2020 RTO Membership Analysis
March 2020

Contents

1 Executive Summary

This analysis was performed to update the 2018 RTO Membership Analysis and determine whether membership in the Midcontinent Independent System Operator ("MISO") or the PJM Interconnection ("PJM") Regional Transmission Organizations ("RTOs") may provide potential benefits to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively "Companies") retail and wholesale requirements customers.

As in the 2018 analysis, a cross-functional team was organized to evaluate the major costs, benefits, opportunities, and uncertainties of RTO membership as compared to the status quo operations of the Companies.[1] The team started with confirming that the components expected to have financial impacts in the 2018 analysis continued to remain the correct components to address in the updated quantifiable analysis. It was determined that it was appropriate to perform the updated quantifiable analysis using mostly the same components, subject to some minor revisions in the underlying assumptions associated with those components as described below.[2] 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 below, and an updated list and brief summary of non-quantifiable considerations is appended hereto.

The Companies' 2018 RTO Membership Analysis indicated that membership in MISO or PJM was not beneficial at that time. While the quantifiable results vary slightly from 2018, this updated analysis concludes that the costs and uncertainties of membership in either MISO or PJM continue to exceed the known potential benefits. Furthermore, the updated analysis, including several non-quantifiable considerations, demonstrate that periodically reevaluating the potential costs or benefits of RTO membership in the future continues to have merit.

---

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

[2] As described in more detail below, the updated review excluded the consideration of certain transmission "depancaking" arrangements for certain customers exporting to or importing from MISO. In addition, variability in coal pricing was included in the fuel prices evaluated as an enhanced consideration to the commodity pricing discussion in the trade benefits analysis to better reflect the impact that volatility in this area has in trade optimization.

2 Objective

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 membership analysis, RTO membership includes transferring functional control of transmission assets and mandatory participation by the Companies' generation and load in the various markets administered by the RTO.

3 Background

The Companies were founding members of MISO, operating within MISO from 2002 until September 1, 2006, when the Companies terminated their MISO membership in accordance with the determination of the Kentucky Public Service Commission ("Commission") authorizing the withdrawal.[3] While the Companies are no longer members of MISO, the Companies are market participants in, and regularly transact in, both RTOs.

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. Most recently, the Companies submitted the 2018 RTO Membership Analysis as Exhibit LEB-2 to Lonnie E. Bellar's direct testimony in base-rate cases filed with the Commission in September 2018.[4] On April 30, 2019, the Commission issued an Order in these base-rate cases that required the Companies to update the studies annually and file such updates with the Commission. Accordingly, the Companies completed an updated review and are submitting this report in response to the Commission's Order. This report is modeled after the 2018 RTO Membership Analysis and updated to reflect the best available data at the time of the updated analysis.

[3] In 2003, the Kentucky Public Service Commission ("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).

[4] In the Matter of: *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* Case No. 2018-00294 and *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295.

4 Methodology

After reviewing the methodology used in the 2018 RTO Membership Analysis and the status of developments in the RTOs over the last year, the Companies determined that it was appropriate to use the same methodology as was used in the prior analysis with updates to the different component to reflect RTO operational changes and other new information.

This is a ten-year analysis focused on estimating the net financial impact to customers by comparing the status quo operations of LG&E and KU to estimated incremental benefits and costs of RTO membership. As with the 2018 analysis, the team developed and studied three scenarios using different projections and assumptions to provide a range of potential outcomes. The High Case uses assumptions most supportive of RTO membership, such as lower administration costs, higher trade benefits, and higher capacity prices, and lower transmission expansion costs. The Mid Case uses assumptions and forecasts reflective of limited volatility using published forecasts for administration costs, historic market performance information, 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 and volatility by assuming poor market performance and increased costs. Appendix A contains a description of the methodology used to develop the underlying assumptions that differ between the three scenarios

Although the scenarios apply the underlying assumptions across all ten years, it is possible that actual performance across the ten-year 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 ten years, not to say that there are only three sets of possible outcomes.

5 Key Assumptions and Methodology

- The time period of the analysis was 2022 through 2031. A 10-year term is consistent with the term used in the 2018 analysis and the term analyzed in association with other analyses provided to the Commission.
- The total financial impact of Firm Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), and congestion costs over the ten-year 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 trade benefits using their commodity price forecasts, generation available for sales, and native load forecasts used for annual business planning.
- The Companies did not use generator-specific or load-specific Locational Marginal Pricing ("LMP") models.
- The Companies assumed that no changes to the Companies' generating fleet occur during the analysis time period. However, as the Companies develop least-cost compliance plans for environmental regulations, including the Effluent Limitations Guidelines, the Affordable Clean Energy Rule, and the National Ambient Air Quality Standards, the Companies' generating fleet may change. If retirements occur, the trade and capacity benefits included in this report would also change, depending on the amount and nature of any replacement capacity.
- 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.
- Merger mitigation depancaking ("MMD") costs are excluded from the analysis. While the MMD arrangements were treated as costs for the purpose of the 2018 analysis, the Federal Energy Regulatory Commission ("FERC") granted the Companies' request to eliminate the MMD obligation.[5] While the elimination of MMD is subject to the implementation of a transition mechanism not yet accepted by FERC,[6] it was determined that these costs should not be a material consideration in evaluating the potential benefit of RTO membership as such membership will likely not be determinative as to the elimination of these costs.
- Generating capacity above the RTO Planning Reserve Margin results in a benefit and is quantified in the Capacity Auction Benefits.
- 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 change in overall headcount.
- No financial impacts from deviations between day ahead and real time energy markets, operations, and load are included in the analysis.

[5] *Louisville Gas and Elec. Co., et al.,* 166 FERC ¶61,206 (2019), *order on reh'g*, *Louisville Gas and Elec. Co., et al.,* 168 FERC ¶61,152 (2019).
[6] *See, Louisville Gas and Elec. Co., et al.,* 168 FERC ¶61,151 (2019).

6 RTO Cost Components

6.1 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.

- For MISO membership, the Companies' annual costs would range from $48 million to $53 million in the Mid Case.
- For PJM membership, the Companies' annual transmission expansion costs would range from of $11 million to $13 million in the Mid Case.

6.1.1 MISO

Under current MISO policy, the cost of new transmission projects that address energy policy or provide widespread benefits across the footprint are considered "multi-value projects" ("MVP"). The cost of MVP are allocated 100% to load in the northern and Central regions of MISO using a "postage stamp" methodology, i.e., all load pays the same rate for MVP irrespective of where the load is located in the applicable footprint, and are recovered under Schedule 26A of the MISO Tariff.[7] LG&E and KU's estimated share of the roughly $6.6 billion in MVP projects currently identified in the MISO Transmission Expansion Planning ("MTEP") process is based on the "indicative annual charges for approved MVP" published on the MISO website applied to the Companies' forecasted loads.[8]

The annual expansion 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. There could be transmission expansion costs allocated to the Companies' loads beyond MVP cost. Local transmission reliability planning is only one of several transmission planning objectives that can drive transmission expansion costs in MISO.

6.1.2 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 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. Of note, in this analysis the Companies'

---

[7] *See*, MTEP19, Executive Summary, at p. 7, https://cdn.misoenergy.org//MTEP19%20Executive%20Summary%20and%20Report398565.pdf

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

used PJM's RTEP project information, dated October 2019. There were significant differences in the cost allocation in PJM's October 2019 information as compared to the March 2018 data provided by PJM and used in the 2018 RTO Membership Analysis. Because of the changes made in the cost allocations in the updated information from PJM, this analysis reflects a large decrease in the projected transmission expansion costs associated with PJM membership.

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 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. The cost allocation for RTEP projects in PJM is subject to the potential for periodic revision and reallocation based on changes in flow[9] and other cost allocation factors.

6.2 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. The RTOs are expecting their administration costs to increase between 1% to 2.5% each year.

MISO forecasts administrative rate increases around 1% based on expected savings from reduced spending, closing the Metairie office, and other efficiencies. MISO annual cost in the Mid Case is $14 million beginning in 2022 and increases to $15 million by 2031. MISO's 2019 forecasted administrative rate for 2020 was escalated 1% 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 2019 revenue requirement forecast.

PJM annual cost in the Mid Case is $18 million beginning in 2022 and increases to $22 million by 2031. The Companies based these estimates on 2018 state-of-the-market reports submitted by PJM's market monitor. The 2018 rates were then escalated 2.5% each year. For the period 2013 through 2018 PJM's rates have increased by an average of 2.3%, in line with PJM's expected rate of around 3%.

Although revenue requirements for administrative costs are expected to increase around 1% to 3% 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

[9] *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.

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.

6.3 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 million per year, while PJM uplift is expected to average just over $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. The Companies used an average rate of $0.17 for this study to account for potential market volatility. The study rate is the average of 2018 and 2019, and the same rate used in the 2018 analysis.

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, while 2018's uplift cost was $0.23 per MWh. The Companies used MISO's 2018 rate for this study to be consistent with the time 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.

6.4 Lost Transmission Revenue

The analysis reflects an expected decrease in the sale of point-to-point transmission service resulting from RTO membership, and this lost revenue is included in the analysis. The forecasted lost annual revenue ranges from $2.2 to $4.0 million.

6.5 Lost Joint Party Settlement Revenue

An additional $1.4 to $1.6 million of lost revenue was also included because of the existing settlement agreement between MISO, SPP, and the Joint Parties (including the Companies). This joint party 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.

6.6 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 to $2 million per year, similar to the assumption used in the 2018 RTO Membership Analysis. 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.

7 RTO Benefit Components

7.1 Trade Benefits

The Companies estimated trade benefits using the Companies' existing planning models, which required only minimal changes to estimate the trade benefit components. These models are of the Companies' system; they are not RTO-wide regional models. An analysis using a complete RTO-wide regional market model may be advisable before making any decision to join an RTO based on expected trade benefits. The results of this analysis do not support incurring the expense of such further market analysis at this time.

The Companies used their production cost software tool, PROSYM, to forecast the potential trade benefits 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. The following model revisions were made to PROSYM to reflect RTO membership for purposes of this forecast:

- 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 329 MW in the business plan to 225 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 $0.52/MWh with an average annual increase of 3%. Initial RTO expenses (Peak: $0.48/MWh, Off-Peak: $0.43/MWh, Weekend: $0.32/MWh) were in 2019 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 $1.38/MWh with an average annual increase of 1%. Initial RTO transmission rates (Peak: $1.29/MWh, Off-Peak: $1.29/MWh, Weekend: $1.29/MWh) were in 2019 dollars and reflect the current rates as of the 2020 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 $4.74/MWh with an average annual increase of 1%. Initial

LG&E-KU transmission rates (Peak: $6.08/MWh, Off-Peak: $2.95/MWh, Weekend: $2.95/MWh) were in 2019 dollars and reflect the current rates in the 2020 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 $0.11/MWh with an average annual increase of 2%.
- **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 $2/MWh hurdle can be achieved. Under the RTO analysis, this hurdle rate is eliminated.

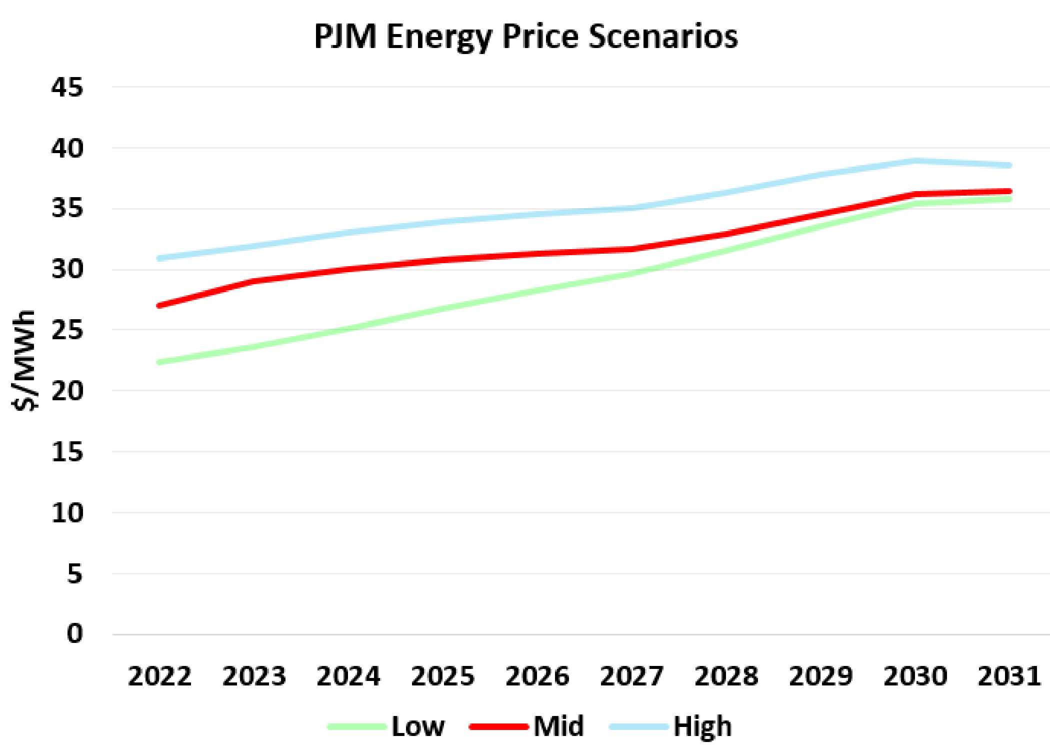
The PJM and MISO analyses used a range of commodity prices: low, mid, and high fuel price forecasts for the Companies' generation units and the corresponding low, mid, and high electricity price forecasts specific to each RTO. The table below summarizes the minimum and maximum estimated annual net trade benefits over the ten-year period of 2022-2031.

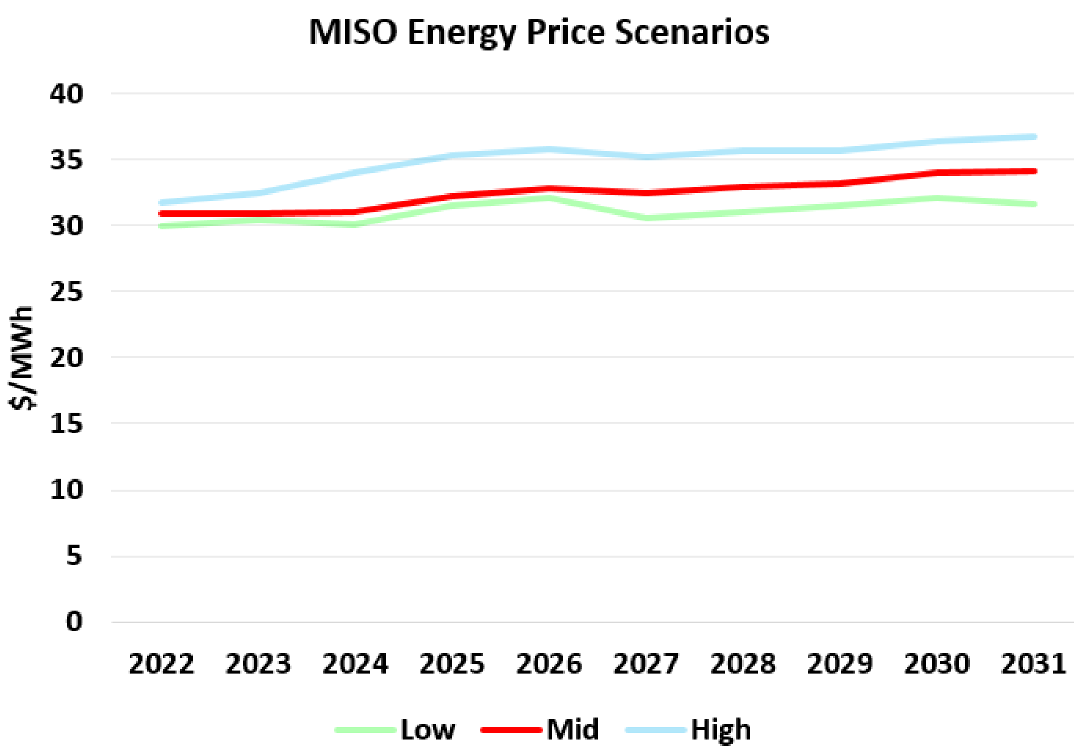
Range of Annual Net Trade Benefits ($ millions)						
	Low Benefit		Mid Benefit		High Benefit	
	Min	Max	Min	Max	Min	Max
PJM	4	14	6	14	10	20
MISO	6	9	7	12	11	21

As detailed in Appendix C, the net trade benefits 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 the Companies' business plan. In all scenarios, the estimated benefit of additional energy sales margin was greater than the additional cost of purchasing market energy for native load. In the 2018 RTO Membership Analysis high fuel prices and high electricity prices were aligned to create the most favorable trade benefit and reflected in the High Case. In this updated analysis, in most forecasted years, the net benefit was most favorable with high commodity prices and least favorable with low commodity prices. However, in some years the unfavorable impact of high fuel prices more than offset the favorable impact of high electricity prices (and vice versa). As a result, high electricity prices and high fuel prices did not always result in the most favorable trade benefit. As such, the High benefit case will not always be reflective of high electricity prices and high fuel prices. Instead, the most favorable trade benefit results in every year were placed in the High Case and least favorable placed in the Low Case and so forth.

As noted in the prior analysis, trade benefit 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 performance. They may also be indirectly influenced by many external factors, including state and federal policy.

The following charts display the low, mid, and high market energy price forecasts used in the analysis for PJM and MISO.





7.2 Capacity Auction Benefits[10]

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 market constructs for both RTOs remain in flux.

A protracted dispute over PJM's minimum offer price rule (MOPR) has resulted in lengthy suspension of the PJM capacity auction.[11] FERC's recent order requiring modifications to PJM's MOPR has resulted in significant pushback from several states and participants within PJM and is current under rehearing. PJM filed tariff modifications and auction timelines on March 18, 2020 in response to the MOPR order. The tariff modifications are open for comment through April 22, 2020 and the Commission is not likely to act on the tariff modifications until 60 days after its filing so the full impact of these changes cannot yet be estimated.

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 a number of potential modifications to MISO market

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

[11] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-pjm-message-regarding-suspension-of-rpm-base-residual-auction-activities-and-deadlines-until-further-notice.ashx?la=en

design, resource requirements, and incentives that may or may not come to fruition during the period of time studied in this analysis.

The state of uncertainty and evolution for both markets, means that there is inadequate information available to incorporate a consideration of future market construct changes into the updated analysis. As such, the Companies decided to use the same methodology for evaluating capacity auction benefits as was used in the 2018 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 of 17 percent to 25 percent.[12] Therefore, to the extent that the Companies forecast their reserve margin to be above the RTO target, the potential exists to sell capacity into the RTO capacity auctions. This analysis evaluates the potential value of capacity available for auction within both the PJM and MISO capacity market constructs assuming the following:

- Forecasted demand based upon normal weather and other economic assumptions,
- Capacity less the forecasted load obligation is assessed for value in the market,
- The Companies' capacity offered into the capacity market may not clear at 100 percent, and
- Capacity pricing is consistent with historical auction results.

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

7.2.1 PJM Reliability Pricing Model ("RPM")

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

- Installed Capacity ("ICAP")[13] – excludes small-frame combustion turbines,[14] Curtailable Service Rider ("CSR") load, and Demand Conservation Program ("DCP"),[15]

---

[12] The Companies' planning reserve margin for 2022 is 24.7%, excluding the proposed 100 MW solar PPA. Excluding the Companies' capacity resources and demand conservation programs that would not qualify for the RTOs' capacity markets (small-frame CTs, Curtailable Service Rider ("CSR") interruptible capacity, and Direct Load Control ("DLC")), the Companies' 2022 reserve margin is 19.9%.

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

[14] The Companies have five 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.

[15] 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.

but includes capacity available through the Companies' ownership share of Ohio Valley Electric Corporation ("OVEC").

- Unforced Capacity ("UCAP")[16] – 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 to the average of their winter and summer ratings.[17]
- Cleared Capacity – three levels of capacity clearance rate were considered based on PJM's historical capacity clearance rate by fuel type.
- Capacity Need – based upon the Companies' joint system peak using the business plan base load forecast, adjusted for 1) peak diversity between LG&E and KU and PJM RTO based upon a normal weather year and 2) PJM's applicable Forecast Pool Requirement factor.
- Capacity Prices – three capacity price cases representing low, mid, and high price ranges were examined against a base load forecast for the analysis period.

7.2.2 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,[18] but includes capacity available through the Companies' ownership share of OVEC.
- UCAP – same as PJM UCAP input.
- Cleared Capacity – all capacity bid is assumed to clear the auction given MISO's Zone 6 historical clearance rate for all resource types.[19]
- Capacity Need – based upon the Companies' joint system peak using the business plan base load forecast adjusted for 1) normal weather peak diversity between LG&E and KU and MISO, 2) MISO's UCAP planning reserve margin, and 3) MISO's transmission loss factor.
- Capacity Prices – same as PJM Capacity Prices inputs.

7.2.3 Projected Results

For both RTOs, capacity available to auction is estimated as a function of cleared UCAP minus Capacity Need. With no plans for resource additions or retirements over this review

[16] 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)].

[17] PJM Manual 18: Capacity Market," Section 5.4.1; *see*: http://pjm.com/-/media/documents/manuals/m18.ashx?la=en

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

[19] MISO data summarized at the zonal level without specificity by fuel type.

period, installed capacity, and consequently unforced capacity, remains relatively flat across the planning period. Peak loads are also relatively flat across the period. As a result, it is possible that the Companies could have a consistent amount of capacity, above the amount they would need to purchase to serve load, available to offer into each RTO's capacity auction, although the level of availability differs due to each RTO's reserve margin requirements.

Even though the Companies may have a consistent amount of 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 83% to 91% of coal capacity offered since the 2016/17 auction. For natural gas capacity, this range is 95% to 97%.

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. Therefore, under the MISO capacity auction construct, 100% of capacity offered is assumed to clear the auction.

Across all price cases, the calculated annual capacity value for PJM's RPM ranges from ($1M) to $40M annually.[20] For MISO, with a more limited auction history and typically significantly lower auction clearing price results, the calculated annual capacity value ranges from $0.2M to $14M across all price cases.

7.2.4 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

[20] A limited evaluation of the Fixed Resource Requirement alternative offered by PJM to meet Capacity Performance found that option to be within this range of alternatives as well.

function of the net cost of new entry ("CONE") for the particular delivery area in which the resource is located, based upon PJM's modeling. For 2021/22, this rate is estimated to be $3,660 per MWh.[21] As an 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 in excess of $2M.[22]

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.[23] 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 2020/21 planning year is $240.49 per MW-day.[24] Though this analysis does not quantify these non-performance charges, the risk associated with non-performance is significant.

7.3 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

---

[21] Non-Performance Charge Rate estimated using the value of net CONE for PJM Zone 6 which includes EKPC and DEOK.

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

[23] 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.

[24] Non-Performance Charge Rate estimated using the value of net CONE for MISO Zone 6 Indiana and the northwestern portion of Kentucky, which includes BREC, DUK(IN), and SIGE.

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.

7.4 FERC Charges

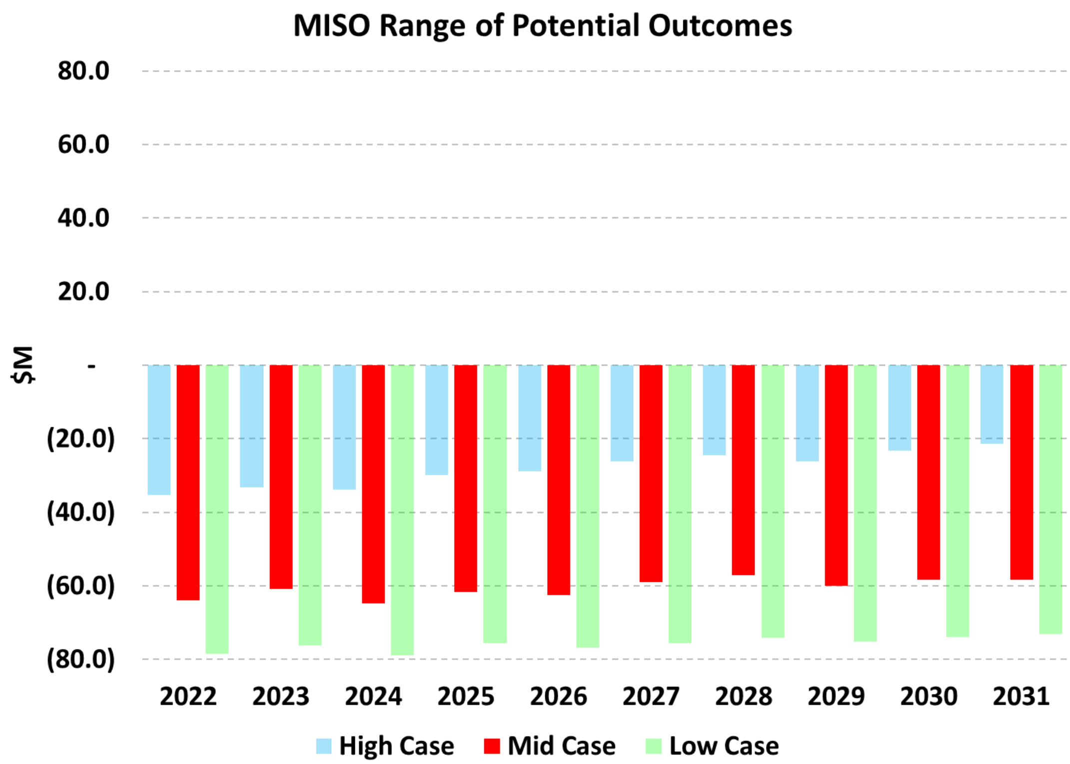
Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as the Companies are assessed outside of an RTO. For this analysis, the projected FERC assessment charges were included in RTO administrative charges. The amount that the Companies currently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

7.5 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.

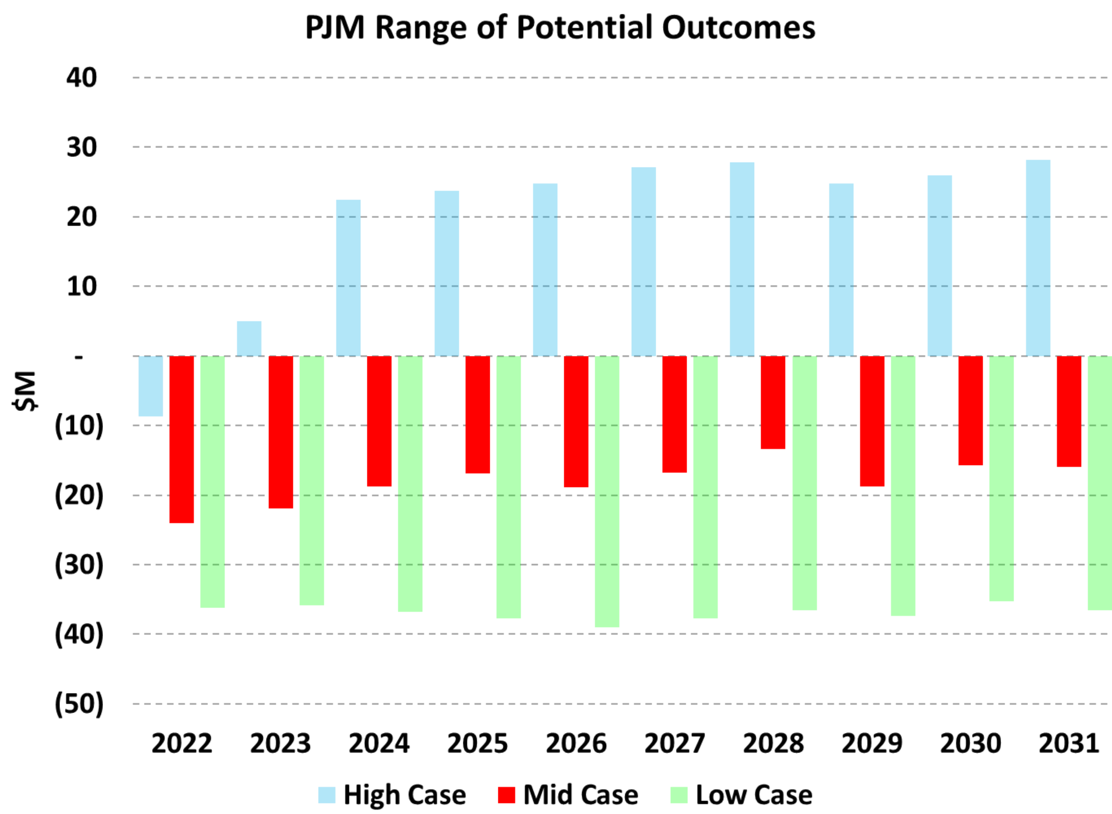
8 Quantitative Results

The following charts display the values for all three cases (Low, Mid, High) by year for both MISO and PJM (See Appendix B for detailed annual values):



The MISO membership analysis indicates an expected net cost each year for the entire ten-year term in all three cases. Of note, in this updated analysis the MISO High Case does not indicate net benefits in any year. This difference in results as compared to the 2018 RTO Membership Analysis reflects a significant reduction in potential trade benefits. It also reflects the removal of MMD as a consideration in the analysis as a result of the FERC order allowing for the termination of MMD. Exclusion of the MMD costs as a benefit of RTO membership is appropriate because, while the elimination of MMD is subject to the implementation of a transition mechanism not yet accepted by FERC,[25] the Companies have received approval to terminate these costs completely independent from any RTO membership arrangements. As such, the inclusion of MMD elimination as a benefit of RTO membership unduly inflates the value of that membership as such membership is not the cause of the elimination of these costs.

[25] *See, Louisville Gas and Elec. Co., et al.,* 168 FERC ¶61,151 (2019).



The wide range of potential high and low outcomes annually in the PJM membership analysis results is indicative of the uncertainty involved. While the range of difference between the Low and High Case results is narrower than what was seen in the 2018 RTO Membership Analysis, it remains a significant indicator of the risks involved in relying on either of the two outlying cases as a basis for any determination. The results of the Mid Case present a more reasonable basis for reviewing the net value of membership. Notably, that case indicates a net cost of PJM membership for all ten years studied.

9 Risk & Uncertainty

The decision to join an RTO is a significant 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 their customers. Fundamentally, it is a decision to transfer functional control to the RTO and participate in 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.[26] 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 costly to reverse.

Although this report quantifies projected potential benefits and costs of integration into the RTOs utilizing available data and assumptions to anticipate financial impacts, the estimates of potential benefits in this analysis are uncertain. Numerous external factors can and will impact pricing in the RTO markets, including fuel costs, weather events, load reductions, incremental resource additions, transmission performance, changes in suppliers, forced or unplanned outages, and federal policy and regulatory changes (e.g., changing environmental regulations or FERC-directed changes in market compensation or requirements). 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, and a transmission owner. Therefore, the potential for material changes and unanticipated costs, as well as the uncertainty of any potential benefits, should be considered in making a decision to integrate. Though the Companies focused on quantifiable elements in performing this analysis, certain non-quantifiable considerations were also reviewed. An initial list of non-quantifiable considerations that would need to be considered further before integrating into an RTO are provided in Appendix D.

10 Conclusion

The current analysis does not indicate net benefits from RTO membership within the timeframe analyzed. In addition, downside risk is estimated to outweigh upside opportunities. As anticipated in the 2018 RTO Membership Analysis, evaluating the potential benefits with updated information has resulted in slightly different results. Considering the continuing evolution of the RTOs, their markets, and membership, it would be prudent to continue to monitor and study the RTOs to see how market dynamics and uncertainties evolve over time. Therefore, RTO membership is not recommended at this time; however, the Companies will continue to monitor RTO operations and periodically refresh this analysis.

---

[26] 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.

Appendix A – Scenario Inputs

	Low Case	**Mid Case**	**High Case**
PJM			
Reliability Pricing Model (RPM)			
All cases: Year 1 (2019/2020) uses estimate of incremental auction value based upon historical ratios to BRA. Capacity clearance rates for hydroelectric and solar units of 100%.	Price constant at 2016/17 auction value (lowest value since 2016/17). Capacity clearance rate for coal- and gas-fired based upon average clearance rate since 2016/17 auction from Year 2 forward.	Price constant at average of results for 2016/17-2021/22 auctions from Year 2 forward. Capacity clearance rate based upon the highest observed for coal- and gas-fired unit clearance rate since 2016/17 auction.	Price constant at 2018/19 auction value (highest value since 2016/17). Capacity clearance rate of 100% for all resource types.
Trade Benefits – Assumed Price Forecast			
All cases are based on Companies' electricity market price forecasts	Least beneficial combination of electricity market price forecast and fuel price forecast	Mid-range for Companies' electricity market price forecast and fuel price forecast	Most beneficial combination of electricity market price forecast and fuel price forecast
Transmission Expansion Costs			
	Annual expansion costs were increased by 20% from the Mid Case.	Used PJM's "tcic" spreadsheet applied to forecasted load and project load-ratio share.	Annual expansion costs were reduced by 20% from the Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on 2018 state of the market reports submitted by PJM's market monitor.	Costs were reduced by 20% from the Mid Case.
MISO			
Planning Resource Auction (PRA)			
All prices are from ERZ (external zone) auction results. Capacity clearance rate of 100% assumed for all cases based upon historical Zone 6 clearance rates since 2016/17 auction.	Price constant at 2017/18 auction value (lowest value since 2016/17).	Price constant at last known auction value from 2019/20 auction.	Price constant at 2016/17 auction value (highest value since 2016/17).

Trade Benefits – Assumed Price Forecast			
All cases are based on Companies' electricity market price forecasts	Least beneficial combination of electricity market price forecast and fuel price forecast	Mid-range for Companies' electricity market price forecast and fuel price forecast	Most beneficial combination of electricity market price forecast and fuel price forecast
Transmission Expansion Costs			
	Annual expansion costs were increased by 20% from the Mid Case.	MISO published indicative annual charges for approved MVP applied to forecasted loads.	Annual expansion costs were reduced by 20% from the Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on cost projections contained in MISO's 2019 revenue requirement forecast.	Costs were reduced by 20% from the Mid Case.

Appendix B – Cost Analyses

Tables of rolled up components for all three scenarios.

MISO Membership Cost Analysis - Mid Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Admin Cost	-13.5	-13.6	-13.8	-13.9	-14.0	-14.2	-14.3	-14.5	-14.6	-14.8
MISO Uplift Cost - Revenue Neutrality Uplift	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4
MISO Transmission Expansion Cost (MVP)	-51.3	-51.1	-53.4	-51.4	-50.9	-50.4	-49.9	-49.4	-48.8	-48.3
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost XM Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-79.6	-76.9	-79.3	-77.8	-77.3	-76.8	-77.0	-77.3	-76.5	-76.2

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Trade Benefits	8.5	8.8	7.2	8.7	7.3	10.2	12.1	9.3	10.1	10.0
MISO Capacity Auction Benefits	1	1	1	1	1	1	1	1	1	1
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
Sum of Benefits	15.6	16.0	14.5	16.2	14.8	17.9	19.9	17.3	18.1	17.9

Net of Cost + Benefits	-64.0	-60.9	-64.9	-61.7	-62.5	-58.9	-57.2	-60.0	-58.4	-58.3

MISO Membership Cost Analysis - High Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Admin Cost	-10.8	-10.9	-11.0	-11.1	-11.2	-11.3	-11.5	-11.6	-11.7	-11.8
MISO Uplift Cost - Revenue Neutrality Uplift	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4
MISO Transmission Expansion Cost (MVP)	-41.1	-40.9	-42.7	-41.2	-40.7	-40.3	-39.9	-39.5	-39.1	-38.7
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost XM Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-66.6	-64.0	-65.9	-64.8	-64.3	-63.9	-64.2	-64.5	-63.9	-63.6

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Trade Benefits	11.6	10.9	11.5	13.8	14.3	16.4	18.4	17.0	19.1	20.7
MISO Capacity Auction Benefits	13.2	13.3	13.8	14.2	14.1	14.1	14.2	14.1	14.1	14.0
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
Sum of Benefits	31.3	30.8	32.0	34.8	35.4	37.6	39.8	38.4	40.5	42.1

Net of Cost + Benefits	-35.3	-33.2	-33.9	-29.9	-29.0	-26.3	-24.4	-26.1	-23.3	-21.5

MISO Membership Cost Analysis - Low Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Admin Cost	-16.2	-16.4	-16.5	-16.7	-16.8	-17.0	-17.2	-17.4	-17.5	-17.7
MISO Uplift Cost - Revenue Neutrality Uplift	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4
MISO Transmission Expansion Cost (MVP)	-61.6	-61.4	-64.0	-61.7	-61.1	-60.5	-59.9	-59.2	-58.6	-58.0
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost XM Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-92.5	-89.9	-92.7	-90.9	-90.3	-89.7	-89.9	-90.0	-89.2	-88.8

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
MISO Trade Benefits	7.3	6.8	6.8	8.1	6.2	6.7	8.3	7.3	7.6	8.1
MISO Capacity Auction Benefits	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
Sum of Benefits	14.0	13.7	13.8	15.2	13.5	14.1	15.8	14.9	15.3	15.8

Net of Cost + Benefits	-78.6	-76.2	-78.9	-75.7	-76.8	-75.6	-74.1	-75.1	-73.9	-73.0

PJM Membership Cost Analysis - Mid Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Admin Fee Cost	-18.0	-18.4	-18.9	-19.3	-19.8	-20.3	-20.9	-21.4	-21.9	-22.4
PJM Energy Uplift (BOR) Cost	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
PJM Transmission Expansion Cost	-12.7	-12.6	-12.3	-12.0	-11.7	-11.4	-11.2	-10.9	-10.9	-10.9
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost Transmission Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-43.5	-41.2	-41.4	-41.9	-42.0	-42.0	-42.9	-43.8	-44.0	-44.6

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Trade Benefits (Production Costs)	11.1	8.0	7.8	10.0	8.0	10.1	14.3	9.8	12.9	13.4
PJM Capacity Auction Benefits	1.9	4.7	8.1	8.2	8.2	8.1	8.0	7.9	7.9	7.8
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
	19.5	19.3	22.7	25.0	23.1	25.3	29.6	25.1	28.2	28.6

Net of Cost + Benefits	-24.0	-21.9	-18.8	-16.9	-18.9	-16.7	-13.4	-18.7	-15.8	-16.0

PJM Membership Cost Analysis - High Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Admin Fee Cost	-14.4	-14.8	-15.1	-15.5	-15.9	-16.3	-16.7	-17.1	-17.5	-17.9
PJM Energy Uplift (BOR) Cost	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
PJM Transmission Expansion Cost	-10.1	-10.1	-9.8	-9.6	-9.4	-9.1	-9.0	-8.8	-8.8	-8.8
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost Transmission Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-37.3	-35.0	-35.2	-35.6	-35.7	-35.7	-36.5	-37.3	-37.4	-37.9

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Trade Benefits (Production Costs)	14.1	10.2	11.3	12.8	13.8	16.3	17.6	15.5	16.8	19.6
PJM Capacity Auction Benefits	8.0	23.2	39.7	39.7	39.6	39.5	39.5	39.3	39.3	39.2
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
Sum of Benefits	28.6	40.0	57.6	59.4	60.4	62.9	64.3	62.1	63.4	66.1

Net of Cost + Benefits	-8.7	5.0	22.5	23.7	24.8	27.2	27.8	24.8	26.0	28.2

PJM Membership Cost Analysis - Low Case

Costs ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Admin Fee Cost	-21.6	-22.1	-22.7	-23.2	-23.8	-24.4	-25.0	-25.6	-26.3	-26.9
PJM Energy Uplift (BOR) Cost	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
PJM Transmission Expansion Cost	-15.2	-15.1	-14.7	-14.4	-14.1	-13.7	-13.5	-13.1	-13.1	-13.1
LG&E/KU Internal Staffing & Implementation	-1.9	-1.1	-1.1	-1.0	-1.0	-1.0	-0.9	-0.9	-0.9	-0.8
LG&E/KU Lost Transmission Revenue	-4.0	-2.2	-2.3	-2.6	-2.5	-2.4	-2.9	-3.6	-3.2	-3.2
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.4	-1.4	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6
Sum of Cost	-49.6	-47.4	-47.7	-48.2	-48.3	-48.4	-49.3	-50.3	-50.6	-51.2

Benefits ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Trade Benefits (Production Costs)	7.6	5.8	5.4	4.8	3.5	4.9	6.9	6.9	9.3	8.7
PJM Capacity Auction Benefits	-0.6	-0.8	-1.3	-1.2	-1.2	-1.3	-1.3	-1.4	-1.4	-1.4
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.4	7.4
Sum of Benefits	13.4	11.6	10.9	10.4	9.2	10.7	12.7	12.9	15.3	14.7

Net of Cost + Benefits	-36.1	-35.8	-36.8	-37.7	-39.0	-37.7	-36.6	-37.4	-35.3	-36.6

Appendix C – Trade Benefits

The tables below show the projected incremental total system trade benefits and costs from joining MISO and PJM compared to the Companies' current business plan. Negative figures reflect net benefits; positive figures reflect net costs.

PJM $M		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Low Commodity Prices	Market Energy Sales	-60	-82	-119	-164	-183	-209	-256	-304	-357	-358
	Native Load Cost	46	74	113	159	180	204	249	297	348	349
	Total	-14	-8	-5	-5	-4	-5	-7	-7	-9	-9
Mid Commodity Prices	Market Energy Sales	-187	-239	-253	-272	-257	-245	-275	-302	-344	-340
	Native Load Cost	180	233	245	262	249	235	261	292	331	327
	Total	-8	-6	-8	-10	-8	-10	-14	-10	-13	-13
High Commodity Prices	Market Energy Sales	-248	-255	-267	-281	-275	-269	-306	-332	-360	-333
	Native Load Cost	237	245	256	268	261	252	288	317	343	314
	Total	-11	-10	-11	-13	-14	-16	-18	-15	-17	-20

MISO $M		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Low Commodity Prices	Market Energy Sales	-303	-307	-281	-316	-308	-235	-237	-231	-235	-209
	Native Load Cost	294	298	274	308	301	228	229	224	227	201
	Total	-9	-9	-7	-8	-6	-7	-8	-7	-8	-8
Mid Commodity Prices	Market Energy Sales	-310	-293	-278	-308	-297	-259	-263	-244	-259	-246
	Native Load Cost	302	287	271	299	290	248	251	235	249	236
	Total	-7	-7	-7	-9	-7	-10	-12	-9	-10	-10
High Commodity Prices	Market Energy Sales	-272	-271	-300	-327	-316	-271	-280	-259	-272	-271
	Native Load Cost	260	260	288	313	301	255	262	242	253	250
	Total	-12	-11	-12	-14	-14	-16	-18	-17	-19	-21

Appendix D – Non-Quantifiable Considerations

Consideration	Stability	Description
Governance		
Stakeholder Process – Tariff Filings and Operating Decisions	Continues to Evolve and Change	Although the structure 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.[27]
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

[27] 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.

		some of the most significant changes in RTO tariffs are often driven by FERC initiative and mandate rather than stakeholder proposals.[28]
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. 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	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, 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 into a bankruptcy proceeding that disrupts or prevents recovery through collateral, other RTO members are allocated a portion of the default.[29]

[28] 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 were unable to agree. FERC rejected both proposals in June 2018 and recommended PJM pursue a third alternative.

[29] For example, 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 Energy, LLC FTR portfolio in accordance with the PJM Tariff, PJM requested a waiver to the Tariff in order to liquidate the FTR portfolio in a manner that it felt would minimize distortion to the market. This waiver request was protested by certain marketers and initially denied by FERC before being sent to paper hearing prior. Ultimately PJM settled the dispute, allowing it to liquidate the GreenHat Energy, LLC FTR portfolio in its preferred manner but also involved 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).

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.[30]
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.[31] 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[32] resulting in a tariff filing with the FERC in March of 2019.[33] 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.[34]

[30] *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.

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

[32] 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

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

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

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.[35]
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 and who bears the costs associated with the projects are subject to still evolving RTO rules.[36] In both RTOs load is typically assigned some, if not most, 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.[37]
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 approval of outages and maintenance, determinations impacting fuel supply and fuel supply arrangements, and dispatch decisions.

[35] For example, *see supra* fn 15 describing the Linden VFT, LLC RTEP project cost dispute with PJM.

[36] 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.

[37] 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).

Drivers Behind Generation Dispatch Decisions	Unpredictable	The RTO would make the decisions on when to start the Companies' generating units. RTO dispatch decisions in normal conditions are driven by market indicators rather than practices focused on ensuring load service as performed today by the Companies.[38]
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. Transmission development is a competitive process in RTOs, which has led to considerable litigation. Though these issues continue to be litigated, appellate courts have recently upheld the removal of the federal right of first refusal by FERC.
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. Therefore, MISO currently has a fixed resource plan that allows a load serving entity to demonstrate that it has designated capacity to meet all or a portion of its reserve requirement.

[38] For example, while the Companies are currently able to plan for the risks associated with extreme cold weather events by starting units early and reducing the risk of non-performance, RTO membership would limit this discretion and authority.

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	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.[39]

[39] 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.
Fine 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.[40]

[40] 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.