse considers these findings applicable to areas served by an interregional HVDC transmission line with novel Voltage Source Converters (VSC) performing DC to AC transformations such as GBX.

Table 3: Qualitative HVDC Project Benefits

Benefit	Benefit Description	Analysis Methodology	Potential GBX Benefits
Hedge against future generation retirements	Mitigates reliability and resource planning risks created by the rapid retirement of coal generation	Qualitative summary of planned coal retirements and issues encountered by other States adopting renewables in place of fossil generation	Protects electric customers from reduced competition in markets where generation capacity is scarce due to retirements and import capacity is constrained
Transmission system restoration capability	GBX provides black start capability without dependency on local generation and onsite fuel	Technical research backed description of HVDC Voltage Source Converters (VSC) system restoration capabilities	Zero marginal cost black start resource provides enhanced reliability to four States
HVDC operational flexibility	HVDC VSC resources provide transmission operators with the ancillary services typically provided by the rapidly retiring synchronous generator fleet	Technical research backed description of HVDC system operation enhancement characteristics	Provides cost effective replacement of ancillary services as legacy fleet of synchronous generation rapidly retires across the country

2. Introduction

It is widely recognized that a safe, reliable, and resilient power grid requires robust high voltage infrastructure to connect the lower voltage grids to the regional electric transmission network. In 2022 both the United States Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) identified the need for new interregional high voltage transmission projects such as GBX. In their Building a Better Grid Initiative Notice of Intent (NOI), the DOE recognizes that the industry standard 10-year transmission planning cycles are not designed "to identify long-term (beyond 10-year planning cycles), flexible, and interregional solutions that will meet national interests by enhancing electric system resilience across regions."[2] According to the DOE, current regional 10-year transmission planning processes are not structured in a way that considers and approximates key value streams generated by interregional transmission projects including:

- Enhance[d] grid reliability and. . . cost-effective integration of clean energy.[2]
- Modernizing, hardening, and expanding the grid will enhance the resilience of our entire electric system, and ensure that electricity is available to customers when it is needed most. Aging infrastructure leaves the grid increasingly vulnerable to attacks.[2]
- Investment in transmission infrastructure can help protect the grid against supply disruptions due to physical and cyber-attacks or climate-induced extreme weather, minimize the impact of supply disruptions when they happen, and restore electricity more quickly when outages do occur.[2]
- Expanding transmission capacity also improves reliability by creating stronger and more numerous energy delivery pathways, helping to ensure that consumers have a dependable source of electricity to power their homes, schools, and businesses. When one generation source is physically unavailable or uneconomic, transmission enables delivery from other generation sources, making the system better equipped to meet delivery requirements under the broader range of real circumstances and stresses seen in recent years.[2]

Additionally, FERC's April 21, 2022 Notice of Proposed Rulemaking (NOPR) regarding Regional Transmission Planning and Cost Allocation (Docket No. RM21-17-000) recognizes the need to reform existing interregional planning protocols under FERC Order 1000 and proposes "to require that public utility transmission providers. . .revise their existing interregional coordination procedures. . .to provide for. . .the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities."[3] As an approximately 800 mile HVDC transmission line with injection points in three neighboring states and four balancing authorities, Grain Belt Express is strongly representative of the high value interregional projects called for by the DOE and FERC.

Guidehouse performed in-depth research and detailed analyses to substantiate specific value streams the Project might generate to the benefit of electric utility customers in regions where GBX will add incremental electric transmission transfer capability. In this report Guidehouse provides detailed documentation, calculations and industry research supporting the following reliability and resilience value

[2] US Department of Energy, January 11, 2022. Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization. **https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf**

[3] FERC, 4/21/2022. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection. **https://www.ferc.gov/media/rm21-17-000**

streams applicable to this novel HVDC transmission line serving the states of Kansas, Missouri, Illinois, and Indiana. Additionally, in this report we have provided footnotes that identify the sources of information used by Guidehouse.

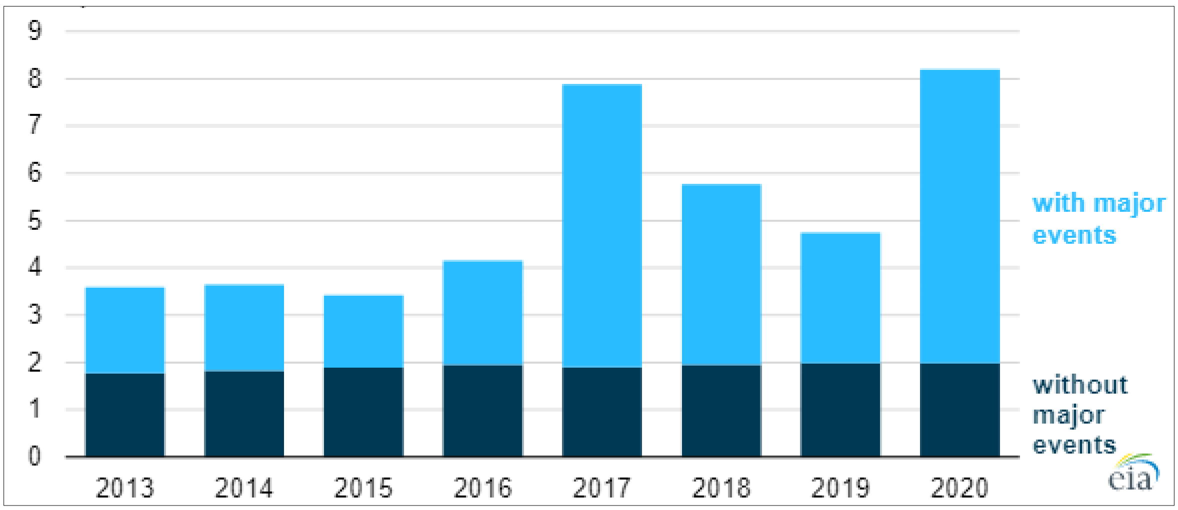
3. Mitigation of High Energy Prices During Extreme Weather Events

The value of a strongly interconnected grid has been highlighted by the lack of transfer capability during extreme weather events. Events like those experienced on January 17, 2018, where system operators in MISO "declared an Energy Emergency, because it had insufficient reserves to balance generation and load in the South portion of its footprint. while all four of the reliability coordinators experienced constrained bulk electrical system (BES) transmission."[4] Guidehouse gathered research documenting the frequency and impact of recent extreme weather events and quantified the potential resilience benefit the Project could have provided during these scenarios.

3.1 Increasing Frequency of Major Events

Utilities have the option to report their electric reliability performance metrics with major events, without major events, or both. From the reporting data depicted in Figure 1 and 2, there has been an upward trend of increased electric power interruption duration since 2013 even though reporting without major events has remained relatively constant.

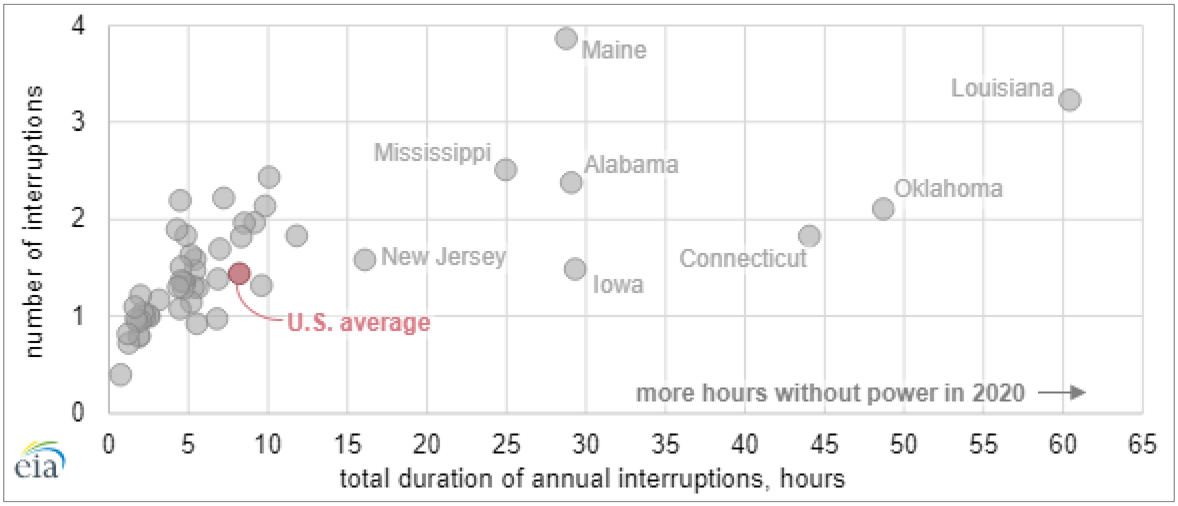
Figure 1: Average Duration of Total Annual Electric Power Interruption, U.S. (2013-2020) Hours per Customer[5]



[4] FERC and NERC Staff, July 2019. The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018. **https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf**

[5] US EIA, November 10, 2021. U.S. electricity customers experienced eight hours of power interruptions in 2020. **https://www.eia.gov/todayinenergy/detail.php?id=50316#**

Figure 2: Electrical Power Interruption Duration and Frequency per Customer by U.S. State (2020)[5]



3.2 Emergency Energy Prices

These extreme weather events drive shortfalls of generation capacity due to a lack of weatherization of capital upgrades and lead to increased Locational Marginal Prices, especially at the seams between ISOs and Regional Transmission Organizations (RTO). In its 2013 report the Executive Office of the President estimated that “weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion [during the 2003-2012 period]” and notes that “[g]rid resilience is increasingly important as climate change increases the frequency and intensity of severe weather.”[6] Going forward the annual cost of future weather events will increase significantly not only due to the increased frequency of events, but also in part due to FERC Order 831 under which MISO and SPP both have a $1,000/MWh cap on incremental bids whereas PJM has a cap of $2,000/MWh on cost-based offers (the associated prices and protocols for each are outlined in Table 4). In making this order, FERC cited the need to “provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and...ensure that all suppliers have an opportunity to recover their costs.”[7] In addition to enabling market participants to fairly recover their costs during exceptional operation conditions, such as extreme weather events, Order 831 helps provide “correct incentives for market participants to... make efficient investments in facilities.”[7] The high Locational Marginal Prices observed during the events described in Section 3.1.3 of this report reflect the value of building new interties between systems to effectively mitigate the customer cost impacts of increasingly frequent extreme weather events.

[6] Executive Office of the President, August 2013. ECONOMIC BENEFITS OF INCREASING ELECTRIC GRID RESILIENCE TO WEATHER OUTAGES. https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

[7] FERC, November 17, 2016. Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators. **https://www.ferc.gov/sites/default/files/2020-06/RM16-5-000.pdf**

Table 4: ISO Bid Caps

	Bid Caps	Onset Trigger/Protocols	Duration
MISO[8]	$500/Megawatt (MW)	▪ Emergency Operations Resources committed in real-time participate in Extended Locational Marginal Pricing (ELMP) ▪ Tier I Emergency Offer Floor established as the highest economic offer in the emergency area, subject to a minimum explained below and a maximum of Energy Offer Hard Bid Cap ▪ The Tier I Emergency Offer Floor minimum value is the lowest of: (1) the highest step of the lowest type Transmission Constraint Demand Curve (TCDC), (2) the highest step of the Sub-Regional Power Balance Constraint (SRPBC) demand curve, and (3) the Energy Offer Soft Bid Cap	1-4 hours
	$1,000/MW	▪ Emergency Operations Resources committed in real-time participate in ELMP pricing ▪ Tier II Emergency Offer Floor established as the highest economic or emergency offer in the emergency area, subject to a minimum of Energy Offer Soft Bid Cap and a maximum of Energy Offer Hard Bid Cap. If applicable, the Tier II Emergency Offer Floor shall be greater than or equal to the preceding Tier I Emergency Offer Floor	1-4 hours
PJM[9]	Load Management		
	$1,100/MWh	Primary Reserve Warning: Primary Reserve capacity is less than the Primary Reserve requirement	2 hours
	$1,425/MWh	Voltage Reduction Warning: Synchronized Reserve capacity is less than the Synchronized Reserve requirement	1 hour
	$1,825/MWh	Manual Load Dump Warning: Primary Reserve capacity is less than the largest operating generator (or a transmission tripping jeopardizes reliable operations)	30 min
	Maximum Generation Emergency Action		
	$2,000+/MWh	Maximum Generation Emergency Action: Generation is needed beyond the Economic Max MW energy level of all resources ▪ Units may be dispatched to Emergency Max MW limits ▪ Emergency Energy bids are requested	N/A
	Voltage Reduction and Manual Load Dump Action		
	$850/$1,700 MWh	Reserves at the maximum level of the demand curve	N/A

[8] MISO, August 2021. Emergency Pricing Reforms Primer. **https://cdn.misoenergy.org/Emergency%20Pricing%20Enhancements%20Primer591363.pdf**

[9] PJM, December 10, 2021. Emergency Procedures and Shortage Pricing. **https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/2021/20211210/20211210-item-03-emergency-procedures-and-shortage-pricing.ashx**

SPP[10]	150% of the Locational Marginal Price (LMP) or the greater of $100 MWh	Some utilities enter into an Emergency Energy Transactions Agreement with SPP to provide emergency service where: $Total\ Emergency\ Energy\ Charge = Energy\ Portion + Transmission\ Charge$	5-minute intervals or 1 hour

3.3 Notable Storms Impacting the BES 2014-2022

In response to Winter Storm Uri and several other major storms impacting the BES, Grid Strategies LLC prepared an analysis, "Transmission Makes the Power System Resilient to Extreme Weather,"[11] of five recent severe weather events and determined the resilience value that transmission expansion projects like GBX would have provided customers during these instances. Four out of five of the extreme events analyzed by Grid Strategies LLC impacted the SPP, MISO and PJM systems that GBX will provide significant incremental capacity to. In the following sections Guidehouse summarizes conclusions from the Grid Strategies LLC report[11] relevant to the Project.

3.3.1 Northeast "Bomb Cyclone" Cold Snap, December 2017-January 2018

"New England, New York, and the Mid-Atlantic region suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England... one gigawatt (GW) of stronger transmission ties between eastern and western PJM, the grid operator for much of the region between the Mid-Atlantic and Chicago, would have provided over $40 million in net benefits during this event."[11] As planned GBX provides significant incremental injection capacity of firm renewable and hybrid resources into Eastern PJM that can be transferred by system operators to relieve storm driven constraints in the Northeast.

3.3.2 Northeast "Polar Vortex," January 2014

"New England, New York, and the Mid-Atlantic region suffered several days of extreme cold in early January 2014. The grid operator for the Mid-Atlantic region, PJM, resorted to voltage reductions to avoid the need for rolling outages. Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns."[11]

In their report, Energy Strategies notes that "regions switched between importing and exporting as the most extreme cold migrated from region to region... lagged the other by an hour or two in experiencing the highest prices."[11] Projects like GBX enable markets and system operators to leverage resource diversity across extended geographic distances to minimize service interruptions and mitigate price spikes.

3.3.3 Midwest "Polar Vortex," January 30, 2019-February 1, 2019

"While an additional 1 GW of transmission between MISO and PJM would have saved around $2.4 million dollars during this short-lived cold snap, this event was notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward

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[10] Southwest Power Pool, December 15, 2021. Emergency Energy Transactions Agreement. **https://www.spp.org/documents/66214/20211215_psco-spp%20emergency%20energy%20transactions%20agreement_er22-651-000.pdf**

[11] Grid Strategies, LLC, July 2021. Transmission Makes The Power System Resilient To Extreme Weather. **https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf**

from MISO to PJM, so did the high power prices, and transmission flows switched from westward to eastward."[11] As noted in Table 5 below, GBX can provide at least 1 GW of incremental transfer capacity between MISO and PJM and would have enabled these regions to capture these energy savings had the line been in service.

3.3.4 Winter Storm Uri, February 2021

Grid Strategies' report summarizes the significant impact Winter Storm Uri had on the PJM and MISO markets (in addition to other impacted entities) which GBX will serve. According to the report, "[t]hose two lines [Grain Belt Express and The Plains & Eastern Clean Line] could have provided hundreds of millions of dollars in benefits during Winter Storm Uri alone."[11] The apparent need for more transfer capability between these regions was made clear through market signals as LMPs located at the PJM, SPP and MISO market seams saw transmission congestion costs approach $2,000/MWh numerous times and power prices reach or exceeded $1,00MWh during the weather event.[11] Grid Strategies concludes that MISO and SPP, in addition to ERCOT and TVA, could have also benefited from additional interregional transmission paths during Winter Storm Uri with 1 GW of capacity being valued at over $100 million to each balancing authority.[11]

3.4 Weather Resilience Value of Grain Belt Express

In order to determine the resilience value of the Project, Guidehouse applied Grid Strategies LLC estimation of energy savings per additional GW of transmission capacity during the four extreme weather events. To calculate the avoided emergency energy pricing savings generated by GBX, the following transfer capacities between regions were assumed:

Table 5: Project Injection Capacities

Total Line Rating	Flow Direction	Origin ISO/RTO	Receiving ISO/RTO	Capacity (GW)
5GW	West-East	SPP	MISO	1.50
	West-East	SPP	AECI	1.00
	West-East	SPP	PJM	2.50
	West-East	MISO	PJM	1.50
	West-East	AECI	SPP	1.00
	East-West	PJM	MISO	1.50
	East-West	PJM	AECI	1.00
	East-West	MISO	SPP	1.50
	East-West	AECI	SPP	1.00
	East-West	PJM	SPP	2.50

The resilience values of GBX was determined by multiplying the owner provided transmission transfer capacities into each ISO or RTO by the incremental transmission capacity value ($/GW) determined by Grid Strategies.

Table 6: Incremental Value of Project Transfer Capabilities During Recent Storm Events

Extreme Weather Event (Interregional Transfers)	Savings per additional GW transmission capacity ($M)[11] [A]	GBX Injection Capacity (GW) [B]	GBX Savings ($M) [A] x [B] = [C]
Winter Storm Uri, February 2021			
PJM to SPP South	$129.00	2.50	$322.5
Northeast "Bomb Cyclone" cold snap, December 2017-January 2018			
MISO to PJM	$38.00	1.50	$57.00
Northeast "polar vortex", January 2014			
MISO to PJM	$17.00	1.50	$25.50
Midwest "polar vortex", January 30, 2019-February 1, 2019			
PJM to MISO / MISO to PJM	$2.40	Not Applicable	$2.40[12]
	Total Savings Generated by GBX		**$407.40**

4. Avoided Loss of Load Benefit–MISO Value of Lost Load (VOLL)

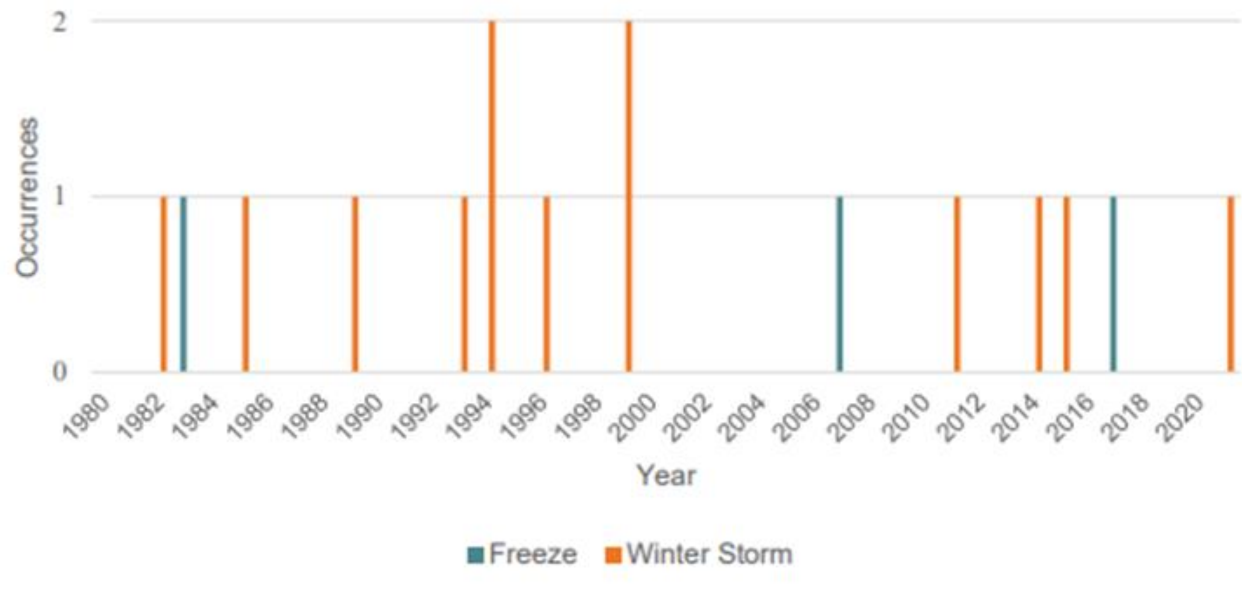
The ability of new BES pathways to avoid loss of load events is a known benefit cited frequently in transmission expansion planning processes. VOLL calculations are performed to estimate the cost that a customer bears due to an interruption in electric supply. In FERC's April 21, 2022 released NOPR regarding Regional Transmission Planning and Cost Allocation (Docket No. RM21-17-000), reduced loss of load probably is highlighted as a Long-Term Regional Transmission Benefit that transmission providers will be required to assess as part of their 20-year forward-looking regional planning processes. FERC notes that "... transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a public utility transmission provider will be unable to serve its load due to a shortage of generation over a given period."[3]

All transmission systems are designed to withstand a certain amount of loss of generation and transmission which could cut off the supply without interrupting load. However, in their LRTP business case, presentation MISO notes that their power system has experienced severe winter weather events,

[12] Grid Strategies assigned Midwest "polar vortex" storm market values equally to MISO and PJM for a total of $2.4 million for 1 additional GW of transfer capacity. In this case Guidehouse did not multiply [A] by [B] in Table 6 and instead captured the entire savings value as GBX can transfer at least 1 GW in either direction between SPP and MISO.

recently Uri, that caused large-scale unplanned generation outages resulting in an extended period of loss of load. In the last 40 years as shown in Figure 4, the events are occurring regularly.

Figure 4: Significant Winter Storm and Freeze Events in MISO Midwest States[13]



Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/. DOI: 10.25921/stkw-7w73

Similarly, the frequency of unplanned generation capacity outage events are becoming more common (Figure 5) and renewable resources regularly experience periods of low output lasting several hours (Figure 6).

Figure 5: Max Gen Alerts, Warnings, and Events in MISO Region[13]

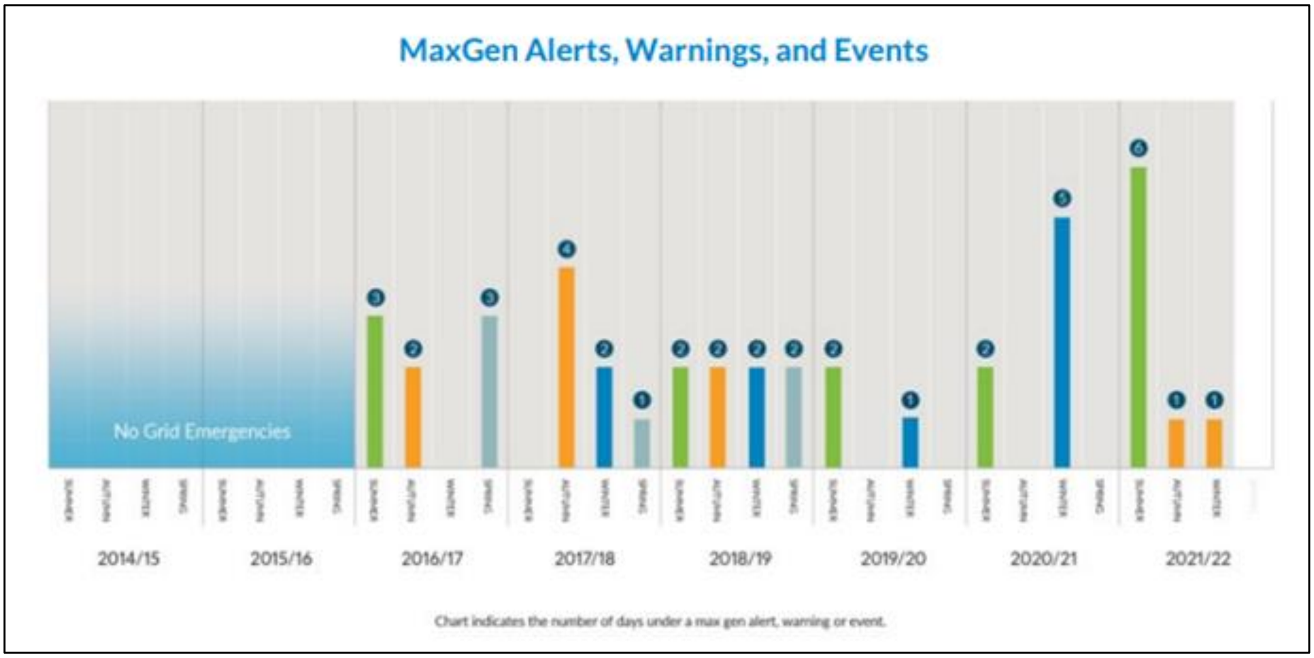
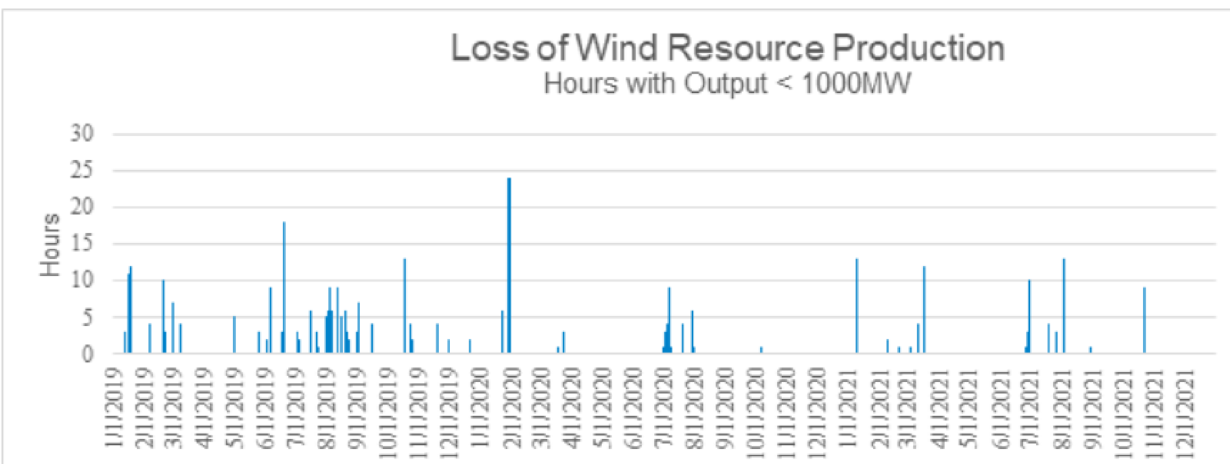


Figure 6: Loss of Wind Resource Production in MISO Region[13]



With the severity and frequency of weather events increasing and the resulting impact of generation interruptions, MISO leveraged the LRTP processes to identify and calculate a VOLL for its planning regions to support valuation of transmission expansion projects.

4.1 MISO VOLL Calculation Methodology

MISO's recent LRTP business case seeks to "identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs and support a competitive energy market"[13] and includes a study determining the probability of loss events, expected unserved load given existing transmission infrastructure and the dollar per megawatt hour ($/MWh) potential value range of mitigated losses. This value is capped at $3,500/MWh at MISO while MISO IMM estimated the uncapped value to be $23,000/MWh.[13 14] MISO has established the following assumptions for VOLL calculations, which are also the assumptions used to calculate the potential VOLL benefits of the Project:

- **Generation Loss Assumption:**[13]
    - Thermal: 40% Pmax
    - Wind: 90% of Pmax
    - Solar: 50% of Pmax

- **Additional Margin on the Forecast Load:**[13]
    - 5% margin

- **Import Limit**:[13]
    - Capacity Import Limit (CIL) for individual zones
    - Total Transfer Capability (TTC) for combined zones or the region

- **Load Loss MW**[13]
    - Load Loss MW = $GenMW_{net}$ – 1.05 * LoadMW – TxLossMW + CIL (MW)
    - Where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

- **Value of Avoided Load Shed**[13]
    - Avoided Risk of Load Shed Value ($) = VOLL * Load Loss MW * duration (hours)[13]
    - Where duration (Y) is assumed to be equal to 16 hours
    - Where VOLL is assumed to be a range of $3,500 to $23,000
        - This value is assumed to be realized over a three year term based on the frequency of severe winter weather events

4.2 Value of Mitigated Lost Load Generated by GBX

Applying MISO VOLL calculation methodology, Guidehouse estimated the Project's MISO Regional VOLL benefits under the assumptions established in section 5.1 of this report and the 2022 LRTP Tranche 1 Portfolio Detailed Business Case winter event shedding scenarios, the full 1.5GW (1,500MW) GBX MISO injection capacity was applied to relieve some of the indicated LRZ 4-7 capacity shortfall of 13,509MW. [13] Guidehouse multiplied this shortfall mitigation by the MISO default outage duration of 16 hours over the identified 3 year valuation period to determine a LRZ 4-7 VOLL benefit of $84 million applying the $3,500/MWh VOLL benefit or $552 million when the $23,000/MWh VOLL benefit is assumed. Guidehouse then performed a lifetime projection of VOLL benefits using a discount rate of 6.057% and a lifespan of 30 years. Over the 30 year lifespan of the Project VOLL generated by GBX ranges from

[13] MISO, March 29, 2022. LRTP Tranche 1 Portfolio Detailed Business Case. **https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf**

[14] Potomac Economics, September 15, 2020. IMM Quarterly Report: Summer 2020. **https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf**

$360.8 million using the $3,500/MWh VOLL benefit and $2.37 billion when the $23,000/MWh figure is used.

Table 7: MISO Project Regional Benefit Calculation

Region	GenLoss (Therm)	GenLoss (Wind)	GenLoss (Solar)	Gen Remaining	Gen Surplus (A)	TTC (Existing) (B)	Shortfall (-B-A)[13]	MISO Injection (MW)	GBX Applicable Benefit (MW)
LRZ 4-7	24,123	6,307	9,553	32,579	-19,702	6,192	13,509	1,500	1,500
Avoided Load Shed (M)									1,500
Assumed Duration (Y)									16
Avoided Load Shed Hours (N=M*Y)									24,000
LRZ 4-7 Avoided Risk of Load Shed Value (O * $3,500[13])									$84,000,000
LRZ 4-7 Avoided Risk of Load Shed Value (O * $23,000[13])									$552,000,000

Table 8: GBX VOLL Region LRZ 4-7 Benefit Summary

	Region Load Shed Hours Avoided (A)	Capped MISO VOLL Benefit (B)	GBX Regional Benefit (C) = (A) x (B)
Benefit (3 year)	24,000	$3,500	$84,000,000
Benefit (3 year)	24,000	$23,000	$552,000,000
Benefit (30 year NPV)	24,000	$3,500	$360,782,162
Benefit (30 year NPV)*	24,000	$23,000	$2,370,854,212

30 year present values are based on an annual benefit value determine with Payment Financial Function with the following assumptions:

- *3 year MISO VOLL value (provided by MISO) converted to 1 year value with Payment Financial Function (3 payments at 6.057% equivalent discount rate)*
- *Discount rate of 6.057%*
- *Asset life of 30 years*

5. Value of Reduced Procurement Obligations

5.1 Reduced Local Resource Adequacy Procurement Obligation

Local Resource Adequacy requirements and Planning Reserve Margin (PRM) are essential tools used by system planners and operators to ensure a reliable supply of generation capacity during exceptional events related to unplanned outages, extreme weather, or critical transmission contingencies. PRM is reflected as a percentage of the excess generation above peak system load to create a buffer to absorb the unexpected loss of capacities such as a piece of equipment at a natural gas plant or an unusual decrease in output of a renewable generator due to seasonal weather aberrations. The procurement of additional generation capacity to satisfy the PRM requirement drives additional costs for customers. In FERC's recently released NOPR regarding Regional Transmission Planning and Cost Allocation, new transmission facilities are recognized for the ability to "increase transfer capability... that either defers or negates the need to invest in generation capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas."[2]

5.2 Deferred or Mitigated Generation Capacity Investment of GBX

In the MISO, SPP, and PJM regions for the purposes of resource adequacy, electrically cohesive regions are defined within which there is no transmission limitation. To satisfy the resource adequacy need, each region needs to be able to supply the load with a certain level of reliability. For example, MISO specifies that each of the resource adequacy zones needs to procure enough capacity that the Loss of Load Expectation (LOLE) is 0.1 day/year. [15] The capacity requirement can be met through generation within the region or the import capability of transmission ties.

Local Resource Adequacy Need <= Generation + Import capability

The Grain Belt Express increases the import capability in Missouri, Illinois, and Indiana which creates potential benefits as follows in the regions. Maintaining financial assumptions used in other analyses in this report, Guidehouse assumed an asset lifespan of 30 years and a discount rate of 6.057%. Applying these figures to the aforementioned approach, the Project is estimated to mitigate additional generation capacity investments of approximately $526 million per year and $7.634 billion over the 30 year life of the project.

[15] MISO, October 31, 2021. Business Practice Manual 11 – Resource Adequacy. **https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip**

Table 9: Project Potential Resource Adequacy Benefit

Point of Interconnection (POI)	Benefitting System	Amount of Injection [MW] (A)	Cost of New Entry (CONE) [$/MW-yr] (B)[16] [17] [18]	Potential Benefit $/yr (A) X (B)
McCredie 345 kV owned by AECI	AECI	1,000MW	$85,610	$85,610,000
New 345 kV owned by Ameren	MISO	1,500MW	$97,190	$145,785,000
AEP Sullivan 345 kV	PJM	2,500MW	$118,000	$295,000,000
Total GBX Potential Resource Adequacy Benefits (All POIs)				
Annual Benefit	Aggregate POIs - Annual	5,000MW	N/A	$526,395,000
Lifetime Benefit	Aggregate POIs – 30 year	5,000MW	N/A	$7,637,969,860

5.3 Hedge Against Future Capacity Procurement Needs

As utilities and load serving entities continue to develop and contract with an expanding base of low cost renewable sources, incentivized by the Federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) programs, the economic pressure on legacy generation units in organized markets, particularly coal, increases. Coal fired power plants throughout the country have accelerated their retirement dates as they are comparatively cost prohibitive to operate, providing customers with little residual benefits from ongoing operations. As a result, owners of uneconomic power generation stations are forced to retire units prematurely sometimes on very short notice. As these units retire at an increasing rate, existing reliability driven transmission planning processes, project permitting requirements, and execution of integrated resource plans are unable to keep pace with rapid changes to the electric system. Furthermore, in some cases these units are needed to maintain reliability, demonstrating the rapid pace of change as transmission system planners are not afforded sufficient time to identify transmission solutions as the older generation units quickly disappear from their systems. As noted by FERC "RMR [Reliability Must Run] agreements are a product of market failure, and they themselves cause markets to

[16] PJM, June 1, 2022. PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants. **https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx**

[17] Southwest Power Pool. Open Access Transmission Tariff, Sixth Revised Volume No. 1-Attachment AA Resource Adequacy-Attachment AA Section 14. **https://www.spp.org/documents/58599/cone-effective%207-1-2018.pdf**

[18] AECI does not provide CONE figures, but given regional proximity to SPP $85,610 is a reasonable proxy

fail. This further failure arises as RMR agreements obscure the market signals that would create incentives for the very development that the markets are intended to deliver."[19]

As more coal generation capacity retires, remaining fossil fuel powered generators such as natural gas fired combined cycle and simple cycle plants, may assume market power that is difficult to mitigate leading to even higher generation capacity prices as these units also come under economic pressure in the states with significant retail electricity sales coming from low marginal cost solar and wind plants supported by tax incentives. This economic pressure has forced independent power producers in California to proactively give notice of intent to retire relatively modern natural gas generation units creating immediate transmission system reliability issues[20] that can only be relieved through (1) emergency and normal procurement of capacity (2) transmission system upgrades (3) RMR designations, all of which create cost burden on utility customers.

As the penetration of renewable resources increases throughout the markets served by the Project, the rate of economic retirements will likely accelerate the frequency of new transmission constraints and generation capacity deficiencies. These scenarios leave regulators, system planners, and utilities very little time to react and plan cost-effective solutions. GBX provides enhanced generation resource diversity, access to low cost renewable capacity, and measurable reductions of local capacity procurement as defined in Section 5 of this report.

Below is a list of existing coal plants in the geographic regions in which the Project will be constructed. A majority of these plants have known retirement dates while others have yet to announce planned retirements. As each of these legacy plants retires or announces its retirement, the likelihood of local capacity deficits increases throughout the SPP, MISO and PJM regions which subsequently enables customers to realize the mitigated capacity investment savings GBX provides throughout its expected 30 year life. Furthermore, the accelerated retirement scenario of fossil fuel powered generators is certain in the state of Illinois given the enacted Climate and Equitable Jobs act which requires municipal coal plants, including Prairie State and City, Water, Light & Power (CWLP) Dallman, to reduce emissions by 45% by 2035 and be 100% carbon free by 2045. Additionally, all privately owned natural gas generators must operate in a zero emissions environment by 2045.[21] Legislative actions such as these will continue to generate demand for the renewable capacity delivered by GBX and increase the cost of reduced local reliability procurements made on the behalf of electric customers.

[19] Commissioner James Danly, July 31, 2020. Commissioner James Danly Concurrence Regarding Greenleaf Energy Unit 2, LLC. **https://www.ferc.gov/news-events/news/commissioner-james-danly-concurrence-regarding-greenleaf-energy-unit-2-llc**

[20] California Public Utilities Commission, January 12, 2018. Resolution E-4909. Authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability. **https://docs.cpuc.ca.gov/publisheddocs/published/g000/m205/k602/205602530.pdf**

[21] State of Illinois, September 15, 2021. Gov. Pritzker Signs Transformative Legislation Establishing Illinois as a National Leader on Climate Action. **https://www.illinois.gov/news/press-release.23893.html**

Table 10: Coal Power Plants in States Served by GBX

Illinois Coal Power Stations[22]

In the state of Illinois 7,735MW of coal generation is scheduled to be retired in the next five years (2027).

Name	Location (IL County)	Nameplate Capacity (MW)	Owner	Status
Prairie State Energy Campus	Marissa	1,630 MW	Prairie State Generating Co.	No retirement announced
Powerton Station	Pekin	1,538 MW	NRG Energy	Retiring by 2028
Baldwin Generating Center	Baldwin	1,157 MW	Vistra	Retiring by end of 2025
Kincaid Generation	Christian County, Illinois	1,108 MW	Vistra	Retiring by end of 2027
Joppa Steam Plant	Joppa	948 MW	Vistra	Retiring by end of 2022
Waukegan Station	Waukegan	689 MW	NRG Energy	Will close in June of 2022
Newton Power Plant	Jasper County	595 MW	Vistra	Retiring by end of 2027
E.D. Edwards Power Plant	Bartonville	560 MW	Vistra	2022
Will County Station	Romeoville	510 MW	NRG Energy	2022
Dallman	Springfield	355 MW	City Water, Light & Power	Retiring two oldest units by end of 2020 and the third-oldest by early 2023."
Archer Daniel Midland Decatur		335 MW	Southern Illinois Power Cooperative	No retirement announced
SIPC – Lake of Egypt	Marion	272 MW	Southern Illinois Power Cooperative	Larger of two units closing fall of 2020

[22] Inside Climate News, March 18th, 2022. 'Last Gaps for Coal' Saw Illinois Plants Crank up Emission-Spewing Production Last Year **https://insideclimatenews.org/news/18032022/last-gasp-for-coal-saw-illinois-plants-crank-up-emission-spewing-production-last-year/**

SIUC		3 MW	Southern Illinois University	2030
Total		**9,700 MW**		

Indiana Coal Power Stations[23]

In the state of Indiana, 2,661 MW of coal generation will be retired by 2027 with an additional 4,720 MW scheduled for decommissioning.

Name	Location (IN County)	Nameplate Capacity (MW)	Owner	Status
A.B. Brown	Posey Co. / Vand Co.	707 MW	Vectren	No retirement announced
Cayuga	Vermillion Co.	1,104 MW 2 Units: 552 MW Each	Duke Energy Indiana	Closing in 2028
Clifty Creek	Jefferson Co.	1,303 MW	Ohio Valley E.C.	No retirement announced
Crawfordsville Mun.	Motgomery Co.	24.1 MW	Crawfordsville E.L & P.	No retirement announced
F.B. Culley	Warrick Co.	415 MW originally Unit 1 – 46 MW (Decommissioned) Unit 2 – 104 MW Unit 3 – 265 MW	Vectren	Unit 1 closed in 2006. Unit 2 is scheduled to close in 2023. Unit 3 to continue to operate
Eagle Valley	Morgan Co.	302 MW	AES / AED Indiana	No retirement announced
Merom	Sullivan Co.	1,080 MW 2 Units – 540 MW Each	Hoosier Energy	2023
Gibson	Northwestern Gibson Co.	3,145 MW All Units: 630 MW	D.E.I.	2026 – Unit 4 2034 – Unit 3 & 5 2038 – Units 1 & 2
Logansport	Cass Co.	43 MW	Logansport Municipal Utility	No retirement announced

[23] Cayuga Closing - https://www.euci.com/duke-energy-indiana-looks-to-close-4100-mw-of-coal-fired-plants-adding-natural-gas-and-solar/
F.B. Culley - https://www.courierpress.com/story/news/2018/02/20/vectren-natural-gas-plant-solar-farm-join-energy/356818002/
Merom - https://www.hoosierenergy.com/press-releases/hoosier-energy-announces-new-20-year-resource-plan/
Gibson - https://www.14news.com/2019/06/21/duke-energy-working-cleaner-energy-plans-retire-gibson-station-units/
Rockport - https://www.14news.com/2021/04/24/energy-company-unveils-plan-fully-retire-rockport-power-plant/
RM Schahfer - https://www.nisource.com/news/article/nisource-reports-third-quarter-2021-results-20211103

Michigan City	Laporte Co.	540 MW	NIPSCO	2028
Petersburg	Pike Co.	1,873 MW	AES Indiana	No retirement announced
Rockport	Spencer Co.	2,600 MW	Indiana – Michigan Power	2028 – Unit 1 and 2 (540 and 556 MW)
R.M. Schahfer	Jasper Co.	847 MW Unit 17: 423.5 MW Unit 18: 423.5 MW	NIPSCO	Unit 15 and 16 in 2021 Units 17 and 18 in 2023
Warrick	Warrick Co.	755 MW	Vectren	No retirement announced
Whitewater Valley	Wayne Co.	93.9 MW	Richmond Power and Light	No retirement announced
Total		**14,786 MW**		

Missouri Coal Power Stations[24]

In Missouri, 2,120 MW of coal generation is scheduled to close in the next five years.

Name	Location (MO County)	Nameplate Capacity (MW)	Owner	Status
Sikeston Power Station	Scott Co.	235 MW	Sikeston Board of Municipal Utilities	No retirement announced
Labadie	Franklin Co.	2,371 MW	Ameren	No retirement announced
Iatan	Platte Co.	1,594 MW	Evergy	No retirement announced
Rush Island	Jefferson Co.	1,182 MW	Ameren	2024
New Madrid	New Madrid Co.	1,154 MW	Associated Electric Cooperative Inc	No retirement announced
Thomas Hill	Randolph Co.	1,133 MW	Associated Electric Cooperative Inc	No retirement announced
Sioux	St. Charles Co.	974 MW	Ameren	No retirement announced
Hawthorn	Jackson Co.	948 MW	Evergy	No retirement announced
Meramac	St. Louis Co.	938 MW	Ameren	2022
Sibley Generating Station	Jackson Co.	524 MW	Evergy	Closed in 2018

[24] Meremac - **https://www.transmissionhub.com/articles/2014/07/ameren-missouri-to-shut-aging-meramec-coal-plant-by-2022.html**

Rush Island - **https://www.stltoday.com/business/local/ameren-aims-to-charge-customers-for-closure-of-rush-island-coal-plant/article_97bb05a7-6116-5ea8-a785-906a335c7528.html**

John Twitty Energy Center	Greene Co.	603 MW	Springfield City Utilities	No retirement announced
Total		**11,113 MW**		

Kansas Coal Power Stations[25]

In Kansas, 517 MW of coal generation is scheduled to be closed by 2027 with an additional 720 MW to be shut down in 2030.

Name	**Location (KS County)**	**Nameplate Capacity (MW)**	**Owner**	**Status**
Holcomb	Finney Co.	348.7 MW	Sunflower Electric Power Corp.	No retirement announced
Jeffrey Energy Center	Pottawatomie Co.	2,160 MW	Evergy	Unit 3 (720 MW) to shut down in 2030
Lawrence Energy Center	Douglas Co.	517 MW Unit 4: 114 MW Unit 5: 403 MW	Evergy	Units 1, 2 & 3 closed Unit 4 and 5 to close in 2023
La Cygne	Linn Co.	1,599 MW	Evergy	No retirement announced
Nearman Creek	Wyandotte Co.	261 MW	City of Kansas City	No retirement announced
Total		**4,885.7MW**		

5.4 GBX Impact on MISO Planning Resource Auction Price 2022/2023

In order to continuously serve customers with safe and reliable electric service, MISO conducts a resource adequacy auction, also known as the PRA, every April to ensure LRZs have procured enough generation capacity to meet their respective Local Reserve Requirement (LRR) and MISO Regions have met the Planning Reserve Margin Requirement (PRMR) for the year. These auctions ensure that sufficient capacity is secured to meet the established 0.1-day-per-year (1 day in 10 years) loss of load expectation target required by the MISO tariff[26]. In cases of inadequate supply during a PRA, the auction will clear offers received in the LRZ at the CONE price approved by FERC. Additionally, in the event of a shortfall of resources participating in a PRA, the LRZ or Transmission Provider region would be short of planning resources for the planning year, negatively impacting the system's LOLE.

MISO's 2022/2023 PRA experienced abnormally high auction clearing prices due to nearly 3.4GW generation capacity electing to not participate in the annual auction.[27] Although roughly 2.5GW of net new

[25] Jeffrey Energy Center - **https://www.kmbc.com/article/evergy-moves-up-timeline-to-close-coal-fired-plants-to-help-reduce-use-of-fossil-fuels-lawrence-st-marys/36302057#**

Lawrence Energy Center - **https://www.powermag.com/evergy-to-build-solar-array-at-kansas-city-coal-power-plant-site/#:~:text=The%20most%20significant%20generation%20reduction,97%20MW)%20in%20late%202024.**

[26] MISO FERC Electric Tariff Module E-1 68A.2.1. March 1st, 2018. **https://docs.misoenergy.org/legalcontent/Module_E-1_-_Resource_Adequacy.pdf**

generation resources participated in the 2022/2023 PRA, the MISO North/Central territory experienced a net generation capacity shortfall of approximately 1,230MW.[27] This shortfall impacted the MISO North/Central territory in two measurable ways:

1. A net shortfall in participating capacity (less generation procured than needed to satisfy Zonal LRRs and Regional PRMRs) lowered the actual MISO LOLE to 1 day in 5.7 years. This is an indicator of a significantly less resilient electric system and is 43% less than the MISO tariff required LOLE of 1 day in 10 years.[27] [26]
2. The regional capacity shortfall caused the auction clearing price (ACP) for all MISO North/Central Zones to be equal to CONE of the least costly Zone 3, which is currently $236.66 per MW-day.[13] For comparison purposes in the years where there are milder constraints (2017/2018, 2018/2019, 2019/2020 and 2021/2022) in the MISO North/Central the price has averaged below $30/MW-Day.[27]

Sections 6.2 and 6.3 of this report examine two important properties of GBX that ultimately influence the ACP of the annual PRA and the overall reliability of an electric system; (1) resource adequacy procurements and (2) future availability of regional generation resources. In the case of MISO, Zones and Regions can meet LRR and PRMR requirements through direct procurement of accredited local generation or imported generation capacity delivered through the transmission system. As planned, GBX has the potential to increase supply to MISO Zone 6 and Region LRZ 4-7 by up to 1,500MW which would significantly improve the resource adequacy outlook within the MISO footprint. The 2022/2023 PRA net shortfall of participating generation is likely to continue given the research presented in Section 6.3 which documents the planned retirement of 7,735MW of coal generation in Illinois (MISO Zone 4) and 2,661MW of coal generation in Indiana (MISO Zone 6). Additionally, MISO's summary of the 2022/2023 PRA results indicates that "[u]nless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue."[27]

5.4.1 Approach to Estimating ACP and LOLE Influence of GBX

The relatively expensive 2022/2023 MISO PRA ACP is the result of a net capacity shortfall of approximately 1,230MW which, due to MISO auction procedures, defaulted the ACP to the lowest cost CONE of $236.66/MW-day (Zone 3). This ACP is significantly higher than observed prices during the past 7 auctions which resulted in ACPs ranging from $1.50/MW-day up to $72.00/MW-day.

[27] MISO 2022/2023 Planning Resource Auction (PRA)Additional Detail, Revised June 3, 2022. **https://cdn.misoenergy.org/20220525%20RASC%20Item%2004d%20PRA%20Detail624732.pdf**

Figure 7: MISO PRA Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>IMM Conduct Threshold</td><td>25.01</td><td>24.52</td><td>23.67</td><td>24.74</td><td>26.63</td><td>24.40</td><td>25.69</td><td>23.10</td><td>22.88</td><td>22.84</td><td>26.67</td></tr>
<tr><td>Cost of New Entry</td><td>250.05</td><td>245.18</td><td>236.66</td><td>247.40</td><td>266.27</td><td>243.95</td><td>256.90</td><td>230.99</td><td>228.82</td><td>228.44</td><td>266.68</td></tr>
</table>

Given that GBX has planned injection capacity of 1,500MW into Zone 5, the ability of the project to alleviate the approximately 1,230MW capacity shortfall driving the observed 2022/2023 auction prices is reasonable. Additionally, MISO notes that "[f]or 2022-23 Zones 4, 5 and 6 relied significantly on the Auction to meet their Resource Adequacy Requirements."[27] This further reinforces the relationship between retirement of local generation and increased cost to maintain a reliable and resilient electric system.

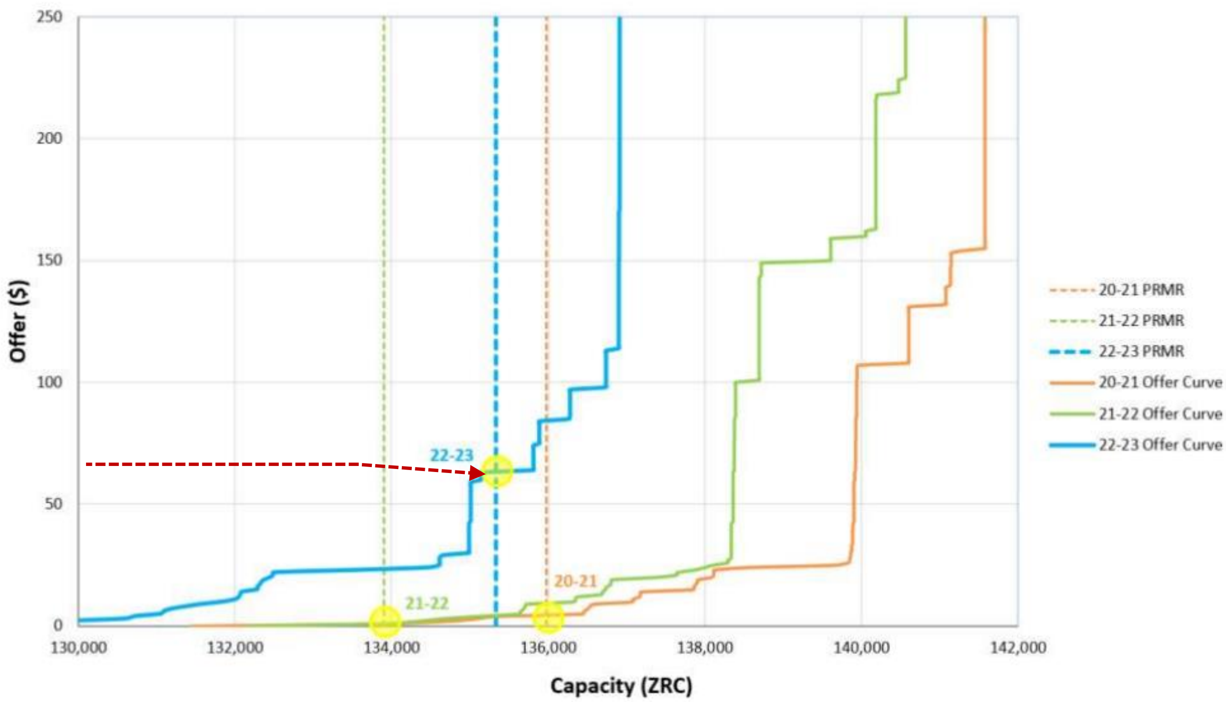
In order to estimate the influence GBX can have on the result of future PRAs, a reasonable alternative ACP must be established and multiplied against the MISO load exposed to the ACP. Establishing the alternative 2022/2023 ACP can be accomplished through a number of methods, Guidehouse documents two approaches here:

1. Historical Average ACP

   Guidehouse used 6 years of prior MISO PRA ACP to generate a weighted average price of $26.82/MW-day which is representative of typical market conditions including outlier events. See Appendix B for calculation details of the historical average ACP.

2. An extremely conservative approach would apply the unconstrained clearing price under a no binding constraint scenario which assumes no transmission constraints exist between MISO Central/North and South territories. This would enable lower priced resources in MISO Zones 8, 9 and 10 to bid into the PRA. This value is presented by MISO to be approximately $60/MW-day represented by the intersection of the 22-23 PRMR and 22-23 Offer Curves.

Figure 8: 2022/2023 MISO PRA Unconstrained Offer Curves[27]



In both alternate ACP estimate methods described above, it is assumed that GBX provides owners of low cost renewable generation access to the MISO PRA. As the origin for GBX, Kansas has robust wind generation resources with "the state ranked among the top five states in total wind energy generation, and Kansas had the second-largest share of electricity generated from wind—following closely behind Iowa."[28]

Using MISO provided blind bid information for 2022/2023 PRA auction results, Guidehouse was able to determine an approximate $/MW-day value that typical wind generation resources would likely submit into future MISO PRAs. These resources are able to participate in MISO PRA through the new path created by GBX. In Zone 6 of the 2022/2023 PRA, a single 46.5MW wind resource participated in the auction.

[28] EIA, Kansas State Profile. May 20, 2021. **https://www.eia.gov/state/analysis.php?sid=KS#68**

Figure 9: 2022/2023 PRA Resource Participation[27]

Generation Resource Count								
Zone	1	2	3	4	5	6	7	Totals
Gas	0	0	0	4	0	0	5	9
Wind	4	0	8	3	0	1	2	18
Solar	0	6	1	2	0	0	3	12
Water	0	0	0	0	0	0	2	2
Coal	0	1	0	0	0	0	0	1
Totals	4	7	9	9	0	1	12	42

ZRCs by Fuel Type								
Zone	1	2	3	4	5	6	7	Totals
Gas	0.0	0.0	0.0	184.1	0.0	0.0	1,096.1	1,280.2
Wind	124.5	0.0	137.3	61.2	0.0	46.5	34.3	403.8
Solar	0.0	141.5	12.0	134.5	0.0	0.0	94.5	382.5
Water	0.0	0.0	0.0	0.0	0.0	0.0	359.6	359.6
Coal	0.0	25.3	0.0	0.0	0.0	0.0	0.0	25.3
Totals	124.5	166.8	149.3	379.8	0.0	46.5	1,584.5	2,451.4

Filtering the MISO blind bid data by Zone = 6 and Quantity = 46.5 quantity reveals a bid price of $0/MW-day, indicating a self-scheduling resource willing to accept the ACP. Given that a reliable and economic portfolio of generation should include a mix of both intermittent renewables and firm generation an ACP of $0 is unreasonable but supports the scenario in which a significant amount of new $0/MW-day bids (very likely wind resources located in Kansas) are received in future PRAs, driving down the average future ACPs to levels suggested by Guidehouse and observed in past MISO PRA results.

5.4.2 Estimated Annual PRA Savings Attributable to GBX

Guidehouse applied the estimated alternate ACPs that assume GBX in-service at a minimum 1,500MW injection rating to MISO and the MISO provided quantity of load exposed to the 2022/2023 ACP to determine the potential annual PRA savings generated by GBX.

Assumptions:

- 2022/2023 ACP (Zone 3 CONE): $236.66/MW-day
- Adjusted ACP With GBX In Service: $26.82/MW-day or $60/MW-day (see Section 6.4.1)
- Load exposed to 2022/2033 ACP: 5.3% of PRMR in the MISO North/Central= 5.3% of 101,249 MW = 5,366MW[27]
  - MISO indicates the 2022/2023 PRMR to be 135,326.5MW, but this includes the Southern territory. In maintaining a conservative approach, Guidehouse has removed the approximate load share of the Southern MISO Zones to adjust the estimated cost savings appropriately as these zones are not exposed to the 2022/2023 ACP.

Table 11: Estimated PRA Savings Generated by GBX

2022/2023 Actual ACP (A)	Adjusted ACP (B)	Load Exposed to Adjusted ACP (C)	Annual Estimated PRA Savings[29] (C) = (A-B)*C*365
$236.66/MW-day	$26.82/MW-day	5,366 MW	**$410.9 million**
	$60/MW-day	5,366 MW	**$346.0 million**

6. Operational Improvement Value of HVDC Resources

6.1 Value of System Restoration Capabilities

In order to ensure the capability to start the electric system from a shutdown condition, power system operators have typically relied on fossil fuel powered generating stations with coupled auxiliary power units such as reciprocating engines and stand-alone diesel generation units to perform system restoration or black-start services. Black-start units are typically certified by RTOs or ISOs as capable of restoring load, stabilizing generation, frequency, and providing voltage control. This approach to ensuring system restoration capability has been standard practice for vertically integrated utilities before the advent of wholesale energy markets and the organization of RTOs or ISOs. As the scale of fossil generation capacity provided by independent power producers to organized markets such as MISO, PJM and SPP has increased, these ISO/RTOs have also become increasingly reliant on these facilities to provide black-start capabilities within their respective transmission planning regions.

Recent investigations into the extreme weather events described in this report revealed that more than one-third of the plants that lost generation during the 2018 Northeast “Bomb Cyclone” cold snap did not have winterization procedures in place during the time of the event.[4] For units designated as black-start resources, failure to make deferred winterization upgrades and establish appropriate operational plans could have a devastating social impact during an exceptional event if the unit failed to perform its black-start obligation. Unfortunately, owners of fossil powered plants have made little progress since the 2018 Bomb Cycle and the same failure to winterize generating stations became a major contributor to electric system failures during Winter Storm Uri. FERC reported that “a combination of freezing issues (44.2%) and fuel issues (31.4%) caused 75.6% of the unplanned generating unit outages, derates, and failures to start. Of particular note, protecting just four types of power plant components from icing and freezing could have reduced outages by 67% in the ERCOT region, 47% in the SPP, and 55% in the MISO regions.”[30]

Guidehouse performed a literature review including academic research papers proposing ideas on how HVDC converters, similar to those proposed for GBX, can be used for black-start resources. Successful black-start using VSC HVDC between Kristiansand (Norway)-Tjele (Denmark) showed the capability of

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[29] Annual savings assumes persistent shortfall of local resources in MISO Regions and Zones in addition to continued lack of transfer capability between MISO North/Central and MISO South.

[30] FERC, November 16, 2021. Final Report on February 2021 Freeze Underscores Winterization Recommendations. **https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations**

the HVDC system to be used for black-start of a major power grid.[31] In addition, after the 2003 Blackout, New York Power Authority's (NYPA) HVDC tie with Quebec helped some of the demand in upstate New York to stay energized.[32] The 1,000MW HVDC New England Power Link project, currently under construction, is also credited with the ability to provide black-start capability to restore the electric grid in the event of a blackout.[33]

Given its unique HVDC technical properties, geographically diverse points of interconnection and low ongoing variable maintenance expenses the Project provides a cost-effective, novel system restoration tool for SPP, MISO, and PJM that does not depend on the viability of a coupled power generation facility.

Resource diversity value:

a. As proposed, GBX has 3 planned VSC DC/AC converter stations with one each in Kansas, Missouri and Indiana. These 3 converter stations enable the project to inject or withdraw capacity to/from 4 different balancing authorities through interconnecting AC facilities with SPP, AECI, MISO and PJM.
b. Given this geographic diversity, the Project as a black-start resource is not dependent on a single local power station, auxiliary power unit, and onsite fuel storage for initial energization. Regardless of local conditions and regional weather patterns, the Project can provide energy for system restoration processes.

Cost-effective black-start capability:

a. Traditional black-start units typically leverage three cost components when determining a revenue requirement upon which they earn a typical 10% return on investment:
    i. Annual amortized fixed costs to provide black-start service.
    ii. Variable service costs including operations, maintenance, and onsite fuel inventory expense.
    iii. Training and compliance expenses reasonably incurred to retain and train employees to efficiently operate black-start units.
b. An HVDC transmission line and accompanying VSC will not incur any incremental variable service costs in order to provide black-start capabilities to its interconnecting electric systems. Additionally, the number of full-time employees is likely reduced given that no onsite resources are required to provide black-start functionality. Like all modern substations and transmission resources, the asset can be operated remotely via Transmission Supervisory Control and Data Acquisition (SCADA) systems.

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[31] T. Midtsund, A. Becker, et. all "A Live Black-start Capability test of a Voltage Source HVDC Converter," 2015 CIGRÉ Canada Conference, Winnipeg, Manitoba, August 2015. **https://library.e.abb.com/public/97ac6612486f42dcbe4e5342edd41a01/A%20Live%20Black%20Start%20Capability%20test%20of%20a%20Voltage%20Source%20HVDC%20Converter.pdf**

[32] "Technical Analysis of the August 14, 2003, Blackout: What happened, Why, and What Did We Learn?" Report to the NERC Board of Trustees, NERC Steering Group, NERC, July 2004. **https://www.nerc.com/docs/docs/blackout/NERC_Final_Blackout_Report_07_13_04.pdf**

[33] State of Vermont Public Service Board, January 27, 2016. Section 231 Petition supporting materials. **http://www.necplink.com/docs/regulatory/TDI-NE-231-Petition-and-Exhibits.pdf**

6.2 Unique HVDC Reliability Values

Modern HVDC resources electing to use VSC technology for performing DC to AC conversions for final interconnection to the local transmission backbone provide regional system operators with enhanced reliability levers that traditional conversion technologies cannot. The majority of these reliability benefits come from the ability of VSC resources to provide transmission operators with the power quality control properties typically provided by the rapidly retiring synchronous generator fleet. As inverter-based generation is used to meet a growing percentage of total system load, the ancillary services provided by retiring legacy generators will become more scarce and increasingly valuable. Recent FERC 1000 competitive solicitations of Flexible AC Transmission System (FACTS) devices in California indicate the high capital expense, estimated to be approximately $370 million, required to maintain reliability in the California Independent System Operator (CAISO) territory as the state rapidly integrates inverter-based generation and retires synchronous generators.[34] The addition of GBX VSC based converter stations will offer SPP, MISO, and PJM the following system wide and local advantages at no incremental cost to customers:

Active and reactive power controlled electronically accurate in real-time to the millisecond:

a. VSC stations for HVDC systems can independently and quickly control active and reactive power.[35] This enables the HVDC converter to adjust the output and provide active and reactive support to the connected AC power system when necessary. This becomes more important considering that the grid is moving toward high penetration of inverter-based resources (IBRs) and synchronous generators are replaced by IBRs. Synchronous generators are traditionally used for providing active and reactive power quickly, but as they are replaced by IBRs, alternatives such as VSC-HVDC becomes important to ensure reliable and stable operation of the grid.
b. The addition of GBX's VSC based HVDC resources can provide a reasonable hedge against a future need for investing in new FACTS devices such as Static Synchronous Compensators (STATCOM) and Static Var Compensators (SVCs).

Voltage and frequency control:

a. As the penetration of renewable resources which are mainly inverter-based increases in the electric grid, the inertia of the system which traditionally is provided by synchronous generators, decreases, and this makes the grid vulnerable to rapid changes in supply and demand and this may lead to drastic changes in the grid's frequency. VSC-HVDC can provide fast frequency support due to its characteristics and support of frequency stability.[36] This will provide another source for fast frequency support in the power system and may decrease the required amount of spinning reserve to ensure the reliable operation of the grid. Grain Belt Express will make more resources available for fast frequency response in the

[34] CAISO, March 29, 2019. 2018-2019 Transmission Plan. **https://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf**

[35] N. Flourentzou, V.G. Agelidis, and G.D. Demetriades, "VSC-Based HVDC Power Transmission Systems: An Overview," IEEE Trans. Power Electron. 2009, 24, 592–602. **https://ieeexplore.ieee.org/abstract/document/4773229**

[36]. Fradley, R. Preece and M. Barnes, "VSC-HVDC for frequency support (a review)," 13th IET International Conference on AC and DC Power Transmission (ACDC 2017), 2017. **https://ieeexplore.ieee.org/abstract/document/7934991**

regions that have ties with AC systems with a converter station and this alleviates required spinning reserves in the ISO/RTOs' territories.

b. VSC-HVDC has the capability of controlling active and reactive power independently, and this characteristic makes VSC-HVDC capable of providing voltage support to the AC power system[37]. Reactive power support and voltage regulation have been traditionally provided by synchronous generators. Considering that on the path to clean and renewable energy, synchronous generators are replaced with IBRs, and the number of available resources for voltage support is decreasing. Grain Belt Express can provide a significant source of voltage support in its converter station locations and provide ancillary services for voltage regulation.

Dynamic voltage support (reduces losses):

a. Considering that VSC-HVDC can control active and reactive power independently, it can provide dynamic voltage support and improve voltage stability. The dynamic voltage support offered by HVDC can increase the capability of the adjacent AC transmission as well.[38]

Emergency power control and power modulation:

a. In severe transient disturbances in a power system, the kinetic energy in the rotors of the synchronous generators may not be released in the first power swing and may cause generators to go out of step from the grid when the fault is cleared. The fast power run-back capability of the VSC-HVDC can help mitigate this impact by releasing the excess kinetic energy to the healthy part of the grid.[39]

Damping of electro-mechanical oscillations

a. Active damping of interarea oscillations is essential to improve power system stability.[40] Power can be controlled very rapidly by VSC-HVDC and this can provide strong damping to disturbances.[41] Modulation controls implementation in the Intermountain Power Project (IPP) HVDC line in the Western Electricity Coordination Council (WECC) system verified that it could significantly dampen interarea oscillations.[42] The other implemented examples of fast

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[37] H.F. Latorre, M. Ghandhari, L. Söder, "Active and reactive power control of a VSC-HVdc," Electric Power Systems Research, Volume 78, Issue 10, 2008, Pages 1756-1763. **https://www.sciencedirect.com/science/article/abs/pii/S0378779608000965**

[38] M. P. Bahrman, "HVDC transmission overview," 2008 IEEE/PES Transmission and Distribution Conference and Exposition, 2008, pp. 1-7. **https://ieeexplore.ieee.org/document/4517304**

[39] L. Zhang, L. Harnefors, P. Rey, "Power System Reliability and Transfer Capability Improvement by VSC-HVDC," CIGRE Regional Meeting, Tallinn, Estonia, June 2007. **https://library.e.abb.com/public/158b677a7b207f5bc125731d00477d6a/Power%20system%20reliability%20and%20transfer%20capability%20improvement%20by%20VSC%20-%20HVDC%20Light.pdf**

[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. **https://ieeexplore.ieee.org/document/8353481**

[41] J. J. Dougherty and T. Hillesland, "Power System Stability Considerations with Dynamically Responsive DC Transmission Lines," in IEEE Transactions on Power Apparatus and Systems, vol. PAS-89, no. 1, pp. 34-45, Jan. 1970. **https://ieeexplore.ieee.org/document/4074010**

[42] D. E. Martin, W. K. Wong, D. L. Dickmander, R. L. Lee and D. J. Melvold, "Increasing WSCC power system performance with modulation controls on the Intermountain Power Project HVDC system," in IEEE Transactions on Power Delivery, vol. 7, no. 3, pp. 1634-1642, July 1992. **https://ieeexplore.ieee.org/document/169595**

modulation of an HVDC line that could improve the transient stability of the grid is the BritNed HVDC Interconnector between Great Britain and Netherland.[43] Successful implementation of previous HVDC oscillation damping control shows that the Grain Belt Express Project has the potential to provide transient stability support and oscillation damping to the power system.

[43] S. P. Teeuwsen and R. Rössel, "Dynamic performance of the 1000 MW BritNed HVDC interconnector project," IEEE PES General Meeting, 2010, pp. 1-8. **https://ieeexplore.ieee.org/document/5589451**

Guidehouse Outwit Complexity

7. APPENDIX A. Adjusted 2022/2023 MISO PRA ACP

Guidehouse used 6 years of prior MISO PRA ACP to generate a weighted average price representative of typical market conditions including outlier events.

PRA Year	Zone	ACP (A)	Zone PRMR [MW] (B)	Zone Price = (A) * (B)
2020-2021	1	$5.00	18,476.00	$ 92,380.00
2020-2021	2	$5.00	13,728.20	$ 68,641.00
2020-2021	3	$5.00	10,129.10	$ 50,645.50
2020-2021	4	$5.00	9,794.60	$ 48,973.00
2020-2021	5	$5.00	8,456.30	$ 42,281.50
2020-2021	6	$5.00	18,720.60	$ 93,603.00
2020-2021	7	$257.53	21,945.30	$ 5,651,573.11
2019-2020	1	$5.00	18,374.90	$ 91,874.50
2019-2020	2	$5.00	13,449.90	$ 67,249.50
2019-2020	3	$5.00	9,882.00	$ 49,410.00
2019-2020	4	$5.00	9,792.30	$ 48,961.50
2019-2020	5	$5.00	8,297.10	$ 41,485.50
2019-2020	6	$5.00	18,659.80	$ 93,299.00
2019-2020	7	$24.30	21,976.00	$ 534,016.80
2018-2019	1	$1.00	18,414.00	$ 18,414.00
2018-2019	2	$10.00	13,463	$ 134,630.00
2018-2019	3	$10.00	9,805	$ 98,050.00
2018-2019	4	$10.00	10,060	$ 100,600.00
2018-2019	5	$10.00	8,549	$ 85,490.00
2018-2019	6	$10.00	18,741	$ 187,410.00
2018-2019	7	$10.00	22,121	$ 221,210.00
2017-2018	1	$1.50	18,316	$ 27,474.00
2017-2018	2	$1.50	13,366	$ 20,049.00
2017-2018	3	$1.50	9,781	$ 14,671.50
2017-2018	4	$1.50	9,894	$ 14,841.00
2017-2018	5	$1.50	8,598	$ 12,897.00
2017-2018	6	$1.50	18,422	$ 27,633.00
2017-2018	7	$1.50	22,295	$ 33,442.50
2016-2017	1	$19.72	18,185	$ 358,608.20
2016-2017	2	$72.00	13,589	$ 978,408.00

2016-2017	3	$72.00	9,879	$ 711,288.00
2016-2017	4	$72.00	10,375	$ 747,000.00
2016-2017	5	$72.00	8,518	$ 613,296.00
2016-2017	6	$72.00	18,750	$ 1,350,000.00
2016-2017	7	$72.00	22,406	$ 1,613,232.00
2015-2016	1	$3.48	16,525	$ 57,507.00
2015-2016	2	$3.48	12,429	$ 43,252.92
2015-2016	3	$3.48	8,876	$ 30,888.48
2015-2016	4	$150.00	9,518	$ 1,427,700.00
2015-2016	5	$3.48	8,176	$ 28,452.48
2015-2016	6	$3.48	17,592	$ 61,220.16
2015-2016	7	$3.48	20,522	$ 71,416.56
Totals		**$2,692.55**	**598,847.10 (D)**	**$ 16,063,475.71 (C)**
			Weighted Average ACP = (C)/(D)	**$ 26.82**