2021 RTO Membership Analysis

PPL companies

October 2021

Contents

1 Executive Summary

This analysis was performed to evaluate whether membership in the Midcontinent Independent System Operator (“MISO”) or the PJM Interconnection (“PJM”) Regional Transmission Organizations (“RTOs”) may provide potential net benefits to Louisville Gas and Electric Company (“LG&E”) and Kentucky Utilities Company’s (“KU”) (collectively “the Companies”) retail and wholesale requirements customers. This study is designed to be a high-level screening analysis to determine if the potential benefits and costs of RTO membership support future RTO membership, particularly in conjunction with the assumed retirement of Mill Creek unit 2 and Brown unit 3 in 2028.

This report discusses the risks, uncertainties, and non-quantifiable considerations regarding RTO membership and presents the results of the Companies’ financial analysis. The Companies evaluated the sum of the financial impacts of the items shown in Table 1 through 2027. In 2028, the Companies assume that the retirements of Mill Creek unit 2 and Brown unit 3 will occur resulting in a capacity need. While the timing of these retirements is uncertain, this analysis assumes a 2028 retirement year. Once the Companies become “short” of capacity, the analysis of potential RTO benefits becomes much more challenging and uncertain. Inside an RTO, the Companies’ resource planning activities change from focusing on the lowest cost means to reliably serve load to one of managing the market price risk of serving load (note that in an RTO, all load is served at market prices). The items in Table 1 reflect the potential incremental costs and benefits of RTO membership compared to non-RTO membership through 2027 but do not capture potential costs associated with actively managing the market price risk of serving customers’ load.

Table 1: RTO Membership Cost and Benefit Components

Costs	Benefits
• RTO Admin Fee • Energy Uplift • Transmission Expansion • Internal Staffing & Implementation • Lost Transmission Revenue • Lost Joint Party Settlement Revenue	• Misc. Avoided Fees • Elimination of Depancaking • RTO Energy Market Impacts • RTO Capacity Market Impacts

The Companies’ 2020 RTO Membership Analysis indicated that membership in MISO or PJM was not beneficial at that time. Key assumption changes from the 2020 study are

(1) evaluating a longer study period, which aligns with the analysis period of the Companies’ 2021 Integrated Resource Plan (IRP), and

(2) considering the long-term impacts and risk profile regarding the composition of the Companies' generating fleet after the assumed retirements of several of the Companies' existing generating units.

The second assumption is a key change and a major consideration in this updated analysis, as retirements present a range of options for replacements of the retired units with associated potential savings and risks. While there may be an option to avoid future generation investments by joining an RTO, the attendant savings from such an option come with reliability risks and the need to effectively manage what could be significant exposure to market price risks for energy and capacity in the RTOs. Recognizing the range of uncertainties, the Companies have not attempted to develop an assumed price risk management plan for RTO membership but instead reviewed the potential new costs and benefits associated with the new risk profile inherent in RTO membership. Specifically, to demonstrate the range of the market uncertainties, the Companies identified the magnitude of supply side cost savings that will be required in 2028 and beyond to offset the added costs of joining an RTO.

Figure 1 and Figure 2 depict the annual sums of the ranges of values for the component items shown in Table 1 through 2027 for each RTO and demonstrate a range of favorability of RTO membership in the near term.[1] While the cases shown present discrete views for RTO membership favorability, they are intended to represent the distribution of potential outcomes. The green bars represent the high-favorability case, which is the combination of assumptions that results in the most favorable case for RTO membership in each year. The blue bars represent the least favorable combination of assumptions in each year. The red bars represent a case with mid-level assumptions. As the figures show, joining MISO is unfavorable in each year in all cases. The analysis for joining PJM is a bit more mixed with the high case showing the potential for savings and the mid case near zero (ranging between $4 million unfavorable and $2 million favorable). This difference is due primarily to the lower transmission expansion costs and higher forecasted capacity prices assumed in PJM compared to MISO.

[1] Negative values in Figure 1 and Figure 2 indicate that RTO membership is unfavorable.

Figure 1: MISO Range of Potential Near-Term Outcomes ($M)[2]

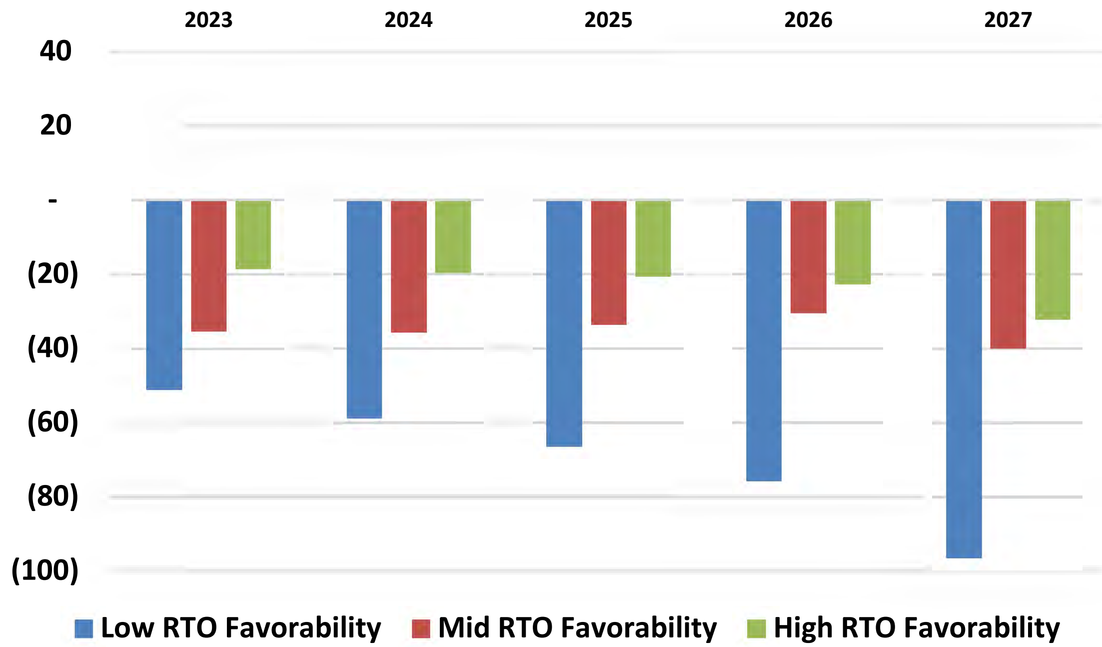
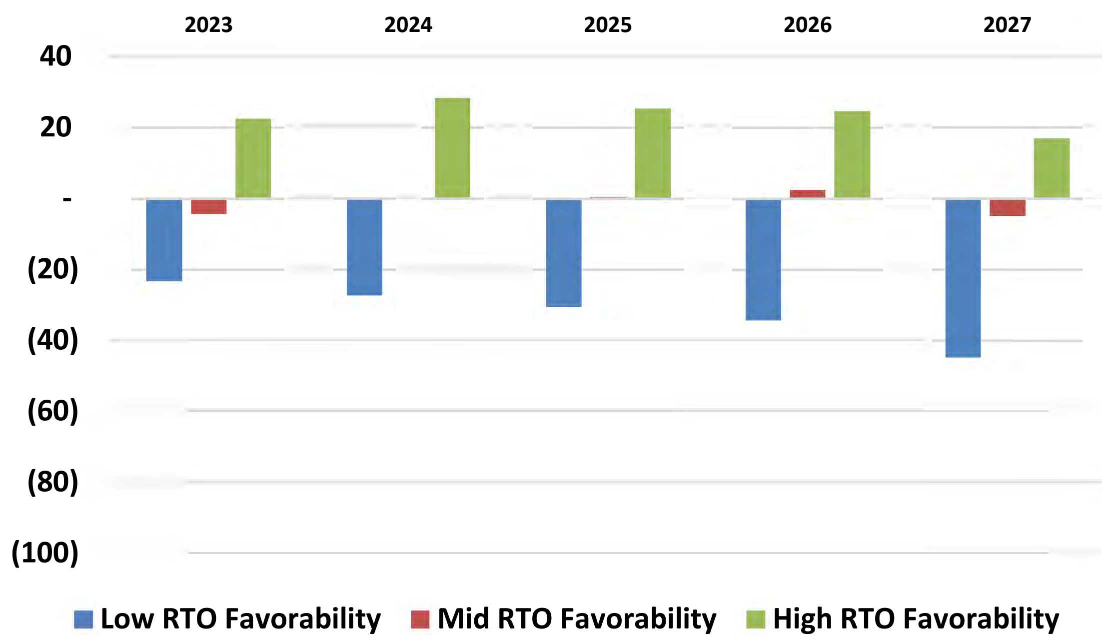


Figure 2: PJM Range of Potential Near-Term Outcomes ($M)[2]



PJM's high-favorability case ranges between $22 million and $28 million more favorable than the mid-case. Achieving this high favorability in the RTO requires the alignment of

[2] Negative values indicate that RTO membership is unfavorable.

favorable assumptions for several of the cost and benefit components shown in Table 1. Table 2 shows the annual variance between the mid-favorability case and the high-favorability case for each of these variable components.

Table 2: Variances between PJM High and Mid-Favorability Cases ($M)

	2023	2024	2025	2026	2027
Lower Admin Fees	3.6	3.7	3.7	3.8	3.9
Energy Market Benefits	10.4	8.9	5.3	2.3	3.5
Capacity Market Benefits	8.4	11.8	11.8	11.8	11.8
Elimination of Depancaking	4.2	4.0	4.0	4.1	2.4
Total Variance	**26.6**	**28.4**	**24.8**	**22.0**	**22.0**

Figure 3 and Figure 4 provide longer-term views of the range of each RTO's projected fixed costs and shows that by the end of the study period in 2036, up to approximately $100 to $220 million in costs would need to be offset by savings for RTO membership favorability to break even. The difference between PJM and MISO is primarily due to the lower transmission expansion costs assumed in PJM compared to MISO. Such savings can come in the form of energy and capacity revenues and/or avoided generation investments. But such savings can also come with energy and capacity market price risk, the level of which depends highly on the Companies' strategy to mitigate this exposure, whether through financial hedging and/or through constructing or purchasing generating resources to participate in the RTO markets. Note that the market attributes (e.g., capacity price level, energy prices, etc.) that might make RTO membership attractive or unattractive prior to 2027 when the Companies are anticipated to have ample physical generation may have the opposite effect post-2028 when the Companies are assumed to be capacity deficient. For example, the potential to earn higher capacity revenues in PJM through 2027 would add to costs once Mill Creek units 1 and 2 and Brown unit 3 are retired.

Figure 3: Projected Fixed Costs Range - MISO ($M)

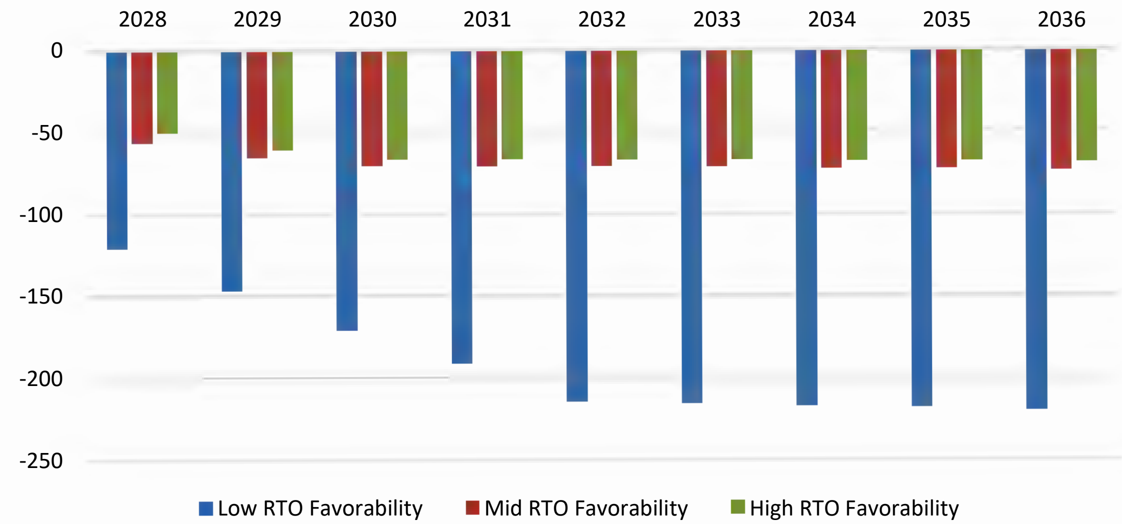
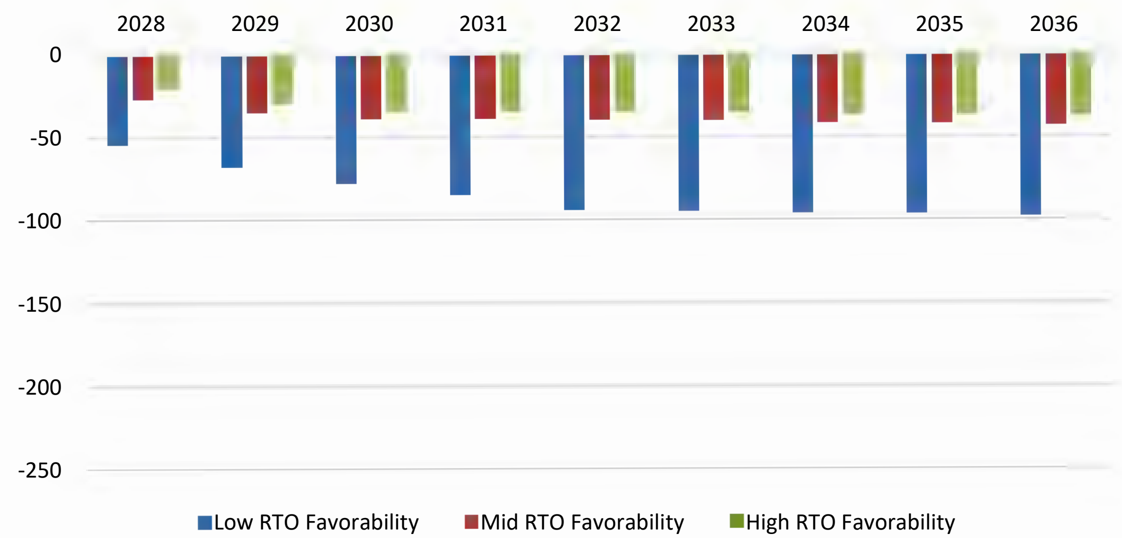


Figure 4: Projected Fixed Costs Range - PJM ($M)



Based on the analysis detailed in this report and the great deal of uncertainty regarding the evolving RTO markets, the Companies do not recommend RTO membership at this time. However, potential RTO membership should be considered in conjunction with the retirement timing for Mill Creek unit 2 and Brown unit 3. This study indicates that there is likely little benefit to joining MISO prior to 2028 while joining PJM could be beneficial before then if actual capacity and energy prices are high. However, when future generation retirements are assumed to occur starting in 2028, the Companies' evaluation of replacement generation would change in an RTO compared to operating on a standalone basis. Being in an RTO involves a change in mindset from having a fleet of physical generation assets to reliably serve load 8760 hours a year as a standalone utility to thinking in terms of financial risk management of both generation and load as independent activities. In an RTO, the Companies would be relying on a separate entity for managing reliability and dispatching the RTO's generation fleet to serve real-time load. At the same time, being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology, as RTO membership may support higher levels of renewable penetration with lower integration costs.

2 Introduction

As described in this report, the Companies have performed an updated review using available information and existing modeling functionality to determine whether RTO membership in MISO or PJM may provide potential net benefits to the Companies' customers. For purposes of this analysis, RTO membership includes transferring functional control of transmission assets and mandatory participation by the Companies' generation and load in the various markets currently administered by the RTO. It results in a much different operating paradigm and risk profile than the status quo. But as the industry transitions to cleaner energy resources, RTO membership may present the best path for integrating high levels of renewable penetration if necessary changes are achieved by the RTOs to address potential shortfalls in capacity and energy adequacy and reliability.[3]

As in the 2018 and 2020 analyses, a cross-functional team evaluated the major costs, benefits, opportunities, and uncertainties of RTO membership as compared to standalone operations of the Companies.[4] The team started with confirming that the components expected to have financial impacts in the 2020 analysis continued to be the correct components to address in the updated quantitative analysis. It was determined that it was appropriate to perform the updated quantitative analysis using mostly the same components, subject to some revisions in the underlying assumptions associated with those components as described below. In addition, the team re-examined and updated non-quantifiable considerations and uncertainties determined to have the potential to materially impact the decision. Critical non-quantifiable considerations are addressed in the next section, and an updated list and summary of non-quantifiable considerations is

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[3] For example, see "MISO's Renewable Integration Impact Assessment," February 2021, at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

[4] The team consisted of representatives from Corporate Compliance, Energy Planning Analysis & Forecasting, Federal Policy, Legal, Power Supply, Transmission, and State Regulation and Rates.

appended hereto. The subsequent sections describe each of the cost and benefit components considered in the quantitative portion of the analysis, which are then summarized to lead to the Companies' conclusion of not joining an RTO at this time but to continue to evaluate possible future membership and the risks involved.

3 Risk and Uncertainty

3.1 Decision Analysis

The decision to join an RTO is a significant and possibly permanent, long-term commitment that requires careful consideration of many variables and assumptions, including whether operation under the rules of the RTO is consistent with the Companies' obligations to reliably serve customers at the lowest reasonable cost. Fundamentally, it is a decision to transfer functional control of generation and transmission operations to the RTO and participate in current and future RTO-administered wholesale markets for generation and load. RTO policies, requirements, and operations are driven by the changing regulatory landscape, variable market conditions, and diverse stakeholder groups that represent varying interests across multiple states.[5] RTO members, their stakeholders, and state regulators cede control over significant revenue streams, cost incurrence and allocation, and decisions impacting the transmission system and generation fleet – and ultimately cost of service to customers. Furthermore, the decision to join an RTO is complex and extremely difficult to reverse.

This report quantifies projected potential benefits and costs of integration into the RTOs utilizing available data and assumptions to anticipate financial impacts. The range of outcomes of this analysis demonstrate the uncertainty involved, especially in later years. In the near term, however, the data is somewhat clearer and lead the Companies to recommend not joining an RTO at this time. Market prices can be volatile in both the energy and capacity markets, as discussed in the next section. Transmission expansion costs remain an evolving area as transmission planning requirements continue to change and RTO cost allocation provisions are revisited.

Fully integrating into an RTO would commit the Companies to comply with RTO requirements as a supplier, a load-serving entity, and a transmission owner. Therefore, the potential for material changes and unanticipated costs, as well as the uncertainty of

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[5] MISO operates over 15 US states and one Canadian province to manage approximately 71,800 miles of high voltage transmission and 192,285 MW of generating resources. PJM operates over 13 states and the District of Columbia to manage over 84,000 miles of high voltage transmission lines and 187,000 MW of generating resources.

any potential benefits, should be considered and fully understood before deciding to join an RTO. Though the Companies focused on quantifiable elements in performing this analysis, certain non-quantifiable considerations form a vital context in which to consider the quantifiable elements.

3.2 Market Price Risk

A key decision for any RTO member is how to manage the risk to customers of paying high market prices for energy and capacity when the member is a net purchaser in these markets. Numerous external factors impact RTO market pricing including fuel costs, weather events, load reductions, incremental resource additions, transmission performance, changes in suppliers, unplanned outages, and federal policy and regulatory changes (e.g., changing environmental regulations or FERC-directed changes in market design, compensation, or requirements). Managing these risks can come in the form of financial hedging forward energy prices, maintaining a level of owned or purchased generation resources to adequately cover capacity and energy needs on a net basis, or a combination of the two.

The RTO capacity markets have demonstrated volatility historically, with prices ranging between $50 and $165/MW-day in PJM and between $1.50 and $72/MW-day for MISO since the 2016/2017 planning year. However, recent prices remain well below the theoretical capacity price ceiling of the cost of new entry ("CONE"), which is currently $264/MW-day in PJM and $244/MW-day in MISO.

The energy markets can be particularly volatile in times of strain on the system when resources are scarcely meeting load. During the extreme cold period in February 2021, MISO's and PJM's real-time prices at LG&E and KU's interface points averaged over $100/MWh for the four days between February 15 and February 18 and reached up to $444/MWh. Prices at MISO's Texas Hub averaged $600/MWh and reached MISO's energy price cap of $3,500/MWh in response to the energy scarcity event in Texas during that period.[6]

On a standalone basis, the Companies manage energy risk in three areas:

1. Managing fuel risk: maintaining coal inventories, purchasing forward natural gas for generation, and purchasing natural gas transportation rights.
2. Unit reliability: keeping generating units in working order and preparing for extreme operating conditions.

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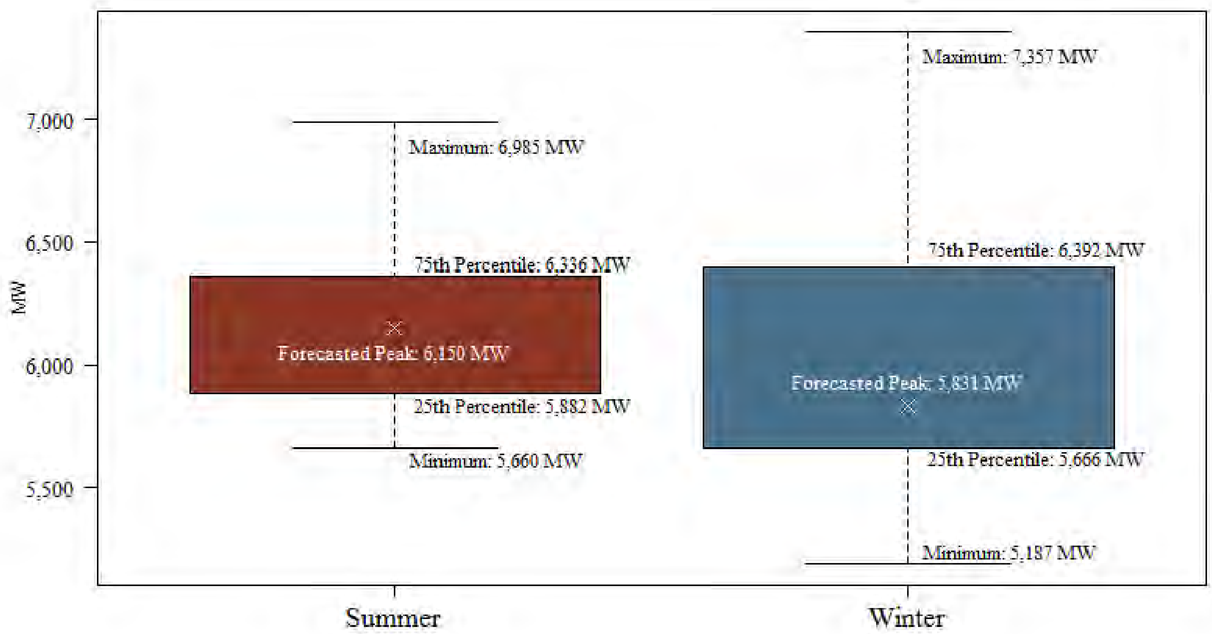
[6] The RTOs' current energy price caps are $3,500/MWh for MISO (LMP total) and $3,750/MWh for PJM (energy portion of LMP, plus congestion and losses).

3. Maintaining reserves: maintaining reserves to accommodate a reasonably wide range of potential seasonal load fluctuations.

In an RTO, fuel risk management and unit reliability would remain the Companies' responsibility while defining required system reserve levels and real-time dispatch would be the RTO's responsibility. The Companies currently manage reserves to meet a range of potential summer and winter peak loads, as shown in Figure 5. In an RTO, the Companies' focus would shift to evaluating the volatility in electricity prices and its correlation with electricity demand (financial risk) rather than just physical electricity demand (reliability risk). Determining the optimal hedging strategy when entering an RTO will require new analytical methods and tools beyond the scope of the Companies' traditional optimization and risk management modeling.[7]

Figure 5: Distributions of Summer and Winter Peak Demands, 2025[8]



[7] For example, given the importance of RTO capacity and energy prices, it would be important to be able to model and forecast RTO regional prices, something the Companies previously did when they were a MISO member. NERC's 2020 Long Term Reliability Assessment shows the differing existing and planned portfolios and reserve expectations between MISO and PJM. *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[8] See Companies' 2021 IRP, Volume III, "2021 IRP Reserve Margin Analysis," October 2021.

3.3 Non-Quantifiable Considerations

3.3.1 Changing Market Rules

The RTOs operate on a defined set of rules and tariffs that dictate all aspects of how participants function in the RTOs' various markets. A key assumption in the Companies' quantitative RTO membership analysis is that these RTO rules and tariffs remain unchanged over the 14-year analysis period because there is no basis on which to make any other assumption. However, what is certain is that the RTOs' market rules are in fact in a constant state of change in response to market participants' demands, changes in the industry, and unpredictable changes in regulations and policy.[9] For example, the capacity markets in both PJM and MISO continue to be modified in an attempt to better drive new capacity investments with the appropriate market signals. The RTOs have seen very low capacity prices, much lower than the actual cost of new entry. This combined with the limited forward visibility of PJM's 3-year-ahead and MISO 1-year-ahead market leads to little incentive for the construction of new capacity, which could lead to capacity deficiencies if not addressed. MISO has been evaluating a longer visibility period as well as a seasonal capacity market, which may result in new capacity rules. PJM continues to modify its capacity market rules and has often been at odds with FERC on proposed market changes, most recently regarding minimum capacity offer prices and state subsidies for certain capacity types.

3.3.2 Clean Energy Transition

As many entities with fossil fuel fired generation resources contemplate a transition to increased renewable resources, RTOs could be an attractive option for supporting this transition. The diverse geography, resources, and loads in an RTO allow for the integration of higher penetration of intermittent resources than what the Companies could likely achieve on a standalone basis and potentially at lower cost. The RTOs are anticipating this transition by considering the future changes required. MISO projects that up to 30% renewable penetration can be achieved with transmission expansion and significant changes to planning, markets, and operations.[10] MISO projects that even higher penetration can be achieved with more transformational changes and coordination.

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[9] *STRETCHED TO THE BREAKING POINT - RTOs and the Clean Energy Transition* (Tony Clark and Vincent Duane, July 2021) "*RTOs, their stakeholders and regulators have become accustomed to a never-ending refinement of market rules chasing the goal of incentive compatibility.*" Link: https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf

[10] "MISO's Renewable Integration Impact Assessment," February 2021. See https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

However, as more companies lean on the RTOs to integrate increasing levels of renewables and replace dispatchable generation, reliably meeting customers' energy needs at every moment has the potential to become unsustainable. Furthermore, the RTOs themselves have considered ways to reduce CO_2, including carbon pricing, in the absence of national CO_2 regulations. Achieving CO_2 reductions with new renewables, especially wind resources, will likely require significant transmission investments to move the power from areas with high generation resources to load centers. Depending on these and other variables, it could be more cost-effective for the Companies to be on their own transition path rather than that of the RTOs.

3.3.3 Generation Dispatch Decisions

Generation dispatch decisions in an RTO are driven by a region-wide security constrained dispatch rather than the least-cost means to serve the Companies' customers. The Companies are currently able to make short term decisions to reliably meet their customers' energy needs. This is particularly important prior to and during extreme weather events (like the polar vortices of 2014 and 2015 and the cold weather event in February 2021).[11] An example of the short-term decisions currently available to the Companies during these events include starting units early (particularly simple cycle combustion turbines) to mitigate the potential impacts of forecasted cold weather. Yielding functional control of these real-time generation dispatch decisions to an RTO creates risk of inability to reliably serve load and increased costs (through non-performance or increased maintenance costs) as RTO dispatch decisions are driven by market prices and tariff rules.

3.3.4 Market Defaults

Defaults of other market participants remains unpredictable in RTOs. Both RTOs have established credit policies consistent with FERC requirements designed to limit the potential impacts of default, but a degree of default risk remains. Developers, choice marketers, independent generation, distributed energy resource aggregators, and demand resources participate in the markets alongside traditional load-serving utilities. Entity defaults and bankruptcies present a potential risk that the costs of such behavior will fall to other market participants. When entities default in excess of the financial security held by the RTO or enter bankruptcy proceedings that disrupt or prevent

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[11] On September 23, 2021, FERC and NERC issued preliminary findings and recommendations following their inquiry into the February 2021 cold weather event. Of the twenty-eight recommendations, nine are characterized as key recommendations and include changes to NERC Reliability Standards. Link: February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations | Federal Energy Regulatory Commission (ferc.gov)

recovery through collateral, other RTO members are allocated a portion of the default.[12] A market participant in MISO recently filed bankruptcy because of the February 2021 winter event that predominantly affected Texas, leaving MISO with $10.3 million in unpaid market charges. These charges were assessed to all market participants.

Additional non-quantifiable considerations that would need to be considered further before integrating into an RTO are provided in Appendix D.

3.4 Reliability Metrics[13]

In this 2021 RTO Analysis, the Companies reviewed relevant generation and transmission metrics to compare reliability performance within the RTOs versus the Companies' stand-alone performance. Reliably serving customers' energy needs requires properly aligned long term planning and risk assessment of future energy serving scenarios. As the scenario becomes clearer, executable decisions are reached and actionable activities (which may take years) are set in motion. The quality of such planning decisions, then, manifests in reliability performance metrics. Importantly, these long-term planning activities and responsibilities are different as a member of an RTO than they are as a standalone utility. As an example, the February 2021 outage event in ERCOT illustrates how reliability planning and responsibility is more diffuse in an RTO than would be the case for the Companies currently.

3.4.1 Generation Metrics

Equivalent Forced Outage Rate (EFOR) and Equivalent Unplanned Outage Rate (EUOR) are standard industry metrics that provide a view of the reliability performance of a generator or a generation fleet. EFOR reflects times when generation is forced out of service while EUOR also encompasses short term unplanned maintenance outages; both metrics include derated portions of unit capacity. Figure 6 and Figure 7 contain a three-and-a-

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[12] One example is the default of FTR market participant GreenHat Energy, LLC, and subsequent liquidation of the entity's FTR portfolio. Due to concerns that liquidation of the entire GreenHat FTR portfolio in accordance with the PJM tariff, PJM requested a tariff waiver to liquidate the FTR portfolio in a manner that would minimize market distortion. This waiver request was protested by certain marketers and initially denied by FERC before being sent to paper hearing. Ultimately PJM settled the dispute, allowing it to liquidate the GreenHat FTR portfolio in its preferred manner but also with certain "compromise payments" to the protesting marketers totaling $12.5 million. *See* "Submission of Settlement Agreement and Offer of Settlement," *PJM Interconnection, L.L.C.,* Docket Nos. ER18-2068-000 and ER18-2068-001 (submitted October 9, 2019); *letter order accepting,* 169 FERC ¶ 61,260 (2019). However, liability to current PJM market participants is based on the total default amount, which currently stands at $181.7 million. If LG&E and KU had been load-serving entities in PJM during the GreenHat default, they would have ultimately been responsible for approximately 4% of the total default amount, or $7.3 million.

[13] The Commission Staff Report (issued July 2020) from the Companies' 2018 IRP indicates the Company should consider potential benefits such as "improved reliability" in future RTO Analyses.

half-year history of LG&E and KU's EFOR and EUOR compared to the Reliability First Corporation's (RFC) top quartile and average performance for similar sized baseload units. RFC overlaps both MISO and PJM.

Figure 6: Equivalent Forced Outage Rate

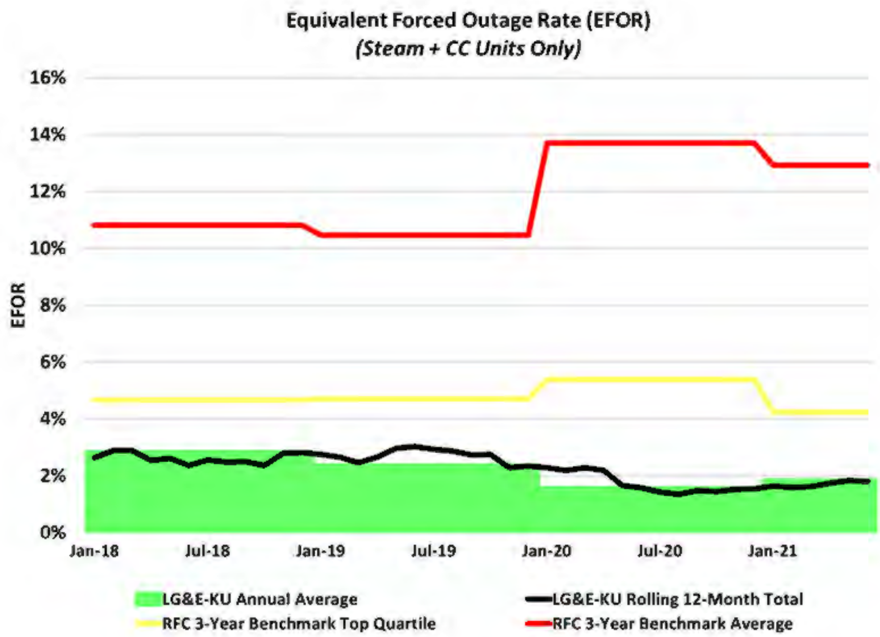
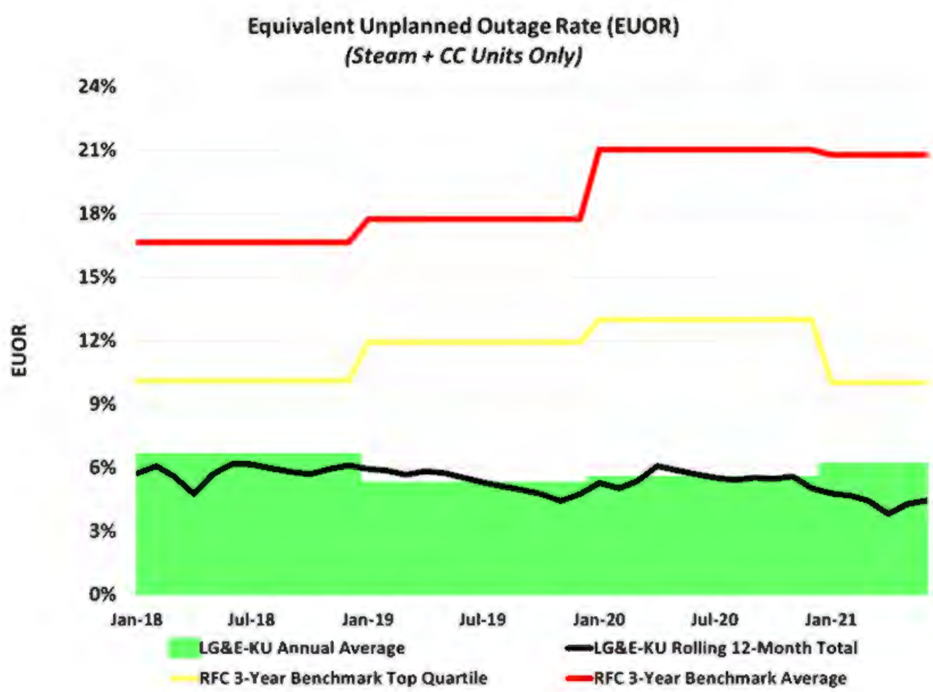


Figure 7: Equivalent Unplanned Outage Rate



Higher than expected EFOR and EUOR increase the likelihood of multiple generation outages occurring concurrently, potentially leading to a capacity shortfall and subsequent energy deficiency.

An Energy Emergency is a condition in which a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected load obligations.[14] An Energy Emergency Alert (EEA) is initiated on that entity's behalf when such conditions are present. As such, EEAs can be an indicator of capacity issues within an RTO. Since exiting MISO in 2006, the Companies have never experienced a resource shortage impacting LG&E/KU load service requiring declaration of an energy emergency alert.

The Companies have identified eight EEA events experienced within MISO since 2017. Of those eight, two reached EEA 3, the most severe level of EEA, resulting in firm load interruption. In August 2020, MISO directed 500 MW of firm load interruption in East Texas due to generation and transmission outages caused by Hurricane Laura. In February 2021, MISO directed 700 MW of firm load interruption across its South region due to its inability to balance generation and load in the face of extreme cold temperatures.

PJM has performed comparatively better during this period, experiencing a single EEA event within its territory in October 2019 caused by unseasonably warm temperatures.

As recently as this summer, NERC's Reliability Assessment indicated several ISOs and RTOs (including MISO[15]) were at elevated risk of experiencing energy supply shortfalls during above normal demand periods, as shown in Figure 8.

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[14] Definition from NERC Glossary of Terms

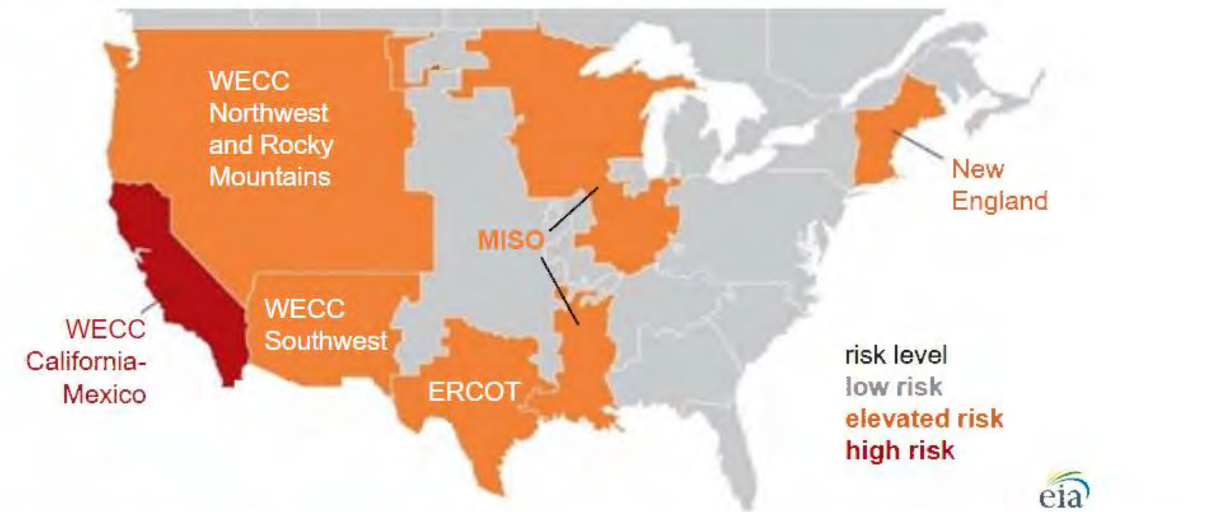
[15] MISO also recognizes their ISO is increasingly facing reliability risks, even outside of the summer peak-load months. *See* https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL_updated%204-29-2021504018.pdf at 3 ("[T]he region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges.").

Figure 8: NERC 2021 Summer Reliability Assessment

JUNE 30, 2021

NERC report outlines potential electricity disruptions in the United States this summer

U.S. energy emergency risk areas, summer (June–September) 2021

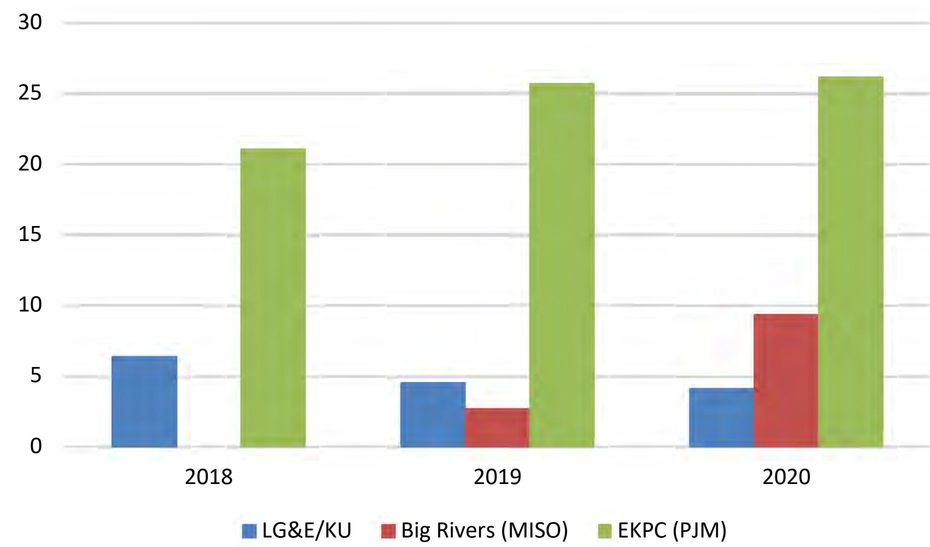


Source: Map by U.S. Energy Information Administration, based on North American Electric Reliability Corporation (NERC) *2021 Summer Reliability Assessment*
Note: ERCOT is the Electric Reliability Council of Texas; MISO is the Midcontinent Independent System Operator; WECC is the Western Electricity Coordinating Council.

3.4.2 Transmission Metrics

Transmission System Average Interruption Duration Index (SAIDI) is a metric to track transmission reliability. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Figure 9 shows a comparison of the SAIDI metric for LG&E/KU, Big Rivers (MISO RTO), and EKPC (PJM RTO) for 2018, 2019, and 2020. This data excludes Major Event Days (MED), each of which includes a severe windstorm or ice storm. Note that SAIDI is not tracked or reported to the RTO; rather, it is used and tracked by each member individually.

Figure 9: SAIDI Comparison Excluding MED[16]



3.4.3 Metrics Summary

The Companies have a long history of reliably serving the energy needs of their customers, even during extreme weather events. These generation and transmission reliability performance metrics quantitatively show successful planning and execution have exceeded neighboring utilities that participate in RTOs. Based on this data, there is no reason to believe that overall customer reliability would improve by joining an RTO.

4 Background

The Companies were founding members of MISO, operating within MISO from 2002 until September 1, 2006, when the Companies terminated their MISO membership with Kentucky Public Service Commission ("Commission") approval.[17] While the Companies are no longer members of MISO, the Companies are market participants in, and regularly transact in, both MISO and PJM.

Since exiting MISO, the Companies have periodically conducted high-level analyses to evaluate whether full membership in an RTO might be beneficial to its customers, and

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[16] Big Rivers SAIDI from 2018 was 15 but it included MED. Therefore, for 2018 the data was not included.

[17] In 2003, the Commission initiated on its own motion an investigation into the Companies' membership in MISO to determine if that membership provided net benefits to customers. *In the Matter of: Investigation of the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266, Order (July 17, 2003). The Commission determined in late May 2006 that ongoing MISO membership was not likely to provide ongoing net benefits to customers and authorized the Companies to terminate their MISO membership. Case No. 2003-00266, Order (May 31, 2006).

they currently have an obligation to file an annual RTO analysis.[18] The Companies filed their 2020 RTO Membership Analysis with the Commission on March 31, 2020.[19] The Companies are filing this updated analysis contemporaneously with their IRP filing in accordance the Commission's February 18, 2021 and March 22, 2021 Orders in Case Nos. 2018-00294 and 2018-00295. This report is modeled after the Companies' previous RTO Membership Analyses and updated to reflect the best available data at the time of this analysis.

5 Methodology

Consistent with the Companies' IRP, this analysis is through 2036. After reviewing the methodology used in the two most recent RTO Membership Analyses and the status of recent developments in the RTOs, the Companies determined that it was appropriate to use the same methodology as was used in the prior analyses for the near term, with updates to the different components to reflect RTO operational changes and other new information for 2023 through 2027. For this period, the analysis focuses on estimating the net financial impact to customers by comparing the standalone operations of LG&E and KU to estimated incremental benefits and costs of RTO membership. As with prior analyses, the team developed and studied three scenarios using different projections and assumptions to provide a range of potential outcomes.[20] The High Case uses assumptions most supportive of RTO membership, such as lower administration costs, higher energy and capacity prices, and lower transmission expansion costs. The Mid Case uses assumptions and forecasts reflective of mid-range assumptions using published forecasts for administration costs, mid-range market energy and capacity prices, and transmission expansion costs based on published MISO rates and the use of a neighboring PJM utility as a proxy. The Low Case captures the downside risk of RTO membership uncertainty by assuming low market energy and capacity prices, and higher costs. Appendix A contains

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[18] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order at 29-30 (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order at 33 (Ky. PSC Apr. 30, 2019).

[19] In accordance with the Commission's April 30, 2019 Orders in Case Nos. 2018-00294 and 2018-00295, the Companies filed their 2020 RTO Membership Analysis in the post-case correspondence of those proceedings.

[20] Although the scenarios apply the underlying assumptions across all years, it is possible that actual performance across the analysis period could be of mixed results with some years more consistent with the High Case, with others more consistent with the Low or Mid Case. In other words, the purpose of the three cases is to provide a reasonable range of possible outcomes across the analysis period, not to say that there are only three sets of possible outcomes.

a description of the methodology used to develop the underlying assumptions that differ between the three scenarios.

Beginning in 2028, when this analysis assumes Mill Creek 2 and Brown 3 will be retired, the analysis considers the projected range of the fixed cost components of RTO membership and focuses on the new market risk profile of the Companies as more generating units retire and customers are subject to increasing market exposure.

6 Key Assumptions

- The period of the analysis is 2023 through 2036. This 14-year term is slightly longer than the term used in the 2020 analysis to provide alignment with the time horizon of the IRP.
- The total financial impact of Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), and congestion costs over the analysis period have net zero cost. When the Companies were MISO members, the congestion management strategy was to hedge congestion costs, seeking to minimize such costs and not speculate. It is assumed this will be the approach if the Companies were RTO members in the future.
- The purchase or sale of ancillary services has net zero cost because the Companies are both buyers and sellers of these products and any charges are offset by credits. This assumption is consistent with other analyses provided to the Commission.
- The Companies estimated potential energy market benefits and costs using their commodity price forecasts, generation available for sales, and native load forecast used for annual business planning and the 2021 IRP.
- The Companies did not use generator-specific or load-specific Locational Marginal Pricing ("LMP") models but used forecasts for market energy prices at the Companies' interfaces with MISO and PJM.
- The Companies assumed retirements of the Companies' generating units to occur according to the units' depreciable lives, except for Mill Creek Unit 1, which is assumed to retire in 2024, and Mill Creek Unit 2 and Brown Unit 3, which are assumed to retire in 2028. Ghent Units 1 and 2 and Brown Unit 9 are assumed to retire in 2034; Brown Units 8 and 10 are assumed to retire in 2035; Brown Unit 11 is assumed to retire in 2036. These assumptions are consistent with the Companies' 2021 IRP.
- The analysis does not attempt to address how the retirements of existing units would be replaced by new generation resources in the case of RTO membership. Instead, starting with the Companies' assumed capacity need in 2028 (with base load), it evaluates the fixed costs of RTO membership and contemplates the market energy

and capacity risk exposure and potential mitigation methods. In an RTO, the Companies would no longer be focused on matching generation to load but would rely on the RTO for reliability. If the Companies were to join an RTO, they would need to evaluate the market energy and capacity price risk to customers of participating in these markets and consider an appropriate hedging strategy to mitigate this risk. This analysis does not incorporate any optimization of such a hedging strategy.

- The analysis focuses on impacts to the Companies' native load customers only and not third-party generators, loads, or other potentially impacted parties.
- Quantifiable items do not include any value adjustments to account for potential future changes in policy or market rules.
- Generating capacity above the RTO Planning Reserve Margin results in a benefit and is quantified in the Capacity Market Benefits. Capacity below the Planning Reserve margin would result in a cost.
- Uplift costs are based on RTOs' estimates of costs to load.
- Some reallocation of human resources is assumed to be necessary, but it is assumed that there is no incremental change in overall headcount attributable to joining an RTO.
- No financial impacts from deviations between day-ahead and real-time energy markets, operations, and load are included in the analysis.

7 RTO Cost Components

7.1 Allocation of Transmission Expansion Costs

Transmission planning and the allocation of expansion costs are major activities for each RTO. A significant cost in this analysis is the allocation of transmission expansion costs allocated to RTO members' load.

- For MISO membership, the Companies' annual costs were estimated to range from \$45 million to \$53 million in the Mid Case.[21]
- For PJM membership, the Companies' annual transmission expansion costs were estimated to range from \$17 million to \$19 million in the Mid Case.

7.1.1 MISO

Under current MISO policy, the cost of a new transmission project that addresses energy policy or provides widespread benefits across the footprint is considered a "Multi-Value

[21] These estimates do not include anticipated allocation of costs for transmission expansion projects currently being considered by MISO in its Long-Range Transmission Plan (LRTP) process.

Project" ("MVP"). The cost of MVPs is allocated 100% to load in the northern and central regions of MISO using a "postage stamp" methodology—i.e., all members' load pays the same rate for the MVP irrespective of where the load is located in the applicable footprint—and are recovered under Schedule 26A of the MISO Tariff. The Companies' estimated share of the roughly $6.6 billion in MVP projects currently approved in the MISO Transmission Expansion Plan ("MTEP") is based on the "indicative annual charges for approved MVP" published on the MISO website applied to the Companies' forecasted loads.[22]

For the High Case, the annual expansion costs were not changed from the Mid Case because the vast majority of the existing MVPs, which were approved as a portfolio in 2011, have been completed, which eliminates any rationale for assuming a reduced expansion cost. For the Low Case, the transmission expansion costs were assumed to increase 14.8% per year over the first 10 years of RTO membership, and remain level thereafter to simulate a quadrupling of the Mid Case cost based on the impact of the anticipated significant transmission build out as discussed below.

As part of its Reliability Imperative initiative, MISO determined that the generation resource evolution and electrification represented in its Futures analysis necessitated a "Long-Range Transmission Plan" (LRTP) to identify needed transmission solutions. This effort is, in large part, in response to expected nation-wide grid expansion needs to accommodate renewable generation. MISO developed an initial transmission roadmap to indicate the expected scope of significant long-range transmission needs in its Futures 1, 2, and 3 planning scenarios and is currently in the process of identifying possible transmission projects through the LRTP for inclusion and approval in Appendix A of the annual MISO Transmission Expansion Plan (MTEP). MISO intends to identify such LRTP projects while analyses, business cases, and cost allocation are developed. Although projects identified in the LRTP are not initially designated for cost allocation purposes prior to approval in the MTEP, it is likely under current MISO cost allocation rules[23] that they will be regionally, rather than locally, allocated to members' load.

7.1.2 PJM

Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculation. These

[22] https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/

[23] MISO and its stakeholders are currently discussing through its Regional Expansion Criteria and Benefits (RECB) Working Group forum various potential cost allocation methodologies, both existing and new, to be applied to Future 1 transmission expansion projects identified in the LRTP.

charges are recovered under Schedule 12 of the PJM tariff. The Companies estimated their allocation for projects documented in the RTEP within this analysis period using PJM's publicly posted RTEP project information. As was done for the 2020 RTO Membership Analysis, in this analysis the Companies used PJM's most-current RTEP project information (2020). There were significant differences in the cost allocation in PJM's 2020 information as compared to the 2019 data provided by PJM and used in the Companies' 2020 RTO Membership Analysis, in particular PJM's approval and allocation of a $288 million transmission project in Virginia in 2020.[24] Because of the changes made in the cost allocations in the updated information from PJM, this analysis reflects a sizeable increase in the projected transmission expansion costs associated with PJM membership, which also demonstrates the increased uncertainty caused by cost allocation methodologies in larger-scale regional RTO footprints.

In developing the Low and High cases, the Companies used the same variance assumptions for PJM as applied concerning MISO. The annual expansion costs were not changed from the Mid Case to assign a value for the High Case and increased by 14.8% per year from the Mid Case to assign a value to the Low Case. This is based on similar potential in PJM for large-scale transmission buildout in response to expected nation-wide grid expansion needs to accommodate renewable generation. The cost allocation for RTEP projects in PJM is subject to the potential for periodic revision and reallocation based on changes in flow and other cost allocation factors.[25]

7.2 Administrative Charges

MISO and PJM have various tariff schedules to recover the administrative cost of operating the markets and providing services to their respective members.

MISO forecasts annual administrative rate increases between 3% and 5%. MISO annual cost in the Mid Case is $14.8 million beginning in 2023 and increases to $24.1 million by 2036. MISO's 2020 forecasted administrative rate for 2021 was escalated 4% each year and then applied to the Companies' annual load forecast to estimate annual MISO administration expense. The administration rates are based on cost projections contained in MISO's 2020 revenue requirement forecast.

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[24] To estimate transmission expansion costs that the Companies would expect to be allocated as a member of PJM, the Companies used EKPC's 2020 transmission expansion allocation and adjusted appropriately to account for differences between Companies' load and EPKC's load.

[25] *See e.g.*, Linden VFT, LLC v. PJM Interconnection, L.L.C., 170 FERC ¶ 61,123 (2020), in which FERC denied a complaint filed by Linden VFT, LLC challenging revised cost allocation for two projects following the termination of Consolidated Edison Company of New York, Inc.'s transmission service agreements that resulted in an alleged increase in costs from $10 million to approximately $132 million.

PJM annual cost in the Mid Case is $18 million beginning in 2023 and increases to $24.2 million by 2036. The Companies based these estimates on 2020 state-of-the-market reports submitted by PJM's market monitor. The 2020 rates were then escalated 2.5% each year. PJM's administrative cost rates have increased by an average of 1.9% per year from 2015 through 2020, in line with PJM's expected rate of around 2.5%.

Although revenue requirements for administrative costs are expected to increase around 1% to 5% each year, the average cost to load can be more volatile, driven by the amount of load (weather and demand dependent) and the number of customers to allocate expense, which can vary by RTO membership entries and exits. Results from prior years have shown double-digit year-over-year changes at times to the cost per MWh to load, both positive and negative, e.g., ranging from 17% lower to 15% higher. To reflect forecast rate volatility compared to Mid Case results, the annual administration costs were reduced by 20% from the Mid Case to assign a value for the High Case and increased by 20% from the Mid Case to assign a value to the Low Case.

7.3 Uplift Costs

MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, these costs for both RTOs are the result of committing units in real-time that were not committed in the day-ahead market. MISO refers to uplift costs as "revenue sufficiency guarantee" ("RSG") costs; PJM refers to such costs as "balancing operating reserve" ("BOR") expense. Uplift expense for MISO is expected to average around $7.5 million per year, while PJM uplift is expected to average just under $5 million per year. Rates are based on state-of-the-market reports submitted by each RTO's market monitor.

Although uplift costs have declined compared to 2014, there remains a risk of material additional cost assignment driven by extreme weather events and unplanned outage risk.

In 2014 PJM collected $960 million in uplift, with an average cost to load of $1.15 per MWh. PJM then took steps to address issues contributing to uplift, including implementation of enhanced testing requirements for generators receiving capacity payments, increased penalties for non-performance, and the shift of reserve capacity from the West Region to the East. As a result, in 2015 uplift cost declined 67% to $0.38 per MWh and then saw another 55% decrease in 2016 to $0.17 per MWh. While the 2017 cost was $0.14 per MWh, expense increased to $0.23 per MWh in 2018 but then declined to $0.11 per MWh for 2019 before increasing slightly to $0.12 per MWh in 2020. The Companies used an average rate of $0.15 for this study to account for potential market volatility. The rate is the average of 2018 through 2020.

MISO uplift costs have also decreased compared to 2014, although on a less extreme and more stable basis as compared to PJM, resulting from a combination of RTO improvements related to cost causation and lower fuel expense. Uplift cost of $0.40 per MWh to load in 2014 declined to $0.22 per MWh in 2015 and then decreased further to $0.20 in 2016. MISO's 2017 cost increased to $0.25 per MWh, decreased to $0.23 per MWh in 2018, and then decreased again to $0.18 per MWh in 2019. However, in 2020 the Uplift cost rose to $0.31 per MWh, the highest since 2014. The Companies used the rate of $0.24 per MWh, the average of 2018 through 2020 MISO uplift costs, to be consistent with the period used in PJM's analysis.

Planning for and managing through extreme weather and unplanned outage events is difficult, particularly because the response would be directed by the RTO juggling resource, market, and other considerations over a wide area. Therefore, uplift costs are a potentially material expense risk for RTO participants.

7.4 Lost Transmission Revenue

The analysis reflects an expected decrease in the sale of point-to-point transmission service resulting from RTO membership as the Companies would be under the RTO tariff and not offer point-to-point transmission service directly. The lost transmission revenue included in this analysis ranges from $1.2 to $2.7 million.

7.5 Lost Joint Party Settlement Revenue

An additional $1.4 to $1.9 million of lost revenue was also included because of the existing settlement agreement between MISO, SPP, and the Joint Parties (including the Companies). The settlement agreement addressed issues identified by SPP and the Joint Parties that arose from MISO's southern expansion to include Entergy and operate as a single Balancing Authority Area. Under the settlement agreement, MISO compensates SPP and the Joint Parties for the use of these parties' systems. It is not clear that the Joint Parties agreement as applied to the Companies would terminate as a result of RTO membership, but the Companies determined that it was reasonable to assume for the purposes of this analysis that compensation to the Companies under the settlement agreement would stop if the Companies were to integrate into MISO or PJM. The Companies did not include in this analysis an assumption that if they were to join MISO, they would potentially be asked to contribute an as-yet unknown amount to the compensation paid by MISO to SPP and the Joint Parties.

7.6 Implementation Costs

The Companies would incur costs to fully integrate their operations into an RTO. For the purpose of this updated analysis, the Companies assumed that these costs would be approximately $1 million per year for additional metering hardware and software required by RTOs. It should be noted though that the stability of these costs is also uncertain as RTO initiatives impacting metering requirements and computer hardware and software enhancements develop.

8 RTO Benefit Components

8.1 Capacity

Joining an RTO has significant implications for the Companies' future capacity profile. A primary benefit of RTO membership is the ability to share capacity across a diverse collective load profile, which allows for a lower need for collective reserves compared to the total reserves that would be required for each entity individually. The Companies evaluated the RTO capacity impact through 2027 by modeling the benefit of selling capacity in the RTO capacity markets.

8.1.1 Capacity Market Benefits and Costs[26]

As an initial matter, the performance of an analysis of potential capacity auction benefits for either RTO must come with a significant caveat that the capacity market constructs for both RTOs remain in flux.

A protracted dispute over PJM's minimum offer price rule (MOPR) resulted in a lengthy suspension of the PJM planning year 2023/2024 capacity auction. PJM filed tariff modifications and auction timelines on March 18, 2020 in response to FERC's order to modify the MOPR rules. PJM proposed changes to the capacity market and in October 2020 FERC approved PJM's plans. However, significant opposition to the proposed changes remained as many PJM stakeholders believed the MOPR rules remained intact. Maryland and New Jersey reportedly considered exiting the capacity market altogether. In response, PJM initiated a stakeholder process to comprehensively revise the MOPR, resulting in new rules that exempted renewable energy facilities, new natural gas facilities, and nuclear power plants. The new rules went into effect on September 29, 2021 when FERC failed to reach a decision on a 2-2 split vote.

In a separate matter, on October 4, 2021 PJM submitted a request for rehearing to FERC regarding a September 2, 2021 FERC order establishing new capacity market seller offer cap (MSOC) rules. The new offer cap would limit capacity bids to the "unit-specific net avoidable cost rate" and would take effect in the January 2022 capacity auction. It is highly

[26] While this cost-benefit analysis is based upon RTO membership, membership is not required to participate in PJM or MISO capacity markets.

uncertain as to whether the new rules will stand. PJM questioned the feasibility of the new offer cap methodology and broad opposition exists amongst generators in PJM.

MISO has identified several projects to “redefine markets” as a part of its “MISO Forward” report and integrated road map. For example, MISO’s Resource Availability and Need (“RAN”) initiative alone is exploring several potential modifications to MISO market design, resource requirements, and incentives that may or may not come to fruition during the period studied in this analysis.

The state of uncertainty and evolution for both markets means there is inadequate information available to consider all possible future market construct changes into the updated analysis. As such, the Companies used the same general methodology for evaluating capacity auction impacts as was used in the 2020 RTO Membership Analysis.

Both PJM and MISO take the position that they can provide appropriate generation reliability with a lower target annual peak reserve margin as compared to the Companies’ target summer reserve margin range of 17 percent to 25 percent. Therefore, to the extent that the Companies forecast their reserve margin to be above the RTO target, the potential exists to sell capacity (net of their capacity needs for load) into the RTO capacity auctions. However, after the retirement of the Companies’ generating units occur, the Companies expect to be a net purchaser of capacity from the RTO. This analysis evaluates the potential value or cost of capacity sales and purchases in both the PJM and MISO capacity market constructs assuming the following:

- Forecasted low, mid, and high peak demand based on normal weather and a range of forecast assumptions consistent with the 2021 IRP,
- The difference between the Companies’ generating capacity and each RTO’s forecasted load obligation is assessed for net sales or purchases in the RTO capacity market,
- The Companies’ capacity offered into the capacity market may not clear at 100 percent, and
- Capacity pricing that considers the median of historical auction results.

Inputs to this analysis are sensitive to these assumptions and deviations would result in material impacts to the projected results.

8.1.2 PJM Reliability Pricing Model (“RPM”)

Inputs to estimating the value of the PJM capacity market are as follows:

- Installed Capacity ("ICAP") [27] – excludes small-frame combustion turbines, [28] Curtailable Service Rider ("CSR") load, and Demand Conservation Program ("DCP"),[29] but includes capacity available through the Companies' ownership share of Ohio Valley Electric Corporation ("OVEC").
- Unforced Capacity ("UCAP")[30] – calculated by adjusting ICAP for the business plan forced outage and maintenance outage rates for coal and natural gas units. Hydro and solar units were adjusted using PJM's specified ELCC Class Ratings for intermittent resources.[31]
- Cleared Capacity – three levels of capacity clearance rate were considered based on PJM's historical capacity clearance rate by fuel type.
- Capacity Need – based on the Companies' joint system peak load forecast, adjusted for 1) historical average peak diversity between LG&E and KU and PJM RTO and 2) PJM's applicable Forecast Pool Requirement factor.
- Capacity Price – reflects the median historical base residual auction price since the 2016/2017 planning year of $100/MW-day, which occurred for the 2019/2020 planning year.

8.1.3 The MISO Planning Resource Auction ("PRA")

Inputs to estimating the value of the MISO capacity market to the Companies are as follows:

- ICAP – excludes small-frame combustion turbines, CSR load and DCP,[32] but includes capacity available through the Companies' ownership share of OVEC.

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[27] ICAP is defined by RTOs as a unit's net summer capability.

[28] The Companies have four small-frame natural gas-fired peaking units. Because of their age, the Companies plan to limit spending on the small-frame SCCTs and retire the units when significant investment is needed for their continued operation.

[29] CSR load reduction was excluded due to uncertainty as to whether rights under the retail CSR tariff would be consistent with RTO capacity performance obligations. DLC load reduction is seasonal and therefore does not appear to meet RTO capacity performance requirements.

[30] Unforced capacity is defined as installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating. For this analysis, Unforced Capacity is calculated as the Installed Capacity adjusted for 5-year average $EFOR_d$ plus 25% of EMOR or UCAP=ICAP*[1-(EFORd+0.25*EMOR)].

[31] PJM ELCC Class Ratings; *see*: https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx.

[32] CSR and DCP load reductions were excluded due to uncertainty as to whether these retail programs would be consistent with MISO tariff requirements.

- UCAP – same as PJM UCAP input for coal, natural gas, hydro, and fixed-panel solar units. Tracking-panel solar units were adjusted using MISO's specified capacity credits for solar resources.[33]
- Cleared Capacity – capacity bid is assumed to clear the auction using a range of MISO's Zone 6 historical clearance rates for all resource types.[34]
- Capacity Need – based on the Companies' joint system peak load forecast adjusted for 1) historical average peak diversity between LG&E and KU and MISO, 2) MISO's UCAP planning reserve margin, and 3) MISO's transmission loss factor.
- Capacity Price – reflects the median historical capacity auction price since the 2016/2017 planning year of $5/MW-day, which occurred for MISO's two most recent planning years of 2020/2021 and 2021/2022.

8.1.4 Capacity Market Financial Impacts

For both RTOs, capacity net sales and purchases are estimated as a function of cleared UCAP minus RTO Capacity Need. If resources are not fully replaced as units retire over the review period, installed capacity, and consequently unforced capacity, declines through the period. Peak loads are relatively flat across the period. As a result, it is likely that in the near term, the Companies would have capacity above the amount they would need to purchase to serve load, which would be available to offer into each RTO's capacity auction, although the level of availability differs due to each RTO's reserve margin requirements. As existing resources retire and are assumed to be replaced with solar resources to meet the RTOs' minimum reliability levels, the Companies would be in a net purchasing position to the extent their portfolio did not clear the annual capacity auction.

Even when the Companies may have capacity available to offer in each market, PJM has a rate of capacity clearance by fuel type that varies from year to year but is less than 100% of the capacity offered into the market. For example, coal capacity clearing the auction has ranged from 81% to 91% of coal capacity offered since the 2016/2017 auction. For natural gas capacity, this range is 92% to 98%.

MISO data on capacity clearance rates is not provided with the granularity of PJM data, so clearance rates could not be applied by fuel type; however, clearance data provided by zone indicates nearly 100% of all offered resources have cleared the auction for Zone 6, which is adjacent to the Companies' service area, since 2016. A range of historical

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[33] MISO wind and solar capacity credit; See: https://cdn.misoenergy.org/2021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf.
[34] MISO data summarized at the zonal level without specificity by fuel type.

capacity clearance rates since 2016/2017 was applied to all resources in each of the cases analyzed.

Across all cases, the calculated annual capacity impact for PJM's RPM ranges from ($7) million to $23 million annually in 2023 through 2027. For MISO, with typically significantly lower capacity auction clearing prices but higher resource clearing rates, the calculated annual capacity market impact ranges from $1 million to $1.7 million across all cases.

8.1.5 Performance Risks

PJM has established stringent Capacity Performance ("CP") requirements for generator performance. All generation capacity resources that are capable or can reasonably become capable of qualifying as CP resources must be offered into the capacity market as CP resources. Exceptions are permitted if the seller can demonstrate that a resource is reasonably expected to be physically incapable of meeting CP requirements. A resource that requires substantial investment to qualify as a CP resource is not excused from the CP must-offer requirement but is expected to include such costs in its CP sell offer.

Generators must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves during performance assessment hours throughout the Delivery Year. Penalties are applied when actual performance is less than expected performance. The non-performance charge rate for capacity performance is a function of the net cost of new entry ("CONE") for the delivery area in which the resource is located, based upon PJM's modeling. For 2022/2023, this rate is estimated to be $3,169 per MWh.[35] For example, one hour of unplanned outage for the Companies' natural gas combined cycle with a UCAP of 632 MW could result in a non-performance charge of more than $2 million.[36]

MISO has not designated capacity performance requirements in the same manner as PJM; however, Planning Resources are obligated to provide capacity to their designated zone for the entire planning year, as well as to perform during system emergencies.[37] If a load-serving entity does not achieve resource adequacy for the planning year, a capacity deficiency charge will be assessed based upon 2.748 times the CONE. MISO's CONE for Zone 6 for the 2021/2022 planning year is $244.16 per MW-day.[38] Though this analysis

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[35] Non-Performance Charge Rate estimated using the value of net CONE for PJM RTO.

[36] Non-Performance Charge = Performance Shortfall MW *Non-Performance Charge Rate

[37] A resource may be designated as a Planning Resource either through the MISO PRA or as part of a fixed resource adequacy plan for a load serving entity (LSE). Only Planning resources cleared through the PRA are subject to capacity credits and penalties.

[38] Non-Performance Charge Rate estimated using the value of net CONE for MISO Zone 6.

does not quantify these non-performance charges, the risk associated with non-performance is significant.

8.2 Energy Market Benefits and Costs

The Companies estimated energy market benefits and costs using the Companies' existing planning models. These models are of the Companies' system; they are not RTO-wide regional models. An analysis using a complete RTO-wide regional market model would be advisable before making any decision to join an RTO based on expected energy market benefits and costs.

The Companies used their production cost software tool, PROSYM, to forecast the potential energy market benefits and costs of joining an RTO by estimating the potential net impacts to (1) market energy purchase costs for retail and wholesale requirements customers and (2) market energy sales margins, using a base load forecast and a range of commodity price forecasts. The following model revisions were made to PROSYM to reflect RTO membership.

- Dispatching/selling generating units into the RTO energy market and purchasing native load energy from the RTO energy market.
- The Companies' normal business plan assumptions include constraints on starting combustion turbines for the sole purpose of making market sales to model the typical dispatch of these units. The analysis of RTO membership eliminated these constraints on dispatch because the RTO would be directing dispatch decisions.
- The Companies' assumption for the spinning reserve requirement was reduced from 327 MW in the business plan to 220 MW in the RTO analysis based on the Companies' projected load ratio share of the estimated spinning reserve requirements in the RTO.
- The Companies eliminated several expenses applied to market sales and purchases in the Companies' current business plan.
    - **RTO expenses**. RTO balancing operating reserve charges on sales and purchases are included in the business plan to cover deviations between the day-ahead and real-time market. The average of these RTO expenses that were eliminated in the RTO analysis over the study period were assumed to be \$0.39/MWh with an average annual increase of 2%. Initial RTO expenses (Peak: \$0.42/MWh, Off-Peak: \$0.38/MWh, Weekend: \$0.26/MWh) were in 2021 dollars based on recent historical averages.
    - **RTO transmission**. RTOs charge for transmission to "drive-out" energy from the RTO footprint for expenses for purchases made by the Companies. The average of these RTO transmission charges that were eliminated in the RTO

analysis over the study period were assumed to be $1.51/MWh with an average annual increase of 1%. Initial RTO transmission rates (Peak: $1.4/MWh, Off-Peak: $1.4/MWh, Weekend: $1.4/MWh) were in 2021 dollars and reflect the current rates as of the 2022 business plan.

- **LG&E-KU transmission.** The Companies also charge for transmission for market sales made by the Companies. The average of these transmission charges that were eliminated in the RTO analysis over the study period were assumed to be $6.55/MWh with an average annual increase of 1%. Initial LG&E-KU transmission rates (Peak: $8.31/MWh, Off-Peak: $4.04/MWh, Weekend: $4.04/MWh) were in 2021 dollars and reflect the current rates in the 2022 Business Plan.
- **Losses**. When generating energy for market sales, the Companies must generate additional electricity above the transacted volume to compensate for losses on the transmission lines. The Companies' 2020 Business Plan estimated the cost associated with losses to be 0.5% of the fuel cost to generate the energy sold. In an RTO, the Companies' generation would be sold at the generator bus versus the RTO interface. The RTO analysis assumes that over the study period the average cost of losses eliminated is $0.1/MWh with an average annual increase of 1.5%.
- **Market price buffer**. To manage the uncertainty that exists between real-time market electricity prices and aggregated hourly settled prices, the Companies' normal business plan assumes that energy sales and purchases will not be transacted unless a minimum of a $5/MWh hurdle can be achieved. Under the RTO analysis, this hurdle rate is eliminated.

The PJM and MISO analyses used a range of commodity prices: low, mid, and high fuel price forecasts for the Companies' generation units and the corresponding low, mid, and high electricity price forecasts specific to each RTO. Table 3 summarizes the minimum and maximum estimated annual net energy market benefits and costs for the 2023-2027 period for each commodity price forecast. The net energy market impact figures reflect the sum of (1) the potential favorable incremental benefits of selling energy into the RTO market and (2) the potential incremental costs or benefits of purchasing market-priced energy for the Companies' retail and wholesale requirements customers, relative to non-RTO membership.[39]

[39] Appendix C shows the annual benefits and costs of each of these components for each scenario.

Table 3: Range of Annual Net Energy Market Benefits, 2023-2027 ($M)

Commodity Prices	Low	Mid	High
MISO	15-21	7-10	12-16
PJM	16-21	7-10	10-14

In all scenarios, the estimated benefit of additional energy sales margin was greater than the additional cost of purchasing market energy for native load through 2027. These benefits represent about 1-3% of the total native load cost of $670 to $840 million per year in these scenarios. The value is highly dependent on energy market prices, which can be volatile at times. As noted in the Companies' prior RTO analyses, energy market impact estimates are highly uncertain as they depend on the level of market electricity prices, which directly depend on many uncertain variables including fuel prices, weather, and RTO-wide load and generation capacity and performance. They may also be indirectly influenced by many external factors, including state and federal policy.

Figure 10 and Figure 11 display the ranges of market energy price forecasts used in the near-term analysis for MISO and PJM.

Figure 10: MISO Energy Price Forecast Scenarios (Nominal Annual Average $/MWh)

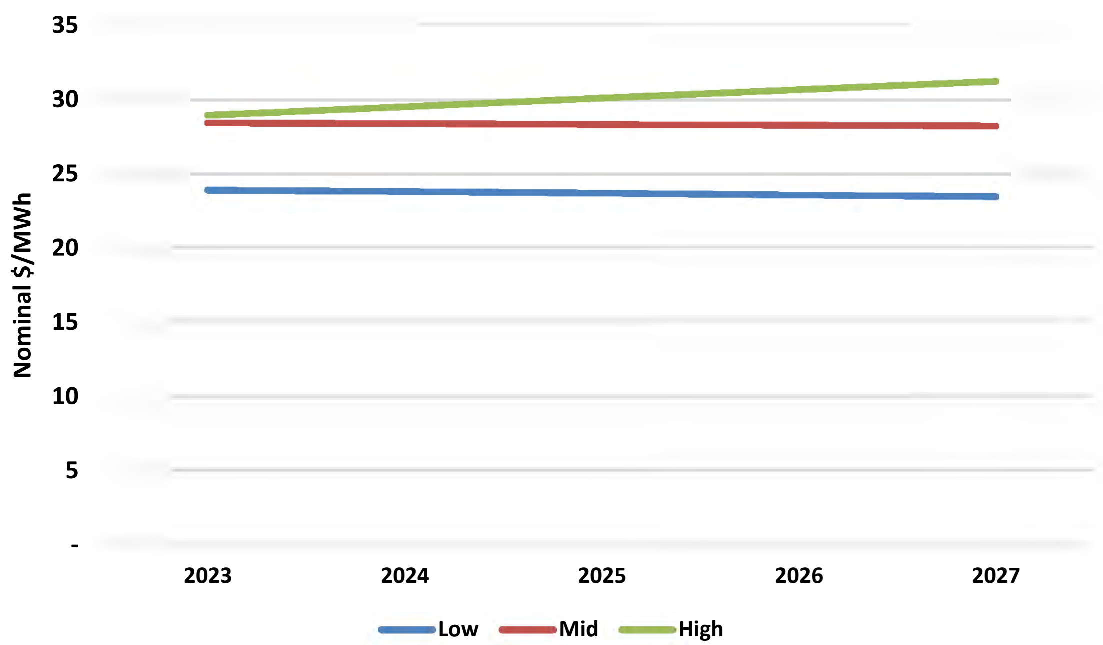
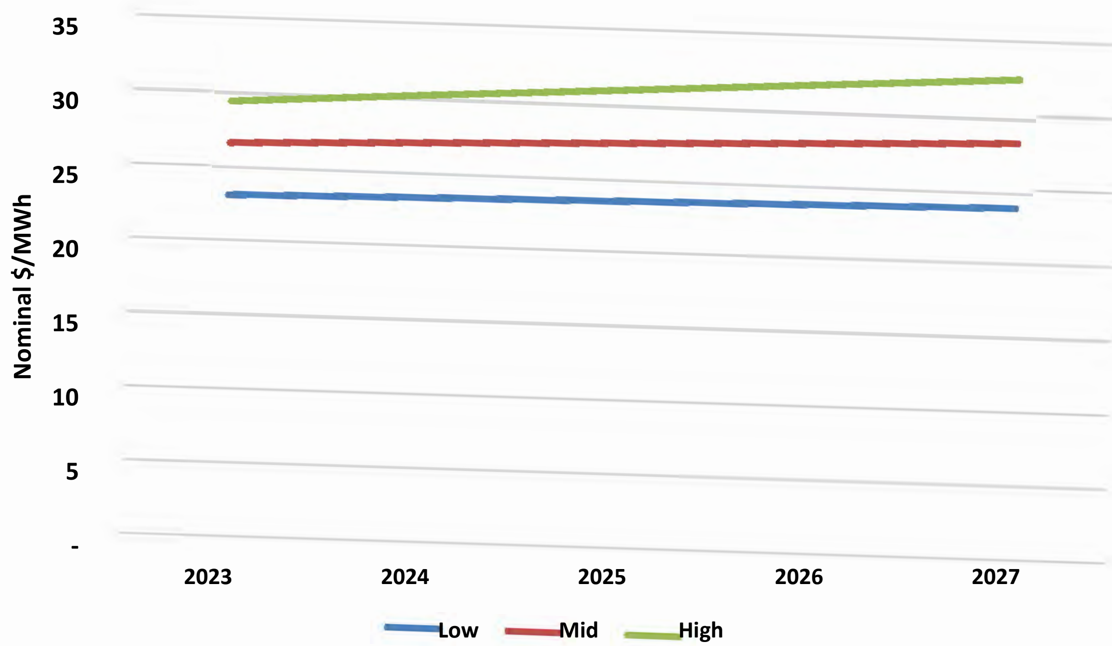


Figure 11: PJM Energy Price Forecast Scenarios (Nominal Annual Average $/MWh)



8.3 Transmission Revenue

In both MISO and PJM, the Companies would have a "zonal" transmission rate that would be calculated in a similar fashion to how their transmission rate is calculated currently with the Companies as stand-alone transmission providers. In an RTO, the zonal transmission rate would apply to any Network or Point-to-Point ("PTP") transmission that sinks in the zone and the rate would continue to be based on the Companies' transmission revenue requirements.

The Companies would also potentially receive an allocation of revenues from each RTO based on the revenues that each RTO collects for PTP transmission service that does not sink within the RTO (i.e., drive-out and drive-through transmission service). Both PJM and MISO have a mechanism for this allocation based on combinations of transmission plant in service ratio and flow-based derivations. Due to the difficulties in projecting drive-through and drive-out transmission use as well as flows and ratios that would drive the Companies' allocation of revenues, the Companies did not attempt to determine the potential projected value of this allocation and therefore did not include it in this analysis. When the Companies were previously members of MISO, revenues for drive-through and drive-out transmission use were around $1M annually. Due to the passage of time and changes in transmission facilities and use since the Companies' exit, the Companies did not use this historical performance value as a proxy but do believe it indicates that revenue from this service is not likely to be significant.

8.4 FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as the Companies are assessed outside of an RTO. For this analysis, the projected FERC assessment charges were included in RTO administrative charges. The amount that the Companies currently pay is included as a projected benefit to quantify properly the net change in cost.

8.5 Eliminated Administration Charges

Membership in either PJM or MISO would result in cost savings from the elimination of certain third-party services. For the purposes of this analysis, the Companies assumed they would no longer need the current Independent Transmission Organization ("ITO") or Reliability Coordinator ("RC") services provided by TranServ and TVA, respectively. In addition, the analysis assumes the current reserve-sharing contract with TVA would no longer be needed.

8.6 Elimination of De-Pancaking Expense

The Companies currently provide MMD credits to certain entities importing from MISO.[40] The Companies assumed all credits for MISO charges and waiving of their transmission charges would cease if they joined MISO and all but MISO Schedule 26A would be eliminated if the Companies joined PJM.[41] The benefit amount from eliminating MMD expense is based on such expenses included in the Business Plan and allocated to LG&E and KU retail and wholesale customers. For the High Case, the depancaking expenses were increased by 20% to account for potential increase in the MISO drive-out rate. For the Low Case, the depancaking expenses were assumed to increase to align with the increased MISO transmission expansion cost that is assumed in the Low Case. This results

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[40] The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. *See*, *E.ON U.S., LLC, et al.*, Docket No. ER06-1279-000. The Companies received FERC approval to eliminate this obligation, but subject to the implementation of a transition mechanism for certain power supply arrangements. The transition mechanism is currently in effect, under which the Companies must still provide certain credits for MISO transmission charges, but the details of such transition mechanism are still under litigation. *See*, FERC Docket Nos. EC98-2-001, ER18-2162-000, EC98-2-002, ER18-2162-001, ER19-2396-000, ER19-2397-000, ER19-2396-001, ER19- 2397-001, EC98-2-003, ER18-2162-002, EC98-2-004, ER18-2162-003, ER19-2396-002, ER19-2397-002 and D.C. Circuit Court of Appeals Docket Nos. 19-1236, 19-1237, 20-1282, 20-1326, 20-1452, 20-1459, 21-1013, 21-1025 (consolidated).

[41] FERC has required that transmission across the MISO-PJM be depancaked through the use of license plate rates. An exception to this general depancaking rule was created for MISO Schedule 26A in 2016. *See*, *Midwest Independent Transmission System Operator, Inc.*, 156 FERC ¶61,034 (2016) (Order on Remand from the Seventh Circuit finding that, in light of current conditions, the limitation on export pricing to PJM is no longer justified for MISO Schedule 26A charges.)

in slightly higher annual depancaking expense in the Low Case ranging from 2% to 29% year over year from the Mid Case.

9 Near-Term Quantitative Results

The Companies developed a range of results reflecting low, mid, and high favorability for joining each RTO through 2027. The high-favorability cases reflect the combinations of benefit/cost items that result in the most RTO favorability. The low and mid-favorability cases were developed similarly to demonstrate a broad range of reasonable uncertainty. Appendix A details the assumptions that were included in each favorability case. Figure 12 and Figure 13 display the values for all three favorability cases by year for both MISO and PJM (See Appendix B for detailed annual values).

Figure 12: MISO Range of Near-Term Potential Outcomes ($M)

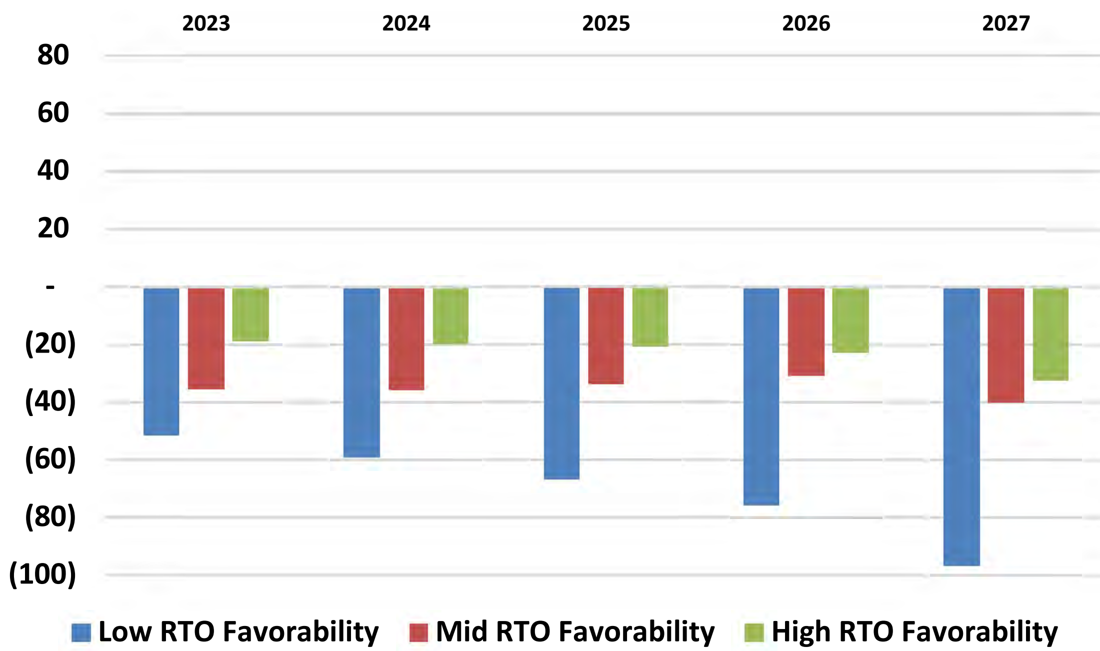
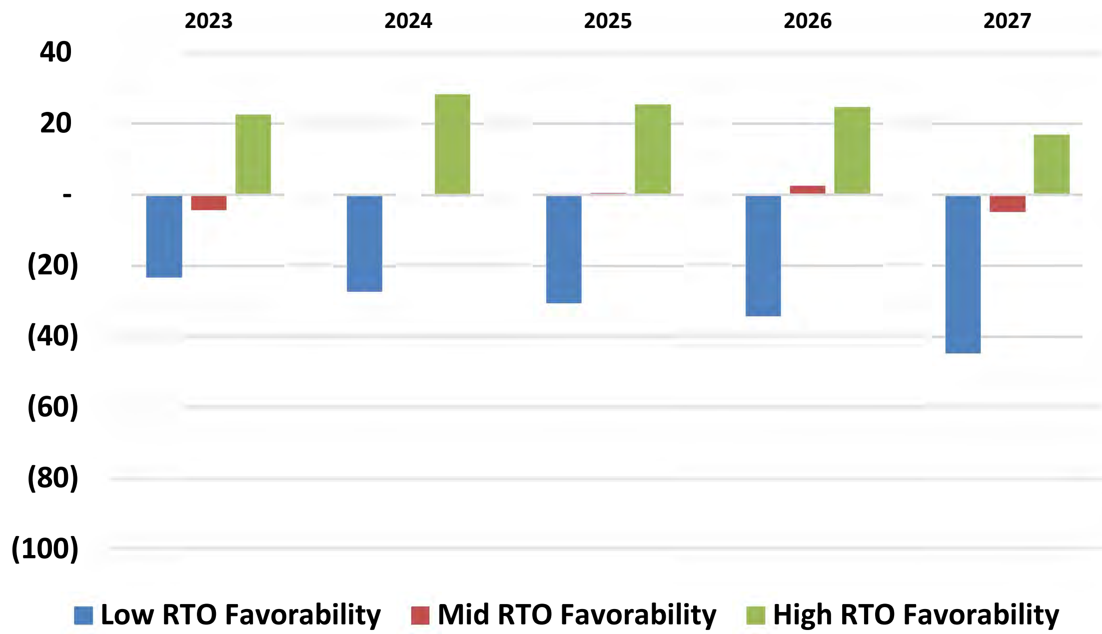


Figure 13: PJM Range of Potential Near-Term Outcomes ($M)



Before 2028, the projected potential net benefits and costs of joining an RTO are mixed. While the cases shown present discrete views for RTO membership favorability, they are intended to represent the distribution of potential outcomes. The green bars represent the high-favorability case, which is the combination of assumptions that results in the most favorable case for RTO membership in each year. The blue bars represent the least favorable combination of assumptions in each year. The red bars represent a case with mid-level assumptions. As the figures show, joining MISO is unfavorable in each year in all cases. The analysis for joining PJM is a bit more mixed with the high case showing the potential for savings and the mid case near zero (ranging between $4 million unfavorable and $2 million favorable). This difference is due primarily to the lower transmission expansion costs and higher forecasted capacity prices in PJM compared to MISO.

PJM's high-favorability case ranges between $22 million and $28 million more favorable than the mid-case. Achieving this high favorability in the RTO requires the alignment of favorable assumptions for several of the cost and benefit components. Table 4 shows the annual variance between the mid-favorability case and the high-favorability case for each of these variable components.

Table 4: Variances between PJM High and Mid-Favorability Cases ($M)

	2023	2024	2025	2026	2027
Lower Admin Fees	3.6	3.7	3.7	3.8	3.9
Energy Market Benefits	10.4	8.9	5.3	2.3	3.5
Capacity Market Benefits	8.4	11.8	11.8	11.8	11.8
Elimination of Depancaking	4.2	4.0	4.0	4.1	2.4
Total Variance	**26.6**	**28.4**	**24.8**	**22.0**	**22.0**

- **Admin Fees – the high-favorability case assumes 20% lower admin fees vs. the base case.**
- **Energy Market Benefits** – the high case reflects low commodity prices (see Table 3). In this case, low prices allow for the lowest increase in the cost to serve native load but still allow for a more-than-offsetting increase in market sales vs. standalone operations. The net of these impacts is the most favorable with low prices.
- **Capacity Market Benefits** – the high case reflects the highest capacity auction clearing rates observed since the 2016/2017 planning year.
- **Depancaking** – the high case assumes that 20% higher depancaking expenses can be avoided by joining an RTO by assuming an increase in MISO's drive-out rate.

10 Longer-Term Considerations

Absent RTO membership, the Companies project needing new capacity as they retire their coal fleet.[42] As the need for new capacity develops, the RTO membership evaluation becomes more complex. On a standalone basis, the Companies would need to decide what amount and type of new capacity to add to meet their optimal reserve margin range for reliability. In an RTO, the Companies would need to determine the appropriate risk profile that (1) offsets the fixed costs of RTO membership with financial benefits to customers and (2) mitigates customers' exposure to price volatility in the RTOs' energy and capacity markets. While the Companies own their existing resources, there is a natural hedge to this price risk by offsetting the costs with energy and capacity revenues in the RTO markets. But as more of the Companies' existing units retire, this hedge degrades, and exposure increases, without mitigation in some form.

At one extreme, the Companies could increasingly rely on the RTO for their net energy and capacity needs as their own generation retires. This unhedged approach would avoid

[42] These retirement assumptions are not yet firm commitments but will require further evaluation as the units continue to operate and as potential new environmental regulations develop.

the costs of new generation but would come with significant exposure to volatility in the energy and capacity markets. In periods of high energy prices (which are often correlated with periods of high load/extreme temperatures), the costs to customers could increase drastically.

A fully hedged portfolio would be similar to one under the Companies' standalone planning in which the Companies would expect to cover their own capacity and energy needs on a net basis, similar to the RTOs' fixed resource requirement option. Such a portfolio would effectively eliminate market price risk but may be more costly than a portfolio with fewer resources and some amount of market exposure.

An optimal hedging strategy could include physical assets, financial instruments, or both to mitigate price exposure. Designing the appropriate hedging strategy will require an assessment of the optimal risk exposure through a detailed evaluation of the market prices at an LMP granularity and a robust forecast of price volatility, which the Companies have not undertaken for this high-level screening analysis. For RTO membership to be favorable, the expected benefits of joining the RTO should outweigh the expected range of fixed costs consistently over time and in a clear and convincing manner because it is highly uncertain whether the Companies would be able to exit an RTO a second time. Figure 14 and Figure 15 show the projected range of fixed costs for each RTO and that by the end of the study period in 2036, the Companies would annually need to realize up to \$220 million of benefits in MISO or \$100 million in PJM for RTO membership to be favorable in the long term.[43]

[43] The main driver of the difference between MISO's and PJM's high case for net fixed costs is the assumed potential for much higher transmission costs in MISO.

Figure 14: Projected Fixed Costs Range - MISO ($M)

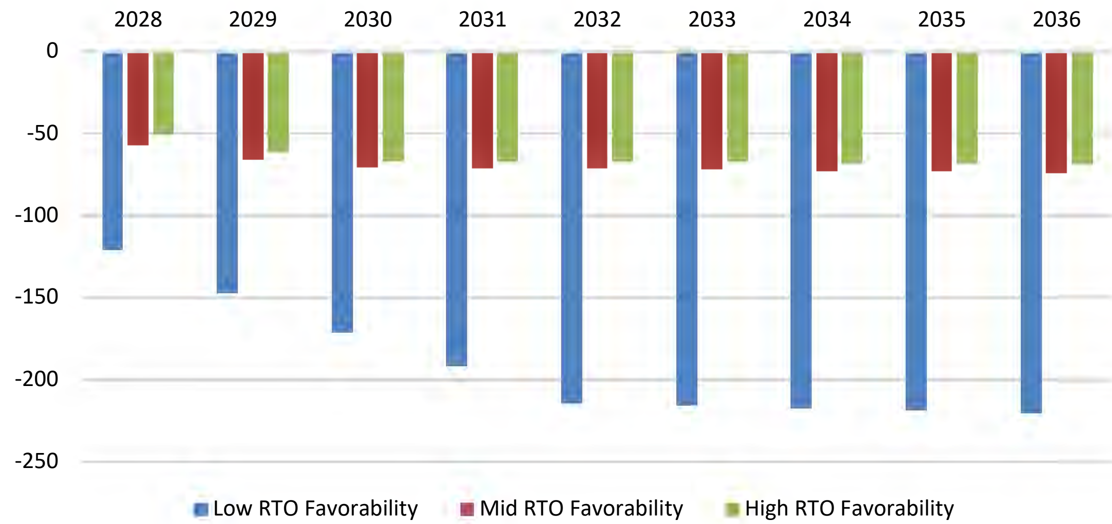
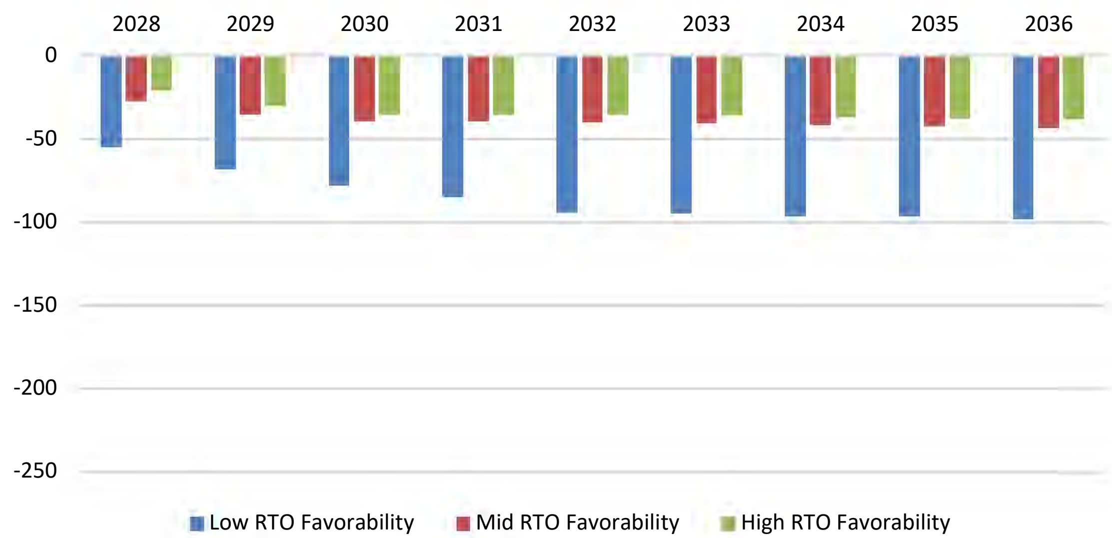


Figure 15: Projected Fixed Costs Range - PJM ($M)



11 Conclusion

The Companies do not recommend RTO membership at this time but will continue to evaluate RTO membership annually with a particular focus on the retirement timing for Mill Creek unit 2 and Brown unit 3 in 2028. This study indicates that there is likely little benefit to joining MISO prior to 2028, while joining PJM could potentially be beneficial before then if actual capacity and energy prices are high. However, when future generation retirements are assumed to occur starting in 2028, the Companies' evaluation of replacement generation would change in an RTO compared to operating on a standalone basis. Being in an RTO involves a change in mindset from having a fleet of physical generation assets to reliably serve load 8760 hours a year as a standalone utility to thinking in terms of financial risk management of both generation and load as independent activities. In an RTO, the Companies would be relying on a separate entity for managing reliability and dispatching the RTO's generation fleet to serve real-time load. At the same time, being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology because RTO membership may support higher levels of renewable penetration with lower integration costs.

12 Appendix A – Scenario Inputs

	Low Favorability Case	Mid Favorability Case	High Favorability Case
PJM			
Reliability Pricing Model (RPM)			
Base Load. All cases: Year 1 price is the historical incremental auction value to Base Residual Auction (BRA) ratio applied to the year 2 BRA value. Year 2 BRA price is median clearing price since the 2016/2017 planning year. UCAP for Ohio Falls hydroelectric and solar units reflect PJM ELCC factors. Dix Dam reflects year-round rating. MC2 assumed offline Apr-Oct each year through 2024. Base unit retirement schedule.	Low capacity clearance rates by fuel type.	Base capacity clearance rates by fuel type.	High capacity clearance by fuel type.
Energy Market Benefits – Assumed Price Forecast			
Base Load. All cases are based on Companies' electricity market price forecasts	Mid-range commodity prices.	High commodity prices.	Low commodity prices.
Transmission Expansion Costs			
	Annual expansion costs were increased from the Mid Case by compounded 14.8% per year for 10 years to reflect	Used PJM's "tcic" spreadsheet applied to forecasted load and project load-ratio share.	No change from Mid Case.

	potential large transmission grid build out to support renewable integration.		
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on 2020 state of the market reports submitted by PJM's market monitor.	Costs were reduced by 20% from the Mid Case.
Depancaking Expense			
	Increased to align with increased Transmission Expansion Cost included in Low Case	Based on current projections and assumption that only 26A would be reimbursed	Increased the Mid Case by 20% to reflect increased MISO transmission rates.
MISO			
Planning Resource Auction (PRA)			
Base Load. All auction prices reflect the median Planning Resource Auction (PRA) Zone 6 clearing price since the 2016/2017 planning year. Capacity clearance rates are based on aggregate Zone 6 figures, not fuel specific. UCAP for Ohio Falls hydroelectric reflects 42% capacity factor (as used for PJM, MISO did not specify capacity credit for intermittent hydro resources). Brown Solar UCAP reflects 38% capacity factor (as used for PJM, MISO did not specify	Low capacity clearance rates for Zone 6.	Base capacity clearance rates for Zone 6.	High capacity clearance rates in Zone 6.

capacity credit for fixed solar resources). All other Solar PPA capacity reflects MISO solar capacity credit. Dix Dam reflects year round rating. MC2 assumed offline Apr-Oct each year through 2024. Base unit retirement schedule.			
Energy Market Benefits – Assumed Price Forecast			
Base Load. All cases are based on Companies' electricity market price forecasts	Mid-range commodity prices.	High commodity prices.	Low commodity prices.
Transmission Expansion Costs			
	Annual expansion costs were increased from the Mid Case by compounded 14.8% per year for 10 years to reflect potential for large transmission build out to support renewables integration.	MISO published indicative annual charges for approved MVP applied to forecasted loads.	No change from Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on cost projections contained in MISO's 2020 revenue requirement forecast.	Costs were reduced by 20% from the Mid Case.
Depancaking Expense			
	Increased to align with increased Transmission Expansion Cost included in Low Case	Based on current projections	Increased the Mid Case by 20% to reflect increased MISO transmission rates.

13 Appendix B – Cost Analyses

The following tables show the cost and benefit components for all three favorability scenarios for each RTO. The market impacts are included for years 2023-2027, but are undetermined thereafter.

MISO Membership Cost Analysis - Low Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-17.8	-18.5	-19.1	-19.8	-20.5	-21.3	-22.0	-22.9	-23.7	-24.7	-25.6	-26.6	-27.7	-28.9
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-60.8	-69.0	-77.8	-87.9	-99.4	-112.8	-127.5	-144.4	-163.7	-186.1	-186.1	-186.1	-186.1	-186.1
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-89.8	**-98.7**	**-108.1**	**-118.6**	**-131.0**	**-145.1**	**-160.6**	**-178.5**	**-198.9**	**-222.3**	**-223.3**	**-225.1**	**-226.0**	**-227.7**

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Energy Market Benefits/(Costs)	6.5	7.5	8.6	8.6	9.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.0	1.1	1.2	1.3	1.3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.6	24.7	25.1	26.3	16.4	17.3	6.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	38.7	**39.9**	**41.7**	**43.0**	**34.5**	**24.3**	**13.8**	**7.6**	**7.8**	**7.8**	**7.8**	**7.8**	**7.9**	**7.9**

Net Benefits/(Costs)	**-51.1**	**-58.7**	**-66.4**	**-75.6**	**-96.4**	**-120.8**	**-146.8**	**-170.8**	**-191.2**	**-214.5**	**-215.5**	**-217.3**	**-218.1**	**-219.8**

MISO Membership Cost Analysis - Mid Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-14.8	-15.4	-15.9	-16.5	-17.1	-17.7	-18.4	-19.0	-19.8	-20.6	-21.4	-22.2	-23.1	-24.1
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-79.0	**-79.0**	**-78.5**	**-78.1**	**-78.0**	**-78.0**	**-77.9**	**-78.2**	**-78.5**	**-78.9**	**-79.1**	**-80.2**	**-80.4**	**-81.5**

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Energy Market Benefits/(Costs)	11.8	11.7	13.5	15.6	15.4	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.2	1.3	1.3	1.4	1.5	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.1	23.6	23.4	23.8	14.1	14.4	5.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	43.7	**43.2**	**45.0**	**47.6**	**38.0**	**21.4**	**12.3**	**7.6**	**7.8**	**7.8**	**7.8**	**7.8**	**7.9**	**7.9**

Net Benefits/(Costs)	**-35.3**	**-35.7**	**-33.5**	**-30.5**	**-40.0**	**-56.6**	**-65.6**	**-70.5**	**-70.8**	**-71.1**	**-71.3**	**-72.3**	**-72.5**	**-73.7**

MISO Membership Cost Analysis - High Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-11.9	-12.3	-12.7	-13.2	-13.7	-14.2	-14.7	-15.2	-15.8	-16.5	-17.1	-17.8	-18.5	-19.3
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-76.0	**-75.9**	**-75.3**	**-74.8**	**-74.6**	**-74.5**	**-74.3**	**-74.4**	**-74.6**	**-74.8**	**-74.8**	**-75.7**	**-75.7**	**-76.7**

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Energy Market Benefits/(Costs)	20.7	20.0	18.5	15.2	16.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.3	1.3	1.4	1.5	1.6	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	28.9	28.3	28.1	28.6	17.0	17.3	6.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	57.4	**56.2**	**54.7**	**52.1**	**42.4**	**24.3**	**13.3**	**7.7**	**7.8**	**7.9**	**7.9**	**7.9**	**7.9**	**8.0**

Net Benefits/(Costs)	**-18.6**	**-19.6**	**-20.6**	**-22.7**	**-32.2**	**-50.2**	**-60.9**	**-66.6**	**-66.7**	**-66.9**	**-66.9**	**-67.8**	**-67.8**	**-68.8**

PJM Membership Cost Analysis - Low Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-21.6	-22.1	-22.5	-22.9	-23.4	-24.0	-24.4	-25.0	-25.6	-26.3	-26.8	-27.5	-28.2	-29.0
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-22.3	-25.3	-28.4	-33.0	-37.0	-41.4	-46.4	-51.9	-58.0	-66.6	-66.6	-66.6	-66.6	-66.6
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-52.8	-55.7	-59.2	-64.1	-68.6	-73.5	-79.1	-85.3	-92.3	-101.5	-102.2	-103.7	-104.1	-105.4

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	7.0	8.2	8.8	8.6	10.1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	-4.8	-6.4	-6.7	-6.0	-4.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	20.9	20.1	20.0	20.4	11.9	12.2	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	29.7	28.6	28.8	29.9	24.0	19.2	11.4	7.6	7.8	7.8	7.8	7.8	7.9	7.9

Net Benefits/(Costs)	**-23.2**	**-27.1**	**-30.4**	**-34.2**	**-44.6**	**-54.3**	**-67.7**	**-77.7**	**-84.5**	**-93.7**	**-94.4**	**-95.8**	**-96.3**	**-97.6**

PJM Membership Cost Analysis - Mid Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-18.0	-18.4	-18.7	-19.1	-19.5	-20.0	-20.4	-20.8	-21.3	-21.9	-22.4	-22.9	-23.5	-24.2
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-19.4	-19.2	-18.8	-19.0	-18.5	-18.1	-17.7	-17.2	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-46.4	-45.9	-45.8	-46.2	-46.3	-46.2	-46.2	-46.5	-46.7	-47.3	-47.9	-49.2	-49.5	-50.7

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	10.5	12.1	12.6	13.9	14.0	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	4.2	6.7	6.9	7.5	8.6	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	20.9	20.1	20.0	20.4	11.9	12.2	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	42.2	45.6	46.2	48.7	41.5	19.2	11.4	7.6	7.8	7.8	7.8	7.8	7.9	7.9

Net Benefits/(Costs)	**-4.2**	**-0.3**	**0.4**	**2.5**	**-4.8**	**-27.0**	**-34.9**	**-38.8**	**-38.9**	**-39.5**	**-40.1**	**-41.4**	**-41.7**	**-42.9**

PJM Membership Cost Analysis - High Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-14.4	-14.7	-15.0	-15.3	-15.6	-16.0	-16.3	-16.7	-17.1	-17.5	-17.9	-18.3	-18.8	-19.3
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-19.4	-19.2	-18.8	-19.0	-18.5	-18.1	-17.7	-17.2	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-42.8	-42.2	-42.1	-42.4	-42.4	-42.2	-42.2	-42.3	-42.5	-42.9	-43.4	-44.6	-44.9	-45.9

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	20.9	21.0	17.8	16.3	17.5	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	12.6	18.5	18.8	19.3	20.4	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	25.1	24.2	24.0	24.5	14.3	14.6	5.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	65.2	70.3	67.3	67.0	59.1	21.6	12.2	7.7	7.8	7.9	7.9	7.9	7.9	8.0

Net Benefits/(Costs)	22.4	28.1	25.3	24.5	16.8	-20.6	-29.9	-34.6	-34.6	-35.0	-35.5	-36.7	-36.9	-38.0

14 Appendix C – Energy Market Benefits

The tables below show the projected incremental total energy market benefits to market sales revenues and costs to native load through 2027 of joining MISO and PJM compared to the Companies' current business plan across the low/mid/high commodity price forecast scenarios for each RTO. Negative figures reflect net benefits; positive figures reflect net costs.

MISO - Mid Load ($M)		**2023**	**2024**	**2025**	**2026**	**2027**
	Market Energy Sales	-151	-148	-148	-141	-138
	Native Load Cost	130	129	130	126	121
Low Commodity Prices	**Total**	-21	-20	-18	-15	-17
	Market Energy Sales	-243	-242	-231	-208	-188
	Native Load Cost	236	234	222	199	178
Mid Commodity Prices	**Total**	-7	-8	-9	-9	-10
	Market Energy Sales	-229	-239	-233	-210	-204
	Native Load Cost	217	227	219	195	189
High Commodity Prices	**Total**	-12	-12	-14	-16	-15

PJM - Mid Load ($M)		**2023**	**2024**	**2025**	**2026**	**2027**
	Market Energy Sales	-128	-138	-147	-153	-159
	Native Load Cost	107	117	129	136	142
Low Commodity Prices	**Total**	-21	-21	-18	-16	-18
	Market Energy Sales	-186	-202	-207	-201	-199
	Native Load Cost	179	194	199	192	189
Mid Commodity Prices	**Total**	-7	-8	-9	-9	-10
	Market Energy Sales	-248	-269	-269	-253	-254
	Native Load Cost	237	257	256	239	240
High Commodity Prices	**Total**	-10	-12	-13	-14	-14

15 Appendix D – Non-Quantifiable Considerations

Consideration	Stability	Description
Governance		
Stakeholder Process – Tariff Filings and Operating Decisions	Continues to Evolve and Change	Although the structures of the two RTOs differ, both RTOs have defined rules with respect to regulatory filing rights. This means that certain stakeholders have considerably more power than others to push RTO policy and RTO requirements.
Stakeholder Mix – Weighted Voting Rights	Continues to Evolve and Change	MISO has approximately 189 voting entities (of which 146 are members) in ten different stakeholder sectors with weighted voting rights, including but not limited to sectors for Transmission Owners, Marketers, Public Consumer Advocates, Environmental and other groups, and Transmission Developers. PJM has approximately 133 voting members in five different sectors for transmission owners, generation owners, retail end-use customers, electric distributors, and suppliers who do not qualify for any of the other four sectors.[44]
Policy Impact	Stable	The RTOs have demonstrated considerable impact on the creation and implementation of federal energy, environmental, and market policy. Whether or not the RTO position aligns with the interests of the Companies and their customers would determine whether an RTO will be an effective advocate or a complicating hurdle in managing an evolving federal regulatory landscape. Given the diversity among stakeholders and their and the RTO's own interests, alignment cannot be assumed.
FERC Oversight of Tariff and Markets	Continues to Evolve and Change	Although FERC review of RTO tariff filings is subject to the statutory authorities conveyed in the Federal Power Act, the implementation of this statutory authority to further federal policy objectives continues to evolve. The PJM and MISO tariffs, including the market rules and requirements, are complex, and some of the most significant changes in

[44] Because of the size of the Companies, it is unlikely that the Companies would fall into the small group of stakeholders able to essentially unilaterally move or strongly influence RTO policy. Therefore, simply joining an RTO would eliminate a significant amount of the control that the Companies have to manage costs and operations to the benefit of their customers.

		RTO tariffs are often driven by FERC initiative and mandate rather than stakeholder proposals.[45]
Markets		
Market Structure	Continues to Evolve and Change	Market structure and market prices administered by RTOs are subject to change over time from various drivers, including FERC-directed market changes (which can include such things as changes to market compensation structures, performance requirements, and participant responsibilities), stakeholder initiatives, independent market monitor recommendations, or actions from the RTOs themselves.[46] The PJM MOPR dispute, the MISO's strategic initiatives as documented in the MISO Forward report and integrated roadmap, and the efforts of both RTOs to integrated energy storage technology and develop new reserve products are illustrative of this continuing evolution.
Default of Other Market Participants	Unpredictable	See Section 3.2
Misconduct of Other Market Participants	Unpredictable	Entities' market activities designed to suppress or inflate market prices can directly impact other market participants' opportunities and market performance. Although there are processes at FERC to disgorge amounts if there is a finding of unlawful manipulation, recovery of disgorged profits is not guaranteed and takes significant time.[47]

[45] For example, in February 2018, PJM presented two alternatives for a rule change to FERC and requested the Commission determine between these alternatives the appropriate approach since PJM, its market monitor, and its stakeholder committee members were unable to agree. FERC rejected both proposals in June 2018 and recommended PJM pursue a third alternative.

[46] *See, e.g.,* FERC's notice convening technical conferences, titled *Modernizing Electricity Market Design*, in FERC Docket No. AD21-10. The technical conferences are intended to discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time.

[47] *See e.g.*, *Virginia Electric & Power Company, d/b/a Dominion Energy Virginia (DEV)*, Docket No. IN19-3-000, Order Approving Stipulation and Consent Agreement, 167 FERC ¶61,103 (2019), in which DEV was assessed a civil penalty of $7 million and required to disgorge $7 million in profits due to the FERC's finding that DEV had violated market manipulation prohibitions by allegedly improperly targeting and increasing its receipt of lost opportunity cost credits; *PSEG Energy Resources & Trade, LLC*, Docket No. IN18-4-000, Order Approving Stipulation and Consent Agreement, 163 FERC ¶61,022 (2018), in which PSEG was assessed a civil penalty of $8 million and required to disgorge approximately $27 million in profits and $4.5 million in interest due to the FERC's finding that PSEG had violated market manipulation prohibitions by allegedly submitting incorrect cost-based offers into the PJM market.

Market Maturity	Continues to Evolve and Change	With the recent MOPR order, the future of PJM's RPM is uncertain. The MISO PRA underwent reforms to create External Resource Zones to allocate excess auction revenues to Load Serving Entities impacted by changes to MISO's resource adequacy construct through Historic Unit Considerations, and align parameters used to calculate auction inputs such as import and export limits and Local Clearing Requirements with the use of these limits in the PRA.[48] In addition, the MISO Forward report and integrated roadmap include several market reform initiatives to accommodate the changing composition of MISO's market.
Market Efficiency	Continues to Evolve and Change	PJM issued a Problem Statement in 2017 identifying a concern that the current Locational Marginal Prices ("LMP") do not accurately represent the true incremental cost of generation or send the right price signals. Over the course of 2018 PJM developed a proposal to address this concern[49] resulting in a tariff filing with the FERC in March of 2019.[50] FERC has yet to issue an order on the filing. One of the key areas of focus identified by MISO in 2019 was the Resource Adequacy and Need initiative, to identify near-term solutions to increase the conversion of committed capacity resources into energy during times of need.[51]
Future Costs and Cost Allocation		
Cost Allocation	Continues to Evolve and Change	Cost allocation methods are periodically revisited and can potentially change in the future. An individual RTO member has little control over cost-related decisions and challenges to those decisions can be lengthy and unproductive.[52]
Transmission Expansion Costs	Continues to Evolve and Change	RTOs have seen consistent growth in transmission projects and development. In RTOs, determinations as to whether projects are built

[48] *Midcontinent Independent System Operator, Inc.,* Docket Nos. ER18-1173-000 and ER18-1173-001, 164 FERC ¶ 61,081 (2018).

[49] Price Formation: Energy Price Formation Senior Task Force, PJM Interconnection, December 14, 2018, https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx

[50] *PJM Interconnection, L.L.C.*, Docket No. EL19-58.

[51] https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

[52] For example, *see supra* fn 15 describing the Linden VFT, LLC RTEP project cost dispute with PJM. See also Section 7.1.1 above, in particular footnote 14, regarding evolving cost allocation discussions in MISO for transmission expansion projects identified in its Long-Range Transmission Plan (LRTP) process.

		and who bears the costs associated with the projects are subject to still-evolving RTO rules.[53] In addition, federal and state policy on transmission expansion and cost allocation continues to evolve and is uncertain.[54] In both RTOs, load is typically assigned some, if not most or all, of the costs associated with transmission expansion. Factors that trigger the need for projects, how those projects are designated, who is awarded the option to build, and the percentage of expansion cost assigned locally rather than across the RTO footprint is governed by the RTO's tariff and transmission planning processes. Individual transmission owners within an RTO have limited power to control these costs.[55] However, the Companies will be required to comply with the results of the ANOPR proceeding at FERC regardless of whether they are in an RTO or not, thus there is presently considerable uncertainty in the industry generally regarding transmission planning and cost allocation.
Planning and Operational Control		
Functional Control of Generation Assets	Stable	RTO integration requires the Companies to transfer functional control of their transmission system to an RTO in addition to committing the Companies' generation assets and load to participation in the RTO administered markets. The transfer of control and commitment of generation means that the RTO makes both planning and operating decisions for the Companies' assets that affect reliability, asset performance and longevity, and costs borne by load. This extends to the

[53] MISO changed aspects of its transmission cost allocation in 2003, 2007, 2009, and 2012, and recently started another stakeholder project to review cost allocation. In 2018, PJM changed the cost allocation for certain regional and lower voltage facilities included in RTEP to provide that one half of the costs of these facilities would be allocated on a load-ratio share basis and the other half of the costs allocated based on the solution-based distribution factor (DFAX) method. *PJM Interconnection, L.L.C.*, Docket Nos. ER18-579-000 and ER18-579-001.

[54] *See, e.g.,* FERC's issuance of an Advance Notice of Proposed Rulemaking, titled *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, in FERC Docket No. RM21-17-000 (July 15, 2021) (the "ANOPR").

[55] *See, e.g.,* FERC's approval of the PJM filing associated with the assignment of cost responsibility for 39 baseline upgrades from the 2017 Regional Transmission Expansion Plan, rejecting a challenge to the allocation of several projects by Old Dominion Electric Cooperative who had argued that PJM provided an inadequate basis for the allocation. FERC approved PJM's use of a proxy in assigning the costs entirely to the local zone. *PJM Interconnection, LLC*, 161 FERC ¶ 61,190 (2017).

		approval of outages and maintenance, determinations impacting fuel supply and fuel supply arrangements, and dispatch decisions.
Drivers Behind Generation Dispatch Decisions	Unpredictable	See Section 3.2.
Transmission Planning	Continues to Evolve and Change	Transmission Owners and Transmission Planners in an RTO are subject to the RTO's transmission planning criteria. Although some limited authority remains with the Transmission Owners and Transmission Planners, the RTO would be the Planning Authority for the region and planning studies would need to conform to the RTO's criteria. Transmission Owners who integrate into an RTO assume an obligation to build in accordance with the applicable RTO's tariff and agreements.
Other/Optional Upgrades	Continues to Evolve and Change	In RTOs, market participants and transmission developers are able to propose and build transmission projects that do not otherwise pass transmission-planning criteria in order to obtain Financial Transmission Rights.
Right of First Refusal	Continues to Evolve and Change	FERC directed transmission providers to eliminate provisions in FERC jurisdictional tariffs and agreements that granted incumbent Transmission Owners a right of first refusal to transmission facilities in their respective service territories or have a right to build regional transmission projects when the costs of those projects would be assigned to the incumbent's load.
Resource Adequacy	Continues to Evolve and Change	The PJM states are deregulated, with the RTO setting resource adequacy requirements and procuring capacity through auction to meet projected need. MISO states, on the other hand, have typically been regulated, with state commissions setting resource adequacy. Both PJM and MISO have fixed resource plans that allow a load serving entity to demonstrate that it has designated capacity to meet all or a portion of its load and reserve requirements.
Regional Operations	Stable	RTOs are able to leverage resources and redispatch options across a broad region, which may provide efficiencies and flexibility in mitigating operating issues and resource optionality.

Regional Coordination	Stable	Integrated operations across the different Transmission Owner systems within the RTO region is well established and centralized operations and formal dispute processes have eliminated many of the coordination issues between systems within the RTO.
Interregional Coordination	Continues to Evolve and Change	Interregional coordination between the RTOs and neighboring external systems is structured but also subject to frequent litigation and change. Issues along the RTO seams, both between markets and between markets and non-RTO areas, remain problematic, and any integration that may change or impact an existing seam is likely to pose additional issues that would require resolution.
Competitive Transmission	Continues to Evolve and Change	Development of transmission for which the costs are regionally allocated is a competitive process in RTOs, although little results have been seen by way of competitive transmission projects in RTOs to date. The types of transmission projects subject to competitive bidding requirements in the RTOs continues to evolve. In 2019, FERC instituted a proceeding to require PJM to include projects needed to meet local transmission planning criteria in the competitive bidding process.[56]

[56] *PJM Interconnection, L.L.C.*, Docket No. EL19-61-000, 168 FERC ¶ 61,132 (2019).

Compliance		
Compliance Program Costs	Continues to Evolve and Change	An analysis of the NERC Compliance impact of RTO membership found the impact to be cost-neutral, with a slight potential that it could actually increase compliance costs. Although responsibility for compliance with some standards and requirements is transferred to the RTO, the member companies retain responsibility for most compliance, and may still be required to provide evidence of compliance with standards for which the RTO is responsible.
Audits	Stable	Membership in an RTO does not alleviate any of the burden and expenses related to periodic audits. Member companies would still be subject to periodic regulatory audits by the regional entity and may also be subject to additional audits by the RTO to ensure compliance with standards and RTO-specific manuals or processes.
Fines and Penalties	Unpredictable	For any fines and penalties that result from the failure of a member to comply with a standard or requirement, the cost of the fine is allocated back to that member. For any fines or penalties assessed based on the RTO's failure to comply, the cost of the penalty is allocated to all member companies. For any violations where the RTO assigned responsibility for the standard or requirement, or there is joint responsibility between the RTO and the member company, the RTO retains all control over decisions to self-report and negotiate penalties.
Exit Fees		
Costs to Exit	Stable	MISO's and PJM's transmission owner agreements provide a mechanism for a transmission-owning member of either RTO to withdraw from the RTO. The notice period and requirements of such withdrawals vary with the RTOs, but both contain language that the withdrawing member shall remain liable for obligations undertaken while under the respective RTO agreement.[57]

[57] As the Companies experienced with its MISO withdrawal in 2006, exiting an RTO can be complex and time consuming, and may result in a significant level of financial obligation.