KENTUCKY

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

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Contents

Appendices

Section 1: Executive Summary

A. Duke Energy Kentucky Overview

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) is a wholly-owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio) that provides electric and natural gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by Duke Energy Ohio. Duke Energy Kentucky provides electric service to approximately 153,400 customers and natural gas service to approximately 104,500 customers in its approximately 300 square mile service territory, and it has 1,197 megawatts (MW) of installed generation capacity. The Company has both a legal obligation and a corporate commitment to meet the energy needs of its customers in a way that is adequate, efficient, and reasonable.[1]

B. Integrated Resource Plan

The objective of the integrated resource planning process is to develop a robust and reliable economic strategy for meeting the needs of customers in a very dynamic and uncertain environment. The Company conducts quantitative analysis and considers qualitative factors to identify the best options to serve customers' future energy and capacity needs. Quantitative analysis provides insights into future risks and uncertainties associated with the load forecast and fuel and energy costs. Qualitative factors, such as fuel diversity, emerging environmental regulations, including state and federal energy policy, and the progress of emerging technologies, are also considered. The result is an integrated resource plan (IRP) that serves as a roadmap to guide business decisions and help the Company effectively meet customers' near- and long-term needs.

In its 2021 Integrated Resource Plan (2021 IRP), Duke Energy Kentucky reflected the continued operation of its existing generating resources including East Bend 2 and the Woodsdale combustion turbines (CT), supplemented by firm dispatchable resources (FDR) and renewable resources. Figure 1.1 below depicts the Company's 2021 IRP.

[1] KRS 278.030.

Figure 1.1: Summary of the 2021 Duke Energy Kentucky IRP Preferred Portfolio

Resources (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend (coal)	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
FDR															605
Solar	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150
Battery	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30
Wind				40	50	60	70	80	90	100	110	120	130	140	150

The Company's 2024 IRP shares some of the characteristics of its previous IRPs, and it is Duke Energy Kentucky's proposed roadmap to meet future energy and demand requirements without compromising reliability of service, energy affordability or the power demands of a growing region. The 2024 IRP reflects updated fuel and load forecasts, as well as updated new generation capital costs reflecting a dynamic macroeconomic and inflationary environment impacting supply chain and resource costs. Additionally, the 2024 IRP includes updated policies at both the state and federal level including:

- The Inflation Reduction Act (IRA) particularly expanded investment and production tax credits for non-CO_2 emitting generating resources
- The Environmental Protection Agency (EPA) Clean Air Act (CAA) Section 111 April 2024 Updates (EPA CAA Section 111 Update) regulating existing coal and new natural gas generation facilities
- Updates to Effluent Limitation Guidelines (ELG); 316 a & b (thermal discharge limits and fish impingement/entrainment at water intakes); and tightened Mercury & Air Toxics Standards (MATS)
- Removal of a CO_2 tax on plant emissions as a likely future policy primarily due to the inclusion of the IRA and EPA CAA Section 111 provisions

As described in Figure 1.2 below, the 2024 IRP reflects Duke Energy Kentucky's conversion of East Bend from 100% coal generation to coal generation with gas co-firing capabilities, or dual fuel operation (DFO) in 2029. The 2024 IRP includes continued operation of Woodsdale CT and the addition of a combined cycle (CC) at East Bend beginning in 2039. The resource mix is supplemented by demand response and solar resources.

Figure 1.2: Summary of the 2024 Duke Energy Kentucky IRP Preferred Portfolio

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

The primary difference between the 2021 plan and the 2024 plan is the conversion of East Bend from 100% coal generation to coal generation with natural gas co-firing capabilities, or dual fuel operation. This change is driven by the EPA CAA Section 111 update that was not in place in 2021, which provides coal plants with four different compliance pathways:

1. Retire by 1/1/2032 without restriction on operation until retirement
2. Convert to full natural gas operation by 1/1/2030
3. Convert to at least 40% gas-cofiring by 1/1/2030
4. Add Carbon Capture and Sequestration (CCS) by 1/1/2032

As discussed in Sections 6 and 7, the Company determined that natural gas-cofiring adds needed fuel diversity and security to the Duke Energy Kentucky system, reduces customers' exposure to PJM Interconnection LLC (PJM) market prices, provides for a measured energy transition while allowing time for technological advancements related to permanent replacement generation, and is in line with Kentucky's energy policies and priorities.

Other changes since the 2021 IRP are the inclusion of a 1x1 CC as the replacement resource for East Bend at the time of its retirement and updates to renewable resource assumptions. The 2021 IRP identified a generic FDR, or Firm Dispatchable Resource, as the replacement resource. This resource represented an asset that would be capable of flexible operations over long periods of time to ensure reliable capacity performance and emit significantly less carbon dioxide (CO_2) and other emissions relative to East Bend. While the 2024 IRP identifies replacement generation as a 1x1 CC, there is time between this filing and East Bend's retirement to allow other technologies such as nuclear small modular reactors (SMR) or CC paired with CCS (CC w/ CCS) to evolve.

Since the 2021 IRP, Duke Energy Kentucky also assessed the availability of onshore wind as a viable resource in the 2024 IRP. As discussed in greater detail in Section 4, onshore wind is not likely to materialize as an available resource in the Duke Energy Ohio/Kentucky (DEOK) PJM load zone in the near future, and there are significant risks to acquiring or contracting wind resources outside of the load zone. As a result of this analysis, onshore wind was not allowed as a selectable resource in modeling until 2032 in the 2024 IRP. The exclusion of onshore wind as a resource did increase the value of solar in this plan. As also discussed in Section 4, under PJM's updated Effective Load Carrying Capability (ELCC) study, solar contributes less than 15% of its nameplate capacity towards meeting PJM's planning reserve requirements; however, solar does contribute valuable energy that helps diversify Duke Energy Kentucky's energy mix and reduces customer exposure to market price fluctuations.

In addition to the EPA CAA Section 111 Update portfolio, Duke Energy Kentucky also assessed the implications to the plan if the updates to Section 111 were stayed or eventually repealed. As discussed in Section 7, a number of parties, including the Commonwealth of Kentucky have challenged the rule and filed motions to seek a stay. If these parties are successful, the impacts on the Duke Energy Kentucky plan would depend on the timing of the stay and what actions Duke Energy Kentucky had already taken to meet the EPA CAA Section 111 Update requirements. Figure 1.3 below presents Duke Energy Kentucky's resource plan if the EPA CAA Section 111 Updates were repealed prior to the Company taking significant steps towards compliance with these new requirements. This plan is similar to the 2021 IRP in that it continues to operate East Bend on coal through 2035, at which point it is retired and replaced with a 1x1 CC. As described further in Section 6, this plan has a lower Present Value of Revenue Requirements (PVRR) than the Company's base plan, which fully complies with the EPA CAA Section 111 Update requirements, primarily because it allows time for the Company to conduct an orderly transition out of coal in the mid-2030s rather than expediting that transition through the DFO project and requiring East Bend to operate, at least partially, on natural gas through the 2030s.

Figure 1.3: 2024 IRP Without EPA CAA Section 111 Update Portfolio

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600	600	600	600	600					
East Bend CC w/CCS (1x1)												588	588	588	588	588
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Importantly, should the EPA CAA Section 111 Update be repealed after the Company has made significant progress on converting East Bend to DFO, the DFO project would still provide significant benefits to the Company's customers including increased fuel flexibility and fuel diversity in Duke Energy Kentucky, which would help limit customers exposure to market price fluctuations.

It should be noted that each IRP starts with the previous IRP and updates the strategic direction based on new information learned over the preceding three years. This means that the resources described in each IRP are not firm commitments but rather are dynamic and represent what the Company believes is the best direction to move toward at the time of the analysis. This check-and-adjust approach with each IRP cycle allows the Company to keep an eye on the long-term direction in its IRPs and takes a more focused view as it executes specific resource decisions through the Certificate of Public Convenience and Necessity (CPCN) process.

C. Three-Year Implementation Plan

Environmental regulations are affecting the nation's generating fleet, as predicted in Duke Energy Kentucky's 2021 IRP, and the Company must conduct its resource planning pursuant to the policies (i.e., enacted and published laws and orders) at both the federal and state levels. Duke Energy Kentucky must balance the EPA CAA Section 111 Update and the state's policy focus on promoting fossil, and, specifically, coal generation, above other resources. The three-year implementation plan of the 2024 IRP Preferred Portfolio provides the most reasonable pathway by complying with existing state and federal regulations and adding needed fuel diversity to Duke Energy Kentucky's system while limiting customer exposure to market price fluctuations.

The three-year IRP review cadence allows the Company to navigate a measured energy transition and allows time for consideration of technological advancements related to replacement generation in future IRP analysis as time progresses and future regulatory deadlines approach. Duke Energy Kentucky's customers continue to explore paths to achieve their sustainability goals in a cost-effective manner that does not compromise reliability. The ability to provide an increasingly clean energy supply at a reasonable rate is critical to economic development and the overall competitiveness and long-term vitality in an increasingly global economy.

Duke Energy Kentucky has and will continue to engage stakeholders to develop projects and strategies that add value to the system and communities it serves. The Company uses a comprehensive approach to ensure stakeholders have the opportunity to share their perspectives in the way infrastructure is sited, built and maintained. The Company will continue to monitor changes in public policy as well as the fuel and power markets, and it will seek regulatory approval of projects as needed to implement the 2024 IRP resource plan as part of its three-year implementation plan.

Section 2: Objectives and Process

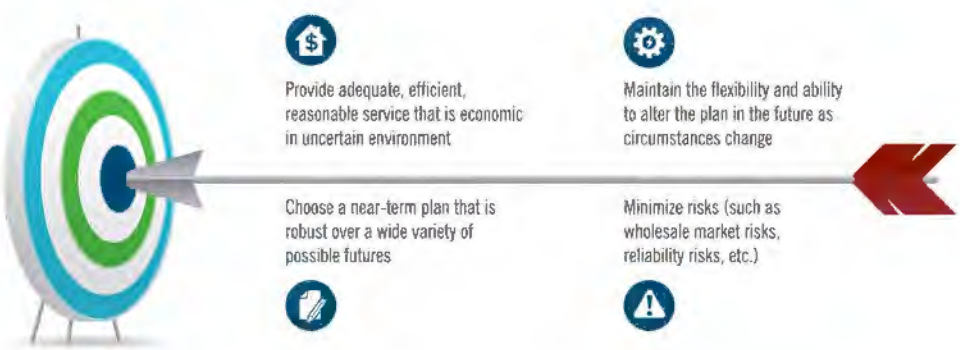
A. Introduction

This chapter describes the objectives of, and the process used to develop, Duke Energy Kentucky's 2024 IRP. In the IRP process, the modeling includes the firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the Duke Energy Kentucky service territory.

B. Objectives

The purpose of the 2024 IRP is to develop a robust strategy to furnish electric energy services to Duke Energy Kentucky's electric customers in an adequate, efficient, and reasonable manner while considering the uncertainty of the current and future environment. The planning process must be dynamic and adaptable to changing conditions. The 2024 IRP Preferred Portfolio represents the most robust and cost-effective outcome based upon various assumptions and sensitivities. Due to current and future policy, regulatory, economic, environmental, and operating uncertainties, Duke Energy Kentucky performed sensitivity analyses to evaluate various scenarios. The long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, communities, suppliers, employees, and shareholders). At times, this involves striking a balance between competing objectives. For reliability purposes, Duke Energy Kentucky is subject to PJM reserve margin requirements and, as such, models a minimum planning reserve margin requirement of -6.13% on an Unforced Capacity (UCAP) basis. Figure 2.1 below depicts the objectives presented in the IRP.

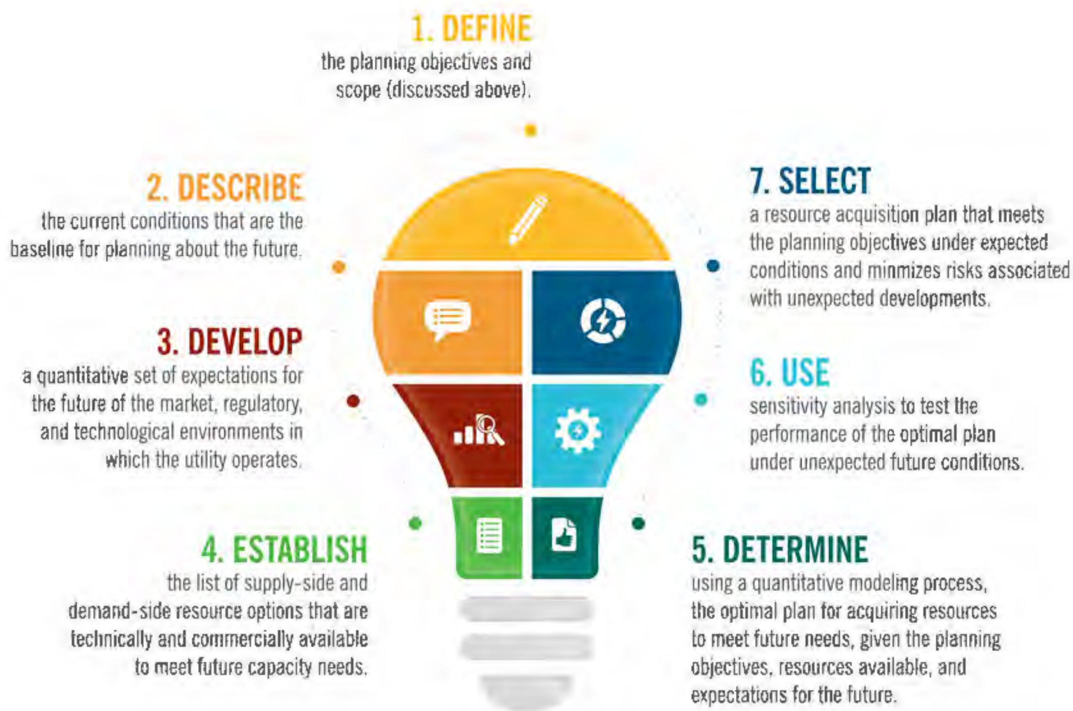
Figure 2.1: Objectives Presented in the IRP



C. Steps in Integrated Resource Planning

As discussed throughout this subsection, creating an IRP is a multi-stage process. Figure 2.2 below provides a high-level overview of the steps involved in developing the IRP.

Figure 2.2: Steps in Developing the IRP



1. Developing a Base Case

An IRP cannot be constructed without some set of expectations about what the future holds. The Preferred Portfolio is developed under a scenario that includes the EPA CAA Section 111 Update, which replaces any other assumptions of future carbon regulations due to its restrictive rules on future fossil generation. The EPA CAA Section 111 Update remains effective throughout the planning horizon within this IRP. For the purposes of the IRP, the Preferred Portfolio is developed under a set of expectations that are described in quantitative terms in the form of forecasts. The main sources of uncertainty for which forecasts must be developed are:

1. Load;
2. Fuel prices;
3. EPA CAA Section 111 Update;
4. Market power prices; and
5. Costs associated with acquiring and operating each resource considered.

In addition to the factors listed above, regulation is an important source of uncertainty. Future regulation cannot be forecasted in a quantitative manner; therefore, the current regulatory environment is assumed to persist throughout the planning period. The one major exception to that assumption is regarding a stay of, future changes to, or repeal of the EPA CAA Section 111 Update, which, given its potential impact, is addressed in several sensitivities under a “without EPA CAA Section 111 Update” scenario.

2. Technical Screening of Resource Options

In addition to constructing a Preferred Portfolio for the operating environment, it is necessary to assemble a full catalogue of the resource options, both supply-side and demand-side, that will be considered for inclusion in the plan to meet future capacity needs. The Company included supply and demand-side resources for consideration if they are technically feasible and commercially available in its service territory during the planning window.

3. Scenario Analysis

Scenario analysis is used to assess the cost and reliability risks associated with unexpected future developments. The purpose of this analysis is to evaluate the resource needs of the system across various scenarios involving East Bend, the Company’s primary base load resource. Duke Energy Kentucky evaluated potential pathways for East Bend’s continued operation and replacement options under two scenarios: with and without the EPA CAA Section 111 Update. For each scenario, an optimized portfolio was developed. The specific optimized portfolios that were run are listed below.

Additionally, alternate portfolios were developed based on results of the optimized portfolios and to test resource-specific strategies. The alternate portfolios analyzed model results from the two scenarios with and without EPA CAA Section 111 Update, as it is important to understand both the impacts and risks of this policy in the development of the Preferred Portfolio. The primary criteria for evaluating each portfolio is affordability using PVRR as the metric, CO_2 reduction and level of market purchases. This rigorous testing allows the Company to select a plan that best serves customers in the near term and preserves options to react to changing circumstances over the medium-to-long term.

The specific portfolios *evaluated are:*

Optimized Portfolios (retirements and/or additions are effective by January 1 of year shown)

1. With EPA CAA Section 111 Update Scenario
    a. East Bend DFO Conversion by 2030
    b. East Bend Natural Gas Conversion by 2030
    c. East Bend Retirement by 2032

2. Without EPA CAA Section 111 Update Scenario
    a. East Bend DFO Conversion by 2030
    b. East Bend Natural Gas Conversion by 2030
    c. East Bend Retirement by 2036

Alternate Portfolios (retirements and/or additions are effective by January 1 of year shown)

1. With EPA CAA Section 111 Update Scenario
    a. East Bend DFO Conversion with CC Replacement by 2039
    b. East Bend DFO Conversion with nuclear SMR Replacement by 2039
    c. East Bend DFO Conversion with CC with CCS Replacement by 2039
    d. East Bend DFO Conversion with CC Replacement by 2036 and Accelerated Renewables
    e. East Bend Retirement by 2032 with CC replacement

2. Without EPA CAA Section 111 Update Scenario
    a. East Bend DFO Conversion with CC Replacement by 2039
    b. East Bend DFO Conversion with SMR Replacement by 2039
    c. East Bend DFO Conversion with CC Replacement by 2036
    d. East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables
    e. East Bend Retirement by 2036 and Accelerated Renewables
    f. East Bend Retirement by 2042

4. Forecasting Methods

Load Forecasting

Electric energy and peak demand forecasts are prepared each year as part of the planning process by a staff that is shared among Duke Energy Corp. (Duke Energy) affiliated utilities. Each affiliated utility utilizes the same methodology. However, Duke Energy does not perform joint load forecasts among affiliated utility companies. Each forecast is prepared independently. The load forecast is one of the most important parts of the IRP process. Customer demand provides the basis for the resources and plans chosen to supply the load.

The general load forecasting framework includes a national economic forecast, a service area economic forecast, and the electric load forecast. The national economic forecast includes projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. Moody's Analytics, a national economic consulting firm, provides the national economic forecast. Similarly, the histories and forecasts of key economic and demographic variables for the service area economy are obtained from Moody's Analytics. The service area economic forecast is used together with the energy and peak demand models to produce the electric load forecast.

Energy sales projections are prepared for the residential, commercial, industrial, and other sectors. Sales projections and electric system losses are combined to produce a net energy forecast. These forecasts provide the starting point for the development of the IRP.

Forecasting Fuel Prices

The Company uses a combination of observable short-term market-based price forecasts and longer-term fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamental based pricing, to develop its coal and natural gas pricing forecasts. The former incorporate data from third-party market sources along with public exchanges including New York

Mercantile Exchange (NYMEX) and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The long-term fundamental forecast is created as a composite of several nationally recognized fuel forecasts including both publicly available data (e.g., United States Energy Information Administration (EIA)) and third-party proprietary forecasts from multiple reputable fundamental forecast providers.

Forecasting Power Prices

With Duke Energy Kentucky's participation in the PJM market, the Company needs to be mindful not only of its own system but also the impact Duke Energy Kentucky has on the PJM system and the impact the PJM system has on Duke Energy Kentucky. As such, for each scenario, specific PJM-level model runs were made that incorporate that scenario’s specific assumptions to develop power prices unique to that specific scenario. The Company uses this method to ensure consistency and provide a linkage between fuel, the EPA CAA Section 111 Update scenario, and power price assumptions.

Environmental Regulations Included in the IRP

The EPA CAA Section 111 Update, updates to ELG, 316 a & b, and tightened MATS along with the IRA tax incentives benefiting non-CO_2 emitting resources are included in this IRP. With these regulations in place, a tax on CO_2 emissions is not included, as these regulations are intended to reduce CO_2 emissions using a carrot (tax credits) and a stick (increased costs and forced reductions in electricity generated from coal).

Forecasting Capital Costs

Duke Energy Kentucky developed cost estimates for all generation technologies included in the IRP analysis using a combination of third-party estimates and internal expertise. Future cost projections are based on Technology Forecast Factors from the EIA Annual Energy Outlook (AEO) 2023, since there have not been new curves released for 2024. The 2023 curves have been normalized to 2024 values to retain forecast relationships for application to 2024 values. The AEO provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS).

Using 2024 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019). From NEMS Model Documentation 2016 2018, July 2017 April 2019:

> "Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Capacity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines. Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology.

> Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."

To develop a more accurate forecast for rapidly developing technologies (e.g., solar photovoltaic (PV) and battery storage), the Company blended the AEO forecast factors with additional third-party capital cost projections.

5. Resource Options

Supply-side resources may include existing generating units; repowering options for these units; potential bilateral power purchases from other utilities, Independent Power Producers (IPPs) and co-generators; short-term energy and capacity transactions within the PJM market; and new utility-owned generating units (conventional, advanced technologies, and renewables). When considering these resources for inclusion in the portfolio, the Company assesses their technical feasibility, commercial availability, fuel availability and price, useful life or length of contract, construction or implementation lead time, capital cost, operation and maintenance (O&M) costs, reliability, and environmental impacts.

The first step in the screening process for supply-side resources is a technical screening to eliminate from consideration those technologies that are not technically or commercially available during the planning window. Technologies excluded from consideration on these grounds include solar steam augmentation, fuel cells, supercritical CO_2 Brayton cycle, and liquid air energy storage. Also excluded from further consideration are technologies that are not feasible or available in the Duke Energy Kentucky service territory. These include geothermal, offshore wind, pumped storage hydropower, and compressed air energy storage.

Supply-side resources not excluded for availability reasons were included as potential options in the economic optimization modeling process. The Company considered for inclusion in this IRP a diverse range of technologies utilizing a variety of different fuels, including pulverized coal units, CTs, CCs, and nuclear stations. Renewable resources, including onshore wind and solar photovoltaic, as well as battery energy storage options, were also available in the analysis. Carbon capture and sequestration technology were also made available as selectable beginning in 2035 in this IRP, due to the current state of maturity of the technology and the time required for such a project. Lastly, in consideration for EPA CAA Section 111 Update compliance, DFO and full gas conversion were available as options for East Bend.

On September 17, 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222[2] regarding the participation of distributed energy resources in electricity markets run by regional grid operators. Updates to this order were made on March 18, 2021[3] and June 17, 2021[4]. Distributed

[2] FERC Order No. 2222 in Docket No. RM18-9-000. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

[3] FERC Order No. 2222-A in Docket No. RM18-9-002. https://www.ferc.gov/media/e-1-rm18-9-002

[4] FERC Order No. 2222-B in Docket No. RM18-9-003. https://www.ferc.gov/media/e-4-061721

energy resources (DERs) that might be incentivized by FERC under these orders were modeled as impacts to the load forecast.

6. Planning Models

EnCompass is an economic optimization model used to develop IRPs while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional units (e.g., CTs, CCs, coal units, integrated gasification combined cycle, etc.), and renewable resources (e.g., wind, solar). EnCompass uses a linear programming optimization procedure to select the most economic expansion plan based on PVRR. The model calculates the cost and reliability effects of modifying the load with customer programs or adding supply-side resources to the system. EnCompass also has detailed production-cost model capability for simulation of the optimal operation of an electric utility's generation facilities. Key inputs include generating unit costs and characteristics, fuel price forecasts, load forecast, Regional Transmission Organization (RTO) market data, customer program information, emission and allowance cost data, and utility-specific system operating data.

Section 3: Future Resource Considerations

A. Fuel Prices

The Company's expectation is for low natural gas prices through the early half of the planning period, followed by price increases slightly outpacing inflation through the remainder of the planning period. Power sector demand for natural gas is expected to continue to grow in the near-term as coal generation is displaced. Liquified natural gas exports and exports to Mexico are forecasted to ramp up over the planning horizon, adding to total demand. Low-cost supply from associated natural gas/oil production is expected to rise, partially mitigating this demand growth as oil prices strengthen. Natural gas markets closer to Appalachian supply sources may rise more slowly than the main US index, Henry Hub, due to high supply and constraints on pipeline capacity to transport natural gas out of the region. [5]Utility demand for coal is expected to decline over the foreseeable future, which could potentially impact viability of sources of supply over the long term. However, currently coal prices are projected to rise only slightly above inflation for much of the planning horizon. Annual US coal consumption has fallen over 30% in the last decade in response to coal plant retirements and relatively low natural gas prices. With tens of additional gigawatts (GW) of capacity potentially retiring in the next decade, utility demand for coal should continue to weaken.[6] Some limited upward pressure on thermal coal prices exists due to Asian and European export demand.

The Company's high and low fuel price forecasts are based on alternative fuel price cases in the EIA AEO for 2023. The EIA Low Oil and Gas Resource and Technology case describes a future in which resource supplies are constrained and high extraction costs are realized, driving up natural gas prices. Conversely, the EIA High Oil and Gas Resource and Technology case describes a future with high resource availability and low extraction costs which leads to persistently low natural gas prices. Figures 3.1 and 3.2 below depict the high, base and low Henry Hub gas and coal price forecasts.

[5] S&P Global Commodity Insights *North American Natural Gas Long-Term Outlook*, February 2024

[6] U.S. Energy Information Administration (EIA) "Use of Coal" https://www.eia.gov/energyexplained/coal/use-of-coal.php

Figure 3.1: High, Base and Low Henry Hub Gas Price Forecasts

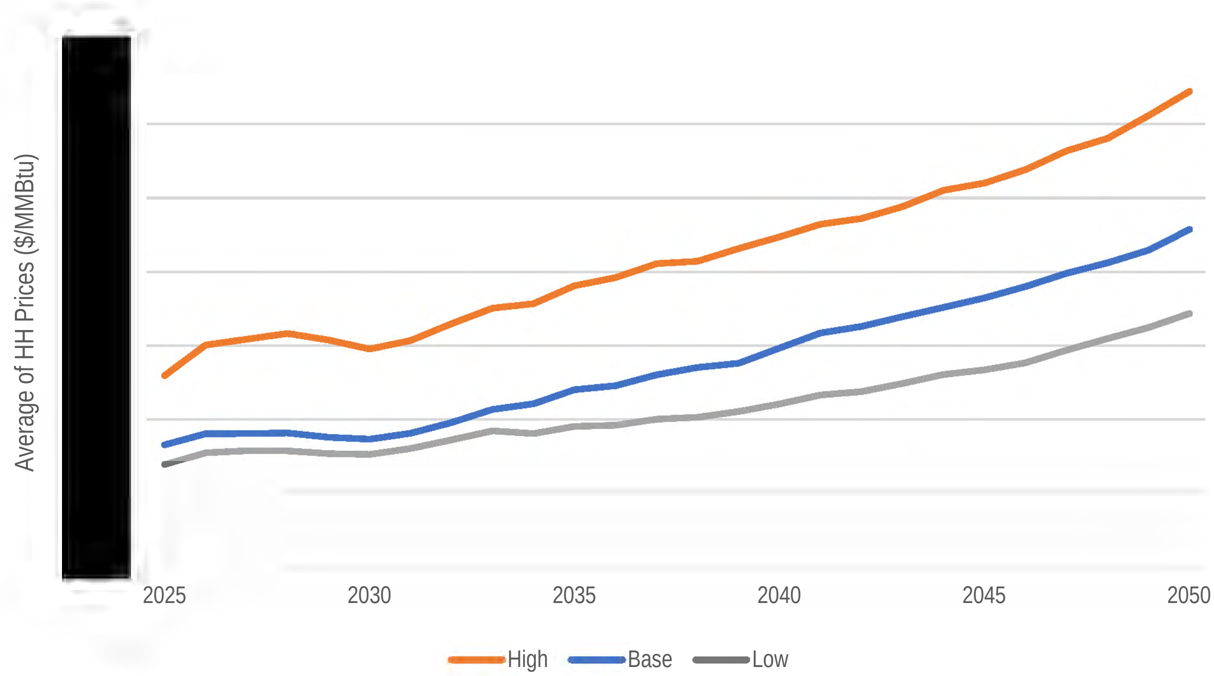
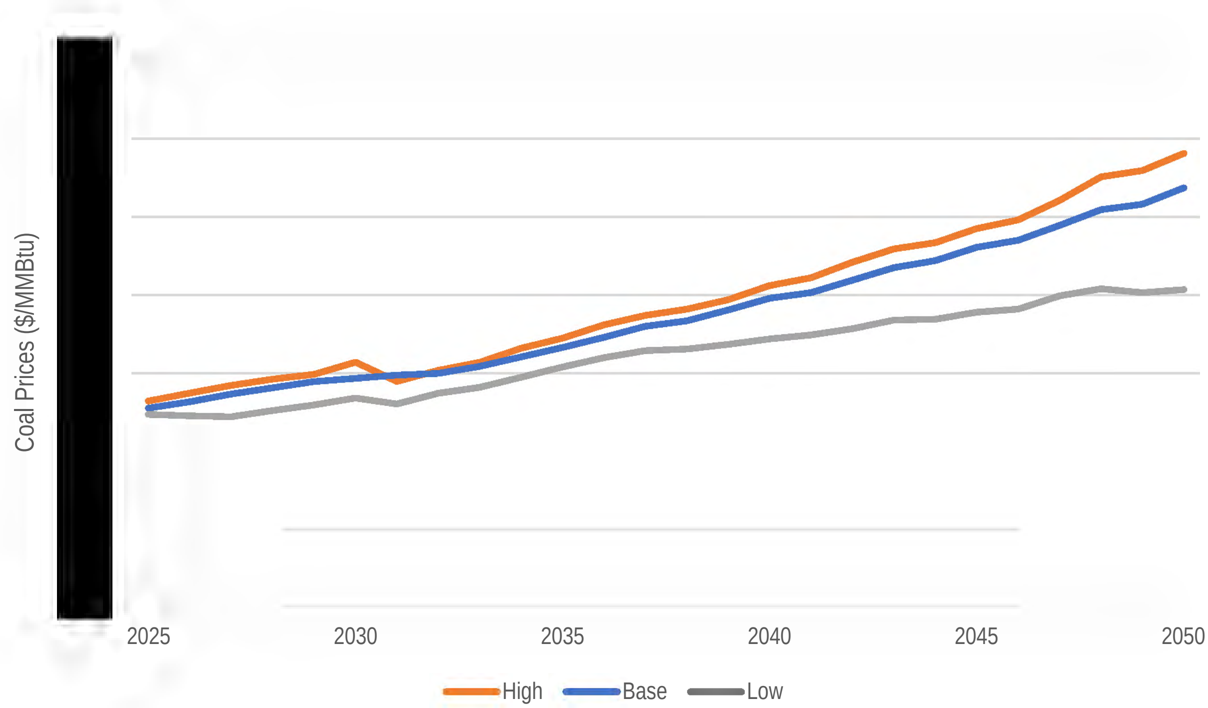


Figure 3.2 High, Base and Low Coal Price Forecasts (East Bend Delivered Coal Price ($/mmBTU))



B. Power Prices

Forecasting Methodology

Power prices are a function of the assumed fuel price forecasts and assumptions around the EPA CAA Section 111 Update. Additionally, changes in the RTO generation fleet are modeled to align with the assumptions of each specific scenario.

Generation expansion plans were developed for the entire Eastern Interconnection, which is the power grid reaching from Central Canada eastward to the Atlantic Coast, south to Florida and west to the foot of the Rockies (excluding most of Texas), for six scenarios: three different fuel price forecasts (high, base, low) under two different policy futures (one with the EPA CAA Section 111 Update and one in which the rule is never implemented). Table 3.1 below further describes the expansion plans.

Table 3.1: Generation Expansion Plan Scenarios

# Scenarios	Policy	Fuel Forecast
1	**With** EPA CAA Section 111 Update	Base Fuels
2		High Fuels
3		Low Fuels
4	**Without** EPA CAA Section 111 Update	Base Fuels
5		High Fuels
6		Low Fuels

These expansion plans were modeled in EnCompass, and hourly energy prices were developed to simulate the PJM power price for Duke Energy Kentucky. The generic unit characteristics and reserve margin requirements are consistent across expansion plans for each of the operating regions. Existing generating units were allowed to economically retire in each scenario.

Expansion Plans With EPA CAA Section 111 Update

Scenarios 1, 2 and 3 in Table 3.1 above considered the EPA CAA Section 111 Update in conjunction with base, high, and low forecast for fuel prices. The figures below show the nameplate capacity and generation for PJM in each of these three scenarios.

With the EPA CAA Section 111 Update – Base Fuels Forecast

In Figures 3.3 and 3.4 below, the implications of the EPA CAA Section 111 Update hastens the retirement of coal generation, which is primarily replaced with combined cycles and solar.

Figure 3.3: With the EPA CAA Section 111 Update, Base Fuels, Nameplate Capacity (GW)

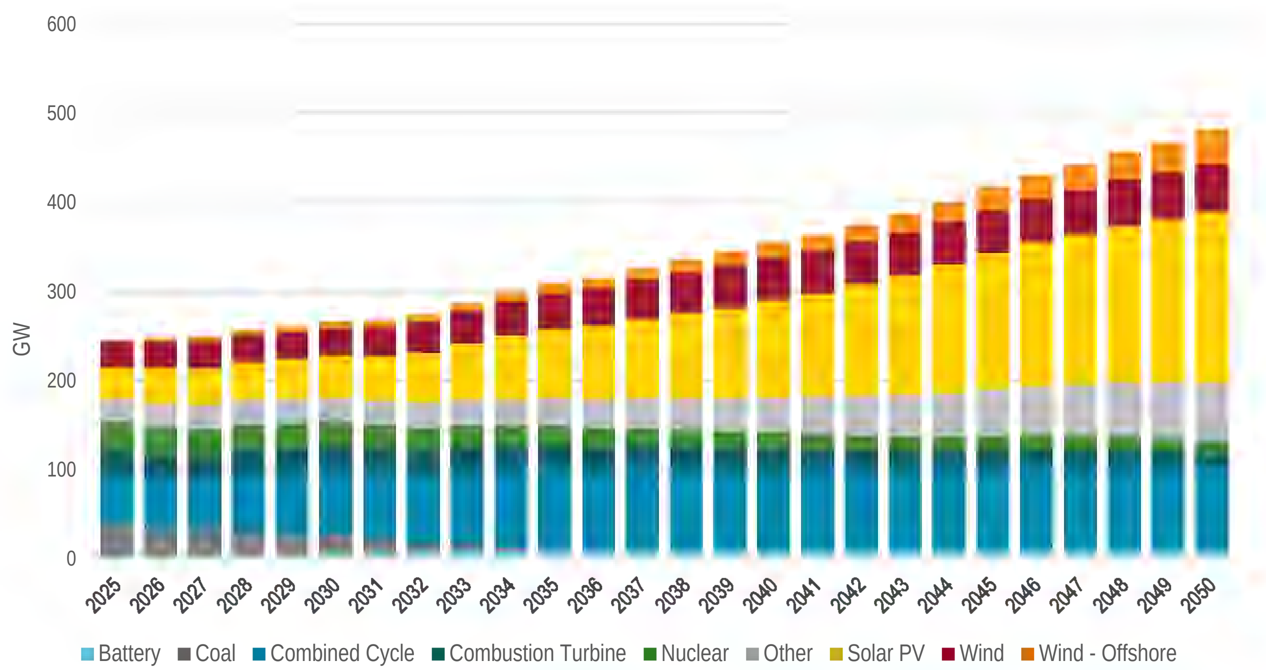
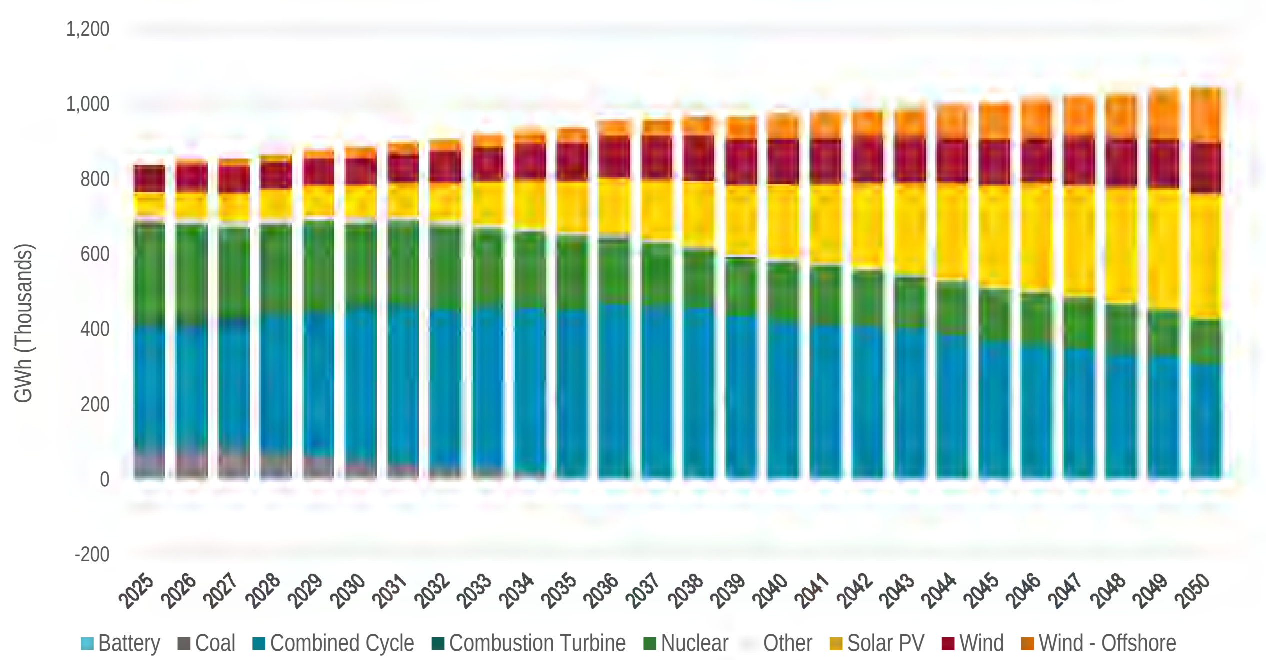


Figure 3.4: With the EPA CAA Section 111 Update, Base Fuels, Generation (Gigawatt-hour (GWh))



With the EPA CAA Section 111 Update – High Fuels Forecast

The combination of the EPA CAA Section 111 Update and high fuel prices drives several significant changes, as described in Figure 3.5 and Figure 3.6 below:

- The EPA CAA Section 111 Update combined with high fuel prices result in higher power prices
- Thermal generation growth is stagnant due to the high fuel prices
- Renewable generation benefits from the high fuel prices, particularly solar and offshore wind
- Solar provides the most energy of all available resources starting in the 2030's

Figure 3.5: With the EPA CAA Section 111 Update, High Fuels, Nameplate Capacity (GW)

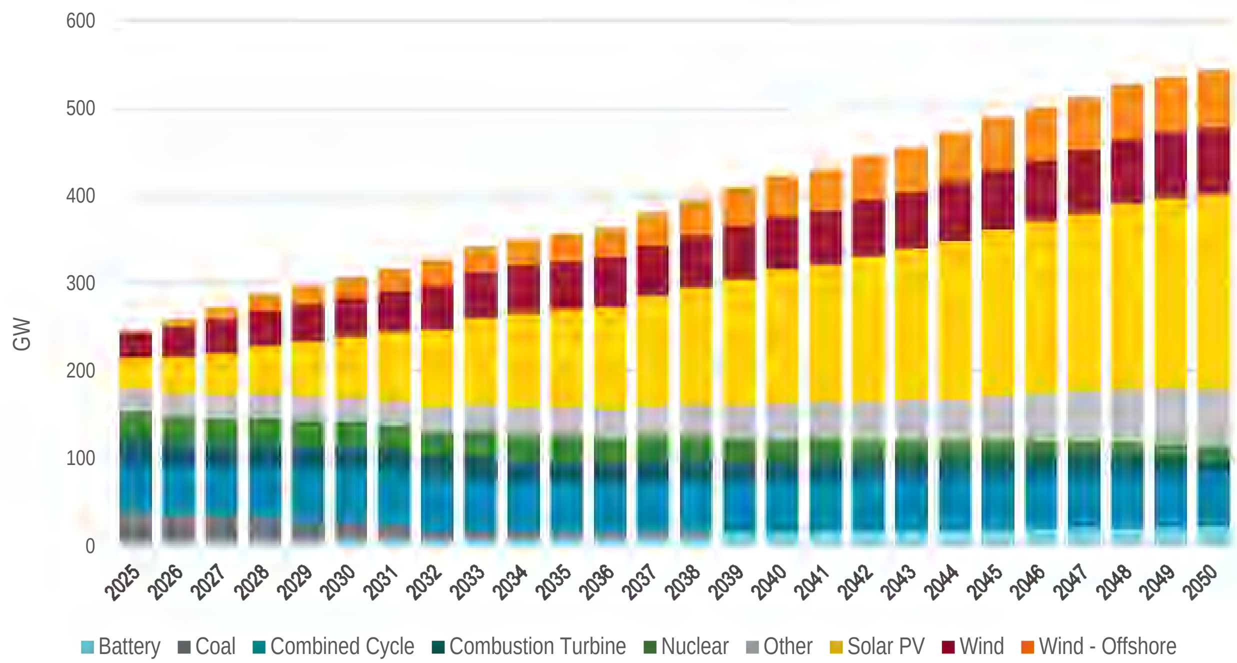
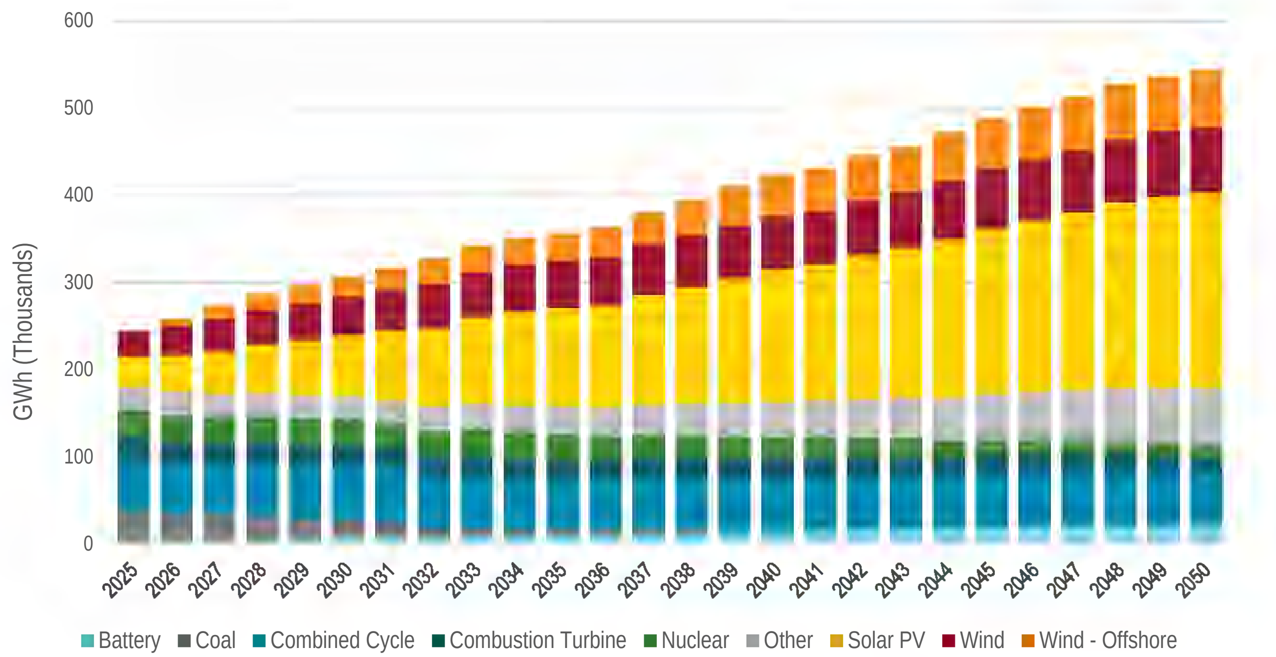


Figure 3.6: With the EPA CAA Section 111 Update, High Fuels, Generation (GWh)



With the EPA CAA Section 111 Update – Low Fuels Forecast

Low fuel prices in the EPA CAA Section 111 Update benefits combined cycle generation. As described in Figures 3.7 and 3.8 below, renewable additions are tempered until the 2040s, while nuclear generation remains an important part of PJM's generation mix through the 2030s.

Figure 3.7: With the EPA CAA Section 111 Update, Low Fuels, Nameplate Capacity (GW)

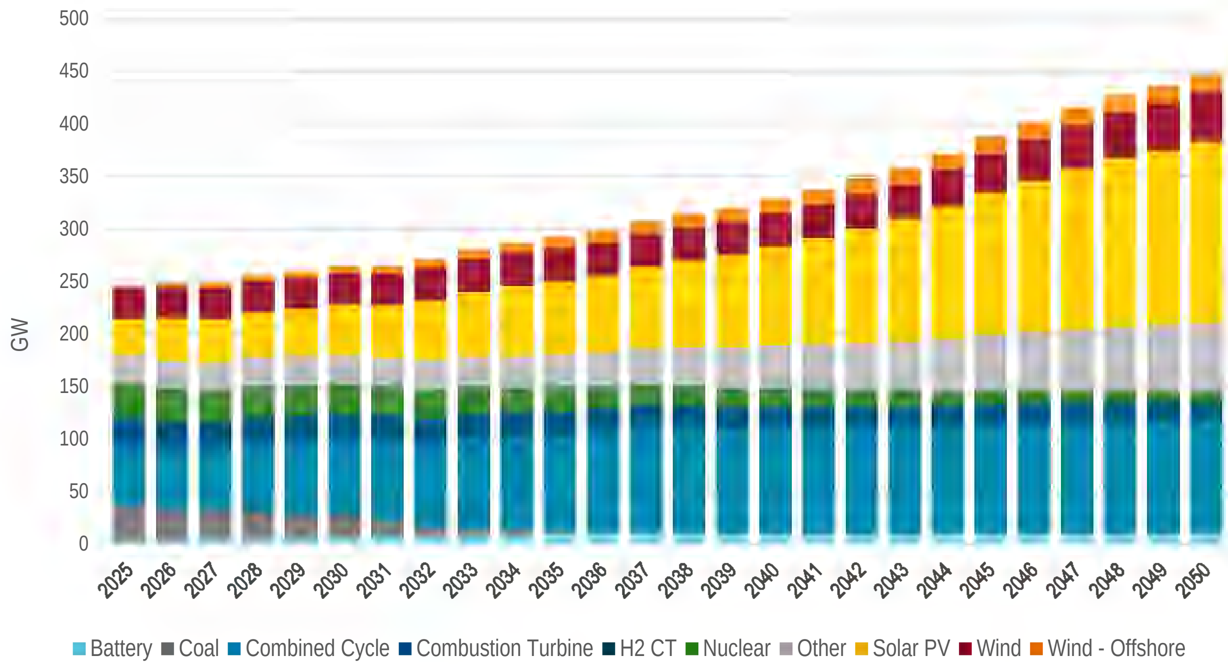
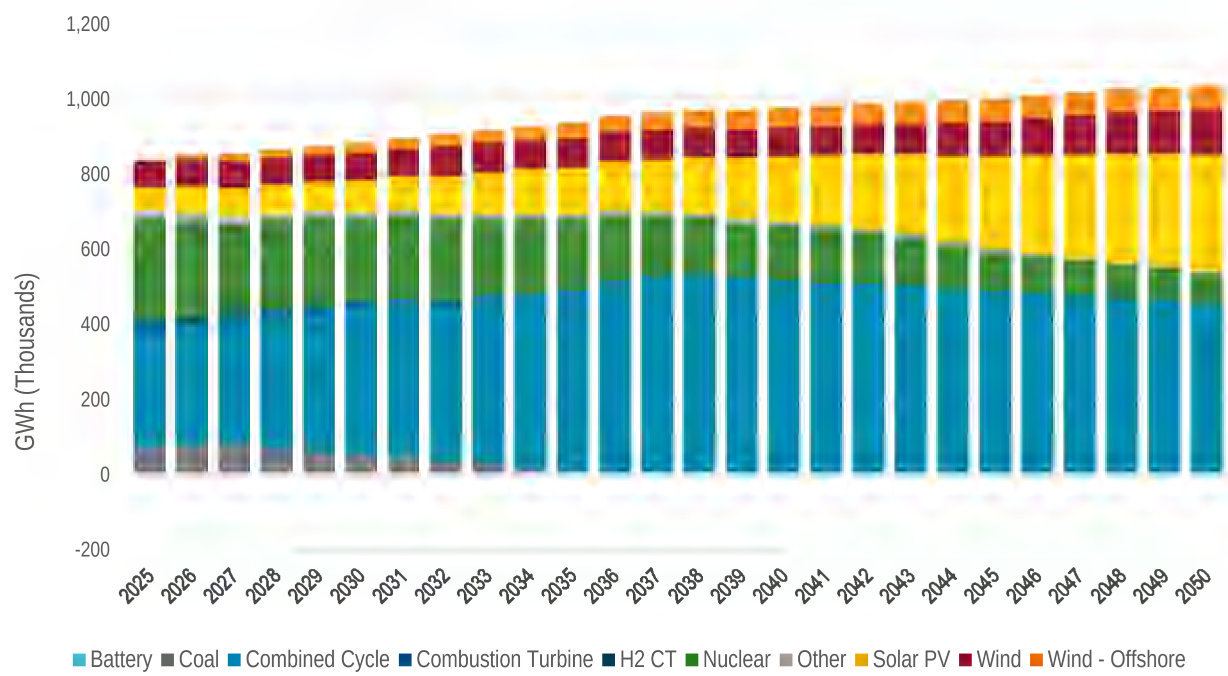


Figure 3.8: With the EPA CAA Section 111 Update, Low Fuels, Generation (GWh)



Expansion Plans Without the EPA CAA Section 111 Update

Scenarios 4, 5, and 6 in Table 3.1 omitted assumptions around the EPA CAA Section 111 Update in conjunction with base, high, and low forecasts for fuel prices. The figures below show the nameplate capacity and generation for PJM in each of these three scenarios.

Without the EPA CAA Section 111 Update – Base Fuels Forecast

As depicted in Figures 3.9 and 3.10 below, without the implications of the EPA CAA Section 111 Update, coal units continue to operate until they reach the end of their useful lives and are mostly replaced by combined cycles. Renewable capacity increases as capital costs come down relative to other forms of generation.

Figure 3.9: Without the EPA CAA Section 111 Update, Base Fuels, Nameplate Capacity (GW)

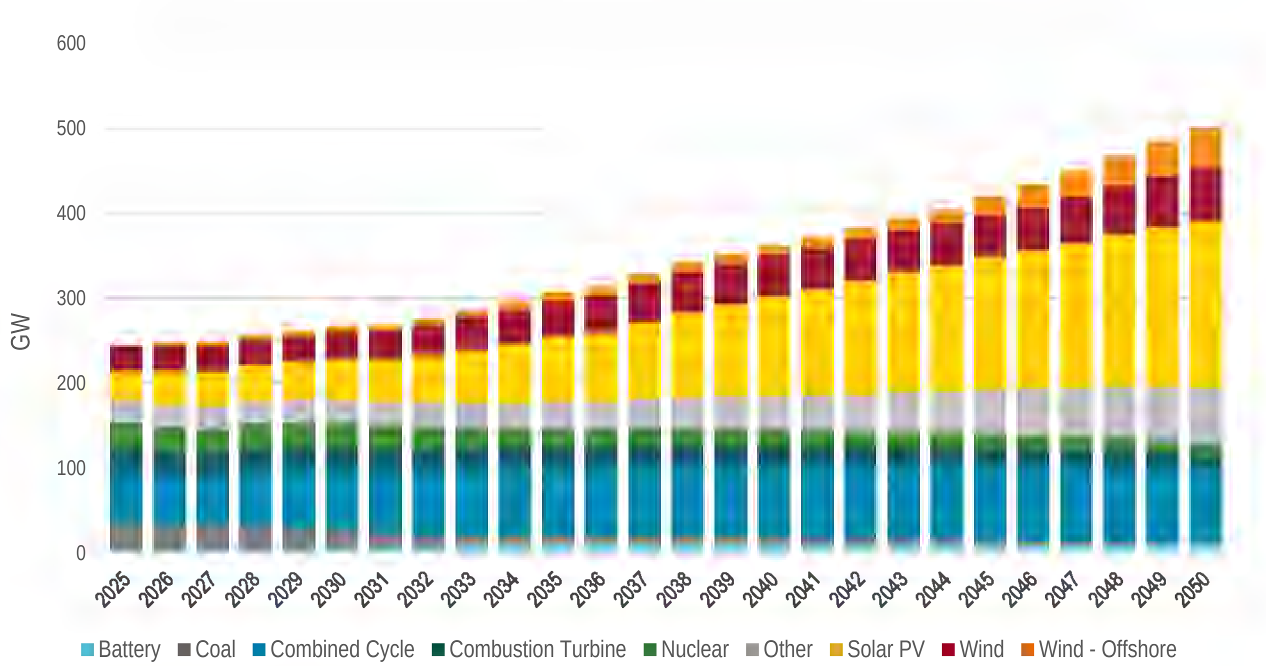
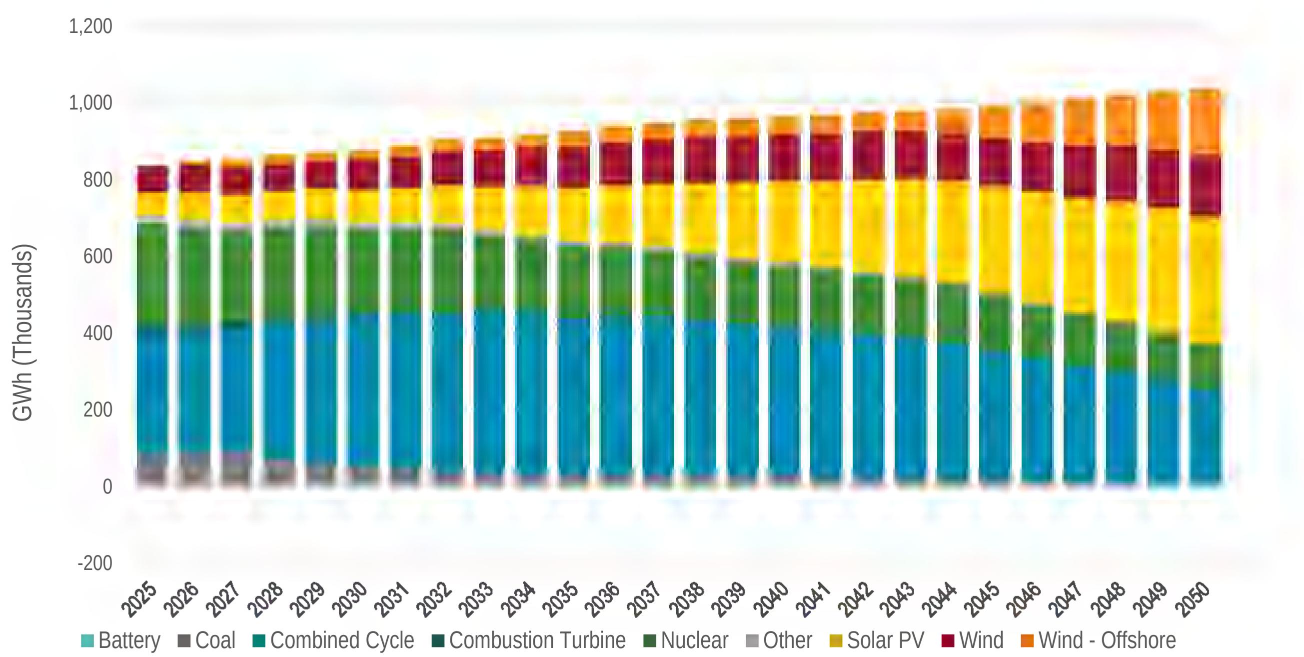


Figure 3.10: Without the EPA CAA Section 111 Update, Base Fuels, Generation (GWh)



Without the EPA CAA Section 111 Update – High Fuels Forecast

As depicted by Figure 3.11 and 3.12 below, higher fuel prices in this scenario keep coal facilities online longer due to the higher power prices and increase in the dispatch cost of gas resources. There is an increase in buildout of renewables, and solar and wind (both onshore and offshore) provide significant contributions to PJM's total generation.

Figure 3.11: No EPA 111, High Fuels, Nameplate Capacity (GW)

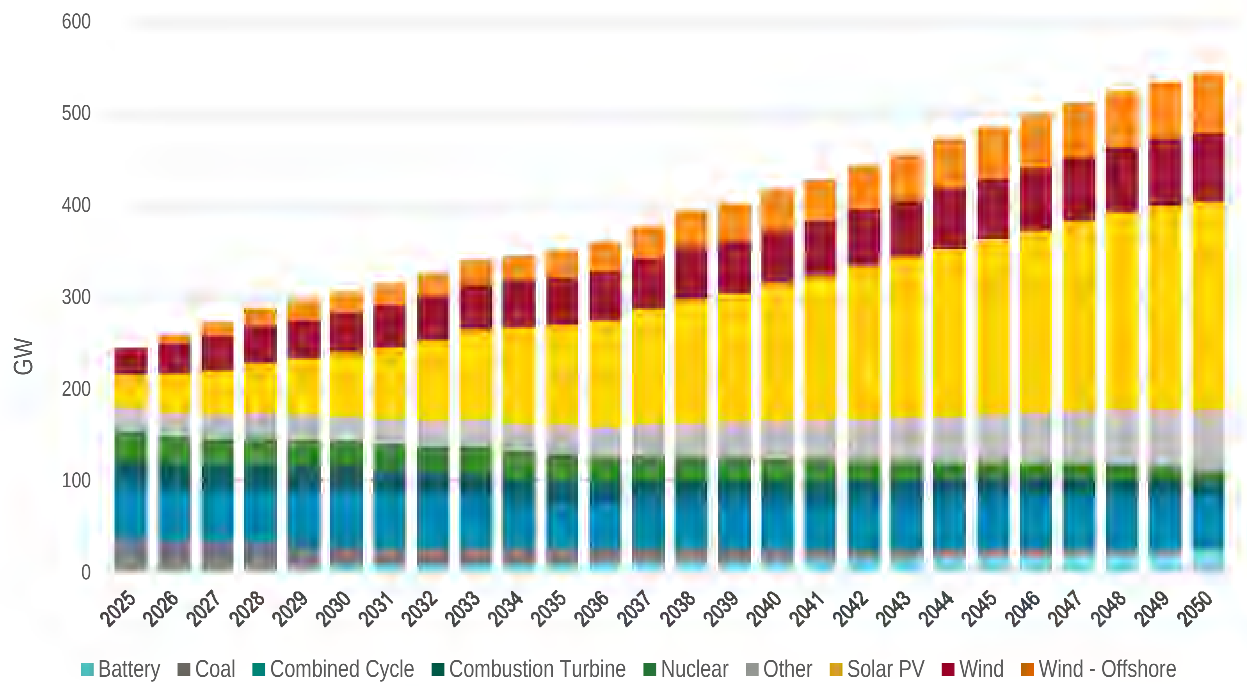
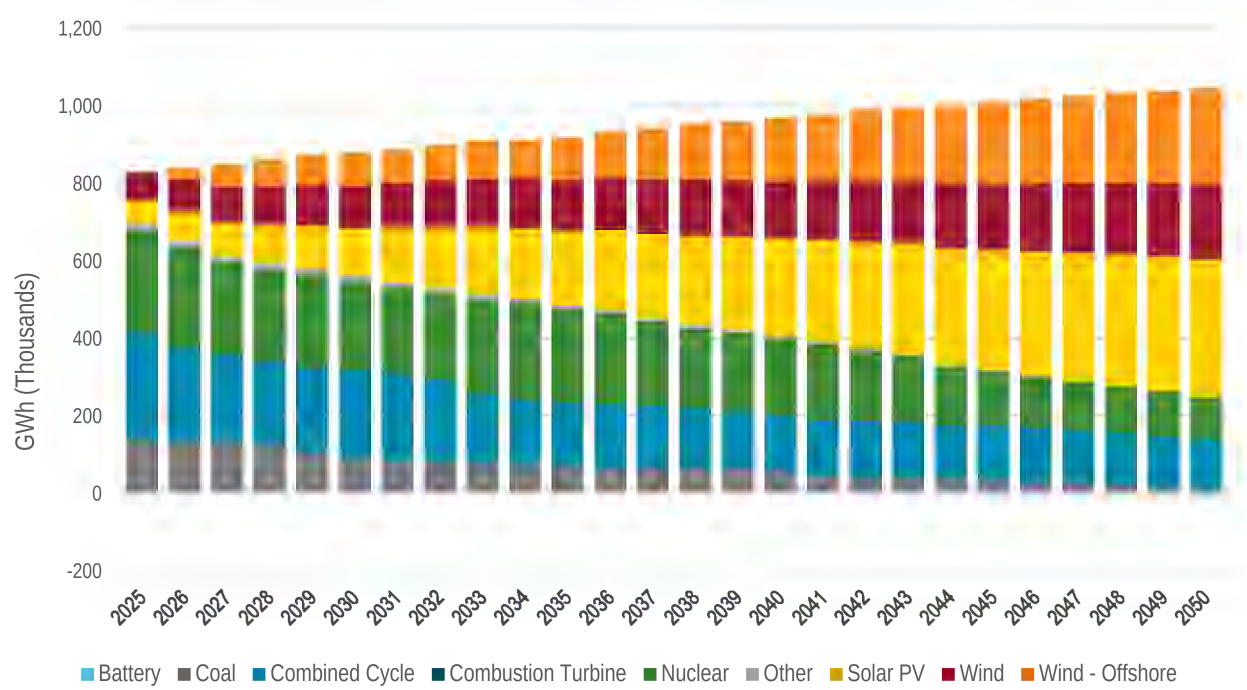


Figure 3.12: No EPA 111, High Fuels, Generation (GWh)



Without the EPA CAA Section 111 Update – Low Fuels Forecast

As depicted in Figure 3.13 and 3.14 below, the Without the EPA CAA Section 111 Update – Low Fuels Forecast scenario has the lowest power prices due to low fuel prices and the absence of compliance with the EPA CAA Section 111 Update. As a result, most of the change is the increased reliance on growing levels of combined cycle generation.

Figure 3.13: Without the EPA CAA Section 111 Update, Low Fuels, Nameplate Capacity (GW)

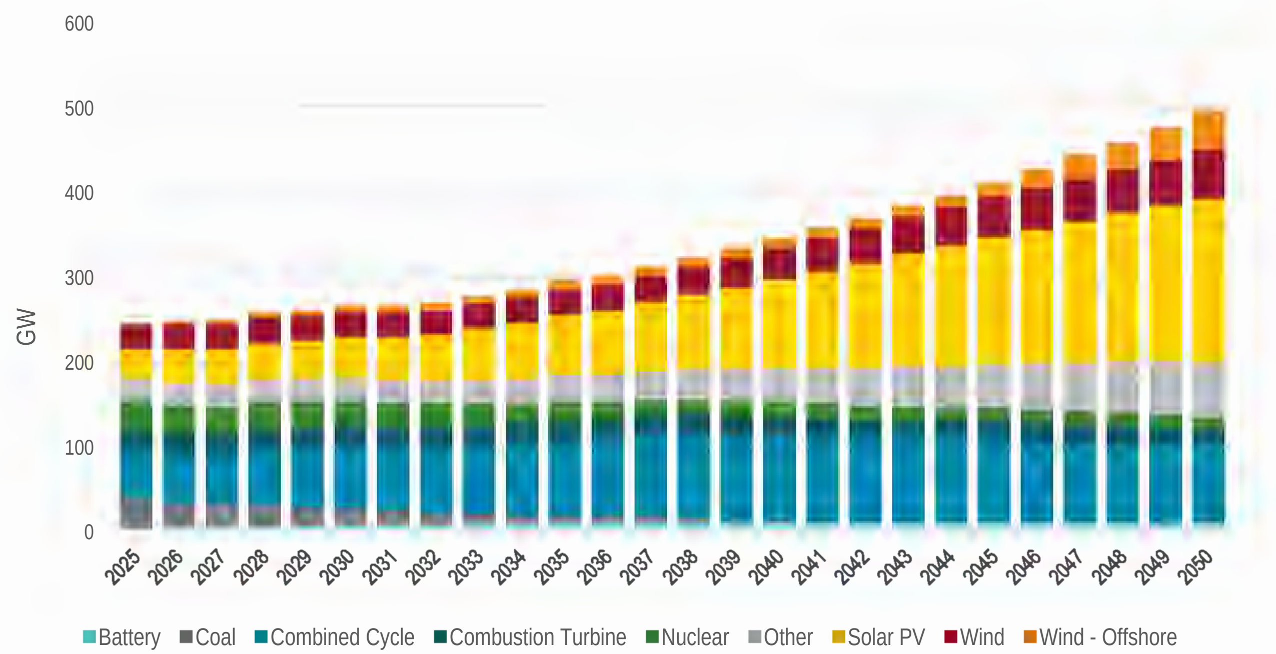
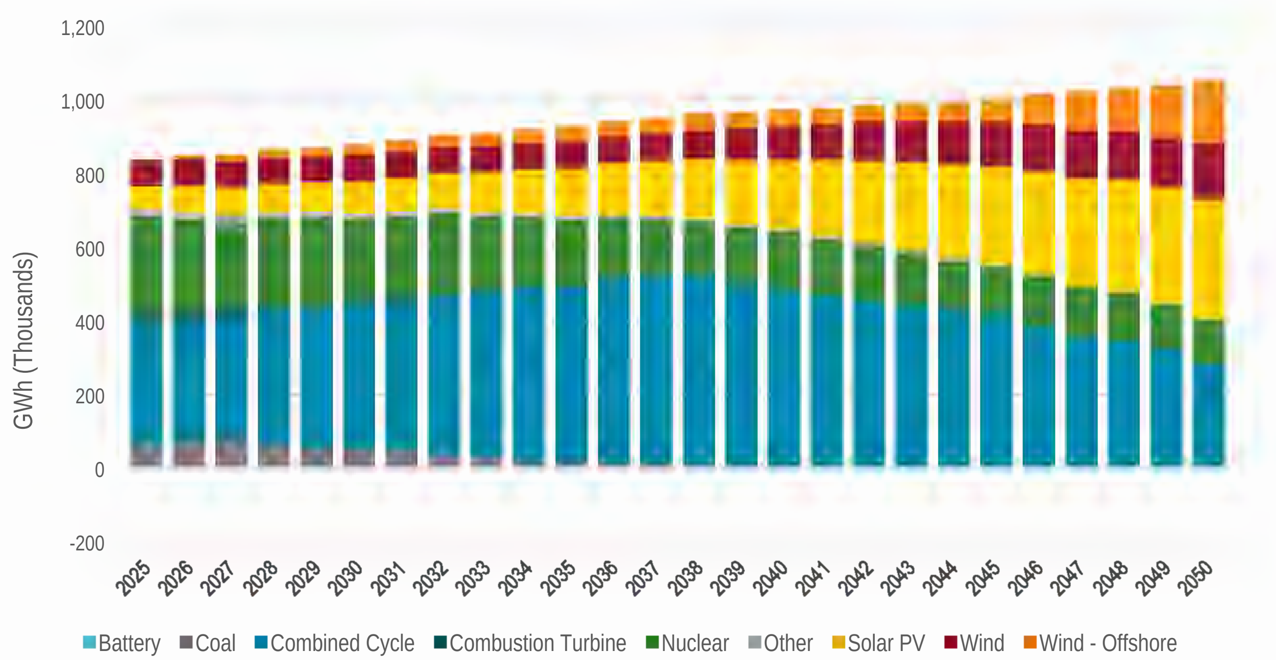


Figure 3.14: Without the EPA CAA Section 111 Update, Low Fuels, Generation (GWh)



Observations from Scenario Analysis

The six scenarios described above show the trade-offs between the various generation technologies and how they are impacted by the EPA CAA Section 111 Update and fuel prices. These impacts can best be understood by comparing how the underlying assumptions affect the overall level of the power markets and the possible impact on generation technologies' dispatch costs. The disparate paths that the scenarios show highlight the need for the preferred portfolio to preserve the flexibility to adapt to changing circumstances.

Forecasting Results

Figures 3.15 and 3.16 below depict the six power price forecasts based on the scenarios described above.

Figure 3.15: PJM Power Prices with the EPA CAA Section 111 Update

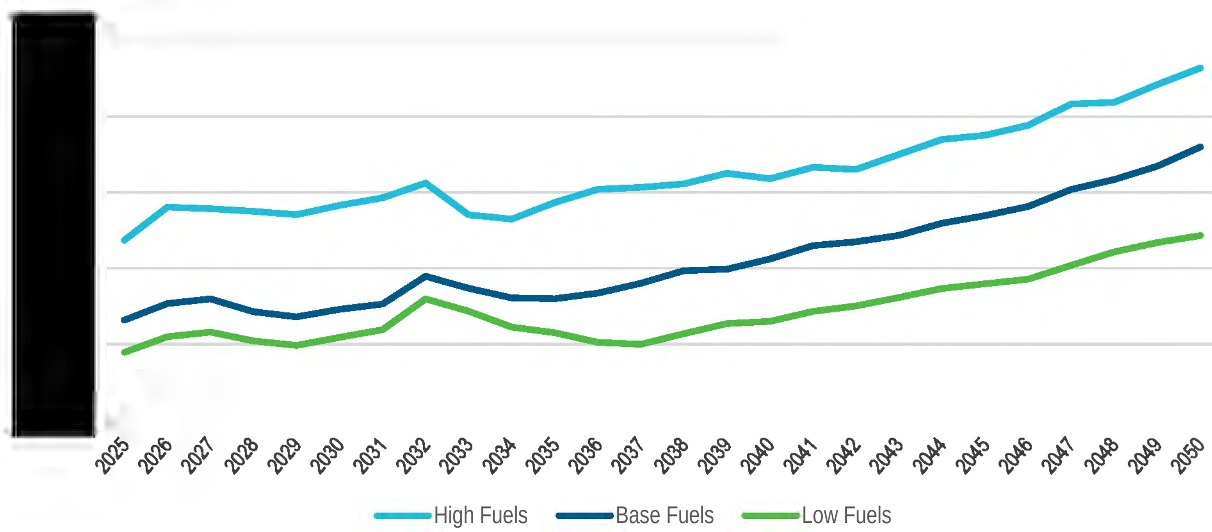
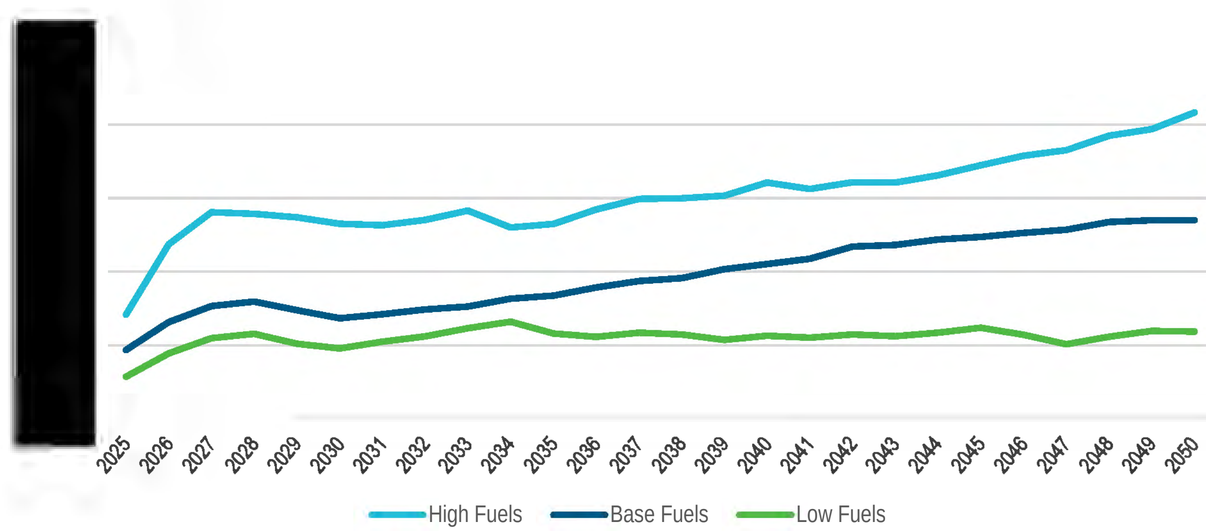


Figure 3.16: PJM Power Prices without the EPA CAA Section 111 Update

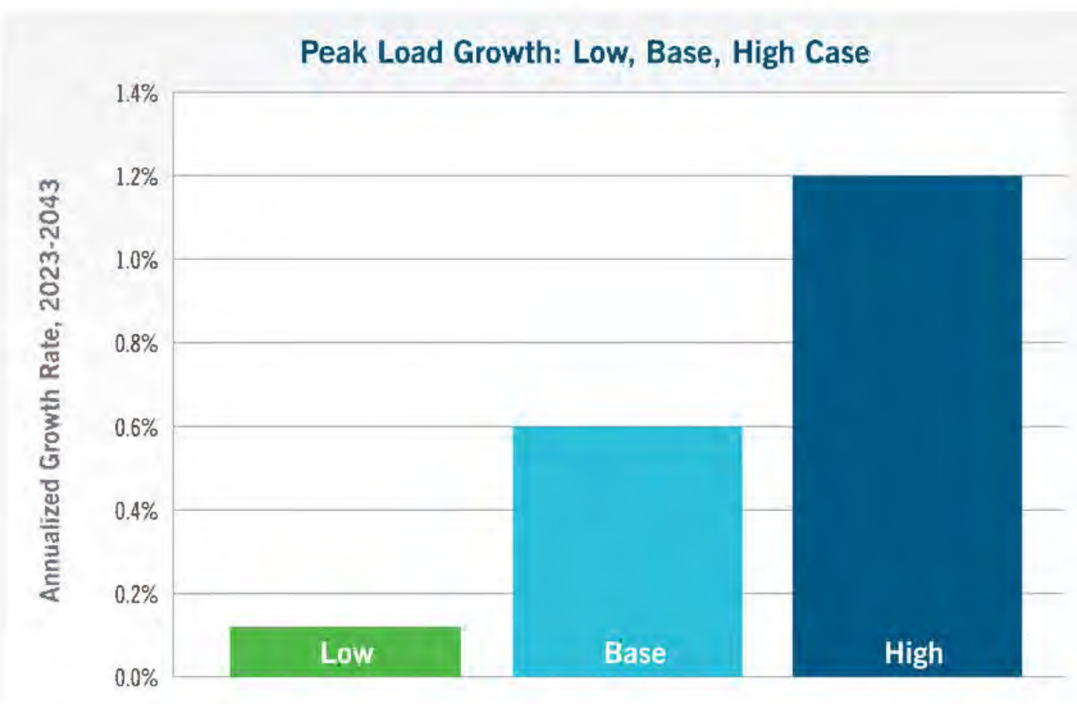


C. Load Forecast

Duke Energy Kentucky has historically experienced steady load levels. However, in 2020, there was a significant decline in energy usage by non-residential classes. While there has been some recovery in load since then, the outlook remains mostly flat. Looking ahead, the Company anticipates mostly stable load with modest growth, particularly in the residential class. This modest growth is expected to be initially driven by a sustained increase in the number of residential customers, followed by an increased in load due to the adoption of electric vehicles (EVs). The non-residential classes are expected to benefit from strong economic growth, particularly growth in real gross domestic product (GDP) and real median income. However, some of that growth is projected to be offset by the implementation of Demand-Side Management (DSM) programs including increased EE deployments.

In addition to the load forecast the Company considers most likely, as depicted in the figures below, the inherent uncertainty in load forecasting is addressed by estimating upper and lower ranges for expected load on the system. Factors such as weather assumptions, economic trends, future economic development, and electric vehicle adoption influence demand, and deviations from the growth assumptions underlying the forecasts could result in actual load being above or below the Company's current expectations. However, the impact of such deviations is likely to be limited. By the 10th year of the forecast period, load in a stronger-than-expected economy (upper range) is expected to exceed load in a near-term recession (lower range) by about 10%. The upper and lower ranges for the load forecasts are illustrated in Figure 3.17. For additional details on the load forecasts, see Appendix A.

Figure 3.17: Peak Load Growth



D. Inflation Reduction Act Assumptions

The IRA was signed into law on August 16, 2022. For Duke Energy Kentucky, the IRA will primarily provide tax incentives for zero-carbon generation, including tax credits in the form of Production Tax Credits (PTC) and Investment Tax Credits (ITC). The IRA consists of a base credit and bonus credits based on meeting certain criteria. PTCs are an inflation adjusted federal tax credit for each kilowatt-hour (kWh) of electricity generated during the first 10 years of operation. ITCs are a federal tax credit based on a percentage of the capital investment and can be taken immediately upon facility completion.

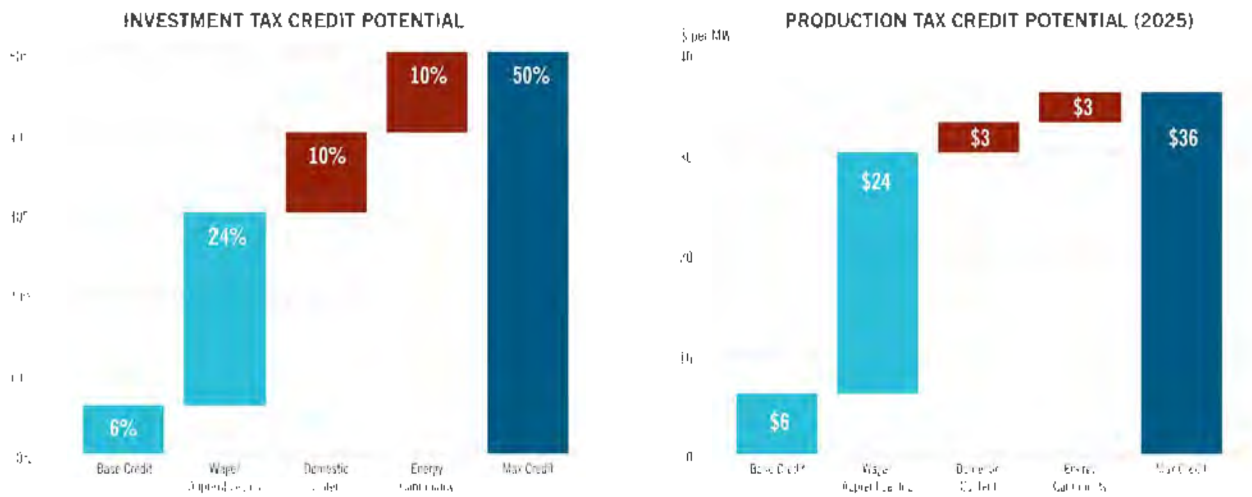
Both the PTC and ITC are allocated in base and bonus amounts if certain criteria are met. As seen in Figure 3.18 below, the base credit for building a zero-carbon emitting resource is 6% of eligible investment for ITC and $6/Megawatt-hour (MWh) (2025) of PTC[7] for the first 10 years of operation There are three types of bonuses that can be added by meeting certain criteria for projects greater than 5 MW: 1) Wage and Apprenticeship, 2) Domestic Content and 3) Energy Communities, which are subject to certain conditions:

- Wage & Apprenticeship: Project wages must be equal to or greater than local prevailing wages; certain percentage of work hours must be performed by qualified apprentices
- Domestic Content: Project's iron, steel and other components must be made in the U.S.
- Energy Community: Project must be located in a coal closure area, a statistical area or a brownfield area
- <5 MW solar, wind and associated storage can receive up to 70% ITC with statutory limits

Meeting wage and apprenticeship criteria adds a five times multiplier on the base credit, which results in a base ITC increase by 24% to a total of 30% and an increase in base PTC by $24/MWh to a total of $30/MWh. Meeting domestic content or energy community criteria can increase ITC by 10% each or 20% combined and PTC by $3/MWh each or $6/MWh combined. Potential maximum credit if all bonus criteria is met is 50% for ITC and $36/MWh (2025) for PTC.

[7] PTC values are indicative based on inflation assumptions.

Figure 3.18: Inflation Reduction Act of 2022



The Company's modeling assumes that it can meet wage and apprenticeship guidelines for all technologies in its 2024 IRP modeling, so the baseline for all eligible projects will be 30% ITC or $30/MWh PTC (2025). Domestic content was assumed on 50% of wind projects beginning in 2030 and 100% of wind projects beginning in 2035. Energy community bonuses are based on siting projects on retired coal generation sites or closed mined sites, brownfield sites or statistical area categories with historical employment in fossil areas and high unemployment. It was assumed that 25% of standalone solar, 25% of solar plus storage and 25% of batteries would be located in energy communities and that 100% of SMRs would be located in energy communities.

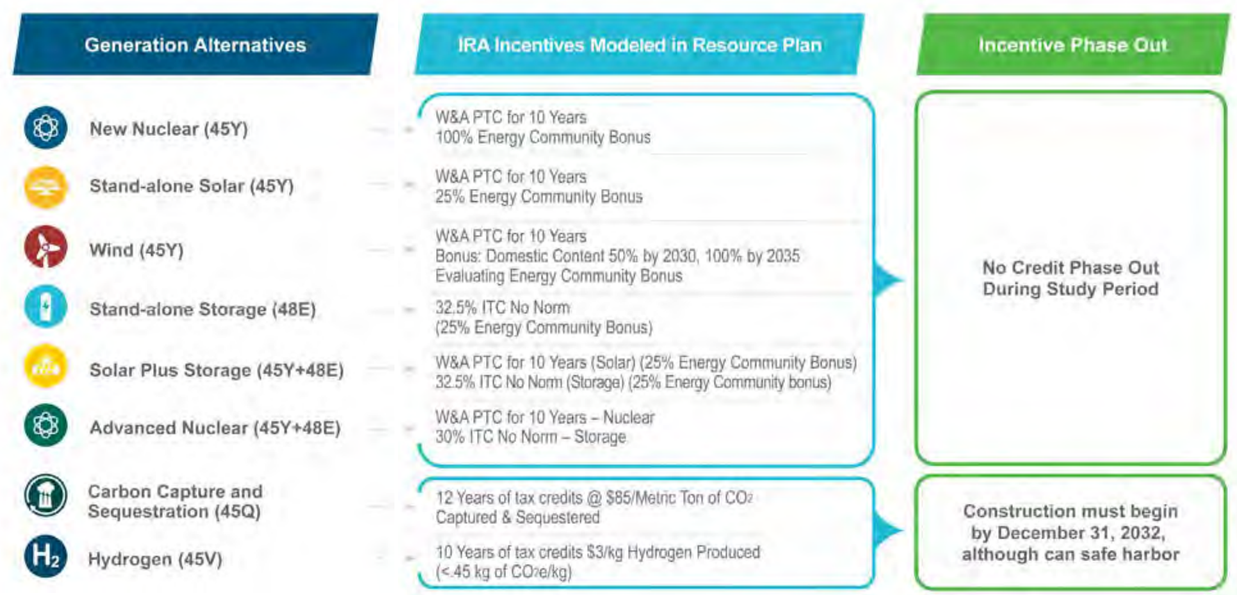
Figure 3.19 provides an overview of ITC and PTC assumptions for each technology type, including where applicable bonus incentives created in the IRA are included. Modeling assumes that stand-alone solar, wind and advanced nuclear will receive PTCs and all storage whether paired or standalone will receive ITCs. These assumptions will be modified based on site and project specific criteria during procurement.

Modeling also assumes that all projects eligible for IRA will qualify for five-year modified accelerated cost recovery system (MACRS). In addition, the Companies' modeling assumes that the credits for IRA Sections 45Y and 48E shown below in Figure 3.19 do not phase out during the 2024 IRP planning period. The IRA states that credits will phase out the later of "the year after 2032" or when the electric power sector GHG emission achieves a 75% reduction of 2022 levels.[8] From review of studies from Rhodium, REPEAT, Resources for the Future, Energy Innovation and other recent IRPs, Duke Energy has determined that the 75% reduction from 2022 levels will not be reached until the mid-2040s at the earliest. With uncertainty in the date in which the energy sectors GHG emissions achieve 75% reduction and with safe harbor provision extending the availability for tax credit eligibility, modeling assumes no phase out of IRA credits over the planning horizon.

[8] A 75% reduction in GHG emissions from 2022 levels corresponds to an approximate 83% reduction in GHG emissions from 2005 levels.

Additional tax credit assumptions include that CCS can earn tax credits of $85/metric ton of CO_2 captured and sequestered for the first twelve years of operation and hydrogen production can earn $3/kg for the first 10 years of operation. Construction on both technologies must begin by the end of 2032 and wage and apprenticeship requirements must be met.

Figure 3.19: 2024 IRP Inflation Reduction Act Modeling Assumptions



The Companies will continue to monitor and refine their assumptions as more Treasury Guidance is given and will maximize benefits to its customers. These credits will pass directly to customers and will lower the cost of the energy transition to customers.

E. EPA CAA Section 111 Update

Released in April 2024, the EPA CAA 111 Update includes restrictive measures on both existing coal units and new natural gas combustion turbines. As mentioned in Section 2, the EPA's CAA 111 Update reduces fossil generation from existing coal and new baseload gas unless CCS can be installed and operating by 2032, a timeframe which, as described in more detail in Section F, Duke Energy views as unrealistic given the maturity of the technology and time required for such a project. An overview of the EPA CAA Section 111 Update is provided in Table 3.2 below.

Table 3.2: EPA CAA Section 111 Update

Coal			New Gas		
Option 1	Option 2	Option 3	Baseload	Intermediate load	Low load gas
Retire by 2032	40% gas co-fire by 2030, retire in 2039*	Install carbon capture sequestration (CCS) by 2032, continue operations indefinitely	(>40% capacity factor) 90% CCS operation by 2032	(20-40% capacity factor) CO_2 intensity restrictions	(<20% capacity factor) Low intensity gas

**If coal is converting to 100% gas and intends to run past 2039, it must be converted to gas steam unit and be off coal by 1/1/2030*

Existing Coal Units:

As highlighted in Table 3.2 above, the following measures would apply to East Bend:

- No restrictions on coal units scheduled for retirement by 1/1/2032
- Coal units operating up to 1/1/2039 must achieve a 16% emission rate reduction from baseline based on 40% natural gas cofiring (DFO) by 1/1/2030
- Coal units converting to 100% natural gas must do so by 2030 if they plan to operate past 2039
- Units operating beyond 1/1/2039 require CCS, which EPA has determined to be the Best System of Emission Reduction (BSER), by 1/1/2032 and must maintain an 88.4% CO_2 emission reduction from baseline

Executing on these compliance pathways will require updates to Kentucky statutes.

Future Gas Turbine Units:

As highlighted in Table 3.2 above, future large baseload gas turbine units (defined by 40% or greater capacify factor and heat input of 2,000 MMBtu/hr) would be required to:

- Install advanced class combined cycle units to meet the requirements of Phase 1:
    - Phase 1 emission limitation, effective upon initial operation, of 800 lb. CO_2/MWh (on a 12-month calendar year basis)
- Install CCS by 1/1/2032 to be able to operate at a capacity factor >40%:
    - Phase 2 emission limitation of 100 lb. CO_2/MWh (on a 12-month calendar year basis) based on 90% CCS technology.

F. Responses to Rule Section 9: Financial Information for Preferred Portfolio

Table 3.3: Revenue Requirements (Present value (PV), annual and per kWh)

PVRR: $2,669 million
Discount Rate: 7.07%
Inflation Rate: 2.50%

Annual Revenue Requirements ($ million)																	
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Nominal	$195	$250	$293	$194	$238	$207	$337	$241	$252	$275	$245	$335	$255	$256	$265	$379	$391
Real 2024$	$195	$244	$279	$180	$215	$183	$291	$203	$207	$220	$192	$256	$190	$186	$187	$262	$264

Revenue Requirements per Kilowatt Hour																	
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Nominal	$0.05	$0.06	$0.07	$0.05	$0.06	$0.05	$0.08	$0.06	$0.06	$0.06	$0.06	$0.07	$0.06	$0.06	$0.06	$0.08	$0.08
Real 2024$	$0.05	$0.06	$0.06	$0.04	$0.05	$0.04	$0.07	$0.05	$0.05	$0.05	$0.04	$0.06	$0.04	$0.04	$0.04	$0.06	$0.06

Note: Does not include existing rate base (generation, transmission, or distribution) or any future investment in transmission or distribution

Section 4: Supply-Side Management Resources

A. Process Description

Supply-side resources may include existing generating units; repowering options for these units; potential bilateral power purchases from other utilities, IPPs and co-generators; short-term energy and capacity transactions within the PJM market; and new utility-built generating units (conventional, advanced technologies, and renewables). It also includes storage assets, which do not generate electricity but can shift energy to times of greater need or from periods of excess renewable energy. When considering these resources for inclusion in the portfolio, the Company assesses their technical feasibility, commercial availability, fuel availability and price, useful life or length of contract, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental impacts.

The first step in the screening process for supply-side resources is technical screening to eliminate from consideration those technologies not technically and commercially available. Also excluded from further consideration are technologies not feasible or available in the Duke Energy Kentucky service territory.

The Company considered for inclusion in this IRP a diverse range of traditional technologies utilizing a variety of different fuels, CTs, CCs, and nuclear SMR. Duke Energy Kentucky also included onshore wind and solar photovoltaic renewable options as well as battery storage options. The supply-side resources not eliminated on technical or commercial availability grounds are listed in the table below. The capacity expansion model was allowed to select fractional units to better assess the timing of new resource needs and the optimal resource type, regardless of size. These resources are further described in Table 4.1 and Figures 4.1 and 4.2 below.

Table 4.1: Supply-Side Resources

Description	Summer capacity (MW)	Typical capacity factor
Nuclear Small Modular Reactor	300	95%
Combined Cycle Gas Turbine, 2x1	1,282	70%
Combined Cycle Gas Turbine, 1x1	636	70%
Combined Cycle Gas Turbine with CCS, 1x1	535	70%
Simple Cycle Gas Turbine	791	10%
Wind	64.5[a]	43%
Solar PV, Single Axis Tracking	25[b]	25%
Battery Storage, 4-hour Lithium-Ion	16[c]	16%

(a) Nameplate capacity is 150 MW, contribution to peak is 43% of nameplate capacity in Summer
(b) Nameplate capacity is 100 MW, contribution to peak is 25% of nameplate capacity in Summer
(c) Nameplate capacity is 100 MW, contribution to peak is 16% of nameplate capacity

Figure 4.1: Inflated Direct Cost of Nuclear Small Modular Reactor (Confidential)

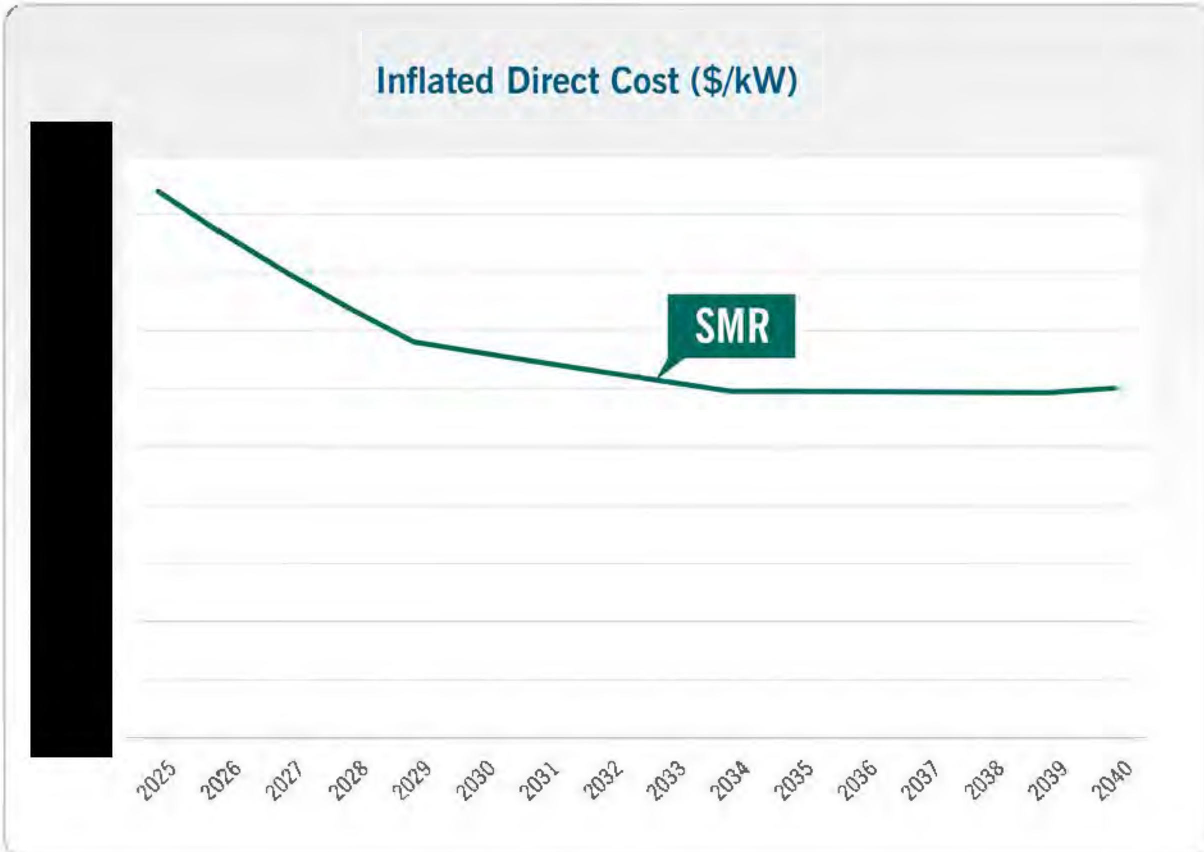
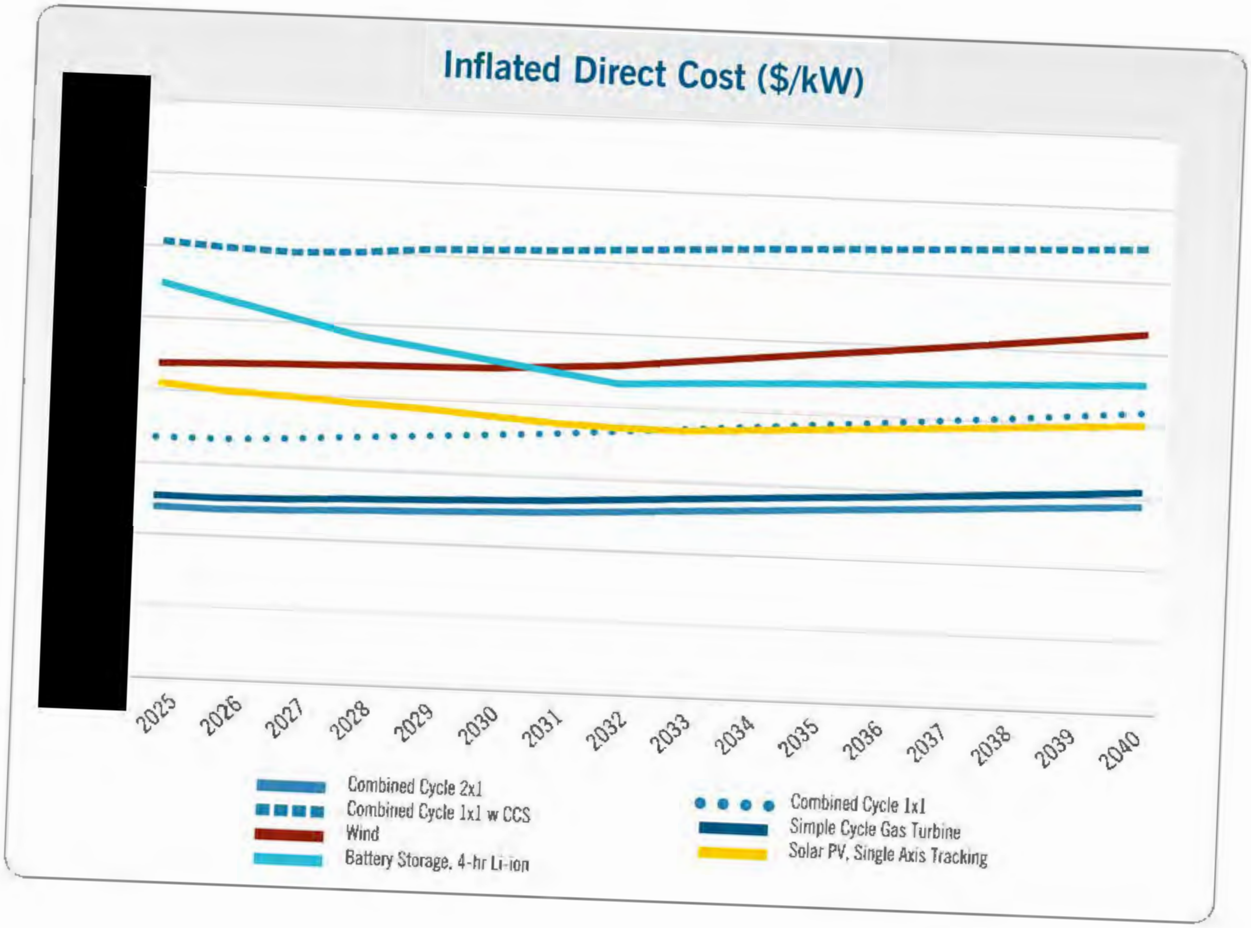


Figure 4.2: Inflated Direct Cost of Other Resources



B. Existing Resources

The total 2024 installed capacity (ICAP) owned by Duke Energy Kentucky is 1,197 MW. This capacity consists of 600 MW of coal-fired steam capacity, 564 MW of natural gas-fired peaking capacity, 24 MW of DR, and 9 MW of solar PV capacity. For the PJM delivery year 2024/2025, Duke Energy Kentucky has an unforced capacity (UCAP) of 959.5 MW, based on the latest PJM accreditation. The UCAP is the portion of the plant's generating capacity to meet PJM's reliability obligations. The steam capacity consists of a single coal-fired unit located at the East Bend Unit 2 Generating Station. The peaking capacity consists of six natural gas CTs located at the Woodsdale Generating Station. A new dual-fuel system consisting of low-sulfur diesel was installed on the Woodsdale CTs in 2019 due to the decommissioning of a nearby propane storage cavern and the need to meet capacity performance requirements for generating resources set by PJM. Duke Energy Kentucky owns four solar assets: two 2 MW fixed-tilt PV plants located at the Walton Solar facility in Kenton County, Kentucky, a 2.8 MW fixed-tilt PV plant located at the Crittenden Solar facility in Grant County, Kentucky, and a 2.5 MW fixed-tilt PV plant located in Boone County, Kentucky. These solar assets are connected on the distribution level, thereby reducing the amount of demand bought from PJM. The Company's ICAP, UCAP and energy mix are depicted in Figures 4.3 through 4.5 below.

Figure 4.3: 2024 Installed Capacity

Figure 4.4: 2024 Unforced Capacity

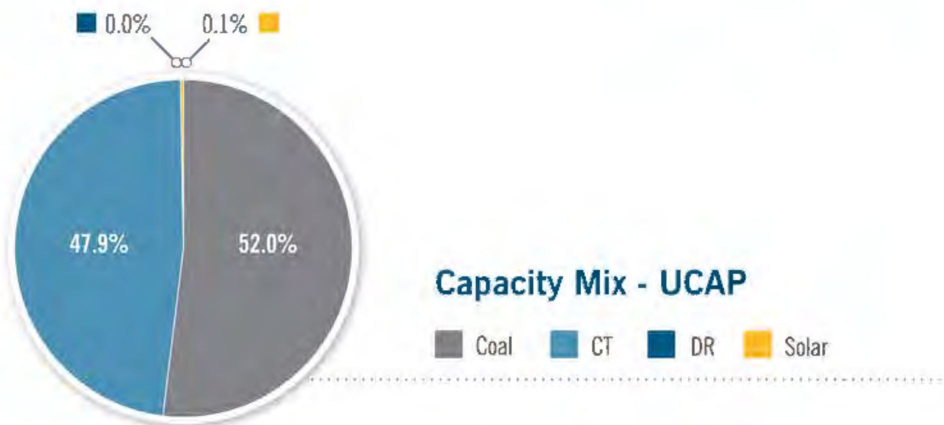
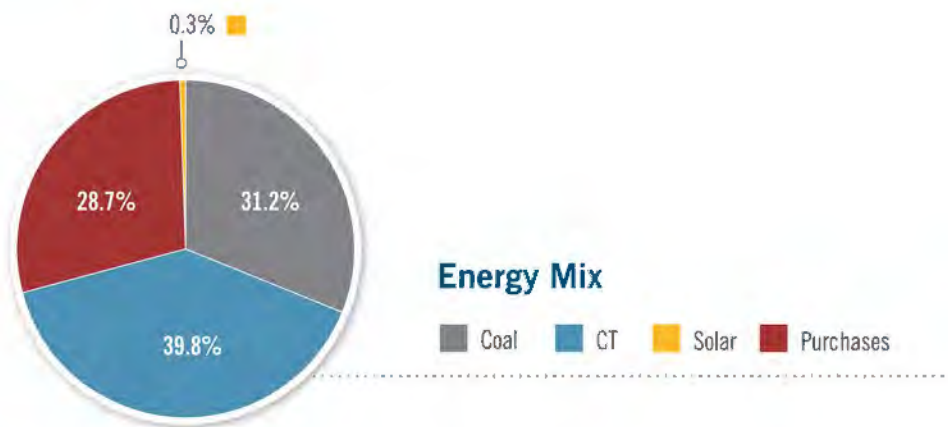


Figure 4.5: Energy Mix



PJM Accreditation - Reserve Margin and Effective Load Carrying Capability (ELCC)

Starting with PJM Delivery Year 2025/2026, PJM will begin to use the ELCC methodology to accredit all capacity resource classes. Table 4.2 below provides the 2025/2026 ELCC class ratings.

Table 4.2: Effective Load Carrying Capability Class Ratings

	2025/2026 BRA ELCC Class Ratings
Onshore Wind	35%
Offshore Wind	60%
Fixed-Tilt Solar	9%
Tracking Solar	14%
Landfill Intermittent	54%
Hydro Intermittent	37%
4-hr Storage	59%
6-hr Storage	67%
8-hr Storage	68%
10-hr Storage	78%
Demand Resource	76%
Nuclear	95%
Coal	84%
Gas Combined Cycle	79%
Gas Combustion Turbine	62%
Gas Combustion Turbine Dual Fuel	79%
Diesel Utility	92%
Steam	75%

No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics. In these instances, the Accredited UCAP is based on a resource-specific ELCC analysis.

For the 2025/2026 Delivery Year, PJM determined that the members of the Gas Combined Cycle Dual Fuel Class are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics. This is due to the Gas Combined Cycle Dual Fuel Class having very few members (less than 10 units) following the dual fuel attestation process for the 2025/26 BRA and there being a large disparity in the observed historical performance during hours of risk across the members of this class. Therefore, no ELCC Class Rating will be determined for the Gas Combined Cycle Dual Fuel Class for the 2025/2026 Delivery Year.

For 2025/2026, PJM establishes the Install Reserve Margin and the Forecasted Pool Requirement to be 17.8% and 0.9387, respectively. The combination of these ELCC and Reserve Margin values are modeled in EnCompass to develop the various portfolios presented in this IRP. The reserve margin in combination with the peak demand forecast reflect the demand that Duke Energy Kentucky must meet. The ELCC values applied to new and existing resources are used to determine the amount of new capacity that must be added to meet Duke Energy Kentucky's peak demand inclusive of reserve margin requirements.

C. Future Resource Considerations

Supply-side resources not excluded for availability reasons are included as potential options in the economic optimization modeling process. The Company considered for inclusion in this IRP a diverse range of traditional technologies utilizing a variety of different fuels, including CTs, CCs (with and without CCS), and small modular and advanced nuclear reactors. In addition, Duke Energy also included onshore wind and solar PV renewable options. Lastly, battery storage options were included in the analysis.

Carbon Capture and Sequestration (CCS)

CCS technology captures CO_2 from coal and natural gas generation. This captured CO_2 is then stored (i.e., sequestered) in suitable geological reservoirs. CCS performance, capital costs and O&M costs used in the modeling process are based on publicly available Front-End Engineering and Design (FEED) studies as well as published studies. The Company's evaluation of the availability of CCS indicates that this technology will not be commercially available until after the 2032 date proposed in the EPA CAA Section 111 Update. Duke Energy is actively evaluating CCS as part of a Department of Energy (DOE)-funded study at its Edwardsport Integrated Gasification Combined Cycle (IGCC) plant in its Indiana service territory. Duke Energy believes CCS can be a cost-effective and viable technology, especially if the project can qualify for the CCS PTC contained in Section 45Q of the Internal Revenue Code. This PTC provides $85/metric ton of CO_2 captured over twelve years if project construction begins prior to January 1st, 2033, and certain other criteria are met.

The company has estimated that CCS technology projects not yet started would not be complete prior to 2032. The implementation timeline of a CCS project is heavily dependent on several factors. One of the more constraining requirements for CCS is sequestration permitting. Permitting requirements for permanent subterranean CO_2 sequestration include EPA Class VI permits, which have taken 24 months or more to receive and involve significant upfront work including subsurface characterization, stakeholder engagement, acquisition of pore space, analysis of CO_2 migration and other state or local requirements. Additionally, CCS is an emerging technology with very few CCS projects in operation in North America. While CCS is a promising technology, given the limited experience with CCS and anticipated complexities, including long lead-time permitting, the Company believes the earliest reasonable operation of a CCS project that is not already approved and in progress would be 2035.

Duke Energy Kentucky Assumption for Wind Resources

Duke Energy Kentucky evaluated wind resources within the Duke Energy Ohio/Kentucky PJM load zone and adjacent PJM load zones. When establishing the execution assumptions, Duke Energy

Kentucky identified that there were no active wind projects queued in the DEOK PJM load zone. Based on the timelines to site and develop a wind resource, it was determined that a wind resource located in Duke Energy Kentucky's service territory was not feasible in the near term. The Company did consider availability of wind resources outside of the DEOK PJM load zone. Focusing on adjacent PJM load zones, there were currently over 5 GW of queued wind capacity in PJM. Such resources could be acquired as direct ownership or contracted through a power purchase agreement.

However, risks and challenges exist in acquiring or contracting for assets outside of Duke Energy Kentucky's service territory, and the DEOK PJM load zone. Duke Energy Kentucky, as a Fixed Resource Requirement (FRR) capacity construct participant in PJM, is required to meet a Minimum Internal Generation Requirement and provide firm capacity to satisfy its final FRR plan. Should PJM increase the minimum capacity required inside of the DEOK PJM load zone, a resource outside of the DEOK PJM load zone may put Duke Energy Kentucky in a short position to satisfy its final FRR plan. The implication would result in PJM penalties and potential FERC referral. If Duke Energy Kentucky were to transition to a Reliability Pricing Model (RPM) participant and own a generating asset outside of the DEOK PJM load zone, Duke Energy Kentucky would be exposed to zonal pricing risk. Duke Energy Kentucky continues to evaluate resources within PJM and will further consider the risks of owning a resource outside of its respective DEOK PJM load zone. Within the modeling execution assumption, opportunities to mitigate the above risks were identified, such as capping the generating size of an asset or considering shorter term power purchase agreements.

Onshore wind capital and operating costs are calculated from third-party forecast tools with the latest cost and performance data available. Information is sourced from the National Renewable Energy Laboratory (NREL) Annual technology baseline, DOE Land-Based market report, and other publicly available information.

Section 5: Demand-Side Management Resources

A. Introduction

Duke Energy Kentucky has been offering DSM programs for almost two decades. Throughout the years, the Company has made many enhancements to its portfolio with the purpose of increasing participation and providing customers new and innovative opportunities to control their electricity consumption and impact their utility bill. Consistent with the Commission's IRP analytical requirements, Duke Energy Kentucky continuously evaluates and considers opportunities to maximize its DSM portfolio within the parameters set by the Commission to meet its resource needs, and specifically as part of this IRP.[9]

Duke Energy Kentucky's DSM programs include traditional conservation EE programs and demand response programs and are expected to help reduce demand on the Duke Energy Kentucky system during times of peak load. Through applications by the Company and in conjunction with the Company's DSM Collaborative, the Commission has approved expansions of the Company's DSM efforts over time. The expansion of the programs has led to the implementation of the programs listed in Figure 5.1 below described in greater detail in Appendix C.

[9] *In the Matter of the Consideration of the New Federal Standards of the Energy Independence and Security Act,* Case No. 2008-00408, Order at p. 18 (July 24, 2013).

Figure 5.1 Projected Demand-Side Management Impacts

B. DSM Programs and the IRP

The projected impacts of DSM programs have been included in this IRP. The energy efficiency programs are projected to reduce energy consumption by 242,830 MWh and 38 MW by 2038. The Residential Direct Load Control Program (Power Manager) is projected to reduce peak demand by about 10 MW and the PowerShare® program another 14 MW by 2038. This brings the total peak reduction across all programs to approximately 62 MW by 2038. Table 5.2 below summarizes the projected load impacts included in this IRP analysis.

Table 5.1 Projected Demand-Side Management Impacts

Year	EE Program Impacts		DR Program Impacts			DSM Impacts Total MW
	MWh	MW*	PowerShare MW	PowerManager MW	Total MW	
2024	11,667	2.2	14.0	9.6	23.7	25.8
2025	29,840	5.1	14.1	9.7	23.8	28.9
2026	48,623	8.1	14.1	9.8	23.9	32.0
2027	67,974	11.2	14.1	9.8	23.9	35.1
2028	87,743	14.4	14.1	9.9	24.0	38.4
2029	107,756	17.6	14.1	9.9	24.0	41.6
2030	127,697	20.8	14.1	9.9	24.0	44.8
2031	147,584	23.9	14.1	9.9	24.0	47.9
2032	167,380	27.0	14.1	9.9	24.0	51.0
2033	183,884	29.5	14.1	9.9	24.0	53.5
2034	198,829	31.8	14.1	9.9	24.0	55.8
2035	210,511	33.5	14.1	9.9	24.0	57.5
2036	221,460	34.9	14.1	9.9	24.0	58.9
2037	232,193	36.5	14.1	9.9	24.0	60.5
2038	242,830	38.0	14.1	9.9	24.0	62.0

Note: EE Program MW impacts are from peak August reductions.

Section 6: Model Results & Sensitivity Analysis

A. Introduction

The analytical approach of evaluating various portfolios in different scenarios (with and without EPA CAA 111 Update), followed by sensitivity analysis allows the Company to select the 2024 IRP portfolio based upon a robust set of criteria.

B. Optimized Portfolios

The six portfolios introduced in Section 2 and detailed in this section were developed to evaluate the range of options for East Bend Station under potential futures with and without the EPA Section 111 Update in place. Portfolios were optimized in Encompass for each East Bend strategy and the modeling results and findings are detailed throughout this section.

Optimized Portfolios with EPA CAA Section 111 Update

Three optimized portfolios that comply with the EPA CAA Section 111 Update were developed .and are summarized in Tables 6.1 through 6.3:

a. East Bend DFO Conversion by 2030
b. East Bend Natural Gas Conversion by 2030
c. East Bend Retirement by 2032

Table 6.1: With EPA CAA Section 111 Update: East Bend DFO Conversion by 2030

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC w/CCS (1x1)															591	591
Battery															100	100
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

Table 6.2: With EPA CAA Section 111 Update - East Bend Natural Gas Conversion by 2030

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend NGC						600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	59	59	59	59

Table 6.3: With EPA CAA Section 111 Update - East Bend Retirement by 2032

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600									
East Bend CT								426	426	426	426	426	426	426	426	426
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	59	159	259	259	259	409	409	409	409
Solar + Storage: Solar								210	210	210	210	210	210	210	280	280
Solar + Storage: Battery								75	75	75	75	75	75	75	100	100
Battery								50	50	50	100	100	100	100	100	100

Optimized Portfolios without EPA CAA Section 111 Update

Three optimized portfolios were developed to reflect a future where the EPA CAA Section 111 Update is stayed or eventually repealed. The portfolios are summarized in Tables 6.4 through 6.6.

Without EPA CAA Section 111 Update Scenario

a. East Bend DFO Conversion by 2030
b. East Bend Natural Gas Conversion by 2030
c. East Bend Retirement by 2036

Table 6.4: Without EPA CAA Section 111 Update - East Bend DFO Conversion by 2030

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC w/CCS (1x1)															59188	59188
Battery															100	100
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	59	59

Table 6.5: Without EPA CAA Section 111 Update - East Bend Natural Gas Conversion by 2030

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend NGC						600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	59	59	109	159	259

Table 6.6: Without EPA CAA Section 111 Update - East Bend Retirement by 2036

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600	600	600	600	600					
East Bend CC w/CCS (1x1)												591	591	591	591	591
Battery												50	50	50	100	100
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

C. Alternate Portfolios

In addition to the six optimized portfolios, eleven alternate strategies were evaluated. These portfolios include five with the EPA CAA Section 111 Update, summarized in Tables 6.7-6.11, and six without, summarized Tables 6.12-6.17:

With EPA CAA Section 111 Update Scenario

1. East Bend DFO Conversion with CC Replacement by 2039
2. East Bend DFO Conversion with SMR Replacement by 2039
3. East Bend DFO Conversion with CC with CCS Replacement by 2036
4. East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables
5. East Bend Retires by 2032 with CC Replacement

Without EPA CAA Section 111 Update Scenario

1. East Bend DFO Conversion with CC Replacement by 2039
2. East Bend DFO Conversion with SMR Replacement by 2039
3. East Bend DFO Conversion with CC Replacement by 2036
4. East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables
5. East Bend Retires by 2036 and Accelerated Renewables
6. East Bend Retires by 2042

These alternate portfolios were developed to assess the value of differing East Bend retirement dates and replacement resource options, primarily under the DFO conversion pathway which emerged as the preferred compliance method as further detailed below and in Section 7. Alternate portfolios were also developed to test the value of accelerating solar that was selected in the late 2030s to early 2040s timeframe in the optimized portfolios.

Alternate Portfolios with EPA CAA Section 111 Update

Table 6.7: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	259	259

Table 6.8: With EPA CAA Section 111 Update – East Bend DFO Conversion with SMR Replacement by 2039

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CT															231	231
SMR															300	300
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	109

Table 6.9: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC with CCS Replacement by 2036

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600					
East Bend CC w/CCS (1x1)												591	591	591	591	591
Battery												50	50	50	100	100
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

Table 6.10: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Table 6.11: With EPA CAA Section 111 Update – East Bend Retires by 2032 with CC Replacement

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600									
East Bend CC (1x1)								664	664	664	664	664	664	664	664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	59	159	209	209	209	259

Alternate Portfolios without EPA CAA Section 111 Update

Table 6.12: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

Table 6.13: Without EPA CAA Section 111 Update – East Bend DFO Conversion with SMR Replacement by 2039

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
SMR															300	300
New CTs															231	231
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	109

Table 6.14: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2036

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600					
East Bend CC (1x1)												664	664	664	664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

Table 6.15: Without EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Table 6.16: Without EPA CAA Section 111 Update – East Bend Retires by 2036 with Accelerated Renewables

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600	600	600	600	600					
East Bend CC (1x1)												664	664	664	664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Table 6.17: Without EPA CAA Section 111 Update – East Bend Retires by 2042

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

D. Cost, CO_2 Reduction & Market Exposure

The model selected resources in the optimized portfolios are instructive and provide considerable insight on the drivers of the resource selection. Additional insights, focusing on cost, CO_2 reduction, and market exposure are detailed below.

Cost

The below graphs show the evolution of PVRR (Present Value Revenue Requirement) through 2040. Given the current long position in capacity requirements, Duke Energy Kentucky's existing fleet is sufficient to handle the near-term load and, as shown in Figures 6.1 and 6.2 there is no cost difference between portfolios in the short-term. The difference in costs between portfolios materializes in the mid-term as varying East Bend compliance pathways are implemented under the EPA CAA 111 Update. Similar trends occur in the scenario where EPA CAA 111 Update is stayed or repelled, as shown in Figures 6.3 and 6.4.

Figure 6.1: PVRR ($000) – Optimized With EPA CAA Section 111 Update

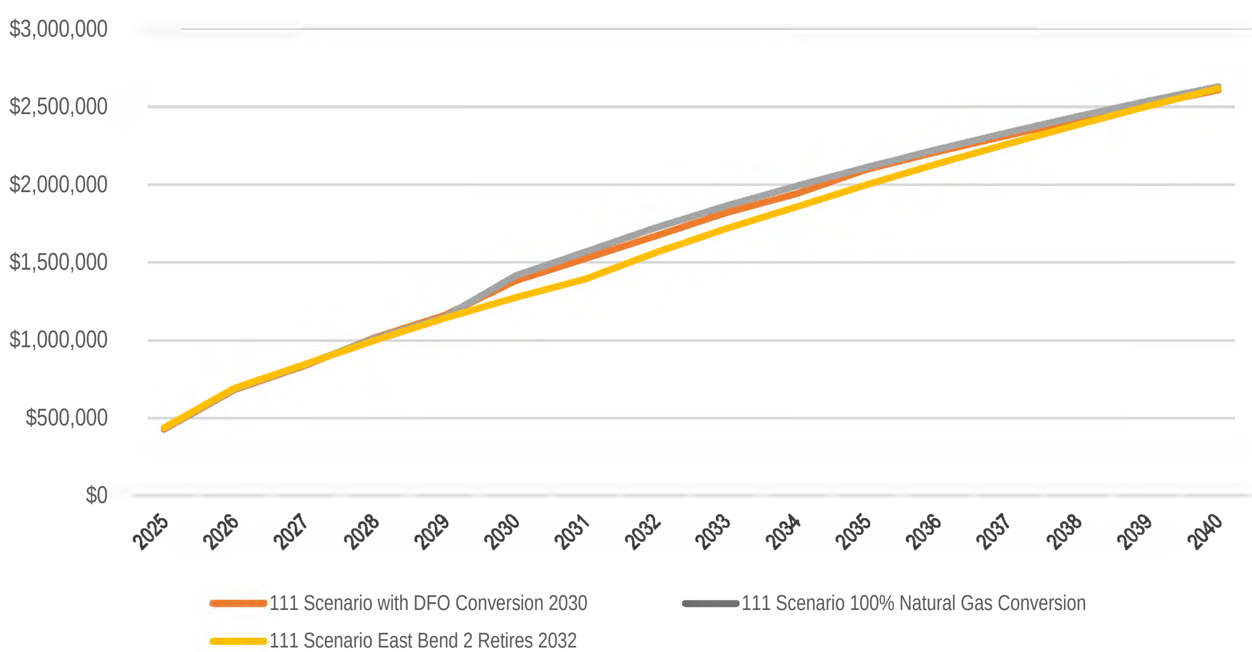


Figure 6.2: PVRR ($000) – Alternate With EPA CAA Section 111 Update

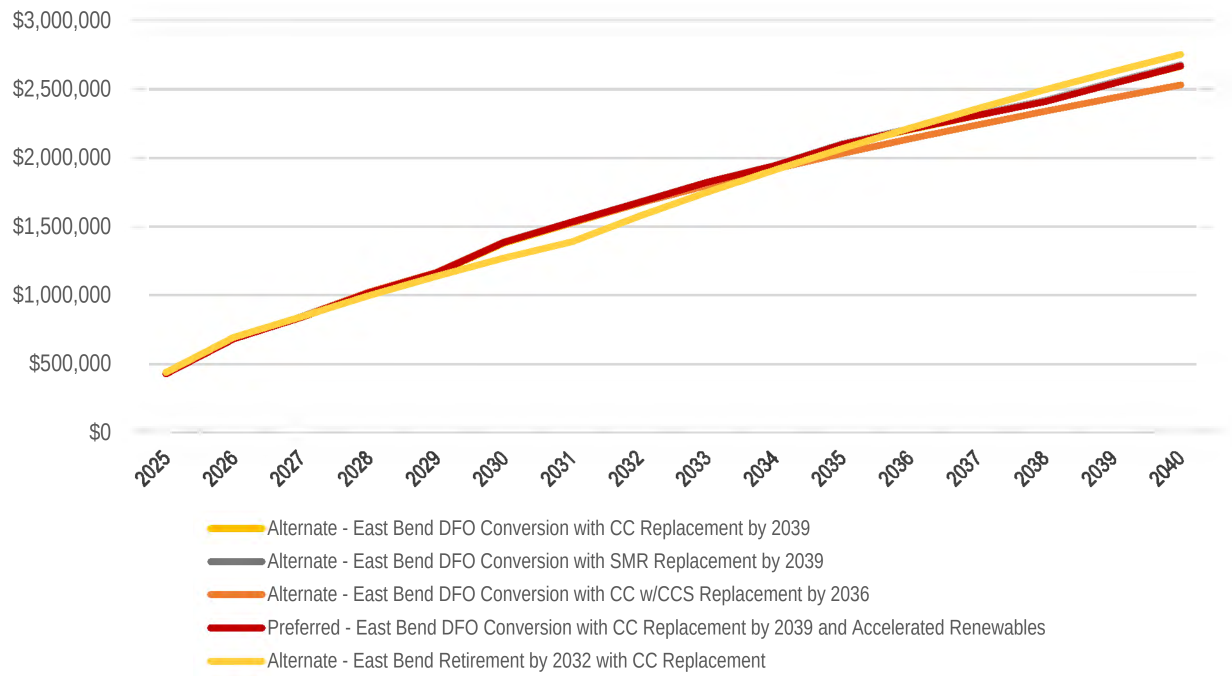


Figure 6.3: PVRR ($000)– Optimized Without EPA CAA Section 111 Update

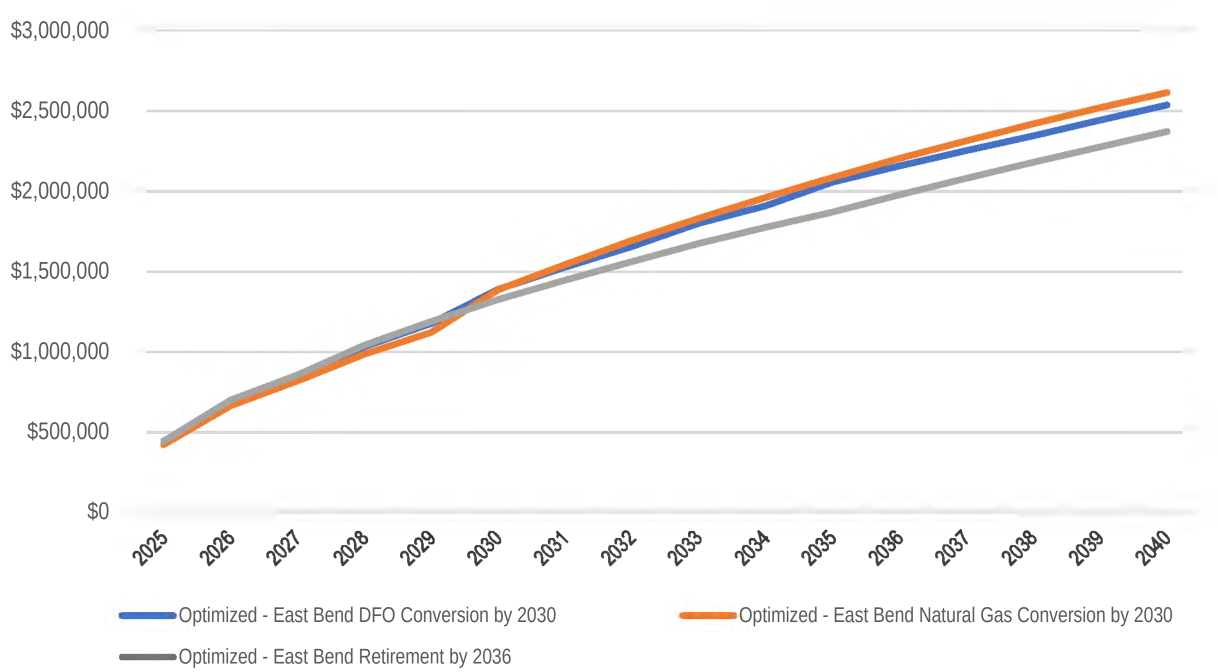
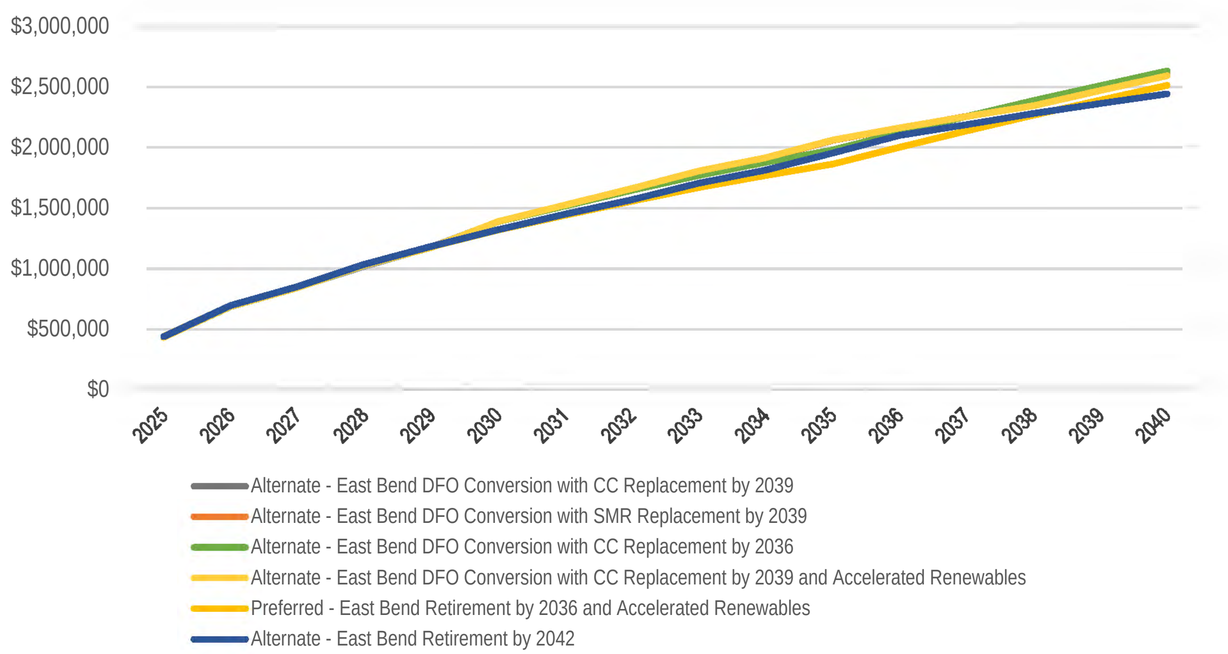


Figure 6.4: PVRR ($000) – Alternate Without EPA CAA Section 111 Update



CO_2 Reduction

The below graphs show the levels of projects CO_2 reduction over time (using 2005 levels as the base for comparison). Figures 6.5 and 6.6, show CO_2 reductions in portfolios with EPA CAA 111 Update, and Figures 6.7 and 6.8 show CO_2 reductions in portfolios without the EPA CAA 111 Update. Varying CO_2 reductions in the mid-2020s, prior to operational changes at East Bend, are due to random outages that are modeled in EnCompass.

Figure 6.5: CO_2 Reduction – Optimized with EPA CAA Section 111 Update

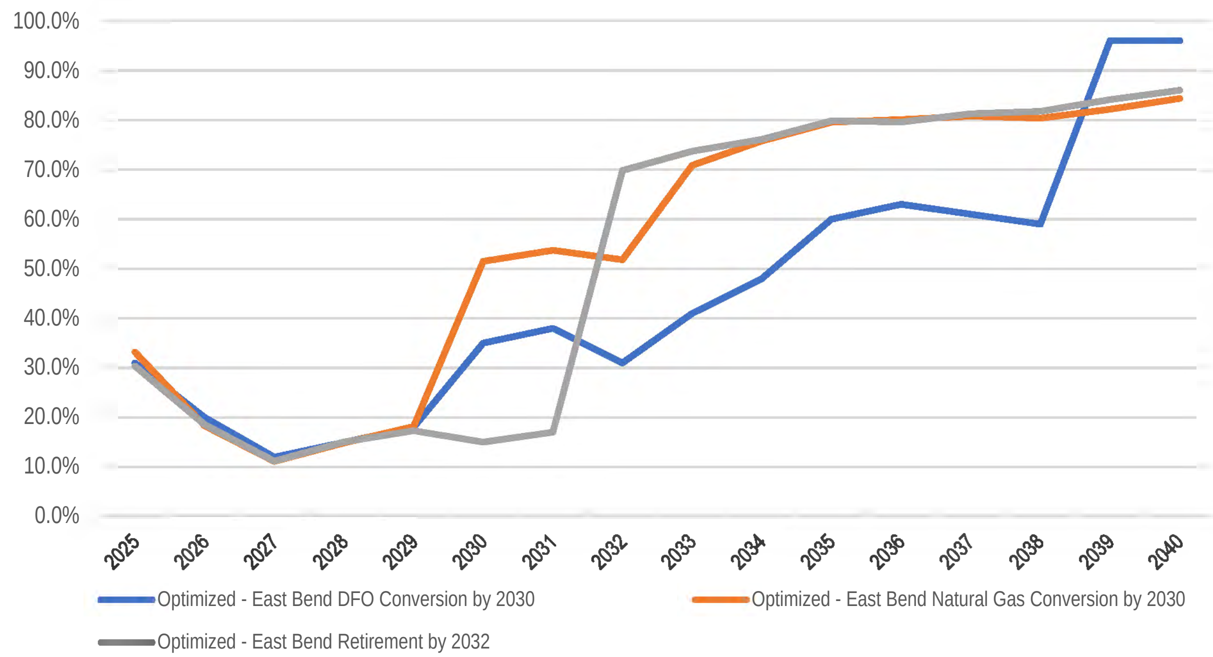


Figure 6.6: CO_2 Reduction – Alternate with EPA CAA Section 111 Update

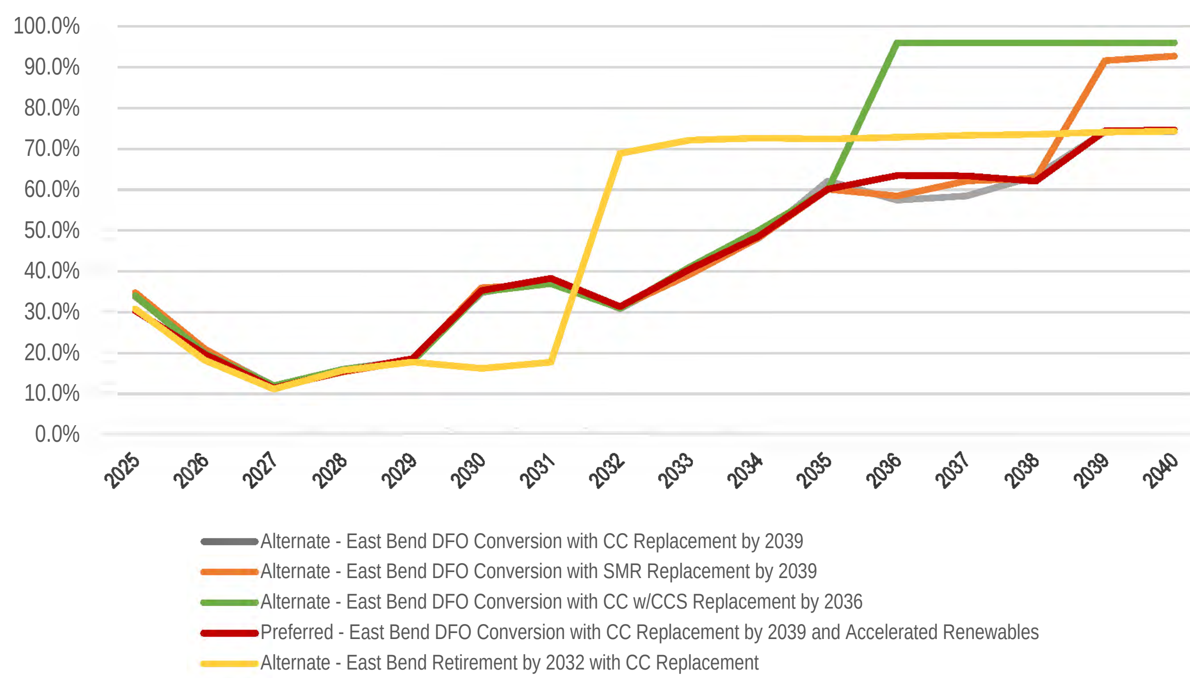


Figure 6.7: CO_2 Reduction – Optimized without EPA CAA Section 111 Update

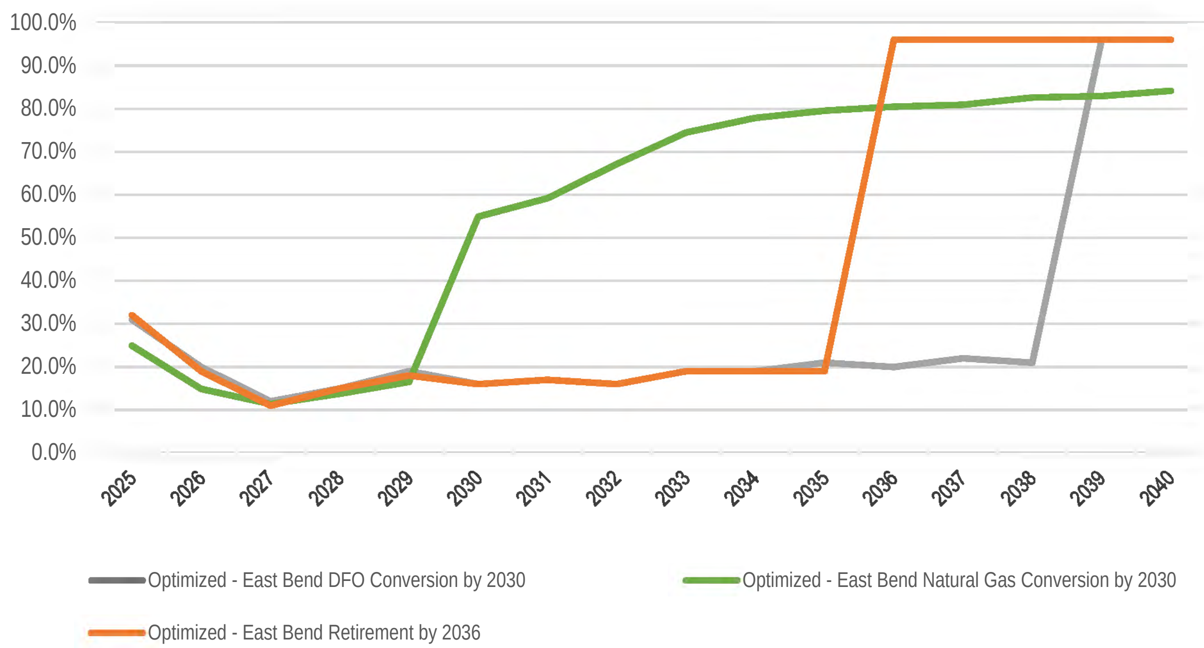
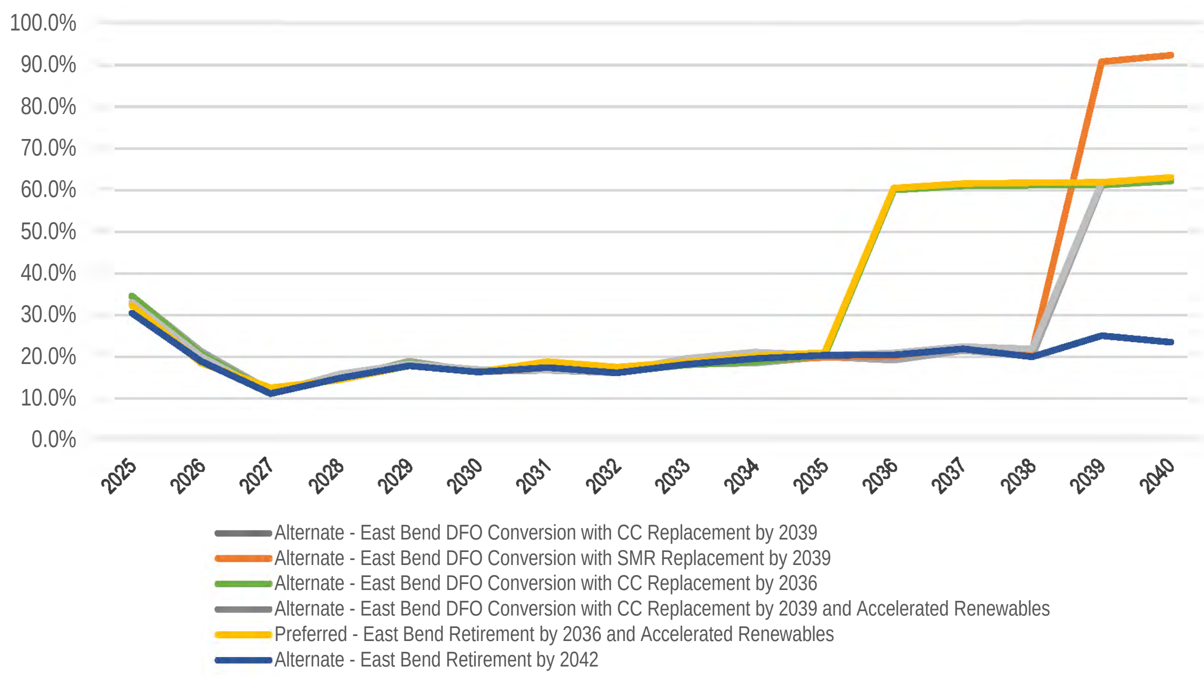


Figure 6.8: CO_2 Reduction – Alternate without EPA CAA Section 111 Update



Market Exposure

Figures 6.9 and 6.10 show the annual amount of market purchases (i.e., energy purchased from the PJM market) as a percent of total load with the EPA CAA Section 111 Update. Figures 6.11 and 6.12 show market purchases in portfolios without the EPA CAA Section 111 Update. Similar to CO_2

reductions in the mid-2020s, market purchases also vary between portfolios prior to operational changes at East Bend due to random outages that are modeled in EnCompass.

Figure 6.9: Market Purchases – Optimized with EPA CAA Section 111 Update

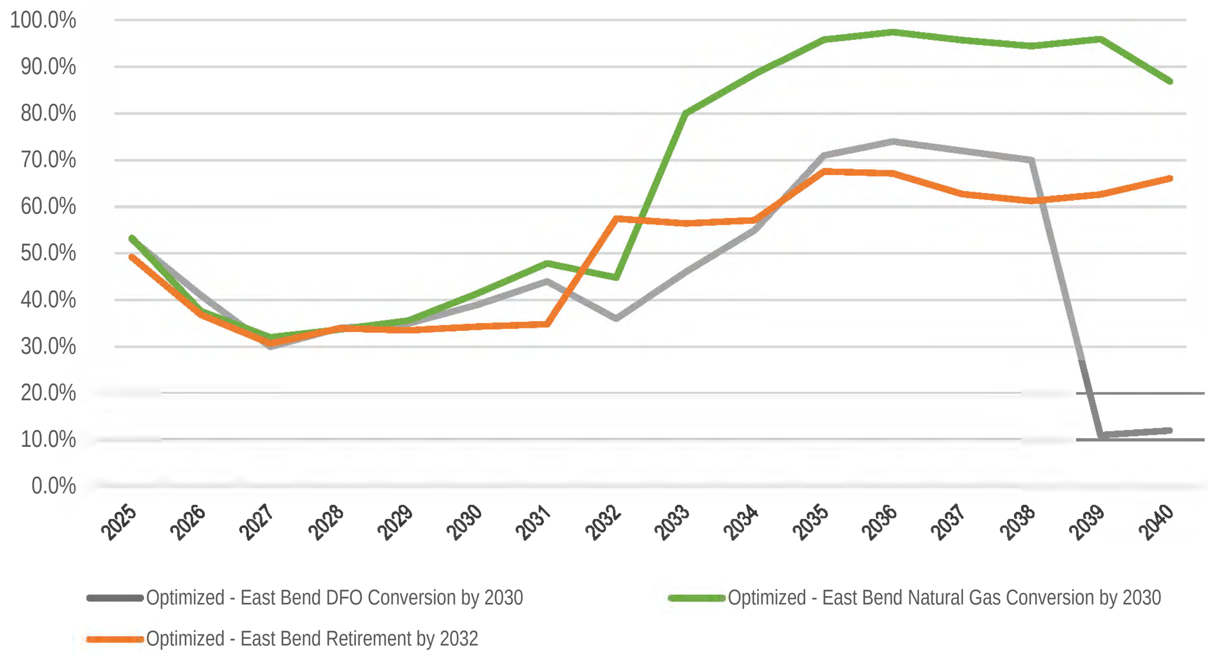


Figure 6.10: Market Purchases – Alternate with EPA CAA Section 111 Update

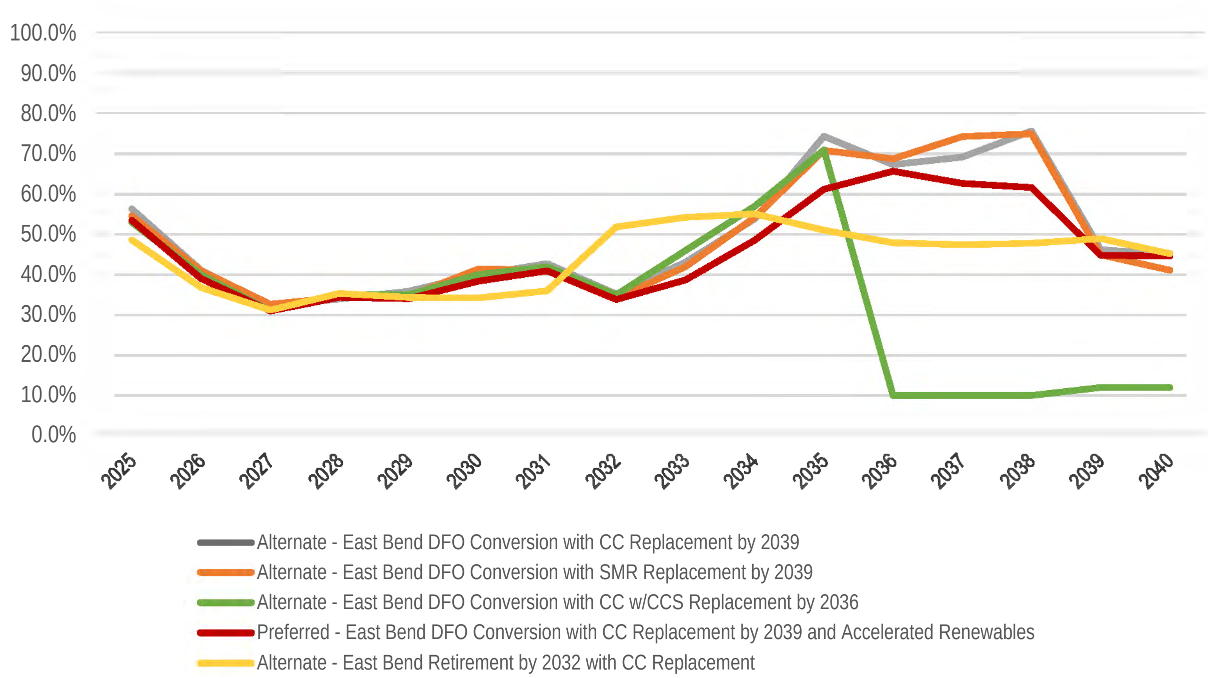


Figure 6.11: Market Purchases – Optimized without EPA CAA Section 111 Update

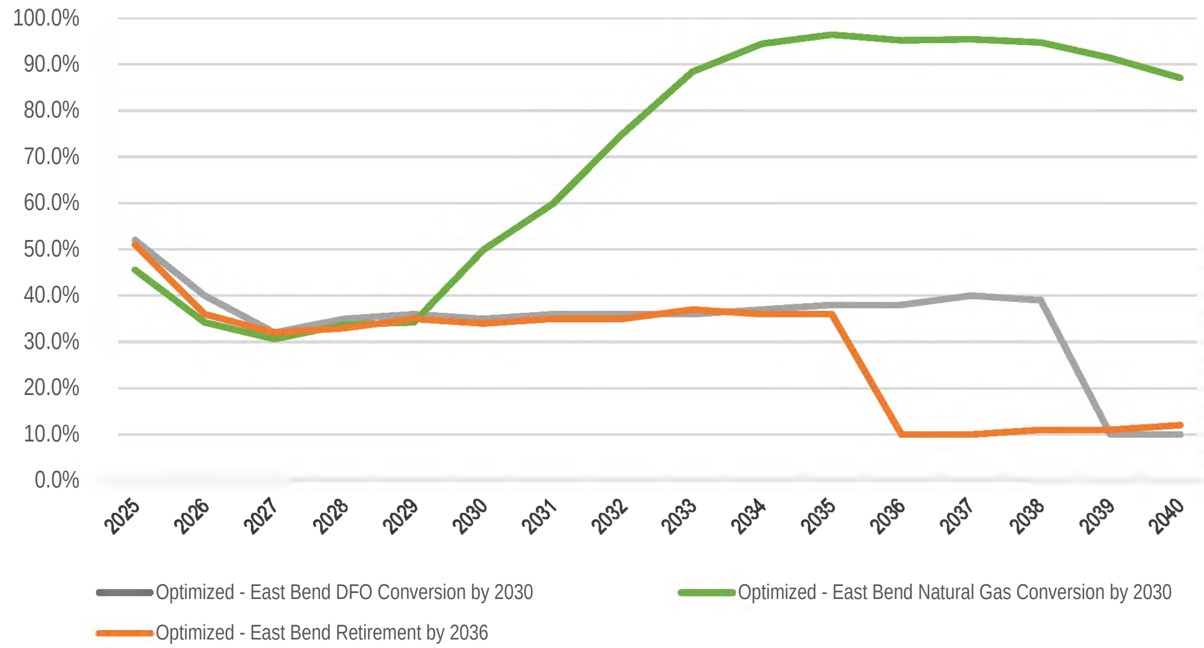
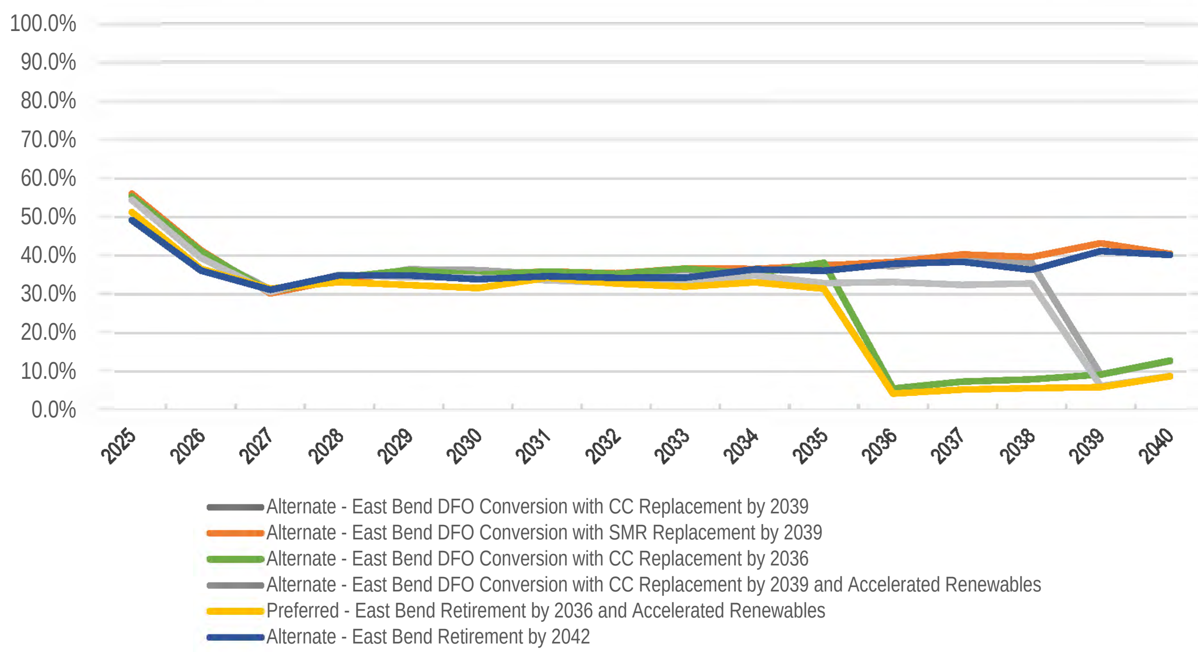


Figure 6.12: Market Purchases – Alternate without EPA CAA Section 111 Update



Observations from Optimized and Alternate Portfolios

East Bend Replacement Generation:

The optimized portfolios were developed under three different compliance pathways 1) retire East Bend by 2032, 2) convert East Bend to natural gas by 2030 and retire by 2045, and 3) convert East Bend to DFO and retire by 2039. The optimized replacement option for East Bend in two of the pathways (Retire by 2032 and Natural Gas Conversion pathways) was a CT, solar, standalone storage, and storage paired with solar. With a CT as the primary capacity replacement for East Bend, Duke Energy Kentucky would be heavily reliant on the market to provide energy for most hours of the year. In the 2032 retirement pathway, the accelerated capital cost of the replacement generation, along with the heavy reliance on the market caused this to be one of the most expensive portfolios.

A CC with CCS was selected in the DFO conversion pathway when East Bend was retired by 2039 when CCS was available *and* the captured CO_2 emissions were eligible for the 45Q tax credits described previously. The 45Q tax credits allowed this pathway to be the least cost of the optimized pathways through 2040.

Because CCS technology is still nascent, the Company evaluated alternative replacement options in the DFO conversion pathway including a CC limited to 40% capacity factor in order to meet the EPA CAA Section 111 Update requirements and an SMR, which is also not a viable replacement option today but could be available by the latter half of the 2030s. The CC replacement option did increase the PVRR of the portfolio and caused this pathway to be slightly more expensive (~$65M PVRR) than the natural gas conversion pathway. However, the CC did lower dependence on the PJM market and would reduce customer exposure to fluctuating market prices compared to the natural gas conversion case, in which Duke Energy Kentucky is generating electricity with natural gas on a much less efficient unit.

Renewable Additions

In all optimized portfolios, solar and battery storage were selected. Solar was selected by 2040 in all cases as it provided valuable energy to avoid market purchases. The Company tested the value of accelerating solar into the late 2020s in the DFO conversion pathway and found that the increase in PVRR was negligible.

Storage was added earlier in portfolios where a CT replaced East Bend, as storage provided additional replacement capacity. Storage was also added in the 2040s as demand increased and additional capacity was needed in Duke Energy Kentucky. Because storage was only selected in periods where there was a capacity need, the Company did not accelerate storage in the alternate portfolios. In a few of the portfolio’s wind was selected, but not until the late 2030’s or 2040’s.

Portfolio Impacts with No EPA CAA Section 111 Updates

Similar analysis to the EPA CAA Section 111 Update was conducted assuming the CAA Section 111 Updates are stayed and eventually repealed. In addition to assuming the DFO conversion project was in place after a stay of the CAA Section 111 Update, the Company also evaluated a scenario where the rule was stayed prior to make significant progress on the DFO conversion project. In the latter scenario, the Company’s preferred portfolio is retirement of East Bend by year end 2035, with a CC as East Bend’s replacement. Without the fuel diversity of the DFO project, East Bend would be reliant on a potentially fading coal market in the latter half of the 2030s and would continue operating with high costs and risks associated with maintaining reliable operations beyond 2035 on 100% coal.

Similar to the preferred portfolio in the EPA CAA Section 111 Update scenario, the No EPA CAA Section 111 Update preferred portfolio accelerates solar into the late 2020s to provide increased energy diversity on the Duke Energy Kentucky system. East Bend Retirement by 2036 and Accelerated Renewables was selected as the preferred portfolio in a scenario without EPA CAA 111 Update.

Finally, the EPA CAA 111 Update increases the PVRR of the resource plans in Duke Energy Kentucky. The Company's preferred portfolio in an EPA CAA 111 Update scenario (DFO conversion) is over $150M more expensive through 2040 versus the preferred portfolio without the EPA CAA 111 Update scenario (retire East Bend by year end 2035).

Conclusions

Due to lower reliance on the market, greater fuel flexibility, and relatively low PVRR, DFO is considered to be the preferred option with the EPA CAA Section 111 Update in place. Additionally, the DFO option allows time for technologies such as CCS and SMRs to evolve and potentially be considered as replacement options for East Bend in the late 2030s. Finally, accelerating solar into the late 2020s allows for increased resource diversity in Duke Energy Kentucky at little to no incremental PVRR.

E. Sensitivity Analysis

Sensitivity analysis was conducted on the Company's preferred portfolio, East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables, with the EPA CAA Section 111 Updates in place. This analysis shows the impact to the expansion plan under three potential scenarios;

1) Increase to the load forecast,
2) Increase to the fuels forecast, and
3) Decrease to the fuels forecast.

Table 6.18: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 – High Load

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Battery											50	50	50	100	100	100
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	359

Table 6.19: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 – High Fuels

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Table 6.20: With EPA CAA Section 111 Update – East Bend DFO Conversion with CC Replacement by 2039 – Low Fuels

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Under the high load sensitivity, batteries were selected in 2035 due the need to maintain reserve margin and serve the increased load. Under high and low fuels sensitivities, there were no changes to the resource plan during the planning horizon.

Figure 6.13: PVRR ($000)– Sensitivities With EPA CAA Section 111 Update

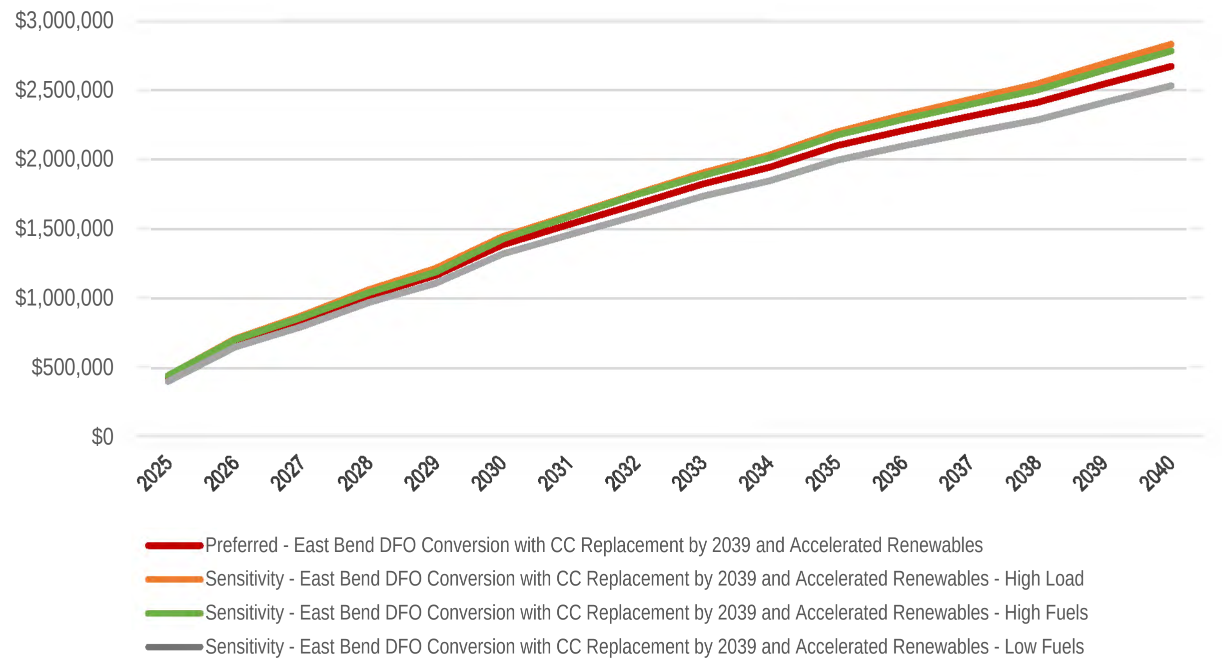


Figure 6.14: CO_2 Reduction – Sensitivities with EPA CAA Section 111 Update

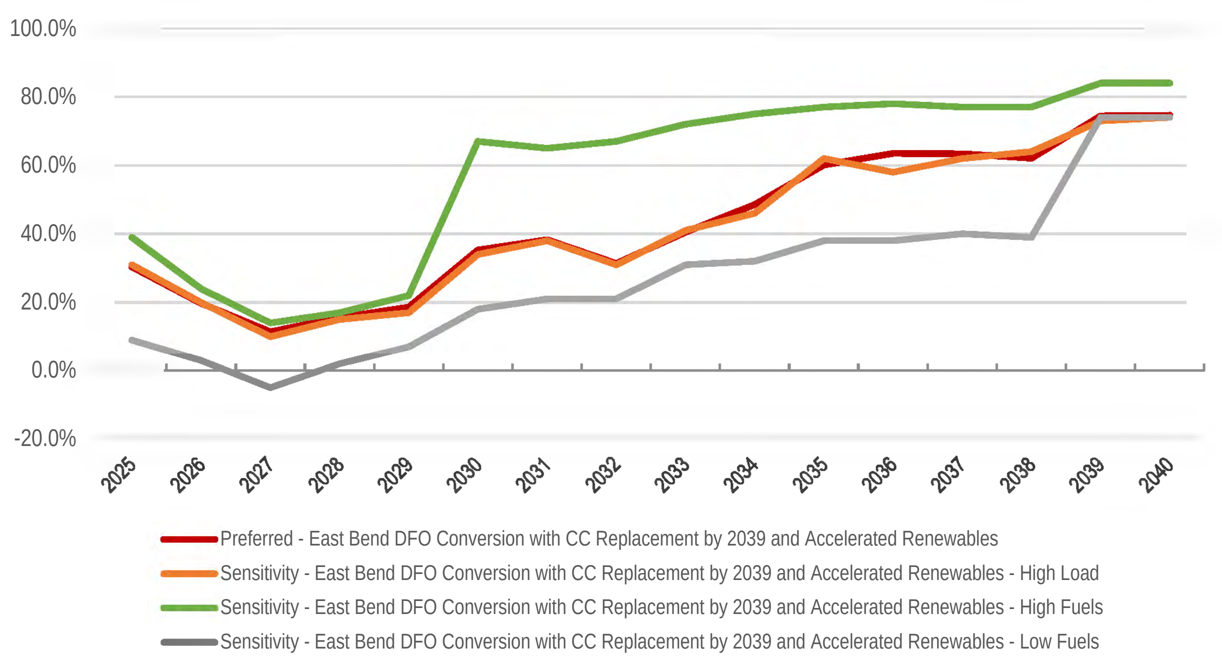
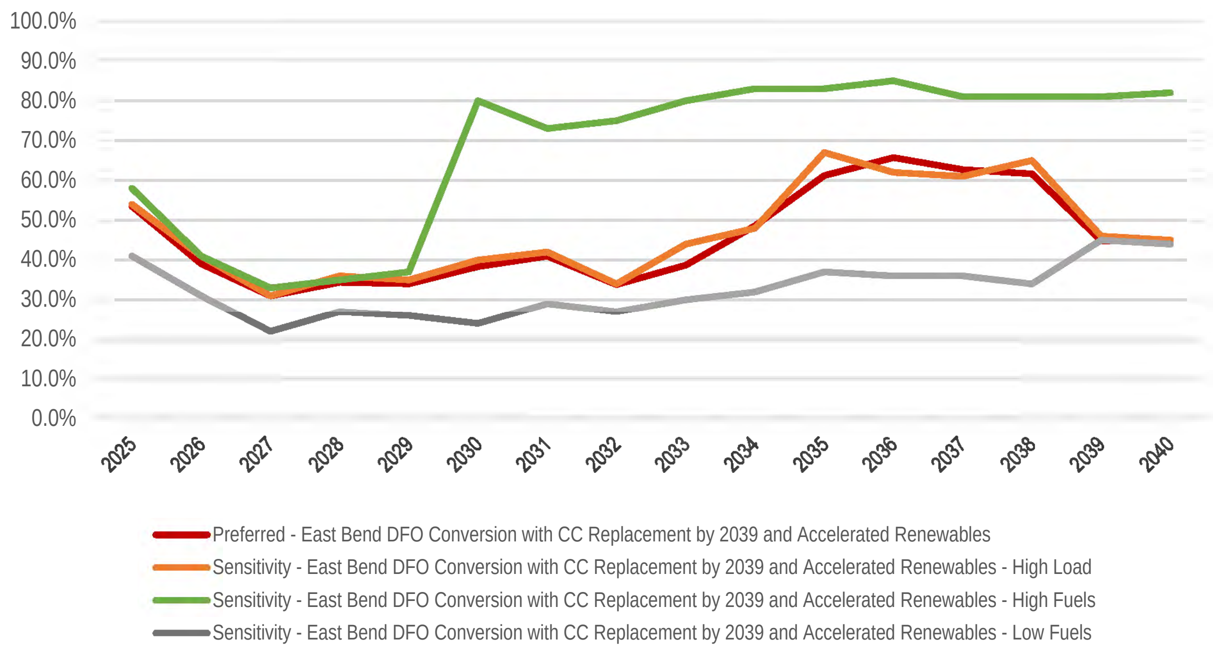


Figure 6.15: Market Purchases – Sensitivities with EPA CAA Section 111 Update



Observations from Sensitivity Analysis

Increasing demand on the Duke Energy Kentucky system will require additional resources in order to maintain adequate planning reserves. In this analysis, the preferred option for meeting additional demand was battery storage and incremental solar additions. The high and low fuel cost sensitivities did not impact resource selection; however, in a high fuel cost scenario, Duke Energy Kentucky could see increased market purchases given the Company's fuel mix.

Section 7: 2024 Integrated Resource Plan

A. Plan Overview

The 2024 IRP Portfolio is described in Figure 7.1 and presented in detail below. It was selected based on several factors, including: cost competitiveness, flexibility for futures with and without the EPA CAA Section 111 Update, and the risk mitigation it provides through increased fuel and fleet diversity and the moderate level of market purchases. This plan is compliant with new environmental regulations and includes opportunities to adjust course should those rules change.

Figure 7.1: 2024 IRP Portfolio

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

Converting East Bend to DFO by 2030 enables Duke Energy Kentucky to reliably serve its customers under the EPA CAA Section 111 Update while providing for a measured transition out of coal generation. While the plan ultimately calls for a combined cycle to replace East Bend, this plan allows East Bend to remain in service until 2039, at which time new technologies, such as SMRs or CC with

CCS, may be available to provide dispatchable generation to continue meeting customers' energy needs for decades to come. Finally, if the EPA CAA Section 111 Update were repealed, DFO at East Bend would provide for fuel flexibility that would allow East Bend to remain competitive under varying market conditions.

The plan also calls for the addition of 50 MW of solar every other year beginning in 2029. This solar provides another energy source that reduces customers' exposure to fluctuating PJM market prices while further diversifying the Duke Energy Kentucky system.

B. Key Variables to Monitor Ahead of the 2027 IRP

Fuel Prices and Impact on Power Markets

DFO at East Bend provides flexibility under varying market power and fuel price conditions. The impact on market power prices from coal and natural gas prices fluctuations will depend on how the broader PJM marketplace reacts to the EPA CAA Section 111 Update. However, converting East Bend to DFO will limit the impacts of these fluctuations on East Bend's competitiveness in the PJM marketplace. It will be able to generate energy from natural gas if gas prices fall below coal prices, and similarly if natural gas prices are more expensive than coal prices, East Bend can generate energy primarily from coal. However, under the EPA CAA Section 111 Update, over an annual period, coal burn must be balanced with natural gas to meet the required emission reduction.

Inflation Impacts on New Generation

High inflation over the past two years has increased the cost of all types of generation, including renewables and conventional generators. If inflation were to continue to increase and prices of new generation remain elevated, replacing existing generation with new resources will be more expensive. If inflation reverses, then replacing existing generation will become more affordable. The 2024 IRP Portfolio, which adds DFO to East Bend in order to allow operation through 2038, allows Duke Energy Kentucky the flexibility to monitor replacement generation costs and adjust the retirement date should inflation reverse over the next decade.

Environmental Regulations Including CO_2

The regulatory environment is currently dynamic and will require close monitoring over the next several months and years. The EPA CAA Section 111 Update regulating existing coal and new natural gas generation has prompted a number of parties to challenge the rule and to seek a stay. If successful, the rule's requirements could be delayed, modified or even repealed. Should the EPA CAA Section 111 Update remain in place and the EPA successfully implements rules on existing natural gas generation, impacts to PJM market prices could be significant. If the EPA CAA Section 111 Update fails to remain in place, power prices could still be impacted depending on actions that utilities take leading up to a final repeal of the existing rule. The 2024 IRP Preferred Portfolio provides a pathway with benefits and flexibility to adapt to either outcome of the motions to stay the EPA CAA Section 111 Update. In addition, the EPA has opened a "non-regulatory" docket to receive comments on potential ways to regulate GHG emissions from existing combustion turbine generation. EPA has stated its intention to develop an additional 111 rule covering existing combustion turbines. That rule could be proposed in late 2024 or early 2025.

Additionally, with these rules in place, along with the IRA tax incentives that were passed into law in August 2022, it is unlikely that a tax on CO_2 emissions would be implemented as these regulations aim to reduce CO_2 emissions using both a carrot (tax credits) and a stick (forced reductions in electricity generated from coal).

Legislation Impacting Existing Fossil Fuel Generation

Kentucky Senate Bill 4 (SB4)[10] and Kentucky Senate Bill 349 (SB349)[11] became effective in 2023 and 2024, respectively. SB4 created a rebuttable presumption against the retirement of any fossil-fuel fired generating unit in Kentucky and establishes certain criteria that must be met before the Kentucky Public Service Commission (KyPSC) can approve a retirement or any related mechanism to recover costs of a retired asset. One of the outcomes of SB349 was that it creates an Energy Planning and Inventory Commission (EPIC) that utilities must provide notice to prior to retiring fossil fuel generation. EPIC is tasked to provide the KyPSC a written report that is to be included in any retirement application made to the KyPSC. Further, the KyPSC shall not approve any retirement application without considering all information received from EPIC. These laws have the impact of creating additional steps prior to retiring existing fossil fuel-fired generation, and any further laws in this area will need to continue to be monitored. The requirements of SB4 and SB349 do not apply to the Company's plan to convert East Bend to DFO.

Changes in Load Forecasts (Economic Development)

Many regions across the US are seeing increasing economic development opportunities from new data centers powering artificial intelligence generation and the onshoring of manufacturing back to the US. As shown in Section 6, the Company is monitoring potential increases in the load forecast beyond the base assumptions in this IRP driven by economic development and is considering how these could lead to an acceleration of new generation for Duke Energy Kentucky in order to maintain planning reserve margin requirements. The Company will continue to monitor developments and will adjust its resource plan as needed.

Changes in PJM Requirements

Duke Energy Kentucky operates within the PJM RTO, and as an RTO, PJM is responsible for defining the requirements for maintaining a reliable electric grid. Duke Energy Kentucky relies on PJMs projections for planning reserve margin requirements ELCC, or capacity contribution, of new and existing resources in the 2024 IRP. Through its analysis, PJM has seen an increased level of risk during winter months which impacts the ELCC of resources on the system. For instance, as risk shifts from summer months to winter months, solar ELCC drops while wind ELCC increases due to the availability of these resources during peak risk hours. Duke Energy Kentucky will continue to monitor changes to how PJM manages reliability of the grid, and the impact that those changes will have on the Company's future plans.

[10] KRS 278.262 to 278.264 https://apps.legislature.ky.gov/law/statutes/chapter.aspx?id=38583

[11] Kentucky Senate Bill 349 https://apps.legislature.ky.gov/recorddocuments/bill/24RS/sb349/bill.pdf

Appendix A: Transmission and Distribution Forecast

A. Preface

This Appendix contains information that addresses the transmission and distribution requirements of 807 KAR 5:058.

The information included in this Appendix discusses a plan summary and resource assessment and acquisition plan relative to Transmission and Distribution assets in Duke Energy Kentucky.

B. Section 5 Plan Summary Responses

Response to 5.(4) Planned Resource Acquisition Summary – Transmission System

There currently are no transmission system projects planned or in-progress affecting any Duke Energy Kentucky transmission facilities that are intended to provide or are associated with the provision of additional resources.

C. Section 8 Resource Assessment and Acquisition Plan

Response to 8.(2)(a) Options Considered for Inclusion

Changes to the Duke Energy Kentucky transmission and distribution systems are based on meeting planning criteria, which are intended to provide reliable system performance in a cost-effective manner. Loss reduction is a secondary goal, which may be considered, when appropriate, in deciding between various alternatives, which serve the primary purpose of maintaining system performance. In general, projects, which are solely intended to reduce losses, are not cost-effective. The costs for such projects are high, and the loss impacts are too small to materially affect the resource plan.

The following improvements were made to the transmission system in 2021-2023 for the purposes of increasing capacity and/or reliability:

- 2021: No transmission system improvements were implemented.
- 2022: No transmission system improvements were implemented.

- 2023: Erected 138 kV line from Duke Energy Ohio-owned Woodspoint Substation to Aero Substation.

The following transmission system improvements are planned for 2024-2026, with exact timing subject to change:

- 2024: No transmission system improvements are planned.
- 2025: Erect 69 kV line, approximately 1 mile in length, from Hebron Substation to a point on the Feeder 15268C line, re-feed the 15268C tap directly from Hebron Substation. Rebuild 1.4-mile section of 69 kV Feeder 6763 from Limaburg Substation to Oakbrook Substation to increase capacity.
- 2026: No transmission system improvements are planned.

The following improvements were made to the distribution system in 2021-2023 for the purposes of increasing capacity and/or reliability:

- 2021: Dry Ridge Substation – 10.5MVA transformer bank installed; Longbranch Substation – 22.4MVA transformer bank installed
- 2022: No distribution system capacity improvements were implemented
- 2023: Richwood Substation – 22.4MVA transformer bank installed

The following distribution system improvements are planned for 2024-2026, with exact timing subject to change:

- 2024: Litton Substation – Add 2 – 22.4MVA transformer banks; Taylor Mill Substation – New substation w/ 22.4 MVA transformer bank; White Tower Substation – Increase transformer bank size to 22.4 MVA from 10 MVA
- 2025: Oakbrook Substation – Add 22.4 MVA transformer bank
- 2026: Buffington Substation – Add 22.4 MVA transformer bank; Turfway Substation – New substation w/ 2 – 22.4 MVA transformer banks; York Substation - Add 22.4 MVA Transformer bank

D. Response to 8(3)(a) Map of Facilities

System Maps, a transmission line thermal capacity table, and a listing of interconnections and their capacities are considered critical energy infrastructure information (CEII). The information will be provided to the KyPSC Staff under seal, not to be released to the general public.

Appendix B: Electric Load Forecast

A. General

Duke Energy Kentucky provides electric service to approximately 153,400 customers and natural gas service to approximately 105,500 customers in its approximately 300 square mile service territory, which includes the cities of Covington, Florence, Fort Thomas, and Newport.

Duke Energy Kentucky owns an electric transmission and distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. Duke Energy Kentucky also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, Bracken, and Pendleton counties in Northern Kentucky.

The electric energy and peak demand forecasts of the Duke Energy Kentucky service territory are prepared each year as part of the planning process by a staff that is shared with the other Duke Energy affiliated utilities, using the same methodology. Duke Energy Kentucky does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

B. Forecast Methodology

The forecast methodology is essentially the same as that presented in past IRPs filed with the Commission. Energy is a key commodity linked to the overall level of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. This linkage to economic activity is important to the development of long-range energy forecasts. For that reason, forecasts of future growth in the national and local economies are key ingredients to energy forecasts.

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of national economic and demographic measures, such as population, employment, industrial production, inflation, wage rates, and income. A national economic forecast and forecasts for smaller economic units relevant to the forecast are obtained from Moody's

Analytics. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional economy.

Service Area Economy

The forecasting methodology encompasses a comprehensive approach, integrating both econometric and end-use methodologies to predict energy sales and peak demand. Specially, the residential and commercial sectors utilize Itron's SAE methodology, while other customer class rely on tailored econometric models. These models are configured to capture unique trends and variations within each class over time. Additionally, peak demand models are made at a granular level, allowing for precise consideration of factors such as incremental impacts (electric vehicle and rooftop solar), energy efficiency, and demand response programs.

Electric Energy Forecast

Customer class models have been calibrated to capture historical relationships with weather and economic/demographic indicators, utilizing monthly data for sales and customer models. Regression analysis has been employed to identify the most significant driver variables explaining monthly sales fluctuations over the historical data. Historical and forecast input variables are derived through a combination of internal and external sources. Internal forecasts are utilized for electricity prices, weather conditions, and customer adoption of rooftop solar and electric vehicles. Additionally, external data sources include Moody's Analytics forecasts of population growth, demographic shifts, and economic trends. Furthermore, residential and commercial end-use models have been integrated from the EIA and Itron to account for changes in comprehensive approach enabling accurate predictions of future consumption trends.

Residential Sector - The forecast of total residential sales is developed by multiplying the forecasts of the number of residential customers and kilowatt hour (kWh) energy usage per customer.

Residential Customers - The change in the number of electric residential customers is a function of the change in the number of projected households in the Duke Energy Kentucky territory.

Residential Use per Customer - Energy use per customer is a function of real household income, real electricity prices and the combined impact of the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather. The derivation of the efficient appliance stock variable and the forecast of appliance saturations are discussed in the data section.

Commercial Electricity Usage - Energy usage per customer is a function of median household income, total employment, real electricity prices, weather, and the combined impact of the commercial saturation of air conditioners, commercial heating, other appliances, the efficiency of those appliances, and commercial square footage. In addition, the expected energy sales associated with a large new facility associated with the Northern Kentucky/Greater Cincinnati Airport were added to this sector.

Industrial Sector - Electricity use by industrial customers is primarily dependent upon the level of real gross manufacturing product (real manufacturing GDP), manufacturing employment and the impacts of real electricity prices, and weather.

Governmental Sector - The Company uses the term Other Public Authorities (OPA) to indicate those customers involved and/or affiliated with federal, state or local government. The OPA sector comprises sales to schools, government facilities, airports, and water pumping stations. Electricity sales to OPA customers are a function of real governmental output and weather.

Street Lighting Sector - For the street lighting sector, electricity usage varies with the number of residential customers and the intensity of the lighting end-use as reported by the EIA long-term forecast. The number of streetlights is associated with the population of the service area. The efficiency of the streetlights is related to the saturation of mercury and sodium vapor lights and compact fluorescent lights (CFLs)/light emitting diode lamps (LEDs).

Total Electric Sales - Residential, Commercial, Industrial, OPA, and Street Lighting sales are combined with Interdepartmental sales to produce the projection of total electric sales.

Total System Send-out - The forecast of total system send-out (net energy) is the combination of the total electric sales forecast and the forecasts of Company Use and system losses.

Peak Load - Forecasts of monthly peak loads are developed using the SAE methodology as applied to peak demand models. The monthly peak demand model combines heating and cooling end-use estimates taken from the monthly forecast models with peak day weather conditions, generating expected peak demand on that day. The highest loads of the summer months and winter months are used for the Summer Peak Forecast and the Winter peak forecast, respectively, with the model automatically exposing winter months (summer months) to heating degree day (cooling degree day) measures and relevant end-uses. The peak forecasting model is designed to closely represent the relationship of weather to peak loads based on the weather conditions for the maximally extreme weather in the month of peak. The summer peak usually occurs in July in the afternoon and the winter peak in January in the morning. Since the energy model produces forecasts under the assumption of normal weather, the forecast of net energy for load is “weather normalized” by design.

Electric Vehicle Forecast

The transportation industry is undergoing a massive transition to EVs from traditional internal combustion engine vehicles (ICEVs). In 2023, ~7.5% of new vehicles sold in the US were electric, compared to ~5.9% in 2022 and ~3.2% in 2021. This adoption trend is expected to continue and accelerate, especially considering federal initiatives and automaker goals such as having at least 50% of new vehicle sales being EVs by 2030. This transition to EVs will require diligent planning and forecasting to provide the energy required to charge the EVs while maintaining grid reliability. In addition to the EV forecasting methodology outlined below, Duke Energy is continuing to monitor and evaluate EV load management and managed charging programs and pilots which will provide additional insights when forecasting EV charging characteristics.

Duke Energy develops its EV load forecast by using the Guidehouse Vehicle Analytics and Simulation Tool. The tool first develops a vehicle forecast using a total cost of ownership calculation based on multiple historical and forecasted parameters such as vehicle registrations (IHS Markit), vehicle MSRP values (Guidehouse Insights), vehicle efficiency characteristics (Argonne National Lab), projections of fuel costs (from EIA and Automotive Association of America), future vehicle availability, consumer acceptance (Guidehouse insights), and vehicle miles traveled (from Federal Highway Administration).

Once the vehicle adoption forecast is created, the associated energy and load are forecasted. Variables to determine energy, such as vehicle miles traveled and vehicle efficiency, can be used to calculate charging energy requirements for the vehicles. Then associated load charging profiles are derived from public, private, and third-party analysis (such as the NREL EVI-Pro tool and Guidehouse Insights). These charging profiles are broken down by three duties: light, medium and heavy. Based on the adoption forecast, the projected amount of energy needed to charge the EVs, and the hourly EV demand profiles, the jurisdictional EV hourly 8760 load forecast is developed. All three duties are calculated using similar methodology and make up the EV load forecast that is added to the Duke Energy load forecast.

In addition to the base forecast, an additional high scenario was developed to capture a range of future EV adoption possibilities. Variables adjusted to derive the scenarios included forecasted MSRP cost of vehicles, availability of EVs and ICEVs, and customer preference towards EVs. By adjusting these variables, the total cost of ownership calculation changed resulting in adoption amounts changing and a higher EV adoption scenario.

C. Assumptions

Macroeconomic

It is generally assumed that the Duke Energy Kentucky service territory economy will tend to react much like the national economy over the forecast period. Duke Energy Kentucky uses long-term forecasts of the national, state, and PMSA economy as prepared by Moody's Analytics.

The nation has experienced a period of mixed economic performance over recent years, marked with resilience and global uncertainties. The national economy exhibited a rollercoaster growth trajectory initially experiencing a downturn in 2020 due to the COVID-19 pandemic. Aggressive fiscal stimulus measures, including the CARES Act and subsequent relief packages, played a crucial role in cushioning the initial shock of the pandemic and supporting consumer spending. The Federal reserve implemented unprecedented monetary policy measures, including near-zero interest rates and large-scale asset purchases to stabilize financial market. While these measures helped the economy recover quickly in the months after the initial COVID-19 recession, economic observers blame these measures for elevated inflation experienced in the recent years.

With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well-positioned to make the adjustments necessary for continuing long-term growth. In the manufacturing sector, major industries include food products, paper, printing, chemicals, steel, fabricated metals, machinery, and automotive and aircraft transportation equipment. In the non-manufacturing sector, major industries are life insurance, professional/business services, and finance, with emerging growth sectors in health and education, leisure and hospitality, and logistics. In addition, the Cincinnati area is the headquarters for major international and national market-oriented retailing establishments.

Local

Forecasts of employment, local population, gross product, and inflation are key indicators of economic and demographic trends. The majority of the employment growth over the forecast period occurs apart from manufacturing, for which Moody's Analytics forecasts continued declines in employment over the long-term. Duke Energy Kentucky is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and — over the long term — lengthening life expectancies. As a result, the portion of the population of the Duke Energy Kentucky service area that is "age 65 and older" increases over the forecast period, and — together with outmigration — this stagnation will cause population growth in the Cincinnati metropolitan area, which Duke Energy Kentucky is part of, to lag the growth rate of the US as a whole. Over the period 2024-2040, Duke Energy Kentucky's service area population is expected to increase at an annual average rate of 0.2%, below expected national growth of 0.3% annually.

The residential sector has the most existing customers and new customer additions per year. Within the Duke Energy Kentucky service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively small.

Specific

Commercial Fuels – Natural gas and oil prices are expected to increase over the forecast period. Regarding availability of the conventional fuels, nothing on the horizon indicates any severe limitations in their supply, especially with the continuing development of an abundance of natural gas reserves in the U.S. There are unknown potential impacts from future changes in legislation or in an unpredictable change in policy toward oil-producing countries that might affect fuel supply. However, these cannot be quantified within the forecast. The only non-utility information source relied upon is Moody's.

Pricing Policy – Duke Energy Kentucky's electric tariffs for residential customers have a customer charge and energy charge component. Conservation is encouraged through a variety of DSM programs. A time-of-day rate has been mandated for all large commercial and industrial customers. The seasonal characteristic motivates conservation during summer months when demand upon electric facilities is greatest.

Year Average Residential Customers – Historical and projected average residential customers for the entire service area are provided in Table B.9 later in this appendix.

Appliance Efficiencies – Trends in appliance efficiencies, saturations, and usage patterns impact the projected use per residential customer. The forecast incorporates a projection of increasing saturation for many appliances including heat pumps, air conditioners, electric space heating equipment, electric water heaters, electric clothes dryers, dish washers, and freezers. In addition, the forecast embodies trends of increasing appliance efficiency, including lighting, consistent with standards established by the federal government.

D. Data Base Documentation

Economic Data

The major groups of data in the economic forecast are employment, demographics, income, production, inflation, and prices. National, state, and local values (which represent the Cincinnati PMSA) for these concepts are available from Moody's and company data.

Employment - Employment numbers are required on both a national and service area basis. Quarterly national and local employment series by industry are obtained from Moody's. Employment series are available for manufacturing and several non-manufacturing sectors.

Population - National and local values for total population and population by age-cohort groups are obtained from Moody's Analytics.

Income - Local income data series are obtained from Moody's. This includes data for personal income; dividends, interest, and rent; transfer payments; wage and salary disbursements plus other labor income; personal contributions for social insurance; and non-farm proprietors' income.

Measures of Inflation - PCE Index and the CPI are obtained from Moody's.

Electricity and Natural Gas Prices - The average price of electricity and natural gas is available from Duke Energy Kentucky financial reports. Data on marginal electricity price (including fuel cost) is collected for each customer class. This information is obtained from Duke Energy Kentucky records and rate schedules, with future projections taken from the Duke Energy Fundamentals Forecast team.

Energy and Peak Models

The majority of data required to develop the electricity sales and peak forecasts is obtained from the Duke Energy Kentucky service area economic data provided by Moody's Analytics and Duke Energy Kentucky financial reports. Generally, all economic information is obtained from Moody's. Local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data used in developing the energy forecasts are megawatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data. The following sections describe the adjustments performed to develop the final data series actually used in regression analysis.

Megawatt-hour Sales and Revenue - Duke Energy Kentucky collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the residential, commercial, industrial, OPA, and other sales categories.

Number of Customers - The number of customers by class by month is obtained from Company records.

Use Per Customer - Average use per customer by month is computed by dividing sales by total customers.

Local Weather Data - Local climatologic data are provided by NOAA for the Cincinnati/Covington airport reporting station. Cooling degree days and heating degree days are calculated on a daily basis using temperature data, before being aggregated up to calendar months or quarters for analysis. The degree day series can also be computed on a billing cycle basis for use in regression analysis.

Appliance Stock - To account for the impact of appliance saturations and federal efficiency standards, an appliance stock variable is created. This variable consists of appliance efficiencies, saturations, and energy consumption values. The appliances included in the calculation of the appliance stock variable are: electric range, frost-free refrigerator, manual-defrost refrigerator, food freezer, dish washer, clothes washer, clothes dryer, water heater, microwave, television, room air conditioner, central air conditioner, electric resistance heat, electric heat pump, and miscellaneous uses such as lighting.

Appliance Saturation and Efficiency - In general, information on historical appliance saturations for all appliances is obtained from Company Appliance Saturation Surveys. Data on historical forecast appliance efficiency and forecast saturation are obtained from Itron, Inc., a forecast consulting firm. Itron has developed Statistically Adjusted End-Use (SAE) Models, an end-use approach to electric forecasting that provides forward looking levels of appliance saturations and efficiencies.

Peak Weather Data - The weather conditions associated with the monthly peak load are collected from daily data recorded by NOAA. Monthly peak data are exposed to transforms of the weather variables meant to correspond to heating degree days or cooling degree days. An average of extreme weather conditions is used as the basis for the weather component in the preparation of the peak load forecast via a calculation of a 30-year normal day on a monthly basis.

Forecast Data

Projections of national and local employment, income, gross product, and population are provided by Moody's. Projections of electricity and natural gas prices are provided by the Company's Financial Planning and Analysis department and fundamental forecast analysis team.

Load Research and Market Research Efforts

Duke Energy Kentucky is committed to the continued development and maintenance of a substantive class load database of typical customer electricity consumption patterns and the collection of primary market research data on customers.

Load Research - Complete load profile information, or 100% sample data, is maintained upon commercial and industrial customers whose average annual demand is greater than 500 kW. Additionally, Duke Energy Kentucky continues to collect whole premise or building level electricity consumption patterns on representative samples of the various customer classes and rate groups whose annual average demands are less than 500 kW.

Duke Energy Kentucky periodically monitors selected end-uses or systems associated with evaluations of EE programs. These studies are performed as necessary and are typically of short duration.

Market Research - Primary research projects continue to be conducted as part of the on-going efforts to gain knowledge about Duke Energy Kentucky's customers. These projects include studies of customer satisfaction, appliance saturation studies, end-use, and competition (to monitor customer switching percentages in order to forecast future utility load); and related marketing research projects.

E. Models

Specific analytical techniques were employed for development of the forecast models.

Specific Analytical Techniques

Regression Analysis - Ordinary least squares is the principal regression technique employed to estimate economic/behavioral relationships among the relevant variables. This econometric technique provides a method to perform quantitative analysis of economic behavior. Ordinary least- squares techniques were used to model electric sales. Based upon their relationship with the dependent variable, several independent variables were tested in the regression models. The final models were chosen based upon their statistical strength and logical consistency.

Qualitative Variables - In several equations, qualitative variables are employed. In estimating an econometric relation using time series data, it is quite often the case that "outliers" are present in the historic data. These unusual deviations in the data can be the result of problems such as errors in the reporting of data by particular companies and agencies, labor-management disputes, severe energy shortages or restrictions, and other perturbations that do not repeat with predictability. Therefore, in order to identify the true underlying economic relationship between the dependent variable and the independent variables, qualitative variables are sometimes employed to account for the impact of the outliers.

Relationships Between the Specific Techniques

The manner in which specific methodologies for forecasting components of the total load are related is explained in the discussion of specific analytical techniques above.

Alternative Methodologies

Duke Energy Kentucky continues to use the same forecasting methodology as it has for the past several years and considers these methods to be adequate.

Methodology Enhancements

The Company changed its approach regarding the development of its appliance stock variable to rely more completely on information from Itron, Inc., for estimates of historical appliance efficiency. The Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's.

The SAE Modeling Specification is now the principle modeling technique employed to estimate economic/behavioral relationships among the relevant variables for the residential and commercial classes. In addition to the advantages generated by the regression technique, the SAE approach also allows the model to generate energy and peak forecasts that incorporate the impacts from appliance end-use saturation and efficiency trends.

The load forecast includes a projection for weather — commonly referred to as weather normalization — and this is handled through a procedure that is standard within the industry. The Company uses a thirty-year window, meaning that weather projections are computed based on an average of the last thirty years. This lengthy window was selected to reduce year-to-year variability (which is 70% reduced from a ten-year window) while accommodating a range of calendar values for time of peak as well as daily weather computations within the year. The identical computation is used to calculate "normal" weather for accounting history along with the projected weather for forecasts. Recent years do suggest a slight warming trend for the data, and this trend is robust to statistical testing, but the impact of this trend is smaller than the year-to-year variability.

Computer Software

All the equations in the Electric Energy Forecast Model and Electric Peak Load Model were estimated using the MetrixND software from Itron.

F. Forecasted Demand and Energy

Service Area Energy Forecasts

Table B.11 contains the energy forecast for Duke Energy Kentucky's service area. Before implementation of any new EE programs or incremental EE impacts, Residential volume for the twenty-year period of the forecast is expected to increase an average of 1.0 percent per year; Commercial energy, 0.8 percent per year; and Industrial energy, 0.8 percent per year. The summation of the forecast across all sectors and including losses results in a growth rate forecast of 0.8 percent for Net Energy for Load.

System Seasonal Peak Load Forecast

Table B.13 summarizes historical and projected growth of the peaks before implementation of EE programs. The table shows the Summer and succeeding Winter Peaks, the Summer Peaks being the higher ones historically. Projected growth in the summer peak demand from 2024-2044 is 1.0 percent. Projected growth in the winter peak demand is 0.6 percent. Including the expected impacts of EE programs will not change these results very much.

Controllable Loads

The native peak load forecast reflects the MW impacts from the PowerShare® demand response program and controllable loads from the Power Manager program. The amount of load controlled depends upon the level of operation of the particular customers participating in the programs. The difference between the peak loads consists of the impact from these controllable loads. See Chapter 4 for a discussion of the impacts of DR programs.

Load Factor

Table B.16 represents the annual percentage load factor for the Duke Energy Kentucky System before any new or incremental EE.

Range of Forecasts

Assuming normal weather, the most likely forecast of electrical energy demand and peak loads is determined from forecasts of economic variables. Moody's Analytics provides the base economic forecast used to prepare the most likely energy demand and peak load forecasts.

In preparing the high and low forecasts, the Company used divergent economic scenarios from Moody's Analytics, varied weather assumptions, and different vehicle adoption projections. These calculations were used to adjust the base forecast up or down, thus providing high and low bands around the most likely forecast. In general, the upper band reflects an optimistic scenario about the future growth of Duke Energy Kentucky sales while the lower band reflects a pessimistic scenario.

Table B.1 below provides the high, low, and base before EE forecasts of electric energy and peak demand for the service area. Figure B-6 provides similar information after implementation of the EE programs.

Table B.1: Energy Efficiency Forecast

	Economic	Weather	Electric Vehicle
Low	Pessimistic	15 most mild years Average	Base
Base	Base	30-year Average	Base
High	Optimistic	15 most extreme years average	High

Monthly Forecast

Tables B.20 through B.23 contain the net monthly energy forecast, the net monthly peak load forecast, and the energy forecast by customer class for the total Duke Energy Kentucky system before and after EE.

Conclusion

The Company's expectations are for continuing growth in the near-term, bolstered by the economy's resilience, as evidenced by the robust labor market. This growth is particularly supported by population growth (for residential sales. The range of economic outcomes that are possible in the near future can have some small impact on this, with a strong economic result implying sales in some classes that could be 5 - 6% higher or lower than projected.

Tables

Table B.2: Load Forecasting Models - Coefficients and Statistics

<table>
<tr><th>Dep Var: Quarterly OPA sales</th><th>Coefficient</th><th>StdErr</th><th>T-Stat</th><th>P-Value</th><th>Definition</th></tr>
<tr><td>Weather_MonthlyStats_B_Filled.CDD_B_65</td><td colspan="4" rowspan="6">[redacted]</td><td>Weather Variable</td></tr>
<tr><td>OPA_SAE.OPA_GDPGov_EGOV</td><td>Economic Variables</td></tr>
<tr><td>Binary3.Y2022M7</td><td></td></tr>
<tr><td>Binary3.Y2022M6</td><td></td></tr>
<tr><td>Binary3.Y2023M4</td><td></td></tr>
<tr><td>AR(1)</td><td></td></tr>
</table>

<table>
<tr><th>Dep Var: Industrial Sales</th><th>Coefficient</th><th>StdErr</th><th>T-Stat</th><th>P-Value</th><th>Definition</th></tr>
<tr><td>Weather_MonthlyStats_B_Filled.CDD_B_65</td><td colspan="4" rowspan="8">[redacted]</td><td>Weather Variable</td></tr>
<tr><td>IND_SAE.IND_RGDP_EMAN</td><td>Economic Variable</td></tr>
<tr><td>Binary3.Y2023M8</td><td></td></tr>
<tr><td>Binary3.Y2022M5</td><td></td></tr>
<tr><td>Binary3.Y2023M11</td><td></td></tr>
<tr><td>Binary3.Y2022M8</td><td></td></tr>
<tr><td>AR(1)</td><td></td></tr>
<tr><td>SAR(1)</td><td></td></tr>
</table>

<table>
<tr><th>Dep Var: Commercial Sales</th><th>Coefficient</th><th>StdErr</th><th>T-Stat</th><th>P-Value</th><th>Definition</th></tr>
<tr><td>COM_SAE.XHeat</td><td colspan="4" rowspan="4">[redacted]</td><td>Heating SAE term</td></tr>
<tr><td>COM_SAE.XCool</td><td>Cooling SAE term</td></tr>
<tr><td>COM_SAE.XOther</td><td>Other SAE Term</td></tr>
<tr><td>AR(1)</td><td></td></tr>
</table>

<table>
<tr><th>Dep Var: Residential Usage (per Customer)</th><th>Coefficient</th><th>StdErr</th><th>T-Stat</th><th>P-Value</th><th>Definition</th></tr>
<tr><td>RES_SAE.XHeat</td><td colspan="4" rowspan="5">[redacted]</td><td>Heating SAE term</td></tr>
<tr><td>RES_SAE.XCool</td><td>Cooling SAE term</td></tr>
<tr><td>RES_SAE.XOther</td><td>Other SAE Term</td></tr>
<tr><td>Calendar.Jun</td><td></td></tr>
<tr><td>AR(1)</td><td></td></tr>
</table>

Table B.2: Load Forecasting Models - Coefficients and Statistics (cont.)

Dep Var: Residential Customers	Coefficient	StdErr	T-Stat	P-Value	Definition
Nati_MSA.CINCI_HH	[redacted]				Economic Variable
Binary3.Y2023M1	[redacted]				
Binary.Y2022_Migration	[redacted]				
AR(1)	[redacted]				

Dep Var: Monthly SL Volumes	Coefficient	StdErr	T-Stat	P-Value	Definition
Binary.log_trend	[redacted]				
Calendar.Jan	[redacted]				
Calendar.Feb	[redacted]				
Calendar.Mar	[redacted]				
Calendar.Apr	[redacted]				
Calendar.May	[redacted]				
Calendar.Jun	[redacted]				
Calendar.Jul	[redacted]				
Calendar.Aug	[redacted]				
Calendar.Sep	[redacted]				
Calendar.Oct	[redacted]				
Calendar.Nov	[redacted]				
Calendar.Dec	[redacted]				
Binary3.Y2018M06	[redacted]				
AR(1)	[redacted]				

Table B.3: Model for Quarterly OPA Sales Volume

Model Statistics	
Iterations	[redacted]
Adjusted Observations	[redacted]
Deg. of Freedom for Error	[redacted]
R-Squared	[redacted]
Adjusted R-Squared	[redacted]
AIC	[redacted]
BIC	[redacted]
F-Statistic	[redacted]
Prob (F-Statistic)	[redacted]
Log-Likelihood	[redacted]
Model Sum of Squares	[redacted]
Sum of Squared Errors	[redacted]
Mean Squared Error	[redacted]
Std. Error of Regression	[redacted]
Mean Abs. Dev. (MAD)	[redacted]
Mean Abs. % Err. (MAPE)	[redacted]
Durbin-Watson Statistic	[redacted]
Durbin-H Statistic	[redacted]
Ljung-Box Statistic	[redacted]
Prob (Ljung-Box)	[redacted]
Skewness	[redacted]
Kurtosis	[redacted]
Jarque-Bera	[redacted]
Prob (Jarque-Bera)	[redacted]

Table B.4: Model for Quarterly Industrial Sales Volume

Model Statistics	
Iterations	[redacted]
Adjusted Observations	
Deg. of Freedom for Error	
R-Squared	
Adjusted R-Squared	
AIC	
BIC	
F-Statistic	
Prob (F-Statistic)	
Log-Likelihood	
Model Sum of Squares	
Sum of Squared Errors	
Mean Squared Error	
Std. Error of Regression	
Mean Abs. Dev. (MAD)	
Mean Abs. % Err. (MAPE)	
Durbin-Watson Statistic	
Durbin-H Statistic	
Ljung-Box Statistic	
Prob (Ljung-Box)	
Skewness	
Kurtosis	
Jarque-Bera	
Prob (Jarque-Bera)	

Table B.5: Model for Monthly Commercial Sales

Model Statistics	
Iterations	[redacted]
Adjusted Observations	
Deg. of Freedom for Error	
R-Squared	
Adjusted R-Squared	
AIC	
BIC	
F-Statistic	
Prob (F-Statistic)	
Log-Likelihood	
Model Sum of Squares	
Sum of Squared Errors	
Mean Squared Error	
Std. Error of Regression	
Mean Abs. Dev. (MAD)	
Mean Abs. % Err. (MAPE)	
Durbin-Watson Statistic	
Durbin-H Statistic	
Ljung-Box Statistic	
Prob (Ljung-Box)	
Skewness	
Kurtosis	
Jarque-Bera	
Prob (Jarque-Bera)	

Table B.6: Model for Per-Customer Residential Usage

Model Statistics	
Iterations	[redacted]
Adjusted Observations	
Deg. of Freedom for Error	
R-Squared	
Adjusted R-Squared	
AIC	
BIC	
F-Statistic	
Prob (F-Statistic)	
Log-Likelihood	
Model Sum of Squares	
Sum of Squared Errors	
Mean Squared Error	
Std. Error of Regression	
Mean Abs. Dev. (MAD)	
Mean Abs. % Err. (MAPE)	
Durbin-Watson Statistic	
Durbin-H Statistic	
Ljung-Box Statistic	
Prob (Ljung-Box)	
Skewness	
Kurtosis	
Jarque-Bera	
Prob (Jarque-Bera)	

Table B.7: Model for Residential Customers

Model Statistics	
Iterations	[redacted]
Adjusted Observations	
Deg. of Freedom for Error	
R-Squared	
Adjusted R-Squared	
AIC	
BIC	
F-Statistic	
Prob (F-Statistic)	
Log-Likelihood	
Model Sum of Squares	
Sum of Squared Errors	
Mean Squared Error	
Std. Error of Regression	
Mean Abs. Dev. (MAD)	
Mean Abs. % Err. (MAPE)	
Durbin-Watson Statistic	
Durbin-H Statistic	
Ljung-Box Statistic	
Prob (Ljung-Box)	
Skewness	
Kurtosis	
Jarque-Bera	
Prob (Jarque-Bera)	

Table B.8: Monthly Street Lighting Volume Model

Model Statistics	
Iterations	[redacted]
Adjusted Observations	
Deg. of Freedom for Error	
R-Squared	
Adjusted R-Squared	
AIC	
BIC	
F-Statistic	
Prob (F-Statistic)	
Log-Likelihood	
Model Sum of Squares	
Sum of Squared Errors	
Mean Squared Error	
Std. Error of Regression	
Mean Abs. Dev. (MAD)	
Mean Abs. % Err. (MAPE)	
Durbin-Watson Statistic	
Durbin-H Statistic	
Ljung-Box Statistic	
Prob (Ljung-Box)	
Skewness	
Kurtosis	
Jarque-Bera	
Prob (Jarque-Bera)	

Table B.9: Electric Customers by Major Classification

Year	1 Residential	2 Commercial	3 Government	4 Industrial	5 SL/other
2018	126,987	13,648	946	360	452
2019	128,049	13,627	935	359	461
2020	131,533	12,442	734	352	297
2021	132,455	12,692	681	344	405
2022	134,464	12,643	904	333	525
2023	136,693	12,734	873	312	512
2024	139,184	12,472	860	324	525
2025	140,321	12,270	866	329	535
2026	141,253	12,143	870	329	538
2027	142,037	12,003	873	329	541
2028	142,799	11,860	878	330	544
2029	143,548	11,727	882	331	547
2030	144,248	11,610	885	332	549
2031	144,871	11,503	886	333	552
2032	145,489	11,396	887	334	554
2033	146,056	11,282	888	335	556
2034	146,533	11,169	889	336	558
2035	146,979	11,062	889	337	560
2036	147,412	10,960	889	338	562
2037	147,805	10,867	888	340	563
2038	148,186	10,783	888	341	564
2039	148,559	10,698	888	342	566
2040	148,910	10,615	887	343	567
2041	149,222	10,534	887	344	568
2042	149,502	10,454	886	345	569
2043	149,738	10,377	886	345	570
2044	149,953	10,300	884	346	571
2045	150,166	10,224	883	347	572

Table B.10: Duke Energy Kentucky System Service Area Energy Forecast After EE

Year	(1) Rural and Residential	(2) Commercial	(3) Industrial	(4) Steet-Hwy Lighting	(5) Sales for Resale[b]	(6) Other	(7) (1+2+3+4+5+6) Total Consumption	(8) Losses and Unaccounted For [c]	(9) (7+8) Net Energy for Load
2018	1,563,656	1,479,511	814,989	14,317	0	285,909	4,158,382	329,698	4,488,080
2019	1,512,664	1,460,450	817,559	13,759	0	276,728	4,081,160	323,583	4,404,743
2020	1,477,914	1,416,427	746,182	13,827	0	188,356	3,842,705	304,677	4,147,382
2021	1,516,485	1,536,653	751,561	13,143	0	152,306	3,970,148	314,769	4,284,917
2022	1,489,339	1,416,933	736,091	12,832	0	232,670	3,887,865	308,265	4,196,130
2023	1,413,744	1,473,510	743,822	12,163	0	227,310	3,870,548	306,878	4,177,426
2024	1,521,775	1,460,036	727,962	12,474	0	251,216	3,973,462	315,042	4,288,504
2025	1,531,911	1,429,597	742,085	12,606	0	253,086	3,969,285	314,710	4,283,996
2026	1,533,956	1,436,236	741,214	12,424	0	251,595	3,975,426	315,197	4,290,623
2027	1,538,474	1,430,971	738,074	12,248	0	250,199	3,969,966	314,764	4,284,730
2028	1,547,199	1,431,949	735,053	12,079	0	249,078	3,975,359	315,192	4,290,551
2029	1,547,804	1,426,981	732,952	11,916	0	248,235	3,967,887	314,599	4,282,486
2030	1,552,517	1,497,937	732,201	11,758	0	247,696	4,042,108	320,485	4,362,594
2031	1,559,522	1,497,984	732,520	11,605	0	247,383	4,049,014	321,033	4,370,047
2032	1,572,058	1,503,791	732,937	11,456	0	247,091	4,067,333	322,486	4,389,818
2033	1,582,593	1,503,765	732,844	11,313	0	246,697	4,077,212	323,269	4,400,481
2034	1,598,235	1,508,308	731,698	11,173	0	246,122	4,095,536	324,722	4,420,258
2035	1,617,342	1,588,063	730,311	11,173	0	245,486	4,192,375	332,401	4,524,776
2036	1,642,840	1,599,382	727,719	11,173	0	244,600	4,225,715	335,045	4,560,760
2037	1,661,427	1,601,837	723,190	11,173	0	243,334	4,240,961	336,254	4,577,215
2038	1,683,929	1,609,048	718,580	11,173	0	242,056	4,264,786	338,144	4,602,929
2039	1,707,174	1,616,024	714,382	11,173	0	240,839	4,289,592	340,111	4,629,703
2040	1,733,954	1,630,395	716,711	11,173	0	240,859	4,333,093	343,560	4,676,653
2041	1,747,994	1,634,757	718,955	11,173	0	240,888	4,353,766	345,200	4,698,965
2042	1,766,815	1,644,617	721,375	11,173	0	240,967	4,384,948	347,672	4,732,620
2043	1,787,850	1,655,959	723,965	11,173	0	241,080	4,420,026	350,454	4,770,481
2044	1,815,023	1,672,505	726,783	11,173	0	241,218	4,466,702	354,155	4,820,857
2045	1,834,988	1,681,453	729,634	11,173	0	241,352	4,498,600	356,685	4,855,285

(a) Includes EE Impacts
(b) Sales for resale to municipals.
(c) Transmission, transformer and other losses and energy unaccounted for.

Table B.11: Duke Energy Kentucky System Service Area Energy Forecast Before EE

Year	(1) Rural and Residential	(2) Commercial	(3) Industrial	(4) Steet-Hwy Lighting	(5) Sales for Resale[b]	(6) Other	(7) (1+2+3+4+5+6) Total Consumption	(8) Losses and Unaccounted For [c]	(9) (7+8) Net Energy for Load
2018	1,568,884	1,489,143	831,846	13,628	0	292,331	4,195,832	332,668	4,528,500
2019	1,529,903	1,475,224	843,415	12,831	0	286,577	4,147,951	328,880	4,476,831
2020	1,494,087	1,469,752	838,398	13,236	0	281,570	4,097,044	324,846	4,421,890
2021	1,524,132	1,545,646	767,299	12,477	0	158,301	4,007,854	317,759	4,325,613
2022	1,501,301	1,426,753	753,276	11,761	0	239,217	3,932,308	311,789	4,244,097
2023	1,429,137	1,485,775	765,285	11,837	0	235,486	3,927,521	311,396	4,238,917
2024	1,524,419	1,461,317	732,445	12,474	0	252,070	3,982,725	315,806	4,298,908
2025	1,540,105	1,433,394	755,375	12,606	0	255,618	3,997,098	316,916	4,314,014
2026	1,548,017	1,442,533	763,254	12,424	0	255,793	4,022,021	318,892	4,340,914
2027	1,558,784	1,439,804	768,988	12,248	0	256,087	4,035,912	319,994	4,355,905
2028	1,574,059	1,443,341	774,923	12,079	0	256,673	4,061,074	321,989	4,383,063
2029	1,581,344	1,440,953	781,853	11,916	0	257,549	4,073,615	322,984	4,396,599
2030	1,592,692	1,514,484	790,116	11,758	0	258,728	4,167,778	330,451	4,498,228
2031	1,606,281	1,517,106	799,448	11,605	0	260,131	4,194,571	332,576	4,527,146
2032	1,625,322	1,525,485	808,867	11,456	0	261,554	4,232,685	335,598	4,568,283
2033	1,639,045	1,528,037	817,795	11,313	0	262,878	4,259,069	337,690	4,596,759
2034	1,656,331	1,535,154	825,660	11,173	0	264,019	4,292,337	340,328	4,632,666
2035	1,676,007	1,617,060	831,801	11,173	0	264,817	4,400,859	348,934	4,749,793
2036	1,701,384	1,630,522	836,708	11,173	0	265,360	4,445,147	352,446	4,797,593
2037	1,719,619	1,635,122	839,688	11,173	0	265,525	4,471,126	354,506	4,825,632
2038	1,741,687	1,644,476	842,578	11,173	0	265,675	4,505,589	357,239	4,862,828
2039	1,763,825	1,653,483	845,490	11,173	0	265,812	4,539,784	359,951	4,899,735
2040	1,788,975	1,668,009	848,360	11,173	0	265,935	4,582,453	363,335	4,945,787
2041	1,801,321	1,672,481	850,990	11,173	0	266,037	4,602,003	364,885	4,966,888
2042	1,819,862	1,682,414	853,665	11,173	0	266,166	4,633,281	367,365	5,000,646
2043	1,840,042	1,693,793	856,385	11,173	0	266,302	4,667,695	370,094	5,037,790
2044	1,866,368	1,710,337	859,196	11,173	0	266,439	4,713,514	373,728	5,087,242
2045	1,885,152	1,719,288	862,056	11,173	0	266,576	4,744,245	376,165	5,120,410

(a) Excludes EE Impacts

(b) Sales for resale to municipals.

(c) Transmission, transformer and other losses and energy unaccounted for.

Table B.12: Duke Energy Kentucky System Seasonal Peak Load Forecast (MW) Before EE, After DR

	Summer			Winter		
Year	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	-8	-0.9%	821	24	3.0%
2020	809	-40	-4.7%	742	-79	-9.6%
2021	838	29	3.6%	678	-64	-8.6%
2022	831	-7	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	785	(49)	-5.9%	744	(66)	-8.1%
2025	788	3	0.4%	736	(9)	-1.2%
2026	793	5	0.7%	739	3	0.5%
2027	796	3	0.3%	744	5	0.6%
2028	799	3	0.4%	747	3	0.5%
2029	802	3	0.4%	749	2	0.3%
2030	815	13	1.6%	759	10	1.4%
2031	824	9	1.0%	764	5	0.7%
2032	831	7	0.8%	764	(1)	-0.1%
2033	839	9	1.1%	775	11	1.5%
2034	846	7	0.8%	780	5	0.7%
2035	865	19	2.2%	795	15	2.0%
2036	875	10	1.2%	799	3	0.4%
2037	886	10	1.2%	800	2	0.2%
2038	896	10	1.1%	800	(0)	-0.1%
2039	906	10	1.1%	820	20	2.5%
2040	913	7	0.8%	829	9	1.1%
2041	919	6	0.7%	828	(1)	-0.1%
2042	933	14	1.5%	834	6	0.7%
2043	944	11	1.2%	837	3	0.3%
2044	956	12	1.3%	837	1	0.1%
2045	966	10	1.1%	862	24	2.9%

(a)Difference between reporting year and previous year.
(b)Difference expressed as a percent of previous year.

Table B.13: Duke Energy Kentucky System Seasonal Peak Load Forecast (MW) Before EE, Before DR

	Summer			Winter		
Year	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	-8	-0.9%	821	24	3.0%
2020	809	-40	-4.7%	742	-79	-9.6%
2021	838	29	3.6%	678	-64	-8.6%
2022	831	-7	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	811	-23	-2.8%	748	-62	-7.7%
2025	814	3	0.4%	739	-9	-1.2%
2026	819	5	0.7%	742	3	0.5%
2027	822	3	0.3%	747	5	0.6%
2028	825	3	0.4%	750	3	0.4%
2029	828	3	0.4%	752	2	0.3%
2030	841	13	1.6%	763	10	1.4%
2031	850	9	1.0%	768	5	0.7%
2032	856	7	0.8%	767	-1	-0.1%
2033	865	9	1.0%	778	11	1.5%
2034	872	7	0.8%	784	5	0.7%
2035	891	19	2.2%	799	15	1.9%
2036	901	10	1.2%	802	3	0.4%
2037	912	10	1.2%	804	2	0.2%
2038	922	10	1.1%	803	0	-0.1%
2039	932	10	1.1%	824	20	2.5%
2040	939	7	0.8%	833	9	1.1%
2041	945	6	0.7%	832	-1	-0.1%
2042	959	14	1.4%	837	6	0.7%
2043	970	11	1.2%	840	3	0.3%
2044	982	12	1.2%	841	1	0.1%
2045	992	10	1.0%	865	24	2.9%

(a)Difference between reporting year and previous year.
(b)Difference expressed as a percent of previous year.

Table B.15: Duke Energy Kentucky System Seasonal Peak Load Forecast (MW) After EE After DR

Year	Summer			Winter		
	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	(8)	-0.9%	821	24	3.0%
2020	809	(40)	-4.7%	742	(79)	-9.6%
2021	838	29	3.6%	678	(64)	-8.6%
2022	831	(7)	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	784	(50)	-6.0%	744	(66)	-8.1%
2025	786	2	0.3%	734	(10)	-1.4%
2026	790	4	0.5%	737	2	0.3%
2027	791	1	0.1%	740	3	0.4%
2028	793	2	0.2%	742	2	0.3%
2029	794	2	0.2%	742	0	0.1%
2030	806	11	1.4%	751	9	1.2%
2031	813	7	0.9%	755	4	0.5%
2032	818	5	0.7%	753	(2)	-0.2%
2033	826	8	1.0%	763	10	1.3%
2034	832	6	0.7%	768	5	0.6%
2035	850	19	2.2%	783	15	1.9%
2036	861	10	1.2%	786	3	0.4%
2037	871	10	1.2%	788	2	0.2%
2038	881	10	1.1%	787	(1)	-0.1%
2039	891	10	1.2%	807	20	2.6%
2040	898	7	0.8%	817	10	1.2%
2041	905	6	0.7%	816	(1)	-0.1%
2042	918	14	1.5%	822	6	0.7%
2043	930	12	1.3%	825	3	0.4%
2044	942	12	1.3%	826	1	0.1%
2045	952	10	1.1%	850	25	3.0%

(a)Difference between reporting year and previous year.
(b)Difference expressed as a percent of previous year.

Table B.16: Load Factor Calculations, Duke Energy Kentucky

	1 Volume	2 Peak	3 Load Factor
2018	4,488,080	857	59.8%
2019	4,404,743	849	59.2%
2020	4,147,382	809	58.4%
2021	4,284,917	838	58.4%
2022	4,196,130	831	57.6%
2023	4,177,426	837	57.0%
2024	4,288,504	808	60.4%
2025	4,283,996	810	60.4%
2026	4,290,623	812	60.3%
2027	4,284,730	812	60.2%
2028	4,290,551	812	60.1%
2029	4,282,486	812	60.2%
2030	4,362,594	822	60.6%
2031	4,370,047	827	60.3%
2032	4,389,818	831	60.1%
2033	4,400,481	838	59.9%
2034	4,420,258	844	59.8%
2035	4,524,776	862	59.9%
2036	4,560,760	872	59.5%
2037	4,577,215	882	59.2%
2038	4,602,929	892	58.9%
2039	4,629,703	902	58.6%
2040	4,676,653	910	58.5%
2041	4,698,965	916	58.4%
2042	4,732,620	930	57.9%
2043	4,770,481	942	57.7%
2044	4,820,857	954	57.5%
2045	4,855,285	965	57.3%

Table B.17: Duke Energy Kentucky System Seasonal Peak Load Forecast (MW) After EE After DR Native Load

Year	Summer			Winter		
	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	(8)	-0.9%	821	24	3.0%
2020	809	(40)	-4.7%	742	(79)	-9.6%
2021	838	29	3.6%	678	(64)	-8.6%
2022	831	(7)	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	784	(50)	-6.0%	745	(66)	-8.1%
2025	786	2	0.3%	734	(10)	-1.4%
2026	790	4	0.5%	737	2	0.3%
2027	791	1	0.1%	740	3	0.4%
2028	793	2	0.2%	742	2	0.3%
2029	795	2	0.2%	742	0	0.1%
2030	806	11	1.4%	751	9	1.2%
2031	813	7	0.9%	755	4	0.5%
2032	818	5	0.7%	753	(2)	-0.2%
2033	826	8	1.0%	763	10	1.3%
2034	832	6	0.7%	768	5	0.6%
2035	851	19	2.2%	783	15	1.9%
2036	861	10	1.2%	786	3	0.4%
2037	871	10	1.2%	788	2	0.2%
2038	881	10	1.1%	787	(1)	-0.1%
2039	891	10	1.2%	807	20	2.6%
2040	899	7	0.8%	817	10	1.2%
2041	905	6	0.7%	816	(1)	-0.1%
2042	919	14	1.5%	822	6	0.7%
2043	930	12	1.3%	825	3	0.4%
2044	942	12	1.3%	826	1	0.1%
2045	953	10	1.1%	850	25	3.0%

(a) Difference between reporting year and previous year.
(b) Difference expressed as a percent of previous year.

Table B.18: Duke Energy Kentucky System Seasonal Peak Load Forecast After EE , Before DR

	Summer			Winter		
Year	Load	Change [a]	Percent Change [b]	Load	Change [a]	Percent Change [b]
2018	857	16	1.9%	797	64	8.7%
2019	849	(8)	-0.9%	821	24	3.0%
2020	809	(40)	-4.7%	742	(79)	-9.6%
2021	838	29	3.6%	678	(64)	-8.6%
2022	831	(7)	-0.8%	710	32	4.7%
2023	834	3	0.4%	810	100	14.1%
2024	809	(25)	-3.0%	748	(62)	-7.7%
2025	812	2	0.3%	738	(10)	-1.4%
2026	816	4	0.5%	740	2	0.3%
2027	817	1	0.2%	743	3	0.4%
2028	819	2	0.2%	745	2	0.3%
2029	820	2	0.2%	746	0	0.1%
2030	832	11	1.4%	755	9	1.2%
2031	838	7	0.8%	759	4	0.5%
2032	844	5	0.6%	757	(2)	-0.2%
2033	852	8	0.9%	767	10	1.3%
2034	858	6	0.7%	772	5	0.6%
2035	876	19	2.2%	787	15	1.9%
2036	887	10	1.2%	790	3	0.4%
2037	897	10	1.2%	791	2	0.2%
2038	907	10	1.1%	791	(1)	-0.1%
2039	917	10	1.1%	811	20	2.5%
2040	924	7	0.8%	820	10	1.2%
2041	931	6	0.7%	820	(1)	-0.1%
2042	944	14	1.5%	825	6	0.7%
2043	956	12	1.2%	828	3	0.4%
2044	968	12	1.3%	829	1	0.1%
2045	978	10	1.1%	854	25	3.0%

(a) Difference between reporting year and previous year.
(b) Difference expressed as a percent of previous year.

Table B.19: Range of Forecasts for Energy and Peak After EE[a]

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) AFTER EE			PEAK LOAD FORECAST (MW) AFTER EE		
Year	**Low**	**Most likely**	**High**	**Low**	**Most likely**	**High**
2024	4,078	4,289	4,480	748	808	887
2025	4,032	4,284	4,513	724	810	892
2026	4,046	4,291	4,526	728	812	896
2027	4,044	4,285	4,524	728	812	898
2028	4,049	4,291	4,533	728	812	899
2029	4,044	4,282	4,535	728	812	902
2030	4,126	4,363	4,623	738	822	913
2031	4,134	4,370	4,639	743	827	922
2032	4,152	4,390	4,665	747	831	928
2033	4,165	4,400	4,686	754	838	938
2034	4,186	4,420	4,713	759	844	945
2035	4,291	4,525	4,824	777	862	965
2036	4,326	4,561	4,864	787	872	977
2037	4,345	4,577	4,888	796	882	989
2038	4,370	4,603	4,919	805	892	1,000
2039	4,397	4,630	4,950	815	902	1,012
2040	4,442	4,677	4,999	822	910	1,020
2041	4,466	4,699	5,030	829	916	1,028
2042	4,499	4,733	5,071	841	930	1,046
2043	4,537	4,770	5,117	852	942	1,060
2044	4,584	4,821	5,173	864	954	1,075
2045	4,620	4,855	5,218	874	965	1,088

(a) Includes EE impacts

Table B.20: Net Monthly Energy/Peak Forecast Before EE, Next Two Years

YEAR 0 (2024)	ENERGY, MWH	PEAK, MW
January	348,963	748
February	385,784	695
March	333,527	601
April	304,726	515
May	319,161	621
June	380,132	743
July	416,086	809
August	416,299	801
September	361,447	667
October	321,947	520
November	326,341	605
December	384,087	688

YEAR 1 (2025)	ENERGY, MWH	PEAK, MW
January	378,673	738
February	357,835	661
March	335,993	603
April	307,137	519
May	321,452	624
June	381,500	744
July	417,969	812
August	417,140	801
September	361,104	666
October	322,662	521
November	327,140	609
December	385,409	694

Table B.21: Net Monthly Energy/Peak Forecast After EE

2024	ENERGY, MWH	PEAK, MW
January	348,963	748
February	385,784	695
March	333,141	600
April	304,242	515
May	318,511	620
June	379,301	741
July	415,083	808
August	415,148	799
September	360,282	665
October	320,700	518
November	324,954	604
December	382,396	687

2025	ENERGY, MWH	PEAK, MW
January	376,821	737
February	356,027	658
March	334,041	600
April	305,179	516
May	319,213	620
June	378,967	739
July	415,198	810
August	414,210	796
September	358,337	661
October	319,869	516
November	324,181	608
December	381,952	692

Table B.22: Service Area Forecast (monthly), by Major Classification, Before EE

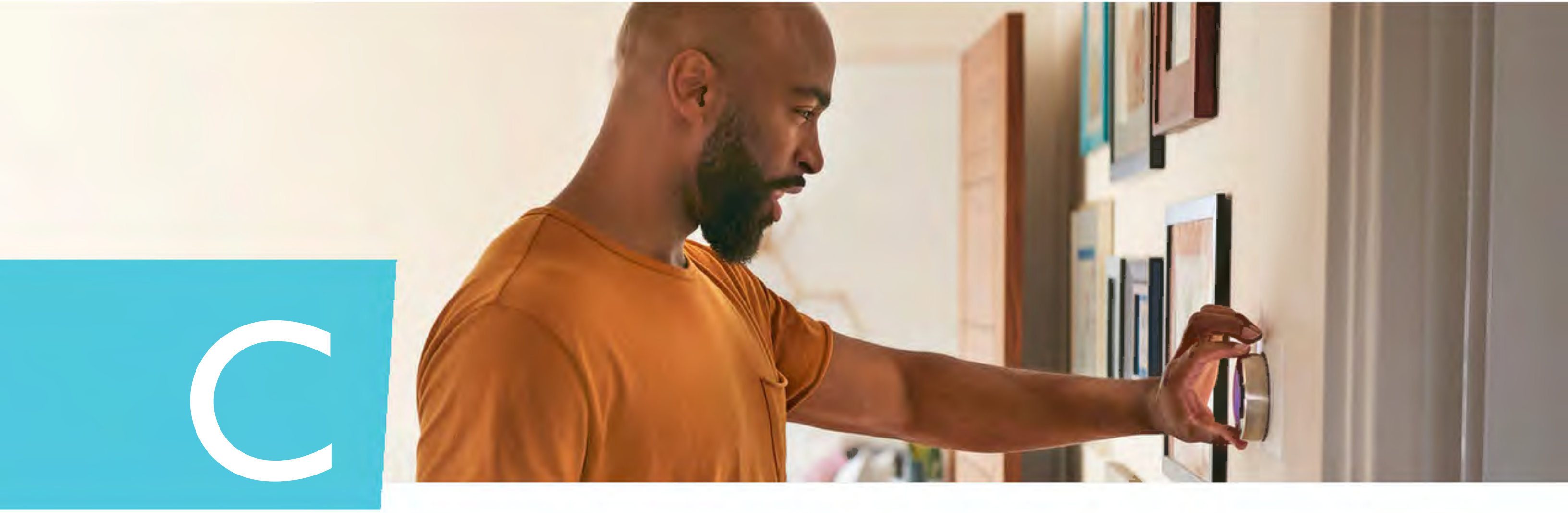
2024	(1) Rural and Residential	(2) Commercial	(3) Industrial	(4) Steet-Hwy Lighting	(5) Sales for Resale[a]	(6) Other	(7) (1+2+3+4+5+6) Total Consumption	(8) Losses and Unaccounted For[b]	(9) (7+8) Net Energy for Load
January	146,008	115,605	45,696	1,066		14,953	323,328	25,635	348,963
February	139,978	134,216	60,903	814		21,534	357,445	28,339	385,784
March	114,043	113,135	59,355	1,059		21,434	309,026	24,501	333,527
April	97,323	106,985	57,581	1,038		19,414	282,341	22,385	304,726
May	101,945	113,203	60,547	984		19,036	295,715	23,447	319,161
June	134,794	134,407	61,411	1,156		20,439	352,207	27,925	380,132
July	156,325	137,543	67,179	1,090		23,383	385,519	30,567	416,086
August	154,475	135,287	70,081	766		25,108	385,717	30,583	416,299
September	119,025	126,689	64,915	1,345		22,921	334,894	26,553	361,447
October	96,398	114,493	63,170	1,008		23,228	298,296	23,651	321,947
November	110,936	109,711	60,891	1,122		19,708	302,367	23,974	326,341
December	153,171	120,044	60,718	1,026		20,912	355,870	28,216	384,087
2025									
January	153,791	118,585	56,373	1,115		20,992	350,855	27,818	378,673
February	141,646	111,578	56,675	1,049		20,600	331,549	26,286	357,835
March	114,604	112,373	62,002	1,051		21,281	311,311	24,682	335,993
April	97,808	106,269	60,196	1,019		19,282	284,574	22,562	307,137
May	102,464	112,449	63,036	970		18,918	297,837	23,615	321,452
June	135,490	133,468	63,078	1,140		20,298	353,474	28,026	381,500
July	157,084	136,583	69,316	1,074		23,206	387,264	30,705	417,969
August	155,230	134,348	71,258	751		24,909	386,496	30,645	417,140
September	119,604	125,816	65,080	1,329		22,747	334,576	26,528	361,104
October	96,904	113,723	64,292	992		23,048	298,959	23,703	322,662
November	111,519	108,975	61,934	1,106		19,572	303,107	24,033	327,140
December	153,960	119,227	62,133	1,010		20,766	357,096	28,313	385,409

(a) Sales for resale to municipals.
(b) Transmission, transformer and other losses and energy unaccounted for.

Table B.23: Service Area Forecast (monthly), by Major Classification, MWh/year, After EE

2024	(1) Rural and Residential	(2) Commercial	(3) Industrial	(4) Steet-Hwy Lighting	(5) Sales for Resale[a]	(6) Other	(7) (1+2+3+4+5+6) Total Consumption	(8) Losses and Unaccounted For[b]	(9) (7+8) Net Energy for Load
January	146,008	115,605	45,696	1,066		14,953	323,328	25,635	348,963
February	139,978	134,216	60,903	814		21,534	357,445	28,339	385,784
March	113,947	113,084	59,177	1,059		21,400	308,668	24,473	333,141
April	97,213	106,920	57,352	1,038		19,371	281,893	22,349	304,242
May	101,798	113,115	60,239	984		18,977	295,113	23,399	318,511
June	134,558	134,304	61,049	1,156		20,370	351,437	27,864	379,301
July	156,033	137,420	66,746	1,090		23,301	384,589	30,493	415,083
August	154,144	135,144	69,582	766		25,013	384,650	30,498	415,148
September	118,743	126,534	64,375	1,345		22,818	333,814	26,467	360,282
October	96,116	114,324	62,578	1,008		23,115	297,141	23,559	320,700
November	110,582	109,531	60,260	1,122		19,587	301,082	23,872	324,954
December	152,656	119,840	60,006	1,026		20,777	354,304	28,092	382,396
2025									
January	153,218	118,363	55,599	1,115		20,845	349,139	27,682	376,821
February	141,085	111,362	55,921	1,049		20,456	329,874	26,153	356,027
March	114,115	112,118	61,108	1,051		21,110	309,502	24,539	334,041
April	97,356	106,006	59,274	1,019		19,106	282,760	22,418	305,179
May	101,947	112,148	61,981	970		18,717	295,763	23,450	319,213
June	134,756	133,156	61,986	1,140		20,090	351,127	27,840	378,967
July	156,263	136,245	68,134	1,074		22,981	384,696	30,502	415,198
August	154,371	133,989	70,001	751		24,670	383,781	30,429	414,210
September	118,917	125,453	63,809	1,329		22,504	332,013	26,324	358,337
October	96,258	113,347	62,977	992		22,797	296,371	23,498	319,869
November	110,745	108,595	60,602	1,106		19,318	300,366	23,815	324,181
December	152,881	118,816	60,695	1,010		20,492	353,893	28,059	381,952

(a) Sales for resale to municipals.
(b) Transmission, transformer and other losses and energy unaccounted for.



Appendix C: Energy Efficiency and Demand-Side Management

A. Introduction

Duke Energy Kentucky offers DSM[12] programs, as listed in Figure 5.1 that have been developed in conjunction with the DSM Collaborative.

B. Cost Effectiveness of Programs

All DSM programs are screened for cost-effectiveness using DSMore, a financial analysis tool designed to evaluate costs, benefits, and risk. DSMore estimates a program's value at an hourly level across distributions of weather and/or energy costs or prices. By examining performance and cost effectiveness over a wide variety of weather and cost conditions, risks and benefits are evaluated in the same way as are traditional generation capacity additions, which ensures that demand-side resources are compared to supply-side resources on a comparable basis.

The analysis of DSM cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Cost Test (PCT). DSMore provides the results of these tests for either the DR or EE category of DSM programs.

The use of multiple tests can ensure the development of a reasonable set of DSM programs and indicate the likelihood that customers will participate. The figure below summarizes the cost effectiveness results for current programs as of the most recent Annual Update filing.

[12] 1 Kentucky Revised Statutes (KRS) § 278.010 define Demand Side Management as "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand including home energy assistance programs." KY. REV. STAT. ANN. § 278.010 (LexisNexis 2021).

Figure C-1 Cost Effectiveness Test Results

Cost-Effectiveness of Programs

THE UCT

The UCT compares utility benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program such as marketing, customer incentives, and measure offset costs, but does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity comsuption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, and the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effeciveness analyses also incorporate avoided transmission and distribution costs and load (line) losses.

THE RIM TEST

The RIM test, or non-participants test, indicates rates increase or decrease over the long run as a result of implementing the program.

THE TRC TEST

The TRC test compares the total benefits to the utility and participants relative to the costs of utility program implementation and costs to the participant. The benefits to the utility are the same as those computed under the UTC. The benefits to the participant are the same as those computed under the Participant Test (below), however, customer incentives are considered a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC through some precedent exists in other jurisdictions to consider non-energy benefits in this test.

THE PARTICIPANT TEST

The Participant Test compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the DSM measure. The costs can include capital cost, as well as increased annual operating costs, if applicable.

Program Name	UCT	TRC	RIM	PCT
Residential Programs				
Low Income Neighborhood	0.37	0.37	0.26	2.02
Low Income Services	0.49	0.49	0.33	1.97
My Home Energy Report	4.73	4.73	0.98	NA
Residential Energy Assessments	1.53	1.44	0.53	32.61
Residential Smart $aver®	1.25	1.05	0.52	3.86
Power Manager	2.30	3.11	2.30	NA
Peak Time Rebate Pilot Program	0.17	0.17	0.17	NA
Total	**1.31**	**1.35**	**0.79**	**3.63**
Non-Residential Programs				
Small Business Energy Saver	1.83	1.25	0.63	3.02
Smart $aver® Non-Residential	3.22	2.12	0.64	5.77
PowerShare®	1.96	4.72	1.96	NA
Total	**2.27**	**2.34**	**0.88**	**5.02**
Overall Portfolio Total	**1.70**	**1.74**	**0.84**	**4.35**

C. Current DSM Programs

Residential Smart $aver®:Energy Efficient Residences and Products Programs

The purpose of the Residential Smart $aver® Energy Efficient Residences portion of the Residential Smart $aver® Program is to offer customers prescriptive incentives for a variety of energy conservation measures designed to target the largest energy consumption equipment and increase energy efficiency in their homes. The program utilizes a network of participating contractors to encourage the installation of high efficiency equipment and the implementation of energy efficient home improvements with eligible customers. Equipment and services to be incentivized include:

- Installation of high efficiency air conditioning (AC) and heat pump (HP) systems;
- Implementation of attic insulation and air sealing services;
- Implementation of duct sealing services; and
- Installation of efficient heat pump water heaters.

The Program includes a tier approach to the level of incentives available for AC and HP system replacements based on the efficiency rating of the system, along with an optional additional incentive if a qualifying smart thermostat is included and installed with the replacement. A referral marketing component for eligible trade allies has also been added as a delivery channel to enhance customer experience as the customer is making the energy efficient purchase decision. The Program continues to experience a steady demand from customers participating in the incentives. During the period July 2022 through June 2023, the Program approved 750 individual rebate applications.

Duke Energy Kentucky currently engages a vendor to administer this program. The program vendor provides services including application processing and fulfillment, data reporting, call center services, and IT support for program tools such as the trade ally portal which allows trade allies to register, check customer eligibility, and submit applications online. These Residential Smart $aver® services are jointly implemented with the Duke Energy Indiana, Duke Energy Carolinas, and Duke Energy Progress territories to reduce administrative costs and leverage promotion. BES has experience in delivering similar utility energy efficiency programs.

Beginning in January 2023, all residential central air conditioners and air source heat pump systems will be required to meet new minimum energy efficiency standards of no less than 15 SEER in the southeast, which includes the state of Kentucky.

Based on the above-mentioned federal standard changes, the program will need to adjust eligibility criteria to remain cost effective. Eligible minimum SEER level will be adjusted to SEER 16 and the program will pay incentives based on the operating status of the equipment being replaced and the efficiency level of the new equipment as follows:

Replacement on Failure Incentive:

Replacement of measures which are not functioning and cannot be repaired will be considered a Replacement On Failure (ROF). Incentives for ROF will be determined by the Company in an amount not to exceed 50% of the installed cost difference between standard equipment or service and higher efficiency equipment or service. The Company may vary the incentive by type of equipment and differences in efficiency to induce customers to purchase greater levels of efficiency at the minimum necessary incentive amount.

Early Replacement Incentive:

Replacement of measures which are functioning or can be repaired will be considered an Early Replacement (ER). Incentives for ER will be determined by the Company based on an amount commensurate with the projected energy savings. The Company may vary the incentive by type of equipment and differences in efficiency to induce customers to purchase greater levels of efficiency.

The purpose of the Residential Smart $aver® Energy Efficient Products portion of the Residential Smart $aver® Program is to provide high efficiency lighting through various channels, along with other high efficiency products in new or existing residences, including pool pumps, water measures for single family, and water measures for multifamily.

The Residential Smart $aver® lighting program launched an Online Savings Store (Store) for specialty lighting on April 26, 2013. The Store is an on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. In 2020, the program was approved to add smart thermostats, water products, LED fixtures, & small appliance- dehumidifiers & air purifiers. The incentive levels vary by product, and the customer pays the difference as well as any applicable taxes. Per measure limits for incentives are: 2 for smart thermostats, dehumidifiers, and air purifiers; 3 for water measures. Customers may choose to order additional products without the Company's incentive. Various promotions are conducted throughout the year, offering customers reduced prices as well as shipping promotions, ranging from free to a reduced flat rate price. Incentives for specialty LED lighting were sunsetted as of July 1, 2023 due to Federal baseline changes. Customers may continue to purchase LED on the Store without the Company’s incentive.

The Store is managed by a third-party vendor. The vendor is responsible for maintaining the Store website, fulfilling all customer purchases, and supporting the program call center. The Store landing page provides information about the store, and energy efficient products. Support features include a toll-free number, email, Live Chat, and frequently asked questions. Customers may choose to browse the site before checking eligibility for incentives. Shipping and order confirmations are included in the email confirmation sent directly to the customer.

Educational and product detail information are available on the Store to assist customers with their purchasing decisions. The information discusses bulb types, application types, benefits of energy efficient products, and understanding watts versus lumens.

The Online Savings Store program carefully tracks towards budget by monitoring marketing activities to customers. During Fiscal Year July 2022 through June 2023, the program delivered 13,871 LED Specialty bulbs, 736 smart thermostats and 26 trim kits, 70 air purifiers, 12 dehumidifiers, and 4 water measures.

The Multifamily Energy Efficiency Program is an extension of the Residential Smart $aver® lighting program and allows Duke Energy Kentucky to use an alternative delivery channel which targets multifamily apartment complexes. The measures are directly installed in permanent fixtures by the program vendor. The target audience for the program is property managers who have properties that are served on an individually metered residential rate schedule. To receive water measures, apartments must have electric water heating.

The program helps property managers save energy by offering water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap. The program also offers smart thermostats to multifamily properties. The property can purchase the smart thermostats for their units and have them installed by the program implementor for a discounted copay. As of July 2023, the program no longer offers lighting measures, due to a change Federal baseline standards.

The program implementer is responsible for all marketing and outreach for the program. This is primarily done through outbound calls and on-site visits to solicit initial interest in the program from property managers in the Company’s service territory. Additionally, program information and supporting documents are available on the Duke Energy Kentucky web site for property managers to learn more about the program and request applications to participate in the program.

A total of 4,374 measures were installed from July 2022 - June 30, 2023. The program installed 330 kitchen and bath aerators, 476 standard showerheads, 2021 feet of insulating pipe wrap, and 955 bulbs.

The Save Energy and Water Kit (SEWK) program is designed to increase the energy efficiency of residential customers by offering customers low flow water devices and water heater pipe insulation wrap to install within their homes. The SEWK offer is available through a business reply card (BRC) or through direct email solicitation, enabling customers to request a kit and have it shipped directly to their homes. A website has been established to provide customers with additional information about the program and instructional videos to assist in the installation of items from the do it yourself (DIY) kit. Additionally, the online platform allowed customers to upgrade the standard showerhead to either a wide spray or hand-held model for a discounted price.

The program implementer changed in September 2021 and the program was temporarily shut down while the program transitioned to a new vendor. The new vendor restarted the program in February 2022. The relaunch of the program focused on offering kits to customer via email and BRC's. A new online platform became available in June 2023, allowing customers to upgrade their showerhead to a hand-held model for a discounted price. The wide spray showerhead is now the standard showerhead offered in the kits to allow for higher customer satisfaction and install service rates.

To be eligible, customers must have an electric water heater, have not already participated in SEWK or another Duke Energy Kentucky program offering water saving devices, and live in a single-family, owner-occupied home. Eligible customers, who respond to the BRC or email offer, will receive a kit free of charge. There are two kit sizes to accommodate homes with one or more full bathrooms. The kit size available to the customer is predetermined based on the square footage of the home. Customers in homes less than or equal to 1,500 square feet receive a one (1) bath kit. Customers in homes greater than 1,500 square feet receive a two (2) bath kit. The kits contain varying quantities of showerheads, two bath aerators, one kitchen aerator and insulated pipe tape.

The SEWK program is an invitation only program where customers are prequalified and then directly solicited for participation. This allows the program to carefully track performance against budget and adjust marketing efforts as needed. From July 1, 2022, to June 30, 2023, the program shipped 1,417 kits containing 4,251 kitchen and bath aerators, 1,993 standard wide spray showerheads, and 8,502 feet of insulating pipe wrap, for a total of 14,746 measures.

Residential Energy Assessments Program

The primary goal of the Residential Energy Assessments Program, marketed as Home Energy House Call (HEHC), is to empower customers to better manage their energy usage and cost. Duke Energy Kentucky partners with several key vendors to administer the program in which an energy specialist completes a 60 to 90-minute walk through assessment of the home and analyzes energy usage to identify energy savings opportunities. The Building Performance Institute (BPI) building certified energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The program targets Duke Energy Kentucky residential customers that own a single-family residence that has electric water heater and/or electric heat, or central air. The energy specialist analyzes energy usage, checks air infiltration, examines insulation levels, checks appliances, and inspects the heating/cooling system(s). The report focuses on the building envelope improvements as well as low-cost and no-cost improvements to save energy. At the time of the home audit, the customer receives a free efficiency kit containing a variety of energy saving measures low flow shower head, low flow faucet aerators, weather stripping and installed pipe wrap on electric water heaters. The auditors will install these measures, if approved by the customer, so the customer can begin saving immediately, and to help insure proper installation and use. Example recommendations might include the following:

- Turning off vampire load equipment when not in use;
- Turning off lights when not in the room;

- Using energy efficient lighting in light fixtures;
- Using a programmable/smart thermostat to better manage heating and cooling usage;
- Replacing older equipment with more energy efficient equipment; and
- Adding insulation and sealing the home.

The program primarily targets through online channels, electronic mail, and direct mail to acquire the participation for this program.

The program offers additional measures that included a blower door test, handheld low-flow showerheads, smart thermostats, specialty globes and candelabras, and recessed LED bulbs. The program ended the fiscal year (June 2023) completing 448 assessments and installed 36 smart thermostats, 22 additional bathroom aerators, 2 specialty showerheads, 86 specialty globes, 41 LED candelabras, 30 recessed LED bulbs, 579 feet of pipe insulation and 2 blower door audits. Starting July 2023, the program no longer incentivized lighting. However, customers will still be able to purchase lighting at discounted costs through program implementor.

The Company requested and received approval in 2023 to expand the offer to allow single family renters, condo/townhomes/manufactured homeowners, and renters the ability to choose a virtual, phone or web-based audit for their home. These customers must have electric service provided by Duke Energy Kentucky to participate in the program.

The additional types of energy assessment include:

1. Web-based – Customers complete an online questionnaire to evaluate their homes efficiency.
2. Phone Assisted – Customers collaborate with the vendor customer support specialist and complete an energy evaluation during a schedule phone appointment.
3. Virtual – Customers collaborate with the vendor energy advisor, who performs computer assisted, onsite home evaluation.

The new virtual, phone and web-based audits will allow customers to learn more about energy savings options and recommendations for their home and receive a free energy efficiency kit based on the path (channel) they choose. The kits will ship to the home after the audits are complete.

Virtual and phone audits kits will consist of water saving measures including a low-flow showerhead, kitchen and bath aerators, weather stripping, Pipewrap, and a furnace filter whistle. The web-based audit kit will consist of faucet bathroom aerators, weather stripping, Pipewrap, refrigerator thermometer and furnace filter whistle.

Customers will receive a detailed assessment report, based on visual and questionnaire responses, providing extra saving recommendations for how they can opt to take advantage of other products and services to improve their homes efficiency. Eligible customers may choose the path or channel that best fits their schedule and desire to learn more about their home's efficiency.

The program completed the following:

Low Income Services Program: Now Income Qualified Services Program

Weatherization

The Weatherization program portion of Low-Income Services is designed to help income-qualified customers that are below 200 percent of the federal poverty level to reduce their energy consumption and lower their energy cost. The program works with local weatherization agencies using Federal DOE/LIHEAP funds as well as other community outreach initiatives for participation. The program provides the agencies incentives for installing energy efficient measures in qualified customers' homes. Agencies also educate customers on their energy usage and other opportunities that can help reduce energy consumption and lower energy costs. The program has provided weatherization services to the following number of customers:

Table C.1: Number of Customers with Weatherization Services

Fiscal Year	Customers Served
1999 - 2000	251
2000 - 2001	283
2001 - 2002	203
2002 - 2003	252
2003 - 2004	252
2004 - 2005	130
2005 - 2006	232
2006 - 2007	252
2007 - 2008	265
2008 - 2009	222
2009 - 2010	199
2010 - 2011	234
2011 - 2012	220
2012 - 2013	228
2013 - 2014	143

2014 - 2015	203
2015 - 2016	162
2016 - 2017	166
2017 - 2018	127
2018 – 2019	120
2019 – 2020	99
2020 – 2021	81
2021 – 2022	127
2022 – 2023	145

The program is structured so that homes needing the most work, and having the highest energy use per square foot, receive the most funding. The program accomplishes this by placing each home into one of two “Tiers.” For each home, the field auditor uses the National Energy Audit Tool (NEAT) to determine which specific measures are cost effective for that home.

Table C.2: Tier Structure Definition

	Therm / square foot	kWh use/ square foot	Investment Allowed
Tier 1	0 < 1 therm / ft2	0 < 7 kWh / ft2	Up to $600
Tier 2	1 + therms / ft2	7 + kWh / ft2	All SIR* > 1.5 up to $4K

Tier 1 Services

Tier 1 services are provided to customers through weatherization agencies. Customers are considered Tier 1 if they use less than 1 therm per square foot per year or less than 7-kWh per square foot per year, based on a year’s usage of Company supplied fuels. Square footage of the dwelling is based on conditioned space only, whether occupied or unoccupied. It does not include unconditioned or semi-conditioned space (non-heated basements). The total program dollars allowed per home for Tier One services is $600.00 per home. Tier 1 services are described in Figure C.1 below.

Figure C.1: Tier 1 Services

Tier 2 Services

Duke Energy Kentucky will provide Tier 2 services to a customer if they use at least 1 therm or at least 7 kWh per square foot per year based on the annual usage of Duke Energy Kentucky supplied fuels.

Tier 2 services are as follows:

- All Tier 2 services; plus
- Additional cost-effective measures (with SIR > 1.5) based upon the results of the NEAT audit. Through the NEAT audit, the agency can determine if energy saving measures pay for themselves over the life of the measure as determined by a standard heat loss/economic calculation (NEAT audit) utilizing the cost of gas and electric as provided by Duke Energy Kentucky. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, floor insulation and sill box insulation. Safety measures applying to the installed technologies can be included within the scope of work considered in the NEAT audit if the SIR is greater than 1.5 including the safety changes; and
- Replacement of heating system if cannot be repaired.

Regardless of placement in a specific tier, Duke Energy Kentucky provides energy education to all customers in the program.

Refrigerator replacement is also a component of this program. To determine replacement, the program weatherization provider performs a two-hour meter test of the existing refrigerator unit. If it is a high-energy consuming refrigerator, as determined by this test, the unit is replaced. Replacing with a new ENERGY STAR® qualified refrigerator, with an estimated annual usage of 400 kWh, results in an overall savings to the average customer typically more than 1,000 kWh per year. The figure below summarizes refrigerators tested and replaced.

Table C.3: Refrigerators Tested and Replaced

Year	Refrigerators Tested	Refrigerators Replaced
2002 – 2003	116	47
2003 – 2004	163	73
2004 – 2005	115	39
2005 – 2006	116	52
2006 – 2007	**136**	72
2007 – 2008	173	85
2008 – 2009	153	66
2009 – 2010	167	92
2010 – 2011	112	76
2011 – 2012	107	64
2012 – 2013	206	69
2013 – 2014	112	37
2014 – 2015	42	24
2015 – 2016	60	22
2016 – 2017	92	54
2017 - 2018	48	18
2018 – 2019	43	12
2019 – 2020	66	15
2020 – 2021	19	15
2021 – 2022	32	17
2022 – 2023	35	18

The existing refrigerator being replaced is removed from the home and recycled in an environmentally appropriate manner to assure that the units are not used as a second refrigerator in the home or do not end up in the secondary appliance market.

In recognition of the COVID-19 environment, proper safety protocols are being adhered to with PPE being worn to ensure everyone's safety if the customer requests.

Payment Plus

The Payment Plus portion of Low-Income Services program is designed to impact participants' behavior (e.g., encourages utility bill payment and reducing arrearages) and to generate energy conservation impacts. The program is made up of three components described in Figure C.2 below.

Figure C.2: Low-Income Services Payment Plus

This program is normally offered twice over six winter months per year (October-March). Since 2020, the program has been offered quarterly to accommodate smaller class sizes.

Duke Energy Kentucky utilizes a community action agency to recruit customers to participate in the Payment Plus program. The Payment Plus program is designed to help income-qualified customers that are below 200% of the federal poverty level to reduce their energy consumption and lower their energy cost. Using a list of potential customers provided by Duke Energy Kentucky, the agency sends a letter describing the program to eligible customers. Included in this letter are various dates, times, and locations of scheduled classes. The courses are designed to accommodate customers with varied schedules and widespread locations. The customer contacts the agency to register for a course. Make-up courses are also offered to those customers who may have missed their initial scheduled time.

For the filing period, 124 participants attended energy education counseling. Of those 124, 124 participants also attended budget counseling and 31 participants' homes have been weatherized.

Residential Direct Load Control - Power Manager® Program

The purpose of the Power Manager® program is to reduce demand by controlling residential air conditioning usage during periods of peak demand, high wholesale price conditions and/or generation emergency conditions during the summer months. It is available to residential customers with central air conditioning. Qualifying customers have the choice between the AC Switch and Bring Your Own Thermostat options.

AC Switch

Duke Energy Kentucky attaches a load control device to the outdoor unit of a customer's air conditioner. This enables Duke Energy Kentucky to cycle the customer's air conditioner off and on under appropriate conditions.

Multiple cycling options are available. Customers selecting the option that moderately cycles their air conditioner, receive a $25 credit at installation. Customers selecting the longer cycling option, receive a $35 credit at installation. Customers also receive annual credits during the months of June-October depending on the cycling option they signed-up for. Customers that signed-up for the moderate control option receives an annual event credit of $2.40 per month for each year they are on the program and customers that signed-up for the longer control option receive an annual event credit of $3.60 per month each year they are on the program.

The AC Switch is primarily marketed through outbound telephone calling. Providing customers with an opportunity to ask questions before deciding to participate has proven to be a significant attribute in making this the most effective sales channel.

Bring Your Own Thermostat

The Company requested an amendment to the program in Case No. 2023-00269 to enhance the Power Manager program by introducing Bring Your Own Thermostat (BYOT). BYOT is a residential DR Power Manager option, leveraging customers "smart" two-way communicating thermostats instead of traditional load control switches that are installed and owned by the utility. It is intended for customers who have already purchased, installed, and registered a smart thermostat in their home, allowing the utility to avoid the hardware and installation costs associated with traditional direct load control programs. The utility can verify how many thermostats are operable and online at any given time, and determine which thermostats are participating in DR events as opposed to opting out. Duke Energy has partnered with a third-party vendor who has contracts with multiple thermostat manufacturers to offer demand response through the different thermostat models. After successfully enrolling, participants will receive a one-time $75 incentive. In addition, participants will receive a $25 incentive each year following the anniversary of their enrollment in the program. Rewards are limited to one per service address.

BYOT is marketed to customers through participating device manufacturers who offer utility branded marketing and enrollment services. Agreements with the aggregation vendor and their thermostat partners allow them to send marketing messages to device owners inviting them to participate in their utility's DR program. Marketing communication may include, but is not limited to, messages within the manufacturers smart phone application, co-branded email, and text messages. Interested customers are then directed to enroll electronically through the various marketing channels. In addition to the thermostat manufacturer communication, the company may use a number of other channels, such as the utility website and social media.

Ongoing evaluation, measurement, and verification (EM&V) is conducted through a sample of Power Manager® customers with devices that record hourly run-time of the air conditioner unit and with load research interval meters that measure the household kWh usage. Operability studies are also used to measure the performance of Power Manager® load control devices in Kentucky. In addition, Duke

Energy Kentucky has reviewed the statistical sampling requirements of PJM for demand response resources of this type. The Duke Energy Kentucky studies comply with all PJM requirements.

There were no Power Manager® events that took place from July 2022 through June 2023 event season. There was a PJM required one-hour test on June 29, 2023.

Program Enhancement - Paging System Upgrade

The paging system is a vital component to the program that communicates with the load control devices at customers' air conditioning unit(s). The existing paging system is outdated, and some components are at end of life. In order to keep the paging network operational, an upgrade to the Prism platform is needed to replace system software, servers, and transmitters. This upgrade was approved in 2023. System upgrade work is scheduled for 2025.

Smart $aver® Prescriptive and Smart $aver® Custom are now combined as Smart $aver® Non-Residential Program

The Smart $aver® Non-residential Incentive Program provides incentives to commercial and industrial consumers for installation of high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. The program also uses incentives to encourage maintenance of existing equipment to reduce energy usage. Incentives are provided based on Duke Energy Kentucky's cost effectiveness modeling to assure cost effectiveness over the life of the measure.

Commercial and industrial consumers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products. The Program provides incentives through prescriptive measures, custom measures, and assessment/ technical assistance.

Prescriptive Measures: The program promotes prescriptive incentives for the following technologies – lighting, HVAC, pumps, variable frequency drives, food services, and process equipment. The eligible measures, incentives, and requirements for both equipment and customer eligibility are listed in the applications posted on Duke Energy's website.

Custom Measures: The Smart $aver® custom program is designed for customers with electrical energy-saving projects involving more complicated, emerging, or alternative technologies or measures not covered by the Non-Residential Smart $aver® prescriptive program. The intent of the program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the non-residential Smart $aver prescriptive program, the program requires pre-approval prior to the project initiation. Starting in August 2023, Custom lighting projects with estimated annual energy savings under 700,000 kWh, can utilize an express option that bypasses the need for pre-approval. Custom Incentives may be applied for after the project has been completed. The option to receive pre-approval is still available. A vendor performs technical reviews of custom applications. All other program implementation and analysis is performed by Duke Energy employees or direct contractors.

The program has developed multiple approaches to reaching the very broad and diverse audience of business customers. In 2022-2023, this consisted of incentive payment applications, with paper and online options, instant incentives offered through the Online Energy Savings Store. As of July 2023, the prescriptive program extends existing rebates through a midstream channel of local distributors and as of April 2024, rebates are offered through an upstream channel of manufacturers. This will help to promote the purchase of energy-saving products at the point of sale for qualifying customers and measures.

Over the years, the program has worked closely with trade allies (TA) to promote the program to business customers at the critical point in time when customers are considering standard or high efficiency equipment options. The Smart $aver® outreach team provides training and technical support to the TA network. The outreach team also recruits new TAs to participate in the program. TA company names and contact information appears on the TA search tool located on the Smart $aver® website. This tool was designed to help customers who do not already work with a TA, to find someone in their location who can serve their needs. The Company continues to look for ways to engage the TAs in promotion of the program as well as more effective targeting of TAs based on market opportunities.

Duke Energy Kentucky continues to evaluate changes to existing measures, to take into consideration changes to market conditions and energy efficiency standards, and the addition of measures to offer customers additional options for energy savings. Any future measure changes will be presented to the Commission in accordance with the applicable review and approval processes and procedures.

For the 2022-2023 fiscal year, Smart $aver® incentive funds were readily available for the majority of the period due to lower participation during the fiscal year. Projects are able to utilize a program prequalification feature reserve incentive funds. During the reporting period of July 2022 through June 2023, the Kentucky Smart $aver® Non-Residential program provided either Prescriptive or Custom incentives to 44 total customers.

The internal marketing channel is comprised of assigned Large Business Account Managers, Segment Managers, and Local Government and Community Relations, Trade Ally Outreach Representatives and Business Energy Advisors, who all identify potential opportunities as well as distribute program collateral and informational material to customers and trade allies (TAs). In addition, the Economic and Business Development groups also provide a channel to customers who are new to the service territory. Additionally, the program developed is developing a robust Account Based Marketing (ABM) strategy to provide levels of personalized engagement to clusters of similar type accounts. This is a highly customized approach that focuses on specific companies and their decision-makers. The Company will pursue a data-driven approach to gathering actionable insights on harder-to-reach markets. The initial focus targets the education, manufacturing, and retail segments. Upon refinement, the Company will develop a comprehensive campaign for greater awareness that will integrate additional programs and customer solutions.

Peak Load Management (Rider PLM) - PowerShare® Program

PowerShare® is the brand name given to Duke Energy Kentucky's Peak Load Management Program (Rider PLM, Peak Load Management Program KY.P.S.C. Electric No. 2, Sheet No. 77). Rider PLM was approved pursuant as part of the settlement agreement in Case No. 2006-00172. In the Commission's Order in Case No. 2006-00426, approval was given to include the PowerShare® program within the DSM programs. The PLM program is voluntary and offers customers the opportunity to reduce their electric costs by managing their electric usage during the Company's peak load periods. Prior to the start of each PJM Delivery Year, Customers and the Company will enter into a service agreement under Rider PLM, specifying the terms and conditions under which the customer agrees to reduce usage. There are two product options offered for PowerShare® - CallOption® and QuoteOption®:

CallOption®:

A customer served under a CallOption® product agrees, upon notification by the Company, to reduce its demand. Each time the Company exercises its option under the agreement, the Company will provide the customer a credit for the energy reduced. Only customers able to provide a minimum of 100 kW load response qualify for CallOption®.

- Emergency events are implemented due to reliability concerns. Participants are required to curtail during emergency events.
- In addition to the energy credit, customers on the CallOption® will receive an option premium credit;
- There are two enrollment choices for customers relative to CallOption. The first choice, "Summer Period", required participants to be able to curtail during the months of May through October, with a maximum event length of 12 hours and no maximum number of curtailment events. The second choice, "Annual", requires participants to be able to curtail during the full contract term of June through May, with a maximum event length of 12 hours during the months of May through October, and with a maximum event length of 15 hours during the months of November through April and no maximum number of curtailment events.

QuoteOption®:

Under the QuoteOption® products, the customer and the Company agree that when the average wholesale market price for energy during the notification period is greater than a pre-determined strike price, the Company may notify the customer of a QuoteOption® event and provide a price quote to the customer for each event hour;

- The customer will decide whether or not to reduce demand during the event period. If they decide to do so, the customer will notify the Company and provide an estimate of the customer's projected load reduction;
- Each time the Company exercises the option, the Company will provide the participating customer who reduces load an energy credit;

- There is no option premium for the QuoteOption® product since customer load reductions are voluntary; and
- Only customers able to provide a minimum of 100 kW load response qualify for QuoteOption®.

PowerShare® 2023-2024 Summary

Duke Energy Kentucky's customer participation goal for 2023 was to retain all customers that currently participate and to promote customer migration to the CallOption® program. The table below displays monthly account participation levels for July 2023 through June 2024, as well as MWs enrolled in the program.

Table C.4: PowerShare® 2023-2024 Summary

	CallOption®		QuoteOption®	
Month	Enrolled Customers*	Summer Capability**	Enrolled Customers*	Summer Capability**
Jul-23	8	8.96	0	0
Aug-23	8	8.96	0	0
Sep-23	8	8.96	0	0
Oct-23	8	8.96	0	0
Nov-23	8	8.96	0	0
Dec-23	8	8.96	0	0
Jan-24	8	8.96	0	0
Feb-24	8	8.96	0	0
Mar-24	8	8.96	0	0
Apr-24	8	8.96	0	0
May-24	8	8.96	0	0
Jun-24	9	9.65***	0	0

*Enrolled customers represent the number of parent accounts participating.
**Summer capability is consistent with the associated program year. Numbers reported are adjusted for losses.
***Estimated Summer capability

During the July 2023 through June 2024 period, there were two PowerShare® CallOption® or QuoteOption® events. There were curtailment tests performed to meet PJM requirements. The table below summarizes event participation.

Table C.5: Duke Energy Kentucky - PowerShare CallOption and QuoteOption Economic, Emergency, and Test Events - July 2023 - June 2024 Activity - Reduction Values in MWs

Date	Event Hours (EDT)	Event Type	Event Participants	Participants Reducing Load Partially or Fully	Average Hourly Load Reduction Expected - At the Meter	Average Hourly Load Reduction - At the Meter	Average Hourly Load Reduction - At the Plant
6/29/2023	2 pm - 4 pm	PJM Test	8	8	6.979	8.494	8.707
8/4/2023	2 pm - 4 pm	PJM Re-Test	2	2	1.101	2.182	2.236

(Note that for the summer period of June 2023 through September 2023, zero PowerShare® events were called. The annual, required, PJM test event was conducted on June 29, 2023, at 2 pm. PJM implemented new testing guidelines in 2023: PJM schedules all annual curtailment tests, and the test duration has been extended to two hours.

Low Income Neighborhood Program – now Income Qualified Neighborhood Energy Saver Program

The Duke Energy Kentucky Neighborhood Energy Saver (NES) Program takes a non-traditional approach to serve income-qualified areas of the Duke Energy Kentucky service territory through the direct installation of energy efficiency measures in customer homes. This customer-facing program allows for the direct engagement in a familiar setting to reduce energy consumption with the installation of energy efficient measures. In addition, Duke Energy Kentucky uses this opportunity to educate and work with customers to efficiently manage and lower their energy bills. Examples of direct installed measures include energy efficient light bulbs, water heater and pipe wrap, low flow shower heads/faucet aerators, window and door air sealing and a year supply of HVAC filter replacements.

As low-income neighborhoods are identified for the program, if at least 50% of the households are at or below 200% of the federal poverty guidelines, a community with an average size of about 900 customers is selected. Duke Energy Kentucky analyzes census and internal data to select and prioritize neighborhoods that have the greatest need and propensity to participate. While the goal is to serve neighborhoods where most residents are low income, the program is available to all Duke Energy Kentucky customers within the selected boundary. This program is available to both homeowners and renters occupying single family and multi-family dwellings in the target neighborhoods that have electric service provided by Duke Energy Kentucky.

In the past, community-based kick-off events have been held in targeted neighborhoods. Kick-off events have featured local community leaders, community-based organization representatives, local weatherization program managers, the installation vendor, and the technical crew. The Duke Energy Kentucky program manager and vendor provide attendees detailed information about NES along with a tentative neighborhood schedule.

The purpose of the kick-off event has been to rally the neighborhood around energy efficiency and educate customers on actions they can take to help lower their energy bills and save energy. Additionally, attendees have had the opportunity to meet technical staff and view measures. In days, or a few weeks, shortly following the kick-off event, customers are contacted by the technical crew to receive the free in-home energy assessments (walk-through) and the appropriate energy saving measures are installed if the customer elects to have the work completed. Direct mail and call center support supplement community-based outreach efforts.

For fiscal year 2022-2023, with a participation goal of 600 homes, the Company has completed 414 homes in Duke Energy Kentucky territory. With the lingering existence of COVID-19, hesitation to allow technicians into one's home still remained an issue. With this challenge, Duke Energy Kentucky continues to collaborate with organizations such as the Northern Kentucky Community Action Commission, People Working Cooperatively and other local agencies, businesses, and government-backed programs to rally around efforts of the NES program. Duke Energy Kentucky's NES program provides residents information about the service and helps leverage additional services available in their communities. The program has been well-received, and neighbors regularly share the benefits of their experience with others.

Duke Energy Kentucky has expanded the NES program by adding NES 2.0. In addition to the current 16 measures offered to customers, Duke Energy will qualify customers of the neighborhood for NES 2.0 measures, which include attic insulation, air sealing, duct sealing, and smart thermostats to address customers high energy use. Eligibility of the revised measures (NES 2.0) will be made available to customers that the Company deems a high-energy user. For fiscal year 2022-2023, the Company has completed 65 attic insulation, 44 air sealing, and 43 duct sealing installations for customers with high energy use.

Home Energy Report Program

The Home Energy Report (HER) compares household electric usage to similar, neighboring homes, and provides recommendations and actionable tips to lower energy consumption. The report also informs a customer of the Company's other energy efficiency programs when applicable. These normative comparisons are intended to induce customers to adopt more efficient energy consumption behavior. HER is delivered in printed and email form. The reports are distributed up to 12 times per year (2 printed reports and 12 electronic reports if the customer provides their email address). Currently, to qualify to receive the report, customers must be living in a single metered, single-family home with 13 months usage history.

The HER program, originally an opt out program, was changed to an opt in program beginning in 2019-2020, the next fiscal term following the Commission's September 13, 2018, Order. The Company provides information on every report as to how a customer may update their information or request to stop receiving the reports. From July 1, 2022, to June 30, 2023, the MyHER program has had zero opted-in customers decide to opt-out of the program after receiving reports. As of June 30, 2023, there were 9,265 Kentucky HER customers receiving reports.

The HER program has requested and received approval to return to an opt-out program design beginning in 2024 with an aim to deliver usage insights and personalized tips to a larger audience and increase program cost effectiveness. The HER program is also requested and received approval to be made available to multifamily customers in Kentucky. The updated program design request included an increase of up to 8 paper reports sent to each customer per year if a customer has not opted out of paper reports.

The Company has designed an interactive portal and enabled email technology to further engage with customers with the intention of increasing the level of engagement with customers and hence their efficiency. This portal is available online and through mobile channels. The portal was rolled out in March 2015 with a small email campaign for HER customers for whom the Company has an email address. The HER program and interactive website were brought in-house at Duke Energy in February of 2021, enabling a more unique experience for participants. As of June 30, 2023, there were 1,308 Kentucky HER customers enrolled in the interactive portal.

The Company launched the HER program in the Duke Energy mobile app starting in 2019. Customers who have opted into the program are now able to see their Home Energy Report monthly comparisons and usage disaggregation on the Duke Energy mobile app.

Business Energy Saver Program

The purpose of Duke Energy Kentucky's Business Energy Saver program (BES Program) is to reduce energy usage through the direct installation of energy efficiency measures within qualifying small non-residential Duke Energy Kentucky customer facilities. All aspects of the BES Program are administered by a single Company-authorized vendor. The BES Program measures address major end-uses in lighting, refrigeration, process, and HVAC applications.

The BES Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Kentucky. Upon receiving the results of the energy assessment, if the customer decides to move forward with the proposed energy efficiency project, the customer makes the final determination of which measures will be installed. The energy efficiency measure installation is then scheduled at a convenient time for the customer and the measures are installed by electrical subcontractors of the Duke Energy Kentucky-authorized vendor.

The BES Program is designed as a pay-for-performance offering, meaning that the Duke Energy Kentucky-authorized vendor administering the BES Program is compensated for kWh energy savings produced through the installation of energy efficiency measures.

The BES Program is available to existing Duke Energy Kentucky non-residential customer accounts with an actual average annual electric demand of 180 kW or less. An individual business entity's participation is limited to no more than five premises on the Company's system during a calendar year.

For the July 2022 to June 2023 period, 40 BES projects were completed in Kentucky, which was below the projected volume, and those 40 projects resulted in savings of over 1,683,000 kWh at the plant or 53% of the filed plan.

While LED lighting measures are expected to remain the primary driver of kWh savings in the Program for the foreseeable future, the Company has been actively working with the vendor to implement initiatives focused on increasing refrigeration, process, and HVAC measure adoption.

Duke Energy Kentucky will continue to evaluate the opportunity to add incentivized measures suitable for the small business market to the approved program which fit the direct install program model. The Company would ultimately like to ensure that small business customers are given the opportunity to maximize their energy savings by being offered a comprehensive energy efficiency project through the BES Program wherever possible.

The Company will start offering SmartPath. This option is available to all eligible accounts. SmartPath is meant to build upon the traditional Small Business Energy Saver option by minimizing financial barriers to customer participation by allowing customers to finance and implement energy efficiency upgrades at little to no upfront costs. The program is implemented by a qualified Trade Ally network who complete energy assessments, develops proposals, and implements the turn key projects on the program's behalf. SmartPath offers customers financing through a partnership with the National Energy Improvement Fund (NEIF). All financing is between the customer and NEIF and is offered by the Trade Allies.

Smart $aver® Performance

Duke Energy Kentucky received approval of this non-residential program: Smart $aver® Non-Residential Performance Incentive Program in Case No 2016-00289. The purpose of this program is to encourage the installation of high efficiency equipment in new and existing non-residential establishments. The program will provide incentive payments to offset a portion of the higher cost of energy efficient installations that are not offered under either the Smart $aver® Prescriptive or Custom programs. The types of measures covered by the program include retro-commissioning and projects with some combination of unknown building conditions or system constraints, coupled with uncertain operating, occupancy, or production schedules. The specific type of measures is included in the contract with the Customer. The Company did not market the program during the 2022-2023 filing period due to the high success of Prescriptive and Custom programs. Similarly, for 2023-2024, unless participation in other Non-Residential programs declines, the Company does not plan to offer the Performance Incentive program.

Peak Time Rebate Pilot Program

The PTR pilot program offers participating customers the opportunity to lower their electric bill by reducing their electric usage during Company-designated peak load periods known as Critical Peak Events (CPE). The Company has branded the program to customers under the name Peak Time Credits and describes CPEs to participants as Peak Day events.

The PTR pilot program launched on July 27, 2020, with the original 2-year pilot group, here referenced as Group 1. These initial participants have completed the initial 2-year pilot period and an additional 3rd year and are now participating in year 4. The Company had requested to discontinue Group 1 in Case No. 2022-00251. In accordance with this request, no budget dollars were requested for the PTR pilot program for July 2023 through June 2024. For purposes of counting the number of events each year for Group 1, the Company designates July 27, 2020, through July 31, 2021, as the first year of the pilot. The second year of the pilot is August 1, 2021, through July 31, 2022. The third year of the pilot is August 1, 2022, through July 31, 2023. August 1, 2023, starts the fourth year of the pilot for Group 1. The Company enrolled a total of 899 participants in Group 1. As of August 23, 2023, 625 participants remain active in Group 1. Almost all attrition has been from customers moving.

Table C.6 below displays the dates CPEs were implemented during years 3 and 4 of the pilot for Group 1. An update for this group is provided below. The EM&V report for Group 1 was submitted to the Commission in Case No. 2022-00251.

Table C.6: CPE Dates Since August 1, 2022, for Group 1

CPE Date	Group 1
8/3/2022	X
7/26/2023	X
7/27/2023	X
7/28/2023	X
8/23/2023	X
8/24/2023	X
8/25/2023	X
1/17/2024	X
6/17/2024	X
6/20/2024	X
6/21/2024	X

Starting in May 2022, the Company launched a PTC pilot extension approved by the Commission to test the incentive amount offered to participants to reduce load during CPEs. This research extension is evaluating the difference in load impacts between a credit of $0.60 / kWh reduced, Group 2, and a credit of $1.20 / kWh reduced, Group 3. The EM&V report on the pilot extension was filed August 15, 2023, in Case No. 2023-00269. Using identical methods for acquiring customers, 667 customers enrolled in the $1.20 / kWh reduced offer, Group 3. In comparison, 679 customers enrolled in the $0.60 / kWh reduced offer, Group 2. The incentive amount did not appear to drastically impact the number of customers interested in enrolling in the pilot and participating throughout the summer.

In addition, the EM&V report filed in August 2023 included results from a post-CPE participant survey. The focus of the survey was to collect participant survey responses for comparison between the two incentive research groups. EM&V results were filed with the Commission in the Company's August 2023 DSM modifications filing and indicated that although the participants at the higher incentive rate were more satisfied, there was no statistically significant difference in the level of load reduction between the two levels of incentive.

As filed and approved, the incentive research extension to the pilot ended on September 30, 2022. The Company does not anticipate budget dollars needed for the incentive research extension in the July 2023 through June 2024 period.

As the Commission required continuation of the pilot program, a corresponding budget of $216,000 was granted to begin on July 1, 2023 and extends until June 30, 2024. The program parameters are still being established.

Response to Section 8 (3)(e)4

Table C.7: Energy Efficiency Program Costs

Energy Efficiency and DSM Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Residential															
Income Qualified Neighborhood	[redacted]														
Income Qualified Services															
My Home Energy Report															
Peak Time Rebate															
Power Manager®															
Residential Energy Assessments															
Residential Smart $aver®															
Total Residential															
Non-Residential															
PowerShare®															
Business Energy Saver															
Smart $aver® Non-Residential															
Total Non-Residential															
Total Energy Efficiency and DSM Programs															

Note: Program costs only. Does not include lost revenues or shared savings. Program costs beyond 2028 are estimated using the same inflation forecast as used in the IRP modeling.
Note: Program costs are estimates and do not reflect any approved program or budget changes beyond June 2023.

Response to Section 8 (3)(e)5

Table C.8: Energy Efficiency Avoided Costs

Energy Efficiency and DSM Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Residential															
Income Qualified Neighborhood	[redacted]														
Income Qualified Services	[redacted]														
My Home Energy Report	[redacted]														
Peak Time Rebate	[redacted]														
Power Manager®	[redacted]														
Residential Energy Assessments	[redacted]														
Residential Smart $aver®	[redacted]														
Total Residential	[redacted]														
Non-Residential	[redacted]														
PowerShare®	[redacted]														
Business Energy Saver	[redacted]														
Smart $aver® Non-Residential	[redacted]														
Total Non-Residential	[redacted]														
Total Energy Efficiency and DSM Programs	[redacted]														

Note: Avoided costs beyond 2028 are estimated using the estimated annual growth rate computed by Avoided Cost component
Note: Avoided costs do not reflect any approved program or budget changes beyond June 2023.

D

Appendix D: Environmental Regulations

Duke Energy Kentucky is required to comply with numerous state and federal environmental regulations. These regulations are changing at a rapid pace as the country moves towards an energy transition. Duke Energy Kentucky continuously monitors developments in these regulations and this Integrated Resource Plan has considered compliance costs with existing rules and regulations as part of the planning process, as well as, forecasting future regulatory actions that should be considered when making long-term decisions regarding generation mix. This combination will ensure Duke Energy can meet future resource needs and environmental requirements in a reliable and economic manner.

With respect to existing fully implemented air emission regulations, Duke Energy Kentucky has taken the necessary, prudent, and economic actions to attain full compliance. That includes, over the years, completing a performance upgrade on the East Bend Unit 2's original flue-gas desulfurization system (FGD) to reduce sulfur dioxide (SO_2) emissions for compliance with the evolution of Acid Rain Program, Clean Air Interstate Rule, Cross State Air Pollution Rule, and the National Ambient Air Quality Standards (NAAQS) requirements for sulfur dioxide. East Bend Unit 2 was also retrofitted with well performing selective catalytic reduction (SCR) for control of nitrogen oxide (NOx) emissions for compliance with Clean Air Interstate Rule, Cross State Air Pollution Rule and the National Ambient Air Quality Standards requirements for Ozone. Together with the existing electrostatic precipitator (ESP) for particulate matter (PM) control, these primary emission controls produce co-benefits for reduction of acid gases, mercury, and other Hazardous Air Pollutants for compliance with the Mercury and Air Toxics Standards Rule. The ESP recently underwent a complete refurbishment during the Spring 2018 planned maintenance outage.

With respect to waste and water environmental regulations, again East Bend Unit 2 is well positioned to continue operating in full compliance. East Bend Unit 2 has minimal exposure to cooling water discharge and intake related regulations (Clean Water Act 316(a) thermal and 316(b) aquatic impingement and entrainment) requirements since it uses a closed loop cooling tower system. Duke Energy Kentucky has not observed significant impacts to the aquatic communities due to the operation of this cooling system. The requisite aquatic studies and reports were submitted in 2019 and no significant findings were found. As a result, no modifications to the existing facilities were required.

For waste water discharge (Steam Electric Effluent Limitation Guidelines (ELG)), in concert with compliance with the Coal Combustion Residuals (CCR) Rule, East Bend Unit 2 has completed the installation of a dry bottom ash management system (flyash was already dry collected for utilization in the FGD product waste fixation system), along with other on-site water management equipment to enable cessation of all waste and water flows to the former bottom ash pond. The ash pond completed certified closure per CCR Rule requirements and has been converted to two lined retention basins to manage water flows. Additionally, Duke Energy Kentucky has recently completed and placed the new west landfill into service at East Bend Station. It is designed to accept and safely manage the CCR from East Bend Unit 2, including the bottom ash, and flyash-fixated FGD product (calcium sulfite) for years to come. Ongoing routine future landfill cell development costs were included in the analysis in this IRP. Lastly, looking further into the future of potential wastewater quality requirements, the recent ELG rule will have only a minor impact limited to addressing landfill leachate. A placeholder for such project cost was included in the IRP analysis for East Bend in the late-2020's timeframe.

Regulation of Greenhouse Gases

In 2007, the U.S. Supreme Court ruled in Massachusetts v. EPA that greenhouse gases are a pollutant subject to regulation under the CAA. Subsequently, the U.S. EPA has undertaken a number of rulemakings targeting greenhouse gas emissions from EGUs. On June 18, 2014, EPA proposed a rule, known as the Clean Power Plan (CPP) to regulate CO_2 emissions from existing fossil fuel-fired EGUs which was finalized on October 23, 2015. Numerous petitions for review were filed with the D.C. Circuit challenging the legal status of the CPP. On February 9, 2016, the U.S Supreme Court granted a stay of the CPP effective until its legal status is resolved.

On April 4, 2017, the U.S. EPA announced in the Federal Register that it is conducting a review of the CPP, in accordance with an Executive Order by the President issued on March 28, 2017. The EPA indicated that it "if appropriate, will as soon as practicable and consistent with law, initiate proceedings to suspend, revise or rescind this rule." On April 28, 2017, the D.C. Circuit issued an order temporarily suspending the litigation while it considers the EPA's motion to stay the litigation while the Agency reviews the rule.

On July 8, 2019, the EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established a process to develop CO_2 emission standards for existing coal-fired power plants. However, with a change in administration, the EPA on February 12, 2021, filed a motion with the D.C. Circuit asking the court to vacate the ACE rule but to stay the issuance of the mandate for the vacatur of the CPP repeal until the EPA can respond to the court remand in a new rulemaking regulating CO_2 emissions from existing coal-fired power plants. In a declaration and memorandum accompanying the U.S EPA's motion, the agency explains that it interprets the court's decision to have the effect of removing the ACE Rule but not reinstating the CPP. On February 22, 2021, the D.C. Circuit granted this motion.

On May 11, 2023, the EPA issued proposed CAA emission limits and guidelines for CO_2 from new and a subset of existing combustion turbine EGUs as well as existing fossil fuel-fired steam EGUs. These standards would be based on what the EPA considered to be cost-effective and available control technologies. The CAA Section 111 directs the U.S. EPA to use different approaches for new and existing sources of greenhouse gas emissions (GHG). For new sources of GHG emissions, CAA 111(b) requires the U.S. EPA to set federal standards for new, modified, and reconstructed sources.

For existing sources, under CAA 111(d), states submit plans for existing sources containing standards consistent with federal guidelines. On May 9, 2024, the EPA published New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units as a final rule which includes requirements under Section 111(b) for new combustion turbines, and under Section 111(d) for existing coal fired EGUs. East Bend is subject to the Section 111(d) provisions; however, litigation of this new rule has already begun.

In its final rule, the U.S. EPA has proposed two subcategories for coal-fired units, and a retirement option. For Long Term Coal-Fired Steam Generating Units installing and operating carbon capture and sequestration beginning in 2032 with 88.4% reduction from baseline may operate indefinitely. Medium Term Coal-Fired Steam Generating Units that elect to cease operations before January 1, 2039, must by January 1, 2030, begin co-firing 40% natural gas that results in a 16% reduction in emission rate compared to their baseline. Finally, units that elect to cease operations before January 1, 2032, have no restrictions. In addition, if a coal unit converts to firing 100% natural gas and intends to run past 2039, it must convert by January 1, 2030, and at by that time cease all firing of coal. These new requirements will impact East Bend and will be implemented as part of a State Plan submitted to EPA for its approval.

In the final rule, the EPA declined to finalize the proposed emissions standards for a subset of existing combustion turbines. The agency instead decided that it would develop an additional rule for addressing existing combustion turbines. On March 26, 2024, EPA opened a non-regulatory docket and issued framing questions to gather input regarding regulation of the entire fleet of existing gas combustion turbines in the power sector. EPA would undertake this rule making while also looking to update requirements such as the Combustion Turbine MACT Rule (see below). According to EPA's schedule, a new rule could be proposed as early as late 2024 or early 2025. The six Woodsdale units would likely be subject to this new rule.

Please see sections 2.C.3 and 3.B of this IRP for discussion of greenhouse gas emission regulation assumptions.

Mercury and Air Toxics Standard (MATS)

Hazardous Air Pollutant (HAPs) emissions from coal-fired and oil-fired electric generating units (EGU) greater than 25 MWs in capacity are regulated using National Emission Standards for Hazardous Air Pollutants (NESHAP) standards under Section 112 of the CAA. Using this authority, EPA issued the Mercury and Air Toxics Standard (MATS). MATS became effective on April 16, 2012, and compliance was required by April 16, 2015 (unless a facility requested a one-year extension). Specifically, MATS uses a command-and-control program that imposes unit-by-unit restrictions on the emission rates of mercury, acid gases such as hydrogen chloride, and certain non-mercury metals, including arsenic, chromium, nickel and selenium. The MATS Rule allows EGUs, as one option, to demonstrate compliance by measuring mercury, hydrogen chloride, and non-mercury metal emissions directly. It also allows EGUs the option of demonstrating compliance by measuring surrogates for acid gases and for non-mercury metals. East Bend began complying with MATS in April 2015.

Subsequently to the MATS rule, EPA conducted a Residual and Technology Review (RTR). In April 2024, EPA finalized a revision to the MATS rule with will require compliance in 2027. Specifically, EPA lowered the filterable PM limit used to demonstrate compliance with the metals emissions standards. The company is currently evaluating the changes EPA finalized in that 2024 rule, but it is believed that these changes have only limited impact on East Bend.

Under Section 112 of the Clean Air Act, EPA must evaluate NESHAP standards after 8 years to address any residual risks posed by the source category (called the “residual risk review”). Additionally, Section 112 requires the EPA, at least every 8 years on an ongoing basis, to review and revise as necessary the MACT standard taking into account developments in practices, processes and control technologies (called the “technology review”).

In 2020, EPA conducted the 8-year residual risk and technology review and determined that the standard was protective of human health and technology had not advanced to warrant updates to the standard. With the change in Administration, EPA was directed to review this decision and it subsequently issued a proposed rule to revise the MATS rule on April 24, 2023.

On April 25, 2024, EPA released a final regulation which details their conclusions regarding the reconsideration of the risk and technology review for the MATS standard. EPA determined that the 2020 technology review was flawed and that developments in control technologies require changes to filterable particulate matter standard (along with other revisions that are not applicable to Duke Energy). However, EPA concluded that the residual risk review appropriately concluded that the existing NESHAP provides an ample margin of safety to protect public health.

Under MATS, existing coal-fired EGUs can demonstrate compliance with the emission limits for non-Hg metal HAP by complying with compound specific standards, or by using filterable particulate as a surrogate. The final rule retains these compliance options for EGUs but lowered each of the associated emission limits. EPA finalized a filterable particulate emission standard of 0.010 lb/MMBtu, average on a 30-day rolling basis (lowered from 0.030 lb/MMBtu). Affected EGUs must demonstrate compliance with these updated limits by July 8, 2027, which is three years after the effective date of the Final Rule.

East Bend demonstrates compliance using the filterable particulate surrogate. To ensure that it can reliably meet the lower filterable particulate standard prior to July 8, 2027, Duke Energy Kentucky is evaluating capital projects that will be required on the electrostatic precipitators (ESP) and flue gas desulfurization (FGD) units. Initial cost estimates for these projects have been included in the IRP modeling efforts to ensure that compliance with the MATS regulation is factored into long-term planning decisions.

Ozone NAAQS

The Clean Air Act directs EPA to develop National Ambient Air Quality Standards (NAAQS) for six criteria pollutants including ozone. The NAAQS are periodically reviewed to ensure they reflect the latest science and are adequately protective. They include both a numerical limit, and the applicable averaging periods. Areas that meet the NAAQS are termed “attainment” areas and those not meeting the standards are “non-attainment” areas. States are required to submit plans that outline measures to be implemented that will bring non-attainment areas to come into compliance.

Section 109(d) of the Clean Air Act requires EPA to review and, if necessary, revise the NAAQS every five years. The ozone standard has been reviewed periodically and the existing primary and secondary standards, established in 2015, are 0.070 parts per million (ppm), as the fourth-highest daily maximum 8-hour concentration, averaged across three consecutive years.

On December 31, 2020, EPA completed its mandatory five-year NAAQS review and announced that it would retain the current 0.070 ppm standard. However, with a change in administration, EPA was directed to reconsider its 2020 decision. In April 2022, EPA published a draft Policy Assessment that recommended retaining the current ozone NAAQS. The Clean Air Scientific Advisory Committee (CASAC) provided extensive comments (June 9, 2023) to EPA on the Policy Assessment. In response to CASAC, the EPA Administrator published a letter (August 18, 2023) responding to the comments and announcing that EPA will begin its next statutory review of the ozone NAAQS and include the reconsideration process for the 2020 ozone NAAQS as part of this review. The Administrator stated that the updated review would be completed “as expeditiously as possible.” On August 25, 2023, EPA initiated the new review and subsequently filed an unopposed motion for voluntary remand of the 2020 actions.

Currently, the Greater Cincinnati area (which includes Boone, Campbell and Kenton Counties in Kentucky) is designated as a Maintenance Area under the 2015 8Hour Ozone NAAQS after formerly being designated as non-attainment. It is not possible to predict the outcome of the ongoing ozone NAAQS review efforts and any resulting implications to Duke Energy Kentucky’s operations. A tightening of the Ozone NAAQS could impact the attainment status of the Cincinnati area and lead to additional reductions in NOx emission allocations and/or imposition of short- term emission rate limits. These could eventually necessitate the need for an SCR performance upgrade. Once a new final standard is promulgated, the company will actively engage with State regulators to support the development of state implementation plans.

Interstate Transport – Ozone “Good Neighbor” Plans

In addition to requiring states to develop regulations to assure attainment of the NAAQS within their own borders, the CAA also requires that the States develop plans to identify and reduce any significant impact that they may have on non-attainment areas in downwind States. The Cross State Air Pollution Rule (CSAPR) has been EPA’s primary tool to implement this process. In February 2022, EPA proposed the Good Neighbor Plan for the 2015 Ozone NAAQS to amend CSAPR and further reduce NOx emission during ozone season. These ozone season requirements were promulgated as a Federal Implementation Plan (FIP) by EPA in response to findings that States within a 23-State region had not adopted adequate State Implementation Plans (SIPs) to address significant impacts on downwind non-attainment areas. Kentucky had filed a Good Neighbor SIP on January 11, 2019, which concluded that emission sources (including EGUs) within Kentucky do not have a significant impact on downwind non-attainment areas.

In February 2023, EPA disapproved nineteen states SIP's including Kentucky's submittal and imposed a FIP (The "Good Neighbor" Plan). The FIP will place additional restrictions on banking and usage of allowances and establish additional requirements that will reduce allowance allocations over time. The restrictions on banking started with the 2023 ozone season. The 2024 ozone season has a new set of requirements including a 0.14 lb/MMbtu back-stop limit for units with an SCR. The EPA will also implement Dynamic State Emission Budgets for allowance distribution in 2026. These rules are currently being litigated and the ultimate outcome cannot be predicted. However, on May 31, 2023, the US Court of Appeals for the 6th Circuit granted Kentucky's request for a stay of the Good Neighbor Plan as it applies to Kentucky. As a result, East Bend and other Kentucky EGUs remain subject to the requirements of the previous 2021 CSAPR revision.

The emission allowance program under CSAPR can impact compliance strategies. The projected allowance market price is a basis against which the costs of compliance are compared to determine the most economic options. The ozone season NOx allowance market is currently a significant driver in compliance planning due to the additional limitations on NOx budgets resulting from the "Good Neighbor" Plan.

The cost of NOx ozone season allowances is above the variable cost of SCR control and is an important factor on short-term planning impacting decisions relative to dispatch and operations and maintenance costs, as well as on longer term strategies to maintain environmental compliance. Duke Energy Kentucky has managed compliance with CSAPR's allowance-based requirements by managing East Bend's SCR performance. It manages emissions risk through use of measures such as the emissions allowance market. The most economic decision is dependent upon the current and forecasted market price of allowances, the cost and lead-time to install control equipment, and the current and forecasted market price of power. These factors will be reviewed as the markets change and the most economic emission compliance strategy will be employed.

PM2.5 NAAQS

As described earlier in this document, the EPA is directed to establish NAAQS for criteria pollutants including particulate matter. Particulates are regulated based on the size of the particle. Specifically, fine particulate matter is defined as particles that are 2.5 microns or less in diameter ($PM_{2.5}$) or particulates that are 10 microns or less in diameter (PM_{10}). Prior to the 2024 changes discussed below, EPA last revised the PM NAAQS in January 2013. The following table outlines the particulate NAAQS that were established in 2013.

Compound	Primary or Secondary Standard	Averaging Period	Standard	Form of the Standard
PM_{10}	Primary and Secondary	24-hour	150 mg/m^3	Not to be exceeded more than once per year on average over 3 years
$PM_{2.5}$	Primary	1-year	12 mg/m^3	Annual mean, averaged over 3 years
	Secondary	1-year	15 mg/m^3	
	Primary and Secondary	24-hour	35 mg/m^3	98^{th} percentile, averaged over 3 years

In December 2020, EPA published a final rule retaining the 2013 particulate NAAQS. However, with a change in administration, EPA announced in June 2021 that the Agency would reconsider the December 2020 decision “because available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the Clean Air Act.”

On February 7, 2024, EPA published a final rule resulting from the reconsideration of the particulate NAAQS. The final rule lowered the primary annual $PM_{2.5}$ NAAQS from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$ to reflect new science regarding particulate pollution. The final rule retains the remaining particulate standards at their current levels. Within two years after setting a new NAAQS or revising an existing standard, EPA must designate, based on the most recent set of air monitoring or modeling data, areas as meeting (attainment areas) or not meeting (nonattainment areas), the standards. In making these designations, a state could request that data collected during time periods which are considered “exceptional events” be excluded from consideration. For an area in moderate nonattainment, the SIP must provide for attainment as expeditiously as practicable but no later than the end of the sixth calendar year after nonattainment designations. Thus, according to EPA, 2032 is “likely the earliest possible year that states would need to demonstrate attainment of the standards.”

Based on current information, the Greater Cincinnati area (including Northern Kentucky) is likely to be designated as non-attainment. However, such a designation does not automatically result in emission limits or other control measures applicable to an emission source. Instead, the NAAQS create an obligation for states and EPA to develop lists of “nonattainment” areas where the $PM_{2.5}$ concentration in the air exceeds the new standards, then states develop (and EPA approves) SIPs that contain requirements necessary to achieve and maintain the NAAQS. How Kentucky would implement its obligations is not known at this time.

As to Duke Energy Kentucky, a likely impact of the more stringent PM NAAQS would be increased permitting requirements for projects that are located in a nonattainment area. Under the Clean Air Act, a new major source of air pollutants or a major modification to an existing source must obtain preconstruction permits, that demonstrate through air quality modeling that the source will not cause or contribute to a NAAQS violation.

Combustion Turbine (CT) MACT Rules

The EPA has identified stationary combustion turbines as major sources of HAP emissions. The NESHAP for combustion turbines (CT MACT) was promulgated in 2004. The regulation set emission standards for new turbines and provided for a number of subcategories. Shortly after promulgation, the EPA received a petition to "delist" several subcategories based on an assertion of limited risk from the sources, this included the lean premix combustion turbines firing natural gas with limited oil backup subcategory. No standards were proposed for existing combustion turbines in the 2004 rule.

On April 7, 2004, the EPA proposed to delist lean premix gas-fired turbines and three additional subcategories of turbines. At the same time, the EPA proposed to stay the effectiveness of the NESHAP for the affected subcategories to ''avoid wasteful and unwarranted expenditures on installation of emission controls which will not be required if the subcategories are delisted.'' The stay was finalized on August 18, 2004.

The proposal to delist the subcategories was never finalized in light of court decisions which addressed limits on the EPA's ability to delist subcategories. In the 2019 proposed residual risk and technology review for the Stationary Combustion Turbine NESHAP, the residual risk analysis did not support a conclusion that the entire Stationary Combustion Turbines source category met the criteria for delisting. Consequently, the EPA proposed to remove the stay of the standards for new lean premix and diffusion flame gas-fired turbines. When the RTR was finalized on March 9, 2020, EPA did not finalize the removal of the stay.

Concurrently, in August 2019, the EPA received a petition to delist the entire Stationary Combustion Turbines source category. While previous actions by the EPA determined that leaving the stay in place while the delisting petitions were reviewed, EPA concluded in 2022 that the new petition to delist the source category does not warrant any further delay in lifting the stay, and on March 9, 2022, the stay was lifted. Subsequently on April 16, 2024, the EPA denied the August 2019 petition. While the emission standards are now in place for new or reconstructed lean premix gas-fired turbines, there are no Duke Energy Kentucky generating units since the six Woodsdale units were constructed prior to 2004.

When the 8-year Risk and Technology Review was completed in March 2020, EPA determined that the standard was protective of human health and technology had not advanced to warrant updates to the standard. In May 2020, the EPA received a petition for reconsideration that addressed 1.) failure to remove the stay on applicability to new units. (resolved as described above) and 2.) not setting standards for HAP emissions that were previously unregulated. The petition was granted in August 2020, but is held in abeyance through July 2023. EPA subsequently initiated a limited Information Collection Request (ICR) to collect additional emissions data It is currently analyzing that limited data set and considering how it could inform a future rulemaking process.

As stated above, the EPA on March 26, 2024, opened a non-regulatory docket and issued framing questions to gather input regarding regulation of existing natural gas combustion turbines in the power sector. Along with the development of a NESHAP that will encompass existing combustion turbines, It is expected that the EPA will promulgate a suite of regulations focused on existing combustion turbines that includes limitations on greenhouse gas emissions and potentially revisions to the CT MACT.

CWA 316(a) and (b) Regulations

As stated previously East Bend Unit 2 is well positioned to remain in full compliance with Clean Water Act 316(a) thermal and 316(b) aquatic impingement and entrainment) requirements. The unit utilizes a closed loop cooling tower system as well as low velocity intake screens. Duke Energy Kentucky has not observed significant impacts to the aquatic communities due to the operation of this cooling system. The requisite aquatic studies and reports were submitted in 2019 and no significant findings were found. As a result, no modifications to the existing facilities were required.

Steam Effluent Guidelines (ELG)

The Clean Water Act (CWA) authorizes the US EPA to establish nationally applicable, technology-based ELGs for discharges from different categories of point sources, such as industrial, commercial, and public sources, for wastewater discharged to surface waters and municipal sewage treatment plants. The EPA issues these regulations for industrial categories based on the performance of treatment and control technologies. The limitations are incorporated into a station's National Pollutant Discharge Elimination System (NPDES) permit.

On September 30, 2015, the US EPA promulgated a rule revising the ELGs for the Steam Electric Power Generating point source category (the "2015 rule"). The 2015 rule addressed effluent limitations and standards for multiple waste streams generated by new and existing steam electric facilities: bottom ash transport water (BATW), combustion residual leachate (CRL), FGD wastewater, flue gas mercury control (FGMC) wastewater, fly ash transport water, gasification wastewater, and legacy wastewater. Challenges to the 2015 rule were filed and ultimately consolidated in the Fifth Circuit Court of Appeals. At the request of the EPA, the Fifth Circuit granted the request to sever and hold in abeyance claims related to 2015 rule limitations for FGD wastewater and BATW. With respect to claims related to limitations applicable to legacy wastewater and CRL, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations. In response to the 2015 rule, East Bend installed necessary equipment to meet the limits in the 2015 rule.

On August 31, 2020, the EPA promulgated the Steam Electric Reconsideration Rule (the "2020 rule"). The 2020 rule revised the 2015 rule requirements related to FGD wastewater and BATW at existing sources and established a subcategory for units that cease combustion of coal by December 31, 2028. This rule had no impact on East Bend as the revised limits could be met with the existing installed equipment.

On May 9, 2024, the US EPA published the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (the "2024 rule"). The rule establishes a no discharge limit for FGD wastewater, BATW, and CRL at sites combusting coal to be met no later than December 31, 2029. Stations that plan to cease coal operations by December 31, 2034 are exempt from the no discharge limits. Numeric limits for CRL at sites that no longer combust coal were included in the rule to be met no sooner than 120 days after combustion of coal ceases and no later than April 30, 2035.

East Bend is well equipped to meet the limits in the 2024 rule by having equipment installed to meet the no discharge limits for both FGD wastewater and BATW. Treatment options for CRL are under evaluation.

Coal Combustion Residuals (CCR)

EPA finalized the Legacy CCR Surface Impoundments rule on May 8, 2024, regulating inactive surface impoundments at retired facilities (legacy CCR surface impoundments) as well as previously unregulated areas of CCR on the land at regulated facilities (CCR management units). Specifically, with the exception of the 2015 CCR rule's location standards and liner design requirements, the Legacy CCR Surface Impoundments rule subjects legacy CCR surface impoundments to the full suite of regulatory requirements currently applicable to inactive CCR surface impoundments at active power plants. In addition, the Legacy CCR Surface Impoundments imposes a subset of the 2015 CCR rule's requirements on any area of land on which any noncontainerized accumulation of CCR is received, is placed, or is otherwise managed, that is not a regulated CCR unit. Owners/operators of all active facilities and any inactive facilities with a legacy impoundment are required to undertake a facility evaluation to identify CCR management units containing one ton or more of CCR. Any CCR management units that contain CCR in amounts equal to or greater than 1,000 tons are subject to the 2015 CCR rule's groundwater monitoring, corrective action, closure, and post-closure care requirements.

EPA also finalized changes to the closure-in-place performance standard, adding a new definition of "infiltration" to include horizontal movement of groundwater through the unit and revising the standard to require the elimination of free liquids before placement of the final cover system.

Duke Energy Kentucky does not have any legacy CCR surface impoundments; however, the company will be required to conduct a facility evaluation at East Bend Station to identify any accumulations of CCR on the land greater than one ton. The full impact of these changes has not yet been determined, but it is not expected to affect the facility's electric generating operations. However, additional investigation work, groundwater monitoring and potential remediation, and closure work will likely be required at East Bend Station.

Appendix E: Screening Curves

The following pages contain screening curves and associated data discussed in Chapter 4 of this filing. The cost and performance data for each technology being screened is based on research and information from several sources. Sources include a variety of internal departments at Duke Energy. In addition to the internal expertise, the following external sources may also be utilized: proprietary third-party engineering studies; the Electric Power Research Institute Technical Assessment Guide Web (TAGWeb®); and EIA. Additionally, fuel and operating cost estimates are developed internally by Duke Energy, from other previously mentioned sources, or a combination of the two. Duke Energy Kentucky and its consultants consider cost estimates provided by consultants to be confidential and competitive information. Duke Energy Kentucky also considers its internal cost estimates to be confidential and competitive information. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders.

Figure E.1: All Technologies Screening

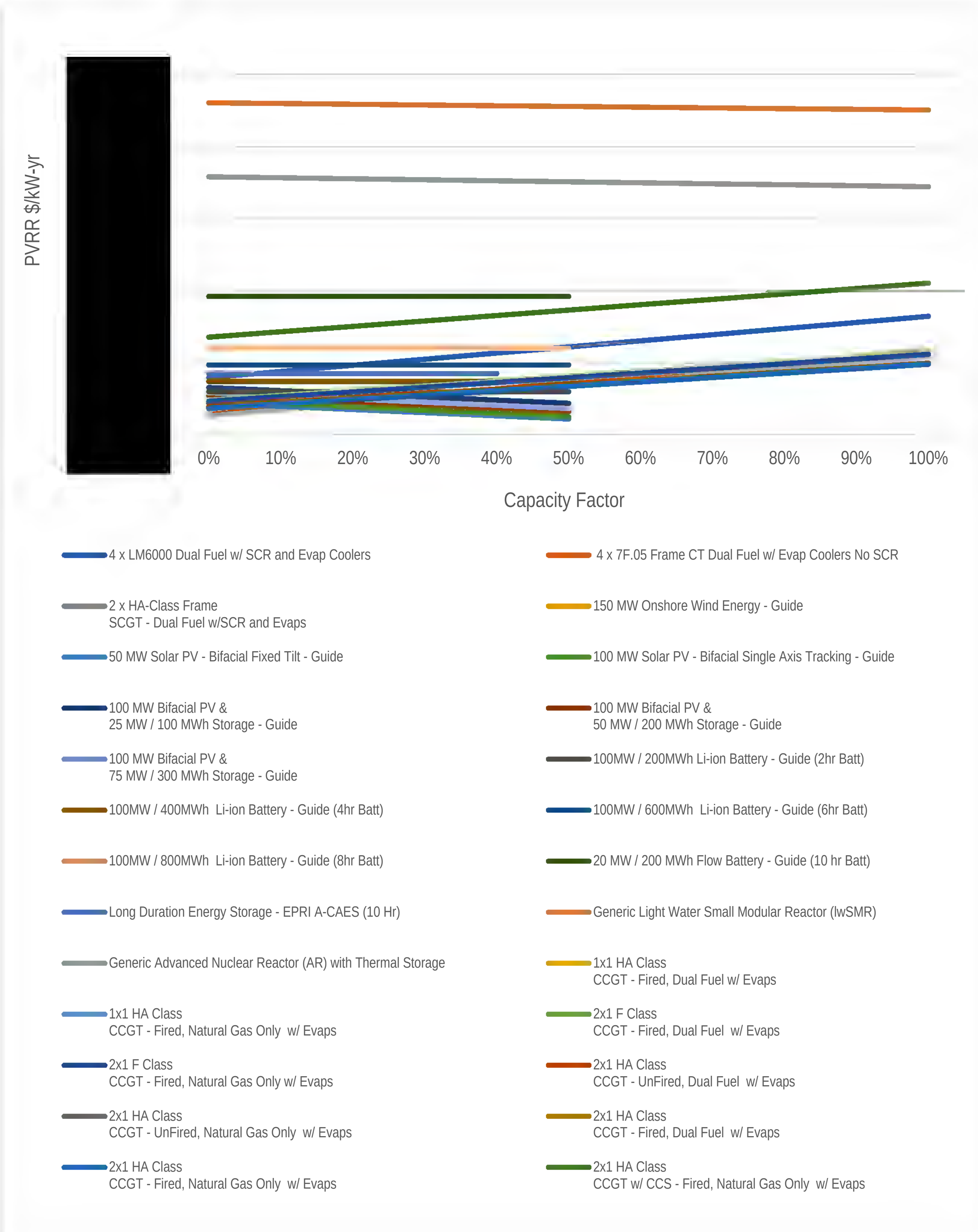


Figure E.2: Baseload Technologies Screening

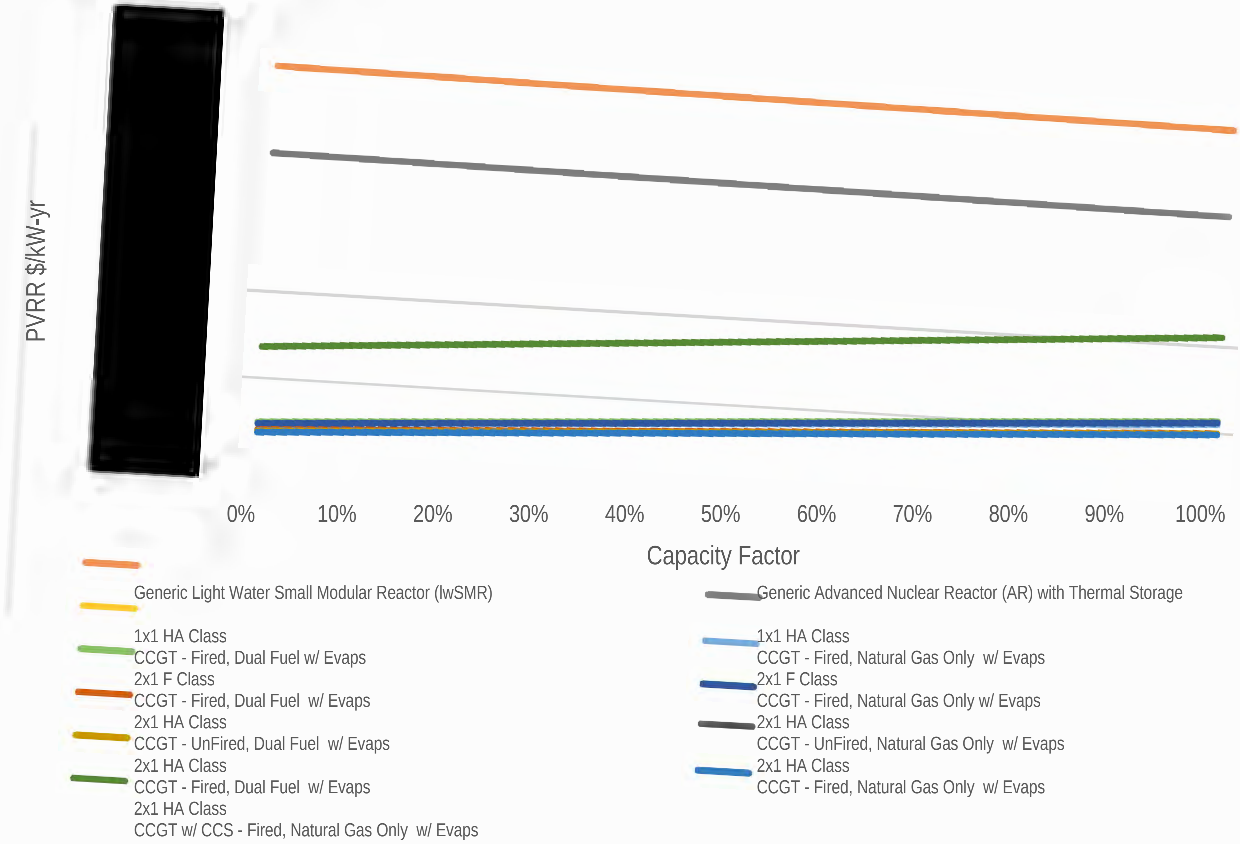


Figure E.3: Peaking Technologies Screening

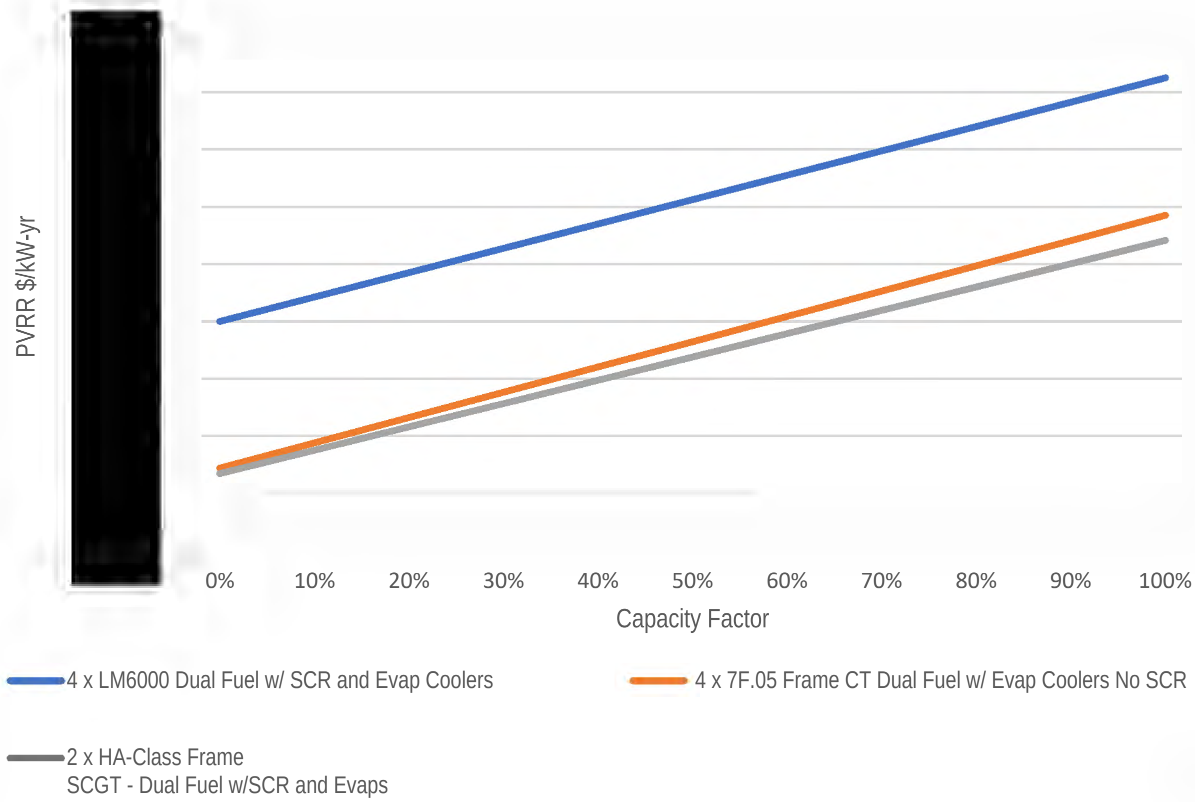


Figure E.4: Renewables Technologies Screening

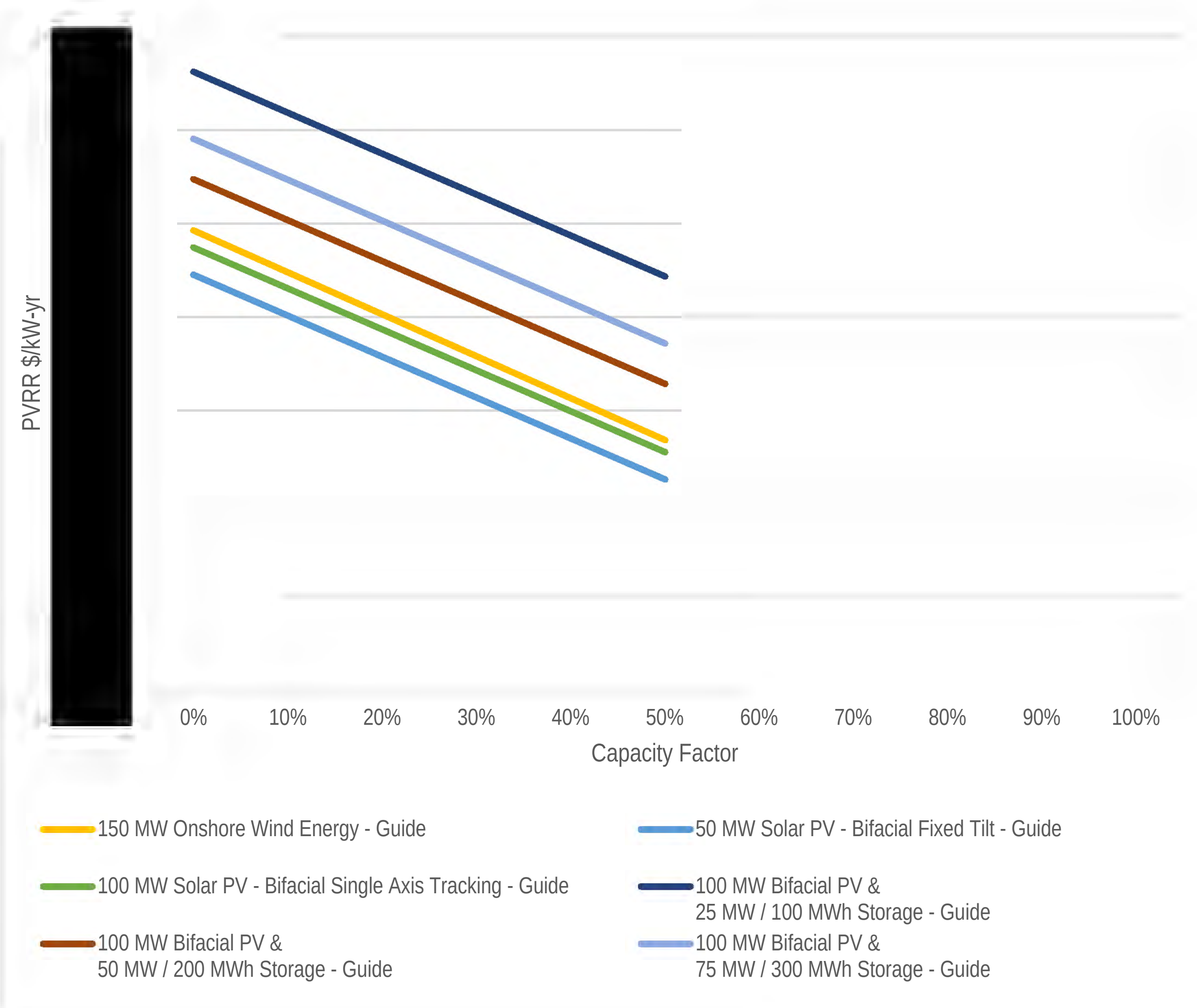
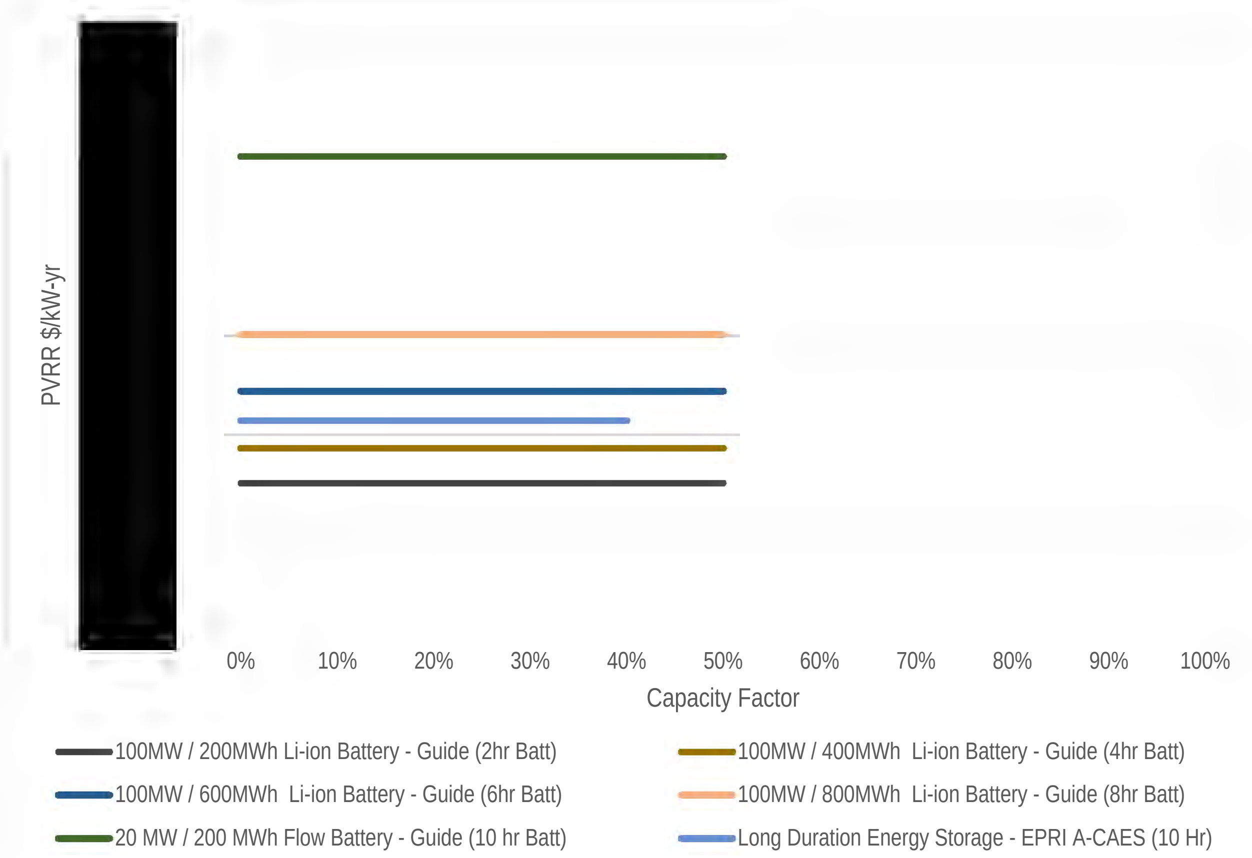


Figure E.5: Storage Technologies Screening



Appendix F: Response to 2021 IRP Staff Comments

A. Load Forecasting

Terminology

Duke Energy Kentucky should be consistent in its use of terminology and references. For example, the term “Internal” is applied to forecasts before the application of either the effects of EE or DR programs.44 However, Figures B-3b (before EE) and B-4b (after EE) both refer to Internal load. The term “Native” is applied to Internal forecasts reduced by DR but not EE.45 However, both Figures B-3a (before EE, after DR) and B-4a (after EE, after DR) refer to Native load. In addition, these tables contain references with no accompanying explanation of the same reference applied to different Items.

Response: The Company has removed the reference to “Internal” and instead the table titles now clearly and accurate describe data being presented. This change ensures clarity and consistency throughout the report.

Presentation of Forecasted Results (e.g., EE & DR)

1. Duke Energy Kentucky should be consistent in its presentations and calculation of forecasted results. For example, the forecasted effects of both EE and DR programs presented in IRP Figure 5.2 on page 41 do not match the effects of these programs inherent in the energy and demand forecasts in IRP Figures B-2a and B-2b on pages 97 and 98 and Figures B-3b and B-4b on pages 100 and 102, respectively. Inconsistent reporting of forecast results call into question the veracity of the results overall. Nonetheless, the program effects inherent in the Figures in Appendix B appear to be used as a starting point to design an appropriate resource portfolio.

   Response:

   The IRP Figure 5.2 values differ from those in Appendix B for several reasons described below:

   - EE Program Impacts (MWh): This EE impacts are higher by 2,027 MWh due to the inclusion of behavioral program impacts. However, for forecasting purposes, these impacts are excluded as they are already accounted for in the baseline actual. As such the savings reported in Appendix B is lower by 2,027 MWh.

- EE Program Impacts (MW): This column represents peak August reductions, which is not coincidental with the system peak reported in Appendix B.
- DR Program Impacts (MW): The DR impacts shown in Figure 5.2 are at the meter level. In the Appendix B, the DR impacts are grossed up for losses because the values are represented at the system-level.

Load Forecast - SAE Modeling

2. Though not discussed in any meaningful way, SAE modeling was used to forecast Residential, Commercial, and Industrial energy use. While becoming more common in modeling Residential and Commercial use, it is not as common to see SAE methods used for industrial classes. In the next IRP, Duke Energy Kentucky should provide detailed discussions of why SAE modeling is considered better than prior forms of modeling and how the various independent variables are derived. In addition, if SAE modeling continues to be used for the industrial class, there needs to be a discussion of the industrial appliance, equipment and process efficiencies being modeled, whether Itron tracks and forecasts these industrial factors, and the extent to which Duke Energy Kentucky has any influence over the growth or appliance saturation levels.

   Response:

   The current forecast was prepared used SAE methodology, which is generally a better approach compared to other methodologies. The SAE methodology offers several key features, including but not limited to the following:

   1. End-Use Breakdown: SAE allow for the decomposition of electricity consumption into specific end-uses (heating, cooling, other), enabling more precise forecasting.
   2. Efficiency trends: SAW incorporate behavior and technology usage patterns, through end-use intensities, leading to improved demand forecast accuracy.
   3. Scenario analysis: SAE enables scenario analysis by adjusting individual drives, providing greater flexibility and agility in the forecasting process.

   These advantages make the SAE methodology a more robust and accurate approach to forecasting, resulting in enhanced forecast.

   The current forecast did not utilize SAE methodology for industrial forecast.

3. The SAE methodology was used in the peak-demand modeling. As with the energy modeling, there was little discussion of how the methodology was applied to each of the independent model variables. For the next IRP, Duke Energy Kentucky should include greater discussion of how independent variables are constructed for both the energy and demand model.

   Response:

The regression models for residential and commercial sales uses the following specification.

$$\mathrm{USE}_t = b_1\mathrm{XHeat}_t + b_2\mathrm{XCool}_t + b_3\mathrm{XOther}_t + \varepsilon_t$$

where each of the variable is contructured as follows:

$$\mathrm{XHeat}_t = \mathrm{HeatIndex}_t + \mathrm{HeatUse}_t$$

where HeatIndex is the intensities from EIA and HeatUse is constructed as such:

$$\mathrm{HeatUse}_t = \left(\frac{\mathrm{HDD}_t}{\mathrm{NormHDD}}\right) x \left(\frac{\mathrm{HHSize}_t}{\mathrm{HHSize}_b}\right)^h x \left(\frac{\mathrm{Econ}_t}{\mathrm{Econ}_b}\right)^e x \left(\frac{\mathrm{Price}_t}{\mathrm{Price}_b}\right)^p$$

where HDD is heating degree days, HHSize is the household size, Econ is the economic variable, and Price is the average price for the specified class, XCool and XOther follows a similar design. However, the OtherUse includes billing days instead of weather.

$$\mathrm{OtherUse}_t = \left(\frac{\mathrm{BillingDays}_t}{365}\right) x \left(\frac{\mathrm{HHSize}_t}{\mathrm{HHSize}_b}\right)^h x \left(\frac{\mathrm{Econ}_t}{\mathrm{Econ}_b}\right)^e x \left(\frac{\mathrm{Price}_t}{\mathrm{Price}_b}\right)^p$$

For Industrial and OPA, the regression specifications are not based on SAE methodology. The following specification is used:

$$\mathrm{IndUSE}_t = b_1\mathrm{XEcon}_t + b_2\mathrm{XWeather}_t + \varepsilon_t$$
$$\mathrm{OPAUSE}_t = b_1\mathrm{XEcon}_t + b_2\mathrm{XWeather}_t + \varepsilon_t$$

The peak model uses the following model:

$$\mathrm{Peak}_t = b_1\mathrm{HeatVar}_t + b_2\mathrm{CoolVar}_t + b_3\mathrm{Other}_t + b_3\mathrm{Energy}_t + \varepsilon_t$$

where HeatVar, CoolVar, and OtherVar are from sales model and Energy is monthly energy.

Regarding the selection of variables (e.g., economic, weather, indicators, etc.), the Company utilizes a combination of judgement and model performance to determine which variables are included in the model.

Load Forecast - Sensitivity Analysis

4. The sensitivity analyses were based on variations in economic activity only. While reasonable, modeling variations in weather, separately and in conjunction with economic activity, would also be reasonable. Modeling the extremes (however defined) of both economic activity and weather together to set plausible upper and lower limits to energy and demand forecasts is prudent. For the next IRP, Duke Energy Kentucky should model more diverse sensitivity analyses, including projected variations in weather.

   Response: The forecasts include a sensitivity analysis using varying levels of electric forecasts, different weather assumptions, and different economic projections from Moody's. The table below details the assumptions used for each forecast to create base, low, and high cases.

	Economic	Weather	Electric Vehicle
Low	Pessimistic	15 most mild years Average	Base
Base	Base	30-year Average	Base
High	Optimistic	15 most extreme years average	High

Load Forecast - Variations of Variables

5. For models in which two variations of the same variable are used, there needs to be additional explanation of why it is appropriate to include such closely related variables as there often does not appear to be any statistically significant collinearity between the variables. Simply improving the regression R-squared value is not a sufficient reason to include both variables. The discussion should also identify and describe the separate effects these variables have on the dependent variable.

   Response: The Company updated its model to only include one variable each for cooling, heating, and other in the regression analysis.

B. Demand-Side Management and Energy Efficiency

6. Duke Energy Kentucky's next IRP should include a detailed explanation of whether peak-time rebates decrease Duke Energy Kentucky's demand and avoid costs as suggested in Case No. 2019-00277, and if so, it should explain how the peak-time rebates decrease Duke Energy Kentucky's demand and avoid costs.

   Response: Duke Energy Kentucky requested to terminate the Peak Time Rebate program in Case No. 2022-00251 due to the low cost effectiveness scores. The Commission scheduled a hearing for March 23, 2023, and an Order was submitted on April 1, 2024 stating the Company should provide the implementation plan based on the order no later than August 15, 2024.

7. The next IRP should also discuss other DSM rate options that Duke Energy Kentucky has explored.

   Response: Duke Energy Kentucky offers several time of use (TOU) based rates to non-residential customers to assist them with managing their bills including Rate RTP, Rate DT, Rate TT, and Rider LM. In addition, the Company currently has a pending TOU residential rate option in Case No. 2022-00372; Rate RS-TOU-CPP. However, these TOU rates are not offered through the Company's DSM portfolio of programs. They are either mandatory or optional rates customers can consider to help manage their bill.

8. Duke Energy Kentucky should continue to examine all reasonable DSM programs for cost-effectiveness and possible implementation regardless of whether they are available year around.

   Response: The Company continues to do this and provides an update on cost effectiveness for every program in the Annual Cost Recovery Filing for Demand Side Management

9. Duke Energy Kentucky should continue to scrutinize the results of each existing DSM program's individual measure's cost-effectiveness test and continue to provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. Duke Energy Kentucky should also be mindful of the increasing saturation of EE products and be watchful for

the opportunity to scale back on programs offering incentives for behavior that may be dictated by factors other than the incentives.

Response: The Company continues to do this and provides an update on cost effectiveness for every program in the Annual Cost Recovery Filing for Demand Side Management and only requests future individual measures that meet the cost-effectiveness tests standards.

10. Commission Staff encourages Duke Energy Kentucky to continue with the DSM Collaborative process and strive to include recommendations and inputs from the stakeholders.

    Response: The Company continues to meet with the DSM Collaborative on an annual basis and as needed.

11. Duke Energy Kentucky should evaluate low-income DSM programs in other jurisdictions and analyze whether such programs would be effective in Duke Energy Kentucky's service territory.

    Response: The Company monitors programs in other jurisdictions and requests changes to the Kentucky programs as deemed necessary.

12. For the next IRP, Duke Energy Kentucky should present its portfolio analyses results with a demand forecast that considers the effects of both EE and DR programs.

    Response: All portfolios were developed with the inclusion of EE and DR forecasts.

D. Resource Capacity Values

13. "…presenting resource capacity values on an ICAP basis is informative; however, since PJM required reserve margins are calculated on a UCAP basis, presenting resource capacity values and reserve margins on a UCAP basis provides a different perspective. This view is important as increasing amounts of renewable generation resources are added to the generation mix. For the next IRP, Duke Energy Kentucky should present results on both an ICAP and UCAP basis.

    Response: Duke Energy Kentucky utilized the PJM Delivery Year 2025/2026 Forecasted Pool Requirement and ELCC ratings to generate UCAP values for reserve margin and existing/future resources. Please review Section 6 of this document for the ICAP and UCAP resource values.

Wind Resource Addition and In-/Out-of-Territory Costs

14. The optimal portfolio shows the addition of wind resources starting with 40 MW's and then adding 10 MW blocks annually beginning in 2024 and 10 MW blocks of solar annually beginning in 2021. Kentucky is not typically selected for utility scale wind resources. Even though wind appears to be a cost-effective resource addition to the portfolio, a greater explanation of the practicality and underlying assumptions would lend credence to the selection. Also, even though there are many merchant-utility scale projects being proposed and possibly built in Kentucky, none are being proposed in Duke Energy Kentucky's service territory. For the next IRP, Duke Energy Kentucky

should discuss for planning purposes whether these renewable resources will be realistically located in its service territory, in Kentucky or out of state. Also, for resources that are located outside its service territory, the estimated cost of wheeling the energy should be included in the analyses and whether Duke Energy Kentucky is acquiring the capacity and energy through direct ownership, a partnership, or through a PPA.

Response: Duke Energy Kentucky provided a detail explanation regarding the potential selection and risks associated with wind resources, both in-and-out of Duke Energy Kentucky's service territory. Please review Section 3 of this documents for the detailed explanation.

Solar Panel Performance

15. The efficiency of solar PV units varies with temperature swings, which impacts its effectiveness in meeting PJM capacity requirements and in meeting Duke Energy Kentucky's needs. For the next IRP, Duke Energy Kentucky should discuss how the evolving performance of solar panels varies and how those variations affect Duke Energy Kentucky's ability to meet its energy and capacity obligations.

    Response: There have been significant increases in the efficiency of solar technologies in recent years and this has provided greater power density for solar cells. Along with increases in the physical dimensions of modules has allowed for greater power output per individual module. This, in turn, has led to better land utilization for solar array area compared to those built years ago. This trend is expected to continue but at a slower rate in the near future.

    The PV module output is affected by the operating temperature of the cells within the solar module. Conversion efficiency decreases because higher cell temperatures result in a decrease in module output voltage. This effect is well known and is accounted for in the DC system design. Typically, this is addressed by installing significantly more DC nameplate capacity than interconnected AC capacity, so the system will perform as required under typical operating conditions.

    Solar irradiance is the primary driver of the output of a PV cell and dictates the current output. The basic relationship of current and voltage is constantly changing in a PV system and is controlled by the weather. The system DC and AC functionality is also modeled dynamically across a wide range of typical weather conditions to better understand the operational power and energy characteristic of the system to determine the energy and capacity expectations.

    Through design and incorporation into forecasts, variations in solar panel efficiency do not impact Duke Energy Kentucky's ability in meeting energy and capacity obligations.

PJM Reliability

16. As renewable resources are added to Duke Energy Kentucky's and within PJM's service territories, operational and reliability challenges from intermittent resources could arise. For the next IRP, Duke Energy Kentucky should discuss any issues that it or PJM is facing currently or in the near future, and if there were any issues, how they would be addressed.

Response: As more intermittent resources come online in PJM, and as dispatchable resources retire, PJM will face operational challenges as uncertainty around performance of intermittent resources at all times of day could create potential issues. In PJM's recent capacity filings in which all resources are moving toward an ELCC framework, dispatchable generation will be more valuable relative to intermittent resources as far as capacity accreditation. This may encourage dispatchable generation to remain online, and possibly to enter the market with likely higher capacity payments.

F. Environmental Laws and Impacts

17. For the next IRP, Duke Energy Kentucky should provide an update to the latest environmental laws and any actions it has taken recently or is planning to take for compliance.

    Response: Appendix D contains updated information on environmental laws and regulations that have changed since the 2021 IRP. Specifically, the sections on the Regulation of Greenhouse Gases and the Mercury and Air Toxics Standard (MATS) rule contain the most impactful developments. Modeling scenarios as described in Sections 2 & 3 were developed that reflect the most recent (April 2024) greenhouse gas rule.

Carbon Regulation

18. Carbon regulation can take several forms, from gradually increasing prices, set prices and market clearing prices as well as physical emission limitations and how the carbon regulations are applied to which fossil resources. Each will have different impacts on the degree to which resource portfolios/generation fleets evolve over time and the subsequent impact on customers' bills. For the next IRP, Duke Energy Kentucky should test the sensitivity of its portfolios to various forms of carbon regulation. The analyses should include detailed explanations of the underlying assumptions.

    Response: Appendix D contains updated information on greenhouse gas requirements that EPA finalized in April 2024. Modeling scenarios as described in Sections 2 & 3 were developed that reflect that rule.

Carbon Capture and Sequestration

19. In addition, Duke Energy Kentucky should include a discussion of the state of carbon capture and sequestration and its potential viability.

    Response: Section 4 addresses carbon capture and sequestration and its potential viability.

Appendix G: Response to Requirements Matrix

Rule Section		Document Section	Document Sub-section
5. Plan Summary	(1)	1. Executive Summary	A. Duke Energy Kentucky Overview
	(2)	2. Objectives and Process	C. 4. Forecasting Methods
	(3)	3. Future Resource Considerations; Appendix B - Electric Load Forecast	C. Load Forecast
	(4)	1. Executive Summary; Appendix A - Transmission	B. Integrated Resource Plan; C. Three-Year Implementation Plan; B. Section 5 Plan Summary Response
	(5)	1. Executive Summary	C. 3-Year Implementation Plan
	(6)	2. Objectives and Process	C. 1. Developing a Base Case
6. Significant Changes		1. Executive Summary	B. Integrated Resource Plan
7. Load Forecasts	(1)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (a)	Appendix B - Electric Load Forecast	C. Assumptions
	(2) (b)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (c)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (d)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (e)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (f)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(2) (g)	Appendix C - Energy Efficiency and Demand-Side Management	
	(2) (h)	Appendix B - Electric Load Forecast	
	(3)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(4) (a)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy

	(4) (b)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(4) (c)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(4) (d)	Appendix B - Electric Load Forecast	F. Forecasted Demand and Energy
	(4) (e)	Appendix B - Electric Load Forecast	
	(5)	Exempt	
	(7) (a)	Appendix B - Electric Load Forecast	D. Data Base Documentation
	(7) (b)	Appendix B - Electric Load Forecast	C. Assumptions
	(7) (c)	Appendix B - Electric Load Forecast	B. Forecast Methodology
	(7) (d)	3. Future Resource Considerations	C. Load Forecast
	(7) (e)	Appendix B - Electric Load Forecast	B. Forecast Methodology C. Assumptions
	(7) (f)	Appendix B - Electric Load Forecast	D. Data Base Documentation
	(7) (g)	Appendix B - Electric Load Forecast	D. Data Base Documentation
8. Resource Assessment and Acquisition Plan	(1)	7. 2024 Integrated Resource Plan	
	(2) (a)	4. Supply-Side Management Resources Appendix A - Transmission and Distribution Forecast	B. Existing Resources 3. Section 8 Resource Assessment and Acquisition Plan
	(2) (b)	Appendix C - Energy Efficiency and Demand-Side Management	
	(2) (c)	4. Supply-Side Management Resources	A. Process Description
	(2) (d)	4. Supply-Side Management Resources	A. Process Description
	(3) (a)	Provided to KyPSC Staff separately under seal	
	(3) (b)	Appendix H - Financial & Operating Projects Over Planning Period	
	(3) (c)	Appendix H - Financial & Operating Projects Over Planning Period	
	(3) (d)	Appendix H - Financial & Operating Projects Over Planning Period	
	(3) (e)	Appendix C - Energy Efficiency and Demand-Side Management	Response to Section 8 (3)(e)4
	(4) (a)	Appendix H - Financial & Operating Projects Over Planning Period	
	(4) (b)	Appendix H - Financial & Operating Projects Over Planning Period	
	(4) (c)	Appendix H - Financial & Operating Projects Over Planning Period	
	(5) (a)	3. Future Resource Considerations	

	(5) (b)	3. Future Resource Considerations	
	(5) (c)	2. Objectives and Process	
	(5) (d)	4. Supply-Side Management Resources	B. Existing Resources
	(5) (e)	7. 2024 Integrated Resource Plan	B. Key Variables to Monitor Ahead of 2027 IRP
	(5) (f)	Appendix D - Environmental Regulations	
	(5) (g)	2. Objectives and Process; 3. Future Resources	C. 4. Forecasting Methods; B. Power Prices
9. Financial Information	(1)	3. Future Resource Considerations	F. Responses to Rule Section 9: Financial Information
	(2)	3. Future Resource Considerations	F. Responses to Rule Section 9: Financial Information
	(3)	3. Future Resource Considerations	F. Responses to Rule Section 9: Financial Information
	(4)	3. Future Resource Considerations	F. Responses to Rule Section 9: Financial Information

Appendix H: Financial & Operating Projections Over Planning Period

Table H.1 – Existing and Planned Generation Existing and Planned Electric Generating Facilities Included in Resource Acquisition Plan

Station	Unit No.	Status	Location	Commercial Operation Year	Planned Retirement Date	Type	Primary Fuel	Secondary Fuel	Firm Summer Rating (MW)	Firm Winter Rating (MW)
East Bend[1]	2	Existing	Boone County, KY	1981	2039	ST	Coal	Gas (2030)	499.0	499.0
Woodsdale[2]	1	Existing	Trenton, OH	1993	Unknown	CT	Gas	Oil	57.9	69.8
	2	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	67.6	79.5
	3	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	63.8	75.0
	4	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	64.7	78.0
	5	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	67.0	78.7
	6	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	67.0	78.7
Walton 1&2 Solar		Existing	Kenton County, KY	2017	Unknown	PV	Sunlight	None	0.4	0.4
Crittenden Solar		Existing	Grand County, KY	2017	Unknown	PV	Sunlight	None	0.3	0.3
Aero Solar		Existing	Boone County, KY	2022	Unknown	PV	Sunlight	None	0.2	0.2
Solar 2029		Planned	TBD	2029	Unknown	PV	Sunlight	None	2.0	2.0
Solar 2031		Planned	TBD	2031	Unknown	PV	Sunlight	None	3.0	3.0
Solar 2033		Planned	TBD	2033	Unknown	PV	Sunlight	None	2.0	2.0
Solar 2035		Planned	TBD	2035	Unknown	PV	Sunlight	None	2.5	2.5
Solar 2037		Planned	TBD	2037	Unknown	PV	Sunlight	None	2.5	2.5
Solar 2039		Planned	TBD	2039	Unknown	PV	Sunlight	None	2.5	2.5
Combined Cycle[3]		Planned	Boone County, KY	2039	Unknown	CC	Gas	Oil	502.3	524.5

Fuel Storage Capacity by Resource:

1. East Bend primary fuel storage capacity is approximately 550,000 tons of coal
2. Woodsdale Station secondary fuel storage capacity is approximately 4 million gallons of oil
3. 2039 Combined Cycle secondary fuel storage capacity is approximately 2 million gallons of oil

Table H.2 – Generation Operational Characteristics

East Bend	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Fixed O&M + Maintenance Capital	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	
EB2 Limestone Conv, DFO Conv, and Firm Transport Costs	[redacted]																	

Woodsdale CT's	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	
Fixed O&M + Maintenance Capital	[redacted]																	

Existing Solar	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	

	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Fixed O&M + Maintenance Capital	[redacted]																	
Future Solar - Tracking	**Units**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	
Fixed O&M + Maintenance Capital	[redacted]																	
Future Solar - Fixed Tilt	**Units**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	
Fixed O&M + Maintenance Capital	[redacted]																	
New 1x1 CC	**Units**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Availability	[redacted]																	
Capacity Factor	[redacted]																	
Average Heat Rate	[redacted]																	
Fuel Cost	[redacted]																	
Variable O&M	[redacted]																	
Average Variable Cost	[redacted]																	
Average Total Production Cost	[redacted]																	
Fixed O&M + Maintenance Capital + Firm Transport Costs	[redacted]																	

Table H.3 Load and Resources

Summer	Units	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Peak Load	MW	808	810	812	812	812	812	822	827	831	838	844	862	872	882	892	902	910
Firm Capacity From:																		
Existing Generation	MW	888	888	888	887	887	887	887	887	887	887	887	887	887	887	887	388	388
Demand Response	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Utility Owned Resources	MW	0	0	0	0	0	2	2	5	4	6	6	9	9	11	11	516	516
Purchases/Sales	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	499	0
Firm Capacity (Total)	MW	888	888	888	888	888	890	889	892	891	893	893	896	896	898	898	904	904
Forecast Pool Requirement (FPR) = 0.94	MW	758	760	762	762	762	762	772	777	780	787	792	809	819	828	837	847	854
Capacity Excess /(Deficit)	MW	80	78	76	76	75	77	67	65	60	55	50	34	24	16	7	2	(5)
Reserve Margin*	%	10%	10%	9%	9%	9%	10%	8%	8%	7%	7%	6%	4%	3%	2%	1%	0%	-1%
Winter	**Units**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Peak Load	MW	748	737	738	740	740	739	747	749	746	755	759	774	777	779	778	798	808
Firm Capacity From:																		
Existing Generation	MW	959	959	959	959	959	959	959	959	959	959	959	959	959	959	959	460	460
Demand Response	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Utility Owned Resources	MW	0	0	0	0	0	2	2	5	4	6	6	9	9	11	11	538	538
Purchases/Sales	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	499	0
Firm Capacity (Total)	MW	959	959	959	959	959	961	960	963	962	965	965	967	967	970	970	998	998
Forecast Pool Requirement (FPR) = 0.94	MW	702	691	692	694	695	694	701	704	701	709	713	727	730	731	730	749	759
Capacity Excess /(Deficit)	MW	211	223	222	220	219	222	214	214	216	210	205	193	190	191	192	200	190
Reserve Margin*	%	28%	30%	30%	30%	30%	30%	29%	29%	29%	28%	27%	25%	24%	25%	25%	25%	23%

* Required Reserve Margin = (FPR-1) = -6.13%

Table H.4 – Energy Supply

Gigawatt Hours	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Forecast Energy Requirement	[redacted]																
Energy From Existing and Planned Resou	[redacted]																
Coal	[redacted]																
Gas	[redacted]																
Solar	[redacted]																
Energy Purchased from PJM Market	[redacted]																
Purchases (% of Total Load)	[redacted]																

Table H.5- Fuel Burns

Fuel Requirements	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal	[redacted]																
000's of Tons	[redacted]																
k MMBtu	[redacted]																
Gas	[redacted]																
Mcf	[redacted]																
k MMBtu	[redacted]																

Glossary of Terms

Acronym / Defined Term	Term
2021 IRP	2021 Integrated Resource Plan
2024 IRP	2024 Integrated Resource Plan
ABM	Account Based Marketing
AC	Air conditioning
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
BATW	Bottom ash transport water
BES Program	Business Energy Saver program
BPI	Building Performance Institute
BRC	Business reply card
BSER	Best System of Emission Reduction
BYOT	Bring Your Own Thermostat
CAA	Clean Air Act
CASAC	Clean Air Scientific Advisory Committee
CC	Combined Cycle
CC w/CCS	CC paired with Carbon Capture and Sequestration
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CEII	Critical energy infrastructure information
CO_2	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CPE	Critical Peak Events
CPP	Clean Power Plan
CRL	Combustion residual leachate
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CWA	Clean Water Act
DEOK	Duke Energy Ohio/Kentucky
DERs	Distributed Energy Resources

DFO	Dual Fuel Operation
DIY	Do it yourself
DOE	Department of Energy
DR	Demand response
DSM	Demand-Side Management
Duke Energy	Duke Energy Corp.
Duke Energy Kentucky, the Company	Duke Energy Kentucky, Inc.
Duke Energy Ohio	Duke Energy Ohio, Inc.
EE	Energy Efficiency
EGU	Electric Generating Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, measurement, and verification
EPA	Environmental Protection Agency
EPA CAA Section 111 Update	Environmental Protection Agency Clean Air Act Section 111 April 2024 Update
EPIC	Energy Planning and Inventory Commission
ER	Early Replacement
ESP	Electrostatic precipitator
EV	Electric vehicle
FDR	Future Dispatchable Resource
FEED	Front-End Engineering and Design
FERC	Federal Energy Regulatory Commission
FERC 2222	FERC Order 2222
FGD	Flue-gas desulfurization
FGMC	Flue gas mercury control
FIP	Federal Implementation Plan
FRR	Fixed Resource Requirement
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutant
HEHC	Home Energy House Call

HER	Home Energy Report
HP	Heat pump
ICAP	Installed capacity
ICEV	Internal combustion energy vehicles
ICR	Information Collection Request
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IRA	Inflation Reduction Act
IRP	Integrated resource plan
ITC	Investment Tax Credit
kWh	Kilowatt-hour
KyPSC	Kentucky Public Service Commission
LED	Light emitting diode
MACRS	Modified accelerated cost recovery system
MATS	Mercury and Air Toxics Standards
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEAT	National Energy Audit Tool
NEIF	National Energy Improvement Fund
NEMS	National Energy Modeling System
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance
OPA	Other Public Authorities
PCT	Participant Cost Test
PJM	PJM Interconnection LLC
PM	Particulate matter
PMSA	Primary Metropolitan Statistical Area

Ppm	Parts per million
Preferred Portfolio	2024 IRP Preferred Portfolio
PTC	Production Tax Credit
PV	Present value
PVRR	Present Value Revenue Requirements
Real manufacturing GDP	Real gross manufacturing product
RIM	Rate Impact Measure
ROF	Replacement on Failure
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
RTR	Residual and Technology Review
SAE	Statistically Adjusted End-Use
SB349	Kentucky Senate Bill 349
SB4	Kentucky Senate Bill 4
SCR	Selective catalytic reduction
SEWK	Save Energy and Water Kit
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO2	Sulfur dioxide
Solar PV	Solar Photovoltaic
Store	Online Savings Store
TA	Trade Allies
The 2020 rule	EPA Steam Electric Reconsideration Rule (August 2020)
The 2024 rule	Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (May 2024)
TOU	Time of Use
TRC	Total Resource Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test