Grain Belt Express Clean Line HVDC Project
Loss of Load Expectation Study

PREPARED FOR: Grain Belt Express Clean Line LLC

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EXECUTIVE SUMMARY

Grain Belt Express LLC (“Grain Belt Express”) is a transmission developer proposing to build the Grain Belt Express Clean Line HVDC project (the “Project”) from wind-rich western Kansas, with a 500 MW delivery to the Midcontinent Independent System Operator (“MISO”) in Ralls County, MO, and an additional 3,500 MW delivery to PJM at the Sullivan Substation near the Illinois-Indiana border.

In support of Grain Belt Express’ application for a Certificate of Convenience and Necessity in the State of Missouri, Grain Belt Express commissioned a study to measure the reliability benefit of the Project. The study performs a comparison of system reliability, measured by Loss of Load Expectation or LOLE, with and without the proposed HVDC line. The model used was designed to be rigorous but not include complexities which will have no effect on the comparison. For the purposes of this analysis, all of the utilities within the State of Missouri and all of their designated resources and load obligations were treated as a single aggregated entity.

The addition of the interconnection of the Missouri HVDC converter station and associated 500 MW of capacity injection from the Grain Belt Express Project reduced LOLE for the State of Missouri, which was studied as an aggregated single system, from 0.013 days per year to 0.004 days per year. This is a 69% improvement. Comparable improvement was observed in LOLE expressed in hours per year and in loss of energy.

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1 METHODOLOGY

The study uses three common, industry-accepted metrics of electric reliability: Loss of Load Probability ("LOLP"), LOLE and loss of expected energy ("LOEE"). In a power system, the excess of available generating capacity over load is termed "reserve". If reserve is greater than zero, all load will be served and some generating capacity will be operated at less than its maximum output. If reserve is less than zero, some load will be unserved or "lost". LOLP, LOLE and LOEE are all measures of the likelihood and severity of lost load due to a lack of adequate generation reserves.

1.1 Loss of Load Probability

Neither the available capacity nor the load at a future time are known precisely; in a statistical sense they are termed "random variables".

Past operating history of each generating unit forms a basis for predicting probabilities of each unit being in various operating states from fully available to fully out-of-service. Better estimated probabilities, having a smaller error band, may be calculated by "pooling" the operating histories of similar units.

All generating units, regardless of technology, require outages for maintenance. These are typically on a schedule extending several years into the future, but subject to modification based on system conditions. Maintenance of units in each plant and across the system is coordinated to fall primarily in off peak periods, with due consideration of holiday schedules and workload constraints with each plant.

In addition to maintenance outages, generators also experience un-scheduled (forced) outages. The Generator Availability Data System ("GADS") database, assembled annually by the North American Electric Reliability Corporation ("NERC"), is the primary source of generator outage probabilities (i.e. forced outage rates) in North America. Assumptions around generator availability used in this study are further described in Section 2 of this report.

Forecasting peak loads for future years can be approached by a variety of econometric and statistical techniques. Loads throughout the year are typically estimated by multiplying the peak by a matrix of proportions between 0 and 1 called a "load profile". Sanity checks of such profiles are appropriate to insure that hour-to-hour, day-to-day and week-to-week changes are not unreasonably large and that seasonal variations are appropriate. For instance, August and January peak loads are higher than May or October.

Not all uses of electricity are equally valued by the customers. Historically some customers have been willing to accept postponing a portion of their use in exchange for a reduction of their rate. This is referred to as Demand Side Management ("DSM"). While this can reduce the need to build generating capacity it should be recognized that it is only effective if the customer would have that type of load in the absence of DSM; interrupting air conditioners in January will not reduce load significantly.

Taking the above factors into account, a probability distribution of load and a probability distribution of available capacity can be estimated for a particular future time. When combined, a generator distribution and a load distribution imply a probability distribution of reserves. The probability of negative reserves, or lost load, is termed the Loss of Load Probability (LOLP) and the expected shortfall is termed the Loss of Expected Energy (LOEE), in megawatt hours. These metrics can be calculated for a single hour, but the more relevant metric is LOLP and LOEE for an entire year. The method for an annual calculation is described below.

1.2 Loss of Load Expectation

If the probabilistic analysis described above is repeated for all 365 days in the year, daily probabilities of negative reserves can be interpreted as "days per year" of lost load, and summed to give a value of Loss of Load Expectation in days per year. An accepted target value in North America is 0.1 *d*ay per year. As a practical matter, daily LOLP values are highest near seasonal load peaks and may be negligible for much of the rest of the year.

Analysis may be further refined by considering hourly loads rather than daily peak loads, as was done in this study. In such an approach, the implicit assumption of the approach outlined above, that the distribution of available generating capacity on each day is statistically independent of the previous and subsequent days, becomes unsupportable. The average duration of forced outages is on the order of hours, so while assuming independence of available capacity on successive daily peaks may be plausible assuming independence on successive hours is not.

1.3 Sequential Monte Carlo Methods

The Multi-Area Reliability Simulation (MARS) program licensed by General Electric (GE), utilizes a Monte Carlo technique to estimate LOLE and LOEE for a portion of the power system. This technique uses repeated trials with the values of random variables, such as the start time and end time of a generator outage, set by a random number generator. The numbers of days and hours having a loss of load, and energy not served, are recorded, and at each iteration cumulative averages are calculated. In the current project 2000 model iterations were run for each case considered.

GE MARS uses sequential Monte Carlo techniques to address the issue of lack of independence of successive generating capacity outcomes. The transitions from one capacity state to another of each generating unit are assumed to be a Poisson process, which means that the rate of transitions is independent of the time the unit has been in its current state, and the distribution of state "dwell times" is exponential.

The GE MARS program has been widely accepted in the industry for a variety of LOLE studies. It is the most widely used program for that purpose in North America today.

2 GENERATING UNIT POPULATION AND PARAMETERS

There are five major components of generating unit input data for this study:

- The population of generating units in the area to be analyzed;
- Forced outage data, based on national averages for comparable units from the NERC GADS survey of generating unit performance;
- A maintenance requirement in weeks per year for each unit;
- Wind, hydro and solar characteristics; and
- Import and export capability

Each of these components is described further below.

2.1 Generating Unit Data

A population of generating units in Missouri was developed by Mr. Neil Copeland of GDS Associates, Inc. for his testimony concerning the production simulation analyses in consideration of the Grain Belt Express Project. This unit population was based on the MISO "Business as Usual" scenario for 2022 from the 2015 MISO Transmission Expansion Plan (MTEP) model. The same population of generating units was used in this analysis. This generator population, as provided by Grain Belt Express witness Mr. Copeland, was used with minor modification, primarily in separating equivalent models of the entire Keokuk, Osage and Taum Sauk hydro and pumped storage plants into individual unit models.

The MISO power flow cases for various scenarios commonly include Regional Resource Forecast ("RRF") units representing unidentified future capacity required to attain appropriate reliability or other goals. The solar plant discussed in Section below is such a resource. A second RRF combustion turbine unit of 600 MW was also included in this analysis since the unit was included in the MTEP15 power flow model. This RRF unit was included to address a perceived capacity shortfall in Load Resource Zone Five (LRZ 5) which includes Ameren Missouri and the City of Columbia. The capacity of this RRF unit was reduced to 75 MW due to the retirement of the 475 MW of Noranda aluminum smelter load plus the associated 12% reserves that would be required to ensure service to the Noranda load.

MISO made certain assumptions about retirements across the Eastern Interconnection and has shut down capacity and added it back via RRF units without consulting the neighboring regions. In our particular case they have added a 600 MW RRF combined cycle unit in Empire District Electric's (EMDE) territory to meet projected resource requirements of the SPP region based on the MISO assumption of how much capacity would be retired in SPP. MISO sites RRF units based on an algorithm which considers the approximate injection capability at various nodes on the transmission system. In the case of the RRF unit sited in the EMDE system, there was no correlation between siting the unit in Missouri in general and EMDE in particular. It was a proxy generator added to meet the regional resource requirements of SPP. Including this 600 MW RRF unit in the State of Missouri, with no direct connection to the resource requirements of any Missouri utility, would have skewed the LOLE results based on the presence of a capacity resource not designated by a Missouri utility.2.6

The MW capacity of units of each type, by owner, is shown in Table 2-1.

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Table 2-1 Generating Unit Population

Area	CC	Conventional Hydro	CT Gas	CT Oil	IC Gas	IC Oil	IC Renewable	Nuclear	Pumped Storage Hydro	Solar PV	ST Coal	ST Gas	Wind	Total
Ameren Missouri		373	3435	350			18	1224	400		4650	274		10724
Associated Electric Cooperative Inc.	492	85	608	45					31		2270		308	3839
City Power & Light Independence			89	68										157
City Utilities Springfield Missouri			375				3				282			660
Columbia Missouri Water and Light Department			237	42		16						35		330
Empire District Electric Co.	1100	16	409								189			1714
Kansas City Power & Light Co.	292		639	520	39					25	3547		249	5310
KCPL-Greater Missouri (MPS)	693		797	61			3				333	38		1925
MidAmerican Energy Co.													146	146
South Mississippi Electric Power Association											658			658
Westar Energy/Western Resources											2164			2164
Total	**2577**	**474**	**6589**	**1087**	**39**	**16**	**24**	**1224**	**431**	**25**	**14093**	**347**	**703**	**27627**

2.2 Unit Forced Outages

Each unit was assumed to have two capacity states, fully on and fully off. Forced outage rate and duration values were also compiled by Mr. Copeland from the generation database using in his production simulation analyses. A summary of average values for each unit type is shown in **Error! Not a valid bookmark self-reference.**. Transition rates were calculated by the following equations.

$$\lambda = \frac{FOR}{FOD * (1 - FOR)}$$

$$\mu = {}^{1}/_{FOD}$$

Where:

$\boldsymbol{\lambda}$ = rate of forced outage transitions, events per hour

FOR = Forced Outage Rate as a fraction

FOD = Forced Outage Duration, hours

µ = rate of restorations, events per hour

Table 2-2 Generating Unit Forced Outage Performance

Type	Forced Outage Rate (%)	Forced Outage Duration (Hrs)
CC	5.44	31
Conventional Hydro	0.50	24
CT Gas	4.36	58
CT Oil	5.78	58
IC Gas	4.20	12
IC Oil	4.79	12
IC Renewable	3.60	12
Nuclear	4.02	168
Pumped Storage Hydro	0.00 (1)	N/A
Solar PV	0.00	24
ST Coal	7.78	46
ST Gas	7.70	75
Wind	0.00	24

(1) GE MARS does not support forced outages of energy storage units.

2.3 Unit Maintenance

Average unit maintenance requirements, in hours per year, were also obtained from Mr. Copeland's data. In accordance with GE MARS data entry formats, these were rounded to the nearest week.

Table 2-3 Generating Unit Maintenance Requirements

Type	Hours per year
CC	355
Conventional Hydro	535
CT Gas	369
CT Oil	402
IC Oil	201
Interruptible Loads	0
Nuclear	Specific 5 week schedule
Pumped Storage Hydro	672
Solar PV	0
ST Coal	845
ST Gas	537
Wind	0

2.4 Missouri Internal Wind Generation

Many system operators assign a relatively low capacity benefit to wind turbines, recognizing that they cannot be depended on to deliver maximum power at peak times even when they are mechanically in good order. GE MARS permits recognizing this by entering a set of eleven probabilities for output states at increments of 10% of total capacity, from 0% to 100%. In this study it was assumed that each wind plant located in Missouri had a probability of 0.20 (20%) of being at zero output, 0.50 (50%) of being at 10% or less, and 1.00 (100%) of being at 20% or less of nameplate rating. This represents a capacity benefit of 13%[1]:

$$0\%\ x\ 0.2 + 10\%\ x\ (0.5 - 0.2) + 20\%\ (1.0 - 0.5) = 0\% + 3\% + 10\% = 13\%$$

Note that variations at different wind plants are assumed to be independent.

2.5 Pumped Storage Hydro Generation

Pumped storage units must use considerably more energy in pumping water to the upper reservoir than can be recovered during periods when they are generating. It was assumed that the Clarence Cannon Dam plant had a daily cycle of 8 hours pumping at 35 MW, 6 hours generating at 31 MW, while each of the two Taum Sauk units had sixteen hours of pumping followed by eight hours of generating, both at 200 MW.

[1] This corresponds with the 12.4% value assigned to Zone 4 and 5 wind facilities by MISO in the December 2015 Wind Capacity Credit report. *Planning Year 2016-2017 Wind Capacity Credit, MISO, December 2015, (available at):* https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf.

All pumped storage units were modeled such that their full capacity was available across the peak load hours and the pumping load occurred off-peak.

2.6 Solar Generation

There are no utility-scale solar plants in Missouri represented in the generation database in MISO at this time, but it was assumed that one will be built to address renewable energy goals. It was assumed that its output was maximum for a four hour period in midday, zero for a 10 hour period overnight, and linearly increasing in the morning and decreasing in the afternoon and early evening. This reflects summer conditions when reserves are tight.

2.7 Imports

The Missouri system is not an electrical island. Units outside Missouri are contracted to supply Missouri load, while units inside Missouri are contracted to supply external loads. The Eastern Interconnection Reliability Assessment Group (ERAG) builds power flow models of the eastern interconnection through its Multi-Regional Modeling Working Group (MMWG). Data published as part of this effort includes a detailed tabulation of capacity transactions between utilities. This tabulation of transactions includes the external resources and obligations which have been mutually agreed to by each utility in the Eastern Interconnection and make up the net scheduled interchange between regions. These transactions result in a net scheduled import of 2337 MW of external designated resources to supply Missouri load:

- External coal 344 MW
- External gas 4 units at 75 MW each, 1 unit at 85 MW
- External hydro 3 units at 289 MW each
- External wind 1 unit at 100 MW, 1 unit at 75 MW
- External Nuclear 566 MW of Wolf Creek Nuclear Plant

The Grain Belt Express Project was modeled as a 500 MW import within the State of Missouri. The Grain Belt Express Project will enable transmission of more than 4,000 MW of new wind generation resources from the Kansas converter station allowing for delivery of up to 500 MW of power to MISO and 3,500 MW of power to PJM. In addition, the Grain Belt Express Project's Kansas converter station will connect to the SPP system, as described in the direct testimony of Grain Belt Express witness Dr. Galli. This will provide the State of Missouri with access to diverse resources from the roughly 79,000 MW of installed capacity in the SPP integrated market in addition to the wind resources which are directly connected to the Grain Belt Express Project. The Grain Belt Express Project's Illinois converter station will connect to the PJM system in Indiana, also as described in the direct testimony of Grain Belt Express witness Dr. Galli. This will provide the State of Missouri with access to additional generation resources from the approximately 185,000 MW of diverse, installed capacity in the PJM integrated market.

Therefore, due to the design of the Grain Belt Express Project, Missouri has access to over 265,000 MW of capacity causing the Missouri terminal to be virtually guaranteed to be capable to deliver 500 MW of capacity at any given time subject to the operating arrangements implemented by Grain Belt Express and the interconnecting utilities. The means by which Load Serving Entities will be able to obtain access to the supplemental generation resources in the SPP and/or PJM regions is described in the direct testimony of Grain Belt Express witness Dr. Galli. The geographic diversity of the SPP, MISO, and PJM regions and the diverse resource mixes that these regions manage through their energy and capacity markets, coupled with the wind generation resources that will be enabled by the Grain Belt Express Project, the assumption that, during capacity emergencies which would lead to a loss of load, the Missouri converter station will be able to deliver the rated capacity of 500 MW to the State of Missouri.

2.8 Exports

In a similar fashion, and based on the same ERAG MMWG net scheduled interchange tables, the capacities of certain units in Missouri or owned by Missouri utilities were adjusted, as they are partly committed to serving load outside Missouri.

- Dogwood 3 Reduced from 693 MW to 593 MW
- State Line 3 Reduced from 500 MW to 300 MW
- Lacygne 2 Reduced from 700 MW to 0 MW

3 DEMAND

Mr. Copeland supplied a load profile with a maximum (peak) of 18064 MW, based on the load represented at Missouri buses at Missouri buses in the MISO power flow case. This was increased by 476 MW (2.6%) to account for firm exports identified exports identified in the ERAG MMWG net scheduled interchange data as described above, and a further 445 MW (2.4%) for 445 MW (2.4%) for transmission losses based on the MTEP peak power flow model and which are part of the resource the resource obligation of Load Serving Entities. Based on the dataset supplied, the peak was identified as occurring in the as occurring in the hour ending at 5 PM on July 22, 2022. Monthly peaks were as shown in

Table 3-1.

Table 3-1 Monthly Peak Loads before adjustment

Month	Peak Load	%
January	12496	66%
February	13627	72%
March	11779	62%
April	11814	62%
May	13831	73%
June	16199	85%
July	18949	100%
August	18762	99%
September	14034	74%
October	14485	76%
November	12937	68%
December	14191	75%

4 RESULTS

The calculated indices for the state of Missouri in the year 2022, without and with the Grain Belt Express Project, are as shown in Table 4-1.

Table 4-1 2022 Missouri Reliability Indices

	Without Grain Belt Express Project	With Grain Belt Express Project	Impact of Grain Belt Express Project (%)
	Year Total	Year Total	Year Total
LOLE (days)	.013	.004	-69%
LOLE (hours)	.040	.014	-65%
LOEE (MWH)	18.8	6.5	-65%

The Grain Belt Express Project has a substantial favorable effect on the reliability of electric service in Missouri. The primary measures of reliability are each improved by approximately 65 – 70%.