STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA ("AES INDIANA") FOR (1) ISSUANCE TO AES INDIANA OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE ACQUISITION AND DEVELOPMENT BY A WHOLLY OWNED AES INDIANA SUBSIDIARY OF A SOLAR POWER GENERATING FACILITY AND BATTERY ENERGY STORAGE SYSTEM PROJECT TO BE KNOWN AS THE PETERSBURG ENERGY CENTER ("THE PETERSBURG PROJECT"); (2) APPROVAL OF THE PETERSBURG PROJECT, INCLUDING A JOINT VENTURE STRUCTURE BETWEEN AN AES INDIANA SUBSIDIARY AND ONE OR MORE TAX EQUITY PARTNERS AND A CAPACITY AGREEMENT AND CONTRACT FOR DIFFERENCES BETWEEN AES INDIANA AND THE PROJECT COMPANY THAT HOLDS AND OPERATES THE SOLAR GENERATION AND STORAGE ASSETS, AS A CLEAN ENERGY PROJECT AND ASSOCIATED TIMELY COST RECOVERY UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF ACCOUNTING AND RATEMAKING FOR THE PETERSBURG PROJECT, INCLUDING AN ALTERNATIVE REGULATORY PLAN UNDER IND. CODE § 8-1-2.5-6 TO FACILITATE AES INDIANA'S INVESTMENT IN THE PETERSBURG PROJECT THROUGH A JOINT VENTURE; AND (4) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER THE JOINT VENTURE, INCLUDING THE PROJECT COMPANY, AS A PUBLIC UTILITY.

CAUSE NO. 45591

PETITIONER'S SUBMISSION OF DIRECT TESTIMONY OF MATTHEW E. LIND

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "Petitioner"), by counsel, hereby submits the direct testimony and attachments of Matthew E. Lind.

Respectfully submitted,

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone: (317) 231-6465
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR PETITIONER
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 30th day of July, 2021, by electronic transmission or United States Mail, first class, postage prepaid on:

Jeffrey M. Reed
Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
jreed@oucc.in.gov
infomgt@oucc.in.gov

Jeffrey M. Peabody

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone: (317) 231-6465
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR PETITIONER
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

VERIFIED DIRECT TESTIMONY

OF

MATTHEW E. LIND

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

D/B/A AES INDIANA

<u>SPONSORING AES INDIANA ATTACHMENTS MEL-1 AND MEL-1(C)</u>

VERIFIED DIRECT TESTIMONY OF MATTHEW E. LIND
ON BEHALF OFAES INDIANA

Q1. Please state your name and business address.

A1. My name is Matthew Lind. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. By whom are you employed and in what capacity?

A2. I am employed by 1898 & Co. as a Director, leading the Resource Planning & Market Assessments Business. 1898 & Co. was established as the consulting and technology division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 200 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 7,000 engineers, architects, construction professionals, scientists, consultants and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. Please describe your duties as Director, Resource Planning & Market Assessments Business at 1898 & Co.

A3. As Director of the Resource Planning & Market Assessments Business, I oversee the related business development, marketing, staff training and project execution for the Business Unit. This Business Unit specializes in development of economic models and analyses associated with generation and transmission planning serving municipal, cooperative, investor-owned utilities, independent generation and transmission developers and regional transmission organizations clients. Projects range from integrated resource planning, new resource procurement evaluation, economic transmission planning, demand-side management, asset retirement, transmission congestion impacts, and other economic planning decisions. The Resource Planning & Market Assessments Business supports clients in markets across the United States and some international markets.

Q4. Please summarize your education background and certifications.

A4. I have received a Bachelor of Science degree in Industrial Engineering from Iowa State University. I have also received a Master of Business Administration degree in Finance from the University of Missouri-Kansas City.

I am a registered Professional Engineer in the state of Kansas. I am a member of RMEL and the Edison Electric Institute ("EEI") and serve on the Transmission Executive Committee supporting the System Planning and Operations subcommittee. I was also recognized as a *Public Utilities Fortnightly* Under 40 in 2020.

Q5. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission")?

A5. Yes. I have previously provided testimony on behalf of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.'s ("Vectren South") in Cause Nos. 44446, 44927 and 45052. I have also previously provided testimony on behalf of Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL" or "Company") in Cause No. 45493.

Q6. What is the purpose of your testimony in this proceeding?

A6. The purpose of my testimony is to describe 1898 & Co.'s role in supporting AES Indiana in its evaluation of power supply proposals received through an all-source request for proposal ("RFP") solicitation process, relevant experience and present the results and methodology used to evaluate the system impacts and congestion associated with select proposals.

Q7. Are you sponsoring any attachments?

A7. Yes. I am sponsoring the following attachments:

Attachment	Description
AES Indiana Attachment MEL-1 and MEL-1(C)[1]	Interconnection Reliability and Congestion Evaluation Summary

Q8. Were these attachments prepared or assembled by you or under your direction and supervision?

A8. Yes. Other 1898 & Co. and AES Indiana personnel with specific areas of expertise were involved in the process of providing inputs or creating the work product, and I served the role of overseeing the project planning process, including coordinating, validating and documenting the modeling efforts.

Q9. Did you submit any workpapers?

A9. Yes. I am submitting workpapers associated with the above referenced report.

[1] AES Indiana Attachment MEL-1(C) is the confidential version.

Q10. How did 1898 & Co. assist AES Indiana in its All Source RFP?

A10. 1898 & Co. supported the evaluation of select proposals received and short listed by AES Indiana and its All Source RFP consultant Sargent & Lundy. 1898 & Co. did not receive nor evaluate all proposals received through the RFP process. For those proposals identified by AES Indiana for further evaluation, 1898 & Co. performed a reliability analysis to estimate potential costs associated with network upgrades needed to maintain system reliability. Subsequent to the identification of network upgrades, 1898 & Co. performed security constrained unit commitment and economic dispatch ("SCED") to determine potential congestion impacts based on the location of each evaluated resource.

Q11. Please summarize the RFP proposals identified by AES Indiana for the generator interconnection reliability analysis and congestion evaluation 1898 & Co. performed.

A11. Eight (8) different proposals were evaluated in AES Indiana Attachment MEL-1 and MEL-1(C). The installed capacity ("ICAP") of proposals ranged from 100 megawatts ("MW") up to 250 MW and included solar and solar co-located with energy storage. The proposals and basic identifying characteristics are shown in the following table (Table 1):

Table 1: Proposal Characteristics Summary

Proposal	Size (ICAP MW)	Fuel	MISO Request ID	Point of Interconnection
[redacted]				

Q12. What experience does 1898 & Co. have in assisting with utility RFPs?

A12. Across multiple decades, 1898 & Co. has provided consulting services to various utilities, developers, and other organizations involving power supply proposal requests. 1898 & Co.'s power supply RFP consulting experience includes independent management of the entire process from request development to proposal evaluation, proposal evaluation only, and assistance preparing RFP participant proposals. 1898 & Co. has supported multiple utility clients within the MISO market including the state of Indiana. 1898 & Co. recently supported Vectren's All Source RFP process and evaluation as part of its 2020 integrated resource plan.

Q13. Why is it important to perform a generator interconnection reliability analysis when evaluating different RFP proposals?

A13. Before a new generating facility can be connected to the grid, the reliability impacts associated with this interconnection must be studied, and, to the extent issues are found, mitigated through electric transmission network upgrades ("NU"). The addition of NUs to address system reliability have the potential to increase the costs associated with a new generating facility project. The regional market that AES Indiana participates in, the Midcontinent Independent System Operator ("MISO"), is responsible for officially studying, identifying, and assigning direct connection and NU costs to the responsible interconnecting generating facilities to maintain system reliability. This study process is referred to as the Definitive Planning Phase ("DPP") of MISO's generator interconnection process.

AES Indiana received proposals through their RFP process that were in varying stages of MISO's DPP process. For those proposals that had not completed a MISO DPP study, the NU costs are unknown. By performing a generator interconnection reliability analysis, the reliability impacts of interconnecting the new generating facility can be determined and NU costs estimated. These costs can be included in the overall cost evaluation for those proposals without a MISO DPP study estimate and compared against proposals with a completed MISO DPP study.

Q14. What was 1898 & Co.'s approach to independently perform a generator interconnection reliability analysis?

A14. For those proposals with a completed MISO DPP study, 1898 & Co. independently reviewed the interconnection request study report, verifying the costs provided. For those proposals without a completed MISO DPP study report, 1898 & Co. independently performed reliability analysis that simulates MISO's DPP study process. The goal of the reliability analysis was to identify the direct connection and NU costs for each proposal identified for this evaluation.

Q15. What are direct connection costs composed of?

A15. Direct connection costs are composed of the scope and equipment necessary to electrically interconnect the new generating facility to the transmission system.

Q16. What are NU costs composed of?

A16. NU costs are derived from network resource interconnection service ("NRIS") impacts, energy resource interconnection service ("ERIS") impacts and any affected system ("AFS") impacts to transmission systems outside of MISO.

Q17. Were there any proposals that already had a completed MISO DPP study and report?

A17. Yes. Proposal [redacted], Proposal [redacted], Proposal [redacted], Proposal [redacted], and Proposal [redacted] had already completed MISO DPP study reports that included direct connection and NU costs determined by MISO. These costs, as reported and determined by MISO, were used as the basis for the direct connection and network upgrade costs for those proposals.

Q18. For those proposals without an available MISO DPP Study report, please describe the models and data sources used by 1898 & Co. to determine potential NRIS, ERIS, and AFS generator interconnection costs.

A18. The NRIS analysis was conducted using the Summer Peak NRIS case from the appropriate MISO DPP Study Cycle. The ERIS analysis was conducted using the Summer Peak and Shoulder ERIS cases from the appropriate MISO DPP Study Cycle.

Both the NRIS and ERIS models were developed and provided by MISO representing the same baseline model starting point as used by MISO in their DPP Study.

The AFS analysis was conducted for the neighboring PJM system starting with the PJM 2023 Summer Peak case from the AF2 feasibility study. This PJM model was further modified to include all active PJM queue projects through the AF2 study class as well as all active MISO Classic queue projects through the DPP 2019 Cycle 1 study class.

Q19. Please summarize the results of 1898 & Co.'s generator interconnection system impact analysis.

A19. Each proposal received by 1898 & Co. was evaluated for network upgrade and direct connection transmission facility costs associated with NRIS, ERIS, and AFS transmission facility impacts as appropriate based on each proposal's capacity, fuel type and planned point of interconnection ("POI"). The results of this analysis indicated certain proposals showing minimal costs associated with interconnection while other proposals had the potential for up to $[redacted] in costs associated with interconnection. A summary of each proposal interconnection option and their direct and NU cost are shown in the following table (Table 2):

Table 2: Interconnection Cost Summary

Proposal	Direct Connection Costs ($)	Network Upgrade Costs ($)	Total Network Upgrade Costs ($)
[redacted]			

The analysis approach and results associated with the generator interconnection reliability analysis are discussed in further detail in Section 2 and Section 3 of AES Indiana Attachment MEL-1.

Q20. Why was a congestion analysis the second step?

A20. AES Indiana engaged 1898 & Co. to perform a congestion analysis in order to identify and compare transmission congestion and losses based on the location of the evaluated proposals. To the extent the generation resource is located remotely from AES Indiana's electric service territory, congestion costs pose a long-term risk of increasing the costs to procure electricity to serve customer load to the extent there is significant price separation between the generation commercial price node locational marginal price ("LMP") and AES Indiana's load commercial price node LMP. In order to approximate this potential price separation, any transmission facilities built or upgraded as a result of the generator interconnection system impact analysis should be factored into the SCED simulations.

Q21. Please explain transmission congestion.

A21. Transmission congestion is a limitation in the transmission facilities within a regional market that inhibits the ability to effectively deliver the most efficient and lowest cost sources of generation to a load. Transmission congestion results in the redispatch of less efficient generation in order to allow transmission facilities to operate within their facility ratings. In a regional market, each commercial pricing node has a LMP which consists of energy, transmission congestion, and losses. To the extent LMPs are different between commercial pricing nodes, transmission congestion is typically the primary factor causing the price difference.

Q22. Please describe the models and data sources used by 1898 & Co. to determine potential congestion costs.

A22. Each of the Phase 3 short-list proposals were evaluated using Hitachi ABB's PROMOD IV ("PROMOD") to simulate security-constrained unit commitment ("SCUC") and SCED across the MISO footprint and neighboring regions. PROMOD simulations calculate the LMP for every bus, including generator and load nodes, within the study region.

The 2020 MISO Transmission Expansion Plan ("MTEP20") PROMOD models and associated constraint files were utilized as the starting point for this analysis. The MTEP20 models were developed by MISO in conjunction with their stakeholders and include five-year-out, ten-year-out, and fifteen-year-out models under varying assumed future conditions. Of the four modeled futures, the Accelerated Fleet Change ("AFC") future was selected as the starting point, using the five (2024) and ten (2029) year out models.

Further modifications were made to these models reflecting announced generator retirements and additions. Commodity and energy demand forecasts were also modified to align with AES Indiana's integrated resource plan ("IRP") assumptions. These modifications are further discussed in Section 4 of <u>AES Indiana Attachment MEL-1</u>.

Q23. What was 1898 & Co.'s approach to performing a congestion analysis?

A23. 1898 & Co. received the modeling parameters for each of the proposals under consideration including the POI and expected hourly production profile. In addition, direct connection and NU transmission facilities identified for each proposal as part of the generator interconnection reliability analysis was modeled. Each of the proposals were added to the MTEP20 PROMOD models and evaluated concurrently. This was done assuming each proposal would be developed, regardless of whether AES Indiana entered into a purchase agreement or not. The adjusted production cost ("APC") measure, which is a typical metric for comparing the overall system-wide benefit of one generation project to another, was not used because each proposal was in the model and therefore the APC for AES Indiana was the same regardless of the proposal. With each proposal located at a unique location, the revenue derived from the generation production at its generator node LMP was calculated and compared. This information was provided to AES Indiana to consider along with the potential interconnection and other costs associated with each proposal.

Q24. Please summarize the results of 1898 & Co.'s congestion analysis.

A24. Results from the MTEP20 PROMOD simulations were summarized for both 2024 and 2029. The generation weighted LMP for each of the proposals are shown in the following table (Table 3):

Table 3: Proposal Generation-Weighted LMP

Proposal	Solar+Storage Capacity (ICAP MW)	Gen-weighted LMP	
		2024	2029
[redacted]			

The generation weighted LMP is calculated by dividing the project's revenue by its generation. The generation weighted LMP represents the revenue the facility generated per MWh of generation. In this way, each of the RFP proposals, which have different ICAP and capacity factors, can be compared to one another. Because the generation weighted LMP represents the $/MWh price at which energy is sold into the market, a higher number is better for AES Indiana's customers.

In the early year simulation (2024), the highest LMP value represents an approximate 8 percent premium above the lowest LMP value; this premium grows to approximately 12 percent in the later year simulation (2029). While that spread is potentially meaningful for the revenue generation of the respective proposals, nearly all of the proposals result in generation weighted LMPs that are fairly close together and on the higher end of the generation weighted LMPs derived. Proposal [redacted] is consistently around the lowest generation weighted LMP in both simulated years while all other proposals have a higher generation weighted LMP. The results are further discussed in Section 5 of AES Indiana Attachment MEL-1.

Q25. Does this evaluation by itself, both the interconnection reliability analysis and congestion evaluation, let AES Indiana make a decision on which proposal(s) to pursue for purchase?

A25. No. The results of these analyses should be considered along with the related purchase costs associated with each proposal when determining a preferred proposal. See AES Indiana Witness Cooper for proposal selection.

Q26. Does this conclude your prefiled direct testimony?

A26. Yes.

VERIFICATION

I, Matthew E. Lind, 1898 & Co., Director, leading the Resource Planning & Market Assessments Business, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated July 30, 2021.

Matthew E. Lind

1898 & CO.

PART OF BURNS & McDONNELL

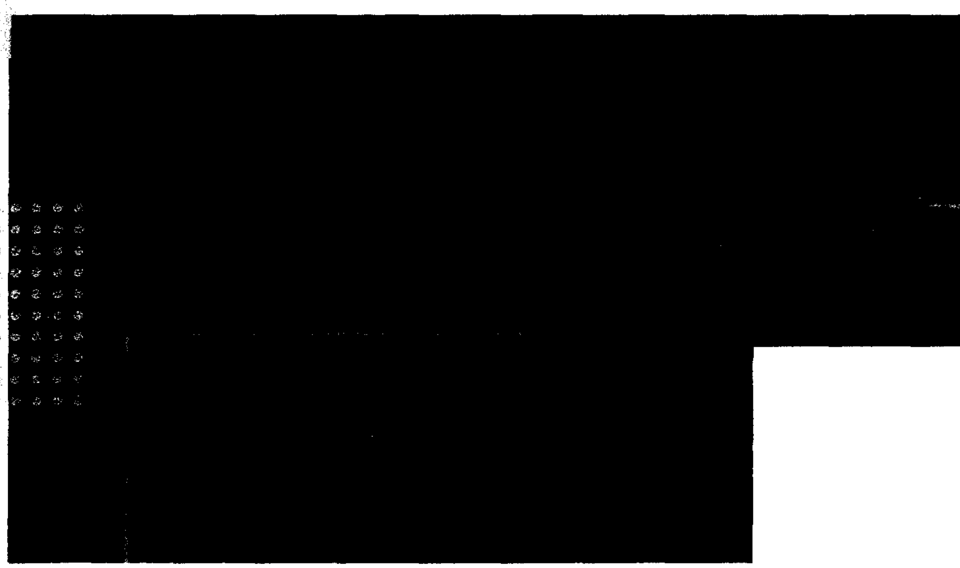
Interconnection Reliability and Congestion Evaluation

aes Indiana

AES Indiana

RFP Support
Project No. 133122

7/21/2021



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1.0 EXECUTIVE SUMMARY

AES Indiana's Preferred Resource Portfolio from the 2019 Integrated Resource Plan (IRP) identified a need of approximately 200 megawatts (MW) of replacement capacity. AES Indiana issued an all source request for proposal (RFP) to identify and procure replacement capacity to address this need. As part of this process, AES Indiana retained 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (1898 & Co.) to perform detailed reliability and congestion evaluations of select resource proposals as identified by AES Indiana and its RFP consultant through the RFP process.

The shortlist of proposals that were included in the evaluation process is provided in Table 1.

Table 1: Proposal Shortlist

Proposal	Solar Capacity (ICAP MW)	Storage Capacity (ICAP MW)	MISO Request ID	Point of Interconnection
[redacted]				

1.1 Reliability Analysis

Before a new generating facility can be connected to the grid, the reliability impacts associated with this interconnection must be studied, and, to the extent issues are found, mitigated through electric transmission network upgrades (NU). The addition of NUs to address system reliability have the potential to increase the costs associated with a new generating facility project.

The regional market that AES Indiana participates in, the Midcontinent Independent System Operator (MISO), is responsible for officially studying, identifying, and assigning NU costs to the responsible interconnecting generating facilities to maintain system reliability. This study process is referred to as the Definitive Planning Phase (DPP) of MISO's generator interconnection process. 1898 & Co. independently reviewed the proposals with interconnection requests that have had MISO DPP reports published and independently

[1] Solar portion of Proposal [redacted] is Proposal [redacted]

[2] Solar Portion of Proposal [redacted] is Proposa [redacted]

analyzed the proposals with interconnection requests that have not had MISO DPP reports published. The goal of the reliability analysis is to identify the direct connection, the Network Resource Interconnection Service (NRIS) impacts, the Energy Resource Interconnection Service (ERIS) impacts, and any appropriate Affected System (AFS) network upgrade costs for each of the proposals. The total reliability costs found for each of the proposals through the evaluation process is provided in Table 2.

Table 2: Reliability Costs

Proposal	Direct Connection Costs ($)	Network Upgrade Costs ($)	Total Network Upgrade Costs ($)
[redacted]			

The reliability impacts for each of the proposals is provided in full detail in Section 3.0.

1.2 Congestion Analysis

The purpose of the Congestion Analysis was to calculate the hourly locational marginal price (LMP) at the shortlisted proposal's interconnection points as well as AES Indiana's load node. This analysis captures potential differences in the congestion and losses components of the LMP between the various RFP proposals. The primary difference can typically be attributed to congestion which results from limitations in the transmission system's ability to cost effectively deliver power. ABB's PROMOD IV was used to simulate security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) across the MISO footprint and neighboring regions for 2024 and 2029. The projected LMPs from these simulations for each of the RFP proposals is summarized below, more details can be found in Section 4.0.

[3] Solar portion of Proposal [redacted] is Proposal [redacted]

[4] Solar portion of Proposal [redacted] is Proposal [redacted]

Table 3: Congestion Analysis Solar LMP Summary

Proposal	Solar Capacity (ICAP MW)	Storage Capacity (ICAP MW)	Storage Duration (Hrs.)	Gen-Weighted LMP[5] ($/MWh)	
				2024	2029
[redacted]					

Table 4: Congestion Analysis Battery LMP Summary

		[redacted]		[redacted]		[redacted]	
Year	Item	Charge	Discharge	Charge	Charge	Discharge	Charge
2024	Gen-Weighted LMP ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	Gen-Weighted LMP ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1.3 Summary

1898 & Co.'s reliability and congestion analysis provided both cost and benefit data points for AES Indiana to consider in selecting any proposals for its capacity need as identified in its most recent IRP.

The reliability analysis provided potential costs that would be borne by the respective proposal in order to interconnect to the grid. [redacted] proposals had [redacted] estimated network upgrade costs (Proposals [redacted] while the remaining proposals all had total network upgrade costs [redacted] of [redacted]

[5] Generation weighted LMPs display the value for the stand-alone solar or only the solar portion of proposals which included storage or optional storage

[6] Solar portion of Proposal [redacted] is Proposal [redacted]

[7] Solar portion of Proposal [redacted] is Proposal [redacted]

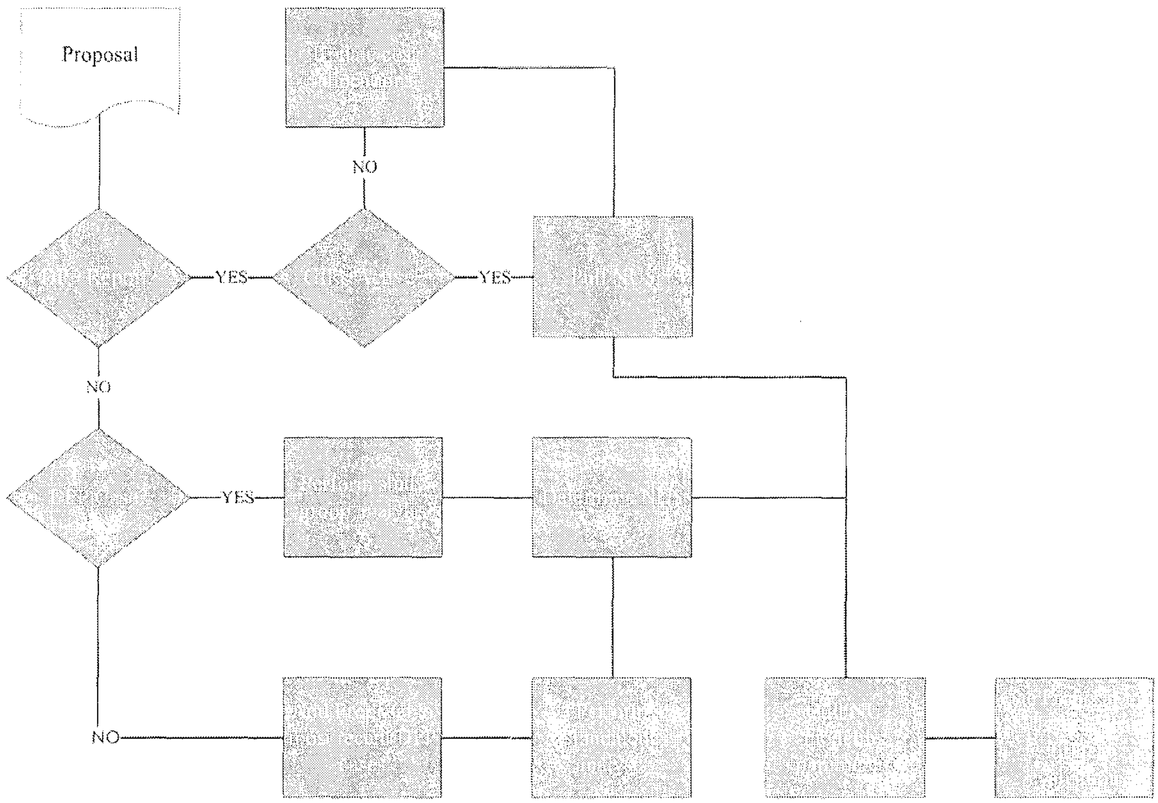
The congestion analysis provided a relative ranking of proposal projects and their potential revenue-making ability to offset customer load payments within the MISO market. Sensitivity analyses were performed for certain proposals based on project-specific conditions including the addition of a battery storage system and the ability to offset some congestion at a particular location based on the nomination of existing ARRs. Based on the modeled simulations, Proposal [redacted] (or Proposal [redacted]) and [redacted] had [redacted] congestion results. When considering potential [redacted], Proposal [redacted] also provides a [redacted] option for congestion mitigation.

The results of these analyses should be considered along with the related purchase costs associated with each proposal when determining a preferred proposal.

2.0 RELIABILITY ANALYSIS APPROACH

The process of evaluating the reliability impacts of each proposal followed the sequence shown in Figure 1.

Figure 1: Reliability Analysis Process



The outcome of evaluating the proposals through the sequence defined above resulted in some projects leveraging posted MISO DPP reports and others that required additional analysis for the PJM Affected System Study [redacted] The reliability analysis setup for each of the proposals is defined in Table 5.

Table 5: Proposal Reliability Analysis Setup

Study Assumptions	[redacted]
GI Queue ID	[redacted]
Point of Interconnection	[redacted]
MISO Study Cycle	[redacted]
MISO Study Status	[redacted]
ERIS Analysis	[redacted]
NRIS Analysis	[redacted]
PJM AFS Analysis	[redacted]

Each of the proposals that required additional analysis were evaluated using the appropriate study cycle models for MISO. For the PJM AFS analysis, as needed, the AF2 PJM GI study cycle models were used. Further details of the analysis are outlined below.

2.1 ERIS Analysis

The Energy Resource Interconnection Service (ERIS) analysis was conducted using the Summer Peak and Shoulder ERIS cases from the appropriate Study Cycle for each proposal under evaluation. Outages simulated included single branch outages, single unit outages, and P1 through P7 planning events for MISO Central areas as provided by MISO in the appropriate Study Cycle study packages. Constraint assessment was performed using MISO's criteria for a network impact or constraint, as defined by the following criteria:

- Constraint I: Generators have greater than a 20% DFAX for P1-P7 events or greater than a 5% DFAX for a P0 event.
- Constraint II: The impact is located at the Outlet Facility.
- Constraint III: Generators have greater than a 20% MW Impact based on the applicable facility rating.
- Constraint IV: If none of the DPP study group interconnection requests meet the initial four impact criteria, but the cumulative MW impact of the group of generators is greater than 20% of the rating of the facility, then only those generators whose individual MW impact is greater than 5% of the facility rating and has a DFAX greater than 5% will be responsible for network upgrade.

The impact of the respective proposal was initially evaluated against Constraint criteria I, II and III, as defined above. If the proposal did not meet any one of the top three criteria, then the Constraint criteria IV was evaluated using the impact of the entire respective study group.

2.2 NRIS Analysis

The Network Resource Interconnection Service (NRIS) analysis was conducted using the Summer Peak NRIS case from the appropriate Study Cycle for each proposal under evaluation. The sending (MISO_EX) and receiving (MISO_IM) subsystems were defined to contain all generators located in the MISO footprint. By including all of MISO as both the source and sink for the system, every generator's deliverability will be studied by TARA Deliverability tool against every other part of the MISO system when identifying study flowgates. Outages simulated included single branch outages, single unit outages, and P1 planning events as provided by MISO in the associated Study Cycle NRIS study package. All transmission facilities under MISO's functional control as well as appropriate external transmission facilities of neighboring entities were monitored.

PowerGEM TARA was used to perform the generator deliverability analysis. Up to 8,000 MW was transferred from MISO_EX to MISO_IM while keeping the MISO interchange at the same level. For purposes of the deliverability study, all flowgates were identified for which the individual proposal had a distribution factor (DFAX) greater than or equal to 5%, and the flowgate itself had a DC loading of greater than or equal to 70%.

For each identified flowgate, the top 30 generators contributing to the flowgate (i.e. the generators with the highest DFAX on the flowgate) and any large offline NRIS generators whose DFAX is greater than 5% and whose MW impact (Pmax * DFAX) is greater than 20% of the line rating had their output increased to their granted NRIS for existing/higher-queued generators or the requested NRIS for study generators. To compensate for the increase in system generation, generators in the rest of MISO_IM were uniformly scaled down. The purpose of this dispatch was to create a severe, yet credible, dispatch for each identified flowgate in the deliverability model.

If a study generator did not contribute more than 5% of the DFAX on any flowgate with a loading violation, it was considered fully deliverable. If a study generator contributed to a flowgate with a loading violation, it was not considered fully deliverable without a network upgrade. For the purpose of this analysis, all NRIS constraints reported up to the proposal's accredited capacity factor required network upgrades.

2.3 PJM AFS Analysis

The PJM Affected System (AFS) analysis was conducted using the PJM 2023 Summer Peak case from the AF2 feasibility study. All active PJM queue projects were modeled through the AF2 study class as well as all active MISO Classic queue projects through the DPP 2019 Cycle study class.

Single contingencies were evaluated for PJM Capacity analysis. Tower outage, bus faults, and breaker faults events were evaluated for PJM Energy analysis. All of the outage files used for the simulations were a part of the AF2 feasibility study package. All PJM facilities 100 kV and above were monitored for impacts. MISO ERIS requests were modeled as PJM Energy only generators and MISO NRIS requests were modeled as PJM Capacity generators. For MISO NRIS solar requests, 100% output was studied for both Capacity and Energy analyses.

PowerGEM's PJM Generator Deliverability module in TARA was used to perform the generator deliverability analysis. The analysis identified overloaded flowgates in which the proposal contributes with a minimum of a five percent (5%) distribution factor consistent with the generator deliverability methodology defined in Attachment C.3 of PJM Manual 14b.

2.4 Network Upgrades

Constraints identified within each respective analysis were reviewed to determine if any network upgrades have already been determined by MISO or PJM. If upgrades were already identified, then the rating of the upgrade was crosschecked to determine if it would be adequate for the loading reported within the respective analysis being conducted. If it wasn't adequate or if there wasn't any network upgrade already determined, then a full rebuild of each transmission line or additional transformer was assumed to be the required network upgrade since the limitation of each constraint is not known. Estimated costs for each of these items were primarily based on MISO-published cost factors in the 2020 MTEP Transmission Cost Estimation Guide and coordinated with AES Indiana. The network upgrade cost assumptions applied are provided in Table 6.

Table 6: Network Upgrade Cost Assumptions

Scope	kV	Cost ($MM)	Unit
Rebuild (All States)	69	1.3	$/mile
	115	1.5	
	138	1.6	
	161	1.6	
	230	1.6	
	345	2.6	
	138/69	5.4	

Scope	kV	Cost ($MM)	Unit
New Transformer (All States)	161/69	5.4	$/unit
	161/138	5.4	
	230/138	6.6	
	230/69	6.6	
	345/115	6.6	
	345/138	6.6	
	345/161	6.6	
	345/230	7.6	
Additional Line Termination	69	1.1	$/unit
	115	1.3	
	138	1.4	
	161	1.6	
	230	1.9	
	345	3.0	
New Substation	69	6.3	$/unit
	115	7.0	
	138	7.7	
	161	8.3	
	230	9.4	
	345	13.5	

2.5 Cost Allocation

For each constraint identified for the proposals from each of the different analyses conducted, all other participating generators that are eligible for cost allocation were determined. For each analysis, the largest MW impact from each of the applicable generators from the same Study Cycle was determined from the constrained facilities that met the criteria. The allocated cost of the network upgrade was based on the pro rata share of the MW contribution on all constraints from each project.

Constraints identified from the PJM AFS could be existing constraints to which the proposal contributes. As such, the triggering generator may not be in same Study Cycle. In order for a generator to be eligible for cost allocation in PJM the following criteria must be met, as defined in PJM Manual 14A:

For network upgrades that cost $5,000,000 or greater:

- If MW impact is greater than 5 MW AND greater than 1% of the applicable line rating, then:
  - For a transmission facility whose rated voltage level is below 500 kV, a New Service Customer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
  - For a transmission facility whose rated voltage level is 500 kV or above, a New Service Customer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.

For network upgrades that cost less than $5,000,000:

- If MW impact is greater than 5 MW AND greater than 1% of the applicable line rating, OR (if its Distribution Factor (DFAX) on the facility is greater than 5% AND its MW impact on the facility's rating is greater than 3% then:
  - For a transmission facility whose rated voltage level is below 500 kV, a New Service Customer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
  - For a transmission facility whose rated voltage level is 500 kV or above, a New Service Customer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.

The cost assigned to the generators that meet the eligibility criteria follow the same formula as defined above. The analysis was conducted using PowerGEM TARA software.

3.0 RELIABILITY ANALYSIS RESULTS

The sections below present the findings for each of the proposals previously defined in Table 1.

3.1 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted]. The generator is the active request [redacted] As a result, the reliability impacts, network upgrades, and associated network upgrade costs had been published by MISO. The costs for the generator, as assigned in the [redacted] study report published [redacted] are outlined in Table 7.

Table 7: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Total NU Cost ($)
[redacted]		

The generator was found to not have contributed to any constraints on the system. As a result no network upgrades were assigned. The direct connection costs for interconnecting at the [redacted] is the only cost currently assigned to the generator. No additional reliability analysis was conducted beyond the results presented in the [redacted] study report.

3.2 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a modification request to Proposal [redacted] as described above to include a [redacted]. This [redacted] request has not been submitted to MISO. Based on the information provided in the proposal, the total net output of the site would not exceed the [redacted]. The [redacted] requests, analysis is conducted to determine if there would be any [redacted]. The analysis for material impact was performed on the following cases from the [redacted] study package below:

[redacted]

- [redacted]

The [redacted] request was updated in the [redacted]. The dispatch of the [redacted] of the project were modified to outputs defined in Table 8, consistent with the approach for [redacted].

Table 8: Proposal [redacted] Reliability Dispatch Assumptions

Scenario	Solar (MW)	Storage (MW)	Total Request (MW)	Storage Mode	ERIS SH (MW)		ERIS SUM (MW)		NRIS SUM (MW)	
					Solar	Storage	Solar	Storage	Solar	Storage
[redacted]										

Using the modified cases, ERIS and NRIS analysis was conducted to determine if any new impacts were reported for the generator or any other request in the [redacted]. The costs for the generator, as determined through the [redacted] analysis are outlined in Table 9.

Table 9: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Total NU Cost ($)
Direct Interconnection Cost	[redacted]	
MISO ERIS		
MISO NRIS		
PJM AFS		

The analysis did not find any change of impacts to other requests in the [redacted]

3.3 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted]. The generator is the active request [redacted] As a result, the reliability impacts, network upgrades, and associated network upgrade costs had been published by MISO. The PJM AFS was evaluated as outlined in the Reliability Analysis Approach section. The PJM AFS analysis was performed using the [redacted] package with specific cases as listed below:

[redacted]

The costs for the generator, as assigned in the [redacted] study report published [redacted] and impacts found in the PJM AFS analysis are outlined in Table 10.

Table 10: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
Direct Interconnection Cost	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
Ameren LPC	[redacted]					
Ameren LPC	[redacted]					
MISO NRIS	[redacted]					

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
	[redacted]					
PJM AFS						

Each analysis found several constraints to which the generator contributes along with other queue requests for MISO constraints and higher-queue requests for PJM constraints. If interconnection request withdrawals occur in MISO and/or in PJM queues that impact the reported constraints, then the allocated costs to the generator may increase. In the NRIS results within [redacted] As a result, the cost allocation of the NRIS network upgrade is a fraction of the overall cost. If interconnection request withdrawals occur in the MISO queue that impact the reported constraints mitigated by the common upgrade, the allocated costs to the generator may increase. Other than PJM AFS, no additional reliability analysis was conducted beyond the results presented in the MISO DPP1 study report.

3.4 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted] The generator is the active request [redacted] As a result, the reliability impacts, network upgrades, and associated network upgrade costs had been published by MISO. The PJM AFS was evaluated as outlined in the Reliability Analysis Approach section. The PJM AFS analysis was performed using the [redacted] study package with specific cases as listed below:

[redacted]

The costs for the generator, as assigned in the [redacted] study report published [redacted] and impacts found in the PJM AFS analysis are outlined in Table 11.

Table 11: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
Direct Interconnection Cost	[redacted]					
Voltage						

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO ERIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					
MISO NRIS	[redacted]					

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
MISO NRIS	[redacted]					
PJM AFS						

*Cost allocated in ERIS Analysis.

Each analysis found several constraints to which the generator contributes along with other queue requests for MISO constraints and higher-queue requests for PJM constraints. If interconnection request withdrawals occur in MISO and/or in PJM queues that impact the reported constraints, then the allocated costs to the generator may increase. In the NRIS results within [redacted] As a result, the cost allocation of the NRIS network upgrade is a fraction of the overall cost. If interconnection request withdrawals occur in the MISO queue that impact the reported constraints mitigated by the common upgrade, the allocated costs to the generator may increase. Other than PJM AFS, no additional reliability analysis was conducted beyond the results presented in the [redacted] study report.

3.5 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted] This [redacted] request has not been submitted to MISO. Based on the information provided in the proposal, the [redacted] requests, analysis is conducted to determine if there would be any material impact to the system based on the replacement. Based on MISO BPM-015, the analysis for [redacted] analysis was performed on the most recent completed [redacted] study models for the [redacted] as listed below:

[redacted]

[redacted]

The [redacted] Bench Cases were used as the benchmark cases for the [redacted] impact evaluation. Study cases were also developed that reflected the [redacted] and the addition of the project as shown in Table 12.

Table 12: Proposal [redacted] Reliability Dispatch Assumptions

Generator	Total Capacity (MW)	Benchmark Case (MW)					Study Case (MW)				
		ERIS SH Discharge	ERIS SH Charge	ERIS SUM Discharge	ERIS SUM Charge	NRIS SUM	ERIS SH Discharge	ERIS SH Charge	ERIS SUM Discharge	ERIS SUM Charge	NRIS SUM
[redacted]											

The [redacted] in the Study Cases as provided by AES Indiana. Using the modified cases, ERIS and NRIS analysis was conducted to determine if any new impacts were reported for the [redacted] generator. Both Charging and Discharging scenario results were compared back to the respective Benchmark season to determine adverse impacts.

The costs for the generator, as determined through the [redacted] analysis, are outlined in Table 13.

Table 13: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Total NU Cost ($)
Direct Interconnection Cost	[redacted]	
MISO ERIS		
MISO NRIS		
PJM AFS		

No adverse steady state impacts were observed for the replacement. Direction connection costs were coordinated with AES Indiana to capture the substation work required to facilitate the interconnection of the [redacted]

3.6 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted] The generator is the active request [redacted] As a result, the reliability impacts, network upgrades, and associated network upgrade costs had been published by MISO. The PJM AFS was evaluated as outlined in the Reliability Analysis Approach section. The PJM AFS analysis was performed using the [redacted] study package with specific cases as listed below:

[redacted]

The costs for the generator, as assigned in the [redacted] study report published [redacted] and impacts found in the PJM AFS analysis are outlined in Table 14.

Table 14: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
Direct Interconnection Cost	[redacted]					
Voltage						
Ameren LPC						
Ameren LPC						

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
	[redacted]					
MISO NRIS						
MISO NRIS						
MISO NRIS						
MISO NRIS						
MISO NRIS						
MISO NRIS						
PJM AFS						
PJM AFS						
PJM AFS						
PJM AFS						

*Cost allocated under a different constraint utilizing the new Edwardsport to Hortonville 345 kV upgrade.

Each analysis found several constraints to which the generator contributes along with other queue requests for MISO constraints and higher-queue requests for PJM constraints. If interconnection request withdrawals occur in MISO and/or in PJM queues that impact the reported constraints, then the allocated costs to the generator may increase. In the NRIS results within [redacted] As a result, the cost allocation of the NRIS network upgrade is a fraction of the overall cost. If interconnection request withdrawals occur in the MISO queue that impact the reported constraints mitigated by the common upgrade, the allocated costs to the generator may increase. Other than PJM AFS, no additional reliability analysis was conducted beyond the results presented in the MISO DPP1 study report.

3.7 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a modification request to Proposal [redacted] as described above to include a [redacted] This [redacted] request has not been submitted to MISO. Based on the information provided in the proposal, the [redacted] For modification requests, analysis is conducted to determine if there would be any material impact to the constraints identified and assigned to any of the interconnection requests in the [redacted] study group. The analysis for material impact was performed on the following cases from the [redacted] study package below:

[redacted]

The [redacted] request was updated in the [redacted] to include the [redacted] The dispatch of the [redacted] of the project were modified to outputs defined in Table 15, consistent with the approach for [redacted] facilities described in MISO BPM-015.

Table 15: Proposal [redacted] Reliability Dispatch Assumptions

Scenario	Solar (MW)	Storage (MW)	Total Request (MW)	Storage Mode	ERIS SH (MW)		ERIS SUM (MW)		NRIS SUM (MW)	
					Solar	Storage	Solar	Storage	Solar	Storage
[redacted]										

Using the modified cases, ERIS and NRIS analysis was conducted to determine if any new impacts were reported for the generator or any other request in the [redacted] study group. The costs for the generator, as determined through the modification analysis are outlined in Table 16.

Table 16: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Total NU Cost ($)
Direct Interconnection Cost	[redacted]	
MISO ERIS		
MISO NRIS		
PJM AFS		

The analysis did not find any change of impacts to other requests in [redacted] study group. It is expected that no additional direct interconnection requests would be incurred for the generator with [redacted]

3.8 Proposal [redacted]

The generator analyzed for Proposal [redacted] represents a [redacted] The generator is the active request [redacted] study group. As a result, the reliability impacts, network upgrades, and associated network upgrade costs had been published by MISO. The PJM AFS was evaluated as outlined in the Reliability Analysis Approach section. The PJM AFS analysis was performed using the [redacted] study package with specific cases as listed below:

[redacted]

The costs for the generator, as assigned in the [redacted] study report published [redacted] and impacts found in the PJM AFS analysis are outlined in Table 17Error! Reference source not found..

Table 17: Proposal [redacted] Reliability Impacts and Network Upgrade Costs

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
Direct Interconnection Cost	[redacted]					
Ameren LPC						

Analysis Type	Monitored Element	Rate (MVA)	Criteria Violation Projects	Final AC Loading	Total NU Cost ($)	Cost Allocation ($)
	[redacted]					
Ameren LPC						
MISO NRIS						
MISO NRIS						
MISO NRIS						

There were no constraints cost allocated to the generator in the PJM footprint. Each MISO analysis found several constraints to which the generator contributes along with other queue requests for MISO constraints. If interconnection request withdrawals occur in MISO queue that impact the reported constraints, then the allocated costs to the generator may increase. In the NRIS results within [redacted] study report, the [redacted] As a result, the cost allocation of the NRIS network upgrade is a fraction of the overall cost. If interconnection request withdrawals occur in the MISO queue that impact the reported constraints mitigated by the common upgrade, the allocated costs to the generator may increase. Other than PJM AFS, no additional reliability analysis was conducted beyond the results presented in the [redacted] study report.

4.0 CONGESTION ANALYSIS APPROACH

Each of the short-list proposals were evaluated using ABB's PROMOD IV (PROMOD) to simulate security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) across the MISO footprint and neighboring regions. PROMOD simulations calculate the locational marginal price (LMP) for every bus, including generator and load nodes, within the study region. Each LMP represents the marginal price of electricity at a specific location on the grid and varies hourly in PROMOD's day ahead dispatch. One component of the LMP is the congestion component, which is generally caused by a limitation in the transmission system to cost effectively deliver the most efficient and lowest cost sources of generation to load. These limitations in the transmission system can cause congestion costs, impact LMPs and effect generation assets dispatch, curtailment, and associated revenues.

4.1 Model Development

4.1.1 Base Model

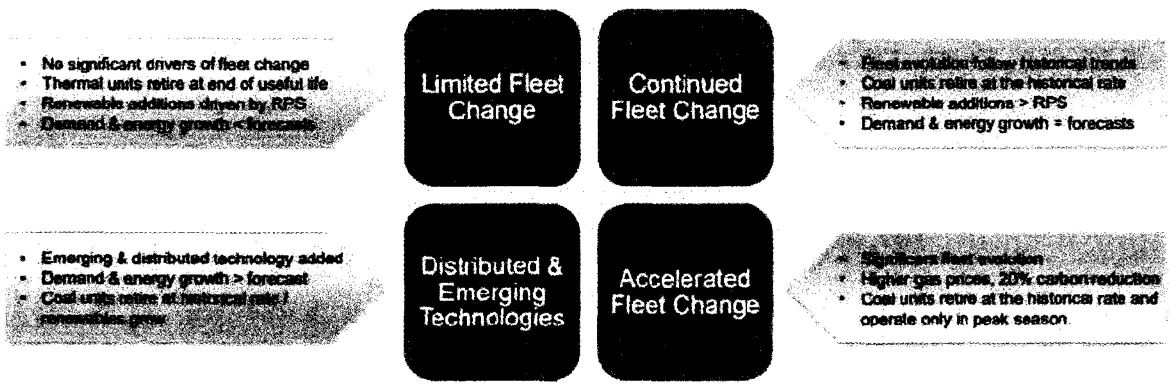
The 2020 MISO Transmission Expansion Plan (MTEP20) PROMOD models and associated constraint files were utilized as the starting point for this analysis. The MTEP20 models were developed by MISO in conjunction with their stakeholders and include five-year-out, ten-year-out, and fifteen-year-out PROMOD models. The models include the following four distinct futures for those three study years:

- Limited Fleet Change (LFC)
- Continued Fleet Change (CFC)
- Distributed and Emerging Technologies (DET)
- Accelerated Fleet Change (AFC)

These four futures developed by MISO represent a wide variety of future operating conditions that AES Indiana and the proposed resources may face, Table 18 below documents the differences between the MISO futures[8] at a high level.

8 https://cdn.misoenergy.org/20190314%20MTEP20%20Futures%20Workshop%20Item%2002-03-04%20MTEP%20Futures%20Presentation327266.pdf

Table 18: MTEP20 Future Assumptions



After reviewing the MTEP futures with AES Indiana, the AFC future was selected as the starting point for this analysis. The fleet evolution included in this model future aligned most closely to current trends and renewable generation development taking place in MISO local resource zone (LRZ) 6. LRZ 6 is the zone where AES Indiana operates. Model years 2024 and 2029 were utilized for this analysis. The 15-year out model was viewed as more speculative by AES Indiana and therefore Model year 2034 was not evaluated.

4.1.2 Additional Generation Retirements and Additions

Future unit retirement and generic resource additions included in the MTEP20 model, specifically in LRZ 6 were reviewed by 1898 & Co. and AES Indiana. Updates to the AFC MTEP model were made to account for recent announcements and utility IRPs which took place since the MTEP20 models were developed. The following updates were made to the base MTEP20 AFC model.

Table 19: Announced Retirements

Announced Retirement	Year	Capacity (MW ICAP)	Area
R Gallagher:2	2023	140	Duke Energy Indiana
R Gallagher:4	2023	140	Duke Energy Indiana
Merom:1	2023	507	Hoosier Energy Rural Elec.
Merom:2	2023	505	Hoosier Energy Rural Elec.
AES Petersburg:1	2023	225	Indianapolis Power & Light
AES Petersburg:2	2023	432	Indianapolis Power & Light
Harding Street:GT1	2023	25	Indianapolis Power & Light
Harding Street:GT2	2023	25	Indianapolis Power & Light
F B Culley:2	2023	90	Southern Indiana Gas & Electric
Gibson:4	2026	627	Duke Energy Indiana
Cayuga:1	2028	505	Duke Energy Indiana

Announced Retirement	Year	Capacity (MW ICAP)	Area
Cayuga:2	2028	500	Duke Energy Indiana
Cayuga:4	2028	120	Duke Energy Indiana
Michigan City:12	2028	469	Northern Indiana Public Service
Rockport:1	2028	1,300	American Electric Power
Harding Street:5NG	2030	109	Indianapolis Power & Light
Harding Street:6NG	2030	109	Indianapolis Power & Light
Harding Street:7NG	2033	435	Indianapolis Power & Light
Bailly:10	2039	31	Northern Indiana Public Service

Table 20: Announced Additions

Announced Additions	Year	Capacity (MW ICAP)	Area
Merom CT	2022	200	Hoosier Energy Rural Elec.
SIGE CT 1	2022	230	Southern Indiana Gas & Electric
SIGE CT 2	2022	230	Southern Indiana Gas & Electric
Rockport CCGT	2022	770	Northern Indiana Public Service
Duke CCGT	2028	1,240	Duke Energy Indiana

Table 21: Generic Units Removed

Generic Units	Capacity (MW ICAP)	Area
RRF MISO CT: 038	300	Duke Energy Indiana
RRF MISO CC: 009	900	Southern Indiana Gas & Electric

4.1.3 Fuel Forecasts

In order to align with AES Indiana integrated resource plan (IRP) assumptions, the Henry Hub natural gas and Petersburg fuel price forecasts were updated in the model. In the MTEP PROMOD models the Henry Hub gas forecast is used as the underlying base forecast, and thus impacts the fuel price for all gas resources, additional basis differentials and delivery adders are incrementally added to the Henry Hub forecast to align with site-specific costs. Each of the four MTEP20 futures (AFC, CFC, DET and LFC) and AES Indiana Henry Hub natural gas forecasts are shown in [redacted] illustrates how AES Indiana's Petersburg coal forecast is similar, [redacted] than the MTEP20 futures forecasts, respectively.

[redacted]

[redacted]

4.1.4 AES Indiana Load

Similar to fuel forecasts, AES Indiana provided updated load forecasts which were used as part of the congestion analysis. AES Indiana's forecast had a [redacted] peak demand than what was originally assumed in the MTEP20 futures in 2024 and 2029, respectively.

[redacted]

4.1.5 Transmission Upgrades

For simulations which the RFP proposals were added into the model, the transmission topology was updated to include the network upgrades identified in the reliability analysis and results documented in Section 3.0.

5.0 CONGESTION ANALYSIS RESULTS

Results from the MTEP20 PROMOD simulations were summarized for both the 2024 and 2029 model years. The generation weighted LMP is calculated by dividing the project's revenue from energy sales into MISO by its generation. The generation weighted LMP represents the revenue the facility generated per MWh of generation. In this way, each of the RFP proposals, which have different installed capacities (ICAP) and capacity factors, can be compared to one another. Because the generation weighted LMP represents the $/MWh price at which energy is sold into the market, a higher number is better for AES Indiana's customers. The RFP proposals are sorted in Table 22 by the average between the 2024 and 2029 generation weighted LMP.

Table 22: Base Congestion Results Summary

Proposal	Solar Capacity (ICAP MW)	Storage Capacity (ICAP MW)	Storage Duration (Hrs.)	Gen-Weighted LMP[9] ($/MWh)	
				2024	2029
[redacted]					

5.1 Sensitivity Results

5.1.1 Financial Transmission Rights (FTR)

Due to historical usage on MISO's transmission system, AES Indiana is entitled to Auction Revenue Rights (ARR) which they can convert into Financial Transmission Rights (FTR) from the [redacted] node to their load node. This provides a financial hedge which can manage the risk of price separation, or congestion, on the system between these two points. [redacted] would be interconnected at [redacted] and therefore AES Indiana would be able to use FTRs

[9] Generation weighted LMPs display the value for the stand-alone solar or only the solar portion of proposals which included storage or optional storage

[10] Solar portion of Proposal [redacted]s Proposal [redacted]

[11] Solar portion of Proposal [redacted] is Proposal [redacted]

to limit their exposure to potential future congestion on the system. FTRs are split into eight separate segments, peak and off-peak for the four seasons. Historically the congestion component of AES Indiana's load node has been [redacted] than at [redacted] therefore if AES Indiana utilized FTRs, the generation weighted LMP of project [redacted] would [redacted] Since 2018 the seasonal delta between the AES Indiana load node and [redacted] has averaged [redacted] MWh. The highest segment was the [redacted] peak which had a delta of [redacted] MWh. Future changes to the transmission system and generation fleet will have an effect on the congestion component delta, however these FTRs provide a hedge to future congestion on the grid between [redacted] and AES Indiana. This provides a mechanism for minimizing potential congestion risk for project [redacted]

5.1.2 Battery Adder Options

Project [redacted] and [redacted] were provided the option to add storage to the project. [redacted] and [redacted] battery options included a [redacted] battery, [redacted] included a [redacted] battery. The storage facility was simulated through PROMOD utilizing a fixed dispatch schedule. The fixed dispatch restricted the battery to charge from the output of the solar resource, which would be required in the near term for the storage to take advantage of the investment tax credit. This fixed charging requirement increases charging costs and results in minimal revenues when only accounting for discharging revenues and charging costs. The annual cycles were limited to the number of days where arbitrage was projected to result in greater discharging revenues than charging costs, with a maximum of [redacted] annual cycles. Operations and maintenance as well as other costs were not included in the calculation but would reduce the benefits associated with the delta between battery discharging revenues and charging costs shown in the table below.

Table 23: Battery Results Summary

		[redacted]					
Year	Item	Charge	Discharge	Charge	Discharge	Charge	Discharge
2024	Revenue/ Expense ($)	[redacted]					
	Charge/ Discharge (MWh)						
	Gen-Weighted LMP ($/MWh)						
	Cycles						
2029	Revenue/ Expense ($)						
	Charge/ Discharge (MWh)						
	Gen-Weighted LMP ($/MWh)						
	Cycles						

Appendix A RELIABILITY RESULTS DETAILS SUMMARY

Appendix A - Reliability Results Detail Summary.xlsx

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Appendix A - Reliability Results Detail Summary.xlsx

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Appendix A - Reliability Results Detail Summary.xlsx

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