This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

STAFF RECOMMENDATIONS FOR LG&E/KU'S 2021 IRP – July 2020

1. **Load Forecast**
    a. **The potential impact of existing and future environmental regulations affecting the price of electricity and other economic variables continues to be a topic of significant interest. Therefore, the effects of such regulations should continue to be examined by LG&E/KU as a part of their load forecasts and sensitivity analyses in the next IRP filing.**

    Section 5.(3) in Volume I of the 2021 IRP summarizes the potential impacts of higher cost of service on the Companies' load forecast. These impacts are evaluated in the Companies' low energy requirements forecast.

    b. **As discussed in the Joint 2018 IRP, the economics of current cost trends of distributed solar generation and electric vehicle penetration can have important effects on the demand for electricity. An increase in adoption rates of the former will tend to decrease electricity demand while increasing demand for the latter. In addition, LG&E's 2020-00016[1] and Siting Board cases 2020-00040[2] and 2020-00043[3] highlight the improving economics and demand for large scale solar projects, which could have an impact on demand growth. For the next IRP, the Companies should closely monitor, discuss, and model the potential impacts of these trends in both base case and sensitivity analyses.**

    Section 5.(3) in Volume I of the 2021 IRP summarizes the potential impacts of distributed generation and electric vehicles on energy requirements.

    The 2021 IRP includes the planned additions of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[4] Due to the improving economics of utility-scale solar, utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis. The results of this analysis are summarized in Section 5.(4).

    c. **LG&E and KU should continue to monitor and incorporate anticipated changes in EE impacts in their forecasts and sensitivity analyses.**

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[1] Case No. 2020-00016, Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option 3 (Ky. PSC May 8, 2020).
[2] Case No. 2020-00040, Application of Turkey Creek Solar, LLC for an Application for a Certificate of Public Convenience and Necessity to Construct an Approximately 50 Megawatt Merchant Electric Solar Generating Facility in Garrard County, Kentucky Pursuant to KRS 278.700 (Application filed March 27, 2020).
[3] Case No. 2020-00043, Application of Glover Creek Solar, LLC for a Certificate of Public Necessity to Construct an Approximately 55 Megawatt Merchant Electric Solar Generating Facility in Metcalf County, Kentucky Pursuant to KRS 278.700 and 807 KAR 5:110 (Application filed March 27, 2020).
[4] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Section 5.(3) in Volume I of the 2021 IRP summarizes energy efficiency assumptions in the base load forecast.

d. **There were four major driving assumptions comprising the Companies' High and Low scenarios and the results were reported on a combined basis. In addition, the discussion did not include the degree to which the Companies varied each of the factors from the base case. Reporting results on a combined basis provides the extreme case scenarios which, in part, is the point of the analyses. However, such reporting masks the effects of varying individual factors, which could provide useful information. For the next IRP, an expanded and more robust discussion (including the reasonableness of the High and Low assumptions) of each of the factors used to shock the base case forecast. For example, in the Low sensitivity analysis, what circumstances would cause the cost of service decline by 5 percent and how would the lower cost be passed on to which customers and how would that affect demand? In the next IRP, in addition to the cumulative shock to the base case, there should be a disaggregated sensitivity analysis.**

Section 5.(3) in Volume I of the 2021 IRP contains a discussion of the high and low load forecasts, the major driving assumptions, and the degree to which the Companies varied the assumptions. In addition, Section 5.(3) provides the disaggregated impact of each high and low case assumption on the base case forecast.

e. **The Base Case energy and peak demand forecasts are based on a 20-year historical period and the peak winter high demand forecast ranges from 6,355 MW to 6,764 MW by 2033. However, the maximum winter demand in the reserve margin analysis is based on an actual peak of 7,336 MW from 45 years ago. This represents a 981 MW – 572 MW difference. It is somewhat counter intuitive that the reserve margin (which seems unreasonably excessive) could be driven, in part, by an extreme outlier weather event, the effects of which are not even closely matched by the Companies' High peak load forecast. The High winter peak forecast in 2021 (the target year of the 2018 Reserve Margin Analysis) is 6,082 MW; a 1,254 MW difference. It is not clear how the reserve margin analysis results would be affected by altering the weather assumptions to better reflect similar assumptions driving the base case and High Low energy and peak demand forecasts. Such disparities in the assumptions' reasonableness can erode the confidence that may be placed in the forecast results and reserve margin analyses. For the next IRP, the Companies should provide more robust and complete explanations as well as a more consistent use of assumptions driving energy, load, and resource planning forecasts.**

Sections 5.(2) and 5.(3) in Volume I of the 2021 IRP more clearly explain the Companies' weather assumptions. The Companies develop their long-term base, high, and low energy requirements forecasts with the assumption that weather will be average or "normal" in every year. In other words, weather does not explain any differences between the base, high, and low peak demand forecasts. The assumption of normal weather is reasonable for long-term resource planning, but weather from one year to the next is never the same. Therefore, for reliability planning, a completely separate planning analysis focused on the Companies' ability to reliably serve load over a range of weather and unit availability scenarios, the Companies produce hourly load forecasts for a single year based on the weather in each of the last 48 years. The resulting ranges of summer and winter peak demands define the range of uncertainty – due solely to weather – for peak demands in the base energy requirements forecast. Thus, these ranges are comparable only to the summer and winter peak demands in the base energy requirements forecasts.

f. LG&E and KU should include discussion and analysis of the increase in distributed energy resources on load forecasts. This should include behind the meter generation at residential, commercial and industrial customer locations. These should be evaluated separately and cumulatively and include a discussion of drivers encouraging and discouraging such development.

Section 5.(3) in Volume I of the 2021 IRP provides a summary of the factors that impact DER economics and the assumptions underlying the Companies' DER forecasts. The Companies' base distributed solar generation forecast assumes retail rate paid for excess generation, instantaneous netting of usage and generation, and a continuation of the federal ITC for residential customers. On September 24, 2021, the Commission ruling on net metering was released. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the forecast could not be updated to reflect the new NMS-2 rates.

2. **DSM/EE**
   a. **The Companies should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders. These meeting should be more than informational, but entail fluid dialog between all vested parties. Any changes to the DSM-EE program must be discussed in full including a transparent analysis of the cost and benefits inputs.**

      The Companies held a DSM Advisory Group Meeting on 9/17/2021 to kick off the upcoming DSM Filing Planning and Development process. A follow-up Advisory meeting is tentatively being planned in Q4 of 2021 to continue the dialog once some initial budget, participation, and cost-effectiveness scoring is ready. Similar to the process in 2017, the Companies have again engaged with Cadmus, Inc. to assist in the development of the upcoming filing. Cadmus has many years of experience assisting other utilities in planning and developing new DSM programs. Also, they have developed, over many years, an in-house, robust cost-effectiveness software tool that has been utilized across the country as well as with the Companies' last DSM Filing in 2017/2018. Further, please see in Volume I the relevant Sections of 6, 7, and 8 for more information on DSM.

   b. **Staff recommends that LG&E/KU continue to identify cost effective energy efficiency opportunities for large customers and continue to offer incentives that encourage them to adopt or maintain energy-related technologies, sustainability plans, and long-range energy planning.**

      See response to part a. above.

   c. **Staff strongly encourages LG&E/KU to consider making AMS usage data available to customers that is closer aligned to real-time data and to consider prepay metering and real-time pricing options to enhance the customer experience for those customers participating in the AMI Pilot Program. In addition, Staff suggests LG&E/KU examine the feasibility of peak time rebate programs and time-of-use rates.**

      See response to part a. above.

   d. **As required by the IRP regulation (807 KAR 5:058, Section 7(4)(d)), the Companies should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

      The Companies plan to continue to improve their Process and Impact Evaluation, Measurement, & Verification (EM&V) of programs as the addition of AMI interval data becomes more available with AMI full deployment. Also, see response to part a. above.

   e. **Staff encourages LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time.**

      See response to part a. above.

3. **Resource Assessment**
   a. **LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.[5]**

   As requested by SREA, the least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity. All renewable cost assumptions are based on the "Moderate" case forecast from NREL's 2021 Annual Technology Baseline and were evaluated with applicable tax incentives.

   b. **Given the recent filing of Case No. 2020-00016, the next IRP's reserve margin analysis and long-term resource plan analysis should model the effects of increased interest and participation of the Companies' large commercial and industrial customers in purchasing increased amount of renewable energy, which may be generated by third party suppliers as opposed to the Companies' own generation sources.**

   The Companies long-term resource planning analysis reflects the planned additions of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[6] As mentioned previously, utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis. The IRP does not specify whether the additional solar is associated with the Green Tariff Option 3 program, but portions of it could be.

   c. **The 2018 Reserve Margin Analysis is well thought out. The starting premise appears to be that the Companies continue to operate as a standalone entity as opposed to being a member of an RTO. That assumption appears to drive several key input modeling constraints, which in turn may drive a higher reserve margin than would otherwise be the case. The Companies mention anecdotally the retirement of generation capacity within PJM and the reserve margins of neighboring utility systems, which may limit its ability to import power when needed as further support for the maintenance of its high reserve margin. The reduction in installed capacity would seem to support the Companies' planned maintenance of a high reserve margin. However, the Companies make no mention of any reliability concerns within the neighboring regions, availability of or additions to generation capacity, reduced demand within the markets, or whether the neighboring regions' stated reserve margins are considered inadequate for planning purposes. In addition, to whether or not neighboring utilities would have excess energy to sell during LG&E/KU's winter peak demand, there is no support for assumptions regarding available transmission capacity. Without further study, evidence, and discussion, it is difficult to ascertain the risk of not being able to rely on neighboring regions to serve and LG&E/KU being able to import energy that would justify such high reserve margins. The circumstances that allow for neighboring**

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[5] See Appendix for intervenors' comments.

[6] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

regional reserve margins to be relatively lower than the Companies' may also be advantageous to the Companies if it were a member of an RTO. It is possible that under some RTO analysis scenarios, the Companies and their customers may benefit from lower costs, lower reserve margins without sacrificing reliability, and, depending on load profiles, higher revenues overall. Staff also notes that LG&E/KU have upgraded select generation units for blackstart capability and that PJM provides compensation for that capability.[7]

In the 2018 IRP, the Companies' forecasted summer reserve margin was 23.5 percent in 2021. The 2018 IRP Reserve Margin analysis demonstrated that the increased reliability and generation production costs from retiring a marginal generation unit and operating at a lower reserve margin would more than offset the savings associated with the unit's stay-open costs. The low cost of the Companies' existing resources is the primary reason the Companies' existing generation portfolio is economically optimal.

In the 2021 IRP, the basis for the Companies' assumptions regarding available transmission capacity is provided in Section 4.4 of the 2021 IRP Reserve Margin Analysis in Volume III of the 2021 IRP. Furthermore, this analysis includes a sensitivity analysis in Section 5.1 where the maximum available transmission capacity is doubled from 500 MW to 1,000 MW. As discussed in the Companies' 2021 RTO Membership Analysis, the Companies do not recommend RTO membership at this time.

d. In the next IRP, the Companies should provide updated comprehensive and detailed cost/benefit studies comparing the full costs of joining MISO or PJM and all potential benefits such as increased revenues, lower reserve margin requirements, and improved reliability versus operating under its existing operating construct.

The Companies' 2021 RTO Membership Analysis is provided as an attachment to the Companies' 2021 IRP.

e. The Companies should provide greater discussion of and support for (reasonableness) the use of various assumptions used in the reserve margin analysis. If not addressed in Section 2, where appropriate, the input assumptions used in the reserve margin analysis should be consistent with those used in energy, load, and resource planning.

See response to 1e. The primary source of misunderstanding in reviewing the 2018 IRP pertained to load assumptions in the long-term resource planning analysis and the reserve margin analysis. The Companies' have attempted to do a better job demonstrating that load assumptions in both analyses are completely consistent.

f. In addition to the current sensitivity analyses methodology, the Companies should provide the effects of varying the input parameters separately so as to gauge the individual effects on the reserve margin. The Companies should also provide more detailed discussion of the implications of varying the modeling input assumptions and

[7] Staff notes that the Companies have recently completed one RTO study. However, over time, circumstances change and key assumptions that were valid previously may have changed too. See LG&E/KU's response to the Attorney General's First Request for Information, Item 76 (Filed Nov. 1, 2019).

greater support for (reasonableness) of how the modeling inputs are varied in the analyses.

Section 5.1 contains the sensitivity analysis for the 2021 IRP Reserve Margin Analysis. The impacts from varying key inputs are presented separately. In addition, the discussion of the sensitivity analysis is expanded to further assess the reasonableness of the results and provide more information regarding the range of inputs evaluated.

g. For the next IRP, the Companies should incorporate SREA's modeling recommendations regarding capacity only planning, allowing renewable energy to compete directly against existing generation units, and energy storage resources into the modeling and forecast methodology. Other recommendations should be incorporated appropriately.

In the 2021 IRP Long-Term Resource Planning Analysis, least-cost generation portfolios were developed with the goal of minimizing energy costs as well as the cost of new capacity.

h. Staff notes that in addition to the ongoing transmission projects, the Companies have taken steps in conjunction with other Kentucky based utilities to ensure the reliability of their respective transmission systems. For example, in Case No. 2017-00410,[8] the Commission approved the joint application for pre-approval of the sale or purchase of utility-owned transformers with an original book value in excess of $1 million and ancillary equipment pursuant to the agreement for Regional Equipment Sharing for Transmission Outage Storage Restoration (RESTORE Agreement). In the next IRP, in addition to a listing of transmission related projects, (including information contained in its annual Transmission System Improvement Plan, the Companies should provide a more robust and complete discussion of all the actions being taken to enhance the efficiency and reliability of the transmission and distribution systems.

Key distribution reliability and resiliency programs are addressed in Section 8.(2).(a). These programs include an Advanced Distribution Management System (ADMS), substation transformer replacements, aging infrastructure replacements, pole inspection and treatment, volt/VAR optimization and advanced metering infrastructure (AMI). These programs will maintain top quartile reliability performance and increase the flexibility of the distribution system to support the integration of DER.

In addition to the efficient transmission processes to add new generation (including renewables) and incremental load provided in Volume III ("Transmission Information"), programs have been implemented to improve the reliability of the transmission system. These programs include replacement of critical line and substation assets, upgrades to the protection and control systems, improved line sectionalization and automatic restoration through the installation of in-line breakers and switches, enhanced

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[8] Case No. 2017-00410, Electronic Joint Application of Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Kentucky Utilities Company, and Louisville Gas and Electric Company for Approval of Transactions Related to the RESTORE Agreement (Ky. PSC Feb. 22, 2018).

vegetation management, pole inspection, and switch maintenance. These programs will ensure long-term system integrity and modernize the transmission system to maintain reliable performance. The Transmission System Improvement Plan and the latest Annual Report can be found at the following links:

> 2016-00370 - ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY
>
> https://psc.ky.gov/pscecf/2016-00370/rick.lovekamp@lge-ku.com/06012021112026/Closed/2-2021_TSIP_Annual_Report.pdf
>
> 2016-00371 - ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY
>
> https://psc.ky.gov/pscecf/2016-00371/rick.lovekamp@lge-ku.com/06012021112143/Closed/2-2021_TSIP_Annual_Report.pdf

i. **Changes in federal and state law and policy could impact the growth of distributed generation, particularly as it relates to net metering. In Kentucky, in Case No. 2019-00256,[9] the Commission initiated an administrative proceeding to consider the implementation of legislation enacted by the 2019 General Assembly. Senate Bill 100, entitled An Act Related to Net Metering (Net Metering Act), which became effective on January 1, 2020. The Companies should address any ruling pertaining to the Net Metering Act in the any future IRPs.**

   See response to 1f.

j. **If not addressed above, the Companies should evaluate energy and capacity including renewable resources that is supplied from resources that are outside LG&E/KU's service territory in their resource assessment and reserve margin analyses. However, in that evaluation all costs, including those associated with transmission and distribution losses, should be included as well the inclusion of any benefits such as government subsidization. In addition, Staff notes that there are a number of merchant solar generation facilities in the process of regulatory approval that may be in response to large industrial customer sustainability goals. The Companies should also incorporate the effects of increased numbers of large renewable facilities within its service territory as a viable resource that is allowed to compete with existing generation.**

   In addition to in-state solar, the Companies' resource screening analysis considered in-state and out-of-state wind. The costs of solar and wind in the Companies' long-term resource planning analysis are consistent with recent RFP responses. Furthermore,

[9] Case No. 2019-00256, Electronic Consideration of the Implementation of the Net Metering Act (Ky. PSC Dec. 18, 2019).

least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity.

k. LG&E/KU should address any possible capacity ratings changes with renewables in their forecast, especially with solar.

The availability of solar during peak events is a key source of uncertainty in the 2021 IRP and is discussed in the 2021 IRP Reserve Margin Analysis.

2021 IRP Resource Screening Analysis

PPL companies

Generation Planning & Analysis
October 2021

Table of Contents

1 Executive Summary

Table 1 and Table 2 list the dispatchable and non-dispatchable resource options that were selected for evaluation in the Long-Term Resource Planning Analysis. These resources set the foundation for a clean energy transition. Non-dispatchable resources include wind and utility-scale solar resources located in Kentucky. Dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines with carbon capture and sequestration ("NGCC w/ CCS"), and 4-hour and 8-hour battery storage. Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions.[1] SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

Table 1: Dispatchable Resources (2022 Installation; 2022 Dollars) Results

			Battery Storage	
	SCCT	**NGCC w/CCS**	**4-hour**	**8-hour**
Summer Capacity (MW)[2]	220	513	1+	1+
Winter Capacity (MW)[2]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[3]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[3]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[3]	22	69	32	58
Firm Gas Cost ($/kW-yr)[4]	22	22	N/A	N/A
Variable O&M ($/MWh)[3]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

With the exception of summer and winter capacity values, firm gas cost assumptions, and renewable contributions to summer and winter peak, the cost and operating inputs for the generation resources in Table 1 and Table 2 are based on the "Moderate" case forecast in the National Renewable Energy Laboratory's ("NREL's") 2021 Annual Technology Baseline ("ATB"). The Companies did not evaluate combined cycle with hydrogen or nuclear resources in the Long-Term Resource Planning Analysis, but these technologies could eventually play an important role in decarbonization and the integration of renewables. In addition, the Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunites for new DSM programs that will be evaluated with data and pilot programs associated with the implementation of AMI.

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[1] NGCC with CCS, like NGCC without CCS, is dispatchable in all weather conditions and has fast ramp rates, but emits less than 10% of the carbon.

[2] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled battery storage resources in 100 MW increments.

[3] Source: NREL's 2021 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2019 dollars, to nominal dollars at 2% annually.

[4] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

Table 2: Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

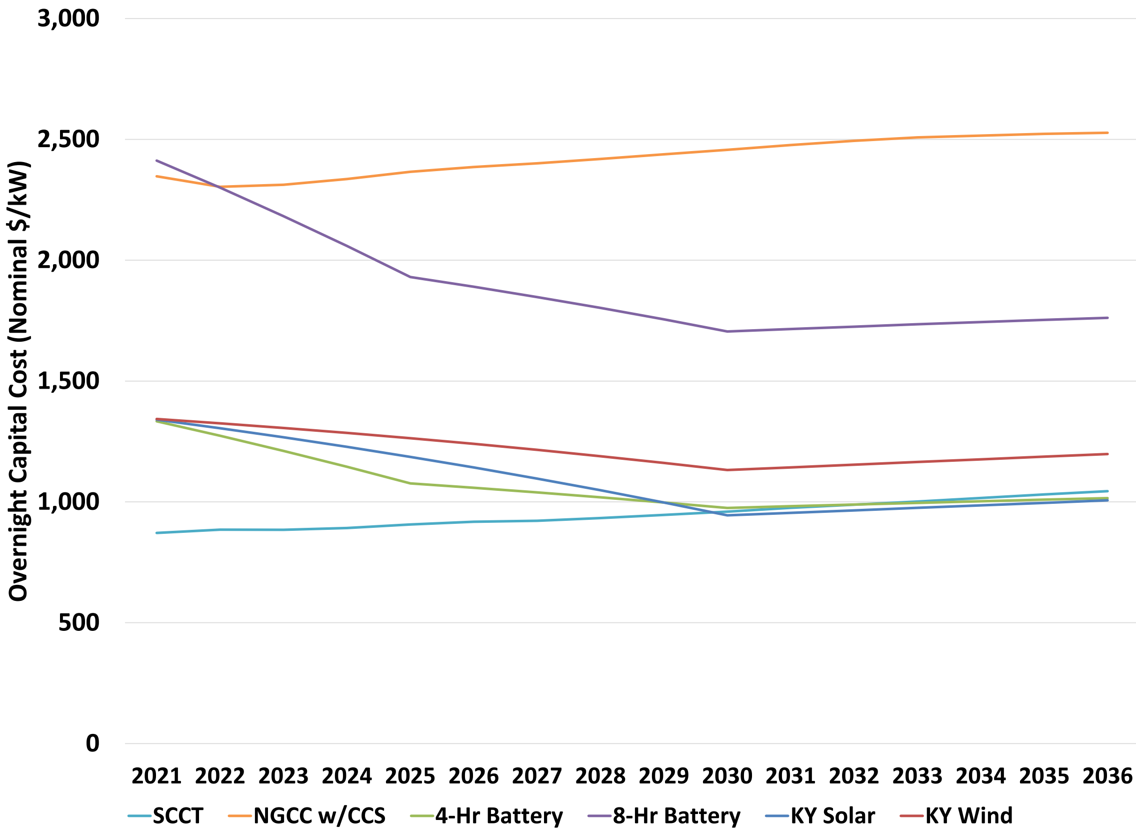
	KY Solar	KY Wind
Summer Capacity (MW)[5]	100+	100+
Winter Capacity (MW)[5]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[3]	25.1%	27.4%
Capital Cost ($/kW)[3]	1,305	1,325
Fixed O&M ($/kW-yr)[3]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[6]	N/A	15

Figure 1 contains NREL's forecast of capital costs through the end of the IRP planning period. As Figure 1 demonstrates, SCCT capital costs are lower than 4-hour battery storage capital costs today; however, by 2030, their capital costs are forecasted to be approximately equal. NREL's fixed O&M assumptions for each resource escalate over time in nominal dollars with the exception of KY Solar and battery storage, which decrease until year 2030 and then escalate. Compared to assumptions in the 2018 IRP, the capital costs of wind and battery technologies for a 2022 installation have decreased and the capital cost of solar resources has increased; however, capital costs for all three technologies are lower by the end of the IRP planning period than capital costs in the 2018 IRP. Fixed operating and maintenance costs have increased significantly from the 2018 IRP for all evaluated technologies with the exception of wind resources.

[5] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled solar and wind resources in 100 MW increments.

[6] Production Tax Credit of $15/MWh included for the first 10 years of wind resources.

Figure 1: Generation Technology Cost Forecast (Nominal Dollars)[7]



Key input assumptions include those listed below.

- Capacity is the net full load output in MW.
- Contribution to peak is the assumed percentage of capacity that is available to serve peak load.
- Net capacity factor is the ratio of the unit's average hourly output over the course of the year to the unit's rated capacity.
- Heat rate is the full load net heat rate.
- Capital cost is the overnight capital expenditure required to achieve commercial operation.
- Fixed operation and maintenance costs are operation and maintenance costs that do not vary with the unit's generation output.
- Firm gas transportation costs are costs associated with reserving firm gas-line capacity.
- Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.
- Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.

[7] Source: 2021 ATB from NREL (https://atb.nrel.gov/).

2 Generation Technology Options

The following sections include a discussion of the resource options considered in this analysis along with the rationale for selecting the resource options evaluated in the Long-Term Resource Planning Analysis.

2.1 Dispatchable Resources

2.1.1 Natural Gas Simple-Cycle Combustion Turbines

Natural gas-fired SCCT options include traditional frame machines and aero-derivative combustion turbines. They are typically used for peaking power due to their fast ramp rates and relatively low capital costs. Aero-derivative machines are flexible, slightly more efficient than larger frame units, and can be installed with high temperature oxidation catalysts for carbon monoxide control and selective catalytic reduction ("SCR") for nitrogen oxides ("NO_x") control, which allows them to be located in areas with air emissions concerns. Additionally, utilities with significantly higher renewable penetration are building aero-derivatives for integration purposes.[8] While not quite as efficient or flexible, frame simple-cycle machines can also be installed with emission controls and are much less expensive to install and operate on a $/kW basis. The cost of SCCT in the 2021 ATB reflects the cost of frame simple-cycle machines. For these reasons, frame simple-cycle machines were evaluated in the Long-Term Resource Planning Analysis.

2.1.2 Natural Gas Combined-Cycle with Carbon Capture and Sequestration

NGCC units with CCS use both gas and steam turbines together to produce up to 50% more electricity than SCCT using the same amount of fuel. The steam turbine uses waste heat from the gas turbine to generate additional electricity. After combustion, up to 99% of the carbon dioxide emissions are captured to be stored or beneficially used. NGCC units with CCS can respond to significant load swings due to their high ramping capabilities and can be cycled overnight. NGCC with CCS is dispatchable in all weather conditions, has fast ramp rates, has low CO_2 emissions, and thus remains a viable resource with clean energy regulations. New NGCC units with CCS are also capable of burning hydrogen with, or instead of, natural gas, and the economics of green hydrogen produced from renewable energy resources continue to improve.

The Companies are global leaders in carbon capture research and operate one of the two carbon capture systems in operation at power plants in the United States today. In 2006, the Companies began a partnership with the University of Kentucky Center for Applied Energy Research ("UK CAER") focused on improving the cost and efficiency of carbon capture technology. In 2014, the team built Kentucky's largest carbon capture unit at the Companies' E.W. Brown generating station, which remains in operation today. University of Kentucky researchers have used this system to run tests for U.S. Department of Energy-funded research projects and have generated 118 publications and have had 17 U.S. patents issued for their work with another four patents pending. One of the current research projects establishes a method of producing hydrogen as a beneficial byproduct from the carbon capture that could in turn be used as fuel for combustion.

[8] https://www.powermag.com/srp-approves-arizona-expansion-with-16-gas-fired-turbines/.

2.1.3 Energy Storage

Energy storage options provide short-term peaking capacity and voltage frequency management. Compressed air energy storage ("CAES") and pumped hydro energy storage systems store off-peak power to be released during on-peak demand periods. However, the cost of CAES and land-use requirements for pumped hydroelectric facilities make these storage technologies unsuitable in the Companies' service territories.

The Companies have been researching and testing lithium-ion batteries since 2016 for their potential to provide short-term energy storage on a utility scale. The basic composition of a lithium-ion battery includes an anode, a lithium-containing cathode, and an electrolyte solution. When the battery is in operation, lithium ions are moved between the negative anode and positive cathode. While discharging, the ions travel from the anode to the cathode and while charging they travel from the cathode to the anode.

Lithium-ion battery energy storage systems have virtually instantaneous response times, allowing flexibility in load management, and their scalability is an advantage over larger peaking options such as frame SCCTs. At higher levels of intermittent renewable penetration, lithium-ion batteries can be used to ameliorate solar intermittency by power smoothing, which discharges power instantaneously when solar output drops, and charges to absorb power when solar power rises suddenly. They can also serve to store excess solar generation from the day and discharge it at night, which can limit the need for solar curtailment. Batteries are also capable of frequency and voltage regulation when installed at scale.

In RTOs, connecting batteries to renewables can increase the capacity value of renewables based on current market rules. But battery storage has the most value for vertically integrated utilities when it is connected to the grid because it increases the likelihood of the battery being charged when needed. The Companies evaluated 2, 4, 6, 8, and 10 hour batteries at varying levels of renewables and determined that 4 and 8 hour batteries are the optimal choice for serving their customers; therefore, 4 and 8 hour batteries were evaluated in the Long-Term Resource Planning Analysis. Table 3 compares costs and assumptions for SCCT and 4- and 8-hour battery storage installed in years 2022 and 2031.[9] According to NREL, SCCT capital costs are expected to increase over time and battery storage capital costs are expected to decrease.

Table 3: Comparison of SCCT and Battery Storage in 2022 and 2031 (Nominal Dollars)

	2022 Installation			2031 Installation		
		Battery Storage			Battery Storage	
	SCCT	4-hour	8-hour	SCCT	4-hour	8-hour
Capital Cost ($/kW)[3]	885	1,274	2,300	975	982	1,715
Fixed O&M ($/kW-yr)[3]	22	32	58	27	25	43
Firm Gas Cost ($/kW-yr)[4]	22	N/A	N/A	24	N/A	N/A
Variable O&M ($/MWh)[3]	5.24	N/A	N/A	6.27	N/A	N/A
Round-Trip Efficiency	N/A	85%	85%	N/A	85%	85%
Book Life (Years)	30	15	15	30	15	15

[9] 2022 and 2031 are the first and tenth years of the IRP planning period, respectively.

Table 4 shows a comparison of the levelized cost of energy ("LCOE") for SCCT and battery storage resources at varying natural gas prices and charging costs, respectively, and assuming 16.7% capacity factor for both resource types. Battery storage technology is currently disadvantaged due to its cost and much shorter life compared to SCCT resources. By 2031, the LCOE for SCCT and battery storage resources are similar, depending on natural gas prices and charging cost assumptions. However, NREL's SCCT capital cost reflects the cost of constructing a single SCCT at a greenfield site. Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower.

Table 4: LCOE of SCCT and 4-Hour Battery Storage ($/MWh)

Installation Year	SCCT Natural Gas Price Forecast			4-Hour Battery Storage Charging Cost ($/MWh)		
	Low	Mid	High	25	30	35
2022	113.91	125.18	135.61	150.59	157.22	163.85
2031	125.64	136.91	147.34	123.68	130.31	136.94

All batteries, including lithium-ion batteries, experience round-trip energy efficiency losses of 15% to 25%, which is primarily lost as waste heat when power travels through the inverter transforming power AC to DC during charging and then DC back to AC when discharging. A round-trip efficiency of 85%, accounting for these inverter losses, is considered standard. However, round-trip efficiencies of 75% have also been observed particularly during very hot or cold weather when significant amounts of energy are required for heating or cooling to keep the batteries within their relatively narrow optimal temperature range. In simple terms, for every 1 MWh of energy stored in batteries, 0.85 MWh can be used.

Utility scale batteries are rated by both their energy and power capacities. For a 1-megawatt ("MW") 4 megawatt-hour ("MWh") battery, the maximum power input or output is 1 MW but not all of the battery's energy capacity (4 MWh) can be used. Lithium-ion batteries are susceptible to fire and thermal runaway especially at higher states of charge ("SOC"). For this reason, SOC is typically limited between 5% and 95%, which results in a 10% reduction in available battery capacity that needs to be accounted for when determining battery installation capacities. At their energy storage testing facility, the Companies limit SOC for safety to between 10% and 90%, meaning that 20% of the battery's energy capacity is unused. Some utilities limit lithium-ion batteries from 25% to 75%, meaning 50% of the battery is unused, and only 50% of the battery's capacity is available. In simple terms, assuming 10% reduction in available battery capacity means for every 1 MWh of energy storage installed, only 0.9 MWh is usable.

The Companies are a leader in utility scale lithium-ion battery research, and installed Kentucky's first and largest battery site with a 1 MW, 2 MWh battery at the E.W. Brown Generating Station in 2016. The battery is continuously monitored and performance data is viewed via a real-time battery performance dashboard. The data is shared with Pacific Northwest National Laboratory and the Electric Power Research Institute. At this site, the Companies are able to program the battery in different operating modes to understand their settings and functionality. Often used is target state of charge where solar energy from the day is stored to be discharged overnight. The battery also allows for research into best practices for safety. In addition to the knowledge gained at the E.W. Brown battery site, the Companies participate in industry research programs to collaborate and share knowledge with other leaders in lithium-ion battery research.

Subject matter experts at the Companies working with researchers from the University of Kentucky have collaborated on multiple research topics related to solar and battery energy storage systems. Over the past three years, nine academic papers and presentations based on data retrieved from the E.W. Brown Solar Dashboard and E.W. Brown 1-megawatt, 2-megawatt-hour battery have been published in international journals, including the distinguished IEEE Transaction for Industry Applications. The publications have covered topics including how energy storage systems can be used to improve the capacity factor for solar farms, methods for developing accurate battery models for computer simulations studies, analysis of solar plant configurations with battery systems, and defined procedures for identifying the equivalent circuit parameters for utility-scale lithium-ion batteries. In a continuation of the partnership, the University of Kentucky Center for Applied Energy Research ("CAER") and the Companies are studying how to recycle lithium-ion batteries once they reach the end of their useful life.

2.1.4 Demand-Side Management

The Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunites for new DSM programs that will be evaluated with data and pilot programs associated with the implementation of AMI.

2.2 Non-Dispatchable Resources

2.2.1 Solar

Photovoltaic ("PV") solar is a proven technology option for daytime energy and a viable option to pursue renewable goals and reduce emissions. Solar generation is a function of the amount of sunlight (i.e., electromagnetic radiation) incident on a surface per day, measured in kWh/ m^2/day. Kentucky receives between 4 and 5.5 kWh/m^2/day. Areas in the western United States with high rates of solar development receive over 7.5 kWh/m^2/day. In Kentucky, the summer peak contribution of solar resources is assumed to be 79 percent of total solar capacity. The PV Solar option was further evaluated in the Long-Term Resource Planning Analysis, which considers the impact of the federal Investment Tax Credit ("ITC").[10]

Table 5 shows a comparison of residential and utility-scale solar resources, using NREL's 2021 ATB assumptions for 2022 and 2031 installations.[11] Utility-scale solar has lower capital and fixed O&M costs, a higher capacity factor, and a lower weighted average cost of capital ("WACC") compared to Residential Solar. For this reason, the Companies evaluated Utility-Scale Solar in the Long-Term Resource Planning Analysis.

[10] The federal ITC for PV solar is currently 26% (see http://programs.dsireusa.org/system/program/detail/658). The Long-Term Resource Planning Analysis assumes this level of ITC continues through the planning period.

[11] The Companies used "Class 6" solar from the 2021 ATB to represent a solar resource located in Kentucky. 2022 and 2031 are the first and tenth years of the IRP planning period, respectively.

Table 5: Comparison of Residential and Utility-Scale Solar (Nominal Dollars)

Item	2022 Installation		2031 Installation	
	Residential Solar	Utility-Scale Solar	Residential Solar	Utility-Scale Solar
Capital Cost ($/kW)[3]	2,514	1,305	1,259	955
Fixed O&M ($/kW-yr)[3]	27.42	23.38	16.90	21.00
Capacity Factor[3]	15.1%	25.1%	15.3%	27.3%
Weighted Average Cost of Capital ("WACC")[3]	4.38%	4.25%	4.38%	4.25%
Levelized Cost of Energy ($/MWh)	108.18	38.62	56.47	28.05

Fixed O&M in NREL's 2021 ATB for utility-scale solar is notably higher compared to the 2020 ATB. As a result, the levelized cost of energy for utility-scale solar is approximately $10/MWh higher than the cost of Rhudes Creek Solar ($27.82/MWh) in 2022 and does not approach the Rhudes Creek price until 2031. To align the analysis with the Rhudes Creek price, the 2031 cost of solar was utilized throughout the IRP planning period.

2.2.2 Wind

The viability of wind generation for a given region is dependent on wind speeds. Kentucky has average wind speeds that are less than 12.5 mph. Areas with wind speeds of at least 14.5 mph are better suited for wind generation. Two land-based wind options were considered – one in Kentucky with a 27-31% capacity factor, and one in Indiana with a 39-44% capacity factor.[12] Table 6 shows a comparison of Kentucky and Indiana wind resources and demonstrates that both wind options have significantly higher LCOE compared to utility-scale solar. As a result, solar resources would be added in Kentucky well before wind resources. Because the Kentucky wind option has a lower LCOE compared to Indiana wind, it was evaluated in the Long-Term Resource Planning Analysis.

Table 6: Comparison of Kentucky and Indiana Wind (Nominal Dollars)

Item	2022 Installation		2031 Installation	
	KY Wind	IN Wind	KY Wind	IN Wind
Capital Cost ($/kW)[3]	1,325	1,325	1,143	1,143
Fixed O&M ($/kW-yr)[3]	44.46	44.46	49.03	49.03
Transmission Cost ($/kW-yr)[13]	N/A	87	N/A	104
Capacity Factor[3]	27.4%	39.8%	29.8%	43.1%
Levelized Cost of Energy ($/MWh)	49.79	63.33	43.10	62.25

[12] The Companies used "Class 9" and "Class 6" wind from the 2021 ATB to represent wind resources located in Kentucky and Indiana, respectively.

[13] Transmission cost is based on current firm transmission costs to import power from an Indiana resource.

3 Other Technologies

The following provides an update on technologies that are either not cost-effective or not ideal for utility-scale applications in the Companies' service territories.

3.1 Nuclear

Nuclear power refers to the generation of electricity using a fission reaction, where the nucleus of one atom is split into two or more nuclei, to produce heat which in turn drives a steam turbine to produce electricity. Nuclear generation emits no air pollution including zero CO_2. The United States has just under 100 GW of nuclear fission capacity in operation at this time, with approximately 5% of that capacity expected to retire in 2021.

Small modular reactors ("SMR") and nuclear fusion are two nuclear technologies that are not commercially available but actively being researched. SMR nuclear fission plants are smaller in capacity than modern fission plants and have the advantages of smaller footprints and reduced capital costs. The United States Department of Energy is working to make SMR technology commercially available by the late 2020s to early 2030s. Nuclear fusion refers to the generation of energy by the combining of atoms rather than splitting. While nuclear fusion reactions have been initiated in laboratories, the critical milestone of a self-sustaining reaction, where more energy is released than is consumed, has not been achieved.

Nuclear power has several challenges including high capital costs, inability to ramp up or down quickly to follow load, economic competitiveness within energy markets, permitting, waste disposal, and public perception. At current nuclear capacity cost, which is greater than $7,000/kW, constructing a relatively small 600 MW nuclear plant is expected to cost approximately $4.2 billion. Environmental permitting and waste disposal is a challenge that was partially addressed by Kentucky 17RS SB 11. Kentucky 17RS SB 11 amended KRS 278.600 to require that nuclear power facilities have a plan for the storage of nuclear waste rather than a means of permanent disposal. Previously a federal permanent nuclear waste storage facility was required but with 17RS SB 11, construction of a new nuclear plant is allowed as long as there is a plan for storing the nuclear waste that is approved by the Nuclear Regulatory Commission.

3.2 Combined Cycle with Hydrogen

Hydrogen combined cycle generation would have the significant advantages of being both dispatchable and carbon free. Hydrogen can be produced by renewables and combusted in a turbine without carbon emissions. Over the next decade, research will focus on designing commercial-scale turbines compatible with the combustion characteristics of hydrogen which include higher flame speed and higher temperature, as well as overcoming the high cost of hydrogen as a fuel relative to natural gas. Given those technical and economic challenges, hydrogen combined cycle generation was not evaluated in the Long-Term Resource Planning Analysis. The Companies continue to research hydrogen combined cycle generation because of the important role it could play in decarbonization and renewable integration.

3.3 Natural Gas Combined Cycle without Carbon Capture and Sequestration

NGCC without CCS has the same operating characteristics as NGCC with CCS and its capital and operating costs are significantly lower. However, Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions. SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

3.4 Integrated Gasification Combined-Cycle ("IGCC")

Integrated Gasification Combined-Cycle ("IGCC") technology continues to be developed and is at various stages of commercialization. Only a limited number of IGCC plants have been built and operated around the world, and the cost of these plants have significantly exceeded expectations. For this reason, no IGCC options were evaluated in the Long-Term Resource Planning Analysis.

3.5 Coal-Fired

Because of the high cost of new coal and environmental risk, no coal-fired options were evaluated in the Long-Term Resource Planning Analysis.

3.6 Hydro

The Companies recently upgraded the hydro units on Dix Dam and Ohio Falls, and are not aware of any viable alternatives near their service territories for expanding their portfolio of hydro generation further. For this reason, the hydro option was not evaluated in the Long-Term Resource Planning Analysis.

3.7 Biopower

Due to high capital and operating costs, biopower options were not evaluated in the Long-Term Resource Planning Analysis.

3.8 Reciprocating Engines, Microturbines, and Fuel Cells

Reciprocating internal combustion engines, microturbines, and fuel cells are easily scalable and are well-suited for distributed generation and combined heat and power applications. Reciprocating engines can accommodate both natural gas and fuel oil, and have high efficiency across the ambient range. Reciprocating engines are more popular in areas with high penetrations of renewable generation due to their quick start times and operational flexibility. At present, fuel cells hold little promise for large utility scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development. For these reasons, these options were not evaluated in the Long-Term Resource Planning Analysis.

3.9 Circulating Fluidized Bed

Circulating fluidized bed ("CFB") boilers are a mature coal technology option that is well-suited to burn fuels with a large variability in constituents. Large CFBs require more than one boiler, which increases capital costs but improves unit availability compared to PC technology options. Like PC technology options, CFB are also subject to NSPS for GHG regulations and would require the same CC technology. For these reasons, no CFB option was evaluated in the Long-Term Resource Planning Analysis.

3.10 Waste to Energy

Waste to energy ("WTE") generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Waste fuel is a very diverse category that includes: municipal solid waste, refuse derived fuel, wood chips, landfill gas, sewage, and tire-derived fuel. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. The greatest challenge to building large WTE plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of WTE fuel poses a significant challenge, depending on the size of the facility. Because of these considerations, no WTE options were evaluated in the Long-Term Resource Planning Analysis.

3.11 Concentrating Solar Power

A concentrating solar power ("CSP") option was not evaluated in the Long-Term Resource Planning Analysis because of its high capital costs and infeasibility in the Companies' service territories. The tower and heliostat technology CSP plants that have been built have had serious technical challenges and have performed far worse than expected. Parabolic trough CSP projects have performed better, but remain uneconomic. CSP options are better-suited for sunnier climates, and cost at least four times more than solar PV resources.

2021 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

October 2021

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1 Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, the Companies have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. In past IRPs, the results of this analysis were communicated in the context of a summer peak reserve margin. However, as more solar generation is integrated into the Companies' generation portfolio and included in the calculation of summer reserve margin, a summer reserve margin will have less meaning as an indicator of the portfolio's ability to reliably serve customers in all hours.[1] Therefore, the results of this analysis are communicated in the context of a summer and winter peak reserve margin. The mathematics – like past reserve margin analyses – continue to assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2018 IRP, the 2021 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2025 over a range of generation portfolios with different reserve margins to identify the optimal generation mix for customers.[2] To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirements of one or more Brown 11N2 simple-cycle combustion turbines ("SCCTs"), Mill Creek 2, and Brown 3.[3] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity and solar to the generation portfolio.

The results of the 2021 analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2025. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources; the reliability and generation production cost benefit for each of the Companies' marginal resources exceeds the costs that would be saved by retiring these units. Table 1 compares the 2018 IRP and 2021 IRP summer reserve margin ranges. The minimum of the summer reserve margin range is unchanged, and the maximum of the range in 2021 IRP is slightly lower due primarily to a decrease in the assumed variability of summer peak demands.

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[1] Solar generation is not available to serve the Companies' winter peak, which occurs at night.

[2] 2025 is the first year of the planning period that reflects the planned retirement of Mill Creek 1 and the assumed retirements of the small-frame SCCTs. As the Companies' analyses show, they do not anticipate needing additional generation capacity prior to 2028.

[3] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11. The analysis assumes Mill Creek 1 and the Companies' small-frame SCCTs will be retired by 2025.

Table 1: Summer Target Reserve Margin Ranges

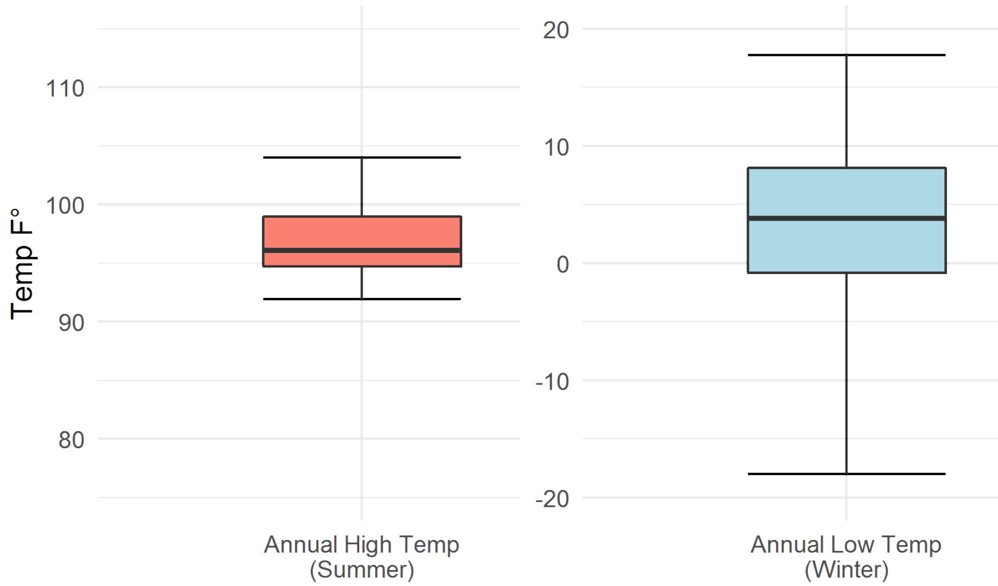
	Summer Range (%)
2018 IRP	17 – 25
2021 IRP	17 – 24

The high end of the 2021 IRP summer reserve margin range (24 percent) is the reserve margin for the generation portfolio that meets the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. The winter reserve margin for the same generation portfolio – computed as a function the forecasted winter peak demand under normal weather conditions – is 35 percent. The low end of the summer reserve margin range is determined by estimating the increase in load that would result in the addition of generation resources. Based on the 2021 IRP analysis, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity if the Companies' load increased by 300 MW. With this load increase, the Companies' summer reserve margin would be approximately 17 percent and the winter reserve margin would be 26 percent. Therefore, the Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.

2 Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Figure 1 shows the distribution of annual high and low temperatures in Louisville over the last 48 years. From 1973 to 2020, the median annual high temperature was 96.1 degrees Fahrenheit and the median annual low temperature was 3.8 degrees Fahrenheit. Additionally, the variability of low temperatures in the winter is significantly greater than the variability of high temperatures in the summer.

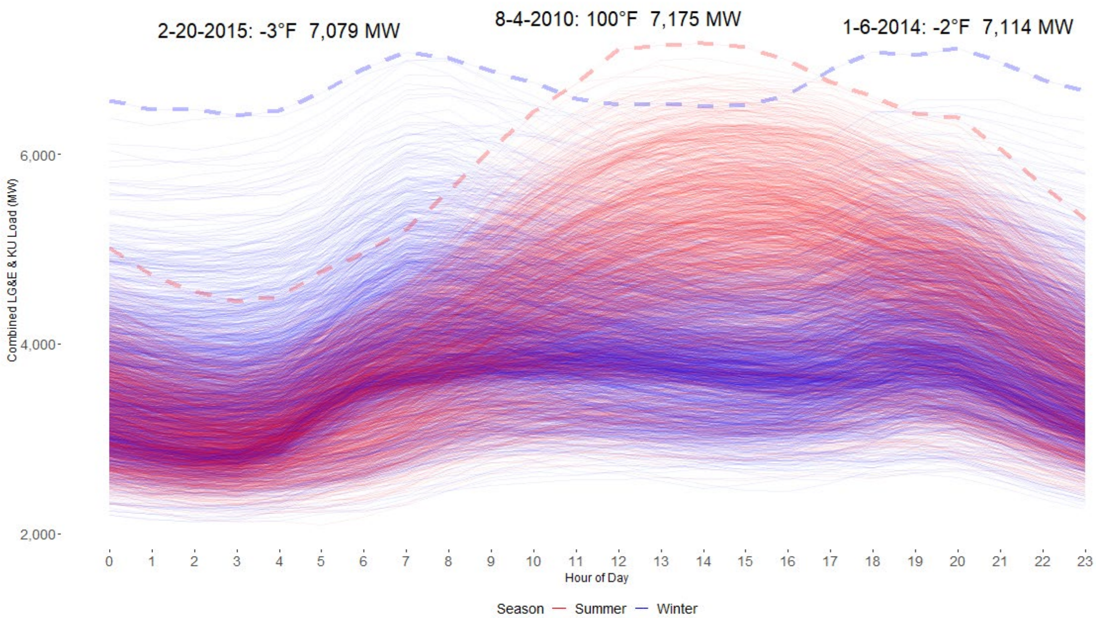
Figure 1: Louisville Annual High and Low Temperature Distributions (1973-2020)[4]



Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015). Figure 2 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

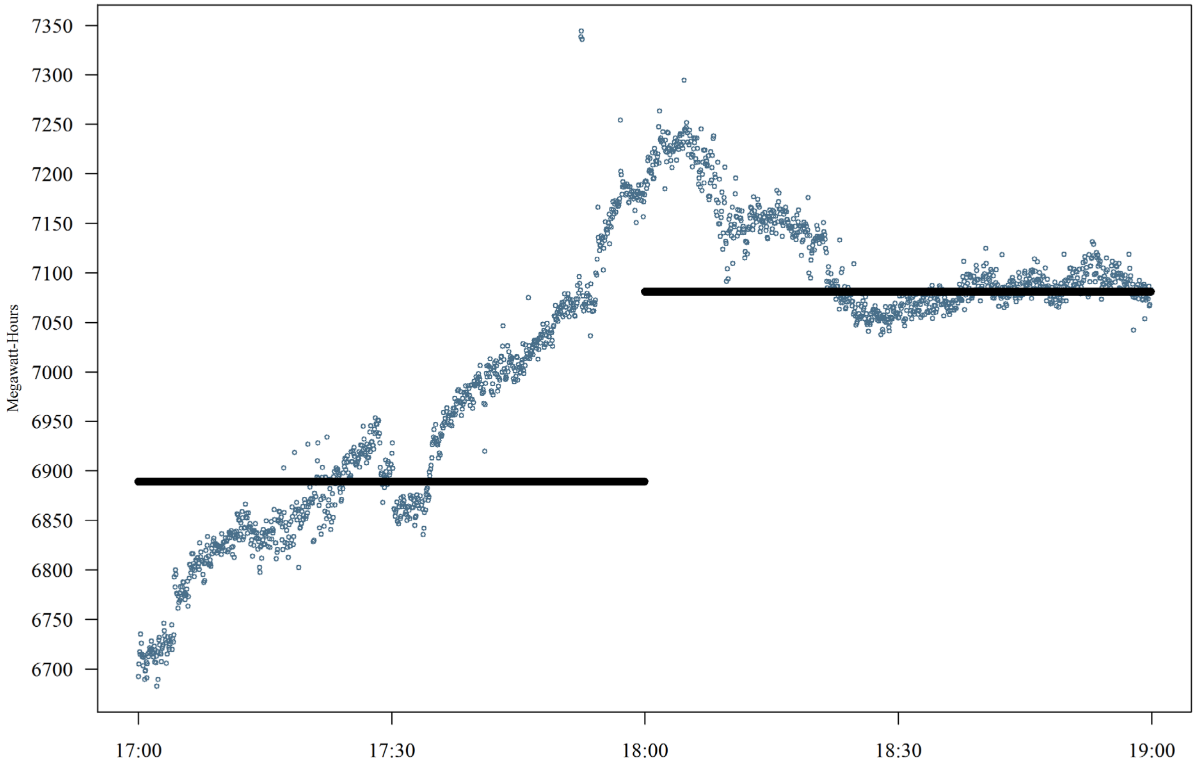
[4] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

Figure 2: Hourly Load Profiles, 2010-2020



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 3 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher.

Figure 3: Four-Second Demands, 5:00-7:00 PM on January 6, 2014



In addition to being reliable, a generation portfolio must possess numerous other attributes to produce power when customers want it. For example, a generation portfolio must possess the ramping capabilities to follow abrupt changes in customers' energy requirements. In addition, the Companies must be able to dispatch at least a significant portion of their generating units when they are needed. Peaking units can start quickly and are needed to respond to unit outages. Baseload units take longer to start, but because their start times are predictable, the Companies can bring them online when they are needed. The size of a resource is also important. If a unit is too big, taking the unit offline for maintenance can be problematic. If a unit is too small, its value in responding to unit outages is limited. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

Customers consume electricity every hour of the year, but no generating resource can be available at all times. Considering the need for maintenance, the Companies' baseload units and large-frame SCCTs are available to be utilized up to 90 percent of hours in a year. The Companies' small-frame SCCTs are over 50 years old and are far less reliable than large-frame SCCTs. The Companies' Curtailable Service Rider ("CSR") limits the ability to curtail participating customers to hours when all large-frame SCCTs have been dispatched. As a result, the ability to utilize this program is limited to, at most, a handful of hours each year.

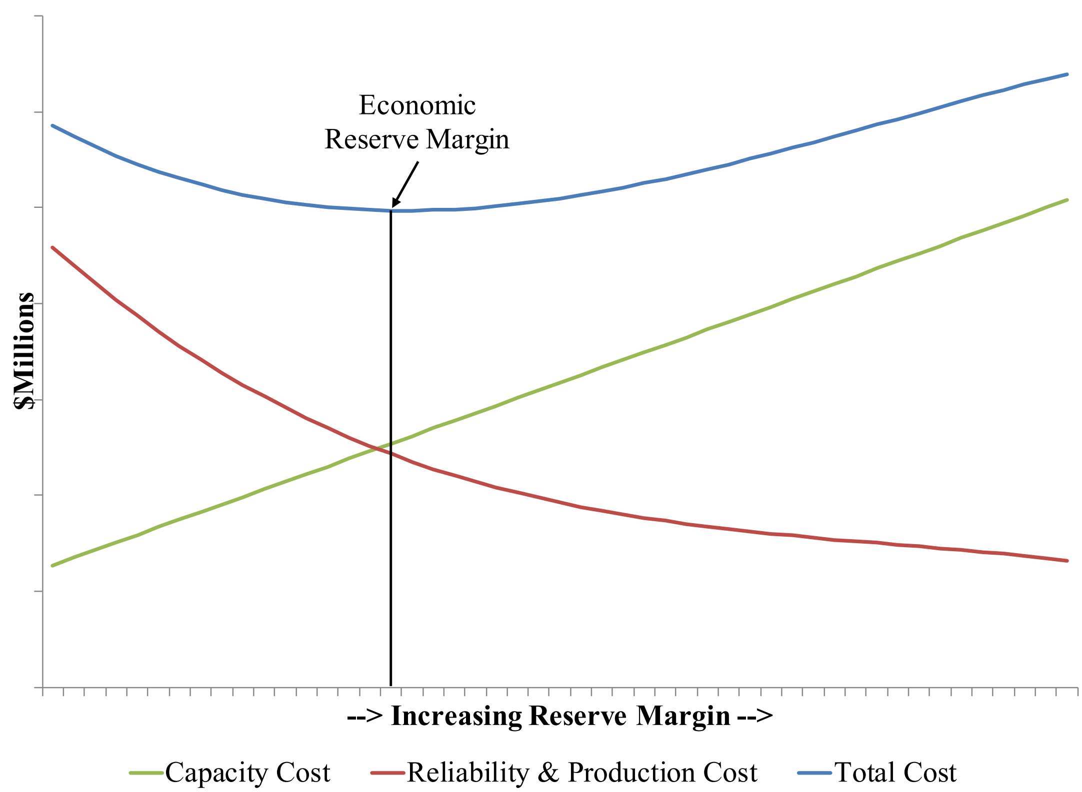
As the Companies evaluate integrating more renewables into their generation portfolio, they must consider the fact that renewables lack many of the characteristics required to serve customers in every moment. Compared to coal- and natural gas-fired resources, the availability of renewables is less predictable and their fuel supply (e.g., sunshine, wind, or water) is more intermittent. Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies' service territories as a source of winter capacity.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

3 Analysis Framework

Figure 4 illustrates the costs and benefits of adding capacity to a generation portfolio.[5] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable), but fixed capacity costs increase. In their reserve margin analysis, the Companies evaluate these costs and benefits over a range of generation portfolios with different reserve margins. The reserve margin for the generation portfolio where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

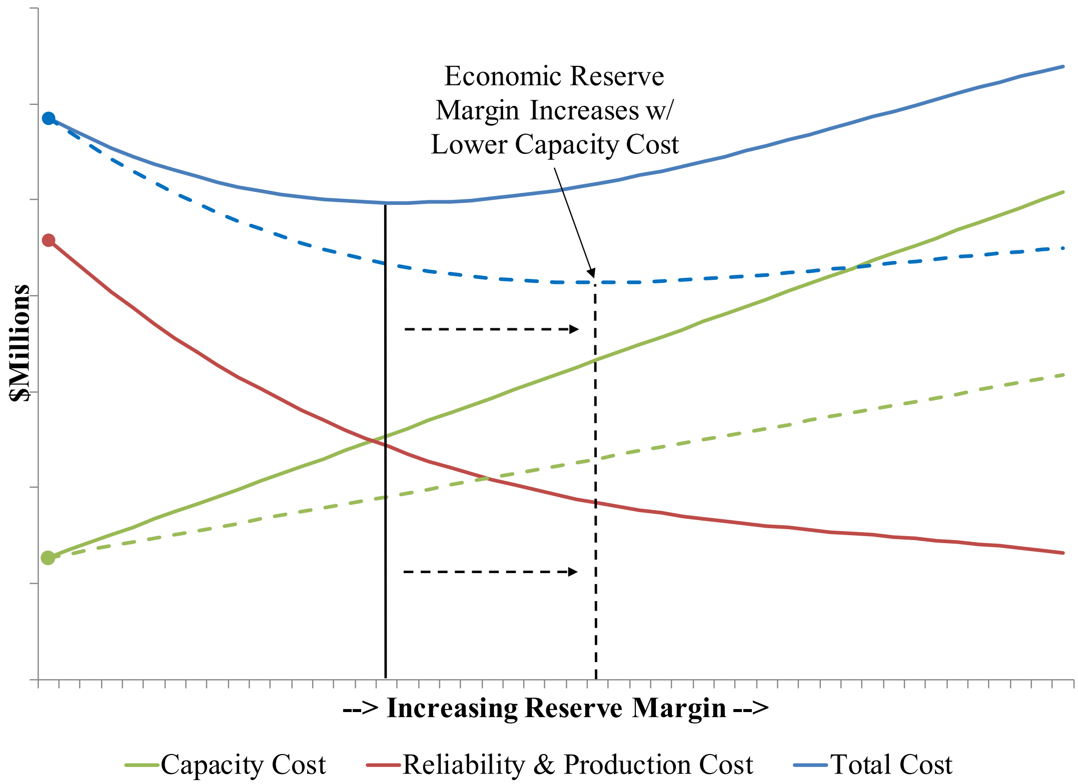
Figure 4: Costs and Benefits of Generation Capacity (Illustrative)



[5] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

Figure 5 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity is reduced to zero.[6]

Figure 5: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit and the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

Table 2 contains the Companies' summer and winter reserve margin forecast for 2025 in the base energy requirements forecast scenario. Generation resources have a higher capacity in the winter primarily because natural gas units can produce more power at lower ambient air temperatures. Mill Creek 1 and

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[6] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

the Companies' small-frame SCCTs are assumed to be retired in 2025. The Rhudes Creek solar facility (100 MW nameplate) is assumed to come online in 2023 and an additional 160 MW of Green Tariff Option 3 solar is added in 2025. None of this capacity is available to serve winter peak because the Companies' winter peak occurs at night. Approximately 79% of the new solar capacity is assumed to be available to serve summer peak.[7]

Table 2: Peak Demand and Resource Summary (MW, Base Energy Requirements Forecast)

	Summer	Winter
Net Peak Load	6,150	5,831
Generation Resources	7,688	7,973
CSR	127	127
DCP	56	0
Retirements/Additions		
Coal[8]	-300	-300
Small-Frame SCCTs[9]	-47	-55
Solar PPAs[10]	204	0
Total Supply	7,728	7,744
Reserve Margin	1,578	1,913
Reserve Margin %	25.7%	32.8%

In 2025, the Companies' forecasted reserve margin is 25.7 percent in the summer and 32.8 percent in the winter. 3.4 percent of the summer reserve margin reflects the assumed availability of the new solar facilities, but the availability of solar is uncertain due to its intermittent fuel source. Figure 6 contains distributions of the average and minimum Brown Solar generation under peak load conditions in June through September. Based on the array's average generation over the hour, between 60 and 88 percent of Brown Solar is available during peak hours.[11] However, based on minimum generation during the hour, between 19 and 56 percent is available. Because the Companies plan generation to serve load in every moment, the distribution of minimum generation is an important consideration and reflects the intermittent nature of solar generation.

[7] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

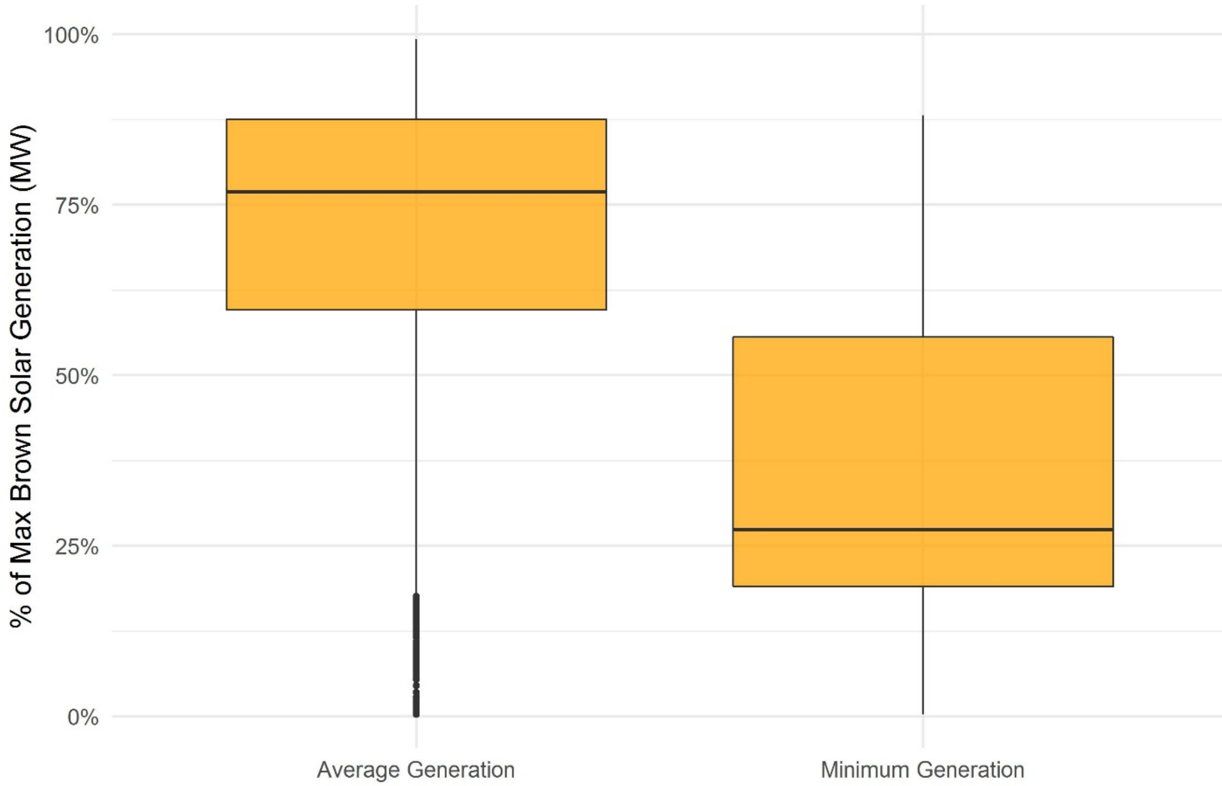
[8] Because Mill Creek 1 and 2 cannot be operated simultaneously during the ozone season due to NOx limits, one of the units (300 MW) is assumed to be unavailable in the summer from 2022 to 2024. Mill Creek 1 is assumed to be retired in 2025.

[9] Haefling 1-2 and Paddy's Run 12 are assumed to be retired in 2025.

[10] Solar PPAs include the Rhudes Creek facility (100 MW nameplate) in 2023 and an additional 160 MW of Green Tariff Option 3 solar in 2025.

[11] 60 and 88 percent are the 25th and 75th percentile values of the distribution.

Figure 6: Distribution of Average and Minimum Brown Solar Generation (June-September; Hours Beginning 1:00 and 2:00 PM EST with System Load > 5,790 MW; 2016-2021)[12]



To evaluate a range of reserve margins, the Companies evaluated the retirement of existing marginal resources and the addition of new resources. In North America, the most commonly used physical reliability guideline is the 1-in-10 LOLE guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs, as well as the expected number of loss-of-load events in ten years ("LOLE"), over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[13] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011, 2014, and 2018 IRPs. SERVM models the availability of generating units in more

[12] 5,790 MW is the 90th percentile load value for these hours. The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

[13] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

detail than ELDCM, but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2025. 2025 is the first year of the planning period that reflects the planned retirement of Mill Creek 1 and the assumed retirements of the small-frame SCCTs.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[14] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of

[14] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 18% (MISO[15]), 14.8% (PJM[15]), and 17% (TVA[16]).[17]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. From one year to the next, the average availability of generating units is fairly consistent. However, the timing and duration of unplanned outage events in a given year can vary significantly. A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events. Table 3 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[15] See NERC's "2020 Long-Term Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[16] See TVA's "2019 Integrated Resource Plan" at https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan.

[17] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 3: 2025 LG&E/KU Generating & DSM Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW)[18]	Net Max Winter Capacity (MW)	EFOR
Brown 3	Coal	412	416	5.8%
Brown 5	SCCT	130	130	8.1%
Brown 6	SCCT	146	171	8.1%
Brown 7	SCCT	146	171	8.1%
Brown 8	SCCT	121	128	8.1%
Brown 9	SCCT	121	138	8.1%
Brown 10	SCCT	121	138	8.1%
Brown 11	SCCT	121	128	8.1%
Brown Solar	Solar	8	0	2.5%
Cane Run 7	NGCC	662	683	2.2%
Dix Dam 1-3	Hydro	32	32	N/A
Ghent 1	Coal	475	479	3.2%
Ghent 2	Coal	485	486	3.2%
Ghent 3	Coal	481	476	3.2%
Ghent 4	Coal	478	478	3.2%
Mill Creek 2	Coal	297	297	3.2%
Mill Creek 3	Coal	391	394	3.2%
Mill Creek 4	Coal	477	486	3.2%
Ohio Falls 1-8	Hydro	64	40	N/A
OVEC-KU	Power Purchase	47	49	N/A
OVEC-LG&E	Power Purchase	105	109	N/A
Paddy's Run 13	SCCT	147	175	8.1%
Trimble County 1 (75%)	Coal	370	370	3.2%
Trimble County 2 (75%)	Coal	549	570	5.1%
Trimble County 5	SCCT	159	179	4.9%
Trimble County 6	SCCT	159	179	4.9%
Trimble County 7	SCCT	159	179	4.9%
Trimble County 8	SCCT	159	179	4.9%
Trimble County 9	SCCT	159	179	4.9%
Trimble County 10	SCCT	159	179	4.9%
Business Solar	Solar	0.2	0	2.5%
Solar Share	Solar	1.3	0	2.5%
Rhudes Creek Solar	Solar	79	0	2.5%
Additional GT Option 3 Solar	Solar	126	0	2.5%
CSR	Interruptible	127	127	N/A
DCP[19]	DSM	56	0	N/A

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[18] Projected net ratings as of 2022. OVEC's capacity reflects the capacity that is expected to be available to the Companies at the time of the summer and winter peaks. The ratings for Brown Solar, Business Solar, Solar Share, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer and winter peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

[19] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 4 and Table 5. Fuel prices in neighboring regions were assumed to be consistent with the Companies' fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 4: 2025 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	[redacted]
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	

Table 5: 2025 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	[redacted]
Ghent	
Mill Creek	
Trimble County – High Sulfur	
Trimble County – PRB	

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 6 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[20] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 127 MW.

[20] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 6: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system and the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 7 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 42% of the time.

Table 7: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	98	42%
1 – 199	2	1%
200 - 399	10	4%
400 - 599	17	7%
600 - 799	11	5%
800 - 999	21	9%
>= 1,000	73	31%
Total	232	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 8 summarizes the summer peak demand forecast for the Companies' service territories and neighboring regions in 2025. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 8: Peak Load Forecasts for 2025

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,150	20,186	34,288	30,170
Target Reserve Margin	N/A	18.0%	14.8%	17%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 48 hourly demand forecasts for 2025 based on actual weather in each of the last 48 years.

Table 9 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions based on these "weather year" forecasts. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated. Because the ability to purchase power from neighboring regions often depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions.

Table 9: Summer and Winter Peak Demand Forecasts, 2025

LG&E/ KU Load	Summer					Winter				
	Weather Year	LG&E/KU	Coincident Peak Demand in Neighboring Regions			Weather Year	LG&E/KU	Coincident Peak Demand in Neighboring Regions		
			MISO-Indiana	PJM-West	TVA			MISO-Indiana	PJM-West	TVA
Max	1983	6,985	20,790	35,110	31,017	1985	7,357	19,181	38,086	36,106
75th %-ile	1995	6,336	20,688	34,740	29,716	1978	6,392	16,984	32,094	30,782
Median	2016	6,043	18,296	30,939	27,248	2011	5,942	18,455	33,416	27,484
25th %-ile	1981	5,882	18,450	30,703	28,514	1987	5,666	18,040	32,521	29,953
Min	1974	5,660	18,208	30,531	23,916	1998	5,187	12,483	26,885	21,713

Figure 7 and Figure 8 contain graphical distributions of the Companies' summer and winter peak demands for 2025. The values in Figure 7 labeled "Forecasted Peak" (i.e., 6,150 MW in the summer and 5,831 MW in the winter) are the Companies' forecasts of summer and winter peak based on average peak weather conditions over the past 20 years. In Figure 8, the year labels indicate the weather years on which the seasonal peaks are based. The Companies' Forecasted Peak is higher in the summer, but the variability in peak demands is much higher in the winter.[21] This is largely due to the wider range of low temperatures that can be experienced in the winter and the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[21] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 127 MW in 2025. The maximum winter peak demand (7,357 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 7: Distributions of Summer and Winter Peak Demands, 2025

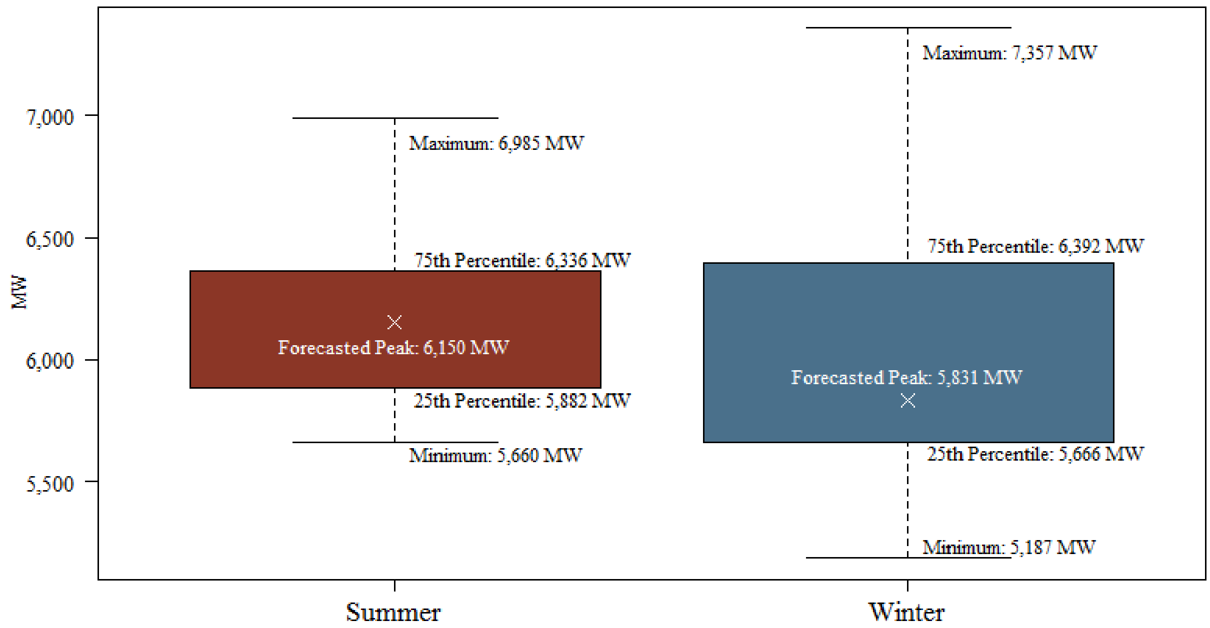
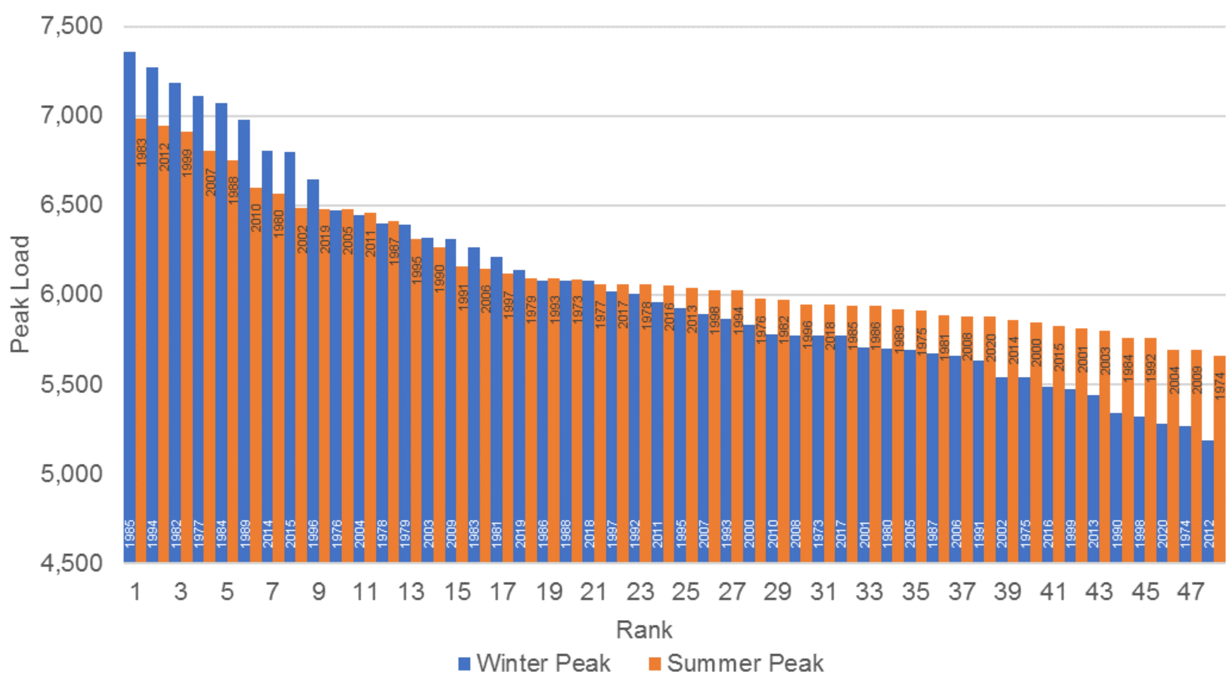


Figure 8: Distributions of Summer and Winter Peak Demands, 2025



4.6 Marginal Resource Costs

Table 10 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, and the Companies' peaking units that are 15 or more years old. The Companies' peaking units include large-frame SCCTs at the Brown, Paddy's Run, and Trimble County stations. The stay-open costs in Table 10 are presented in 2025 dollars. Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 10: Marginal Resource Costs (2025 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.4	27	63
	Ghent 1	72.2	23	36
	Ghent 2	40.9	22	29
	Ghent 3	92.3	23	42
	Mill Creek 2	62.9	22	31
	Mill Creek 3	105.0	23	40
Peaking	Brown 5, 8, 9, 10, & 11	6.0	41	72
	Brown 6 & 7	8.2	29	45
	Paddy's Run 13	21.5	33	57
	Trimble County 5-10	16.1	30	48

To evaluate generation portfolios with lower reserve margins, the sum of stay-open and average energy costs in Table 10 was used to determine which baseload and peaking resources to consider for retirement. For example, based on these costs, the Companies evaluated the retirements of the Brown SCCTs and Brown 3. The retirement of Mill Creek 2 was also evaluated due to its likely need for SCR. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[22]

To evaluate generation portfolios with higher reserve margins, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2021 IRP Resource Screening Analysis and is summarized in Table 11 in 2025 dollars.

[22] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

Table 11: SCCT Cost (2025 Dollars)[23]

Input Assumption	Value
Capital Cost ($/kW)	907
Fixed O&M ($/kW-yr)	23.5
Firm Gas Transport ($/kW-yr)	22.2
Escalation Rate	1.42%
Discount Rate	6.41%
Carrying Charge ($/kW-yr)	112.7

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[24] All studies split customers into residential, commercial, and industrial classes, which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2025 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $19.8/kWh.

Table 12 shows how the numbers were derived. The range for residential customers varied from $1.5/kWh to $3.8/kWh. The range for commercial customers varied from $26.8/kWh to $39.6/kWh while industrial customers varied from $13.9/kWh to $32.2/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $8.0/kWh.

[23] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[24] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

Table 12: Cost of Unserved Energy (2025 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.7	1.5	3.8	3.2
Commercial	36%	39.6	36.1	26.8	27.8
Industrial	30%	22.9	32.2	13.9	27.8
System Cost of Unserved Energy		21.7	23.1	15.1	19.4
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.5	2.6	3.8	2.3
Commercial	36%	26.8	32.6	39.6	12.9
Industrial	30%	13.9	24.2	32.2	18.3
Average System Cost of Unserved Energy			19.8		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 252 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

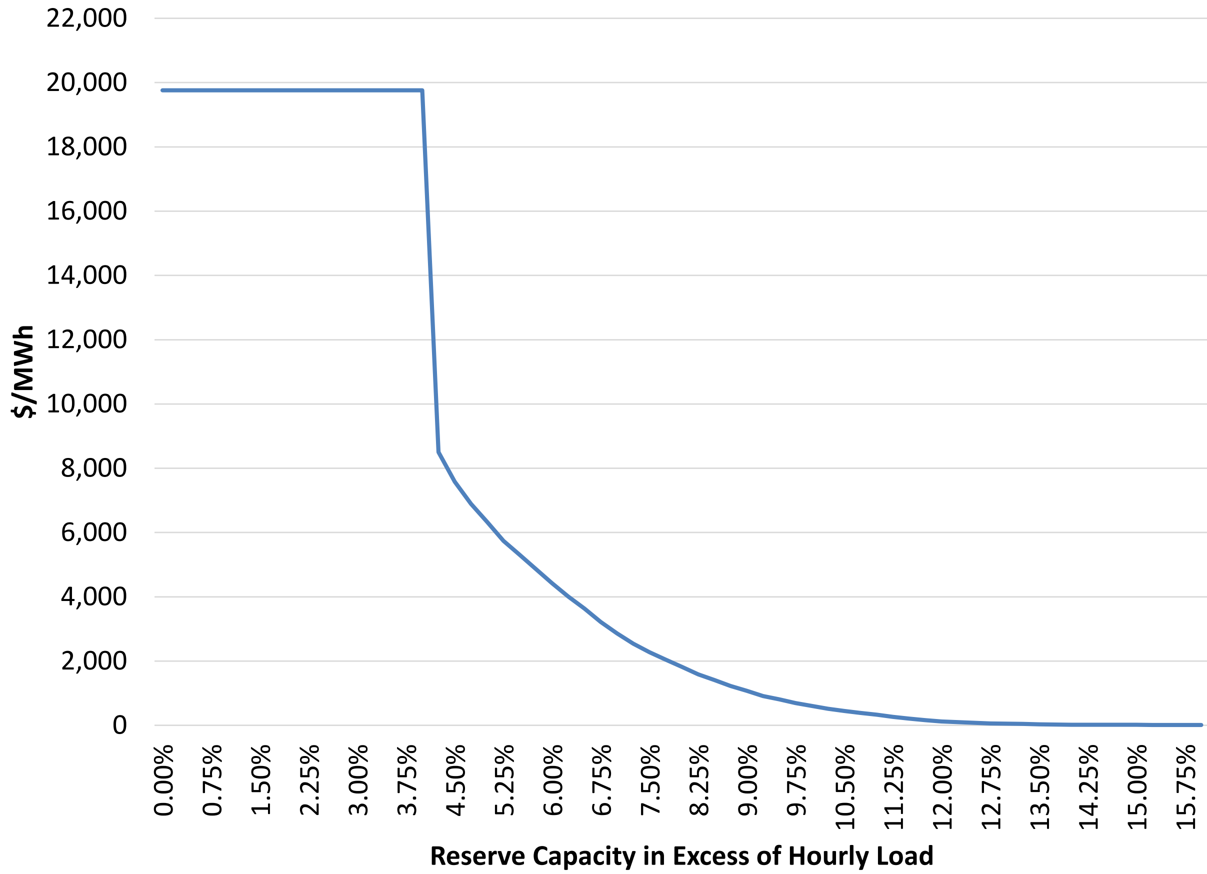
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 252 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 9 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (252 MW) is approximately 4.0% of the forecasted summer peak demand in 2025 (6,150 MW). At reserve capacities less than 4.0% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($19,800/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 9: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value ($100/MWh). Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5 Analysis Results

5.1 Economic Reserve Margin and 1-in-10 LOLE Guideline

Consistent with the methodology used in the 2018 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs over a range of reserve margins to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of their existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity.

The generation portfolios evaluated in this analysis are described in Table 13. As discussed previously, 260 MW of new solar is assumed to come online by 2025, but the availability of the new resources during summer peak is uncertain (see discussion pertaining to Figure 6).[25] For this reason, the Companies first evaluated target reserve margin ranges without the new solar resources.

Table 13: Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Summer Reserve Margin		Winter Reserve Margin	
		w/o New Solar	w/ New Solar	w/o New Solar	w/ New Solar
Existing + 140 MW SCCT	Add SCCT2	24.6%	27.9%	35.2%	35.2%
Existing + 70 MW of SCCT	Add SCCT1	23.5%	26.8%	34.0%	34.0%
Existing[26]	Existing	22.3%	25.7%	32.8%	32.8%
Retire Brown 8	Ret B8	20.3%	23.7%	30.6%	30.6%
Retire Brown 8-9	Ret B8-9	18.4%	21.7%	28.6%	28.6%
Retire Mill Creek 2	Ret M2	17.5%	20.8%	27.7%	27.7%
Retire Brown 8-10	Ret B8-10	16.4%	19.8%	26.2%	26.2%
Retire Brown 3	Ret B3	15.6%	19.0%	25.7%	25.7%
Retire Brown 8-11	Ret B8-11	14.4%	17.8%	24.0%	24.0%
Retire Brown 3, Mill Creek 2	Ret B3_M2	10.8%	14.1%	20.6%	20.6%

LOLE and reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 13 over 48 weather year scenarios and hundreds of unit availability scenarios. For each portfolio without the new solar resources, Table 14 contains the average summer, winter, and total LOLE from ELDCM, as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 15.

Portfolios with LOLE greater than four (i.e., four times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3_M2 portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85th and 90th percentiles ("%-ile") of the reliability and generation production cost distribution.

[25] 260 MW is the sum of capacity for Rhudes Creek Solar (100 MW) and 160 MW of additional Green Tariff Option 3 solar. On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

[26] Existing portfolio excludes Mill Creek 1 and the Companies's small-frame SCCTs, which are assumed to be retired by 2025.

Table 14: Reserve Margin Analysis Results without New Solar (ELDCM, 2025 Dollars)

Generation Portfolio	Loss of Load Events			[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
	Sum	Win	Total		[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.49	0.29	0.79	63.9	754	768	772	818	832	835
Add SCCT1	0.65	0.37	1.04	56.0	754	769	773	810	825	829
Existing	0.86	0.47	1.36	48.1	755	771	775	803	819	824
Ret B8	1.36	0.70	2.11	47.3	758	772	784	805	819	832
Ret B8-9	2.12	0.99	3.19	46.6	761	780	792	808	827	838
Ret M2	2.73	1.20	4.04	29.4	769	792	802	798	822	832
Ret B8-10	3.27	1.47	4.87	45.9	766	793	802	812	839	848
Ret B3	3.77	1.59	5.52	18.7	767	797	808	786	815	827
Ret B8-11	4.98	2.08	7.27	45.1	774	811	824	819	856	870
Ret B3_M2	10.75	3.59	14.87	0.0	803	869	893	803	869	893

Table 15: Reserve Margin Analysis Results without New Solar (SERVM, 2025 Dollars)

Generation Portfolio	Loss of Load Events			[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
	Sum	Win	Total		[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.34	0.25	0.76	63.9	734	757	757	798	820	821
Add SCCT1	0.48	0.33	1.04	56.0	734	755	758	790	811	814
Existing	0.63	0.46	1.42	48.1	735	755	759	783	803	808
Ret B8	0.98	0.69	2.26	47.3	735	757	763	783	805	811
Ret B8-9	1.57	1.03	3.71	46.6	739	763	772	786	810	819
Ret M2	2.14	1.17	4.75	29.4	751	778	789	780	807	818
Ret B8-10	2.38	1.53	5.74	45.9	744	773	784	790	819	830
Ret B3	3.78	1.69	8.05	18.7	752	786	797	771	805	816
Ret B8-11	3.54	2.13	8.64	45.1	752	789	802	797	834	847
Ret B3_M2	10.95	3.57	23.08	0.0	800	858	891	800	858	891

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Approximately one-third of the Companies' total LOLE is associated with serving load in the winter months. With no new solar, the Add SCCT1 generation portfolio (23.5 percent summer reserve margin; 34.0 percent winter reserve margin) has an LOLE slightly greater than one and the Add SCCT2 generation portfolio (24.6 percent summer reserve margin; 35.2 percent winter reserve margin) has an LOLE less than one. Therefore, the summer reserve margin required to meet the 1-in-10 physically reliability standard is approximately 24 percent and the corresponding winter reserve margin is approximately 35 percent. Furthermore, considering the portfolios with an LOLE less than four, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution, the Existing portfolio has the lowest total cost.

Consistent with the 2018 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3 portfolio are $12 million to $17 million higher, but the Companies would expect these costs to be $33 million to $38 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is more reliable and reliability and generation production costs are less volatile.

The ELDCM was used to evaluate the impact of adding 260 MW of nameplate solar to the generation portfolios with the assumption that 79 percent of the capacity would be available to serve summer peak. The results of this analysis are summarized in Table 16. Comparing Table 16 to Table 14, not surprisingly, adding solar to the generation portfolio has a significant impact on LOLE in the summer but not in the winter; approximately one-half (versus one-third) of the Companies' total LOLE is associated with serving load in the winter months.

Table 16: Reserve Margin Analysis Results with New Solar (ELDCM, 2025 Dollars)

	Loss of Load Events				Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
Generation Portfolio	Sum	Win	Total	[A] Capacity Cost ($M/year)	[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.20	0.25	0.46	63.9	737	753	755	801	817	819
Add SCCT1	0.27	0.32	0.60	56.0	738	753	755	794	809	811
Existing	0.37	0.41	0.79	48.1	738	754	756	786	802	804
Ret B8	0.60	0.62	1.24	47.3	740	755	760	787	803	808
Ret B8-9	0.97	0.89	1.89	46.6	742	757	766	788	803	812
Ret M2	1.26	1.07	2.38	29.4	748	767	774	777	796	803
Ret B8-10	1.52	1.32	2.91	45.9	745	769	771	791	815	817
Ret B3	1.75	1.43	3.26	18.7	745	770	772	763	789	791
Ret B8-11	2.38	1.88	4.37	45.1	750	776	788	795	821	833
Ret B3_M2	5.43	3.27	8.96	0.0	768	814	838	768	814	838

If 79 percent of the additional solar capacity is available to serve summer peak, retiring Brown 3 without replacement and assuming more reliability risk – particularly in the witner – will result in slightly lower costs for customers.[27] In addition, the new solar would increase the maximum of the summer reserve margin range from 24 to 25 percent and decrease the maximum of the winter reserve margin range from 35 to 32 percent.[28] However, because the availability of solar under peak load conditions can be much lower than 79 percent (see Figure 6 on page 11), the Companies plan to carefully evaluate the moment-to-moment availability of the Rhudes Creek solar facility before making any further changes to their generation portfolio or their summer and witner target reserve margin ranges.

5.2 Target Reserve Margin Range

The high end of the Companies' target reserve margin range is the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. As discussed above and ignoring for now the potential reliability impacts of new solar generation, the generation portfolio required to meet this guideline has a summer reserve margin of 24 percent and a winter reserve margin of 35 percent.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads. The results of this analysis from ELDCM and SERVM are summarized in Table 17 and Table 18, respectively. Consistent with the 2018 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 14 and Table 15. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 MW (i.e., summer reserve margin decreases to 17 percent and witner reserve margin decreases to 26 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

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[27] Considering the portfolios with an LOLE less than four, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution, the "Ret B3" portfolio has a slightly lower total cost than the "Existing" portfolio.

[28] With the additional solar resources, the Existing generaton portfolio (25.7 percent summer reserve margin; 32.8 percent winter reserve margin) has an LOLE less than one and the Ret B8 portfolio (23.7 percent summer reserve margin; 30.6 percent winter reserve margin) has an LOLE greater than one.

Table 17: Minimum of Target Reserve Margin Range (ELDCM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	22.3%	32.8%	819	825	7	824	829	5
50	21.3%	31.7%	830	837	7	838	841	3
100	20.4%	30.6%	841	848	7	853	855	3
150	19.4%	29.5%	855	860	5	868	870	2
200	18.5%	28.4%	870	872	2	882	885	3
250	17.5%	27.3%	885	888	3	896	900	4
300	16.6%	26.3%	902	901	(1)	911	914	3
350	15.7%	25.3%	920	919	(1)	929	929	(0)
400	14.9%	24.3%	938	936	(2)	950	945	(5)

Table 18: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	22.3%	32.8%	803	811	8	808	814	6
50	21.3%	31.7%	819	824	4	821	827	6
100	20.4%	30.6%	830	838	8	834	840	6
150	19.4%	29.5%	842	849	7	848	853	6
200	18.5%	28.4%	856	861	5	867	867	1
250	17.5%	27.3%	867	873	5	880	884	4
300	16.6%	26.3%	890	889	(1)	897	899	3
350	15.7%	25.3%	912	905	(7)	919	915	(4)
400	14.9%	24.3%	927	918	(9)	931	934	3

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are highly uncertain and hard-to-quantify, the Companies evaluated several sensitivities to the base case inputs. The inputs chosen for sensitivity analysis include cost of unserved enery, scarcity prices, EFOR, and available tranmssion capacity (ATC). The Companies used ELDCM to determine the least-cost generation potfolio for each sensitivity by varying those inputs one at a time.

The base case input for the cost of unserved energy is $19,800/MWh, which is based on information from publicly available studies. The cost of unserved energy is hard to quantify because it varies by customer class. Therefore, the Companies evaluated high and low costs of unserved energy by varying the base assumption by approximately 25 percent. The base case input for scarcity price in ELDCM is $100/MWh, which is difficult to specify because it is a function of reserve capacity determined by unit availability and load. To understand the impact of this input on the analysis, the Companies evaluated significantly higher and lower scarcity prices. As seen in Table 3, the base case inputs for EFOR range from 3.2% for coal baseload units to 8.1% for the Brown SCCTs, and are based on averages from multiple years of history. Historically, EFOR has varied from one year to the next. For the sensitivities, the Companies increased and decreased EFOR by 1.5% and 1%, respectively. For example, the High EFOR case has EFOR ranging from 4.7% for coal baseload units to 9.6% for Brown SCCTs. In the base case, the analysis assumes 500 MW of transmission capacity is available two-thirds of the time, which is based on daily ATC on weekdays during the summer and winter months in 2019-2021. As shown in Table 7, the distribution for ATC has a wide range. For the sensitivities, the Companies decreased and increased ATC to 0 and 1000 MW, respectively.

Table 19 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than four. The results demonstrate that the existing portfolio has the lowest total cost under different assumptions for the highly uncertain and hard-to-quantify inputs, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution.

Table 19: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	85th Percentile	90th Percentile
Base Case	Existing	Existing
Cost of Unserved Energy		
High Cost of Unserved Energy ($25,000/MWh)	Existing	Existing
Low Cost of Unserved Energy ($15,000/MWh)	Existing	Existing
Scarcity Prices		
High Scarcity Prices ($500/MWh)	Existing	Existing
Low Scarcity Prices ($50/MWh)	Existing	Existing
Unit Availability		
High EFOR: Increase EFOR by 1.5 Points	Existing	Existing
Low EFOR: Decrease EFOR by 1.0 Points	Existing	Existing
Available Transmission Capacity		
No Access to Neighboring Markets	Existing	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Existing	Existing

5.4 Final Recommendation

All other things equal, if the Companies' load increases by approximately 300 MW (i.e., summer reserve margin decreases to 17 percent and winter reserve margin decreases to 26 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 24 percent in the summer and 35 percent in the winter. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a summer reserve margin range of 17 to 24 percent and a winter reserve margin range of 26 to 35 percent for resource planning.

2021 IRP Long-Term Resource Planning Analysis

PPL companies

Generation Planning & Analysis

October 2021

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1 Executive Summary

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans over a range of forecasted energy requirements and fuel prices.

Table 1 lists the generating units that are assumed to retire during the 15-year IRP planning period (2022-2036). Mill Creek 1 will be retired in 2024 as part of the Companies' least-cost plan for complying with the amended Effluent Limit Guidelines. Due to their age and inefficiency, the Companies' remaining small-frame SCCTs (Haefling 1-2 and Paddy's Run 12) are assumed to retire by 2025. Consistent with the analysis summarized in Case Nos. 2020-00349 and 2020-00350, Mill Creek 2 and Brown 3 are assumed to retire in 2028. The retirement year for each of the remaining units in Table 1 is the end of the unit's book depreciation life.

Table 1: Assumed Unit Retirement Dates

Unit(s)	Assumed Retirement Year
Mill Creek 1	2024
Haefling 1-2, Paddy's Run 12	2025
Mill Creek 2, Brown 3	2028
Ghent 1-2, Brown 9	2034
Brown 8 and 10	2035
Brown 11	2036

Table 2 lists the Companies' forecasted summer and winter reserve margins in the base, high, and low energy requirements ("load") forecast scenarios and reflects the assumed retirements in Table 1 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[1] The target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.

[1] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Table 2: Forecasted Summer and Winter Reserve Margins[2]

Year	Base Load Scenario		High Load Scenario		Low Load Scenario	
	Summer	Winter	Summer	Winter	Summer	Winter
2022	21.6%	37.3%	21.6%	37.3%	22.7%	38.7%
2023	23.4%	37.9%	23.3%	37.9%	24.8%	39.6%
2024	23.8%	38.2%	22.1%	34.3%	27.0%	42.3%
2025	25.7%	32.8%	23.7%	26.5%	29.3%	36.9%
2026	26.4%	33.4%	22.8%	23.2%	32.1%	39.9%
2027	26.9%	33.8%	23.0%	21.1%	33.2%	40.8%
2028	15.6%	21.7%	11.9%	8.3%	22.4%	28.5%
2029	15.8%	22.1%	11.8%	6.7%	25.2%	29.2%
2030	15.8%	22.3%	11.7%	3.9%	26.0%	29.5%
2031	16.2%	22.6%	11.4%	2.6%	28.8%	30.3%
2032	16.2%	22.5%	11.1%	1.0%	28.7%	30.3%
2033	16.3%	22.8%	11.0%	-0.6%	30.7%	31.0%
2034	-1.6%	3.7%	-6.4%	-17.8%	10.5%	11.3%
2035	-5.6%	-1.0%	-10.5%	-22.8%	6.0%	6.1%
2036	-7.7%	-3.5%	-12.8%	-27.6%	4.5%	3.2%

Table 3 lists total new generation in the least-cost resource plans from this analysis; the timing of new generation additions is summarized in Section 4.3. In the base and low load scenarios, capacity additions are driven by the need to replace retired capacity. In the high load scenario, capacity additions are also needed to serve the increasing load, particularly in the witner months. For example, compared to the Base load scenario, the additional SCCTs, solar, and battery storage in the High load scenario are needed to serve the higher load. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions. The analysis also considered the capital revenue requirements and fixed costs associated with these plans. The least-cost resource plan for each case was identified as the plan with the lowest present value of revenue requirements ("PVRR").

[2] Values reflect the assumed retirements in Table 1 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.

Table 3: New Generation in Least-Cost Resource Plans

Years	Load Scenario	Fuel Price Scenario	Gas	Solar	Wind	Batteries
2026-2030	Base	Base	2 SCCTs[3]	500 MW	0 MW	0 MW
		High	2 SCCTs	1,000 MW	0 MW	0 MW
		Low	2 SCCTs	300 MW	0 MW	0 MW
	High	Base	6 SCCTs	1,500 MW	0 MW	100 MW
		High	5 SCCTs	1,500 MW	0 MW	300 MW
		Low	7 SCCTs	500 MW	0 MW	0 MW
	Low	Base	0 SCCTs	500 MW	0 MW	0 MW
		High	0 SCCTs	1,000 MW	0 MW	0 MW
		Low	0 SCCTs	0 MW	0 MW	0 MW
2031-2036	Base	Base	4 SCCTs	1,600 MW	0 MW	200 MW
		High	0 SCCTs	2,400 MW	300 MW	1,100 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW
	High	Base	0 SCCTs	2,400 MW	100 MW	2,500 MW
		High	0 SCCTs	2,200 MW	1,900 MW	2,000 MW
		Low	10 SCCTs	600 MW	0 MW	0 MW
	Low	Base	4 SCCTs	700 MW	100 MW	200 MW
		High	2 SCCTs	1,600 MW	100 MW	700 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW

Despite a wide range of load and fuel scenarios, some consistent results emerged. Solar and SCCTs are the predominate resource technology choices until the retirement of Ghent 1 and Ghent 2 in 2034. Battery storage is favored in cases with high renewable penetration. The replacement of Ghent 1 and Ghent 2 is expected to rely on renewable resources for energy in most scenarios, and either SCCTs or battery storage for capacity. And NGCC with CCS is not cost-competitive with solar combined with SCCTs or battery storage in any of the scenarios modeled in this analysis. In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors. Successful deployment of Demand-Side Management ("DSM") programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource planning analysis represents the Companies' analysis of the best options to meet customer needs at this point in time, this plan is reviewed, re-evaluated, and assessed against other market-available alternatives prior to commitment and implementation.

[3] A SCCT is assumed to have a summer capacity of 220 MW and a winter capacity of 248 MW.

2 Resource Planning Objectives

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans over a range of forecasted load and fuel prices. These inputs and uncertainties are discussed in the following section.

For each load and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period. The analysis considered all costs for new and existing resources, and it optimized the portfolio to minimize energy and new capacity costs. An annual resource plan was then developed for each case to meet minimum reserve margin requirements (i.e., 17 percent in the summer and 26 percent in the winter) throughout the planning period. The PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base load, base fuel case.

3 Key Inputs and Uncertainties

The following sections summarize key resource planning inputs and uncertainties.

3.1 Load Forecast

The Companies' base, high, and low load forecasts are summarized in Table 4. Table 5 summarizes the base, high, and low forecasts for summer and winter peak demands. The development of these forecasts is discussed in Section 5.(2) and Section 5.(3) in Volume I. A key consideration in resource planning is ensuring reliable service to customers in both summer and winter months.

Table 4: Load Forecast (GWh)

Year	Base	High	Low
2022	32,238	32,271	31,939
2023	32,079	32,152	31,719
2024	32,045	32,980	30,951
2025	31,839	33,039	30,702
2026	31,648	33,816	29,788
2027	31,532	34,019	29,595
2028	31,519	34,387	29,427
2029	31,370	34,651	28,980
2030	31,279	35,036	28,549
2031	31,243	35,425	28,444
2032	31,283	35,968	28,353
2033	31,196	36,358	28,144
2034	31,172	36,866	28,043
2035	31,188	37,368	28,005
2036	31,289	38,001	28,064

Table 5: Peak Demand Forecasts (MW)

Year	Summer			Winter		
	Base	High	Low	Base	High	Low
2022	6,229	6,230	6,175	5,898	5,899	5,839
2023	6,201	6,204	6,134	5,874	5,875	5,804
2024	6,179	6,265	6,024	5,859	6,030	5,693
2025	6,150	6,248	5,975	5,831	6,120	5,656
2026	6,113	6,294	5,849	5,806	6,287	5,535
2027	6,088	6,283	5,800	5,790	6,395	5,502
2028	6,067	6,270	5,731	5,777	6,494	5,472
2029	6,055	6,271	5,602	5,758	6,590	5,444
2030	6,056	6,280	5,564	5,750	6,769	5,430
2031	6,033	6,291	5,445	5,736	6,854	5,395
2032	6,035	6,312	5,448	5,738	6,961	5,395
2033	6,029	6,315	5,362	5,726	7,076	5,367
2034	6,020	6,330	5,364	5,715	7,211	5,325
2035	6,023	6,350	5,361	5,719	7,334	5,337
2036	6,026	6,379	5,321	5,737	7,648	5,364

3.2 Existing Generation Specifications

Table 6 lists the assumed net summer and winter capacity ratings for each of the Companies' existing generating resources.[4]

[4] The Companies expect to retire Zorn 1 by the end of 2021.

Table 6: Existing Generating Resource Characteristics

Resource	Net Max Summer Rating (MW)[5]	Net Max Winter Rating (MW)
Brown 3	412	416
Brown 5	130	130
Brown 6	146	171
Brown 7	146	171
Brown 8	121	128
Brown 9	121	138
Brown 10	121	138
Brown 11	121	128
Brown Solar	8	0
Cane Run 7	662	683
Dix Dam 1-3	32	32
Ghent 1	475	479
Ghent 2	485	486
Ghent 3	481	476
Ghent 4	478	478
Haefling 1-2	24	27
Mill Creek 1	300	300
Mill Creek 2	297	297
Mill Creek 3	391	394
Mill Creek 4	477	486
Ohio Falls 1-8	64	40
OVEC-KU	47	49
OVEC-LG&E	105	109
Paddy's Run 12	23	28
Paddy's Run 13	147	175
Trimble County 1 (75%)	370	370
Trimble County 2 (75%)	549	570
Trimble County 5	159	179
Trimble County 6	159	179
Trimble County 7	159	179
Trimble County 8	159	179
Trimble County 9	159	179
Trimble County 10	159	179
Business Solar	0.2	0
Solar Share	1.3	0

[5] Projected net ratings as of 2022. OVEC's ratings reflect the capacity that is expected to be available to the Companies at the time of the respective summer and winter peaks. The ratings for Brown Solar, Business Solar, Solar Share, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer and winter peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

Table 7 lists the generating units that are assumed to retire during the 15-year IRP planning period (2022-2036). The 2020 ECR analysis demonstrated that installing the water treatment capacity needed to simultaneously operate all four coal units at the Mill Creek station and comply with the amended Effluent Limit Guidelines ("ELG") is not least-cost. In addition, there is some likelihood that a new cooling tower will eventually be needed for Mill Creek Unit 1 to comply with Clean Water Act 316(b) regulations. For these reasons, the 2021 IRP assumes Mill Creek 1 will be retired in 2024, the Mill Creek station's deadline for ELG compliance.

Due to their age and inefficiency, the Companies' small-frame SCCTs do not undergo major maintenance, and the Companies plan to retire these units once a maintenance event renders them uneconomic to repair. Since the 2018 IRP, the Companies have retired Cane Run 11 and Paddy's Run 11 in this manner, and expect to retire Zorn before the end of 2021. For purposes of long-term planning in this analysis, the Companies assume that the remaining small-frame SCCTs, Haefling 1-2 and Paddy's Run 12, will be retired by 2025.

Significant changes in environmental regulations since the 2018 IRP are discussed in Section 6 if Volume I of the 2021 IRP. Based on these changes and the analysis summarized in Exhibit LEB-2 is Case Nos. 2020-00349 and 2020-00350, the 2021 IRP assumes Mill Creek 2 and Brown 3 will be retired in 2028. Based on the current debate regarding new laws and regulations to reduce CO_2 emissions that is mainly focused on stimulating the addition of "clean energy resources" or setting "clean energy standards", the Companies have assumed that all remaining CO_2-emitting units are retired at the end of their book lives for purposes of this analysis.

Table 7: Assumed Unit Retirement Dates

Unit(s)	Assumed Retirement Year
Mill Creek 1	2024
Haefling 1-2, Paddy's Run 12	2025
Mill Creek 2, Brown 3	2028
Ghent 1-2, Brown 9	2034
Brown 8 and 10	2035
Brown 11	2036

3.3 New Generation Specifications

Table 8 and Table 9 list the dispatchable and non-dispatchable resource options that were selected for evaluation in this analysis. These resources set the foundation for a clean energy transition. Non-dispatchable resources include wind and utility-scale solar resources located in Kentucky. Dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines with carbon capture and sequestration ("NGCC w/ CCS"), and 4-hour and 8-hour battery storage. Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions. SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

Table 8: Dispatchable Resources (2022 Installation; 2022 Dollars)

	SCCT	NGCC w/CCS	Battery Storage 4-hour	Battery Storage 8-hour
Summer Capacity (MW)[6]	220	513	1+	1+
Winter Capacity (MW)[6]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[7]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[7]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[7]	22	69	32	58
Firm Gas Cost ($/kW-yr)[8]	22	22	N/A	N/A
Variable O&M ($/MWh)[7]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

Table 9: Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

	KY Solar	KY Wind
Summer Capacity (MW)[9]	100+	100+
Winter Capacity (MW)[9]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[7]	25.1%	27.4%
Capital Cost ($/kW)[7]	1,305	1,325
Fixed O&M ($/kW-yr)[7]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[10]	N/A	15

With the exception of summer and winter capacity values, firm gas cost assumptions, and renewable contributions to summer and winter peak, the cost and operating inputs for the generation resources in Table 8 and Table 9 are based on the "Moderate" case forecast from the National Renewable Energy Laboratory's ("NREL's") 2021 Annual Technology Baseline ("ATB"). NREL's SCCT capital cost reflects the cost of constructing a single SCCT at a greenfield site. Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower. NREL's fixed O&M assumptions for each resource escalate over time in

[6] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled battery storage resources in 100 MW increments.

[7] Source: NREL's 2021 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2019 dollars, to nominal dollars at 2% annually.

[8] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

[9] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled solar and wind resources in 100 MW increments.

[10] Production Tax Credit of $15/MWh included for the first 10 years of wind resources.

nominal dollars with the exception of KY Solar and battery storage, which decrease until year 2030 and then escalate.

This analysis assumes summer reserve margin contributions of 78.6 percent for solar and 24.2 percent for wind, and winter reserve margin contributions of 0.0 percent for solar and 31.9 percent for wind. For purposes of this analysis, the Companies are assuming the Investment Tax Credit ("ITC") will be expanded to apply to battery storage installations regardless of whether or not they are co-located and associated with solar generation.

3.4 Fuel and Emission Prices

3.4.1 Natural Gas Prices

Table 10 contains the range of natural gas prices considered in this analysis. Advancements in natural gas drilling technologies have created an abundance of natural gas supply and greatly improved the economics of NGCC technology. More recently, natural gas prices have been buoyed by growing demand from Mexican pipeline and Liquified Natural Gas (LNG) exports. Additional factors that could provide upward pressure on prices include regulations targeting methane emissions from extraction wells, outright bans on the extraction technique of fracking, and significant growth in gas-fired baseload energy production to support intermittent renewable generation. The level of natural gas prices determines the favorability of renewable technology options; as natural gas prices increase, the value of renewable technology options potentially increases.

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas prices. For the base gas case, the Henry Hub price forecast in 2022 through 2024 reflects monthly forward market prices from NYMEX as of July 14, 2021. In subsequent years, the base forecast is interpolated to reach the Energy Information Administration's ("EIA") High Oil and Gas Supply case from its 2021 Annual Energy Outlook ("AEO") in 2050. The low Henry Hub price forecast reflects the actual spot price in 2020 escalated by half of the compound annual growth rate of the smoothed AEO High Oil and Gas Supply case. The high Henry Hub gas price forecast reflects a smoothed version of the EIA's reference case forecast from its 2021 AEO.

Table 10: Henry Hub Natural Gas Prices (Nominal $/MMBtu)

Year	Low	Base	High
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.2 Coal Prices

Table 11 lists the coal price forecast for the Illinois Basin. In the first five years of the forecast, the market price is a blend of prices based on coal bids received, but not under contract, and forecasts from independent third party consultants. Beyond the fifth year, prices are increased at the annual growth rate reflected in the EIA's 2021 AEO High Oil and Gas Supply case for "All Coals, Minemouth" price forecast. The high and low coal price forecasts reflect the historical relationship of changes in natural gas and ILB coal prices.

Table 11: Illinois Basin Coal Prices (Nominal \$/MMBtu)

Year	Low	Base	High
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.3 SO_2 and NO_x Emissions Allowance Prices

The emissions allowance price forecasts for SO_2 and NO_x are based on a third-party consultant's forecast as of May 2021.

Table 12: SO_2 and NO_x Emission Prices (Nominal \$/short ton)

Year	Annual NO_x	Ozone NO_x	SO_2
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.4 CO_2 Prices

Currently, there is no price associated with CO_2 emissions and no law or regulation is being seriously discussed that would explicitly put a price on such emissions. Instead, much focus recently has been on addressing CO_2 emissions indirectly via a Clean Energy Standard rather than through a CO_2 price or cap and trade scheme. During the Obama administration, the Clean Power Plan sought to reduce CO_2 emissions via state administered programs that focused on either emission rates or mass reductions rather than through a CO_2 price. The Companies have no basis for assuming that a price on CO_2 emissions will or will not be part of part of any such regulations. For these reasons, the 2021 IRP does not evaluate resource expansion plans with an assumed price for CO_2 emissions.

3.5 Other Inputs

3.5.1 Reserve Margin

The Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.[11] The derivation of these reserve margin targets are discussed in detail in 2021 IRP Reserve Margin Study.

3.5.2 Financial Inputs

Table 13 provides the financial inputs used to calculate revenue requirements and the revenue requirements discount rate.

Table 13: Key Financial Inputs

Input	Value
Return on Equity	9.425 %
Cost of Debt	3.96 %
Capital Structure	
Debt	46.78 %
Equity	53.22 %
Tax Rate	24.95 %
Revenue Requirement Discount Rate	6.41 %

[11] Because winter peak demands are more volatile than summer peak demands, the Companies require more reserves (relative to the forecasted summer and winter peak demand under normal weather conditions) in the winter months than in the summer months.

4 Resource Planning Analysis

4.1 Capacity and Energy Need

Table 14 and Table 15 contain the Companies' peak demand and resource summaries in the base load forecast scenario and reflect the assumed unit retirements in Table 7, as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[12]

[12] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Table 14: Summer Peak Demand and Resource Summary (MW, Base Load Forecast)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gross Peak Load	6,522	6,500	6,485	6,461	6,424	6,399	6,378	6,366	6,368	6,344	6,346	6,340	6,331	6,334	6,337
Non-Dispatchable DSM	-294	-300	-305	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311
Net Peak Load	6,229	6,201	6,179	6,150	6,113	6,088	6,067	6,055	6,056	6,033	6,035	6,029	6,020	6,023	6,026
Generation Resources	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Demand Conservation Program ("DCP")	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43
Retirements/Additions															
Coal[13]	-300	-300	-300	-300	-300	-300	-1,009	-1,009	-1,009	-1,009	-1,009	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs[14]	0	0	0	0	0	0	0	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs[15]	0	0	0	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47
Solar PPAs[16]	0	79	79	204	204	204	204	204	204	204	204	204	204	204	204
Total Supply	7,576	7,653	7,651	7,728	7,727	7,725	7,015	7,013	7,012	7,011	7,010	7,009	5,927	5,684	5,562
Reserve Margin	1,348	1,452	1,472	1,578	1,614	1,637	947	958	956	978	975	980	-93	-339	-465
Reserve Margin %	21.6%	23.4%	23.8%	25.7%	26.4%	26.9%	15.6%	15.8%	15.8%	16.2%	16.2%	16.3%	-1.6%	-5.6%	-7.7%

[13] The Companies assume that Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. This analysis assumes that Mill Creek 1 is retired in 2024, Mill Creek 2 and Brown 3 are retired in 2028, and Ghent 1-2 are retired in 2034.

[14] This analysis assumes that Brown 9 is retired in 2034, Brown 8 and 10 are retired in 2035, and Brown 11 is retired in 2036.

[15] This analysis assumes that Haefling 1-2 and Paddy's Run 12 are retired by 2025.

[16] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect 78.6% expected contribution to summer peak capacity as specified in section 3.3.

Table 15: Winter Peak Demand and Resource Summary (MW, Base Load Forecast)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Net Peak Load	5,898	5,874	5,859	5,831	5,806	5,790	5,777	5,758	5,750	5,736	5,738	5,726	5,715	5,719	5,737
Generation Resources	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirements/Additions															
Coal	0	0	0	-300	-300	-300	-1,013	-1,013	-1,013	-1,013	-1,013	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs	0	0	0	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
Solar PPAs[17]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply	8,100	8,100	8,100	7,744	7,744	7,744	7,031	7,031	7,031	7,031	7,031	7,031	5,928	5,662	5,534
Reserve Margin	2,201	2,226	2,240	1,913	1,939	1,954	1,254	1,274	1,282	1,295	1,293	1,305	213	-57	-203
Reserve Margin %	37.3%	37.9%	38.2%	32.8%	33.4%	33.8%	21.7%	22.1%	22.3%	22.6%	22.5%	22.8%	3.7%	-1.0%	-3.5%

Table 16 provides a summary of summer and winter reserve margins across base, high, and low load forecasts. The Companies' analysis assumes maintaining reserve margins in the range of 17 to 24 percent in the summer and 26 to 35 percent in the winter as stated in section 3.5.1. In the base load scenario, the Companies are forecasting a capacity need in 2028 following the assumed retirements of Mill Creek 2 and Brown 3, and further capacity needs in 2034 with the retirements of Ghent 1-2 and Brown 9. In the high load forecast, a winter capacity shortfall exists beginning in 2026 due to a higher penetration of electric space heating, which shortfall renewable resources such as solar would not be well suited to serve. As discussed in Section 5.(3) of Volume I, increases in electric heating penetration were assumed to begin in 2024 to evaluate the effects of a significant increase in electric space heating by the end of the IRP analysis period. Absent a new law or mandate, this transition is unlikely to begin in 2024. In the low load forecast, the Companies do not have a capacity need until the retirements of Ghent 1 and 2 in 2034.

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[17] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect zero expected contribution to winter peak capacity as specified in section 3.3.

Table 16: Reserve Margin Forecasts Across Load Scenarios

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base Load															
Net Peak Load Summer	6,229	6,201	6,179	6,150	6,113	6,088	6,067	6,055	6,056	6,033	6,035	6,029	6,020	6,023	6,026
Net Peak Load Winter	5,898	5,874	5,859	5,831	5,806	5,790	5,777	5,758	5,750	5,736	5,738	5,726	5,715	5,719	5,737
Reserve Margin Summer %	21.6%	23.4%	23.8%	25.7%	26.4%	26.9%	15.6%	15.8%	15.8%	16.2%	16.2%	16.3%	-1.6%	-5.6%	-7.7%
Reserve Margin Winter %	37.3%	37.9%	38.2%	32.8%	33.4%	33.8%	21.7%	22.1%	22.3%	22.6%	22.5%	22.8%	3.7%	-1.0%	-3.5%
High Load															
Net Peak Load Summer	6,230	6,204	6,265	6,248	6,294	6,283	6,270	6,271	6,280	6,291	6,312	6,315	6,330	6,350	6,379
Net Peak Load Winter	5,899	5,875	6,030	6,120	6,287	6,395	6,494	6,590	6,769	6,854	6,961	7,076	7,211	7,334	7,648
Reserve Margin Summer %	21.6%	23.3%	22.1%	23.7%	22.8%	23.0%	11.9%	11.8%	11.7%	11.4%	11.1%	11.0%	-6.4%	-10.5%	-12.8%
Reserve Margin Winter %	37.3%	37.9%	34.3%	26.5%	23.2%	21.1%	8.3%	6.7%	3.9%	2.6%	1.0%	-0.6%	-17.8%	-22.8%	-27.6%
Low Load															
Net Peak Load Summer	6,175	6,134	6,024	5,975	5,849	5,800	5,731	5,602	5,564	5,445	5,448	5,362	5,364	5,361	5,321
Net Peak Load Winter	5,839	5,804	5,693	5,656	5,535	5,502	5,472	5,444	5,430	5,395	5,395	5,367	5,325	5,337	5,364
Reserve Margin Summer %	22.7%	24.8%	27.0%	29.3%	32.1%	33.2%	22.4%	25.2%	26.0%	28.8%	28.7%	30.7%	10.5%	6.0%	4.5%
Reserve Margin Winter %	38.7%	39.6%	42.3%	36.9%	39.9%	40.8%	28.5%	29.2%	29.5%	30.3%	30.3%	31.0%	11.3%	6.1%	3.2%

4.2 Development of Expansion Plan Alternatives

The Companies developed least-cost resource plans over three load and three fuel price scenarios with the resources in Table 8 and Table 9. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions.

4.3 Analysis Results

Table 17 shows the least-cost resource plans in the base load scenario. The base load forecast is relatively flat, so new resources are needed only to replace retired capacity. With base fuel prices, the least-cost expansion plan through 2036 includes 6 SCCTs, 2,100 MW of solar, and 200 MW of batteries. With high fuel prices, there is more emphasis on solar and battery storage in lieu of SCCT capacity. With low fuel prices, the least-cost expansion plan contains significantly less solar. Across all fuel price scenarios, the Companies' expect a greater reliance on the remaining existing generating resources, with a greater proportion of production coming from nighttime hours in proportion to the amount of solar generation that is deployed.

Table 17: New Generation in Least-Cost Resource Plans, Base Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026			
2027			
2028	2 SCCTs, 500 MW Solar	2 SCCTs, 1,000 MW Solar	2 SCCTs, 300 MW Solar
2029			
2030			
2031			
2032			
2033			
2034	4 SCCTs, 1,600 MW Solar	2,400 MW Solar, 800 MW Batteries	4 SCCTs
2035	100 MW Batteries	300 MW Batteries	1 SCCT
2036	100 MW Batteries	300 MW Wind	
Total New Generation	6 SCCTs, 2,100 MW Solar, 200 MW Batteries	2 SCCTs, 3,400 MW Solar, 300 MW Wind, 1,100 MW Batteries	7 SCCTs, 300 MW Solar

Table 18 shows the least-cost resource expansion plans in the high load scenario. The high load forecast has significant increases in peak load and energy as described in Section 5.(3) in Volume I, so new resources are needed not only to replace retired capacity but also to support load growth. With base fuel prices, the least-cost expansion plan through 2036 includes 6 SCCTs, 3,900 MW of solar, 100 MW of wind, and 2,600 MW of battery storage. With high fuel prices, there is more emphasis on wind in lieu of SCCT capacity and battery storage. With low fuel prices, the least-cost expansion plan includes only SCCTs and solar.

Table 18: New Generation in Least-Cost Resource Plans, High Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026[18]	1 SCCT	1 SCCT	1 SCCT
2027	1 SCCT	1 SCCT	1 SCCT
2028	3 SCCTs, 1,500 MW Solar	3 SCCTs, 1,500 MW Solar	3 SCCTs, 500 MW Solar
2029	1 SCCT	100 MW Batteries	1 SCCT
2030	100 MW Batteries	200 MW Batteries	1 SCCT
2031	100 MW Batteries	100 MW Batteries	
2032	100 MW Batteries	200 MW Batteries	1 SCCT
2033	200 MW Batteries	100 MW Batteries	
2034	2,400 MW Solar, 1,200 MW Batteries	2,200 MW Solar, 1,300 MW Batteries	5 SCCTs, 600 MW Solar
2035	500 MW Batteries	200 MW Wind, 300 MW Batteries	2 SCCT
2036	100 MW Wind, 400 MW Batteries	1,700 MW Wind	2 SCCTs
Total New Generation	6 SCCTs, 3,900 MW Solar, 100 MW Wind, 2,600 MW Batteries	5 SCCTs, 3,700 MW Solar, 1,900 MW Wind, 2,300 MW Batteries	17 SCCTs, 1,100 MW Solar

Table 19 shows the least-cost resource expansion plans in the low load scenario. The low load forecast has decreases in peak load and energy as described in Section 5.(3) in Volume I, so fewer resources are needed to replace retired capacity. With base fuel prices, the least-cost expansion plan through 2036 includes 4 SCCTs, 1,200 MW of solar, 100 MW of wind, and 200 MW of battery storage. With high fuel prices, there is more emphasis on solar and battery storage in lieu of SCCT capacity. With low fuel prices, the least-cost expansion plan relies solely on new SCCT capacity. Across all fuel price scenarios, reductions in load and energy mitigate some of the need for replacement generation. In the base and high fuel price scenarios, the Companies expect a greater reliance on the remaining existing generating resources during nighttime hours and when solar generation is otherwise unavailable.

[18] Note that the 2026 and 2027 SCCTs are being added in this scenario to address winter reliability concerns associated with a higher penetration of electric space heating, which concerns renewable resources like solar are not well suited to address.

Table 19: New Generation in Least-Cost Resource Plans, Low Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026			
2027			
2028	500 MW Solar	1,000 MW Solar	
2029			
2030			
2031			
2032			
2033			
2034	4 SCCTs, 700 MW Solar	2 SCCTs, 1,600 MW Solar, 300 MW Batteries	4 SCCTs
2035	100 MW Batteries	300 MW Batteries	1 SCCT
2036	100 MW Wind, 100 MW Batteries	100 MW Wind, 100 MW Batteries	
Total New Generation	4 SCCTs, 1,200 MW Solar, 100 MW Wind, 200 MW Batteries	2 SCCTs, 2,600 MW Solar, 100 MW Wind, 700 MW Batteries	5 SCCTs

Table 20 shows the forecasted CO_2 emissions in 2035 across all three load and fuel price scenarios compared to the Companies' actual emissions from 2010. Emission reductions are greater in scenarios with greater additions of renewable resources, and emissions are expected to drop between 22 to 36 percent in the low fuel price scenario, 36 to 42 percent in the base fuel price scenario, and 42 to 47 percent in the high fuel price scenario.

Table 20: Forecasted CO_2 Emissions vs. 2010 Actuals

Scenario	Year	CO_2 Emissions (short tons)	% Change from 2010
2010 Actual	2010	35,843	--
Base Load, Base Fuel Prices	2035	21,505	-40%
Base Load, High Fuel Prices	2035	19,692	-45%
Base Load, Low Fuel Prices	2035	25,100	-30%
High Load, Base Fuel Prices	2035	22,831	-36%
High Load, High Fuel Prices	2035	20,636	-42%
High Load, Low Fuel Prices	2035	28,079	-22%
Low Load, Base Fuel Prices	2035	20,619	-42%
Low Load, High Fuel Prices	2035	19,155	-47%
Low Load, Low Fuel Prices	2035	22,992	-36%

4.4 DSM Potential

The Companies considered the potential for DSM in context of the base load and base fuel case. Table 17 shows the expansion plan for this case, and Table 21 shows the capacity factors of the Companies' new and existing generating units for this case. The 200 MW of battery storage added in 2035 and 2036 is forecast to operate at a capacity factor of less than 1 percent, and is primarily for serving peak load. Successful deployment of DSM programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

Table 21: Capacity Factors in Base Load, Base Fuel Case

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	23%	29%	27%	30%	26%	25%	26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	2%	2%	2%	2%	2%	3%	3%	7%	6%	5%	2%	2%	3%	2%	3%	5%
Brown 6-7	5%	4%	6%	6%	7%	8%	5%	6%	4%	4%	5%	4%	2%	8%	6%	6%
Brown Solar	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
Cane Run 7	84%	82%	80%	77%	88%	87%	89%	76%	89%	88%	87%	81%	85%	83%	72%	81%
Dix Dam 1-3	29%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Ghent 1	61%	62%	72%	64%	59%	65%	64%	66%	58%	64%	66%	64%	66%	N/A	N/A	N/A
Ghent 2	61%	62%	67%	55%	63%	60%	55%	63%	62%	58%	61%	63%	62%	N/A	N/A	N/A
Ghent 3	65%	61%	62%	58%	57%	53%	56%	61%	60%	56%	58%	59%	60%	59%	59%	58%
Ghent 4	55%	53%	58%	46%	47%	45%	48%	47%	49%	51%	49%	50%	51%	53%	54%	54%
Haefling 1-2	0.1%	0.3%	0.1%	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 1	59%	69%	68%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	35%	30%	31%	36%	79%	76%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	61%	63%	55%	73%	68%	74%	63%	76%	69%	77%	71%	76%	71%	71%	64%	72%
Mill Creek 4	71%	61%	69%	73%	81%	80%	72%	74%	82%	69%	81%	76%	81%	70%	77%	71%
Ohio Falls 1-8	30%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	31%	32%	31%
Paddy's Run 12	0.3%	0.3%	0.1%	0.2%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 13	6%	7%	3%	3%	3%	1%	1%	4%	3%	3%	3%	3%	4%	4%	4%	4%
Trimble County 1	65%	74%	74%	77%	68%	76%	75%	79%	75%	78%	72%	78%	67%	78%	74%	78%
Trimble County 2	76%	69%	61%	65%	64%	59%	67%	69%	68%	67%	66%	67%	66%	60%	66%	65%
Trimble Co 5-10	12%	17%	13%	12%	12%	10%	11%	12%	8%	11%	9%	11%	12%	14%	17%	14%
Zorn 1	0.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Simpsonville Solar	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
New SCCTs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20%	22%	21%	20%	18%	19%	21%	23%	21%
New Solar	N/A	N/A	26%	25%	26%	26%	26%	27%	27%	27%	27%	27%	27%	27%	27%	27%
New Battery Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.4%	0.6%

4.5 Summary of Findings

Table 22 shows the least-cost resource expansion plans across all scenarios. Despite a wide range of load and fuel scenarios, some consistent results emerged. Solar and SCCTs are the predominate resource technology choices until the retirement of Ghent 1 and Ghent 2 in 2034. Battery storage is favored in cases with high renewable penetration. The replacement of Ghent 1 and Ghent 2 is expected to rely on renewable resources for energy in most scenarios, and either SCCTs or battery storage for capacity. And NGCC with CCS is not cost-competitive with solar combined with SCCTs or battery storage in any of the scenarios modeled in this analysis. In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors. Successful deployment of Demand-Side Management ("DSM") programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

Table 22: New Generation in Least-Cost Resource Plans

Years	Load Scenario	Fuel Price Scenario	Gas	Solar	Wind	Batteries
2026-2030	Base	Base	2 SCCTs[19]	500 MW	0 MW	0 MW
		High	2 SCCTs	1,000 MW	0 MW	0 MW
		Low	2 SCCTs	300 MW	0 MW	0 MW
	High	Base	6 SCCTs	1,500 MW	0 MW	100 MW
		High	5 SCCTs	1,500 MW	0 MW	300 MW
		Low	7 SCCTs	500 MW	0 MW	0 MW
	Low	Base	0 SCCTs	500 MW	0 MW	0 MW
		High	0 SCCTs	1,000 MW	0 MW	0 MW
		Low	0 SCCTs	0 MW	0 MW	0 MW
2031-2036	Base	Base	4 SCCTs	1,600 MW	0 MW	200 MW
		High	0 SCCTs	2,400 MW	300 MW	1,100 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW
	High	Base	0 SCCTs	2,400 MW	100 MW	2,500 MW
		High	0 SCCTs	2,200 MW	1,900 MW	2,000 MW
		Low	10 SCCTs	600 MW	0 MW	0 MW
	Low	Base	4 SCCTs	700 MW	100 MW	200 MW
		High	2 SCCTs	1,600 MW	100 MW	700 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource planning analysis represents the Companies' analysis of the best options to meet customer needs at this point in time, this

[19] A SCCT is assumed to have a summer capacity of 220 MW and a winter capacity of 248 MW. In the high load scenario, SCCT capacity is first added in 2026 to address winter reliability concerns associated with a higher penetration of electric space heating. In the base load scenario, SCCT capacity is first added in 2028 to address the reserve margin need resulting from the retirements of Mill Creek 2 and Brown 3.

plan is reviewed, re-evaluated, and assessed against other market-available alternatives prior to commitment and implementation.

IRP 2021 – Transmission Portion

The Companies identify transmission construction projects and upgrades required to maintain the adequacy of their transmission system to meet projected customer demands and address any changes to the generation resource mix. This is accomplished through various existing processes, including the annual Transmission Expansion Plan, Generator Interconnection Requests, and Transmission Service Requests.

Transmission Expansion Plan (TEP) Process

The TEP is developed annually and utilizes customer load forecasts and the expected generation to serve that load over a ten-year period. The TEP complies with NERC Reliability Standard TPL-001, the Companies Transmission Planning Guidelines, and is approved by the Independent Transmission Organization (ITO).

The TEP study process includes analyzing the base case for summer, winter, and off-peak seasons, plus over 100,000 contingencies (i.e., generator and transmission equipment outages and combinations including neighboring systems). This analysis identifies potential transmission constraints and results in construction projects or upgrades to maintain system reliability.

The annual TEP process ensures the transmission system can accommodate any expected future changes in the generation resource mix can meet future customer demand.

Generator Interconnection (GI) Process

New generation resources pursuing interconnection with the Companies' transmission system are required to follow the FERC approved Open Access Transmission Tariff GI process. This process is designed to maintain the reliability of the grid while allowing generation resources to connect in a fair and consistent manner.

The generation interconnection process requires generator owners to submit their generation projects to a queue by providing information that includes the exact location, capacity, and commercial operations start date. Transmission studies are performed in queue order. The studies identify any applicable transmission projects required to prevent reliability issues because of power flow changes on the grid with the generator addition.

The ITO oversees this process and approves new GI requests.

Transmission Service Request (TSR) Process

New delivery points for load or qualifying load increases at existing delivery points (5 MW or more on 69 kV facilities or 10 MW or more at higher voltage facilities) require the load serving entity to submit a TSR. Similar to the GI process, transmission studies are performed in queue order. Any transmission projects needed to accommodate the incremental load are identified.

The ITO oversees this process and approves new GI requests.

Transmission Considerations from Retiring Conventional Spinning Generation & Incorporating Inverter-Based Resources

As the Companies and the utility industry consider the retirement of conventional spinning generation and adding Inverter-Based Resources (IBR), the Companies' Transmission Department is preparing to support such a transition. As final generation resource decisions are made, the processes outlined above will be utilized to maintain system reliability.

Primary considerations that impact whether new or upgraded transmission facilities are needed include:

- Amount of IBR installed capacity
- Location and geographic dispersion of IBR
- Ability of the resulting generation portfolio to provide grid stability

There are two primary reliability functions typically supplied to the grid by conventional spinning generation that provide grid stability: frequency and voltage control. As IBRs are added to the grid in place of conventional spinning generation, transmission studies will be performed to ensure adequacy of voltage and frequency support.

The adequacy of frequency and voltage support is highly dependent on the location of those resources compared to load. For example, if a large generator has strong voltage and frequency support but is connected to the grid far from load centers, the resource will be unable to support voltage and frequency at a level comparable to a resource located close to the load center.

In Kentucky, high renewable penetration is more likely at locations with smaller load centers (i.e., rural areas). Therefore, voltage and frequency support equipment traditionally supplied by conventional spinning generation may be required near load centers. Voltage and frequency support equipment may could include the following:

Voltage Support

- Conversion of retired synchronous machines to condensers
- New synchronous condensers
- Static VAR Compensators (STATCOM)

Frequency Support

- Headroom requirements for new resources
- Synchronous condensers that add inertia to the grid

- Batteries that do not function as a generation resource. These would be partially charged to function as either a load or a generator during frequency events but otherwise are in standby mode.
- Available combustion turbines connected to the grid at minimum levels to provide real power during low frequency events.

The exact quantities and locations of the above listed devices will not be known without detailed information for the generation projects. But through the generation interconnection process, transmission will be able to integrate renewable resources while maintaining grid reliability.

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Kentucky Utilities Company / Louisville Gas and Electric Company

Project Number	Transmission Expansion Plan Projects	Estimated Timetable for Implementation

CONFIDENTIAL

Transmission System Map

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 <u>most</u> favorable case for RTO membership in each year. The blue bars represent the <u>least</u> 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]

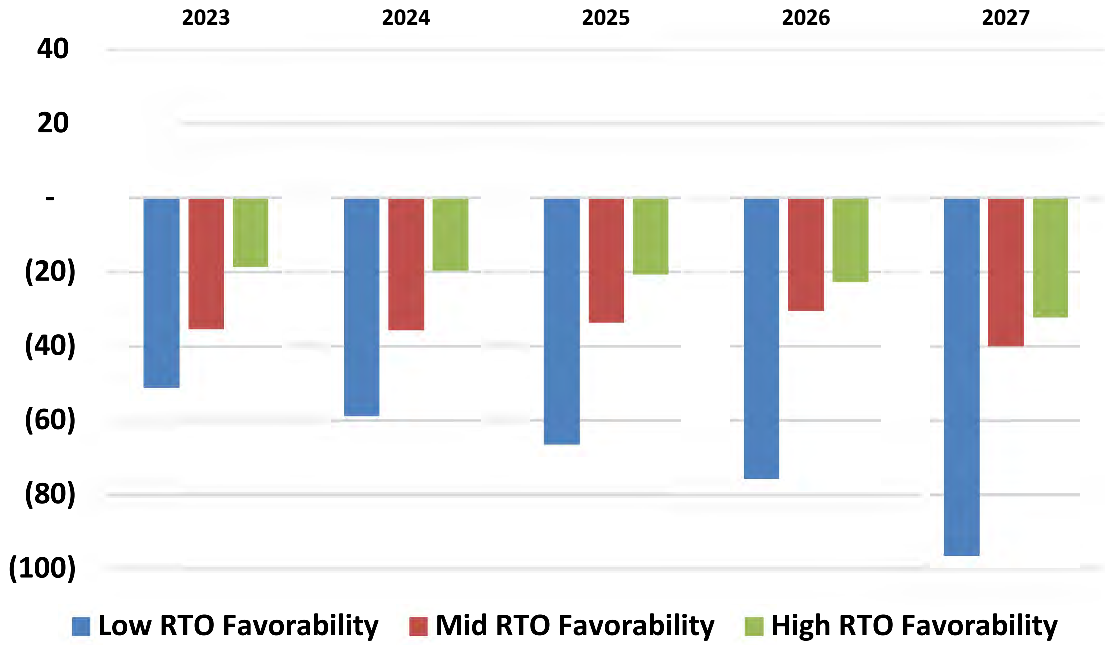
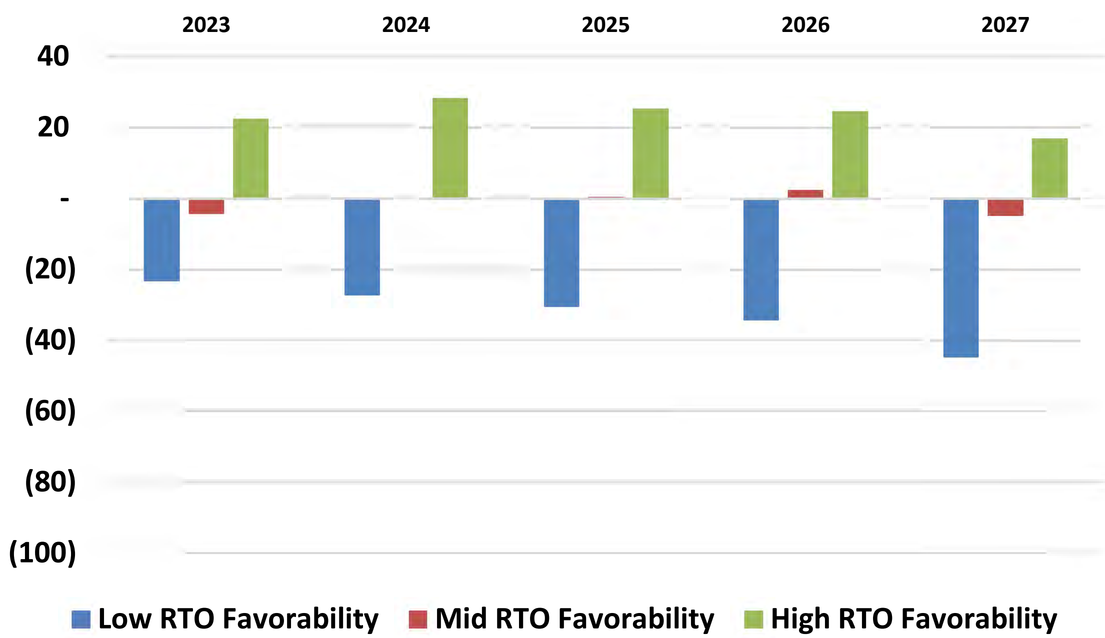


Figure 2: PJM Range of Potential Near-Term Outcomes ($M)[2]



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

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[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)

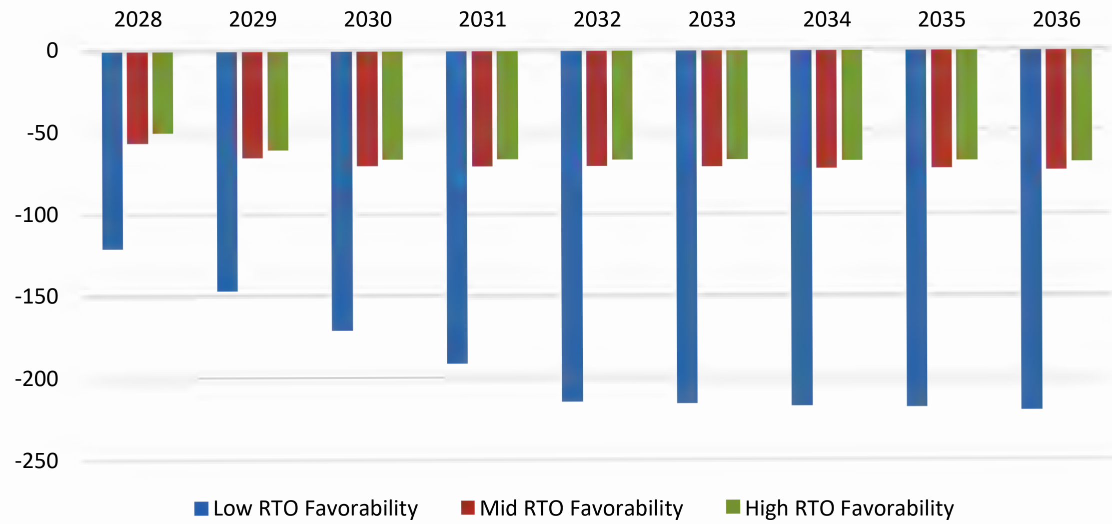
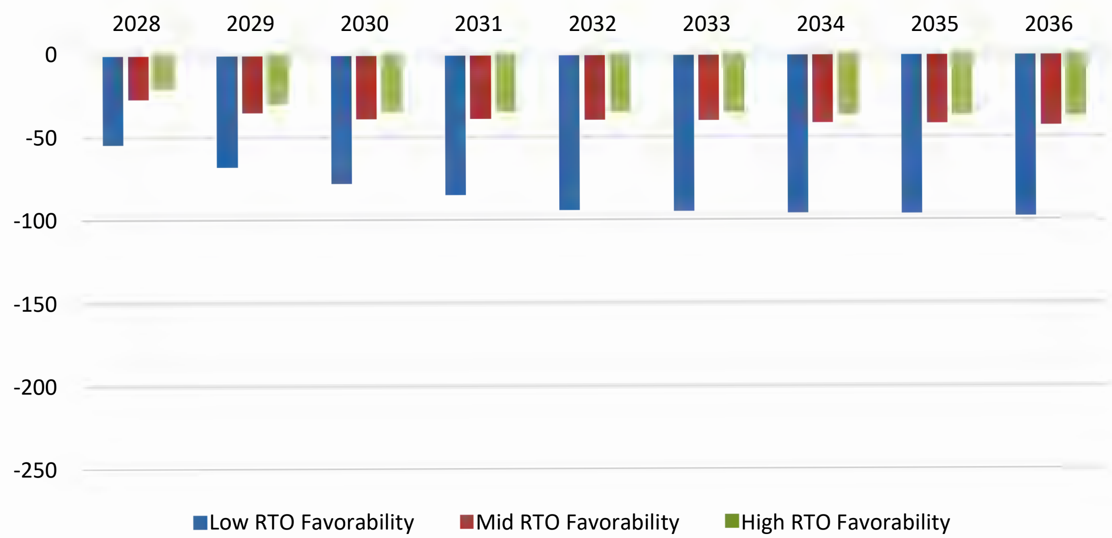


Figure 4: Projected Fixed Costs Range - PJM ($M)



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

[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:

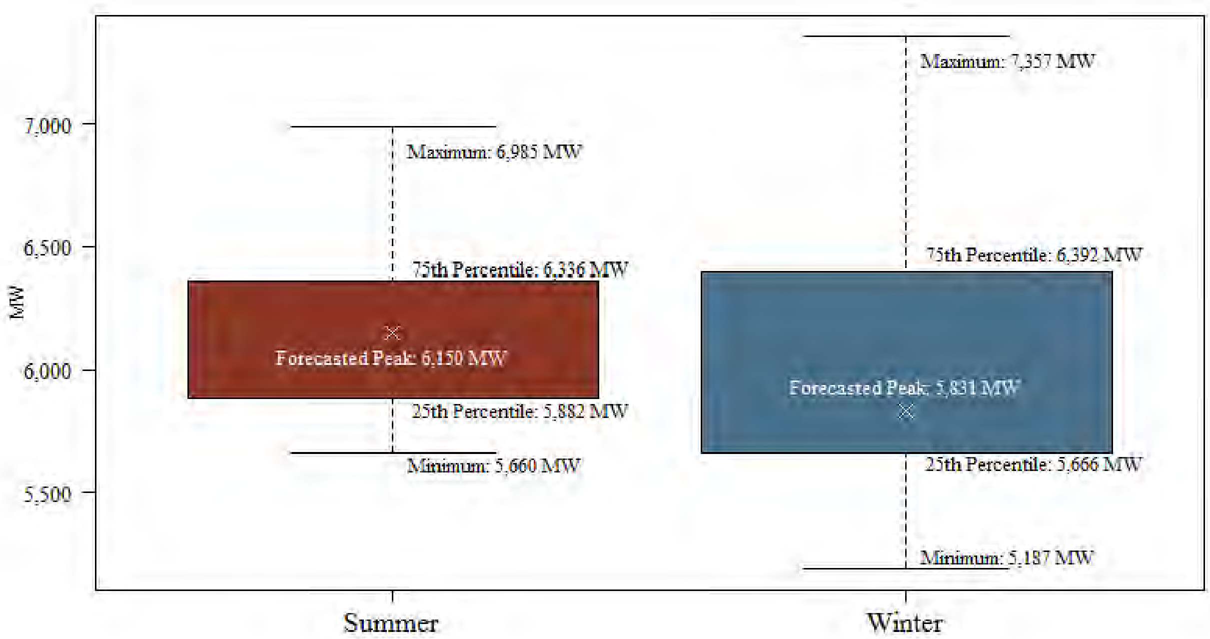
1. Managing fuel risk: maintaining coal inventories, purchasing forward natural gas for generation, and purchasing natural gas transportation rights.
2. Unit reliability: keeping generating units in working order and preparing for extreme operating conditions.

[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

[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

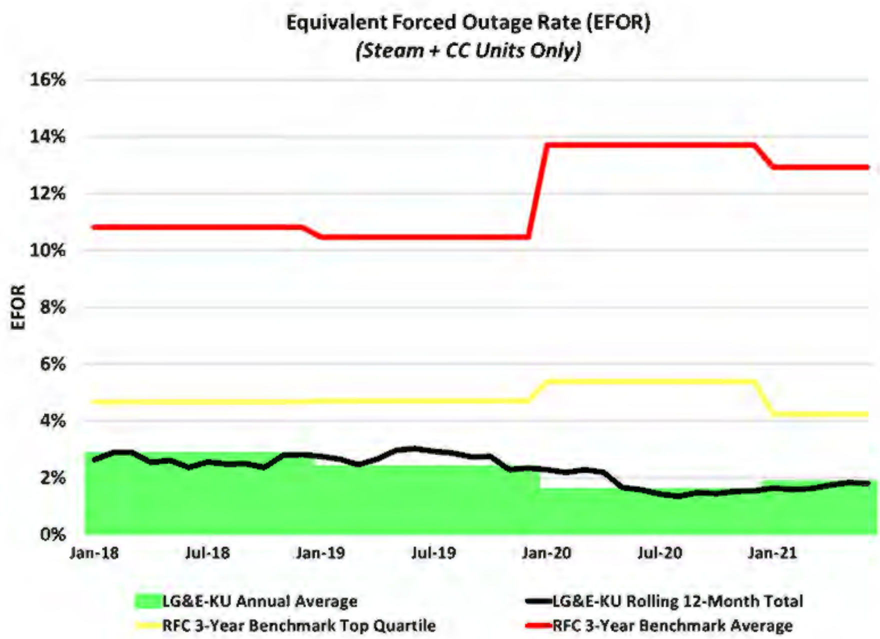
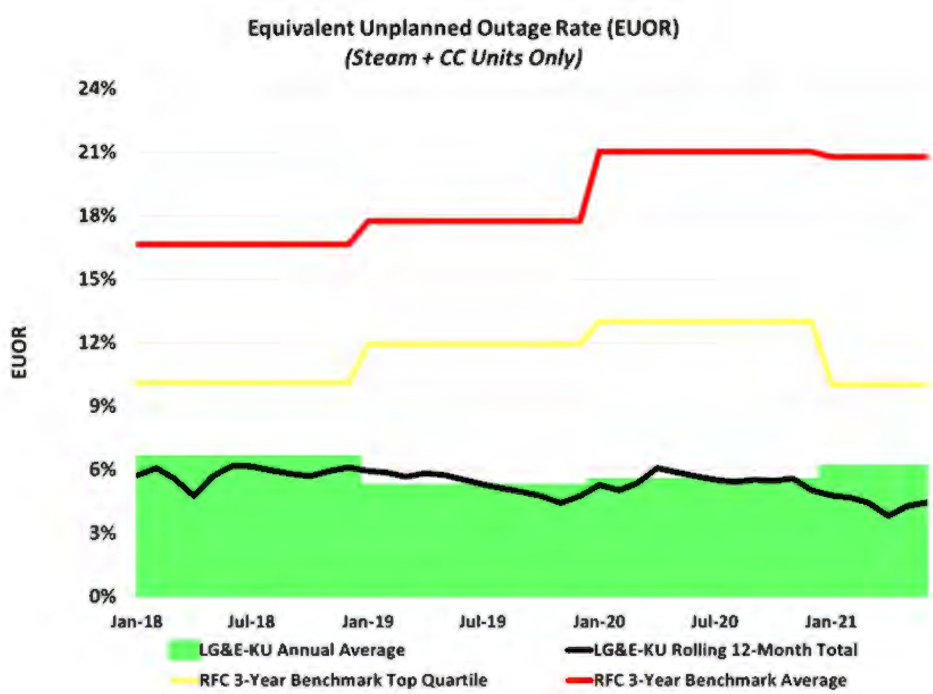


Figure 7: Equivalent Unplanned Outage Rate



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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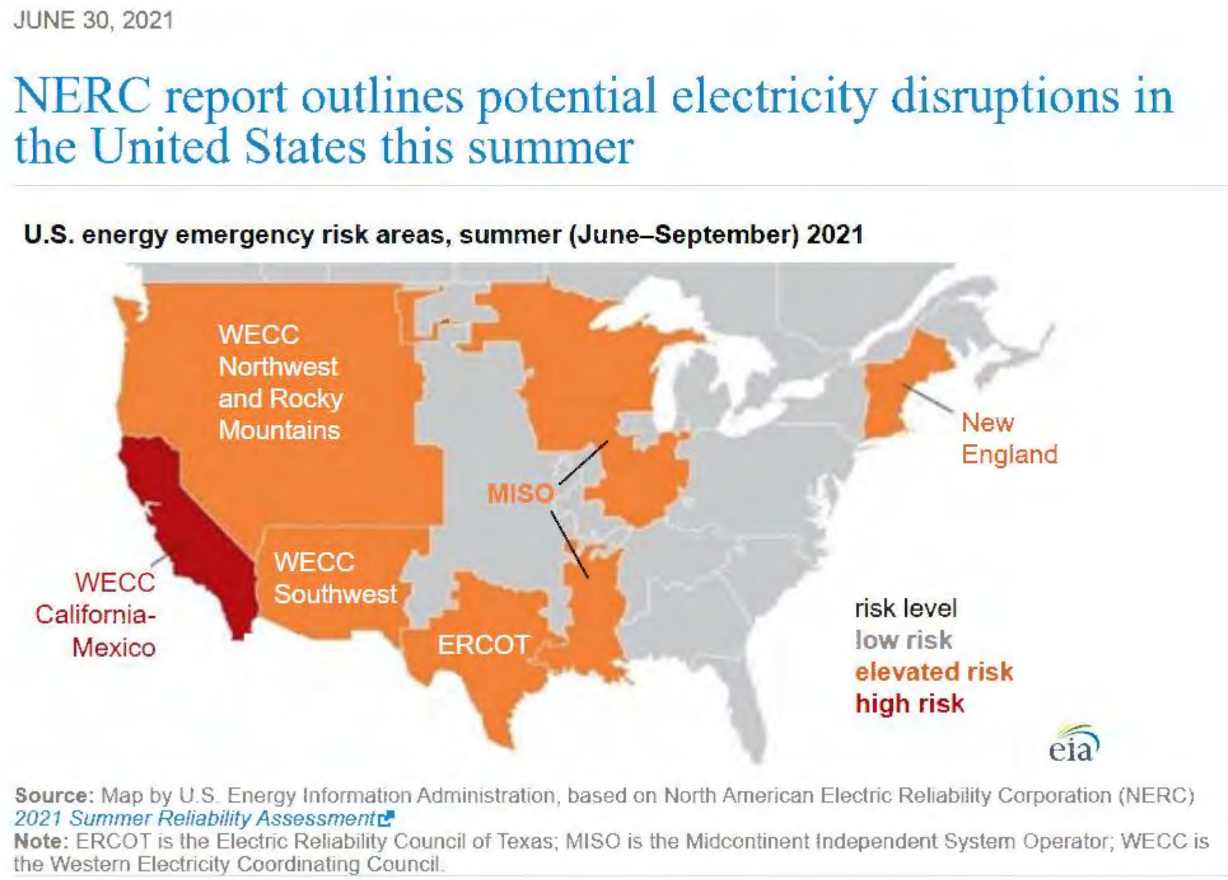
14 Definition from NERC Glossary of Terms

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.").

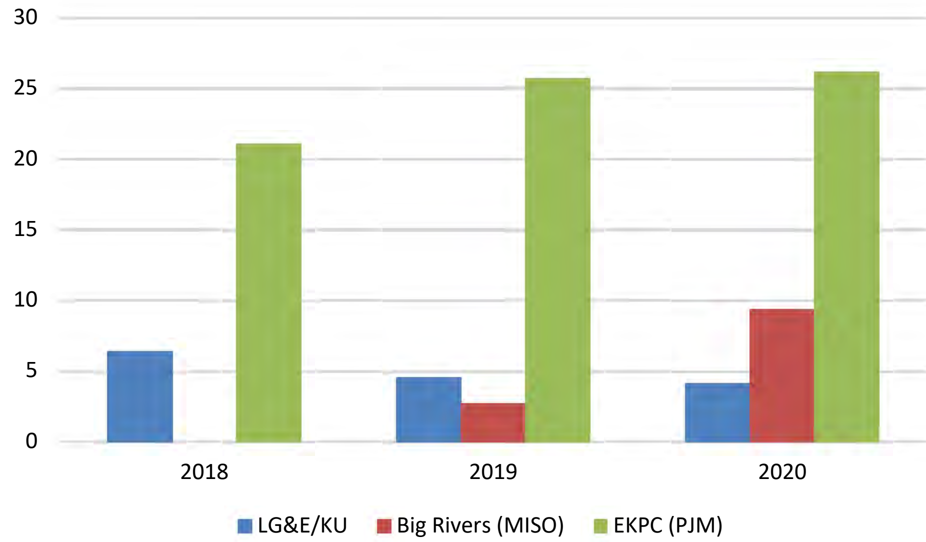
Figure 8: NERC 2021 Summer Reliability Assessment



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

[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

[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

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[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.

[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

[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

[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)

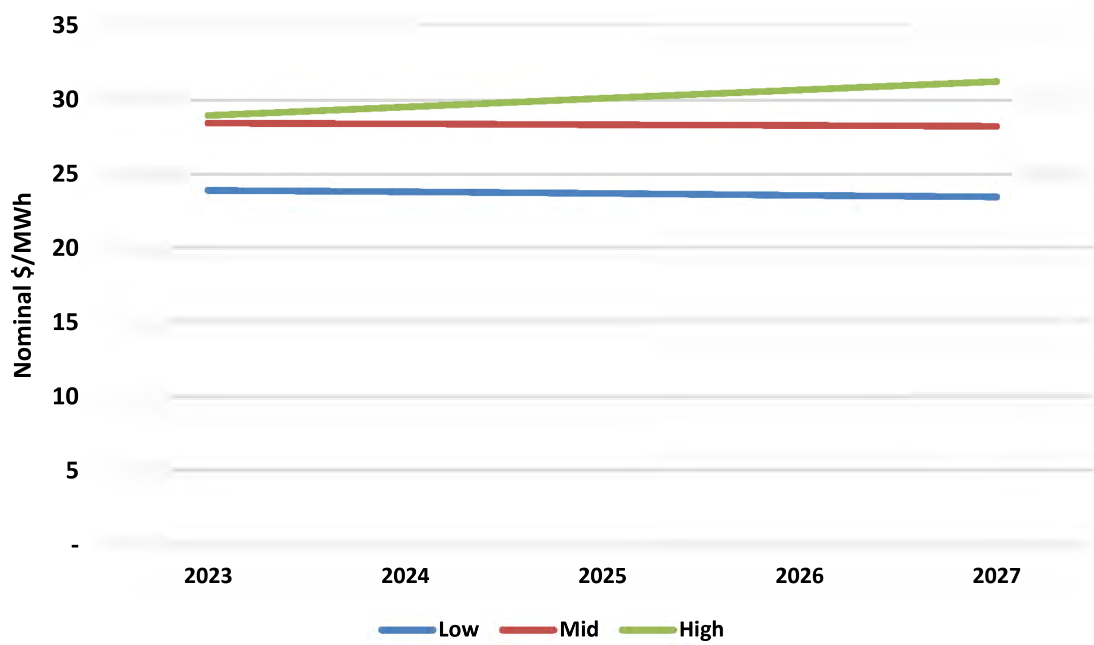
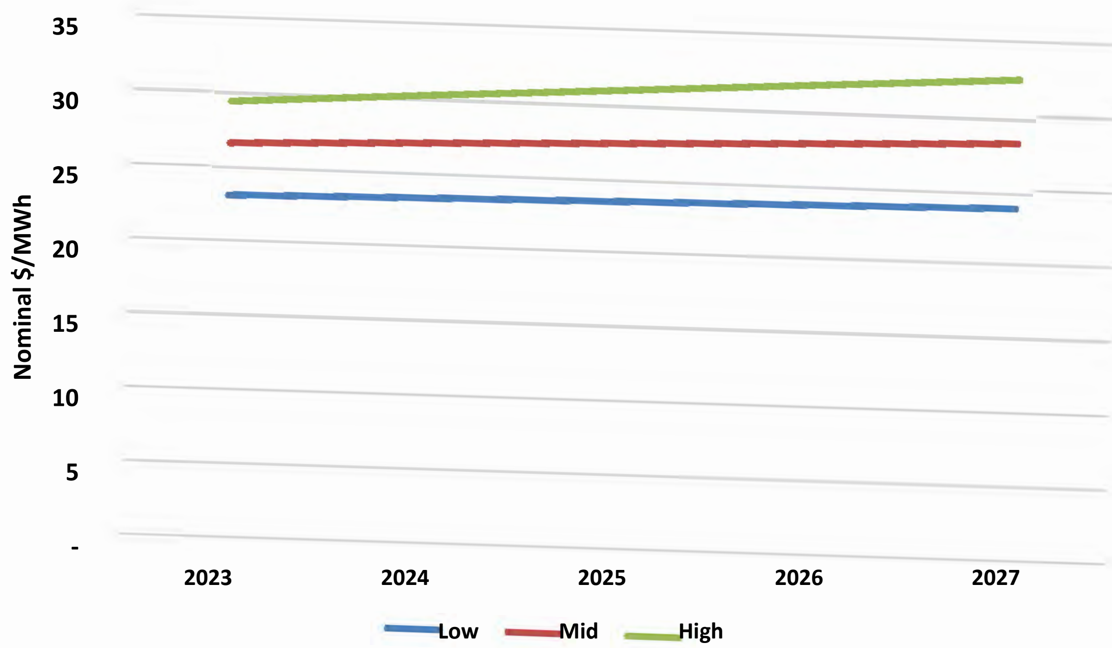


Figure 11: PJM Energy Price Forecast Scenarios (Nominal Annual Average $/MWh)



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

[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)

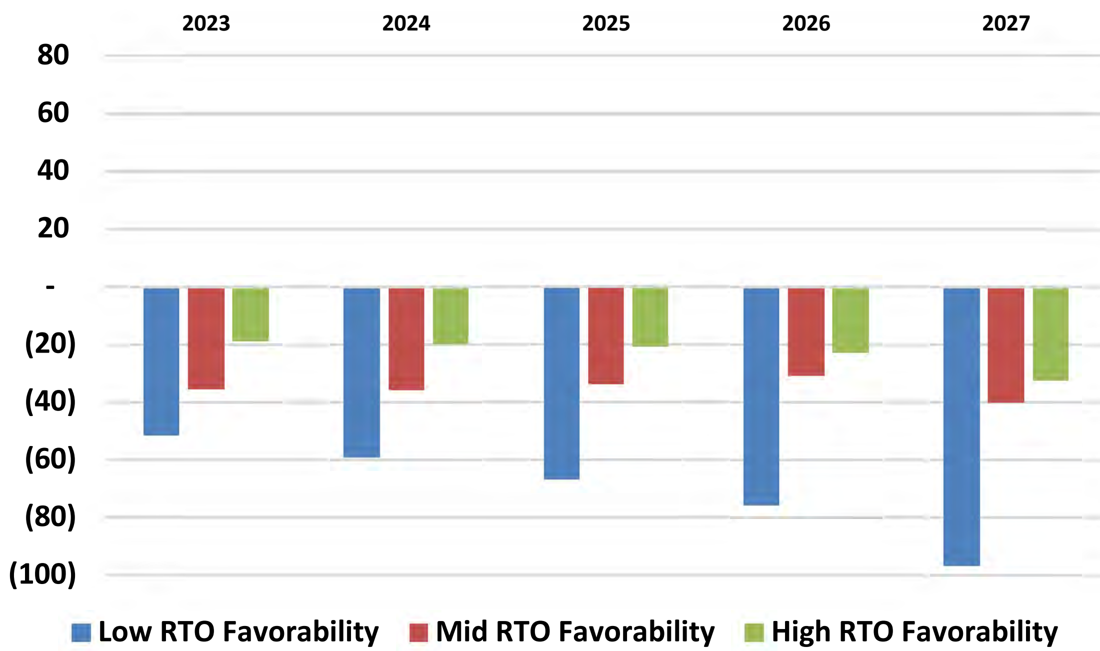
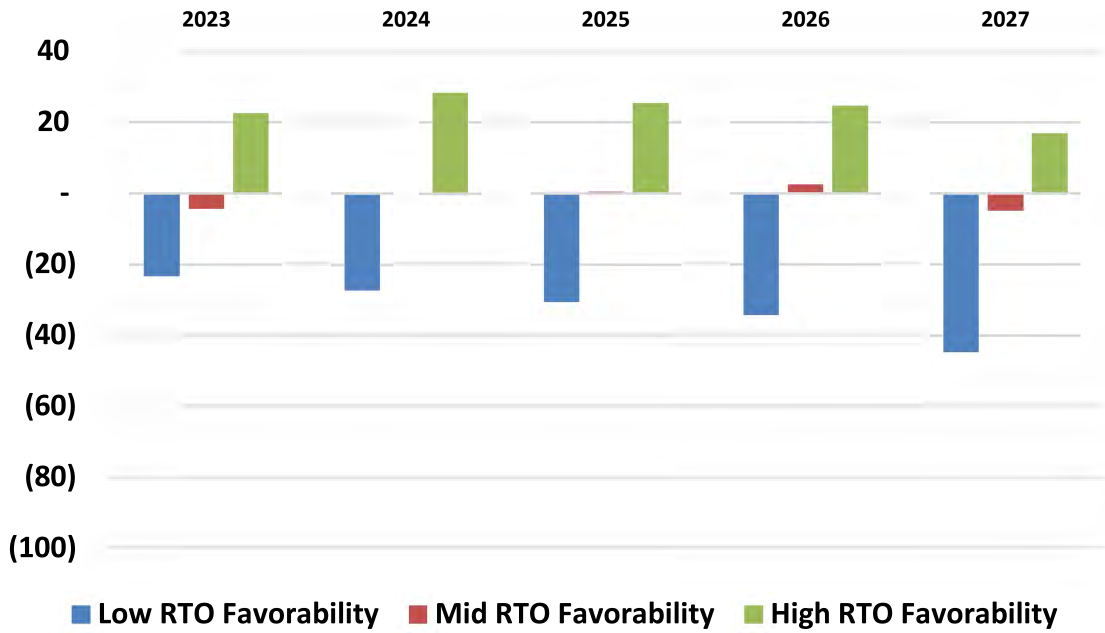


Figure 13: PJM Range of Potential Near-Term Outcomes ($M)



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)

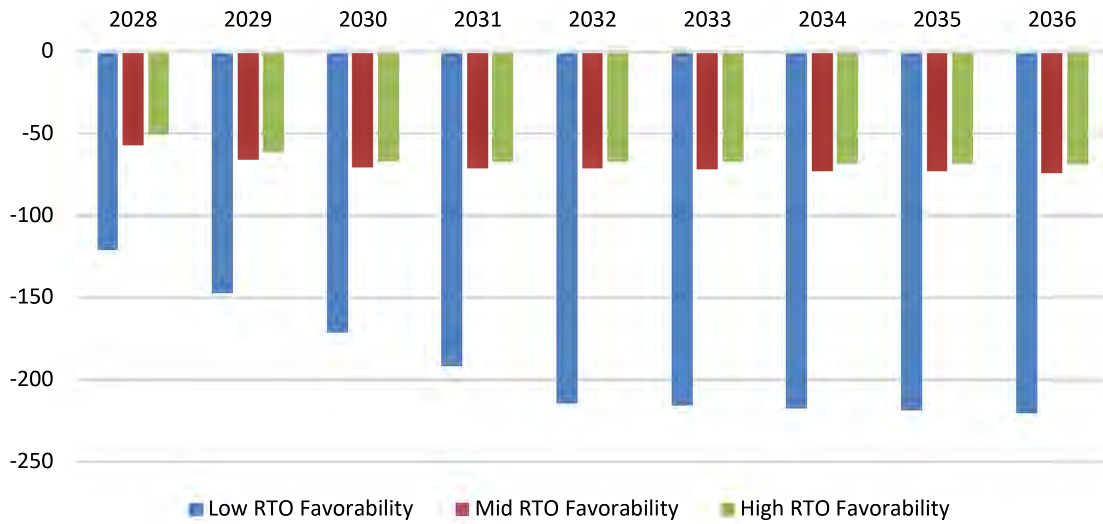
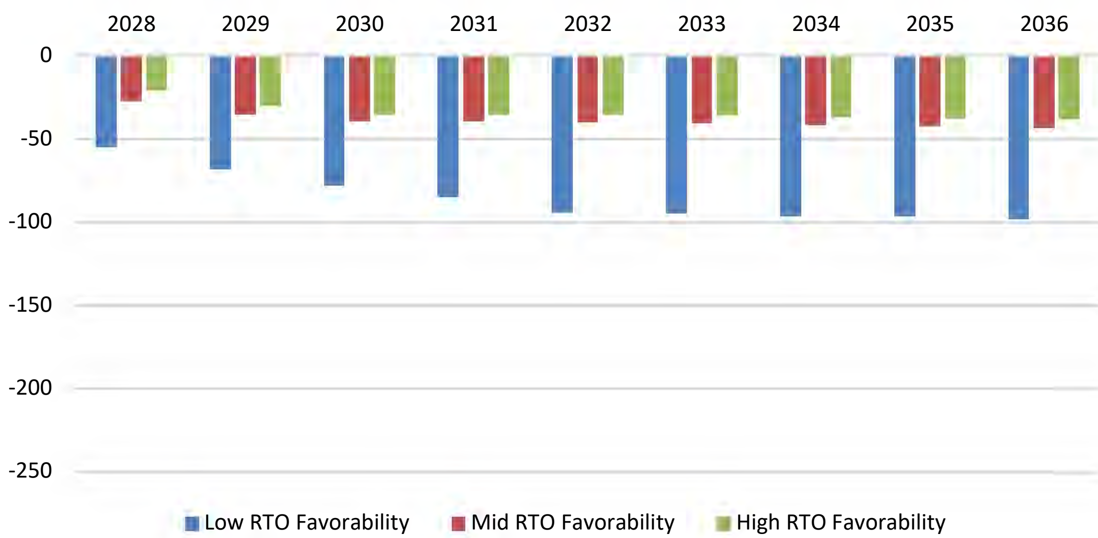


Figure 15: Projected Fixed Costs Range - PJM ($M)



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

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