DUKE ENERGY KENTUCKY

20 TWENTY-ONE INTEGRATED RESOURCE PLAN

CONFIDENTIAL

CONTENTS

APPENDICES

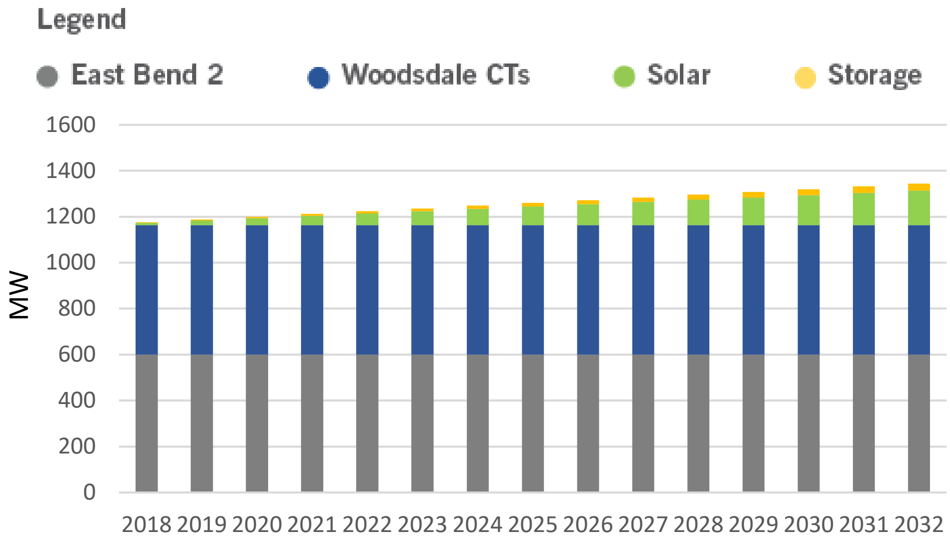
SECTION 1

EXECUTIVE SUMMARY

A. INTEGRATED RESOURCE PLAN

In its 2018 Integrated Resource Plan (IRP), Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) reflected the continued operation of its existing generating resources,[1] supplemented by modest amounts of renewable generation over a fifteen-year period. As such, the 2018 IRP reflected 12% of resources in 2030 from renewable sources, growing to 13% in 2032, the final year of the IRP period.

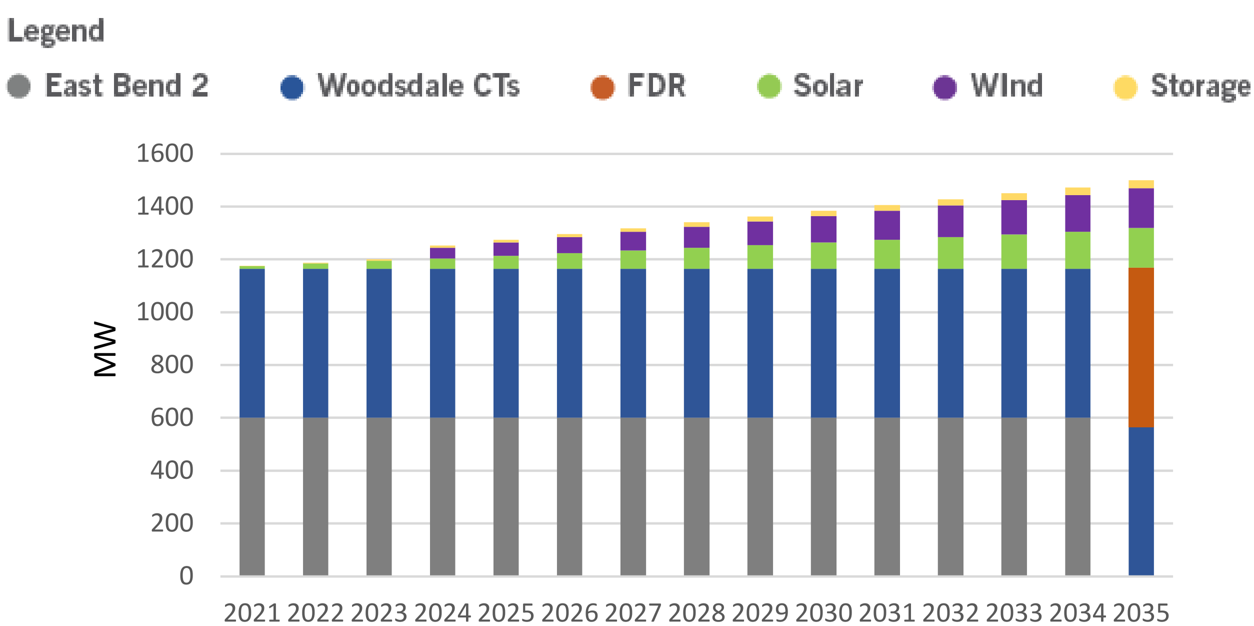
Figure 1.1 – Summary of 2018 DEK IRP



[1] These resources include the East Bend Generating Station, a 600 MW coal plant, and the Woodsdale Station, a 564 MW dual-fuel peaking plant.

The Company's 2021 IRP shares some of the same characteristics as the 2018 plan – it reflects the continued operation of existing generating resources and increasing amounts of renewable generation. The 2021 IRP however, reflects an earlier retirement of the East Bend generating station in 2035 versus the 2041 date in the 2018 IRP. The earlier retirement date is based on several factors, including: (1) likely regulations increasing the costs to operate and maintain the plant; (2) increasing fuel supply risk in the next decade; (3) declining costs of renewable energy resources; and (4) other factors that are likely to increase the costs of the plant to customers. The 2021 IRP reflects replacement of East Bend capacity with a Firm Dispatchable Resource (FDR) 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. The FDR was modeled with operational characteristics and costs of a natural gas combined cycle as a placeholder, recognizing the opportunity to revisit technology selection prior to the Certificate of Public Convenience and Necessity (CPCN) process when the most recent information would be available regarding technology advancements and federal regulations or expansion of clean energy incentives. The 2021 IRP further suggests additional sources of renewable power, beyond those disclosed in prior plans. As discussed in greater detail below, the 2021 IRP proposes 16% of renewable resources in 2030, growing to 22% in 2035, the final year of the IRP period.

Figure 1.2 – Summary of the 2021 DEK IRP



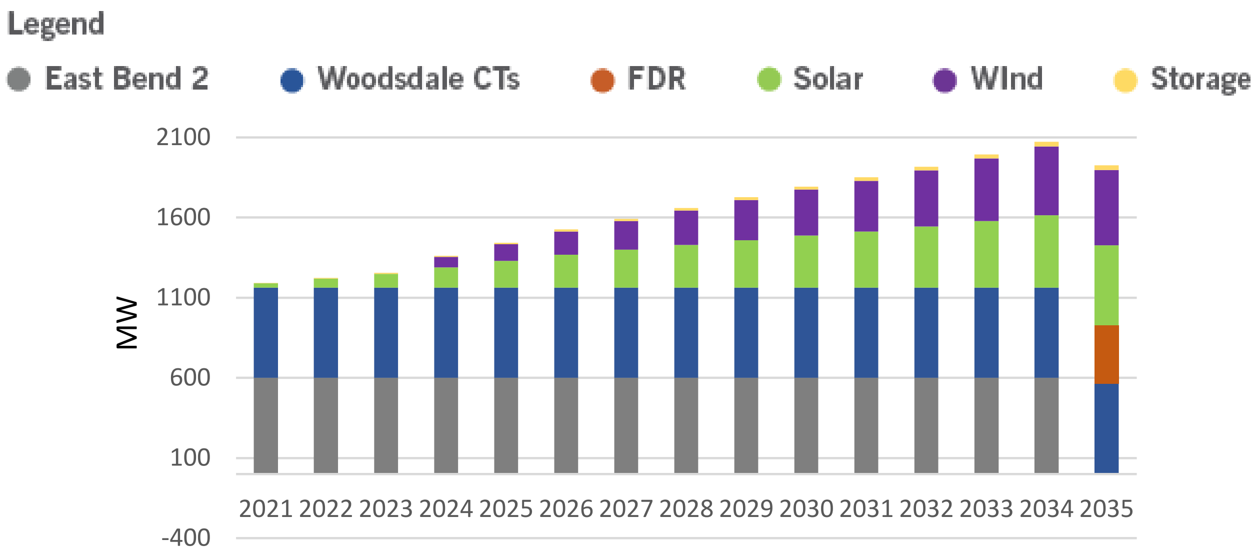
These changes – earlier retirement of coal generation and increasing amounts of cleaner energy sources – are primarily driven by the economic improvement of renewable energy compared to other generation sources, the likelihood of federal clean energy legislation and other environmental regulation, uncertainty surrounding the long-term availability of low-cost fuel and reagent commodities, and increasing customer preference for renewable energy. The relevance of these factors will not diminish over time and, instead, is likely to become more profound. And as a prudent operator with an obligation to adequately and reliably serve its customers, both today and for decades to come, Duke Energy Kentucky must anticipate the potential for changes in environmental policy and the marketplace that will require further revision to its resource planning.

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 on specific resource decisions through the CPCN process.

One example of a dynamic external factor that impacts this analysis is potential new government regulations that are more stringent than what is evaluated in the scenarios that include carbon regulation. If such standards are enacted, then the Company would adjust its plan accordingly based on the specifics of that regulation. Although these changes are discussed in greater detail below, the following chart depicts an alternative federal policy that encourages higher renewable adoption without a specific limit on carbon emissions. In this portfolio, 35% of generation comes from renewables by 2030, growing to 52% in 2035.

Figure 1.3 – Portfolio 3.

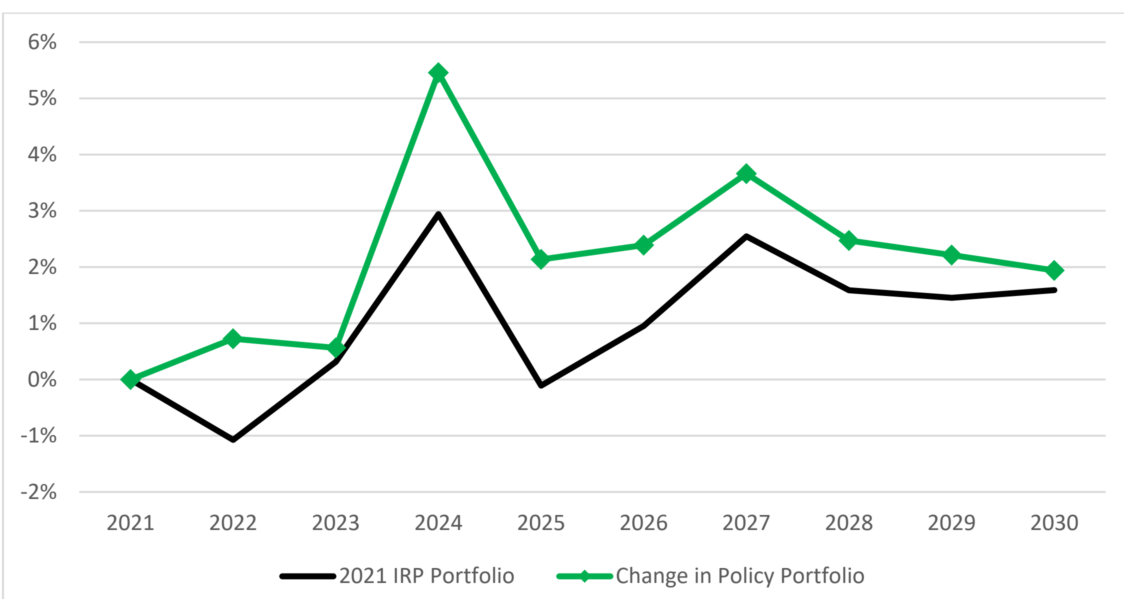
CHANGE IN POLICY PORTFOLIO



While preserving options and diversifying the generating fleet is important, the Company remains mindful of customer affordability. The chart below shows the anticipated year-over-year rate impacts due to changes in the resource mix through 2030 of the portfolios depicted in Figures 1.2 and 1.3.

Figure 1.4 – Year Over Year Rate Impacts.

YEAR OVER YEAR RATE IMPACTS FOR SELECT PORTFOLIOS



B. THREE-YEAR IMPLEMENTATION PLAN

Over the next three years, the forecasts indicate relative stability in the fuel and power markets. However, this stability will be challenged by the introduction of new or different interpretations of existing environmental regulations affecting the nation's generating fleet – an outcome that is becoming increasingly probable. Thus, the Company's resource planning must be capable of adapting to changing circumstances and the three-year implementation plan will focus, in part, on the administration of approved demand-side management (DSM) programs and the development of those renewable resources identified in Figure 1.2 above.

The three-year implementation plan also must make provision for increasing interest on the part of existing and prospective customers for cleaner forms of power. Indeed, customers continue to explore partnerships with the Company through which sustainability goals are achieved in a cost-effective manner that benefits the entire Duke Energy Kentucky system. And the ability to execute on such partnerships is critical to the Commonwealth's economic development activities and overall competitiveness in an increasingly global economy. In response to this growing customer interest and to support the increase in demand or load, implementation needs to accommodate the potential addition of more renewable generation to the Company's generation fleet. Although flexible enough to account for changes in technologies, Duke Energy Kentucky's immediate strategy will focus on solar and storage, with wind resources contemplated for later introduction to allow for additional resource diversity and the potential of more cost-effective wind resources such as higher hub-height turbines facilitated by onsite construction techniques under development. As the specifics of potential new load are determined, the Company will incorporate them into its planning process to meet customers' needs and comply with PJM Interconnection, L.L.C., (PJM) requirements. Within the PJM construct, Duke Energy Kentucky intends to retain its status as a fixed resource requirement (FRR) entity.

The COVID-19 pandemic impacted load beginning in 2020, but the significant declines in load have started to reverse and the Company anticipates organic load growth over the short term. If load recovers or increases more quickly than anticipated, however, Duke Energy Kentucky would pursue reasonable least-cost options for acquiring additional capacity that complies with its FRR obligations. Such options might include short-term capacity purchase agreements with a focus on assets that are in the DEOK load zone and, for the longer term, joint venture or sole ownership of generation projects.

Duke Energy Kentucky will continue to engage with stakeholders to develop projects that add value to the system and communities it serves. This engagement will reflect a preference for siting resources within the Duke Energy Kentucky service territory, understanding, however, that other locations may be appropriate. It will be important for the Company to prioritize locating new capacity assets within the DEOK PJM load zone in the future, particularly given the PJM zone separation history. Finally, the Company will continue to monitor fuel and power markets as well as potential changes in policy and regulation 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, the 2021 Duke Energy Kentucky IRP. In the IRP process, the modeling of Duke Energy Kentucky 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 this IRP is to define a robust strategy to furnish electric energy services to Duke Energy Kentucky customers in an adequate, efficient, and reasonable manner while considering the uncertainty of the current environment. The planning process must be dynamic and adaptable to changing conditions. The IRP represents the most robust and economic outcome based upon various assumptions and sensitivities. Due to current and future 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, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives.

For reliability purposes, the Duke Energy Kentucky is subject to PJM's Reserve margin requirement and as such models a minimum reserve margin requirement of 8.7% on a UCAP basis.

The major objectives of the IRP presented in this filing are:

- **Provide adequate, efficient, reasonable service that is economic in an uncertain environment,**
- **Maintain the flexibility and ability to alter the plan in the future as circumstances change,**
- **Choose a near-term plan that is robust over a wide variety of possible futures; and**
- **Minimize risks (such as wholesale market risks, reliability risks, etc.)**

C. STEPS IN INTEGRATED RESOURCE PLANNING

The following steps are involved in developing an IRP:

DEFINE
the planning objectives and scope (discussed above).

DESCRIBE
the current conditions that are the baseline for planning about the future.

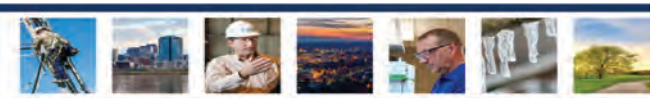
DEVELOP
a quantitative set of expectations for the future of the market, regulatory, and technological environments in which the utility operates.

ESTABLISH
the list of supply-side and demand-side resource options that are technically and commercially available to meet future capacity needs.

DETERMINE
using a quantitative modeling process, the optimal plan for acquiring resources to meet future needs, given the planning objectives, resources available, and expectations for the future.

USE
sensitivity analysis to test the performance of the optimal plan under unexpected future conditions; and.,

SELECT
a resource acquisition plan that meets the planning objectives under expected conditions and minimizes risks associated with unexpected developments.



1. Developing a Base Case

A plan cannot be constructed without some set of expectations about what the future holds. Our Reference with a Carbon Regulation scenario is a description of those expectations considered most likely to unfold over the 15-year planning period with no major disruptions to the business environment. For the purposes of the IRP, our Reference with a Carbon Regulation scenario expectations is 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. Carbon prices;
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 forecast in a quantitative manner, and therefore the current regulatory environment is assumed to persist throughout the planning period. The one major exception to that assumption is in regard to a future price on carbon emissions which, given its potential impact, is addressed in a number of scenarios.

2. Technical Screening of Resource Options

In addition to constructing a reference case 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 acquisition 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 the Duke Energy Kentucky service territory.

3. Scenario Analysis

Scenario analysis is used to assess the cost and reliability risks associated with unexpected future developments. The purpose is this analysis is to evaluate the resource needs of the system across various combinations of two key drivers – carbon regulation and varying levels of gas prices. The specific scenarios that will be run are listed below:

1. CO_2 regulation with High Gas Prices;
2. CO_2 regulation with Base Gas Prices;
3. CO_2 regulation with Low Gas Prices;
4. No CO_2 regulation with High Gas Prices;
5. No CO_2 regulation with Base Gas Prices; and
6. No CO_2 regulation with Low Gas Prices.

For each scenario, a new optimal resource portfolio is be developed. Additionally, other portfolios are evaluated that can be viewed of a hybrid of the optimized portfolios or are tests of resource specific strategies. The specific portfolios evaluated are:

Optimized Portfolios

1. CO_2 regulation with High Gas Prices;
2. CO_2 regulation with Base Gas Prices;
3. CO_2 regulation with Low Gas Prices;
4. No CO_2 regulation with High Gas Prices;
5. No CO_2 regulation with Base Gas Prices; and
6. No CO_2 regulation with Low Gas Prices.

Alternate Portfolios

1. 2021 IRP Portfolio;
2. East Bend 2 Gas Conversion;
3. East Bend 2 retirement with CC replacement;
4. East Bend 2 retirement with CT replacement; and
5. East Bend 2 retirement with renewables heavy replacement
6. Change in Policy Portfolio

The bulk of the analysis is to test each of the 12 portfolios in each of the 6 scenarios. This is done to see how each portfolio responds to a different set of future assumptions. The primary criteria for each portfolio will be cost (with a focus on the near term), 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 long term.

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 forward market prices and long-term commodity price fundamentals to develop coal and gas price forecasts. The former incorporate data from public exchanges including NYMEX, as well as fuel contracts and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The long-term fundamental fuels forecast is a proprietary product developed by IHS Markit Ltd., a leading energy consulting firm. Fuel price forecasts provided by IHS are based on granular, integrated supply/demand modeling using fuel production costs and end-user consumption. The Duke Energy long-term fundamental forecast is approved annually by Duke Energy's leadership for use in all long-term planning studies and project evaluations.

Forecasting Power Prices

With Duke Energy Kentucky's participation in the PJM market, the Company needs to be mindful of its own system but also the impact upon the PJM system. As such, for each scenario we make specific PJM level model runs that incorporate that scenario’s specific assumptions to develop power prices unique to that specific scenario. We use this method to ensure consistency and provide a linkage between fuel, carbon, and power price assumptions.

Forecasting Prices on Carbon Emissions

Significant uncertainty remains regarding the regulations that will ultimately replace the Clean Power Plan. Duke Energy Kentucky believes that a constraint or price on carbon is likely to be imposed at some future date, so it is prudent to include a carbon-constrained scenario for long-term IRP modeling purposes. This was based on previous discussions in regulatory space and adjusted under the premise that carbon regulation would be introduced at a lower level so as to not abruptly impact the economy, but continue to escalate to provide a greater incentive to build resources that reduce carbon emissions.

Forecasting Capital Costs

Duke Energy Kentucky, in conjunction with a third-party, developed capital cost projections for all generation technologies included in the IRP optimization models. These projections are based on Technology Forecast Factors from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2021. The AEO provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS).

Using 2021 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 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 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 cogenerators; short-term energy and capacity transactions within the PJM market; and new utility-built 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, operations and maintenance (O&M) cost, 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. 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 are 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, combined cycle (CCs), reciprocating engines, and nuclear stations. In addition, onshore wind, solar photovoltaic, and battery storage options were included in the analysis.

DSM and DERs that might be driven by FERC 2222 will be modeled as impacts to the load forecast. Given the nascent impacts of FERC 2222, Duke Energy Kentucky will continue to monitor and adopt a different approach if warranted.

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 Present Value Revenue Requirements (PVRR). The model calculates the cost and reliability effects of modifying the load with DSM 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 data, fuel data, load data, transaction data, DSM data, 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 2020s, 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 gas/oil production is expected to rise to partially mitigate this demand growth as oil prices strengthen. Gas markets closer to Appalachian supply sources may rise more slowly than the main US index, Henry Hub, due to high supply and demand that is constrained by pipeline capacity.

Coal demand is expected to remain tepid for the foreseeable future, which could potentially impact viability of supply sources over the long term. At this time, however, the price forecast rises 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 of capacity potentially retiring in the next decade, coal demand should remain weak. Some limited upward pressure on prices exists due to Asian and European export demand.

The Company's high and low fuel price cases are based on alternative fuel price cases in the EIA AEO for 2021. The 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 High Oil and Gas Resource and Technology case describes a future with high resource availability and low extraction costs which leads to persistently low gas prices.

The high and low fuel price cases for this IRP were derived by applying the ratio between the EIA reference and alternative cases to the Duke Energy Kentucky business as usual forecasts for coal and gas prices.

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

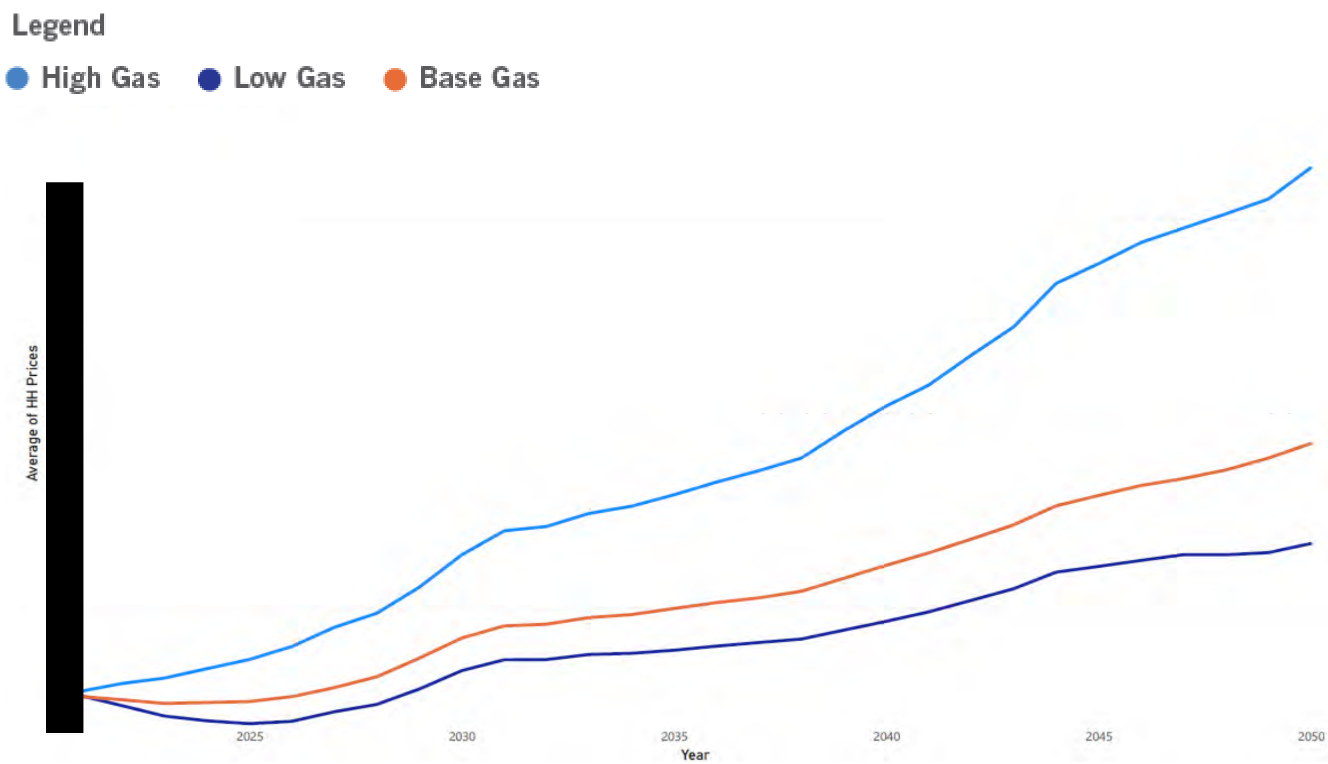
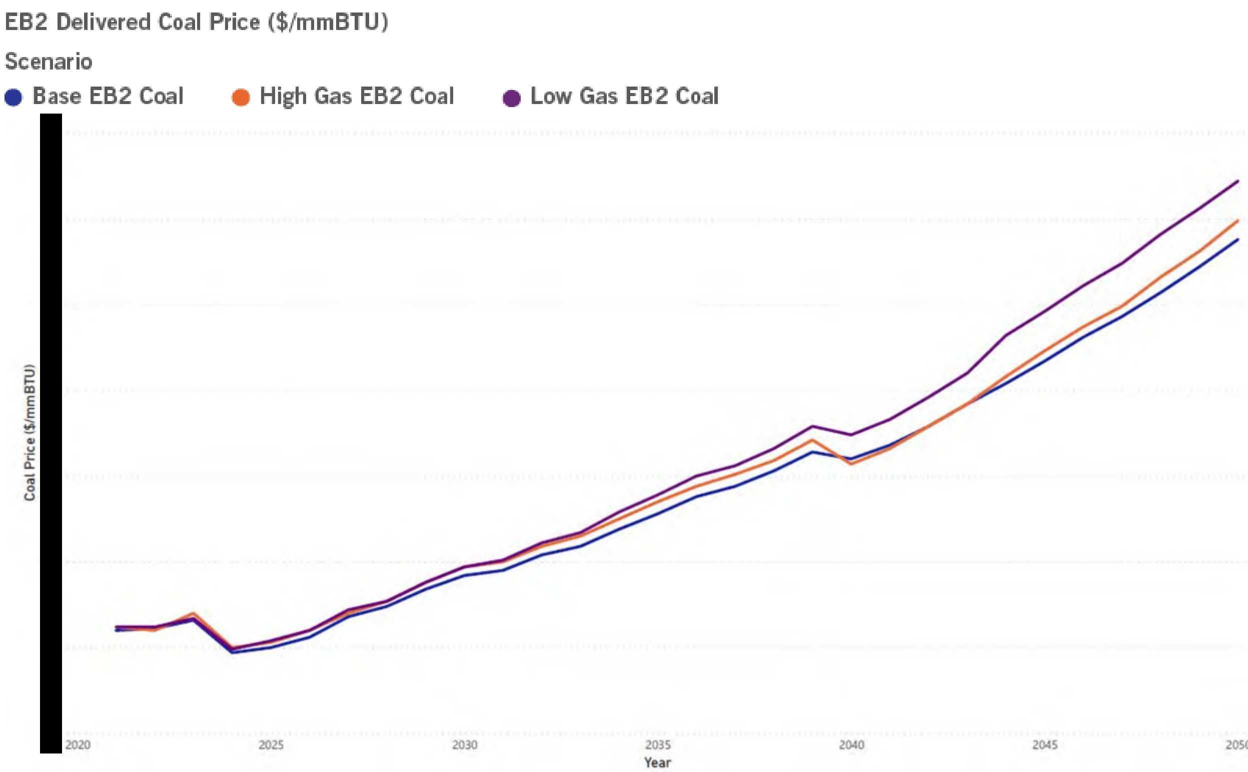


Figure 3.2: High, Base and Low Coal Price Forecasts



B. POWER PRICES

As was described previously, power prices are a function of the assumed fuel and carbon price assumptions. Additionally, changes in the RTO generation fleet are modeled to align with the assumptions of each specific scenario.

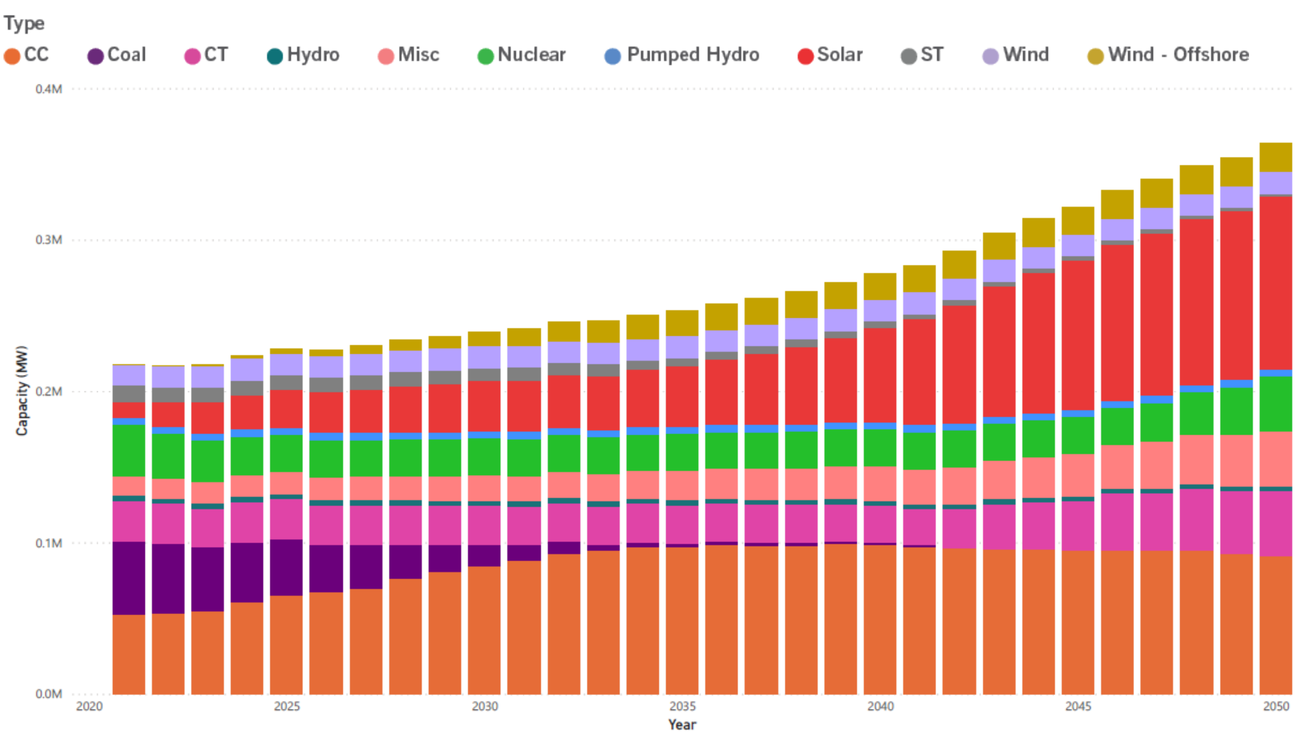
Expansion Plans

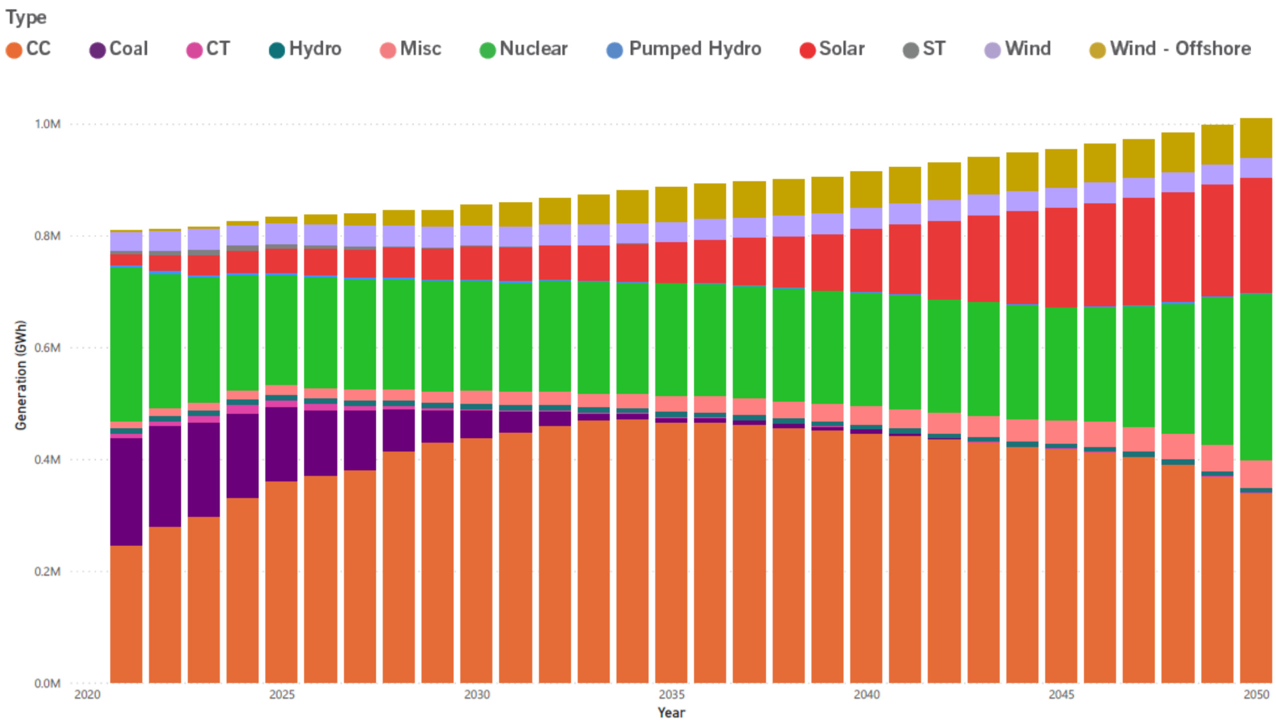
Generation expansion plans were developed for the Eastern Interconnect for six scenarios- various combinations of the presence of a carbon price or not and three different gas forecasts. These expansion plans were input into Encompass and hourly energy prices were developed to simulate the PJM power price for Duke Energy Kentucky. The generic unit characteristics, Reserve Margin requirements and State Renewable Portfolio Standards, are consistent between the expansion plans for each of the operating regions. While the model has the ability to select new nuclear capacity, none was selected for the 15-year planning period in either case. Economically selected retirement of existing generating units and Load and Demand-Side Management (EE and DR) forecasts were scenario specific. A need for new capacity in this timeframe was heightened by the retirement of East Bend 2 in both scenarios.

Expansion Plan assuming future CO_2 regulation

These scenarios considered CO_2 regulation in conjunction with high, base, and low forecast for gas prices. The accompanying charts show the capacity and generation mix for PJM these three scenarios.

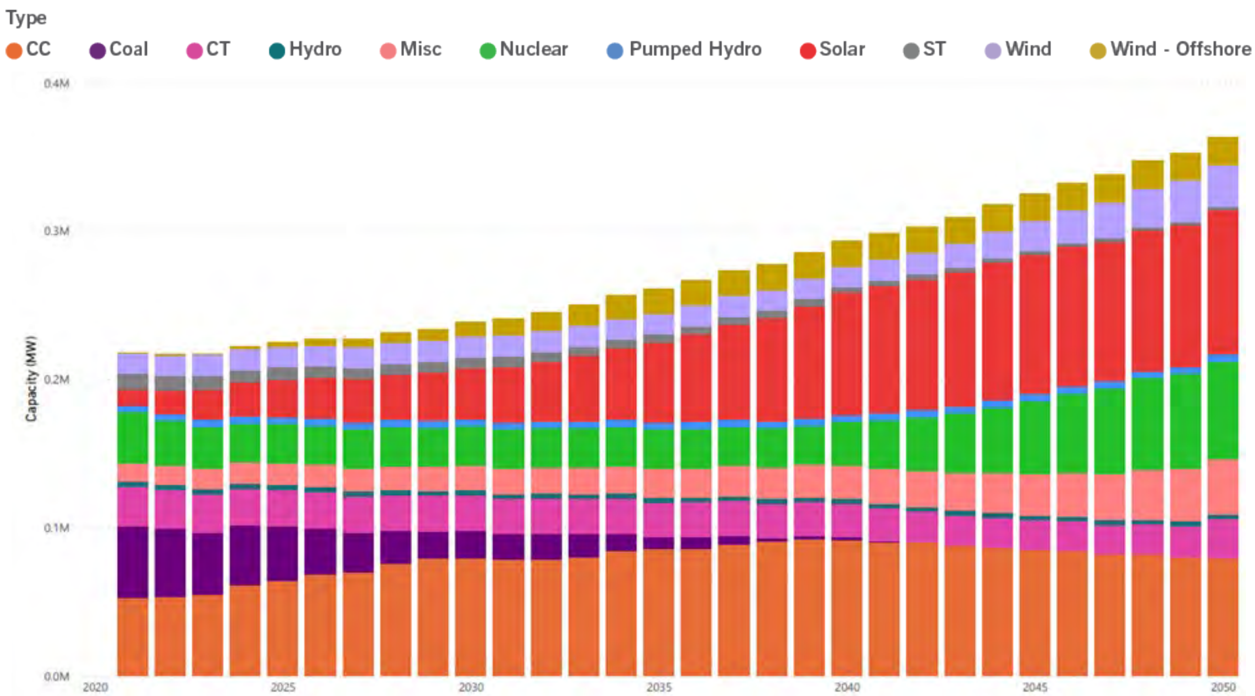
Figure 3.3: Capacity and Generation Forecast in PJM Assuming Future CO_2 Regulation and Base Gas Forecast

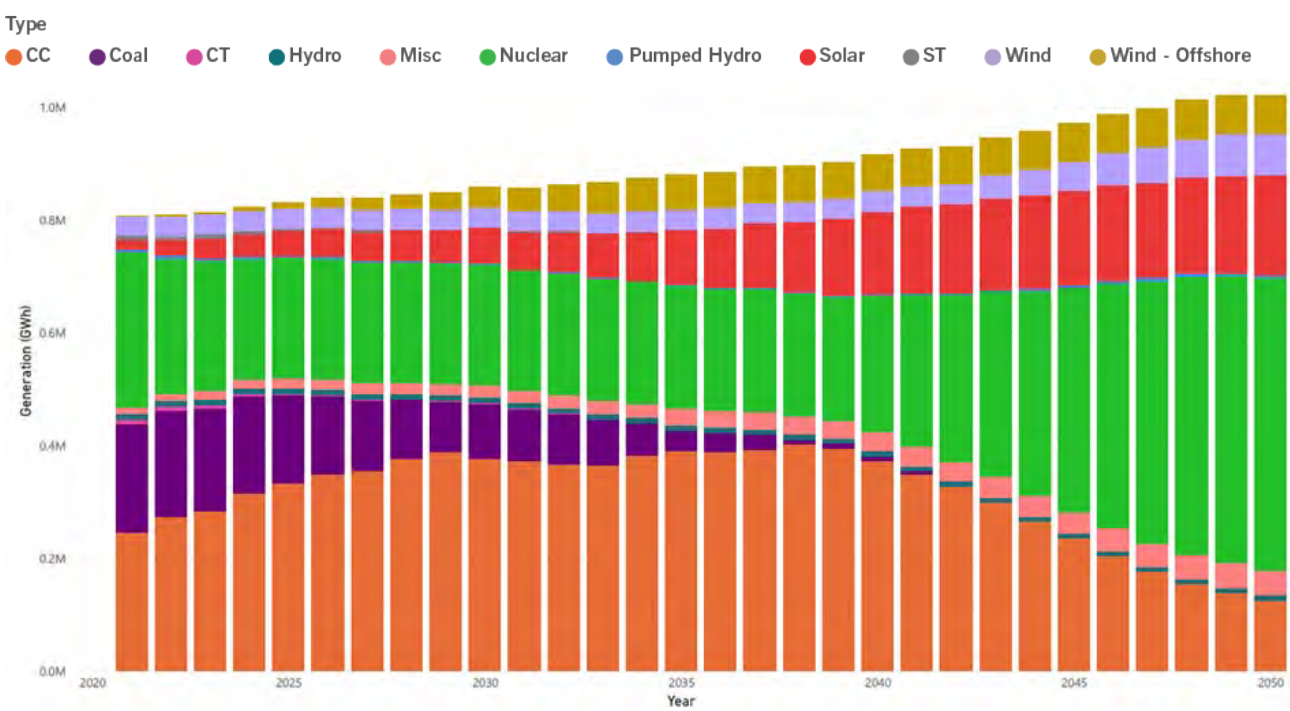




In this scenario, the weight of the carbon price hastens the retirement of coal generation which is primarily replaced with combined cycles and solar.

Figure 3.4: Capacity and Generation Forecast in PJM Assuming Future CO_2 Regulation and High Gas Forecast

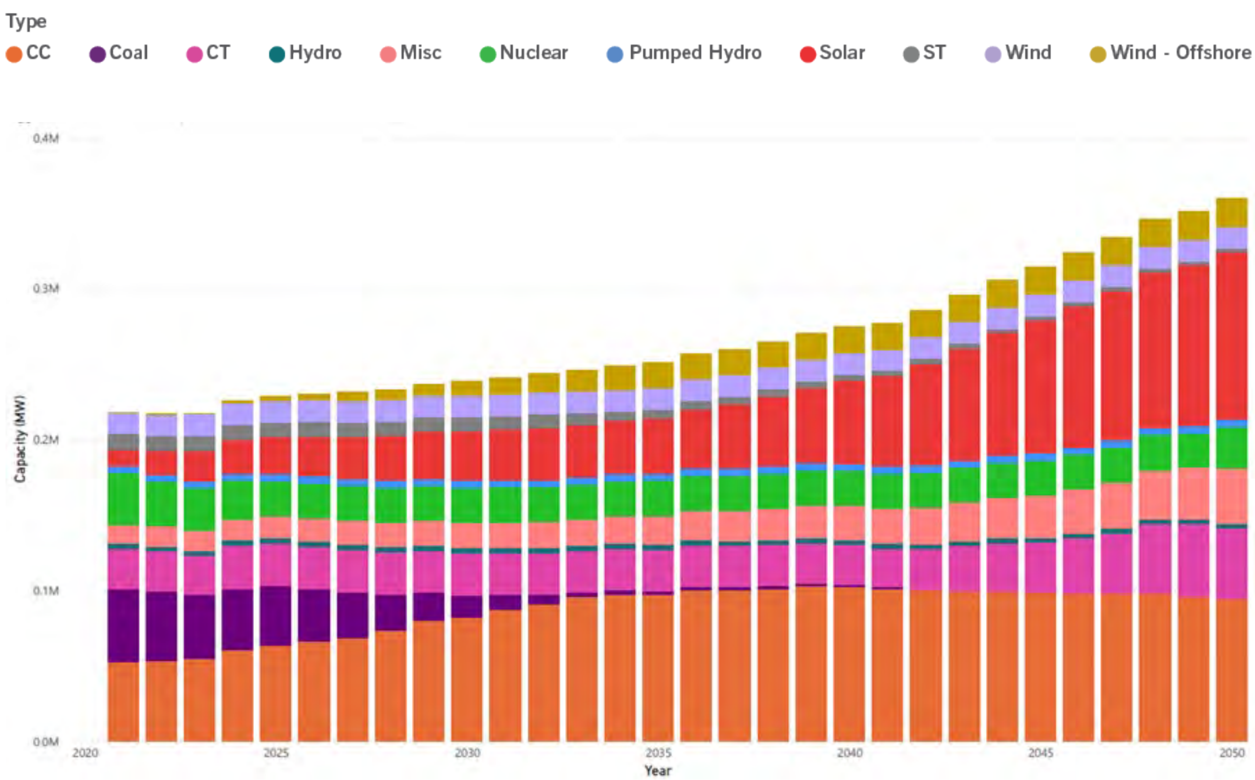


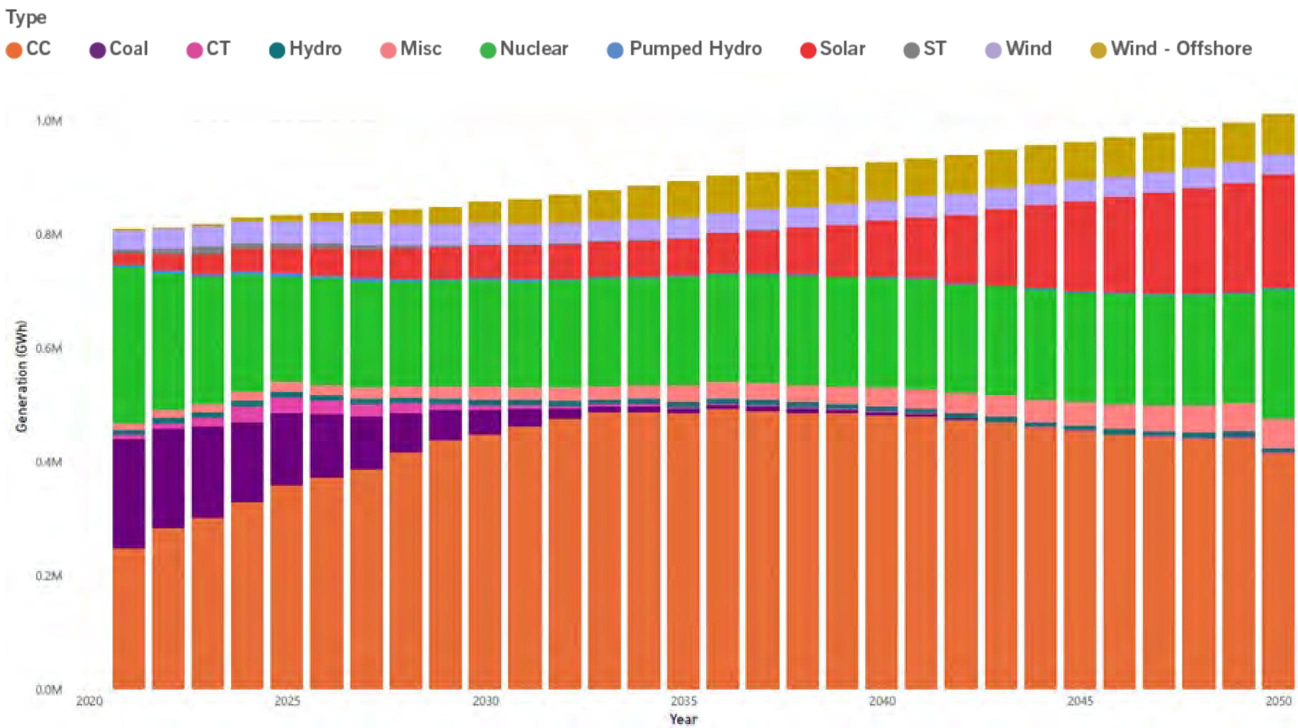


The combination of carbon regulation and higher gas prices drive a number of significant changes:

- The carbon price and high gas prices both drive up power prices;
- Coal generation benefits from higher power prices, but this is offset by the higher dispatch costs due to the carbon price;
- Combined cycle generation is added in the near term, but begins to wane in the later years due to higher carbon cost and gas prices;
- It is interesting to note that this scenario does call for increased levels of nuclear generation and it becomes the primary source of energy for the RTO;
- All renewables benefit from the higher power prices.

Figure 3.5: Capacity and Generation Forecast in PJM Assuming Future CO_2 Regulation and Low Gas Forecast



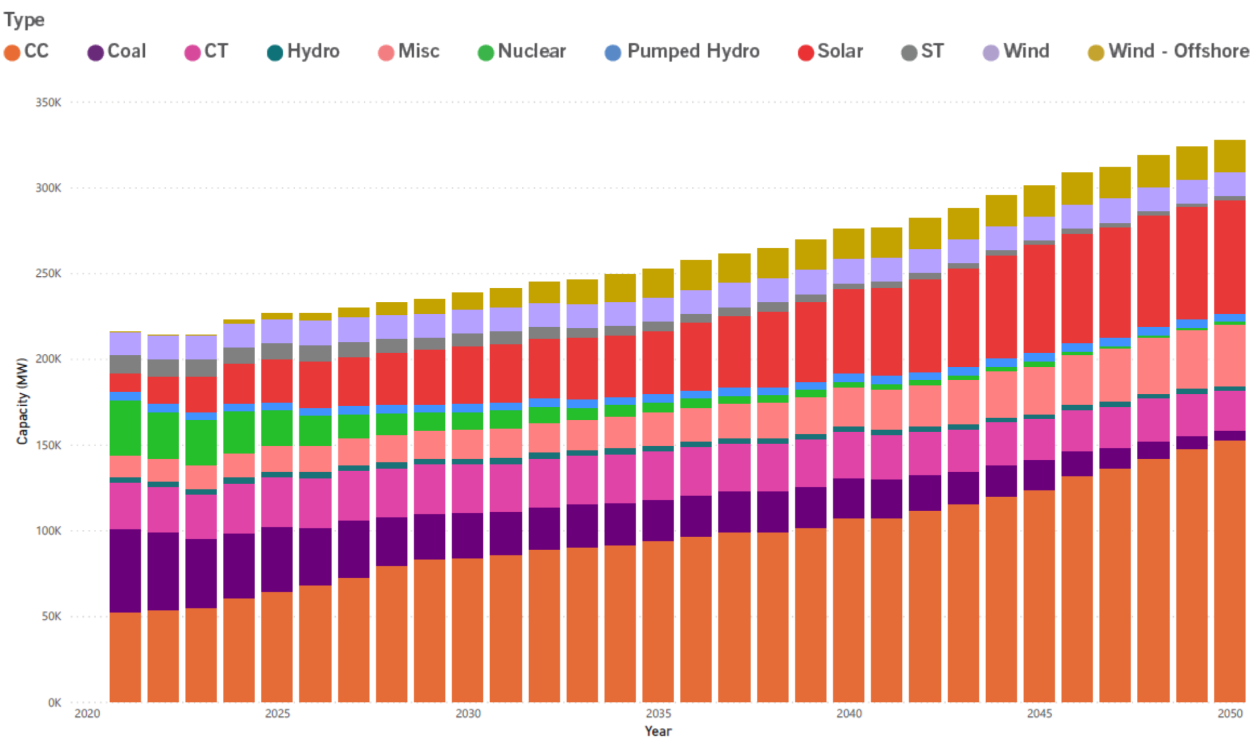


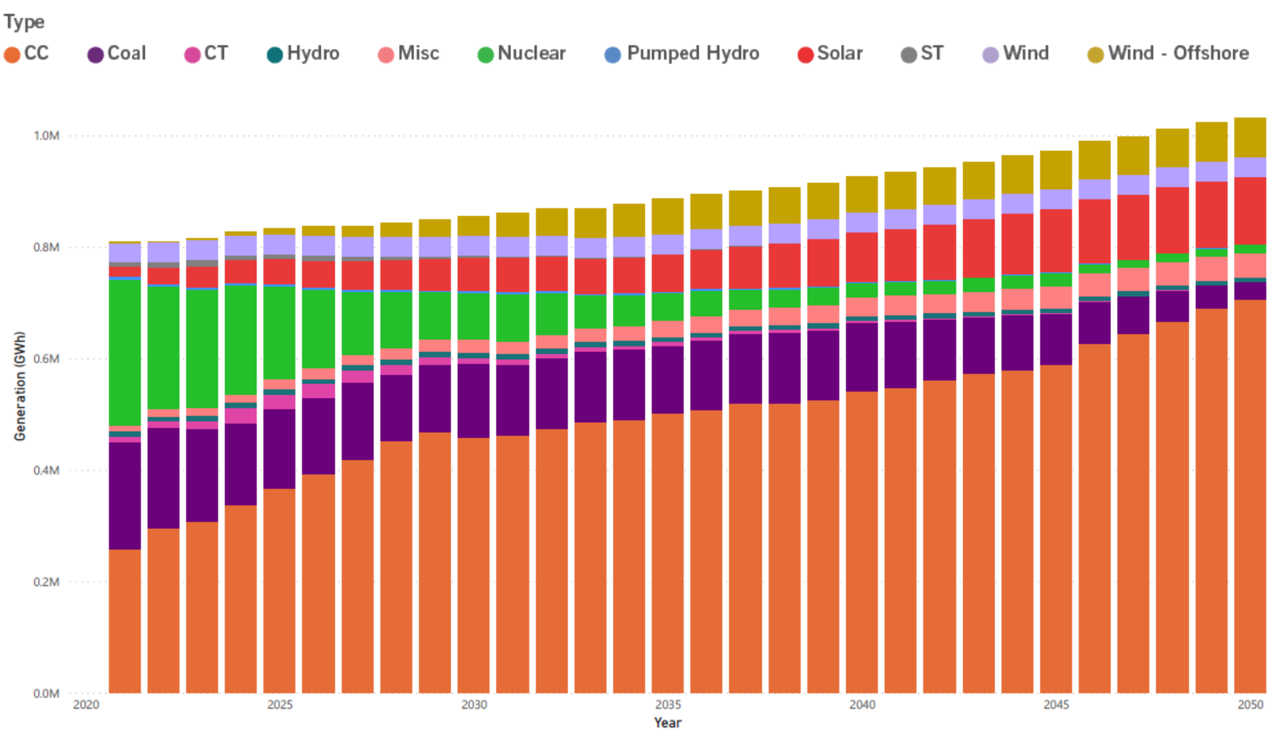
The low gas prices of this scenario benefit combined cycle generation and temper the addition of renewables with nuclear generation continuing to be an important part of PJM's generation mix.

Expansion Plan assuming no CO_2 regulation

These scenarios considered no CO_2 regulation in conjunction with high, base and low forecast for gas prices. The accompanying charts show the capacity and generation mix for PJM these three scenarios.

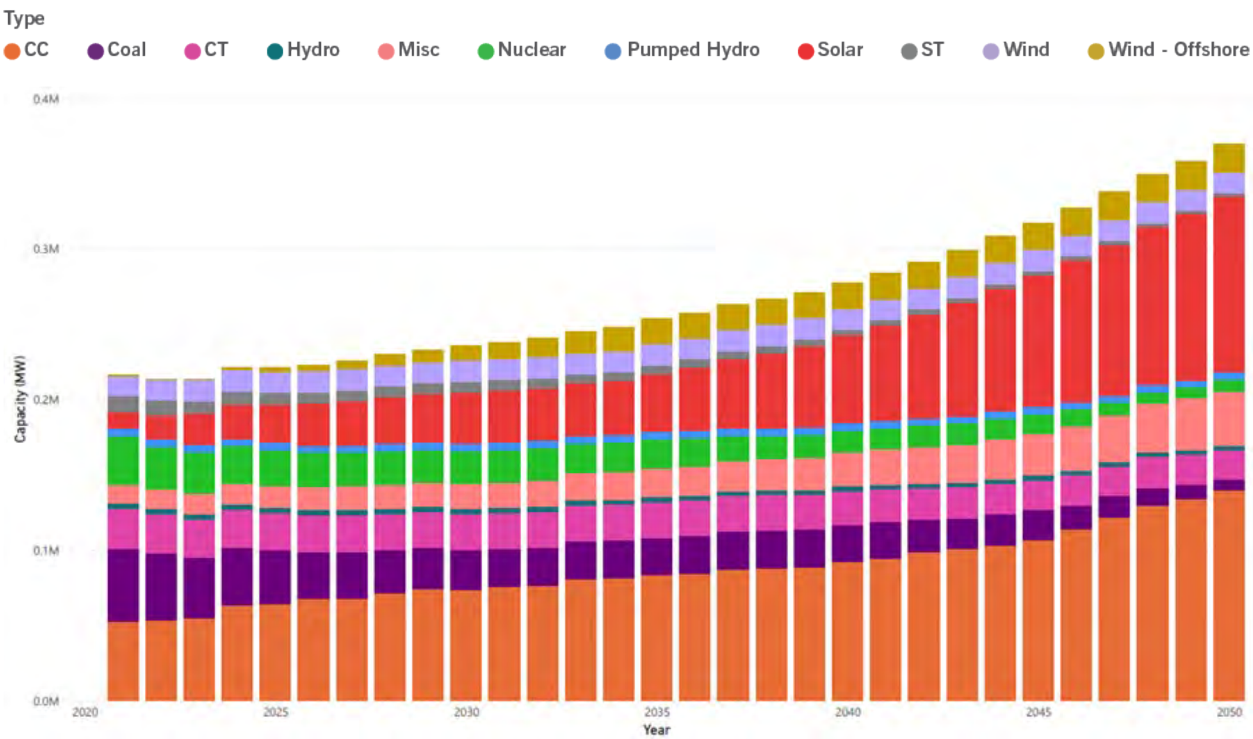
Figure 3.6: Capacity and Generation Forecast Assuming No CO_2 Regulation and Base Gas Forecast

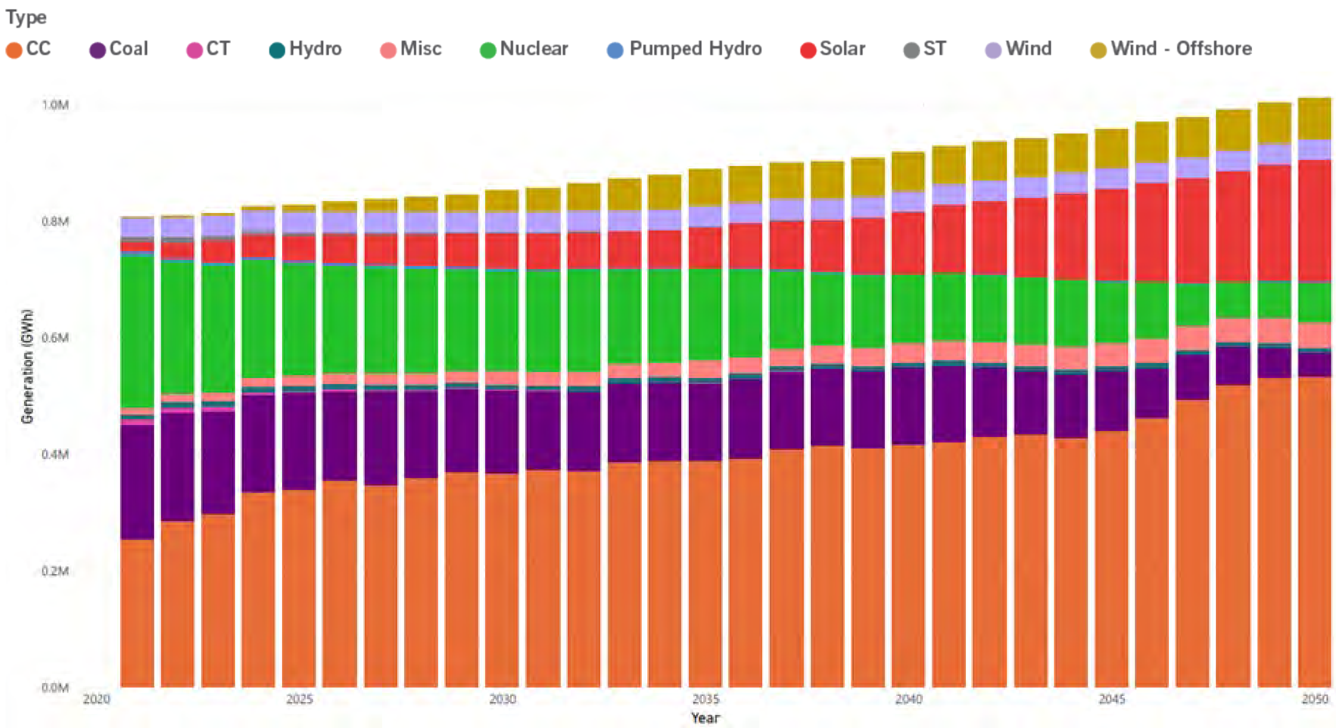




Without the presence of a carbon price, coal units continue to operate until their useful lives are reached and largely replaced by combined cycles. It is also interesting to note that nuclear experiences the same phase out as coal as the nuclear fleet reaches the end of each unit's useful life. Renewable generation increases as costs come down relative to other forms of generation.

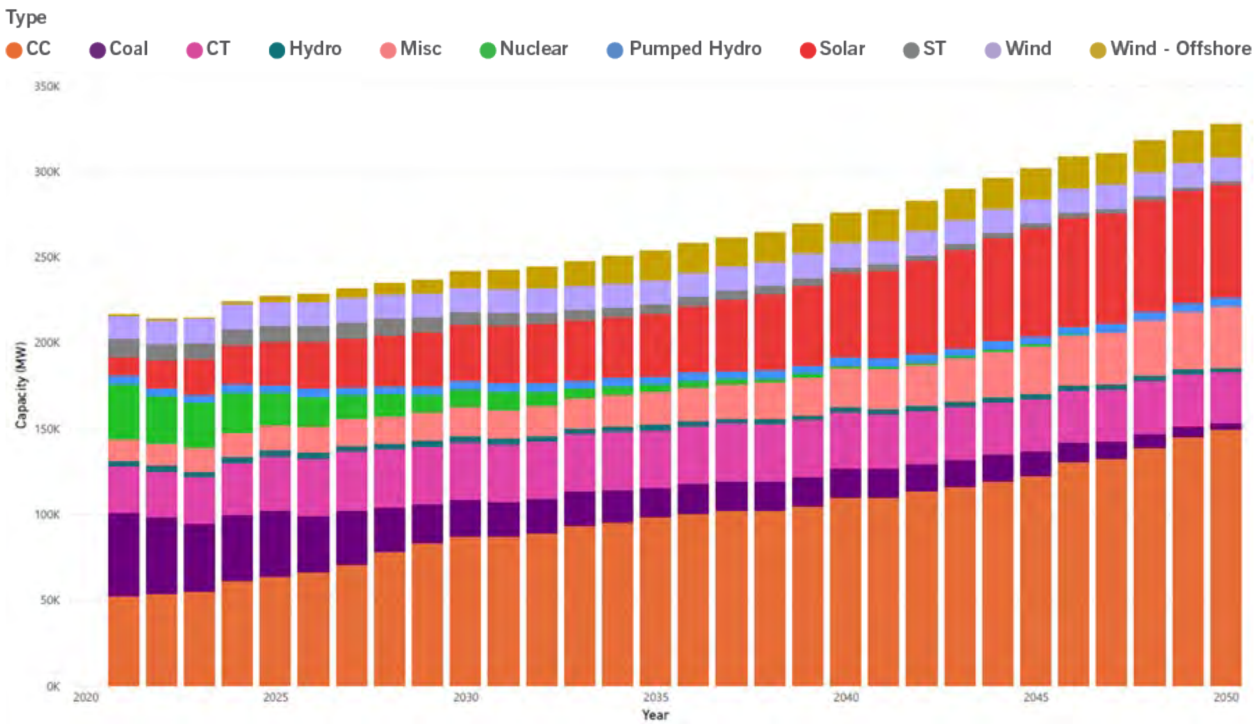
Figure 3.6: Capacity and Generation Forecast Assuming No CO_2 Regulation and High Gas Forecast

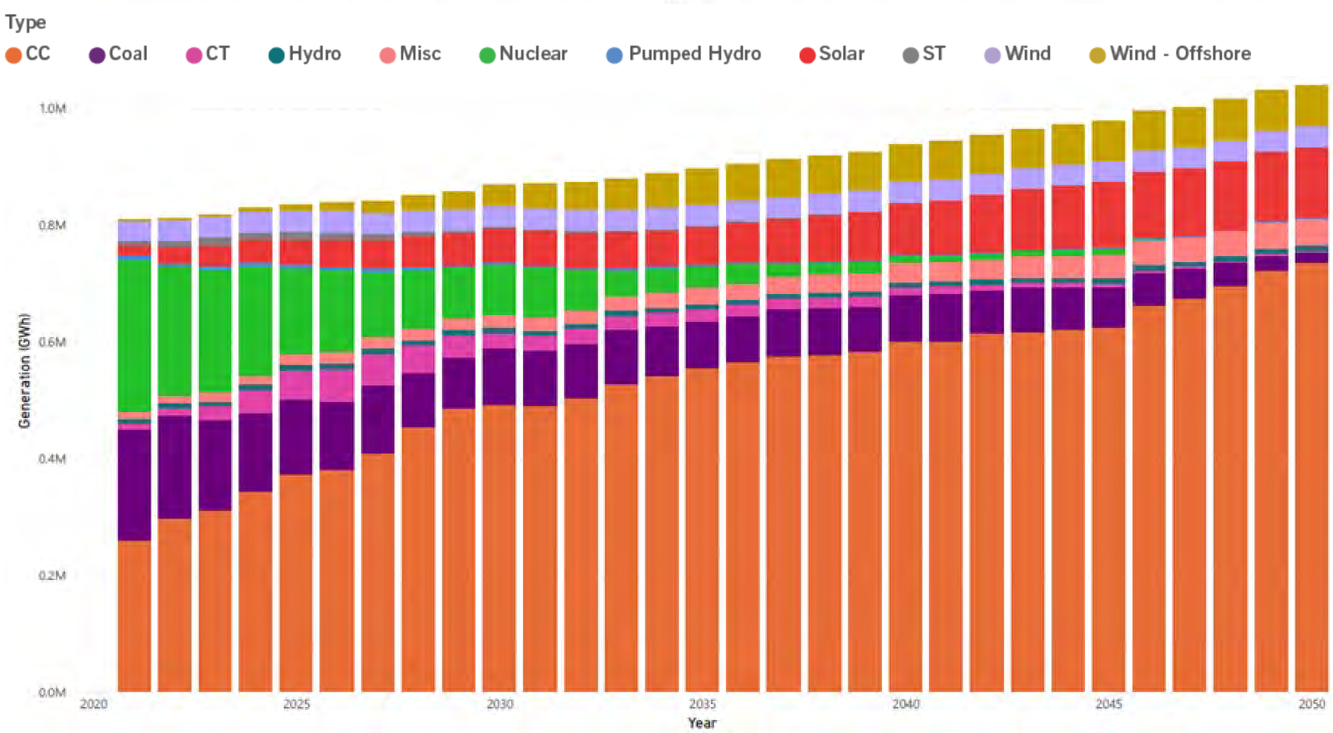




The higher gas prices of this scenario keep coal generation around longer due to the higher power prices without an increase in the dispatch cost of the coal fleet. However, the increase in the power prices are not enough to justify maintaining levels of nuclear generation. Renewables increase due to the higher power prices.

Figure 3.7: Capacity and Generation Forecast Assuming No CO_2 Regulation and Low Gas Forecast





This scenario has the lowest power prices due to low gas prices and absence of a carbon price. As a result, most of the change is the increased reliance on growing levels of combined cycle generation.

OBSERVATIONS FROM SCENARIO ANALYSIS

The various combinations of carbon regulation and gas price forecasts show the trade-offs between the various generation technologies, and the impacts can best be understood by 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.

C. PRICES ON CARBON

As discussed in Section 3.D, Duke Energy Kentucky believes that a price or constraint on carbon emissions is likely to be imposed at some point in the future. In the absence of existing federal policy and considering the uncertainty around the form that such regulation could take, the Company has included a price on carbon dioxide emissions of $5/ton beginning in 2025 and increasing by $5/ton/year in some scenarios and sensitivities.

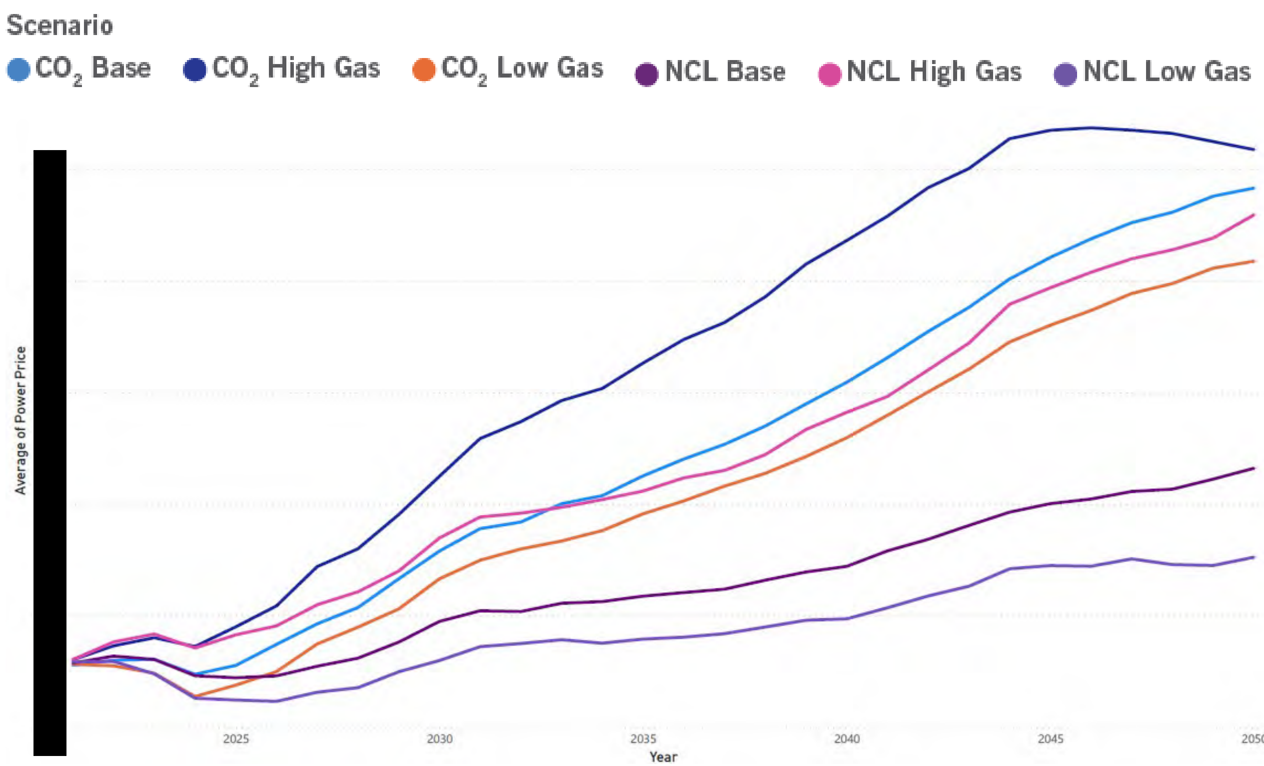
The Duke Energy Kentucky carbon price was developed generally in line with various past legislative initiatives to incentivize lower carbon resource selection and dispatch decisions. Based on the earliest expected time to propose, pass and implement legislation or regulation, the carbon price is set to begin in 2025. The ultimate carbon price will be dependent many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

When comparing alternative plans the inclusion of the carbon price in the overall project economics would be reflective of a carbon tax and if excluded would be reflective a mass CO_2 cap or cap and trade with allowance allocations.

D. POWER PRICES

Below is a chart that shows the six power price forecasts based on the scenarios described above:

Figure 3.8: PJM Power Prices

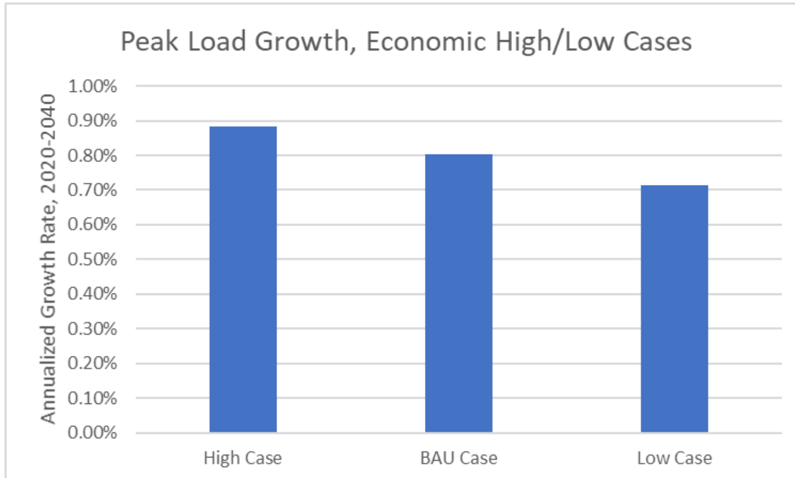


E. LOAD FORECAST

The Company's expectations are for a post-COVID recovery in 2022 and 2023 followed by several years of relatively slow load growth, with demand accelerating into the latter half of the 2020s and beyond. Improving demand will be driven by growth across each of the major classes of customers, with strengthening household incomes and economic output (particularly in manufacturing), as well as a growing population in the service territory. All After UEE charts shown below represent DSM Case #1: Low Income programs only.

In addition to the load forecast the Company considers most likely to occur depicted in the figures above, we address the inherent uncertainty in load forecasting by estimating upper and lower ranges for expected load on our system. With demand influenced by local, regional, and national economic trends; economic developments that deviate from the growth assumptions underlying our forecasts could result in actual load that is above or below the Company's current expectations. However, the impact of such deviations on our load forecast would likely be limited, with load in a stronger-than-expected economy (the upper part of the range) exceeding load in a near-term recession (the lower part of the range) by only about 5% by the tenth year of the forecast period. The upper and lower ranges for our load forecasts are shown in the Figure 3.9. For additional details on our load forecasts, see Appendix B.

Figure 3.9: Peak Load Growth



F. Responses to Rule Section 9: Financial Information

Figure 3.10: Revenue Requirements (Present Value, Annual, and per Kilowatt Hour)

PVRR:	$1,823 million
Discount Rate:	5.96%
Inflation Rate:	2.50%

Annual Revenue Requirements ($ millions)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Nominal:	$190	$139	$150	$204	$172	$151	$164	$161	$169	$181	$181	$188	$194	$202	$265
Real 2021 $:	$190	$135	$143	$190	$156	$134	$141	$136	$138	$145	$141	$143	$144	$146	$187

Revenue Requirements per Kilowatt Hour	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Nominal:	$0.04	$0.03	$0.03	$0.05	$0.04	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.06
Real 2021 $:	$0.04	$0.03	$0.03	$0.04	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04

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

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 in order to better assess the timing of new resource needs and the optimal resource type, regardless of size.

Figure 4.1 Capital Cost Table

DESCRIPTION	SUMMER CAPACITY (MW)	TYPICAL CAPACITY FACTOR	OVERNIGHT CAPITAL COST ($/kW)	COST ESCALATION FACTOR
Nuclear	2,234	90%	[redacted]	1.0%
Small Modular Nuclear Reactor	684	95%		1.0%
Ultra-Supercritical Pulverized Coal	850	70%		1.0%
Combined Cycle Gas Turbine, 2x1	1,157	70%		1.2%
Simple Cycle Gas Turbine	840	10%		1.0%
Reciprocating Engine	201	10%		1.4%
Combined Heat and Power	17	95%		1.0%
Wind	20[a]	18%		1.4%
Solar PV, Single-Axis Tracking	2.5[b]	24%		-2% / .6%[d]
Battery Storage, 4-hour Lithium Ion	8[c]	15%		-3.3% / 1.2%[d]
(a) nameplate capacity is 150 MW, wind contribution to peak is 13% of nameplate capacity in summer				
(b) nameplate capacity is 5 MW, solar contribution to peak is 50% of nameplate capacity in summer				
(c) nameplate capacity is 10 MW, battery contribution to peak is 80% of nameplate capacity				
(d) capital costs for solar PV and battery technologies are forecast to continue to decline for ten years before beginning to increase				

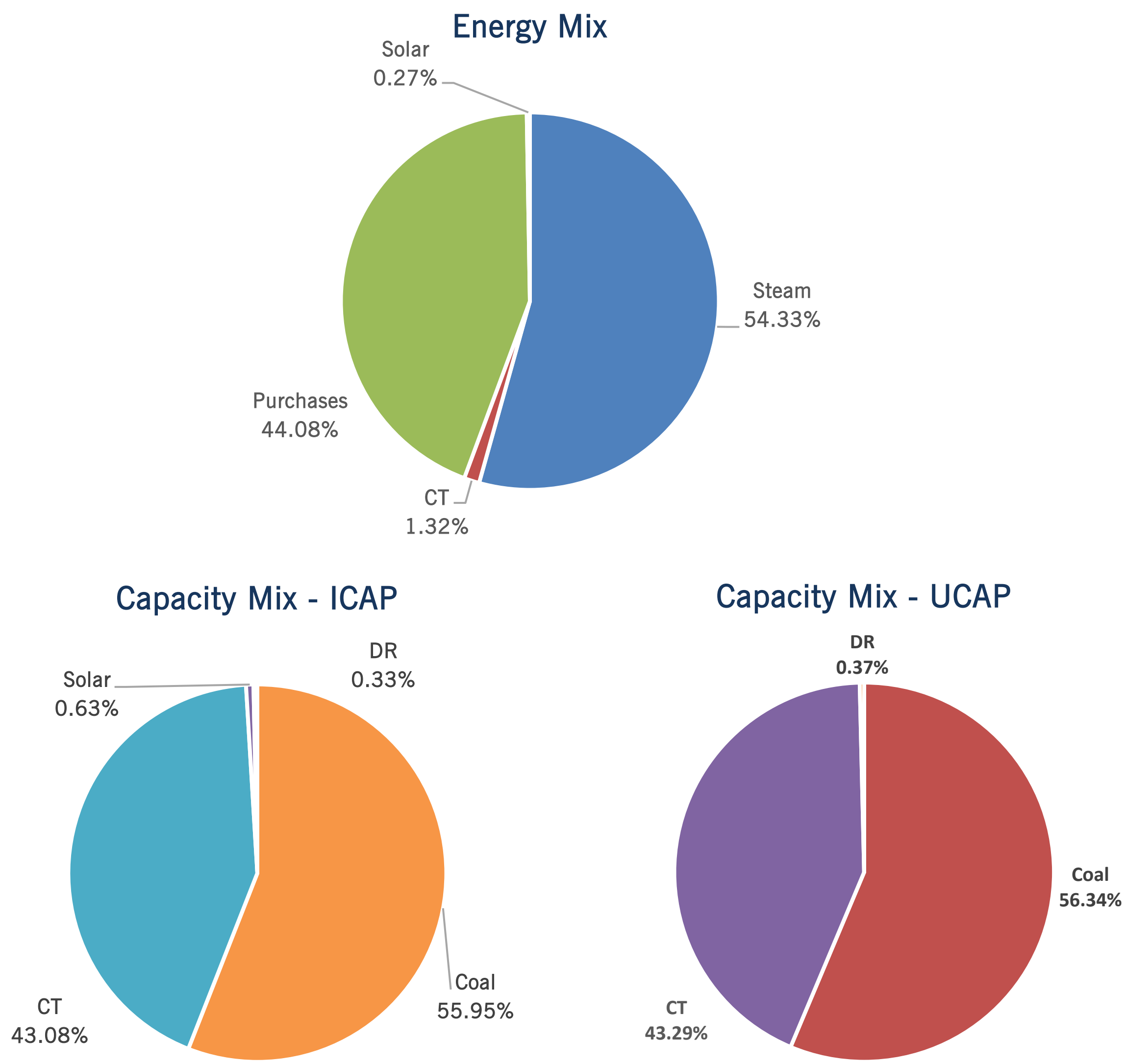
B. EXISTING RESOURCES

The total 2020 installed capacity (ICAP) owned by Duke Energy Kentucky is 1,069 MW. This capacity consists of 600 MW of coal-fired steam capacity, 462 MW of natural gas-fired peaking capacity, and 6.8 MW of solar photovoltaic (PV) capacity. The total 2020 unforced capacity (UCAP) for these assets is 1023.5 MW. 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 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 three solar assets: two 2 MW fixed-tilt PV plants located at the Walton Solar facility in Kenton County, Kentucky and a 2.8MW fixed-tilt PV plant located at the Crittenden Solar facility in Grant County, Kentucky. These solar assets are connected on the distribution level, thereby reducing the amount of demand bought from PJM. Accordingly, they are not shown in the energy and UCAP capacity mix charts below.

The level of purchases is a function of the economics the cost of generating versus the cost of buying power from the PJM market.

Figure 4.2 2020 Duke Energy Kentucky Capacity and Energy Mixes



C. FUTURE RESOURCE CONSIDERATIONS

Supply-side resources may include existing generating units; repowering options for these units; potential bilateral power purchases from other utilities, IPPs and cogenerators; 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 a technical screening to eliminate from consideration those technologies that are not technically or commercially available. Technologies excluded from consideration on these grounds include solar steam augmentation, fuel cells, supercritical CO_2 Brayton cycle, and liquid air energy storage, and advanced compressed air energy storage (CAES). 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 traditional compressed air energy storage CAES.

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 pulverized coal units, integrated coal gasification, CTs, CCs, reciprocating engines, traditional and nuclear stations, and small modular nuclear reactors. In addition, Duke Energy also included onshore wind, and solar photovoltaic renewable options. Lastly, battery storage options were included in the analysis.

SECTION 5

DEMAND-SIDE RESOURCES

A. INTRODUCTION

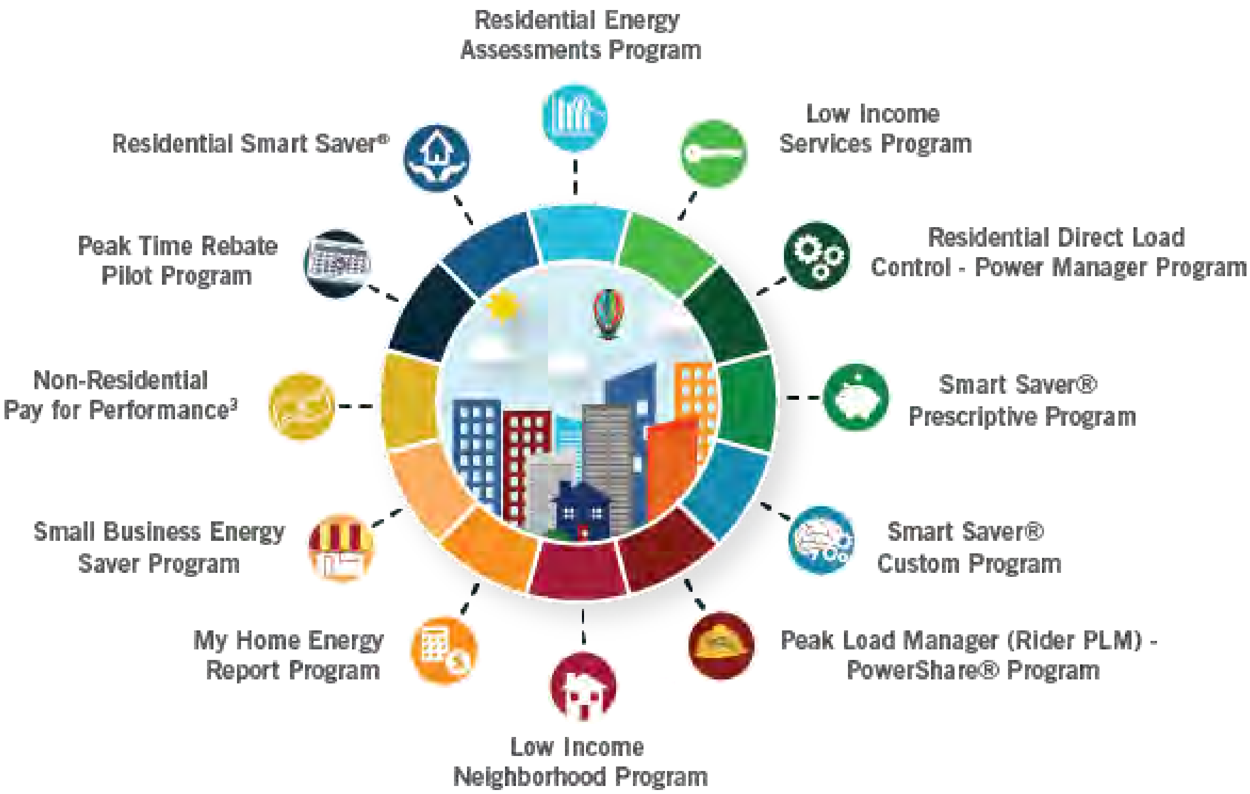
The Company's offering of DSM programs dates back close to two decades. Throughout the years, the Company has offered many enhancements to its portfolio with the purpose of increasing participation and providing customers new and innovative opportunities to control their electricity consumption and impact their utility bill. Consistent with the Commission's IRP analytical requirements and the Commission's Order in Case No. 2008-00408, 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.[1]

Duke Energy Kentucky's DSM programs include traditional conservation EE programs and DR 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 following set of programs described in greater detail in Appendix C.

[1] *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).

DSM Programs

Figure 5.1:



B. DSM PROGRAMS AND THE IRP

The projected impacts of DSM programs have been included in this IRP. The conservation DSM programs are projected to reduce energy consumption by approximately 172,500 MWh and 27 MW by 2035. The Residential Direct Load Control Program (Power Manager) is projected to reduce peak demand by 7 MW and the PowerShare® program another 15 MW by 2035. This brings the total peak reduction across all programs to approximately 50 MW by 2035. Figure 4.2 summarizes the projected load impacts included in this IRP analysis.

Figure 5.2 Projected Demand-Side Management Impacts

Year	EE Program Impacts		DR Program Impacts			DSM Impacts
	MWh	MW*	PowerShare MW	PowerManager MW	Total MW	Total MW
2021	16,375	1.7	15.2	6.9	22.1	23.8
2022	30,314	3.9	15.2	6.9	22.1	26.0
2023	43,690	6.1	15.2	7.0	22.1	28.2
2024	56,900	8.3	15.2	7.0	22.2	30.4
2025	69,725	10.3	15.2	7.0	22.2	32.4
2026	82,550	12.2	15.2	7.0	22.2	34.4
2027	95,376	14.2	15.2	7.0	22.2	36.4
2028	108,207	16.2	15.2	7.0	22.2	38.4
2029	120,760	18.2	15.2	7.0	22.2	40.4
2030	133,310	20.2	15.2	7.0	22.2	42.4
2031	142,761	21.9	15.2	7.0	22.2	44.1
2032	151,865	23.3	15.2	7.0	22.2	45.5
2033	160,274	24.7	15.2	7.0	22.2	46.9
2034	168,903	26.1	15.2	7.0	22.2	48.3
2035	172,452	27.0	15.2	7.0	22.2	49.2

Note: the EE MW impacts are coincident to the Summer Peak.

SECTION 6

MODEL RESULTS & SENSITIVITY ANALYSIS

A. INTRODUCTION

The analytical framework of evaluating twelve different portfolios in six different scenarios allows the Company to test each portfolio across six different futures as well as across several metrics. This allows the Duke Energy Kentucky to evaluate and select the 2021 IRP portfolio based upon a robust set of criteria and in an orderly fashion.

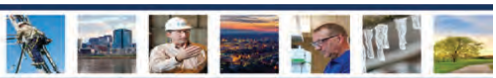
B. OPTIMIZED PORTFOLIOS

The three portfolios below were created based on the assumptions of the corresponding scenario. These were then optimized to minimize the PVRR through 2035. These three portfolios were built assuming the presence of carbon regulation under three different natural gas forecasts.

The portfolio optimized with carbon regulation and high gas prices shows a late build out, but it does trigger several different resource types – including solar, wind, gas generation and a portion of a small modular reactor – to be selected. It is worth noting that the conditions necessary to make nuclear economic and become an important signpost if and when the future starts to develop in the direction of a scenario with carbon regulation and high gas prices.

With the base gas assumption, the retirement of East Bend 2 is accelerated to 2027 and replaced with gas generation and solar. When evaluated in a low gas environment, the retirement of East Bend 2 is accelerated even further to 2025 and largely replaced by a combined cycle resource.

The takeaway from these three scenarios is that, should carbon regulation come to fruition of a similar magnitude to what is assumed in this IRP, economic retirement of East Bend 2 follows within a few



years. Given the swiftness with which carbon regulation can impact the Duke Energy Kentucky portfolio in a significant way, preserving the option to react is paramount.

Figure 6.1: Optimized Portfolios for Scenarios with Carbon Regulation

Ref w/CO_2 (High Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar									5	55	105	155	205	225	250
Wind											35	85	135	185	235
CT															232
CC														121	121
SMR															114
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1169	1219	1304	1404	1504	1695	1516

Ref w/CO_2 (Base Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar					5	5	45	50	55	80	90	110	160	175	185
CC					484	484	484	484	484	484	484	484	484	484	605
TOTAL	1164	1164	1164	1164	1169	1169	1093	1098	1103	1128	1138	1158	1208	1223	1354

Ref w/CO_2 (Low Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar														20	70
CT					580	580	580	580	580	580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1144	1144	1144	1144	1144	1144	1144	1144	1144	1164	1214

The portfolios optimized without carbon regulation and high gas prices show a late build out solar starting in 2031 whereas the portfolio assuming the base gas forecast does not change over the 15 years of the IRP. It is interesting that when the scenario without carbon regulation and a low gas future is evaluated, East Bend 2 economically retires in 2025.

The takeaway from these three scenarios is that without carbon regulation there is less of a driving force to change the portfolio. Furthermore, the economic viability of East Bend 2 may be diminished from two directions – carbon regulation or low gas prices. This will also be an important relationship to monitor going forward.

Figure 6.2: Optimized Portfolios for Scenarios without Carbon Regulation

Ref w/CO_2 (High Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar											20	70	120	170	180
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1184	1234	1284	1334	1344

Ref w/ CO_2 (Base Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	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
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164

Ref w/ CO_2 (Low Gas)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	0	0	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT					580	580	580	580	580	580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144

C. ALTERNATE PORTFOLIOS

In addition to the six optimized portfolios, two transitional and four East Bend 2 replacement strategies were evaluated. The transitional portfolios explore two different trajectories the Duke Energy Kentucky generation fleet could take with respect to renewable additions. This analysis shows the trade-off is that the portfolio with the more measured renewables build out experiences a larger change once the East Bend Unit 2 retires. Conversely, the higher renewables build out offers the benefit of softening the impact of the retirement and replacement of the East Bend Unit 2 but requires a larger overall fleet due to the relatively lower capacity contribution from renewables.

Figure 6.3: Transitional Portfolios

TRANSITIONAL A	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
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
TOTAL	1176	1188	1200	1252	1274	1296	1318	1340	1362	1384	1406	1428	1450	1472	1499

TRANSITIONAL B	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
FDR															363
Solar	25	55	85	125	165	205	235	265	295	325	350	380	415	450	500
Battery	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30
Wind				65	105	145	180	215	250	285	315	350	390	430	470
TOTAL	1191	1223	1255	1362	1444	1526	1593	1660	1727	1794	1851	1918	1995	2072	1927

With East Bend 2 being the single largest resource for the Company, its retirement will be significant. Given that, four different replacement strategies were evaluated to better understand the trade-offs and impacts of each strategy. The retirement date was controlled across each resource strategy at 2030. The reason for this date is that it is in between the retirement dates of the optimized portfolios as well as the planning period.

The first strategy tested was the conversion of East Bend Unit 2 to an electric generation facility that burns gas. This would require a change to the boiler and cost less than a new generator, but the variable costs of such a unit would be higher. This would reduce the capacity factor of the unit and cause Duke Energy Kentucky to become reliant on the market to supply its customers with energy.

Gas generation was featured in the next two portfolios in the form of CC or CT technology. The performance of these two is really a matter of tradeoffs. The CC portfolio has a greater capital cost which provides lower going forward production costs with a lower carbon emissions rate and reduced reliance on market purchases. The CT portfolio comes with lower capital costs (and lower rate impact, all else being equal) but with higher production costs.

Lastly, a portfolio was created that replaced East Bend 2 with a significant amount of renewable resources. It was also worth noting that due to the lower capacity factor of renewables, more MWs of generation needed to be added than were retired in order to be able to serve customers with sufficient energy and not be overly reliant on the market. When replacing higher capacity factor, dispatchable generation with lower capacity factor intermittent generation, more MWs need to be added than retired in general.

Figure 6.4: East Bend 2 Replacement Portfolios

EB2 Gas Conversion	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
EB2 Gas Conversion										600	600	600	600	600	600
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1214	1264	1314	1349

EB2 Retire / CC replacement	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
CC										611	611	611	611	611	611
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1175	1175	1225	1275	1325	1360

EB2 Retire / CT replacement	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
CT										580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1144	1144	1194	1244	1294	1329

EB2 Retire / Ren replacement	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar			40	140	240	340	440	540	640	740	840	940	1040	1140	1240
CT										232	232	232	232	232	232
Battery										150	150	150	150	150	150
Wind				45	95	145	195	245	295	345	345	345	345	345	345
TOTAL	1164	1164	1204	1349	1499	1649	1799	1949	2099	2031	2131	2231	2331	2431	2531

D. LOW COST RENEWABLE SENSITIVITY

Given the interrelated nature of the markets and operations, a traditional sensitivity analysis where a single variable is changed is overly simplistic. To address the impact of lower renewable costs which could come from technological innovation, cost reductions in manufacturing and installation or tax incentives, the capital costs were reduced by 20%. One item of note is that as more solar and wind generation enters the market; those resources will have a depressive impact on the hourly PJM power price which affects the economics of future renewable generation. This new equilibrium is one that will be further impacted by the nature of environmental regulations and fuel markets.

Figure 6.5: Low Cost Renewables Portfolios in Scenarios with and w/o CO_2 Regulation

Low Cost Renewables in Reference w/No CO_2 Reg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	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
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164

Low Cost Renewables in Reference w/ CO_2 Reg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar							484	484	484	484	484	484	484	484	484
CC							45	50	55	80	130	180	215	235	255
TOTAL	1164	1164	1164	1164	1164	1164	1093	1098	1103	1128	1178	1228	1263	1293	1363

In the scenario without carbon regulation, no renewable generation was selected despite the lower cost partially due to the lack of projected resource need. However, in the scenario with carbon regulation, solar is selected within two years of carbon regulation becoming effective.

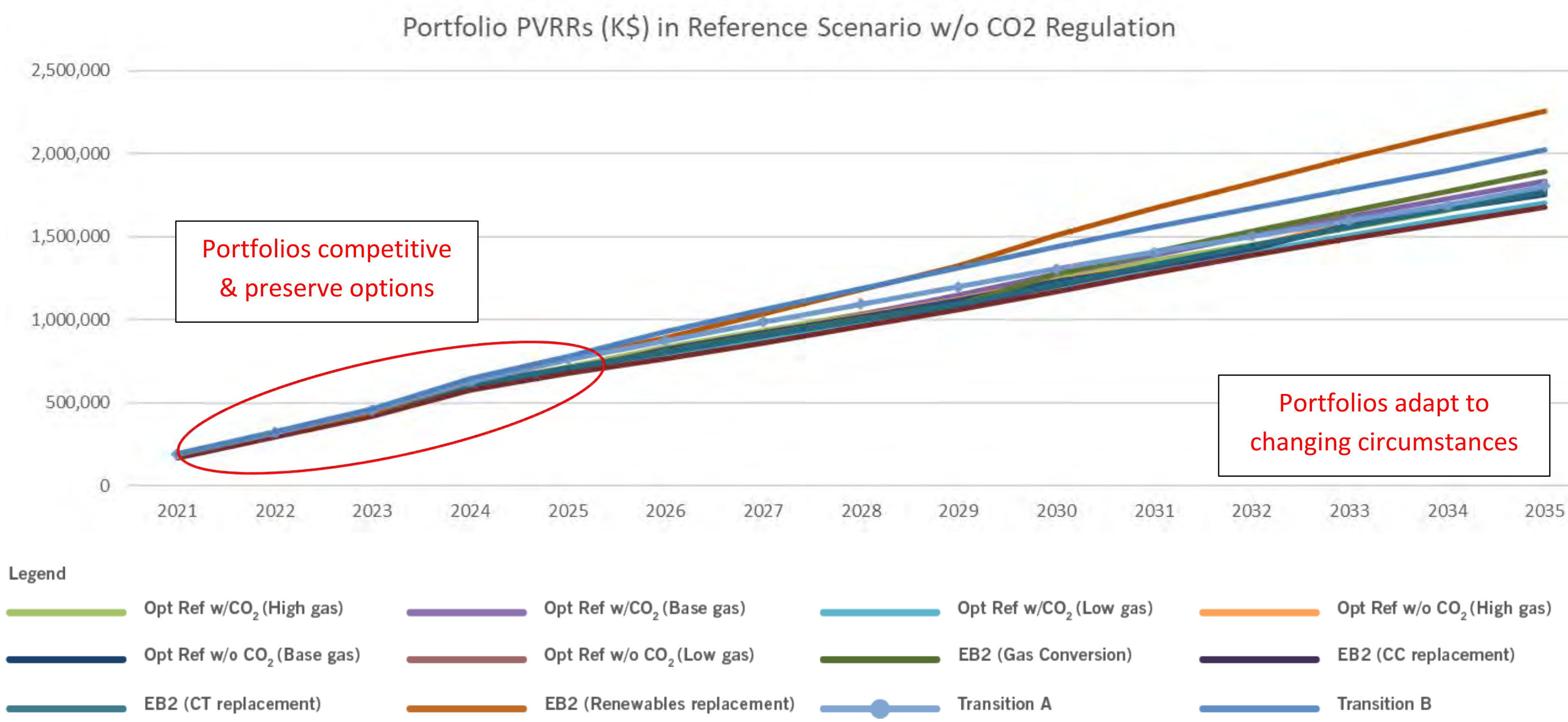
When all the portfolios are considered, it is noteworthy that changes occur within a few years after carbon regulation is put in place. In many cases, the timing of these changes is less than the time it takes to go through the permitting process, procure resources and construct the facility. Because of this, preparing for the likelihood of increased environmental regulation is a prudent course of action.

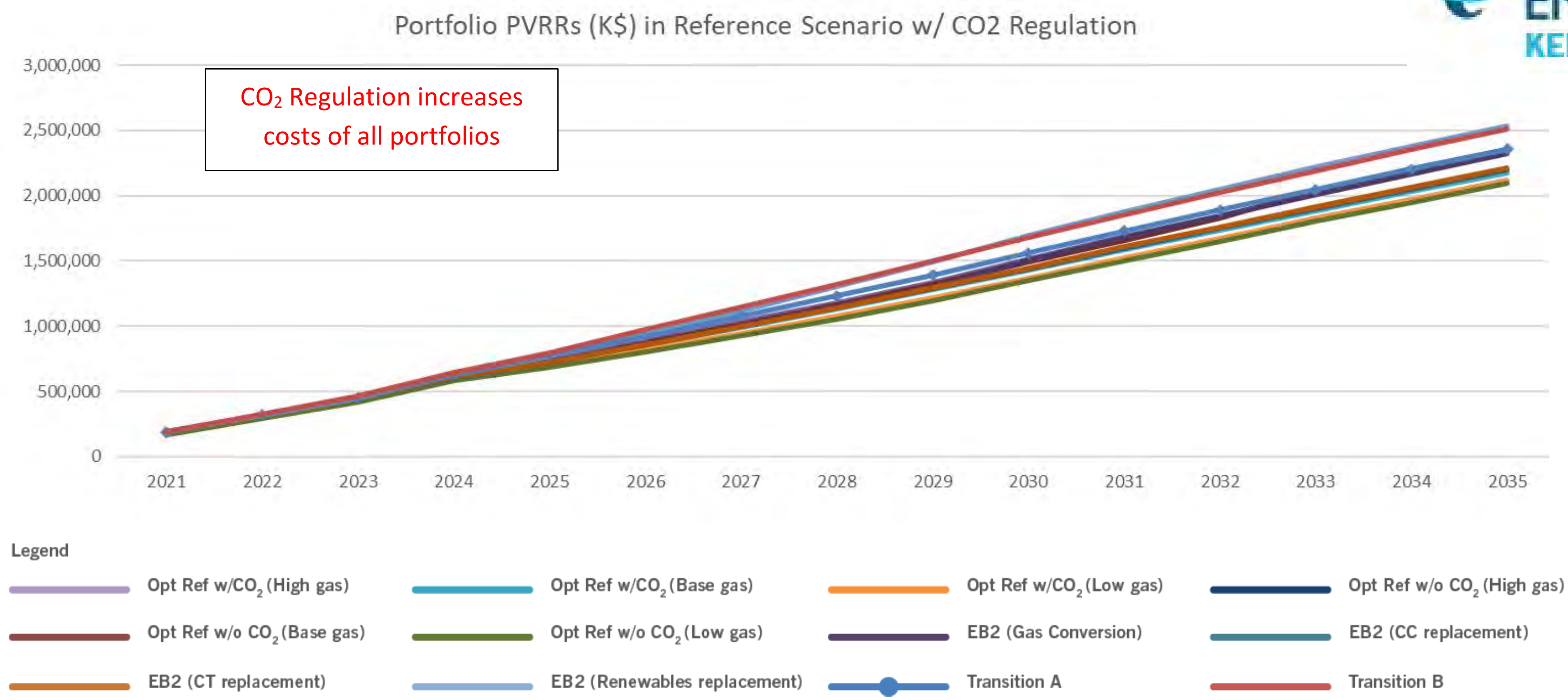
E. COST, CO_2 REDUCTION & MARKET EXPOSURE

The results of the selections made by the optimization model are instructive and provide considerable insight on the drivers of the resource selection. The next phase is to look at other output metrics of additional model runs. The focus of the analysis will be in three broad areas – cost/rates, CO_2 reduction and market exposure.

COST: Figure 6.6 shows the evolution of PVRR over time. Given the ability to adapt to new information, the cost data in the early years should be the primary focus. The first chart shows cost data in the Reference Scenario without CO_2 regulation; the second chart shows cost data in the Reference Scenario with CO_2 regulation.

Figure 6.6: Cumulative PVRR of various portfolios



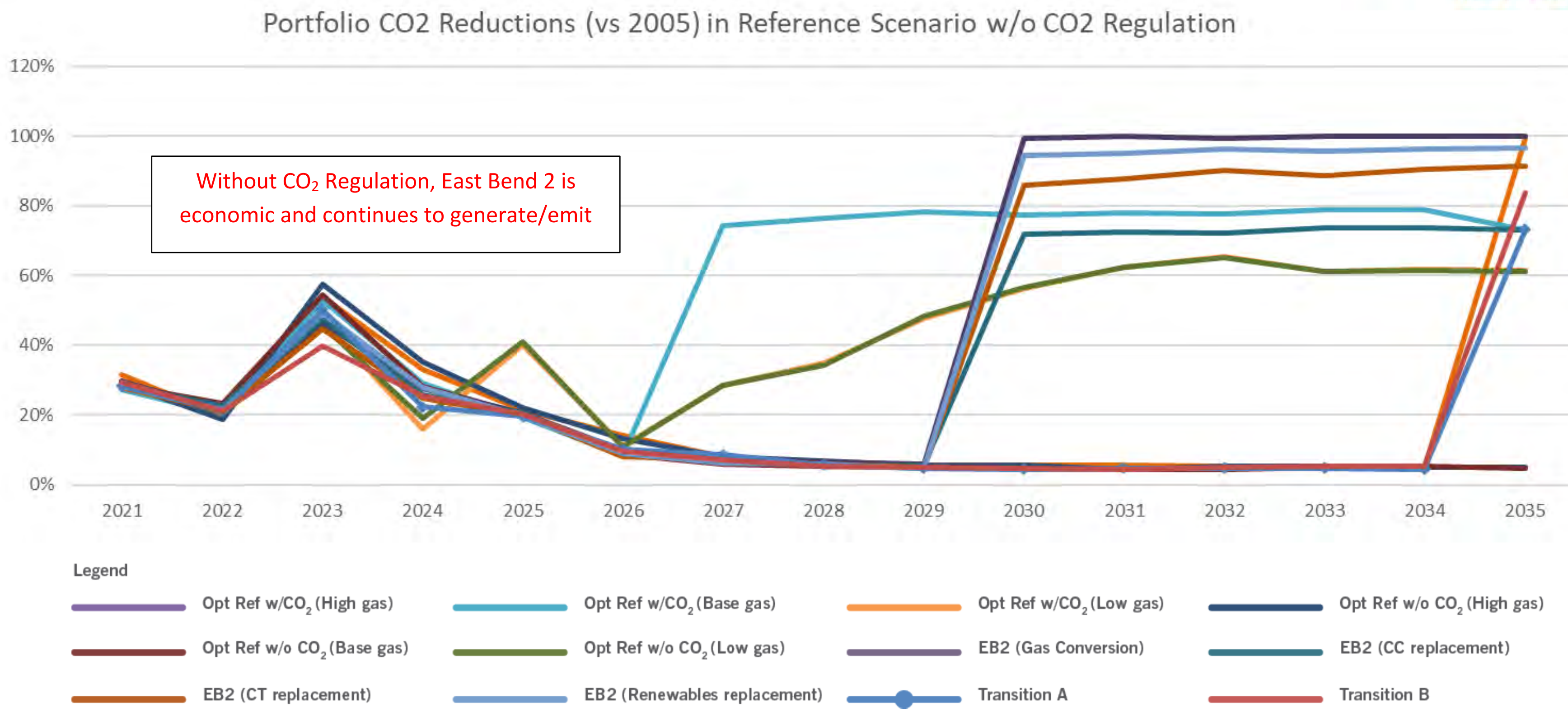


Portfolio PVRRs (K$) in Reference Scenario w/ CO2 Regulation
CO_2 Regulation increases costs of all portfolios
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Legend
Opt Ref w/CO_2 (High gas)
Opt Ref w/CO_2 (Base gas)
Opt Ref w/CO_2 (Low gas)
Opt Ref w/o CO_2 (High gas)
Opt Ref w/o CO_2 (Base gas)
Opt Ref w/o CO_2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B

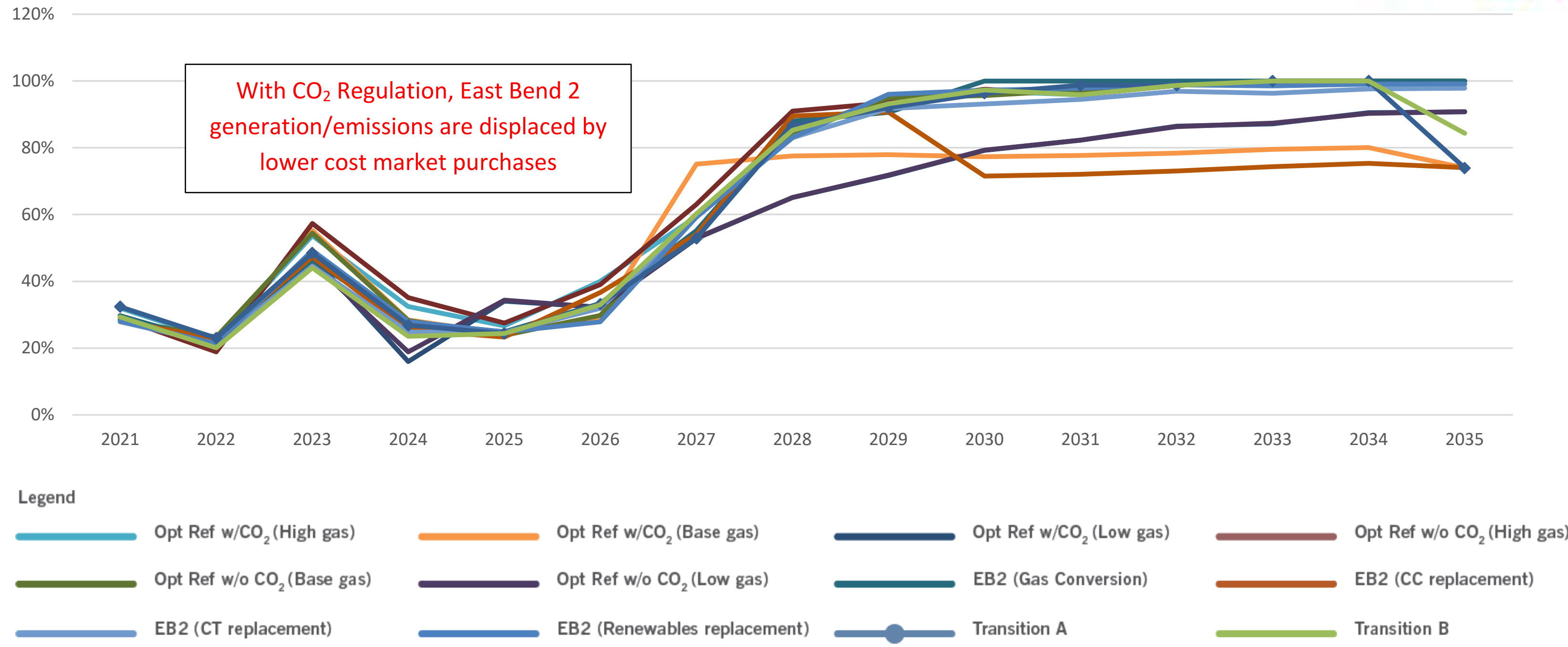
The take-away from both analyses is that cost is driven mostly by the timing of the resource addition that replaces East Bend 2. As of today, East Bend 2's expected retirement is beyond the date of the next IRP in 2024 and will continue to be a point of primary focus. It is also significant to note that any regulation that adversely affects coal generation will raise the cost of East Bend 2, thereby making it less economic and presenting a meaningful impact to customer rates.

CO_2 REDUCTION: Figure 6.7 shows the levels of projected CO_2 reduction over time. Each chart shows very different trajectories despite all the portfolios being the same in the two charts. The difference is attributable to the impact of the carbon tax on the dispatch cost of each generator. The first chart shows CO_2 reductions in the Reference Scenario without CO_2 regulation; the second chart shows CO_2 reductions in the Reference Scenario with CO_2 regulation.

Figure 6.7: CO_2 Reduction of various portfolios



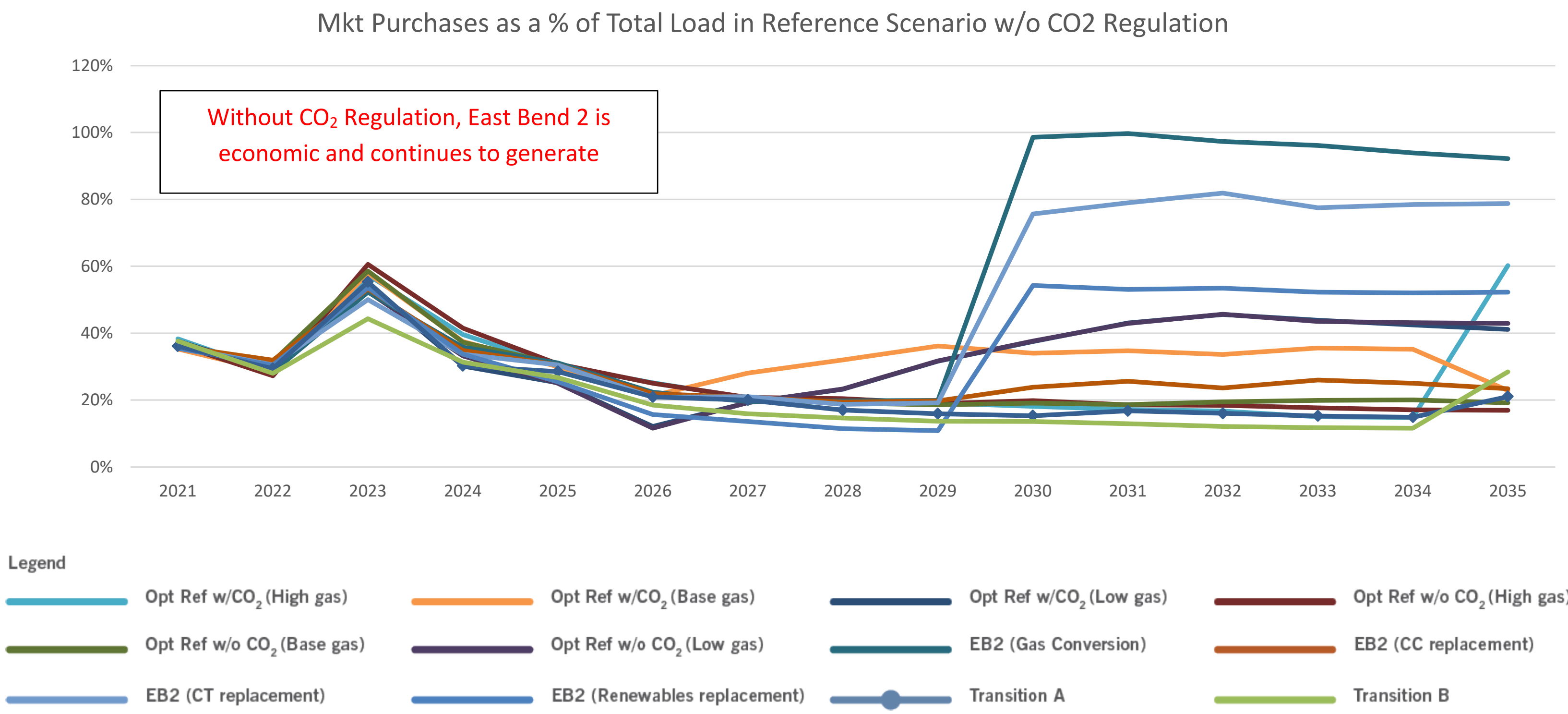
Portfolio CO2 Reductions (vs 2005) in Reference Scenario w/ CO2 Regulation

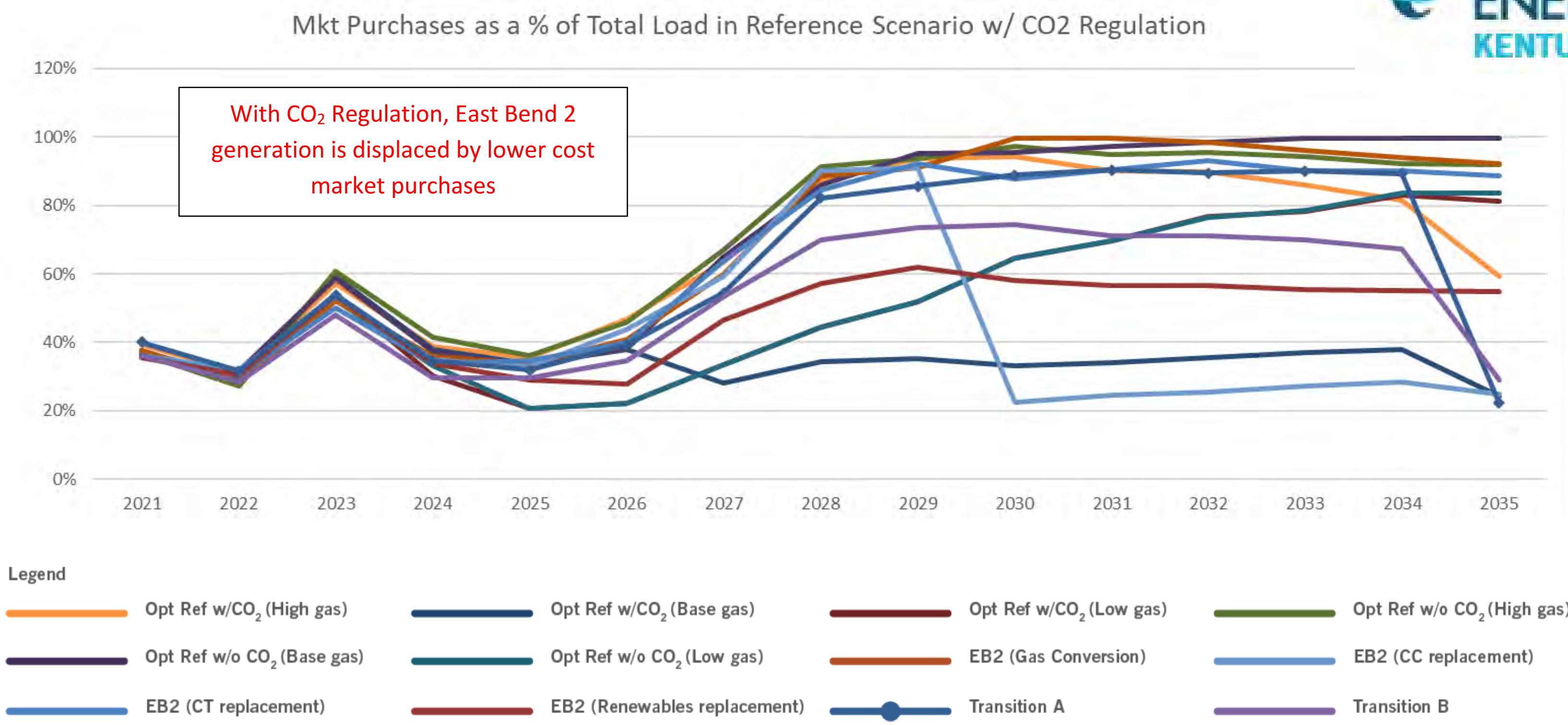


The take-away from both analyses is that CO_2 reduction is driven by carbon regulation in the near term and the timing of the retirement of East Bend 2 in the longer term. The high reduction levels prior to East Bend 2 retirement are due to market purchases not counting toward emissions under current industry reporting standards.

MARKET EXPOSURE: Figure 6.8 shows the percentage of each portfolio's energy mix over time. The first chart shows purchase data in the Reference Scenario without CO_2 regulation; the second chart shows purchase data in the Reference Scenario with CO_2 regulation.

Figure 6.8: Market Purchase Percentage of various portfolios





Mkt Purchases as a % of Total Load in Reference Scenario w/ CO2 Regulation
With CO_2 Regulation, East Bend 2 generation is displaced by lower cost market purchases
120%
100%
80%
60%
40%
20%
0%
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Legend
Opt Ref w/CO_2 (High gas)
Opt Ref w/CO_2 (Base gas)
Opt Ref w/CO_2 (Low gas)
Opt Ref w/o CO_2 (High gas)
Opt Ref w/o CO_2 (Base gas)
Opt Ref w/o CO_2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B

The take-away from both analyses is that, as carbon regulation decreases generation from East Bend 2, the displaced generation is made up by increased levels of market purchases. In the scenario without carbon regulation, East Bend 2 continues to operate at a higher capacity factor resulting in lower market purchases.

The somewhat binary impacts of the presence or absence of carbon regulation supports the continued operation of East Bend 2 while it is economic to do so, but also triggers the transition to a portfolio with greater levels of renewables to better position for the ultimate likelihood of carbon legislation and other forms of environmental regulation, as well as potential fuel or reagent supply issues, that could rapidly increase costs for customers.

A. PLAN OVERVIEW

Based on cost competitiveness (particularly in the near term), the flexibility in the plan, the increase in fleet diversity, CO_2 reduction and the moderate level of market purchases, the 2021 IRP Portfolio is presented in detail below.

Figure 7.1 2021 IRP Portfolio

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
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
TOTAL	1176	1188	1200	1252	1274	1296	1318	1340	1362	1384	1406	1428	1450	1472	1499

This portfolio starts to transition in a measured way while preserving the option to pivot should new regulations come to pass, a change in market prices or the development of a new cost-effective generating resource.

Retirement of East Bend 2 was accelerated to 2035, compared to the 2041 retirement date in the most recent rate case. This approach better positions the portfolio to respond to risk drivers identified in the scenarios that called for the retirement of East Bend 2 in the mid-2020s. This will also make the transition once East Bend 2 retires less impactful to customers by preparing for that possibility.

B. KEY VARIABLES TO MONITOR AHEAD OF 2024 IRP

In terms of impact, the following variables have potentially the greatest impact on the Duke Energy Kentucky generation fleet:

Natural Gas Prices and Impact on Power Markets

The relationship between gas prices and the power prices has been previously discussed. If natural gas prices and power prices increase, the likely impact will be additional generation from East Bend 2 and a decrease in market purchases. If natural gas prices and power prices decrease, the likely impact will be a decrease in generation from East Bend 2 and an increase in market purchases. Persistent low gas prices are a factor that diminishes the competitiveness of East Bend 2 and could be part of the set of conditions that would justify economic retirement of the unit.

Cost of Renewables

The cost of renewable resources is decreasing, which increases the competitiveness of these resources in the market. These near zero variable cost resources have a depressive influence on the power markets, which moderates this impact. As more intermittent resources are added to the Company's system and throughout the PJM footprint, the need for resources that can provide grid support increases. And, as the demands on the grid increase while more coal units are retired, there will be a greater role for energy storage and other new renewable enabling technologies to provide value.

Environmental Regulations Including CO_2

As a regulated utility, environmental regulations are closely monitored, and Duke Energy is an active participant in many environmental regulation discussions. In general, the Duke Energy Kentucky generation fleet is well positioned from the standpoint of complying with current regulations, but increasing stringency of regulations, including but not limited to the potential enactment of a cost on carbon emissions could have a negative impact on East Bend 2 and, to a lesser extent, on Woodsdale Station. A straight CO_2 price on carbon emissions would raise the dispatch cost of East Bend 2 and, in doing so, reduce its capacity factor and the overall CO_2 emissions associated with serving customers' load. CO_2 regulation has the potential to be quite impactful to the operations and remaining economic service life of East Bend 2.

Changes in Load Forecasts

Forecasts of customer loads are frequently monitored and modeled as described in Appendix B. In general, load growth greater than expectation tends to accelerate additions to the source plan and, depending on timing and nature of load growth, could change the resource selection. Conversely, slower than expected load tends to delay resource additions.

Changes in PJM Requirements

Due to changes in requirements for PJM participation, such as the Capacity Performance requirement to increase reliability, the Company will continue to monitor and plan accordingly in a way that is most efficient and cost effective for customers.

TRANSMISSION AND DISTRIBUTION FORECAST

APPENDIX A

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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 2018-2020 for the purposes of increasing capacity and/or reliability:

- **2018:** No transmission system improvements were implemented;
- **2019:** No transmission system improvements were implemented; and
- **2020:** Installed 138-69 kV, 150 MVA transformer at Oakbrook substation. Erected 138 kV line from Oakbrook Substation to the new Aero Substation.

The following transmission system improvements are planned for 2021-2023, with exact timing subject to change:

- **2021:** Erect 138 kV line from Aero Substation to Duke Energy Ohio owned Woodspoint Substation;
- **2022:** No transmission system improvements are planned; and
- **2023:** Erect 69 kV line, approximately 1 mile in length, from Hebron Substation to the existing point where the Feeder 15268C line connects to the Feeder 15268 main 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.

The following improvements were made to the distribution system in 2018-2020 for the purposes of increasing capacity and/or reliability:

- **2018:** Covington TB 2, Cir 43 & 44; New 69 kV- 12 kV 22.4 MVA Trans & 2 circuits Augustine TB 3; new 138- 12 kV 22.4 MVA trans
- **2019:** Donaldson TB 3 & TB 4, Cir 46 & 48; 2 new 138- 12 kV 22.4 MVA trans, 2 circuits cut in
- **2020:** Donaldson Cir 45 & 47; 2 circuits cut in Donaldson 43 moved from inaccessible ROW to UG; Dixie TB 4 Cir 45 & 46; New 69- 12 kV, 22.4 MVA trans & 2 circuits
  Mt Zion TB 2; new 138- 12 kV trans Aero TB 1-4; New substation and 4 new 22.4 MVA trans (90 MVA total) and associated equipment to feed Amazon Air hub and local loading.

The following distribution system improvements are planned for 2021-2023, with exact timing subject to change:

- **2021:** Longbranch Substation – Add second 22.4 MVA with two new circuits; Dry Ridge Substation – Add second transformer
- **2022:** Richwood Substation – Add transformer

- **2023:** White Tower Substation – Add third 10.5 MVA transformer

D. RESPONSE TO 8.(3)(A) MAP OF FACILITIES

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 Commission Staff under seal and subject to a motion for confidential treatment, not to be released to the general public.

DUKE ENERGY®

ELECTRIC LOAD FORECAST

APPENDIX B

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B |  ELECTRIC LOAD FORECAST

A. GENERAL

Duke Energy Kentucky provides electric service to approximately 146,000 customers and natural gas service to approximately 102,422 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. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional economy.

a. Service Area Economy

The service area economy is described by employment, income, inflation, population, production, and output measures, forecasts of which are provided by Moody's. Employment projections include non-agricultural, commercial, industrial, and government sectors. Income for the local economy is forecasted in several categories including wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments, which are combined to produce the forecast of income less personal contributions for social insurance. Inflation is measured by changes in the Personal Consumption Expenditure Index (PCE) for gasoline and other energy goods, or by the Consumer Price index (CPI). Demographic projections include population and households for the Duke Energy Kentucky territory. This information is an input to the energy and peak load forecast models.

b. Electric Energy Forecast

The forecast methodology recognizes that the use of energy is dependent upon key economic factors, as well as historical and projected end-use appliance intensities, and weather. The projected energy requirements for Duke Energy Kentucky's retail electric customers are determined through econometric analysis. Econometric models — sometimes referred to as "regression analysis" — are a means of predicting economic behavior and relationships through the use of statistical methods.

The Duke Energy Kentucky sales forecast is developed by separately forecasting the energy requirements for each of several major customer groups: residential, commercial, industrial, governmental, or other public authority, and street lighting energy sectors. Forecasts are also prepared for three minor categories: Interdepartmental Use (Gas Department), Company Use, and Losses. Similarly, the Duke Energy Kentucky peak load forecast is developed from the aforementioned energy forecast. The following sections provide the specifications of the econometric relationships used to forecast electricity sales for Duke Energy Kentucky's service territory.

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, the number of households, 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 Sector - The forecast of total commercial sales is developed by multiplying the forecasts of the number of commercial customers and kWh energy usage per customer.

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.

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. 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.

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 heating degree days.

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.

C. ASSUMPTIONS

a. 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 prepared as prepared by Moody's analytics. While it is standard — in previous cycles — to use a "baseline" forecast without major wars, economic disruptions, or energy embargoes, Moody's has responded to the current COVID-related disruptions by employing epidemiological modeling techniques and building estimates of Federal Fiscal actions into their baseline scenario. Information on how they do this has been made public by them. While the current crisis has radically affected lives and property, the long-range path of the overall forecast is less gravely altered because of the underlying dynamics of capital accumulation and the ability of vaccinated persons to return to work. Moody's also supplies a "Consensus" scenario, which allows for some projections to be brought down into the very center of the range of alternative forecast providers, but the two were very similar in this cycle.

Observers of the economy over the past thirteen years have good reasons to approach these predictions with humility. The catastrophic recession of 2008 left behind balance sheet scarring and debt overhangs out of which it took years to grow. Frustration with the unevenness and weakness of the recovery has led to a series of changes with regard to policy-making, and the labor market frigidity was unkind to the Cincinnati PMSA, which routinely ranked in the bottom half of major cities with regard to net in-migration from 2010-on. The violent whipsawing of spending and asset prices associated with the SARS-COVID-2 pandemic resulted in recorded economic data that was unlike anything seen since 1945, both downward (during spring of 2020), and upward (during the late summer of 2020). The ultimate outcome in the near term is dependent upon vaccinations and policy as much as economic factors, but we believe — and this is the consensus view among forecasters — that the long-term laws of positive motion remain unchanged. Saving, capital accumulation, and technological progress will continue to determine how rapidly the economy progresses.

With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well-positioned to make the adjustments necessary for continuing 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, data centers, and logistics. In addition, the Cincinnati area is the headquarters for major international and national market-oriented retailing establishments.

b. 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 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 2020-2040, Duke Energy Kentucky's service area population is expected to increase at an annual average rate of 0.45%, below expected national growth of 0.6% 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.

c. 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 – In the following table, historical and projected average year residential customers for the entire service area are provided.

Figure B-0a: Residential Customers by Year

YEAR	RESIDENTIAL CUSTOMERS
2015	122,962
2016	124,307
2017	125,796
2018	126,987
2019	128,049
2020	130,434
2021	130,847
2022	131,957
2023	133,079
2024	134,170
2025	135,208
2026	136,187
2027	137,091
2028	137,974
2029	138,850
2030	139,694
2031	140,488
2032	141,279
2033	142,050
2034	142,785
2035	143,521
2036	144,259
2037	144,971
2038	145,671
2039	146,367
2040	147,055

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

a. 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.

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.

b. 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 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 thirty-year normal day on a monthly basis.

c. 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.

d. 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.

a. Specific Analytical Techniques

Regression Analysis - Ordinary least squares is the principle 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.

Serial Correlation - It is often the case in forecasting an economic time series that residual errors in one period are related to those in a previous period. This is known as serial correlation. By correcting for this serial correlation of the estimated residuals using time series methods, forecast error is reduced and the estimated coefficients are more efficient. An auto-regressive error term is employed to correct for the existence of autocorrelation.

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.

b. 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.

c. 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.

d. 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.

e. Computer Software

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

F. FORECASTED DEMAND AND ENERGY

On the following pages, the loads for Duke Energy Kentucky are provided. Forecast data is provided before and after the incremental impacts of EE programs. The term “Internal” refers to a forecast without reductions for either EE or DR. The term “Native” refers to the Internal forecast reduced by DR.

a. Service Area Energy Forecasts

Figure B-1 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 1.2 percent per year; Commercial energy, 0.3 percent per year; and Industrial energy, 1.3 percent per year. The summation of the forecast across all sectors and including losses results in a growth rate forecast of 1.0 percent for Net Energy for Load. The impact of any expected EE programs on these growth rates is *de minimis*.

b. System Seasonal Peak Load Forecast

Figure B-3 summarizes historical and projected growth of the internal peak 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 2020-2040 is 0.7 percent. Projected growth in the winter peak demand is 0.8 percent. Including the expected impacts of EE programs will not change these results very much.

c. 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 internal and native peak loads consists of the impact from these controllable loads. See Chapter 4 for a discussion of the impacts of DR programs.

d. Load Factor

The table below represent the annual percentage load factor for the Duke Energy Kentucky System before any new or incremental EE. It shows the relationship between Net Energy for Load, Figure B-1, and the annual peak, Figure B-3, before EE.

Figure B-0b: Load Factor Calculations, Duke Energy Kentucky

YEAR	CUSTOMERS
2015	56.7%
2016	52.8%
2017	53.5%
2018	55.4%
2019	54.9%
2020	54.1%
2021	55.7%
2022	56.0%
2023	56.1%
2024	55.9%
2025	56.2%
2026	56.1%
2027	56.2%
2028	56.1%
2029	56.3%
2030	56.4%
2031	56.4%
2032	56.2%
2033	56.4%
2034	56.3%
2035	56.3%
2036	56.1%
2037	56.1%
2038	56.0%
2039	56.0%
2040	55.8%

e. 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 generating the high and low forecasts, Duke Energy Kentucky used divergent economic scenarios from Moody's analytics, with the higher one intended to represent strong short-term upside growth in our economic measures, and the lower one intended to correspond to a moderate recession occurring within the next three years. 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 a relatively optimistic scenario about the future growth of Duke Energy Kentucky sales while the lower band reflects a pessimistic scenario.

Figure B-5 provides the high, low, and most likely 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.

f. Monthly Forecast

Figures B-7 through B-10 contain the net monthly energy forecast, the net monthly internal peak load forecast, and the energy forecast by customer class for the total Duke Energy Kentucky system before and after EE.

g. Conclusion

Our expectations are for continuing growth in the near-term, as the economy resumes an approach to full employment that was interrupted in early 2020 by the pandemic and associated shutdowns. This growth is particularly supported by population growth (for residential sales), and significant expansion for industrial sales. While we write this at a moment of remarkable economic dynamism, 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 0.5% - 1.5% higher or lower than projected.

Figure B-0c: Load Forecasting Models- Coefficients and Statistics

Dep Var: Quarterly OPA sales	Coefficient	StdErr	T-Stat	P-Value	Definition
indep_vars.ky_gdp_gov	[redacted]	[redacted]	[redacted]	[redacted]	Real Government GDP
indep_vars.CDD_65	[redacted]	[redacted]	[redacted]	[redacted]	Cooling Degree Days
indep_vars.HDD_59	[redacted]	[redacted]	[redacted]	[redacted]	Heating Degree Days
AR(1)	[redacted]	[redacted]	[redacted]	[redacted]	

Dep Var: Quarterly Industrial Sales	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	[redacted]	[redacted]	[redacted]	[redacted]	Constant term
qBinary.q3	[redacted]	[redacted]	[redacted]	[redacted]	
qBinary.q1	[redacted]	[redacted]	[redacted]	[redacted]	
indep_vars.CDD_65	[redacted]	[redacted]	[redacted]	[redacted]	Cooling Degree Days
indep_vars.HDD_59	[redacted]	[redacted]	[redacted]	[redacted]	Heating Degree Days
qSALES_SAE_IND.Price	[redacted]	[redacted]	[redacted]	[redacted]	Price Variable
qSALES_SAE_IND.MFG_ren	[redacted]	[redacted]	[redacted]	[redacted]	Indicator for strong rebound period following 2009
qSALES_SAE_IND.yr06	[redacted]	[redacted]	[redacted]	[redacted]	
qSALES_SAE_IND.mfg	[redacted]	[redacted]	[redacted]	[redacted]	Index computed from employment/output
AR(1)	[redacted]	[redacted]	[redacted]	[redacted]	

Dep Var: Qtrly Commercial Usage (per Cust)	Coefficient	StdErr	T-Stat	P-Value	Definition
indep_vars.CXHeat_B	[redacted]	[redacted]	[redacted]	[redacted]	Heating SAE term, 55-Degree Base
indep_vars.CXCool_B	[redacted]	[redacted]	[redacted]	[redacted]	Cooling SAE term, 65-Degree Base
indep_vars.CXOther_B	[redacted]	[redacted]	[redacted]	[redacted]	Base Load SAE term
qUPC_SAE_COM.late_q3	[redacted]	[redacted]	[redacted]	[redacted]	
qCalendar.q3	[redacted]	[redacted]	[redacted]	[redacted]	
qUPC_SAE_COM.Covid	[redacted]	[redacted]	[redacted]	[redacted]	COVID lockdown indicator
AR(1)	[redacted]	[redacted]	[redacted]	[redacted]	

Dep Var: Qtrlyy Residential Usage (per Cust)	Coefficient	StdErr	T-Stat	P-Value	Definition
indep_vars.RXOther_B	[redacted]	[redacted]	[redacted]	[redacted]	Base Load SAE term
indep_vars.RXHeat1_B	[redacted]	[redacted]	[redacted]	[redacted]	Heating SAE Term, 55-degree Base
indep_vars.RXCool1_B	[redacted]	[redacted]	[redacted]	[redacted]	Cooling SAE Term, 60-degree Base
indep_vars.RXCool2_B	[redacted]	[redacted]	[redacted]	[redacted]	Cooling SAE Term, 70-degree Base
qBinary.q3	[redacted]	[redacted]	[redacted]	[redacted]	
qUPC_SAE_RES.pre2014q3	[redacted]	[redacted]	[redacted]	[redacted]	
qBinary.q2	[redacted]	[redacted]	[redacted]	[redacted]	
AR(1)	[redacted]	[redacted]	[redacted]	[redacted]	

Figure B-0c: Load Forecasting Models- Coefficients and Statistics (Cont'd.)

Dep Var: Change in Residential Customers	Coefficient	StdErr	T-Stat	P-Value	Definition
indep_vars.CH_HH	[redacted]	[redacted]	[redacted]	[redacted]	Quarterly Change in Population of MSA, Households
qBinary.q2	[redacted]	[redacted]	[redacted]	[redacted]	
qBinary.q3	[redacted]	[redacted]	[redacted]	[redacted]	
qBinary.q4	[redacted]	[redacted]	[redacted]	[redacted]	
qBinary.q1	[redacted]	[redacted]	[redacted]	[redacted]	
cust_res_nocovid.Catch_up	[redacted]	[redacted]	[redacted]	[redacted]	Covid/Summer 2020 Indicator Variable

Dep Var: General Service Customers	Coefficient	StdErr	T-Stat	P-Value	Definition
qCalendar.q1	[redacted]	[redacted]	[redacted]	[redacted]	
qCalendar.q2	[redacted]	[redacted]	[redacted]	[redacted]	
qCalendar.q3	[redacted]	[redacted]	[redacted]	[redacted]	
qCalendar.q4	[redacted]	[redacted]	[redacted]	[redacted]	
cust_GENSRV.pre2009	[redacted]	[redacted]	[redacted]	[redacted]	
cust_GENSRV.pre2017q2	[redacted]	[redacted]	[redacted]	[redacted]	
AR(1)	[redacted]	[redacted]	[redacted]	[redacted]	

Dep Var: Monthly SL Volumes	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	[redacted]	[redacted]	[redacted]	[redacted]	Constant term
street_light_fcst.lighting	[redacted]	[redacted]	[redacted]	[redacted]	EIA Lighting Intensity Measure
Calendar.Jan	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Feb	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Mar	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Apr	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.May	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Jun	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Jul	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Aug	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Sep	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Nov	[redacted]	[redacted]	[redacted]	[redacted]	
Calendar.Dec	[redacted]	[redacted]	[redacted]	[redacted]	
street_light_fcst.Expr1	[redacted]	[redacted]	[redacted]	[redacted]	Billing correction for 2020 summer

Figure B-0d: Model for Quarterly OPA Sales Volume

Model for Quarterly OPA 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)	

Figure B-0e: Model for Quarterly Industrial Sales Volume

Model for Quarterly Industrial 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]

Figure B-0f: Model for Quarterly Commercial Usage-Per-Cust

Model for Qtrly Commercial Usage-Per-Cust	
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]

Figure B-0g: Model for Per-Customer Residential Usage

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)	

Figure B-0h: Model for General Service Customers

Model for General Service 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)	

Figure B-0i: Monthly Street Lighting Volume Model

Monthly Street Lighting Volume Model	
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]

Figure B-1 Electric Customers by Major Classification

ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATION					
	1	2	3	4	5
	Residential	Commercial	Governme	Industrial	SL/Other
2015	122,962	13,873	958	371	441
2016	124,307	13,932	958	371	446
2017	125,796	13,710	956	365	447
2018	126,987	13,648	946	360	452
2019	128,049	13,627	935	359	461
2020	130,434	13,899	793	362	469
2021	130,847	13,864	929	357	467
2022	131,957	13,904	927	352	478
2023	133,079	13,941	925	348	489
2024	134,170	13,975	923	345	500
2025	135,208	14,006	922	342	512
2026	136,187	14,035	920	339	523
2027	137,091	14,062	918	336	534
2028	137,974	14,086	917	333	545
2029	138,850	14,109	916	331	557
2030	139,694	14,130	914	328	568
2031	140,488	14,150	913	326	579
2032	141,279	14,168	912	324	591
2033	142,050	14,184	911	322	602
2034	142,785	14,199	910	319	613
2035	143,521	14,214	910	317	625
2036	144,259	14,226	909	315	636
2037	144,971	14,238	908	313	648
2038	145,671	14,250	908	311	659
2039	146,367	14,260	907	309	670
2040	147,055	14,269	906	307	682

Figure B-2a: Duke Energy Kentucky System Service Area Energy Forecast After EE

FIGURE B-2a

DUKE ENERGY KENTUCKY SYSTEM SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)[4] AFTER EE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
							(1+2+3+4+5+6)		(7+8)
Year	Rural and Residential	Commercial	Industrial	Steet-Hwy Lighting	Sales for Resale[b]	Other	Total Consumption	Losses and Unaccounted For[c]	Net Energy for Load
2015	1,445,887	1,477,900	812,522	15,120	0	292,528	4,043,958	320,627	4,364,585
2016	1,451,682	1,494,014	810,977	15,264	0	293,918	4,065,855	322,367	4,388,222
2017	1,395,234	1,450,924	800,034	15,077	0	278,593	3,939,861	312,377	4,252,238
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	1,481,262	1,440,776	812,705	13,664	0	226,890	3,975,297	315,187	4,290,484
2022	1,477,026	1,409,837	866,225	13,617	0	267,691	4,034,396	319,874	4,354,269
2023	1,483,566	1,412,460	931,161	13,581	0	269,316	4,110,083	325,876	4,435,959
2024	1,491,406	1,420,430	928,475	13,563	0	269,470	4,123,345	326,927	4,450,273
2025	1,516,641	1,434,560	957,141	13,549	0	270,048	4,191,939	332,367	4,524,306
2026	1,525,979	1,430,349	950,316	13,534	0	270,884	4,191,062	332,297	4,523,359
2027	1,542,689	1,431,046	945,169	13,524	0	272,318	4,204,745	333,382	4,538,128
2028	1,558,264	1,433,163	943,013	13,516	0	273,964	4,221,921	334,744	4,556,666
2029	1,575,040	1,434,509	940,266	13,510	0	275,523	4,238,847	336,087	4,574,934
2030	1,599,006	1,436,910	973,099	13,438	0	277,103	4,299,556	340,901	4,640,457
2031	1,615,818	1,434,916	972,076	13,386	0	278,521	4,314,718	342,103	4,656,821
2032	1,638,609	1,439,347	971,338	13,356	0	279,814	4,342,465	344,304	4,686,768
2033	1,664,855	1,443,726	968,388	13,346	0	280,927	4,371,241	346,586	4,717,827
2034	1,686,490	1,445,171	965,092	13,339	0	281,823	4,391,916	348,225	4,740,141
2035	1,716,110	1,452,757	963,369	13,338	0	282,805	4,428,379	351,117	4,779,496
2036	1,755,426	1,470,077	964,939	13,339	0	284,013	4,487,794	355,828	4,843,623
2037	1,779,930	1,475,189	965,972	13,340	0	285,029	4,519,461	358,339	4,877,800
2038	1,812,453	1,487,979	967,982	13,342	0	285,968	4,567,724	362,167	4,929,891
2039	1,844,418	1,501,546	970,167	13,343	0	286,796	4,616,270	366,016	4,982,287
2040	1,876,353	1,506,320	973,054	13,329	0	287,655	4,656,711	369,223	5,025,934

(a) Includes EE Impacts

(b) Sales for resale to municipals.

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

Figure B-2b: Duke Energy Kentucky System Service Area Energy Forecast Before EE

FIGURE B-2b
DUKE ENERGY KENTUCKY SYSTEM SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)[4] BEFORE EE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Rural and Residential	Commercial	Industrial	Street-Hwy Lighting	Sales for Resale[a]	Other	(1+2+3+4+5+6) Total Consumption	Losses and Unaccounted For[b]	(7+8) Net Energy for Load
2015	1,445,887	1,477,900	812,522	15,120	0	292,528	4,043,958	320,627	4,364,585
2016	1,451,682	1,498,287	818,455	15,264	0	296,767	4,080,455	323,525	4,403,980
2017	1,395,234	1,457,929	812,294	15,077	0	283,263	3,963,797	314,275	4,278,071
2018	1,568,884	1,489,143	831,846	14,317	0	292,331	4,196,521	332,723	4,529,244
2019	1,529,903	1,475,224	843,415	13,759	0	286,577	4,148,879	328,953	4,477,832
2020	1,494,087	1,469,752	838,398	13,827	0	281,570	4,097,635	324,893	4,422,528
2021	1,483,075	1,441,951	816,816	13,664	0	227,673	3,983,179	315,812	4,298,991
2022	1,482,005	1,413,155	877,839	13,617	0	269,903	4,056,520	321,628	4,378,148
2023	1,491,383	1,417,868	950,091	13,581	0	272,921	4,145,843	328,711	4,474,555
2024	1,501,878	1,427,897	954,607	13,563	0	274,448	4,172,392	330,817	4,503,209
2025	1,529,707	1,444,041	990,324	13,549	0	276,369	4,253,989	337,287	4,591,277
2026	1,541,613	1,441,815	990,447	13,534	0	278,528	4,265,938	338,235	4,604,172
2027	1,560,889	1,444,497	992,250	13,524	0	281,285	4,292,447	340,337	4,632,784
2028	1,579,031	1,448,602	997,047	13,516	0	284,256	4,322,451	342,716	4,665,168
2029	1,598,222	1,451,934	1,001,253	13,510	0	287,140	4,352,058	345,064	4,697,122
2030	1,624,475	1,456,322	1,041,040	13,438	0	290,044	4,425,318	350,874	4,776,192
2031	1,643,231	1,456,057	1,046,067	13,386	0	292,615	4,451,356	352,939	4,804,295
2032	1,667,456	1,462,003	1,050,634	13,356	0	294,918	4,488,367	355,874	4,844,240
2033	1,694,521	1,467,913	1,053,042	13,346	0	297,051	4,525,873	358,848	4,884,720
2034	1,716,795	1,470,885	1,055,090	13,339	0	298,966	4,555,075	361,164	4,916,238
2035	1,747,065	1,479,484	1,056,914	13,338	0	300,623	4,597,424	364,522	4,961,946
2036	1,786,508	1,497,012	1,059,210	13,339	0	301,970	4,658,039	369,329	5,027,368
2037	1,810,899	1,502,024	1,059,895	13,340	0	302,919	4,689,078	371,790	5,060,868
2038	1,843,421	1,514,744	1,061,660	13,342	0	303,811	4,736,979	375,588	5,112,567
2039	1,875,408	1,528,266	1,063,687	13,343	0	304,609	4,785,312	379,421	5,164,734
2040	1,907,362	1,533,025	1,066,520	13,329	0	305,458	4,825,694	382,624	5,208,317

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

Figure B-3a: Duke Energy Kentucky System Seasonal Peak Load Forecast Before EE, After DR Native Load

FIGURE B-3a
DUKE ENERGY KENTUCKY SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) BEFORE EE, AFTER DR NATIVE LOAD

		SUMMER			WINTER[d]		
	YEAR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
-5	2015	814			739		
-4	2016	877	63	7.7%	733	(6)	-0.8%
-3	2017	841	(36)	-4.1%	797	64	8.7%
-2	2018	857	16	1.9%	821	24	3.0%
-1	2019	849	(8)	-0.9%	742	(79)	-9.6%
0	2020	809	(40)	-4.7%	678	(64)	-8.6%
1	2021	784	(25)	-3.0%	726	48	7.1%
2	2022	793	9	1.1%	740	14	1.9%
3	2023	809	16	2.0%	739	(0)	-0.1%
4	2024	816	7	0.9%	755	16	2.1%
5	2025	829	12	1.5%	751	(4)	-0.5%
6	2026	832	3	0.4%	750	(1)	-0.2%
7	2027	836	4	0.5%	747	(3)	-0.4%
8	2028	841	5	0.6%	748	1	0.1%
9	2029	846	5	0.6%	760	12	1.6%
10	2030	858	12	1.5%	760	0	0.0%
11	2031	863	5	0.6%	761	1	0.1%
12	2032	871	8	0.9%	757	(4)	-0.5%
13	2033	878	7	0.8%	757	(1)	-0.1%
14	2034	885	7	0.7%	767	10	1.3%
15	2035	894	9	1.0%	784	18	2.3%
16	2036	903	9	1.0%	790	6	0.7%
17	2037	910	8	0.8%	789	(1)	-0.1%
18	2038	923	13	1.4%	795	5	0.7%
19	2039	933	10	1.1%	794	(1)	-0.1%
20	2040	941	8	0.8%	816	22	2.7%

(a) Includes controllable load.
(b) Difference between reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads which occur in the following winter.

Figure B-3b: Duke Energy Kentucky System Seasonal Peak Load Forecast Before EE Internal Load

FIGURE B-3b
DUKE ENERGY KENTUCKY SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) BEFORE EE INTERNAL LOAD[2]

	SUMMER			WINTER[d]		
YEAR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
2015	814			739		
2016	877	63	7.7%	733	(6)	-0.8%
2017	841	(36)	-4.1%	797	64	8.7%
2018	857	16	1.9%	821	24	3.0%
2019	849	(8)	-0.9%	742	(79)	-9.6%
2020	809	(40)	-4.7%	678	(64)	-8.6%
2021	816	7	0.9%	733	55	8.2%
2022	826	10	1.2%	747	14	1.9%
2023	842	16	2.0%	747	(0)	-0.1%
2024	850	7	0.9%	763	16	2.1%
2025	862	12	1.5%	759	(4)	-0.5%
2026	865	3	0.4%	757	(1)	-0.2%
2027	869	4	0.5%	754	(3)	-0.4%
2028	874	5	0.6%	755	1	0.1%
2029	879	5	0.5%	768	12	1.6%
2030	891	12	1.4%	768	0	0.0%
2031	896	5	0.6%	769	1	0.1%
2032	904	8	0.9%	765	(4)	-0.5%
2033	912	7	0.8%	764	(1)	-0.1%
2034	918	7	0.7%	774	10	1.3%
2035	927	9	0.9%	792	18	2.3%
2036	936	9	1.0%	798	6	0.7%
2037	943	8	0.8%	797	(1)	-0.1%
2038	956	13	1.3%	802	5	0.7%
2039	966	10	1.1%	802	(1)	-0.1%
2040	974	8	0.8%	823	22	2.7%

(a) Excludes controllable load.
(b) Difference between reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads which occur in the following winter.

Figure B-4a: Duke Energy Kentucky System Seasonal Peak Load Forecast After EE, After DR Native Load

FIGURE B-4a
DUKE ENERGY KENTUCKY SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) AFTER EE, AFTER DR NATIVE LOAD[b]

	SUMMER			WINTER[d]		
YEAR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
2015	814	814	#DIV/0!	739	739	#DIV/0!
2016	877	63	7.7%	733	(6)	-0.8%
2017	841	(36)	-4.1%	797	64	8.7%
2018	857	16	1.9%	821	24	3.0%
2019	849	(8)	-0.9%	742	(79)	-9.6%
2020	809	(40)	-4.7%	678	(64)	-8.6%
2021	783	(26)	-3.2%	726	48	7.1%
2022	789	6	0.8%	740	14	1.9%
2023	803	14	1.8%	739	(0)	-0.1%
2024	807	4	0.5%	755	16	2.1%
2025	818	11	1.4%	751	(4)	-0.5%
2026	819	1	0.1%	750	(1)	-0.2%
2027	821	2	0.2%	747	(3)	-0.4%
2028	824	3	0.3%	748	1	0.1%
2029	827	3	0.3%	760	12	1.6%
2030	837	10	1.3%	760	0	0.0%
2031	841	3	0.4%	761	1	0.1%
2032	846	6	0.7%	757	(4)	-0.5%
2033	852	5	0.6%	757	(1)	-0.1%
2034	857	5	0.6%	767	10	1.3%
2035	865	8	0.9%	784	18	2.3%
2036	878	13	1.6%	790	6	0.7%
2037	886	8	0.9%	789	(1)	-0.1%
2038	898	12	1.4%	795	5	0.7%
2039	909	10	1.2%	794	(1)	-0.1%
2040	917	8	0.9%	816	22	2.7%

Figure B-4b: Duke Energy Kentucky System Seasonal Peak Load Forecast After EE Internal Load

FIGURE B-4b
DUKE ENERGY KENTUCKY SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) AFTER EE
INTERNAL LOAD[b]

	SUMMER			WINTER[d]		
YEAR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
2015	814			739		
2016	877	63	7.7%	733	(6)	-0.8%
2017	841	(36)	-4.1%	797	64	8.7%
2018	857	16	1.9%	821	24	3.0%
2019	849	(8)	-0.9%	742	(79)	-9.6%
2020	809	(40)	-4.7%	678	(64)	-8.6%
2021	815	6	0.7%	733	55	8.2%
2022	822	7	0.9%	747	14	1.9%
2023	836	14	1.7%	747	(0)	-0.1%
2024	840	4	0.5%	763	16	2.1%
2025	851	11	1.3%	759	(4)	-0.5%
2026	853	1	0.1%	757	(1)	-0.2%
2027	854	2	0.2%	754	(3)	-0.4%
2028	857	3	0.3%	755	1	0.1%
2029	860	3	0.3%	768	12	1.6%
2030	870	10	1.2%	768	0	0.0%
2031	874	3	0.4%	769	1	0.1%
2032	879	6	0.7%	765	(4)	-0.5%
2033	885	5	0.6%	764	(1)	-0.1%
2034	890	5	0.6%	774	10	1.3%
2035	898	8	0.9%	792	18	2.3%
2036	911	13	1.5%	798	6	0.7%
2037	919	8	0.8%	797	(1)	-0.1%
2038	931	12	1.4%	802	5	0.7%
2039	942	10	1.1%	802	(1)	-0.1%
2040	950	8	0.8%	823	22	2.7%

Figure B-5: Load Factor Calculations, Duke Energy Kentucky

LOAD FACTOR CALCULATIONS, DEK			
	1	2	3
	Volume	Peak	Load Factor
2015	4,043,958	814	56.7%
2016	4,065,855	877	52.8%
2017	3,939,861	841	53.5%
2018	4,158,382	857	55.4%
2019	4,081,160	849	54.9%
2020	3,842,705	809	54.1%
2021	3,975,297	815	55.7%
2022	4,034,396	822	56.0%
2023	4,110,083	836	56.1%
2024	4,123,345	840	55.9%
2025	4,191,939	851	56.2%
2026	4,191,062	853	56.1%
2027	4,204,745	854	56.2%
2028	4,221,921	857	56.1%
2029	4,238,847	860	56.3%
2030	4,299,556	870	56.4%
2031	4,314,718	874	56.4%
2032	4,342,465	879	56.2%
2033	4,371,241	885	56.4%
2034	4,391,916	890	56.3%
2035	4,428,379	898	56.3%
2036	4,487,794	911	56.1%
2037	4,519,461	919	56.1%
2038	4,567,724	931	56.0%
2039	4,616,270	942	56.0%
2040	4,656,711	950	55.8%

Figure B-6: "Range of Forecasts" Economic Bands for Energy and Peak after EE

FIGURE B-6
DUKE ENERGY KENTUCKY SYSTEM
RANGE OF FORECASTS[3]
ECONOMIC BANDS

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) AFTER EE			PEAK LOAD FORECAST (MW) INTERNAL[b] AFTER EE		
YEAR	LOW	/IOST LIKEL	HIGH	LOW	/IOST LIKEL	HIGH
2021	4,247	4,290	4,303	807	815	822
2022	4,310	4,354	4,377	797	822	847
2023	4,399	4,435	4,460	811	836	861
2024	4,421	4,450	4,474	818	840	862
2025	4,503	4,524	4,544	831	851	871
2026	4,505	4,523	4,539	833	853	872
2027	4,519	4,538	4,551	836	854	872
2028	4,537	4,556	4,569	840	857	875
2029	4,557	4,574	4,589	842	860	878
2030	4,626	4,640	4,658	853	870	888
2031	4,642	4,656	4,673	856	874	891
2032	4,669	4,686	4,701	861	879	898
2033	4,699	4,717	4,732	867	885	903
2034	4,722	4,740	4,756	872	890	908
2035	4,762	4,779	4,796	879	898	917
2036	4,827	4,843	4,861	892	911	931
2037	4,860	4,877	4,896	899	919	939
2038	4,912	4,929	4,948	911	931	952
2039	4,963	4,982	5,000	922	942	962
2040	5,005	5,025	5,044	929	950	971

(a) Includes EE impacts
(b) Includes controllable load.

Figure B-7: Net Monthly Energy/Peak forecast before EE, next two years

FIGURE B-7 DUKE ENERGY KENTUCKY SYSTEM NET MONTHLY ENERGY AND PEAK FORECAST BEFORE EE			
YEAR 0	2021	ENERGY, MWH	PEAK, MW
January		363,047	702
February		355,424	654
March		329,691	621
April		302,847	549
May		322,246	585
June		378,100	704
July		425,003	816
August		422,724	793
September		364,877	694
October		327,891	509
November		333,588	602
December		373,554	698
YEAR 1	2022		
January		389,930	737
February		361,340	676
March		335,770	638
April		305,715	562
May		325,189	597
June		384,544	713
July		440,056	826
August		427,702	797
September		374,137	695
October		329,885	506
November		331,319	599
December		372,561	695

Figure B-8: Net Monthly Energy/Peak forecast after EE

FIGURE B-8 DUKE ENERGY KENTUCKY SYSTEM NET MONTHLY ENERGY AND PEAK FORECAST AFTER EE		
2021	ENERGY, MWH	PEAK, MW
January	362,932	702
February	355,215	654
March	329,368	620
April	302,448	548
May	321,707	584
June	377,425	702
July	424,165	815
August	421,787	792
September	363,907	692
October	326,886	507
November	332,468	600
December	372,176	695
2022		
January	388,443	733
February	359,891	673
March	334,169	634
April	304,147	559
May	323,382	594
June	382,546	710
July	437,813	822
August	425,391	793
September	371,916	691
October	327,737	503
November	329,010	595
December	369,824	690

Figure B-9: Service Area Forecast (monthly), by Major Classification, before EE

FIGURE B-9
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
BEFORE EE

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
								(1+2+3+4+5+6)		
		Rural and			Steet-Hwy	Sales for		Total	Losses and	(7+8)
Year 0	2021	Residential	Commercial	Industrial	Lighting	Resale[a]	Other	Consumption	Unaccounted For[b]	Net Energy for Load
January		148,094	125,068	56,967	1,139	0	5,108	336,377	26,670	363,047
February		140,632	122,128	59,490	1,201	0	5,865	329,315	26,108	355,424
March		111,441	114,098	65,568	1,124	0	13,240	305,471	24,220	329,691
April		95,186	107,964	62,167	1,202	0	14,081	280,600	22,247	302,847
May		95,308	114,706	66,291	1,022	0	21,245	298,572	23,673	322,246
June		129,132	127,244	70,323	1,135	0	22,491	350,325	27,775	378,100
July		156,643	137,510	73,697	1,145	0	24,786	393,781	31,222	425,003
August		150,340	135,888	78,520	1,108	0	25,813	391,669	31,055	422,724
September		116,635	123,506	72,154	1,159	0	24,618	338,072	26,805	364,877
October		92,417	112,157	73,062	1,101	0	25,066	303,804	24,088	327,891
November		104,942	109,888	70,328	1,164	0	22,759	309,081	24,506	333,588
December		142,305	111,793	68,248	1,164	0	22,601	346,111	27,442	373,554
YEAR 1	2022									
January		152,141	116,184	69,670	1,135	0	22,154	361,285	28,646	389,930
February		134,890	109,399	68,272	1,197	0	21,039	334,797	26,543	361,340
March		107,853	108,235	72,023	1,120	0	21,873	311,104	24,666	335,770
April		89,916	102,989	68,869	1,198	0	20,285	283,257	22,458	305,715
May		92,169	112,695	72,945	1,018	0	22,472	301,299	23,890	325,189
June		128,922	127,960	75,493	1,131	0	22,789	356,295	28,249	384,544
July		165,185	138,396	78,320	1,141	0	24,686	407,728	32,328	440,056
August		151,885	136,768	80,789	1,104	0	25,736	396,282	31,420	427,702
September		123,097	124,391	74,437	1,155	0	23,572	346,652	27,485	374,137
October		92,423	113,575	74,843	1,097	0	23,713	305,651	24,234	329,885
November		105,057	108,305	72,117	1,160	0	20,340	306,980	24,340	331,319
December		138,466	114,260	70,061	1,160	0	21,244	345,192	27,369	372,561

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

Figure B-10: Service Area Forecast (monthly), by Major Classification, after EE

FIGURE B-10
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
AFTER EE

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year 0	2021	Rural and Residential	Commercial	Industrial	Steet-Hwy Lighting	Sales for Resale[a]	Other	(1+2+3+4+5+6) Total Consumption	Losses and Unaccounted For[b]	(7+8) Net Energy for Load
January		148,062	125,054	56,917	1,139	0	5,098	336,270	26,662	362,932
February		140,576	122,102	59,397	1,201	0	5,847	329,122	26,093	355,215
March		111,371	114,054	65,413	1,124	0	13,210	305,172	24,196	329,368
April		95,111	107,907	61,967	1,202	0	14,043	280,230	22,218	302,448
May		95,216	114,627	66,016	1,022	0	21,193	298,073	23,634	321,707
June		128,988	127,151	69,996	1,135	0	22,429	349,699	27,726	377,425
July		156,446	137,398	73,305	1,145	0	24,711	393,004	31,160	424,165
August		150,134	135,760	78,071	1,108	0	25,728	390,801	30,986	421,787
September		116,456	123,367	71,667	1,159	0	24,525	337,174	26,734	363,907
October		92,245	112,010	72,548	1,101	0	24,968	302,872	24,014	326,886
November		104,716	109,731	69,778	1,164	0	22,654	308,044	24,424	332,468
December		141,940	111,616	67,631	1,164	0	22,484	344,835	27,341	372,176
YEAR 1	2022									
January		151,743	115,994	69,006	1,135	0	22,028	359,907	28,536	388,443
February		134,512	109,213	67,619	1,197	0	20,914	333,454	26,437	359,891
March		107,519	108,013	71,245	1,120	0	21,725	309,621	24,549	334,169
April		89,644	102,760	68,070	1,198	0	20,133	281,805	22,343	304,147
May		91,880	112,427	72,007	1,018	0	22,293	299,625	23,757	323,382
June		128,512	127,681	74,516	1,131	0	22,603	354,444	28,102	382,546
July		164,669	138,093	77,262	1,141	0	24,485	405,650	32,163	437,813
August		151,394	136,448	79,671	1,104	0	25,523	394,141	31,251	425,391
September		122,706	124,068	73,308	1,155	0	23,357	344,594	27,322	371,916
October		92,099	113,252	73,714	1,097	0	23,498	303,660	24,076	327,737
November		104,610	107,977	70,971	1,160	0	20,122	304,840	24,170	329,010
December		137,739	113,910	68,835	1,160	0	21,011	342,655	27,168	369,824

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

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

APPENDIX C

CONFIDENTIAL

C 

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

A. INTRODUCTION

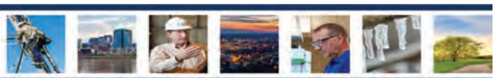
Duke Energy Kentucky offers DSM[1] programs, as listed in Figure 5.1 that have been developed in conjunction with the DSM Collaborative.

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.

[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).*



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 consumption 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-effectiveness analyses also incorporate avoided transmission and distribution costs and load (line) losses.

THE RIM TEST

The RIM Test, or non-participants test, indicates if 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 utililty progam 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 (to the right), however, customer incentives are considered a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC though 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.

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.

Figure C-1 Cost Effectiveness Test Results

Program Name		UCT	TRC	RIM	PCT
Residential Programs					
Low Income Neighborhood		0.51	0.55	0.35	2.19
Low Income Services		0.20	0.28	0.17	2.66
My Home Energy Report		1.09	1.09	0.52	
Residential Energy Assessments		1.41	1.42	0.60	23.57
Residential Smart Saver®		1.98	1.69	0.62	3.91
Power Manager®		3.29	5.22	3.29	
Total		1.81	1.81	0.74	3.99
Non-Residential Programs					
Small Business Energy Saver		2.52	1.57	0.78	2.65
Smart $aver® Custom		4.62	1.2	0.72	2.17
Smart $aver® Prescriptive		5.15	3.42	0.91	5.20
Power Manager® for Business		5.25	36.85	3.63	
PowerShare®		3.15	9.79	3.15	
Total		4.09	2.66	0.99	3.78
Overall Portfolio Total		2.79	2.27	0.88	3.87

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 and insulation 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 2019 through June 2020, the Program approved over 885 individual rebate applications. The smart thermostat option was included on 650 AC and HP replacement systems, for a total of over 1,525 individual measures.

Duke Energy Kentucky currently contracts with Blackhawk Engagement Solutions (BES) to administer this program. BES 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 Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage promotion. BES has experience in delivering similar utility energy efficiency programs.

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 Free Lighting component of the program was discontinued on 6/30/2020 as a result of potential efficiency standards for general service bulbs that may be imposed as a part of the EISA. Although, there is still uncertainty as to how and when this legislation will be imposed, Duke Energy moved forward with its sunsetting strategy. Prior to its discontinuation, the program was designed to increase the energy efficiency of residential customers by offering customers 9-Watt LEDs to install in high-use fixtures within their homes. The LED offer was available through an on-demand ordering platform, enabling customers to request LEDs and have them shipped directly to their homes. Customers had the ability to order in quantities of 3, 6, 8, 12, and 15 packs. Quantities offered by the platform are dependent on past participation in free lighting programs that contribute to their free bulb limit.[2]

Through the ordering platform, customers had the flexibility to order and track their shipments through three separate channels: telephone, Duke Energy web site and My Account (formally Online Services).

Customers had the ability to call a toll-free number to access the IVR (Interactive Voice Response) system which provided prompts to facilitate the ordering process. Both English and Spanish speaking customers may easily validate their account, determining their eligibility and place their order over the phone.

Customers could go online to complete the ordering process. Eligibility rules and frequently asked questions were made available for reference.

Customers who were enrolled in the My Account authenticated portal could place their order through this channel if they were eligible. New customer registrations and eligible customers were intercepted upon logging in to make them aware of the program.

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[2] As approved in Case No. 2016-00112.

The benefits of providing these three distinct channels include improved customer experience, advanced inventory management, simplified program coordination, enhanced reporting, increased program participation and reduced program costs. Overall, in the 2019-2020 fiscal year, over 308,000 LEDs were ordered resulting in the program meeting its kWh impact goal.

The Residential Smart $aver® lighting program launched an online Saving Store for specialty lighting on April 26, 2013. The Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. The program offers a variety of LEDs including: Reflectors (indoor and outdoor), Globes, Candelabra, 3 ways, Dimmables and certain A-line type bulbs of wattages not included in the Free LED offer. The incentive levels vary by bulb type and the customer pays the difference, including shipping.

In 2020, the program was approved to add smart thermostats, water products, LED fixtures, & small appliance- dehumidifiers & air purifiers. Customer purchase limits are as follows:

- Smart thermostats, 2 total;
- Water measures, 3 total;
- LED fixtures (direct wires, portable, & outdoor photocell), limit 8 total; and
- Small appliance, dehumidifiers & air purifiers, limit 2 each total.

Customers can check eligibility and shop for a variety of energy efficient products through the Company Web Site and My Account. The Savings Store is managed by a third-party vendor, Energy Federation Inc. (EFI). EFI is responsible for maintaining the Savings Store and fulfilling all customer purchases. The Saving Store landing page provides information about the store, energy efficient products, account information and order history. Support features include a toll- free number, Live Chat, package tracking and frequently asked questions.

Educational information is available to help assist customers with their purchasing decisions. The information discusses bulb types, application types, benefits of energy efficient products, understanding watts versus lumens and recycling/safety tips.

The Online Savings Store program carefully tracks towards budget by monitoring our marketing activities to customers. The program sold approximately 6,117 bulbs equating to approximately 535 unique orders.

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, Franklin Energy. 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. Properties that have already been served by the Property Manager CFL program are only eligible for water measures and specialty bulbs.

The program helps property managers upgrade lighting with energy efficient LEDs and saves energy by offering water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap. The quantity of lighting measures installed may vary by apartment size but there are no limits on LED installations in permanent fixtures. These measures assist with reducing maintenance costs while improving tenant satisfaction by lowering energy bills.

As program implementer, Franklin Energy 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 web site for property managers to learn more about the program and request applications to participate in the program.

Duke Energy Kentucky received approval to replace CFLs with LEDs for the lighting offering associated with the Multi-Family Program.[3] Beginning in July 2017, the program began installing LED lighting. The program also added two additional bulb types to bring the LED offering to three types with unlimited quantities per unit. The three bulbs (A-Line, Candelabras, Globes) provide more options for tenants, are more aesthetically appealing and create more bill savings. In 2019, the program added new 4000K LED bulb options for A-lines. These bulbs provide a brighter, whiter light which has been requested by several property management companies. Property managers and owners also receive benefits with the longer lasting bulbs, which reduce maintenance costs for the properties and make the units more marketable to tenants.

Multifamily activity for the July 1, 2019 through June 30, 2020 fiscal year totaled 6,231 measure

[3] *In the Matter of the Application of Duke Energy Kentucky, Inc., to Amend its Demand Side Management Programs,* Case No. 2016-00289, KY. P.S.C. Order January 24, 2017.

installations, achieving 90.8% of the 2019-2020 fiscal year goal of 6,860 measures. The program was suspended in mid-March due to the COVID-19 pandemic and concerns for the safety of customers and program staff. The program remained suspended through the end of the fiscal year.

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 insulating pipe tape 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.

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 shower heads, bath aerators, kitchen aerators 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. The program shipped 1,291 kits containing 3,873 kitchen and bath aerators, 1,873 showerheads, and 6,455 feet of insulating pipe wrap for a total of 12,201 measures or 147% of a budget of 8,304 measures.

Per the September 13, 2018 Order from the Commission Duke Energy Kentucky will not be implementing a Retail Lighting marketing channel as planned. This upstream, buy-down retail-based lighting program would have worked through lighting manufacturers and retailers to offer discounts to Duke Energy customers selecting incentivized LEDs and energy-efficient fixtures at the shelf for purchase at the register.

Residential Energy Assessments Program

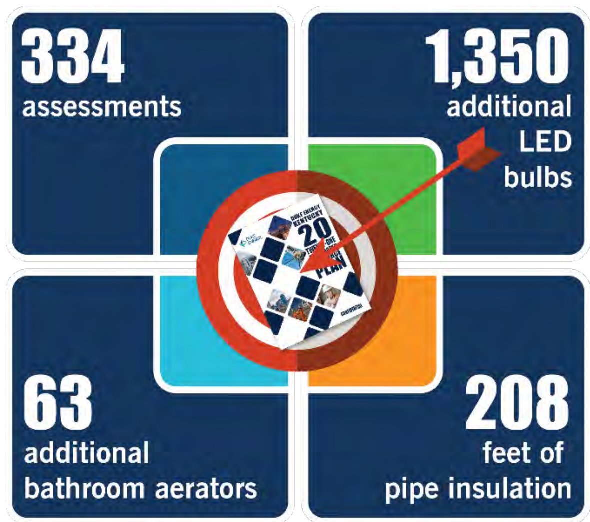
The primary goal for HEHC is to empower customers to better manage their energy usage and cost. Duke Energy Kentucky partners with several key vendors to administer the program which an energy specialist completes a 60 to 90-minute walk through assessment of the home and analyzes energy usage to identify energy savings opportunities. The 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 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 energy efficient lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets and weather stripping. 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 temporarily paused for the remainder of the 2019-2020 fiscal year and discontinued marketing outreach effective March 16, 2020 due to the pandemic. During this time, existing appointments were cancelled or rescheduled based on customer preference. 260 customers were impacted in the duration of the pandemic related pause. The program proactively rescheduled 35% of those appointments in March 2020 when making the cancellation contact. Adapting to the impacts of the pandemic, the program evaluated and coordinated with the current implementor to integrate new safety protocols and effectively relaunched the program in July 2020. The program continues to evaluate customer and employee feedback as it relates to the pandemic to ensure the team is adapting as soon as possible to customer needs as well as maximizing safety awareness.

The program completed the following:



Low Income Services Program

Weatherization

The Weatherization program portion of Low-Income Services 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. 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 number of customers shown in the figure below.

Figure C-2: 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

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.

Figure C-3: 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

*SIR = Savings - Investment Ratio

Tier One 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 One services are as follows:

Tier Two Services

Duke Energy Kentucky will provide Tier Two 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 Two services include all Tier One services and:

- 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;

- 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.

Figure C-4: 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

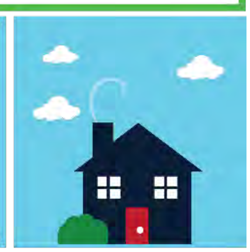
The existing refrigerator being replaced is removed from the home and recycled in an environmentally appropriate manner to assure that the units are not used as a second refrigerator in the home or do not end up in the secondary appliance market.

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. This program is offered twice over six winter months per year (October-March). The program is made up of three components:

Energy Education & Budget Counseling - to help customers understand how to control their energy usage and how to manage their household bills, a combined education/counseling approach is used;

Weatherization - to increase the energy efficiency in customers' homes, participants are required to have their homes weatherized as part of the normal Residential Conservation and Energy Education (low-income weatherization) program unless weatherized in past program years; and,



Bill Assistance - to provide an incentive for these customers to particilate in the education and weatherization, and to help them get control of their bills. Payment assistance credits are provided to each customer once they complete each aspect of the program. The credits are: $200 for participating in the EE counseling, $150 for participating in the budgeting counseling, and $150 for participating in the Residential Conservation and Energy Education program (weatherization services). If all the requirements are completed, a household could receive up to a total of $500 towards their arrearage. This allows for approximately 200 homes to participate per year. Some customers do not complete all three steps or may have already had weatherization services completed prior to the program.

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 most recent filing period, 0 participants attended energy education counseling, 21 participants attended budget counseling and 21 participants' homes have been weatherized. The participation was significantly down in October and the classes were suspended in March due to COVID-19 resulting in lower participation from previous years.

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. 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.

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 May - September depending on the program in which they have enrolled. Customers that sign-up for the moderate control option receive an annual event credit of $2.40 per month for each year they are on the program and customers that sign-up for the longer control option receive an annual event credit of $3.60 per month each year they are on the program.

Duke Energy Kentucky continues to use load control devices manufactured by Eaton's Cooper Power Systems for new installations and replacement of existing load control devices. The load control devices have built-in safeguards to prevent the "short cycling" of the air-conditioning system. The air-conditioning system will always run the minimum amount of time required by the manufacturer. The cycling simply causes the air-conditioning system to run less, which is no different than what it does on milder days. Additionally, the indoor fan will continue to run and circulate air during the cycling event. The Company continued its primary Power Manager® marketing during the past fiscal year 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.

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 five Power Manager® events that took place from the July 2019 through June 2020 event season which, on average, saved 11 Megawatts per event during peak periods of demand. There was a PJM required one-hour test on September 10, 2019.

Smart $aver® Prescriptive Program

The Smart $aver® Non-residential Prescriptive 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 in order 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 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.

The program has developed multiple approaches to reaching the very broad and diverse audience of business customers. In 2019-20, this consisted of incentive payment applications, with paper and online options, and instant incentives offered through the Online Energy Savings Store. 2019-20 results include:

- Program participation tracked well in the first three quarters of the 2019-20 fiscal year. However, participation volume declined in all program channels due to the negative effects of COVID-19 on non-residential customers in the last quarter of the fiscal year. But customers continue to show interest in energy efficiency to save money for their businesses and are leveraging incentives from the Smart $aver® Prescriptive Program when possible;

- Outreach continues to support Trade Allies (TA) virtually working within the program;

- Program marketing efforts were scaled back in the second half of the fiscal year due to COVID-19 considerations; and

- A dedicated team of representatives answering customer questions via phone and email continue to provide high levels of customer service.

The Non-residential Prescriptive program finished the 2019-2020 fiscal year at 72% of the budget spending limit and 88% of the kWh impacts goal. Application volume was down slightly this fiscal year, with 172 applications in total paid for Duke Energy Kentucky prescriptive incentives. 85% of applications were submitted via the online application portal this fiscal year, which is an increase from the 2018-19 fiscal year. The average payment per paid application was $4,866. Sixty-six percent of the applications were paid in the first half of the 2019-20 fiscal year.

Duke Energy Kentucky continues to offer the Business Savings Store on the Duke Energy website, with orders fulfilled by a third-party, EFI. The site provides customers the opportunity to take advantage of a limited number of incentive measures by purchasing qualified products from an on-line store and receiving an instant incentive that reduces the purchase price of the product. The incentives offered in the store are consistent with current program incentive levels. The online application store has been well received by the DIY niche market and allows customer a path for instant incentives without the burden of paperwork.

Over the years, the program has worked closely with TA to promote the program to our 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.

To ensure that program expenditures will not exceed the budget cap, a reservation system was implemented in 2018 and continues to be very beneficial for program planning purposes. Customers and trade allies seeking a prescriptive reservation can now submit a pre-application in advance of starting an energy efficiency project. The pre-application determines equipment qualification and reserves program funds, if available. Applications received that were not previously reserved are still reviewed and paid if unreserved funds are available.

The Company continues to work with outside consultants and internal resources to develop strategies to understand equipment supply/value chains and increase awareness of these measures going forward. Non-residential customers are informed of programs via targeted marketing material and communications. Information about incentives is also distributed to TAs, who in turn sell equipment and services to all sizes of nonresidential customers. Large business or assigned accounts are targeted primarily through assigned Duke Energy Kentucky account managers. Accounts that do not have an assigned account manager typically receive information about the program through direct mail, electronic mail and other direct marketing efforts including outbound call campaigns. Program marketing efforts were scaled back in the second half of the fiscal year due to COVID-19 considerations.

The internal marketing channel is comprised of assigned Large Business Account Managers, Segment Managers, and Local Government and Community Relations, and Business Energy Advisors, who all identify potential opportunities as well as distribute program collateral and informational material to customers and TA. In addition, the Economic and Business Development groups also provide a channel to customers who are new to the service territory.

The Company sought approval[4] to increase the program budget for the underspent non-residential budget for this true-up timeframe by $1,396,010. In anticipation of increased customer demand, the Company requested to add the unspent $1,396,010 to the current Smart $aver® Prescriptive budget of $548,785[5] for July 2020 – June 2021 as approved in Case No. 2019-00406. The case is still under review.

Smart $aver® Custom Program

The purpose of this program is to encourage the installation of high efficiency equipment in new and existing non-residential establishments. The program provides incentive payments to offset a portion of the higher cost of energy efficient equipment.

Duke Energy Kentucky contracts with a third party to perform technical review of applications as part of implementation of this program. This program is jointly implemented with the Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage promotion.

During the current reporting period of July 2019 through June 2020, the Kentucky Smart $aver® Custom Incentive program provided incentives totaling $154,861 to approximately 5 customers. The level of participation in terms of incentives and impacts decreased sharply from the previous year.

Although participation was lower than the prior year, the Custom Incentive program continues to utilize a reservation system to allocate available incentive dollars for each fiscal year. Currently, the majority of funds for 2020-2021 incentive dollars are reserved due to higher levels of participation to start the year.

During the current reporting period of July 2019 through June 2020, the Kentucky Smart Saver® Custom Incentive program was found to have a TRC cost-effectiveness score of 1.20.

Upon receiving a Custom Incentive application, Duke Energy Kentucky reviews the application and performs a technical evaluation as necessary to validate energy savings. Measures submitted by the

[4] Case No. 2020-0026 filed on August 17, 2020.

[5] Program costs only. Does not include lost revenues or shared savings.

customer are then modeled to ensure cost effectiveness to the program overall, given the energy savings, and improves a customer's payback to move them to invest in energy efficiency. Third party evaluation follow-up and review include: application review, site visits and/or onsite metering and verification of baseline energy consumption, customer interviews, and/or use of loggers/sub-meters.

Peak Load Manager (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. 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. 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. Only customers able to provide a minimum of 100 kW load response qualify for CallOption®. For the 2019/20 PowerShare® programs there were three enrollment choices for customers relative to CallOption:

- Limited Summer: required participants to be able to curtail during the months of June through September 2019, with a maximum event length of 6 hours and maximum number of curtailments of 10 during the program year;

- Summer Only: required participants to be able to curtail during the months of June through September 2019, with a maximum event length of 10 hours and no maximum number of curtailment events; and

- Annual: requires participants to be able to curtail during the full contract term of June 2019 through May 2020, with a maximum event length of 12 hours during the months of June through October 2019 and May 2020, and with a maximum event length of 15 hours during the months of November 2019 through April 2020 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 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. Only customers able to provide a minimum of 100 kW load response qualify for QuoteOption®.

PowerShare® 2019-2020 Summary

Duke Energy Kentucky's customer participation goal for 2019 was to retain all customers that currently participate and to promote customer migration to the CallOption® program. Figure C-5 displays monthly account participation levels for July 2019 through June 2020, as well as MWs enrolled in the program.

Figure C-5 Kentucky PowerShare® Participation Update

	CallOption®		QuoteOption®	
Month	Enrolled Customers*	Summer Capability**	Enrolled Customers*	Summer Capability**
Jul-19	17	19.09	0	0
Aug-19	17	19.09	0	0
Sep-19	17	19.09	0	0
Oct-19	17	19.09	0	0
Nov-19	17	19.09	0	0
Dec-19	17	19.09	0	0
Jan-20	17	19.09	0	0
Feb-20	17	19.09	0	0
Mar-20	17	19.09	0	0
Apr-20	17	19.09	0	0
May-20	17	19.09	0	0
Jun-20	17	19.28***	0	0

*Enrolled Customers represents the number of parent accounts participating.

**Summer Capability is consistent with the associated program year. Numbers reported are adjusted for losses.

***Estimated Summer capability

Note: Duke Energy Kentucky has signed 17 contracts for the 2020/2021 PowerShare® CallOption®.

During the July 2019 through June 2020 period, there were zero PowerShare® events for economic or emergency reasons and one QuoteOption event. There were also curtailment tests performed to meet PJM requirements. Figure C-6 below summarizes event participation.

Figure C-6: PowerShare CallOption and QuoteOption Economic, Emergency, and Test Events

June 2019 - May 2020 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
9/10/2019	4 pm - 5 pm	PJM Test	16	16	15.340	18.355	19.772
9/26/2019	4 pm - 5 pm	PJM Re-Test	1	1	0.750	0.917	0.988
10/2/2019	3 pm - 7 pm	QuoteOption	1	1	0.500	0.281	0.303

(Note that for the summer period of June 2019 through September 2019, zero PowerShare® events have been called. The annual, required, PJM test event was conducted on September 10, 2019 at 4 pm. Information on these events will be available and presented in next year's update filing.)

Low Income Neighborhood 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.

In recognition of the COVID-19 environment that now exists, proper safety protocols shall be adhered to, to ensure everyone's safety always. Future kick-off events are anticipated to look different which shall at minimum include an outdoor venue (weather permitting), masks, attendees socially/physically distanced at 6 feet apart, etc. Future community customer engagement opportunities shall be regularly reviewed on a case-by-case basis.

For fiscal year 2019-2020, with a participation goal of 600 homes, we have completed 372 homes in Duke Energy Kentucky territory. The existence of a new COVID-19 environment led to work stoppage due to a local government mandate to engage in customer-facing activities when most safe to do so. 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'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.

My Home Energy Report Program

The My Home Energy Report (MyHER) 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. MyHER 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 MyHER program, originally an opt-out program, has been 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. In 2020, the program has only had 2 opted in customers decide to opt-out of the program after receiving reports. As of June 30, 2020, there were 6,485 Kentucky MyHER customers receiving 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 MyHER customers for whom we have an email address. As of June 30, 2020, there were 4,464 Kentucky MyHER customers enrolled in the portal.

The Company had developed a MyHER program for multifamily dwellings that was available in January 2017. However, the multifamily program was not implemented in KY due to restrictions on program spending.

The Company had developed a dual fuel report for Duke Energy Kentucky customers who receive electricity and gas from the Company. Due to restrictions on program spending, KY customers longer receive the dual fuel report and have reverted to receiving the electric usage only report. The Company rolled out a new and improved design of the report including a view of disaggregated usage in third quarter 2017.

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

Small Business Energy Saver Program

The purpose of Duke Energy's Small Business Energy Saver program (SBES 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 SBES Program are administered by a single Company-authorized vendor. The SBES Program measures address major end-uses in lighting, refrigeration, and HVAC applications.

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

The SBES 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.

The SBES Program launched in late February 2015, after receiving the Order of Approval from the Commission on January 28, 2015.[6] SmartWatt Energy Inc. (SmartWatt), a company that specializes in administering utility energy efficiency programs nationwide like Small Business Energy Saver, was awarded the contract to administer the Program in the Duke Energy Ohio & Kentucky territories after a

[6] Case No. 2014-00280

lengthy competitive bid and vendor evaluation process. In June of 2019, the contract for the program was transitioned from SmartWatt to Lime Energy. Lime Energy is a leader in the direct install pay for performance market and implements the SBES Program in Duke Energy's other regulated markets.

For the July 2018 to June 2019 period, 36 SBES projects were completed in Kentucky, which was a volume lower than what was projected, but those 36 projects resulted in savings of over 1,773,000 kWh at the meter.

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 new vendor Lime Energy to implement initiatives focused on increasing refrigeration 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 SBES Program wherever possible.

In March, the program was shut down due to the spread of the COVID-19 virus. The program uses on site marketing to reach customers and then follows up with an on-site free energy assessment for customers that agree to have one. These activities are considered high risk for getting and spreading the COVID-19 virus. The Program remained suspended through the end of the fiscal year. The program will restart per the guidelines of the State of Kentucky as appropriate.

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 2019-2020 filing period due to the high success of our Prescriptive and Custom programs. Similarly, for 2020-2021, 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 of Peak Time Credits and describes CPEs to participants as Peak Day events. Unfortunately, the development of this pilot program did not start in January 2020 as expected. After Commission approval, development started in April 2020 but shared resources with other marketing and communications staff working on COVID-19 communications. As a result, the program was developed later than anticipated. At the end of June 2020, the program was under development. but launched on July 27, 2020.

On July 27, 2020, in total, 55,265 customers received email offering participation in the pilot. The Company enrolled 899 participants before closing the enrollment process. This enrollment level exceeded the recommended enrollment from the pilot's EM&V vendor, Nexant, but stayed under the 100-customer enrollment buffer approved by the Commission. Nexant's power analysis suggested a required enrollment of 820 customers. This level of enrollment was met and exceeded on August 7, 2020. Per stipulation, August 7, 2020 marks the official start date of the 2-year pilot.

Two Peak Day events have been implemented since the launch of the program. The events occurred on August 25 and August 26, 2020. Currently, these are the only events the Company anticipates until winter. Nexant is not scheduled to review the impacts from these events until next year.

Finally, the Company would like to update the Commission on efforts to lower the PJM load forecast with the pilot using PJM's Peak Shaving Adjustment mechanism (PSA). The Company has submitted information to PJM requesting a PSA. At this time, the Company has not received a PJM decision on the PSA request.

Response to Section 8 (3)(e)4

Figure C-7: Energy Efficiency Program Costs

Energy Efficiency and DSM Programs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	[redacted]														
Low Income Neighborhood															
Low Income Services															
My Home Energy Report															
Power Manager®															
Residential Energy Assessments															
Residential Smart $aver®															
Total Residential															
Non-Residential															
PowerShare®															
Small Business Energy Saver															
Smart $aver® Custom															
Smart $aver® Prescriptive															
Total Non-Residential															
Total Energy Efficiency and DSM Programs															

Note: Program costs beyond 2025 are estimated using the same inflation forecast as used in the IRP modeling

Response to Section 8 (3)(e)5

Figure C-8: Energy Efficiency Avoided Costs

Energy Efficiency and DSM Programs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	[redacted]														
Low Income Neighborhood															
Low Income Services															
My Home Energy Report															
Power Manager®															
Residential Energy Assessments															
Residential Smart $aver®															
Total Residential															
Non-Residential															
PowerShare®															
Small Business Energy Saver															
Smart $aver Prescriptive®															
Smart $aver® Custom															
Total Non-Residential															
Total Energy Efficiency and DSM Programs															

Note: Avoided costs beyond 2025 are estimated using the estimated annual growth rate computed by Avoided Cost component

APPENDIX D

ENVIRONMENTAL REGULATIONS

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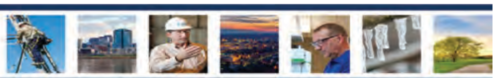
D  ENVIRONMENTAL REGULATIONS

Duke Energy Kentucky is required to comply with numerous state and federal environmental regulations. In addition to current programs and regulatory requirements, new regulations are continuously in various stages of implementation and development that will impact operations for Duke Energy Kentucky over time.

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 original flue gas desulfurization system (FGD) to reduce sulfur dioxide (SO_2) emissions for compliance with the evolution of Acid Rain, Clean Air Interstate Rule, Cross State Air Pollution Rule, and sulfur dioxide National Ambient Air Quality Standards (NAAQS) requirements. 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 Ozone National Ambient Air Quality Standards requirements. Together with the existing electrostatic precipitator (ESP) for particulate matter control, these primary emission controls produce co-benefits for reduction of acid gases and mercury for compliance with the Mercury and Air Toxics Standards Rule. The ESP recently underwent a complete refurbishment during the Spring 2018 planned maintenance outage.

Duke Energy Kentucky continuously monitors developments in these regulations. A 2021 revision to the Cross-State Air Pollution Rule has resulted in more stringent requirements for Kentucky during the ozone season. Ongoing implementation of the Ozone NAAQS and the non-attainment status of the Cincinnati area may lead to additional reductions in NOx emission allocations and/or imposition of short-term emission rate limits, potentially eventually necessitating the need for an SCR performance upgrade. A placeholder for such project cost was included in the IRP analysis for East Bend Unit 2 in the early-2020's timeframe. Costs for ongoing routine SCR catalyst replacement were also included.



Please see sections 2.C.4 and 3.C of this IRP for discussion of greenhouse gas emission regulation assumptions.

With respect to waste and water environmental regulations, again East Bend Unit 2 is well positioned to continue 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 will be completed through about 2020, but no significant findings are anticipated.

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 developed a new lined cell at the on-site landfill footprint at East Bend Station that 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, ongoing evolution of the ELG for additional and more stringent discharge limitations (such as for bromides), may ultimately necessitate additional waste processing changes and/or equipment installations. A placeholder for such project cost was included in the IRP analysis for East Bend in the early-2030's timeframe.

SCREENING CURVES

APPENDIX E

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E | SCREENING CURVES

The following pages contain the screening curves and associated data discussed in Chapter 4 of this filing.

The following pages contain the 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. These sources include a variety of internal departments at Duke Energy. In additional 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 (TAG®); and EIA. In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, 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 No Carbon Price

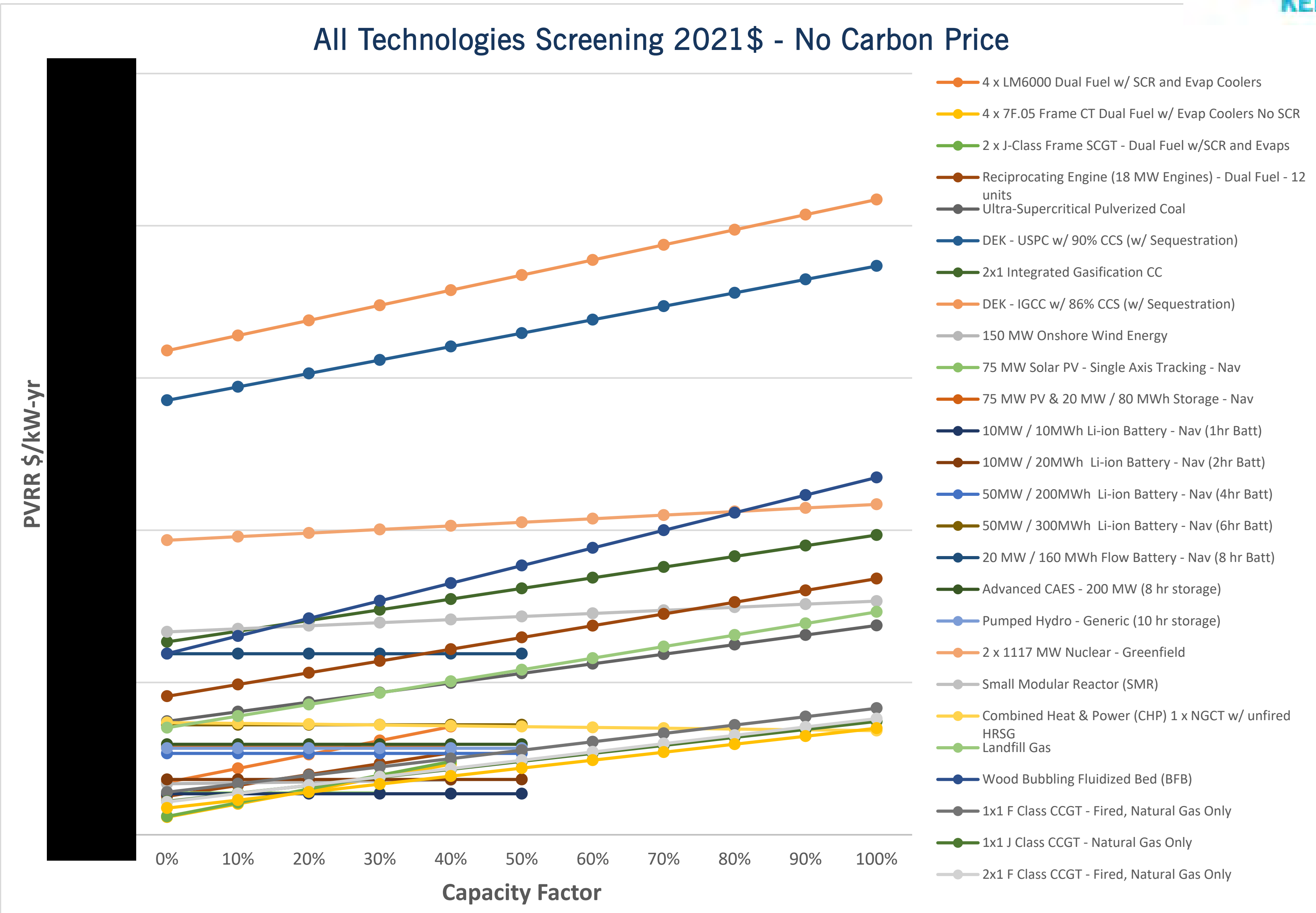


Figure E-2 All Technologies Screening with Carbon Price

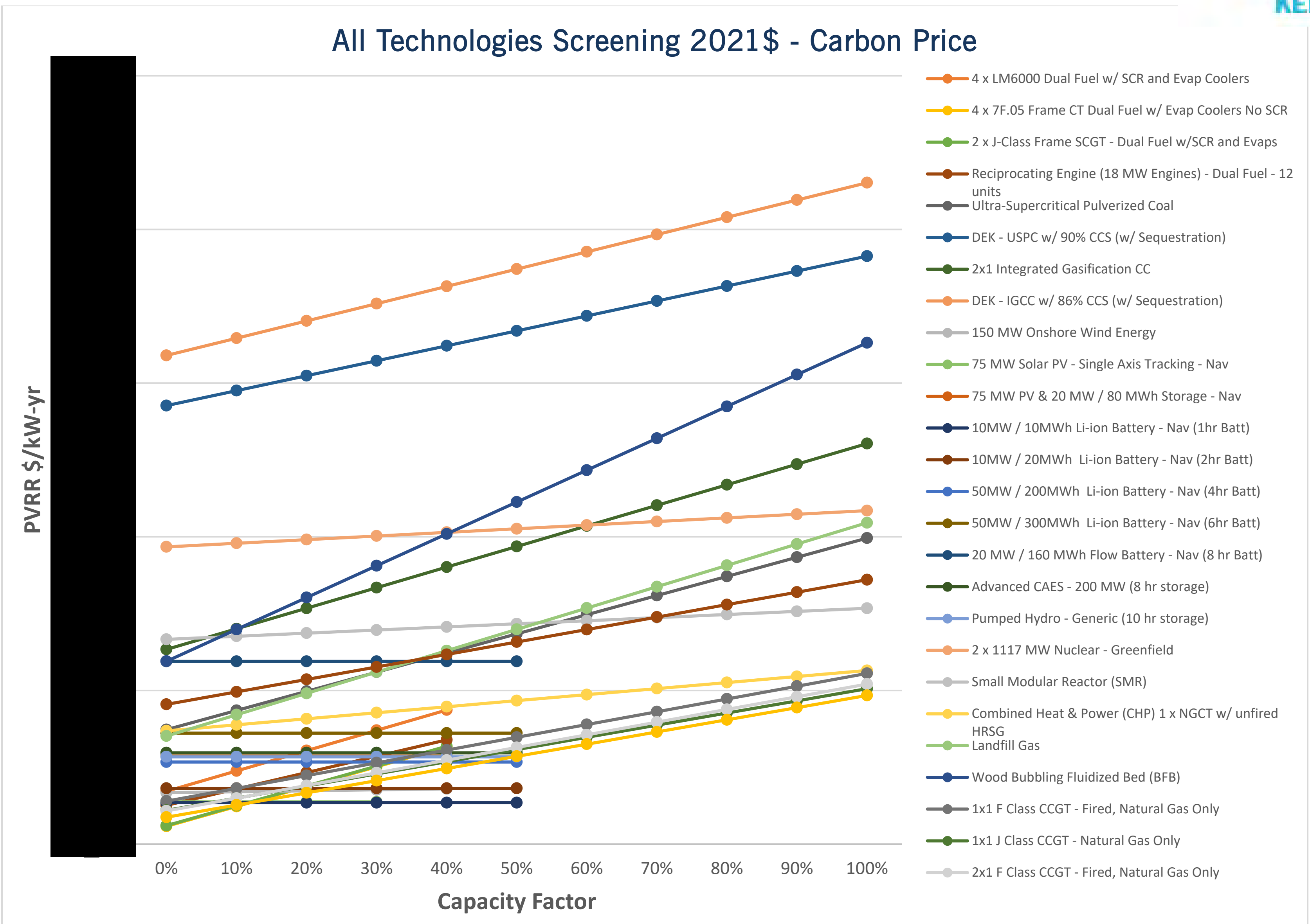


Figure E-3: Baseload Technologies Screening No Carbon Price

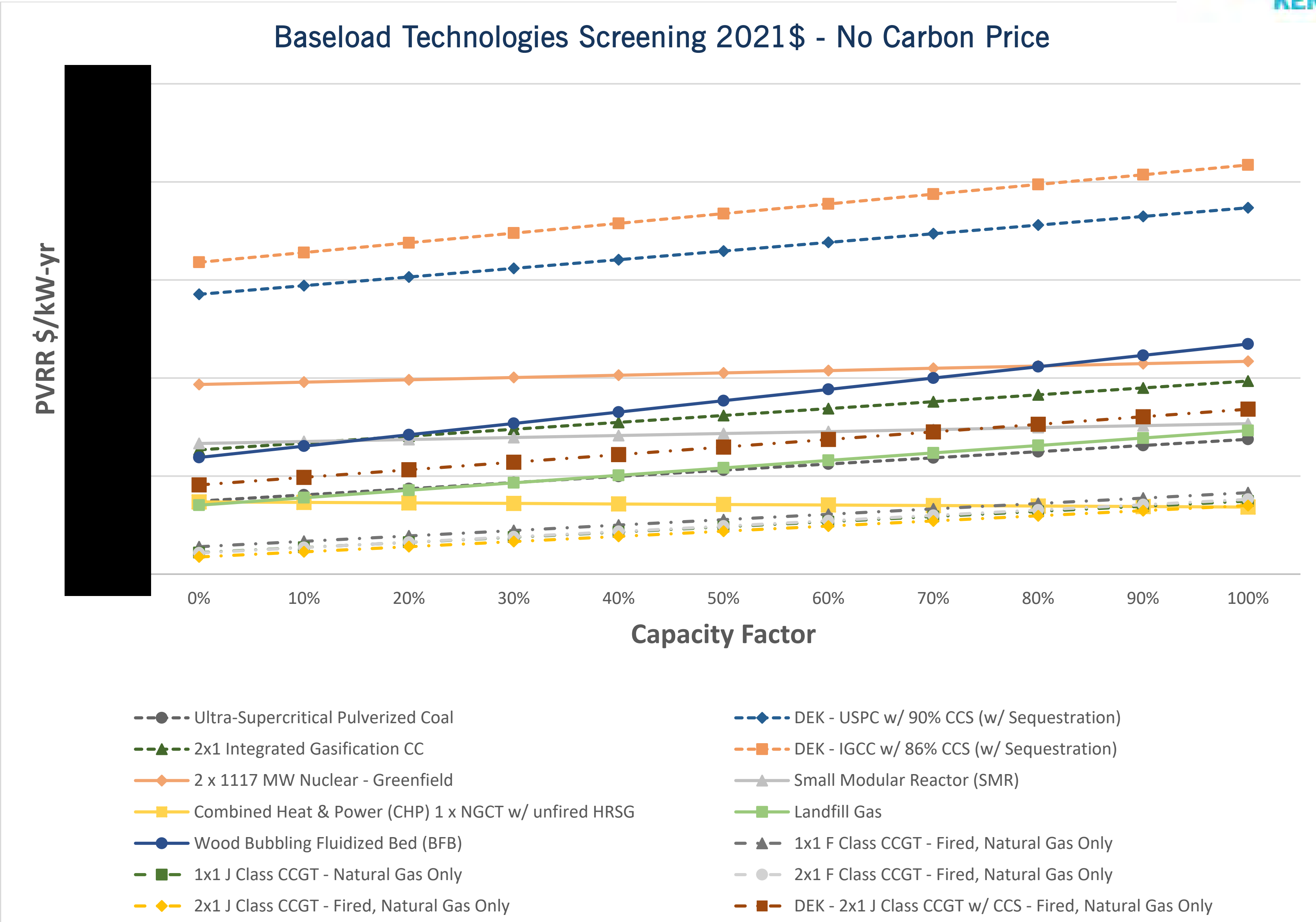


Figure E-4: Baseload Technologies Screening with Carbon Price

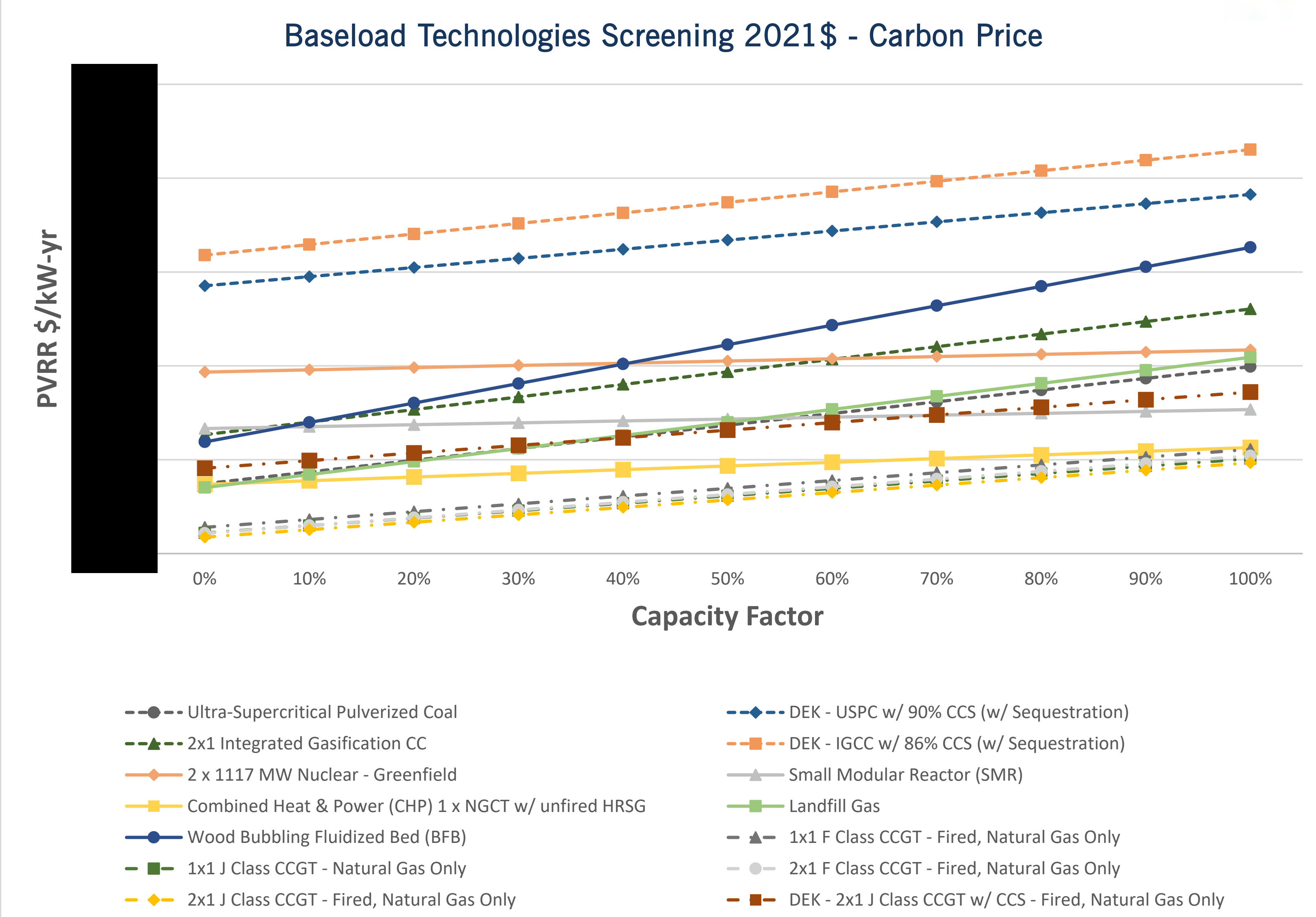


Figure E-5: Peaking Technologies Screening No Carbon Price

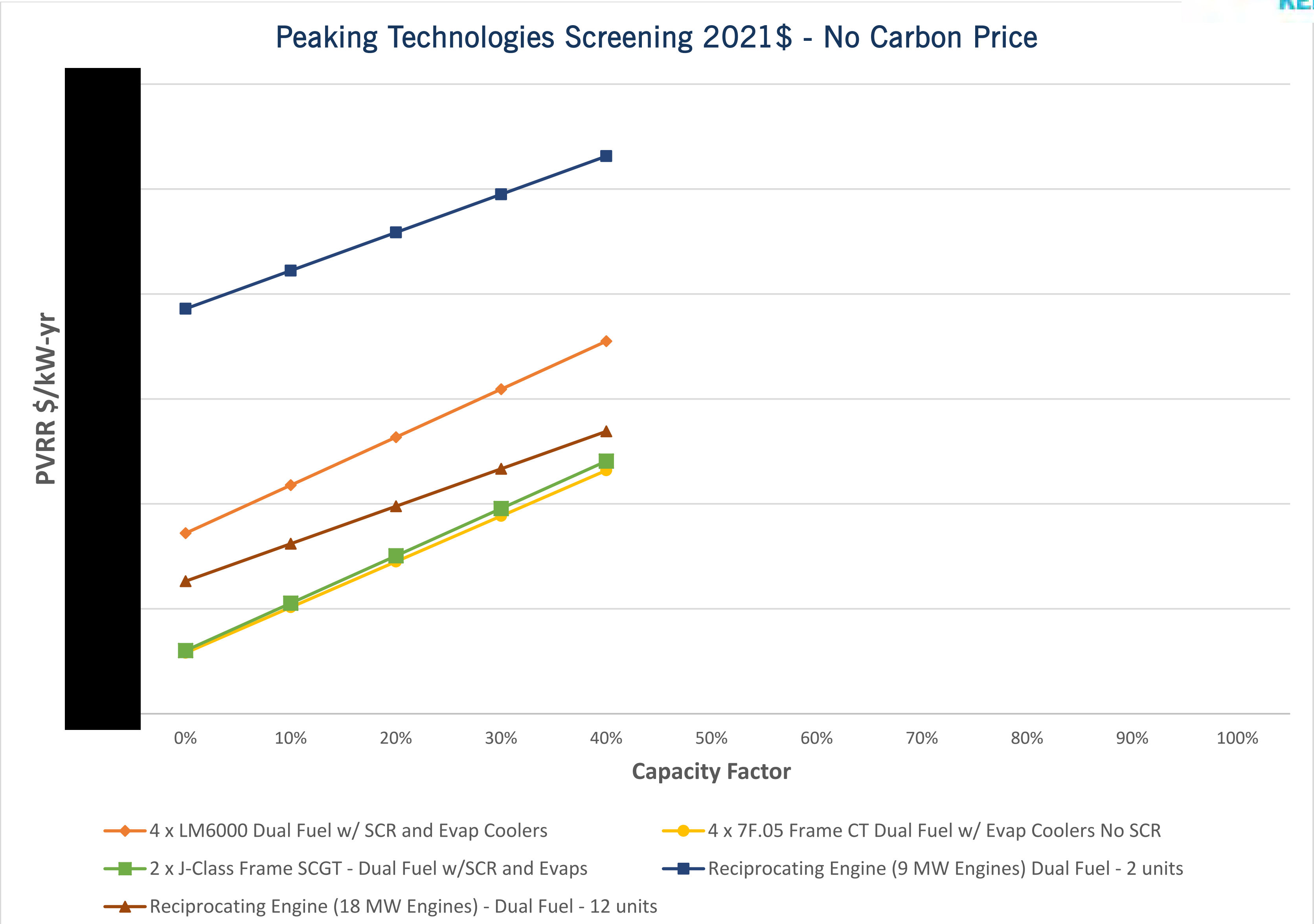


Figure E-6: Peaking Technologies Screening with Carbon Price

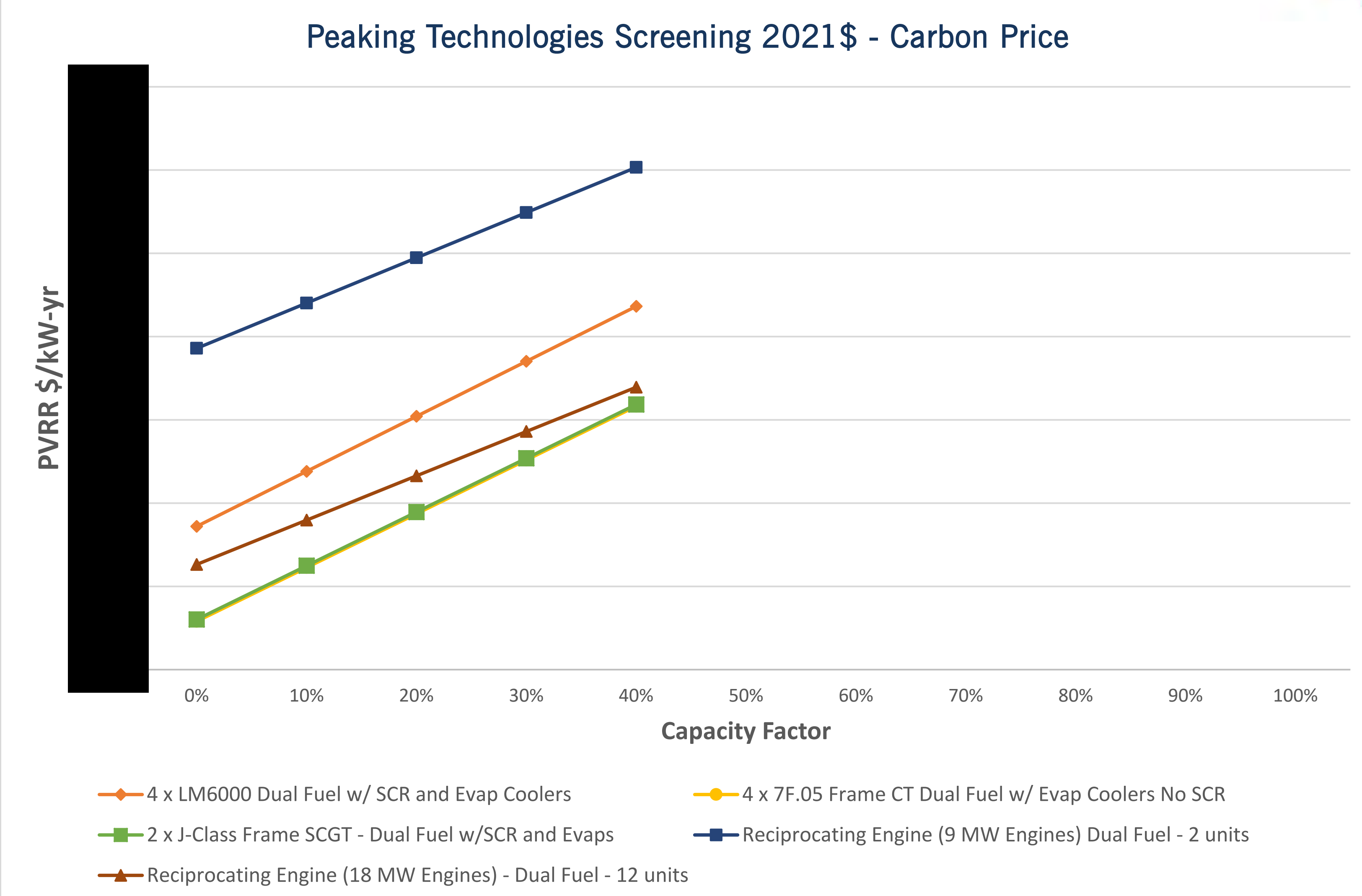


Figure E-7: Renewables Technologies Screening

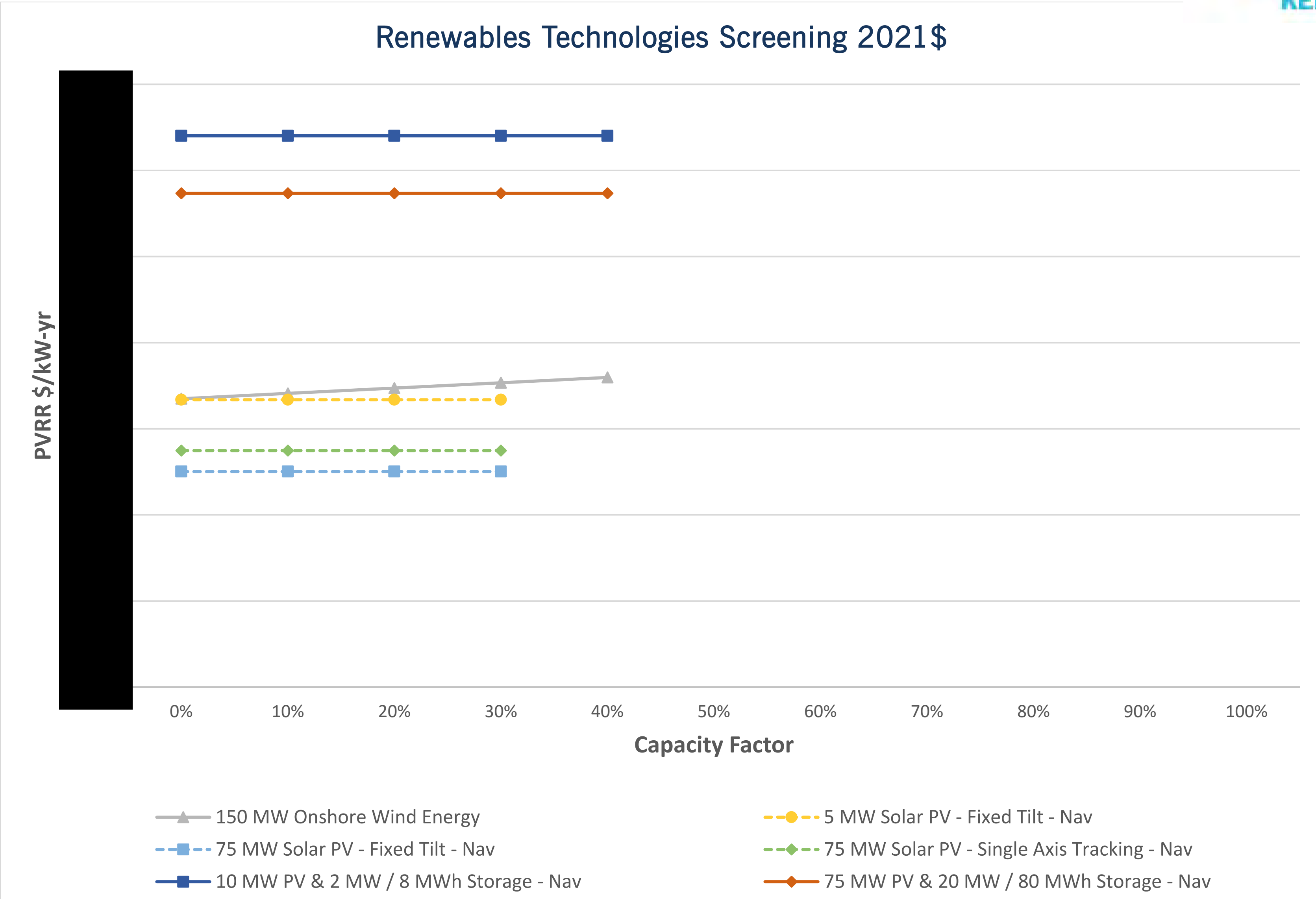
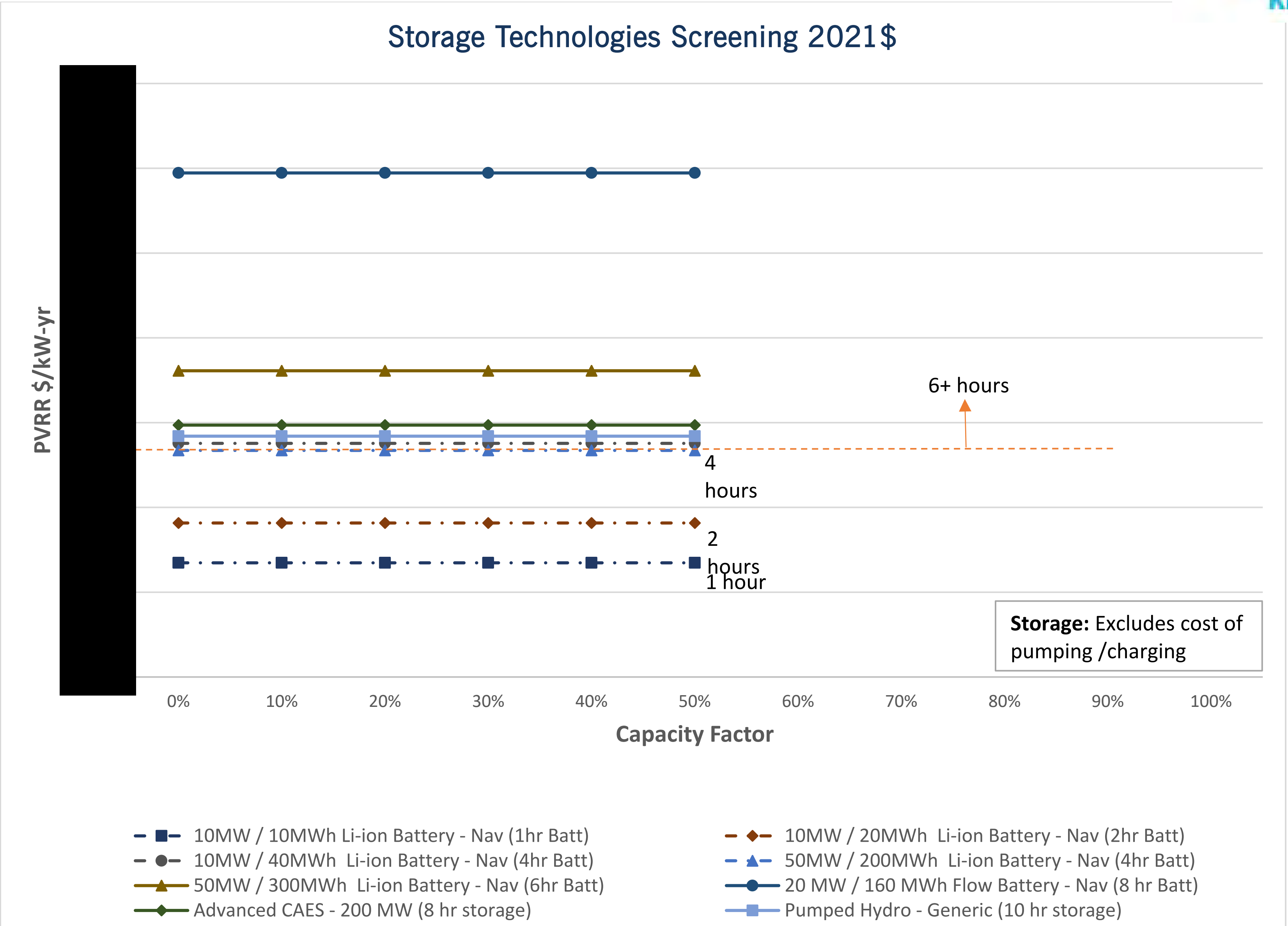


Figure E-8: Storage Technologies Screening



DUKE ENERGY®

RESPONSE TO 2018 STAFF COMMENTS

APPENDIX F

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F

RESPONSE TO 2018 IRP STAFF COMMENTS

A. LOAD FORECASTING

RECOMMENDATION

In its next IRP, Duke Kentucky should ensure that figures reported in tables are consistent throughout the IRP. Any differences in figures and tables should be clearly explained.

RESPONSE

The Company has made every effort to comply with this recommendation.

RECOMMENDATION

1. Duke Kentucky had altered the format of the 2018 IRP from the 2014 IRP in an effort to make it more reader-friendly and customer accessible. Staff appreciated Duke Kentucky's efforts. However, for the Commission's purposes, using a report format similar to what has been used historically is more appropriate. At a minimum, the report should contain a rigorous and detailed discussion of each forecasting model, including the final model equation and the derivation of each variable used in each model equation. This discussion should be organized around each forecasting model. In the current report, the Itron 2018 Residential and Commercial SAE Updates were helpful in this regard.

RESPONSE

Duke Energy has gone back to a format used in the 2014 IRP and has added more rigorous and detailed discussion for each forecasting model. The discussion is formatted for easy association with the respective model.

RECOMMENDATION

2. There is insufficient discussion of the importance and uses of weather normalization and how that has been utilized with respect to sector or to total company forecasts.

RESPONSE

Information on the use of weather normalization has been added and can be found in Section E.d. of Appendix B.

RECOMMENDATION

3. Staff notes that not all of the figures reported and or represented in Tables appear to be consistent throughout the IRP. For example:

    - Table B.2 contains energy usage categories that are not listed in Tables B.3a and B.3b. It is not clear whether the differences between the figures represented in the Tables are attributable to weather normalization only and where the additional energy usage categories reported in Table B.2 are accounted for in Tables B.3a and B.3b.
    - Tables B.3a and B.3b on pages 66-67 contain identical residential energy usage for the years 2013-2017 for "before" and "after' EE and DSM program implementation.
    - Calculating the impacts of EE and DSM programs on residential energy usage reported in Tables B.3a and B.3b and comparing to the EE and DSM impacts reported in Table D.1 a on page 81 and on page 17 yields two different impact results.
    - The Summer Peak forecast in Table B.4b on page 69 matches the Most Likely Peak Load forecast in Table B.6b on page 73. However, footnote b for both Tables is inconsistent regarding controllable load.

- Table B.4a on page 68 (before EE) is an exact match for Table B.4b on page 69 (after EE Case #1). In addition, the Summer Peak load in Table B.4a does not match the Most Likely peak load reported in Table B.6a.

RESPONSE

Duke Energy Kentucky will review to ensure consistency and explain any differences should they arise.

RECOMMENDATION

4. There should be a greater explanation of information found in Tables and in any underlying assumptions driving particular results. In addition, when there are differences between Tables purporting to illustrate the same result, there should be sufficient explanation of each Table to enable the reader to make distinctions and understand the differences.

RESPONSE

Additional commentary and take away information have been added for tables and charts.

RECOMMENDATION

5. There should be a greater explanation of each forecasting model, the specific data used for each customer class forecast, the explanation of each customer class and total forecast for energy usage, peak load, and the sensitivity analysis should be organized in a manner more specific to each customer class. An analysis of possible changes in customer class elasticities should also be included in the sensitivity analyses.

RESPONSE

Greater levels of load forecasting information have been added.

B. DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

RECOMMENDATION

1. Duke Kentucky's next IRP should include the DSM Programs approved by the Commission in Case No. 2017-00427.

RESPONSE

Approved programs are assumed in the 2021 IRP.

RECOMMENDATION

2. Duke Kentucky should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. Duke 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

Through the ongoing Collaborative process and a focus on developing new cost-effective program offerings, Duke Energy has a well-established process for evaluating, identifying, and bringing to market EE and DSM programs that are appropriate for the customers of Duke Energy Kentucky.

C. SUPPLY SIDE RESOURCES AND ENVIRONMENTAL COMPLIANCE

RECOMMENDATION

1. Duke Kentucky should continue to provide a discussion of its efforts to promote cogeneration and its consideration of various forms of renewable and distributed generation.

RESPONSE

Duke Energy Kentucky is committed to continually evaluating the economics of all forms of distributed energy technology and will monitor the impacts caused by FERC 2222 including cogeneration, and the specific benefits that these technologies may bring to our customers. Business development personnel have engaged Duke Energy Kentucky's large customer account representatives to identify industrial and institutional customers that would be suitable candidates for cogeneration facilities also known as Combined Heat and Power (CHP). Suitability is determined by the steam host's need for a minimum sustained level of steam sufficient to support the economics of including the CHP electric generation in the Duke Energy Kentucky generating fleet. Inquiries have been made but no customers have indicated interest at this time. Duke Energy Kentucky will continue to promote CHP and evaluate Duke owned CHP co-located at customers sights as opportunities arise.

RECOMMENDATION

2. Duke Kentucky should provide a discussion on its compliance with PJM CP requirements and identify any non-compliance situations and the reasons for the non-compliance.

RESPONSE

PJM's capacity performance rules were put in place to increase the availability of resources for times when the PJM system is under stress. East Bend 2 has its coal pile that serves as fuel storage and the Woodsdale peaking facility has oil back up the serves the same purpose if fuel supplies should be disrupted.

Capacity performance does present some challenges to renewable resources due to their intermittent nature. The result of this is that renewables will primarily be relied upon for their energy value and hedge value to offset market purchases.

All PJM rules are monitored and assessed in determining a compliance plan that is in the best interest of customers.

RECOMMENDATION

3. Duke Kentucky should provide a detailed discussion of any environmental law changes and their impacts as well as an update to its compliance with existing laws and regulations.

RESPONSE

Duke Energy Kentucky discusses changes of environmental laws in Appendix D.

RECOMMENDATION

4. Duke should have a preliminary discussion on its future plans for supply-side resources as the East Bend and Woodsdale Stations are approaching the end of their service lives at the end of the planning period in the current IRP.

RESPONSE

Both stations are approaching their end of serviceable life in the next two decades. While retirement of each facility is on the horizon, current circumstances are such that it is expected that both are valuable resources for the time being. East Bend is most at risk to economic retirement should there be carbon regulation or sustained low gas prices. Both possibilities have been addressed in the body of the IRP.

The Woodsdale peaking facility's capacity value and operational flexibility will continue to be valuable and as such is expected to operate through the end of its book life or possibly beyond.

The viability of both stations is evaluated in each IRP and risk to each station are also monitored.

RECOMMENDATION

5. Staff expects a more robust discussion on transmission and distribution as Duke Kentucky had in its previous IRPs.

RESPONSE

This IRP has gone back to the format of earlier IRPs that include more information on the transmission and distribution system.

RECOMMENDATION

6. Duke Kentucky should include a discussion on other non-utility supply sources, as there was no discussion of this topic in the current IRP. Duke Kentucky should provide how the utility will meet the sustainability goals of commercial and industrial customers.

RESPONSE

Duke Energy Kentucky works with customers in ways that can help them meet their respective sustainability goals. While there is a theme that some customers want greener sources of energy, each customer has their own specific goals. Duke Energy Kentucky is working to transition the generating fleet in a way that is in the best interest of customers, helps advance customer sustainability goals and attracts new customers to the service territory.

RECOMMENDATION

7. Duke Kentucky should provide how the utility is modeling for impacts that occur behind the meter, specifically with renewable energy sources.

RESPONSE

Behind the meter generation is modeled as a reduction in the load forecast.

RESPONSE TO COMMENTS MATRIX

APPENDIX G

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G 

RESPONSE TO COMMENTS MATRIX

Rule Section		Document Section	
5. Plan Summary	(1)	1. Executive Summary	D. Duke Energy Kentucky Overview
5. Plan Summary	(2)	2. Objectives and Process	C. 4. Forecasting Methods
5. Plan Summary	(3)	3. Future Resource Considerations	E. Load Forecast
5. Plan Summary	(4)	1. Executive Summary	A. Integrated Resource Plan
5. Plan Summary	(5)	1. Executive Summary	B. 3-Year Implementation Plan
5. Plan Summary	(6)	2. Objectives and Process	C. 1. Developing a Base Case
6. Significant Changes		1. Executive Summary	C. Significant Changes from 2018 IRP
7. Load Forecasts	(2) (a)	Appendix B	
7. Load Forecasts	(2) (b)	Appendix B	E. d. Methodology Enhancements
7. Load Forecasts	(2) (c)	Appendix B	F. b. System Seasonal Peak Load Forecast
7. Load Forecasts	(2) (d)	1. Executive Summary	Duke Energy Kentucky Overview
7. Load Forecasts	(2) (e)	1. Executive Summary	Duke Energy Kentucky Overview
7. Load Forecasts	(2) (f)	Appendix B	Figure B2a
7. Load Forecasts	(2) (g)	Appendix D	
7. Load Forecasts	(3)	Appendix B	Figure B2b
7. Load Forecasts	(4) (a)	Appendix B	B. Forecast Methodology
7. Load Forecasts	(4) (b)	Appendix B	A. General
7. Load Forecasts	(4) (c)	Appendix B	Figure B1
7. Load Forecasts	(4) (d)	Appendix B	Figures B3a and B4a
7. Load Forecasts	(5)	Exempt	
7. Load Forecasts	(7) (a)	Appendix B	D. Data Base Documentation
7. Load Forecasts	(7) (b)	Appendix B	C. Assumptions
7. Load Forecasts	(7) (c)	Appendix B	B. Forecast Methodology
7. Load Forecasts	(7) (d)	2. Objectives and Process	C. 1. Developing a Base Case
7. Load Forecasts	(7) (e)	Appendix B	F. g. Conclusion
7. Load Forecasts	(7) (f)	Appendix B	E. d. Methodology Enhancements
7. Load Forecasts	(7) (g)	Appendix B	B. Forecast Methodology
8. Resource Assessment and Acquisition Plan	(2)	4- Supply side Management Options	
8. Resource Assessment and Acquisition Plan	(3) (a)	Provided to KyPSC Staff separately under seal	
8. Resource Assessment and Acquisition Plan	(3) (b)	Appendix H	Table H.2
8. Resource Assessment and Acquisition Plan	(3) (c)	Appendix H	Table H.4
8. Resource Assessment and Acquisition Plan	(3) (d)	Appendix H	Table H.3 & H.4
8. Resource Assessment and Acquisition Plan	(3) (e)	Appendix C	
8. Resource Assessment and Acquisition Plan	(4) (a)	Appendix H	Table H.3
8. Resource Assessment and Acquisition Plan	(4) (b)	Appendix H	Table H.3
8. Resource Assessment and Acquisition Plan	(4) (c)	Appendix H	Table H.5
8. Resource Assessment and Acquisition Plan	(5) (a)	2. Objectives & Modeling Process	
8. Resource Assessment and Acquisition Plan	(5) (b)	3. Future Resource Considerations	
8. Resource Assessment and Acquisition Plan	(5) (c)	7. 2021 Integrated Resource Plan	
8. Resource Assessment and Acquisition Plan	(5) (d)	2. Objectives & Modeling Process	B. Objectives
8. Resource Assessment and Acquisition Plan	(5) (e)	7. 2021 Integrated Resource Plan	B. Key Variables to Monitor Ahead of 2024 IRP
8. Resource Assessment and Acquisition Plan	(5) (f)	Appendix D- Environmental Regulations	
8. Resource Assessment and Acquisition Plan	(5) (g)	2. Objectives & Processes / 3. Future Resources	D. Forecasting Methods / D. Power Prices
9. Financial Information	(1)	3. Future Resource Considerations	Figure 3.10
9. Financial Information	(2)	3. Future Resource Considerations	Figure 3.10
9. Financial Information	(3)	3. Future Resource Considerations	Figure 3.10
9. Financial Information	(4)	3. Future Resource Considerations	Figure 3.10

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FINANCIAL & OPERATING PROJECTIONS OVER PLANNING PERIOD

APPENDIX H

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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	SUMMER RATING (MW)	WINTER RATING (MW)
East Bend	2	Existing	Boone County, KY	1981	2035	ST	Coal	None	600	600
Woodsdale	1	Existing	Trenton, OH	1993	Unknown	CT	Gas	Oil	78	94
Woodsdale	2	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	80	94
Woodsdale	3	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	80	94
Woodsdale	4	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	78	94
Woodsdale	5	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	80	94
Woodsdale	6	Existing	Trenton, OH	1992	Unknown	CT	Gas	Oil	80	94
Walton Solar		Existing	Kenton County, KY	2017	Unknown	PV	Sunlight	None	1.4	0
Crittenden Solar		Existing	Grant County, KY	2017	Unknown	PV	Sunlight	None	1.0	0
Solar 2021		Planned	TBD	2021	Unknown	PV	Sunlight	None	5	0
Solar 2022		Planned	TBD	2022	Unknown	PV	Sunlight	None	5	0
Solar 2023		Planned	TBD	2023	Unknown	PV	Sunlight	None	5	0

Existing and Planned Electric Generating Facilities Included in Resource Acquisition Plan (Cont.)

STATION	UNIT NO.	STATUS	LOCATION	COMMERCIAL OPERATION YEAR	PLANNED RETIREMENT DATE	TYPE	PRIMARY FUEL	SECONDARY FUEL	SUMMER RATING (MW)	WINTER RATING (MW)
Solar 2024		Planned	TBD	2024	Unknown	PV	Sunlight	None	5	0
Solar 2025		Planned	TBD	2025	Unknown	PV	Sunlight	None	5	0
Solar 2026		Planned	TBD	2026	Unknown	PV	Sunlight	None	5	0
Solar 2027		Planned	TBD	2027	Unknown	PV	Sunlight	None	5	0
Solar 2028		Planned	TBD	2028	Unknown	PV	Sunlight	None	5	0
Solar 2029		Planned	TBD	2029	Unknown	PV	Sunlight	None	5	0
Solar 2030		Planned	TBD	2030	Unknown	PV	Sunlight	None	5	0
Solar 2031		Planned	TBD	2031	Unknown	PV	Sunlight	None	5	0
Solar 2032		Planned	TBD	2032	Unknown	PV	Sunlight	None	5	0
Solar 2033		Planned	TBD	2033	Unknown	PV	Sunlight	None	5	0
Solar 2034		Planned	TBD	2034	Unknown	PV	Sunlight	None	5	0
Solar 2035		Planned	TBD	2035	Unknown	PV	Sunlight	None	5	0
Storage 2021		Planned	TBD	2021	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2022		Planned	TBD	2022	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2023		Planned	TBD	2023	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2024		Planned	TBD	2024	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2025		Planned	TBD	2025	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2026		Planned	TBD	2026	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2027		Planned	TBD	2027	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2028		Planned	TBD	2028	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2029		Planned	TBD	2029	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2030		Planned	TBD	2030	Unknown	Li-ion	Electricity	None	1.6	1.6

Existing and Planned Electric Generating Facilities Included in Resource Acquisition Plan (Cont.)

STATION	UNIT NO.	STATUS	LOCATION	COMMERCIAL OPERATION YEAR	PLANNED RETIREMENT DATE	TYPE	PRIMARY FUEL	SECONDARY FUEL	SUMMER RATING (MW)	WINTER RATING (MW)
Storage 2031		Planned	TBD	2031	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2032		Planned	TBD	2032	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2033		Planned	TBD	2033	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2034		Planned	TBD	2034	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2035		Planned	TBD	2035	Unknown	Li-ion	Electricity	None	1.6	1.6

Table H.2 – Generation Operational Characteristics

Actual and Projected Cost and Operating Information for Base Year and Each Forecast Year (Reference w/ CO2 Regualtion Scenario)

	Units	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend	[redacted]															
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Woodsdale																
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Walton & Crittenden Solar																
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Future Solar Facilities																
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Total Capital Cost																

Actual and Projected Cost and Operating Information for Base Year and Each Forecast Year (Reference w/ CO2 Regualtion Scenario)

	Units	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Solar Facilities	[redacted]															
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Total Capital Cost																
Future Wind Facilities																
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Total Capital Cost																
Future FDR Facility																
Availability																
Capacity Factor																
Average Heat Rate																
Fuel Cost																
Variable O&M																
Fixed O&M + Maintenance Capital																
Total Capital Cost																
MW ADDED																
Solar																
Wind																
FDR																

Table H.3 Load and Resources

SUMMER MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak Load	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898
Capacity from:															
Existing Generating Resources	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	567
Demand Response Resources	22	22	15	15	15	8	8	8	8	8	8	8	8	8	8
Planned Utility-Owned Resources*	7	14	20	32	40	48	56	64	72	80	87	95	103	111	724
Purchases (Sales) from (to) Third Parties	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Reserve Requirement (ICAP @ 15%)	937	945	961	966	979	980	983	986	989	1,001	1,005	1,011	1,018	1,024	1,032
Capacity Excess (Deficit)	260	258	241	248	243	243	249	253	258	254	258	259	261	263	(333)
Reserve Margin	47%	46%	44%	45%	44%	43%	44%	45%	45%	44%	45%	44%	44%	45%	45%

WINTER MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak Load	702	733	747	747	763	759	757	754	755	768	768	769	765	764	774
Capacity from:															
Existing Generating Resources	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	564
Demand Response Resources	22	22	15	15	15	8	8	8	8	8	8	8	8	8	8
Planned Utility-Owned Resources*	2	3	5	12	15	17	20	23	26	29	32	35	38	41	649
Purchases (Sales) from (to) Third Parties	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Reserve Requirement (ICAP @ 15%)	807	843	860	859	877	873	871	868	869	883	883	884	880	879	890
Capacity Excess (Deficit)	381	346	324	331	316	317	321	328	329	318	321	323	330	333	(270)
Reserve Margin	69%	62%	58%	59%	56%	57%	57%	58%	59%	56%	57%	57%	58%	59%	58%

Notes:

Solar contribution to peak capacity is 50% of nameplate in summer and 0% in winter

Wind contribution to peak capacity is 13% of nameplate in summer and 13% in winter

Table H.4 – Energy Supply

Gigawatt Hours	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast Energy Requirements	[redacted]														
Energy from Existing and Planned Resources															
Coal															
Gas															
Solar															
Wind															
Energy Purchased from the PJM Market															

Table H.5- Fuel Burns

Fuel Requirements	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Coal	[redacted]														
Thousand Tons															
K MMBtu															
Gas															
Mcf															
K MMBtu															

GLOSSARY OF TERMS

AC	Air Conditioner
AEO	Annual Energy Outlook
Bcf	Billion Cubic Feet
BES	Blackhawk Engagement Solutions
BFB	Bubbling Fluidized Bed
BPI	Building Performance Institute
BRC	Business Reply Card
CAES	Compressed Air Energy Storage
CC	Combined Cycle
CCGT	CC Gas Turbine
CCR	Coal Combustion Residuals
CCS	Carbon Capture & Sequestration
CEII	Critical Energy Infrastructure Information
cir.	Circuit
CFL	Compact Fluorescent Lights
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COVID	Coronavirus Disease
CP	Capacity Performance
CPE	Critical Peak Event
CPI	Consumer Price Index
CT	Combustion Turbine
DEK	Duke Energy Kentucky
DEOK	Duke Energy Ohio/Kentucky
DIY	Do It Yourself
DOE	Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EB2	East Bend 2
ECP	Electric Capacity Planning
EDT	Eastern Daylight Time
EE	Energy Efficiency
EFI	Energy Federation Inc.
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement, and Verification
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FRR	Fixed Resource Requirement
GDP	Gross Domestic Product
GWh	Gigawatt Hour
HEHC	Home Energy House Call
HP	Heat Pump
HRSG	Heat Recover steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IGCC	Integrated Gasification Combined Cycle
IHS	IHS Markit Ltd
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IVR	Interactive Voice Response
KAR	Kentucky Administrative Regulations
kV	Kilovolt
kW	Kilowatt
KYPSC	Kentucky Public Service Commission
LED	Light Emitting Diode
LIHEAP	Low-income Home Energy Assistance Program
mmBTU	Millions of British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NCL	No Carbon Law
NEAT	National Energy Audit Tool
NEMS	National Energy Modeling System
NES	Neighborhood Energy Saver
NGCT	Natural Gas CT
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OPA	Other Public Authorities
PCE	Personal Consumption Expenditure Index
PCT	Participant Cost Test
PJM	PJM Interconnection, LLC
PLM	Peak Load Management
PMSA	Primary Metropolitan Statistical Area
PSA	Peak Shaving Adjustment
PTR	Peak Time Rebate

GLOSSARY OF TERMS (CONT.)

PV	Solar Photovoltaic
PVRR	Present Value Revenue Requirements
RIM	Rate Impact Measure
RTO	Regional Transmission Operator
SAE	Service Area Economy
SBES	Small Business Energy Saver
SCR	Selective Catalytic Reduction
SEWK	Save Energy and Water Kit
SIR	Savings - Investment Ratio
SL	Street Lighting
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
ST	Steam Turbine
TA	Trade Allies
TB	Transmission BUS
TAG®	Technical Assessment Guide
TRC	Total Resource Cost
UCAP	Unforced Capacity
UEE	Utility-sponsored Energy Efficiency
US	United States
UTC	Utility Cost Test

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