Kentucky

The Duke Energy Kentucky 2018 Integrated Resource Plan

Public Version

June 21, 2018

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LIST OF ACRONYMS

AEO	Annual Energy Outlook
BAU	Business As Usual
BPI	Building Performance Institute
CC	Combined Cycle – Natural Gas
CFL	Compact Fluorescent Lamp
CPP	Clean Power Plan
CT	Combustion Turbine
DEK	Duke Energy Kentucky
DEO	Duke Energy Ohio
DEOK	Duke Energy Ohio & Kentucky PJM capacity zone
DR	Demand Response
DSM	Demand Side Management
ECM	Energy Conservation Measures
ECP	Electric Capacity Planning
EE	Energy Efficiency
EFI	Energy Federation, Inc.
EFOR	Effective Forced Outage Rate
EIA	Energy Information Administration
HEHC	Home Energy House Call
HVAC	Heating, Ventilation, and Air-Conditioning
ICAP	Installed Capacity
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LED	Light-emitting Diode
LIHEAP	Low-income Home Energy Assistance Program
LNG	Liquefied Natural Gas
M&V	Measurement and Verification
NEAT	National Energy Audit Tool
NEED	National Energy Education Development

NOAA	National Oceanic and Atmospheric Administration
NEMS	National Energy Modeling System
NTC	National Theater for Children
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OPA	Other Public Authority
PAR	Planning and Risk
PCE	Personal Consumption Expenditure
PJM	PJM Interconnection, LLC
PLM	Peak Load Manager
PMSA	Primary Metropolitan Statistical Area
PROMOD	Transmission/Generation Modeling Software
PVRR	Present Value of Revenue Requirements
RIM	Rate Impact Measure
SAE	Service Area Economy
SBES	Small Business Energy Saver
SO	System Optimizer
ST	Steam Turbine
TA	Trade Ally
TRC	Total Resource Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
UEE	Utility-sponsored Energy Efficiency

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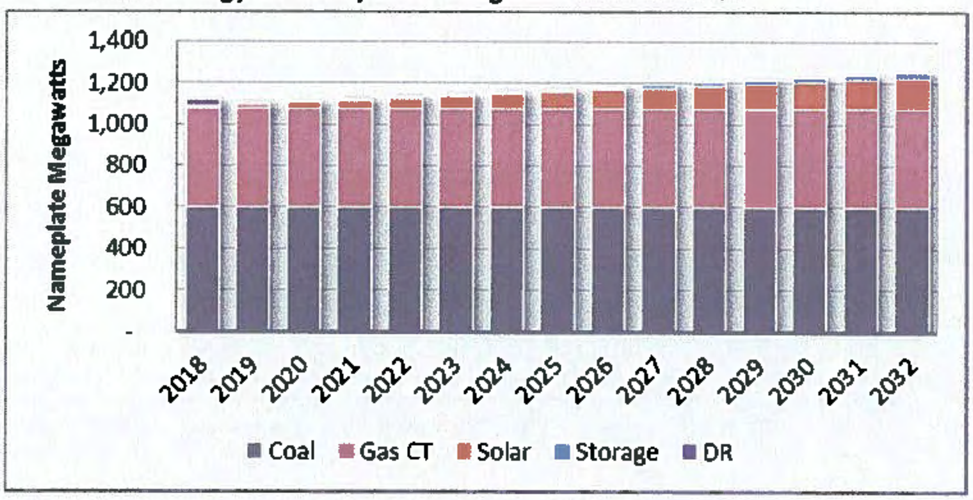
I. EXECUTIVE SUMMARY

A. IRP OVERVIEW

The 2018 Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company) Integrated Resource Plan (IRP) is similar to the 2014 IRP in that it does not include retirement of the East Bend 2 and Woodsdale stations during the term of this analysis. Increasing customer preference for renewable energy, potential additional industrial load and pending matters concerning the utility's demand-side management (DSM) programs have led to minor changes from the 2014 plan.

The result of these changes is the addition of greater amounts of renewable resources to the generation fleet. These additional renewables provide several benefits in addition to those mentioned above, including a reduction in market purchases, which lessens fuel cost variability, and reduced emissions of carbon dioxide (CO_2) associated with serving customer load. The generating capacity mix for each year of the plan is presented in Figure 1.1 below.

Figure 1.1: Duke Energy Kentucky 2018 Integrated Resource Plan



This IRP considers two possible outcomes to the pending DSM matters. The first allows for the continuation of only low-income programs and the second assumes reinstatement of previously implemented programs.

The Company has restructured the format of this IRP to make it more reader friendly and accessible to customers. As a result, the body of the document has been considerably shortened with most technical information placed in the appendices. The Company has done this while maintaining compliance with the requirements of the IRP Rules.

The Company has provided a cross reference of the IRP Rule requirements with the specific section(s) of the IRP in Appendix F and responses to the Commission Staff's comments on the 2014 IRP in Appendix E.

B. 3-YEAR IMPLEMENTATION PLAN

Over the next three years, the Company expects relative stability in fuel and power markets and we consider it implausible that a price is imposed on carbon emissions in that time. Therefore, Duke Energy Kentucky's three-year IRP implementation plan will be focused on the administration of approved DSM programs as well as the development of the solar and storage resources specified in Figure 1.1. The Company has included the addition of 10MW of solar and 2MW of battery storage resources in each year of the plan, starting in 2019.

There is emerging interest from new and existing customers for additional renewable energy to meet their sustainability goals and strategies. These sophisticated customers seek to partner with Duke Energy Kentucky as a trusted energy advisor in achieving sustainability goals in a cost-effective method that benefits the entire Duke Energy Kentucky system. Both existing and potential new sources of load have expressed this desire for the Company to provide greener alternatives to meet customer energy needs. This new load is be driven by significant customer investments and expansion that will create new jobs in the communities the Company serves. In response to this growing customer interest, articulated desire, and to support the increase in demand or load, the Company will continue to look for opportunities to add more renewable resources to the DEK generation fleet. Given the particulars of the DEK footprint; this strategy will likely be, but not exclusively limited to, solar and storage. As the specifics of potential new load are determined, the Company will incorporate them into our planning process to meet customers' needs and comply with PJM requirements.

Regarding PJM requirements, the Company anticipates organic load growth and expects that DEK will remain a Fixed Resource Requirement entity for the foreseeable future. The Company maintains a small margin over PJM load obligation requirements; a margin that may thin considerably if the Commission maintains the suspension of the company's DSM Programs. If the DEK load obligation to PJM were to increase sharply over a short period of time due to either a change in load growth rates or the addition of an industrial or commercial customer with significant load, we would pursue the least cost solution for acquiring additional capacity that maintains compliance with FRR requirements. Short and long-term options could include short-term capacity purchase agreements and joint venture or sole ownership self-built generation projects within the DEOK capacity zone.

The Company will be working with customers and stakeholders to develop projects that add value to the system and community. This will include a preference for siting resources within the footprint of the DEK service territory, but may also include other locations in the DEOK PJM capacity zone or other parts of PJM.

The Company will continue to monitor fuel and power markets as well as potential changes in policy and regulations.

C. SIGNIFICANT CHANGES FROM 2014 IRP

Several key variables have changed since the 2014 IRP, but none have caused a significant change to the 2018 IRP preferred portfolio. In the past four years, Duke Energy Kentucky has seen continued declines in gas prices and the cost of renewables; and regulations on carbon emissions have been delayed. In addition, the Company's DSM programs, other than low income programs, have been suspended. Finally, in 2015, the Company completed the acquisition of the 31% of East Bend 2 that it did not already own, bringing DEK ownership of East Bend 2 to 100% and adding 186 MW of capacity to the system.

Similar to the 2014 IRP, the 2018 IRP shows continued operation of East Bend 2 and the Woodsdale comhustion turbine (CT) units. The 2018 IRP also features the systematic addition of renewahles, albeit at a slightly higher level. Tbe Company plans to add renewable resources to the DEK fleet to further diversify its generation portfolio, gain experience incorporating renewable energy into the DEK system, and to moderate the impact to customers once East Bend 2 ultimately retires.

In short, the DEK generation fleet continues to be well positioned for the future, and through this planning process we are slowly diversifying the portfolio to make it more environmentally friendly and responsive to customer preferences.

D. ENVIRONMENTAL REGULATION

The DEK fleet is well positioned for compliance with all current and anticipated environmental regulations. We continue to monitor evolving environmental regulations and seek implementation of low cost compliance strategies to minimize impact to customers while meeting all legal and regulatory requirements. See Appendix C for further discussion of current environmental regulations relevant to the DEK fleet and investments made to ensure compliance.

E. DUKE ENERGY KENTUCKY OVERVIEW

Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio) that provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by Duke Energy Ohio. Duke Energy Kentucky provides electric service to approximately 142,000 customers and natural gas service to approximately 90,000 customers in its approximately 300 square mile service territory. The Company has both a legal obligation and a corporate commitment to meet the energy needs of its customers in a way that is adequate, efficient, and reasonable.

The objective of the resource planning process is to develop a robust and reliable economic strategy for meeting the needs of customers in a very dynamic and uncertain environment. The Company conducts quantitative analysis and considers qualitative factors to identify the best options to serve customers' future energy and capacity needs. Quantitative analysis provides insights into future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewables. Qualitative considerations, such as fuel diversity, the Company's environmental profile, emerging environmental regulations, and the progress of emerging technologies, are also taken into account. The result is an IRP that is an important tool used to guide business decisions and help the Company effectively meet customers' near- and long-term needs.

II. DUKE ENERGY KENTUCKY TODAY

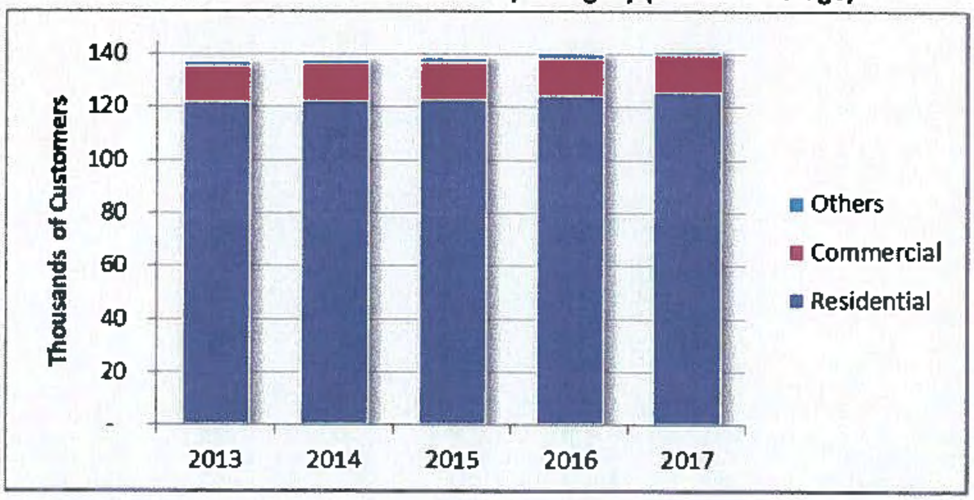
A. HISTORICAL LOAD & CUSTOMER CHARACTERISTICS

Duke Energy Kentucky provides electric and gas service in the Northern Kentucky area which includes the cities of Covington, Florence, Fort Thomas, and Newport. The Company owns a 69 kV electric transmission and distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties.[1]

For the purposes of resource planning and load forecasting, customers are segmented into the following categories: residential, commercial industrial, government, and street lighting. Duke Energy Kentucky has no wholesale contracts at present.

The number of customers in each category, historical energy sales by customer category, and historical winter and summer peak demand are displayed in the figures below. For additional details on historical load, see Appendix B.

Figure 2.1: Historical Number of Customers by Category (Annual Average)



[1] Response to IRP Rule Section 8(3)(a): Maps and the transmission line thermal capacity table are considered critical energy infrastructure information (CEII). The information will be provided to the KyPSC Staff under seal, not to be released to the general public.

Figure 2.2: Historical Energy Sales by Customer Category (after UEE)

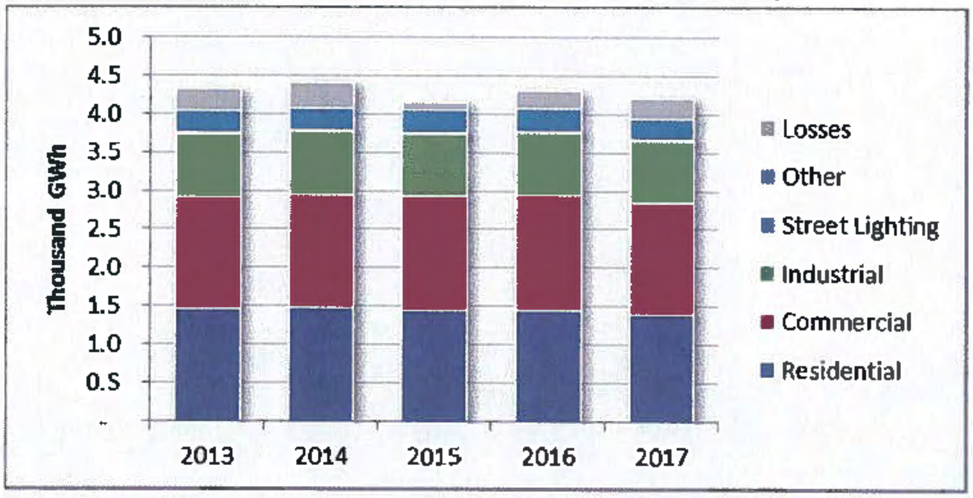
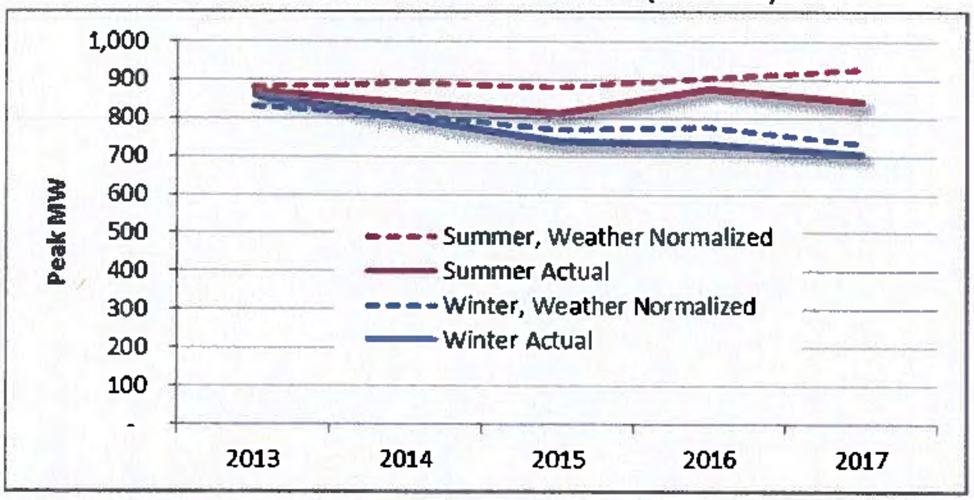


Figure 2.3: Historical Summer and Winter Peak Demand (after UEE)



B. CURRENT RESOURCE PORTFOLIO

Demand-Side Resources

Consistent with the Commission's IRP analytical requirements and the Commission's Order in Case No. 2008-408, Duke Energy Kentucky continuously evaluates and considers opportunities for DSM to meet its resource needs, and specifically, as part of this IRP.[2] Duke Energy Kentucky's DSM programs include traditional conservation energy efficiency (EE) programs and demand response (DR) programs and are expected to help reduce demand on the DEK system during times of peak load.

[2] 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).

Pursuant to a recent order from the Commission, however, all EE and DR programs, with the exception of the Low Income EE programs, have been suspended pending the outcome of Case No. 2017-00427. For the purpose of this IRP, the company evaluated two potential amounts of DSM, one that assumes only the Low Income EE programs are allowed to continue (Case #1) and one that assumes all existing EE and DR programs are reinstated in 2018 (Case #2) and continue during the time horizon of the IRP analysis.

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 portfolio of programs in place during the fiscal year ending June 30, 2017 and that was used as the basis for this IRP analysis was approved by the Commission's June 29, 2012 Order in Case No. 2012-00085 and contains the following set of programs described in greater detail in Appendix D:

- Program 1: Residential Smart $aver® Energy Efficient Residences Program
- Program 2: Residential Smart $aver® Energy Efficient Products Program[3]
- Program 3: Residential Energy Assessments Program (Residential Home Energy House Call)
- Program 4: Energy Efficiency Education Program for Schools Program
- **Program 5: Low Income Services Program**
- Program 6: Residential Direct Load Control- Power Manager® Program
- Program 7: Smart $aver® Prescriptive Program
- Program 8: Smart $aver® Custom Program
- Program 9: Smart $aver® Energy Assessments Program
- Program 10: Peak Load Manager (Rider PLM) - PowerShare® Program
- **Program 11: Low Income Neighborhood Program**
- Program 12: My Home Energy Report Program
- Program 13: Small Business Energy Saver Program
- Program 14: Non-Residential Pay for Performance[4]

[3] The Smart $aver® Residential Energy Efficient Products Program and the Energy Efficient Residences Program are individual measures that are part of a single and larger program referred to and marketed as Residential Smart $aver.® For ease of administration and communication with customers the two measures have been divided into separate tariffs even though they are a single program.
[4] Marketed as Smart $aver® Performance

- Program 15: Power Manager® for Apartments
- Program 16: Power Manager® for Business

As explained above, the projected impacts of DSM programs have been included in this IRP as two separate cases, one assuming that only the Low Income EE programs are allowed to continue (Case #1) and one assuming reinstatement of the full above portfolio (Case #2).

For Case #1, the conservation DSM programs are projected to reduce energy consumption by approximately 9,000 MWh and 1.2 MW by 2032. No peak demand reduction related to the DR programs is included in this case. This case assumes a total peak reduction across all programs of approximately 1.2 MW.

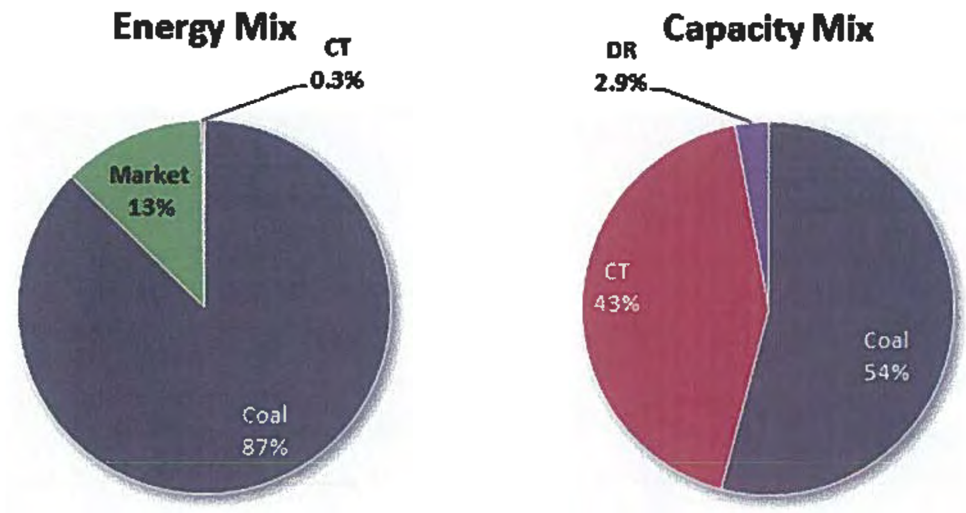
For Case #2, the conservation DSM programs are projected to reduce energy consumption by approximately 382,000 MWh and 37.0 MW by 2032. The Residential Direct Load Control Program (Power Manager) is projected to reduce peak demand by 15.2 MW and the PowerShare® and Power Manager for Business programs another 17.8 MW. This brings the total peak reduction across all programs to approximately 70.0 MW.

Supply-Side Resources

The total installed net summer generation capability owned by Duke Energy Kentucky is 1,083 MW. This capacity consists of 600 MW of coal-fired steam capacity, 476 MW of natural gas-fired peaking capacity, and 6.8 MW (2.4 MW contribution to peak) of solar photovoltaic (PV) capacity.

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-fired CTs located at the Woodsdale station. These units have historically maintained propane as a back-up fuel. The Company is in the process of constructing a new dual-fuel system consisting of low-sulfur diesel, due to the decommissioning of a nearby propane storage cavern and the need to meet capacity performance requirements for generating resources set by PJM Interconnection, LLC (PJM). The solar capacity consists of a 4 MW fixed-tilt PV plant located at the Walton Solar facility in Kenton County, Kentucky and a 2.7MW fixed-tilt PV plant located at the Crittenden Solar facility in Grant County, Kentucky. Because these solar facilities commenced commercial operation at the end of 2017, they are not included in Figure 2.4 below.

Figure 2.4: 2017 Duke Energy Kentucky Capacity and Energy Mixes



III. PLANNING OBJECTIVES, METHODS & TOOLS

A. INTRODUCTION

Duke Energy Kentucky files an IRP approximately every three years with the Kentucky Public Service Commission.[5] The IRP includes analysis of firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the Duke Energy Kentucky service territory. The final product is a fifteen-year plan for providing adequate and reliable supply of electricity to customers at a fair, just and reasonable rate, as required by KRS 278.030.

B. PLANNING OBJECTIVES

The purpose of this IRP is to define a robust strategy to furnish electric energy services to Duke Energy Kentucky customers in a reliable, efficient, and economic manner while remaining dynamic and adaptable to changing conditions. The planning process incorporates sensitivity analysis to address areas of regulatory, economic, environmental, and operating uncertainty. The triennial filing schedule allows the Company to monitor key sources of uncertainty and adjust the plan as necessary, thereby producing an IRP that represents the most reliable and economic path forward based upon robust analysis of emerging information.

Our long-term planning objective is to develop a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community) while maintaining the flexibility to adapt to changing conditions. At times, this involves striking a balance between competing objectives. The major objectives of the IRP presented in this filing are:

- Provide adequate, reliable, efficient, economic service;
- 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.).

[5] The Company's last IRP was filed on July 31, 2014 in Case No. 2014-00273. In the Commission's Order dated September 23, 2015, Duke Energy Kentucky was directed to file its next IRP on June 21, 2018.

Determining a Planning Reserve Margin

We address system reliability and resource adequacy in the planning process by targeting an appropriate planning reserve margin for use in our IRP models. The IRP models utilize the full installed capacity (ICAP) unit ratings to estimate dispatch, so the reserve margin is determined on an ICAP basis. The planning reserve margin for the 2018 resource plan is 13.7%, which is consistent with the 2014 IRP.

C. STEPS IN INTEGRATED RESOURCE PLANNING

The following steps are involved in developing an IRP:

1. Define the planning objectives and scope (discussed above);
2. Describe the current conditions that are the baseline for planning about the future;
3. Develop a quantitative set of expectations for the future of the market, regulatory, and technological environments in which the utility operates;
4. Establish the list of supply-side and demand-side resource options that are technically and commercially available to meet future capacity needs;
5. 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;
6. Use sensitivity analysis to test the performance of the optimal plan under unexpected future conditions; and,
7. Select a resource acquisition plan that meets the planning objectives under expected conditions and minimizes risks associated with unexpected developments.

Developing a Business as Usual (BAU) Case

One cannot construct a plan for the future without some set of expectations about what the future holds. Our business as usual case is a description of those expectations, the conditions 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 BAU expectations are described in quantitative terms in the form of forecasts. The main sources of uncertainty for which forecasts must be developed are:

1. Load;
2. Fuel prices;
3. Market power prices; and,
4. 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 the potential for a future price on carbon emissions which, given its potential impact, is addressed in sensitivity analysis.

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-side resources for consideration if they are technically feasible and commercially available in the Duke Energy Kentucky service territory.

Sensitivity Analysis

Sensitivity analysis is used to assess the cost and reliability risks associated with unexpected future developments. The purpose is to test the sensitivity of the plan to changes in certain assumptions. This could involve, for example, modeling higher or lower load or fuel prices than expected. It could also involve modeling regulatory changes that could occur in the future but are not considered in the reference case. In each sensitivity, a new optimal resource portfolio may be developed, or the portfolio may be kept constant and for the purpose of estimating cost and reliability under the new assumptions. In general, if the change that is analyzed has a long-term impact, such as a new regulation or a sustained change in market conditions, then a new optimal portfolio will be created. If the change is short-term, the portfolio is held constant and the system is allowed to re-dispatch.

D. 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[6]. Fuel price forecasts provided by IHS are based on granular, integrated

[6] This content is extracted from the IHS Markit North American Power, Gas, Coal and Renewables service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS Markit. Any further use or redistribution of this content is strictly prohibited a without written permission by IHS Markit. Copyright 2018, all rights reserved.

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

As with fuel prices, we combine near-term observable market prices and long-term fundamental projections to develop power price forecasts. The Company uses PROMOD to develop the long-term fundamental power price projections based on scenario-specific fuel price forecasts and carbon tax assumptions. PROMOD incorporates this information and simulates the dispatch of power markets to develop a power price forecast for Duke Energy Kentucky. We use this method to ensure consistency and provide a linkage between fuel, carbon, and power price assumptions.

Forecasting Prices on Carbon Emissions

The March 28, 2017 signing of the Executive Order on Energy Independence (E.O. 13783) called for a review of EPA's Clean Power Plan (CPP). The EPA subsequently filed a proposal to repeal the CPP in the Federal Register on October 16, 2017. While the effort to repeal the CPP is likely to succeed, significant uncertainty remains regarding the regulations that will ultimately replace the CPP. Duke Energy believes that a constraint or price on carhon 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.

Forecasting Capital Costs

Duke Energy, 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) 2017. The AEO provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS).

Using 2018 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 2016, July 2017)

From *NEMS Model Documentation 2016, July 2017*:

"Uncertainty about investment costs for new technologies is captured in the Electric Capacity Planning module of NEMS (ECP) 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 due to learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. 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 (i.e. solar PV and battery storage), we blended the AEO forecast factors with additional third-party capital cost projections.

E. 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 and commercially available. Technologies excluded from consideration on these grounds include small modular nuclear reactors, 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, landfill gas, 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, CCs, reciprocating engines, and nuclear stations. In addition, onshore wind, solar photovoltaic, and battery storage options were included in the analysis.

F. PLANNING MODELS

System Optimizer (SO) 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, IGCCs, etc.), and renewable resources (e.g., wind, solar). SO 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.

Planning and Risk (PAR) is a detailed production-cost model 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.

PROMOD is a fundamental electric market simulation solution that incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations. A generator and portfolio modeling system, PROMOD, provides nodal locational marginal price (LMP) forecasting and transmission analysis.

IV. 2018 PLANNING FORECASTS & ASSUMPTIONS

A. 2018 LOAD FORECASTS

The Company's expectations are for slow load growth in the near-term, 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.

Figure 4.1: Monthly Load Forecast by Customer Category (After UEE)

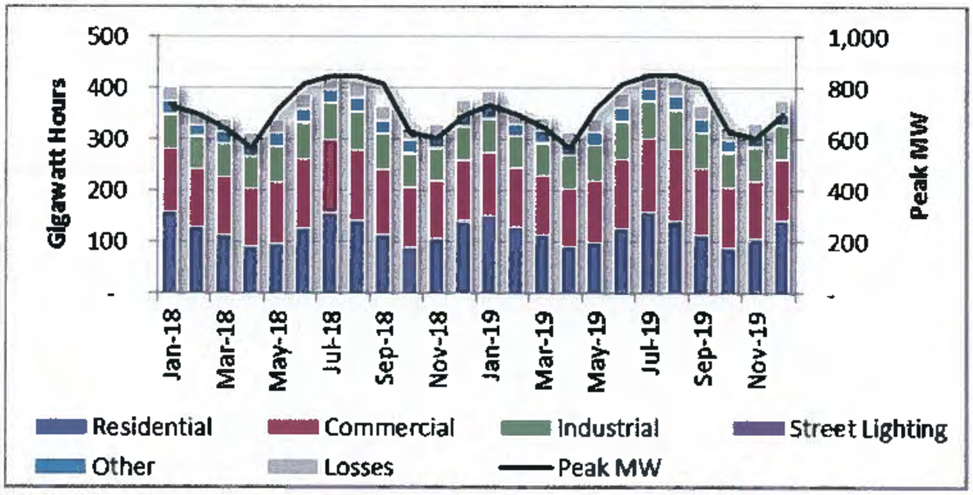
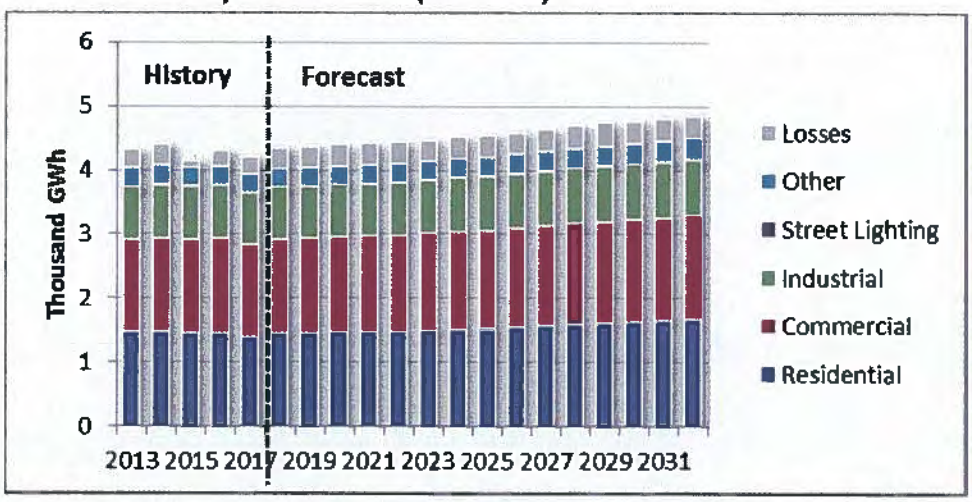
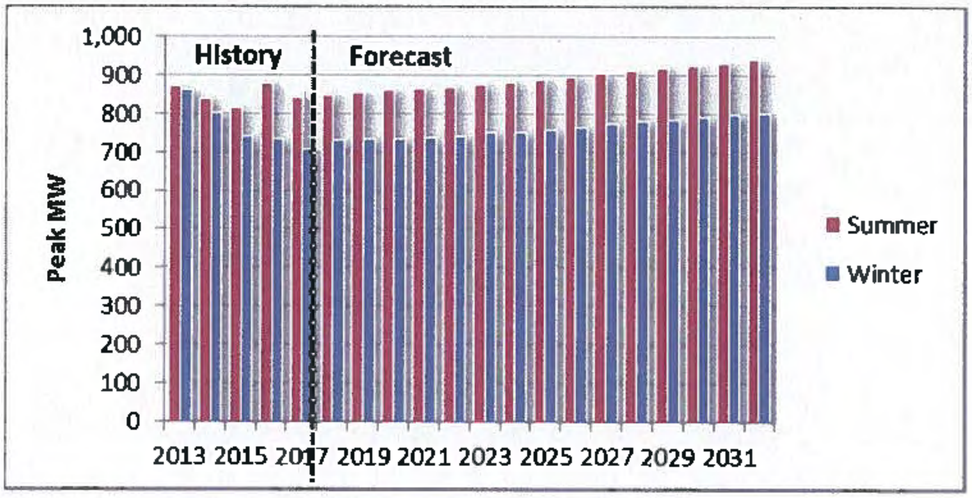


Figure 4.2: Most Likely Load Forecast (After UEE)



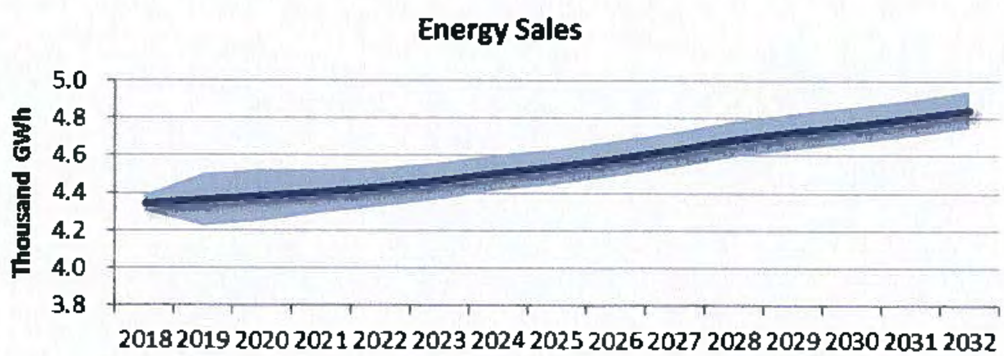
(See section 2 for required detail/disaggregation)

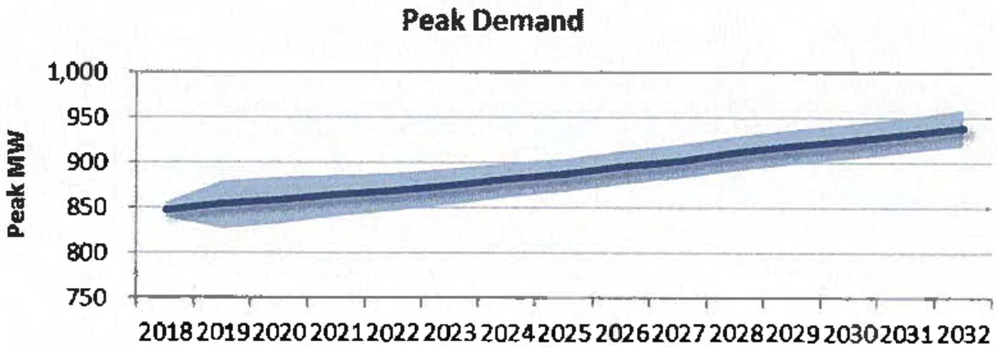
Figure 4.3: Forecast Winter and Summer Peak Demand (Most Likely Case, After UEE)



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 figures 4.4 and 4.5 below.

Figure 4.4: Most Likely Energy and Peak Demand Forecasts with Upper and Lower Ranges





For additional details on our load forecasts, see Appendix B.

B. 2018 FUEL PRICE FORECASTS

The Company's business as usual 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 as coal generation is displaced. LNG exports and exports to Mexico are forecasted to ramp up by approximately 14 Bcf/day 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. Our 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 Asia and Europe export demand.

The Company's high and low fuel price cases are based on alternative fuel price cases in the U.S. Energy Information Administration's (EIA) AEO for 2018. 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 comparatively low coal price variability in the EIA cases is consistent with our own expectations.

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 4.5: Business as Usual and Alternative Henry Hub Gas Price Forecasts

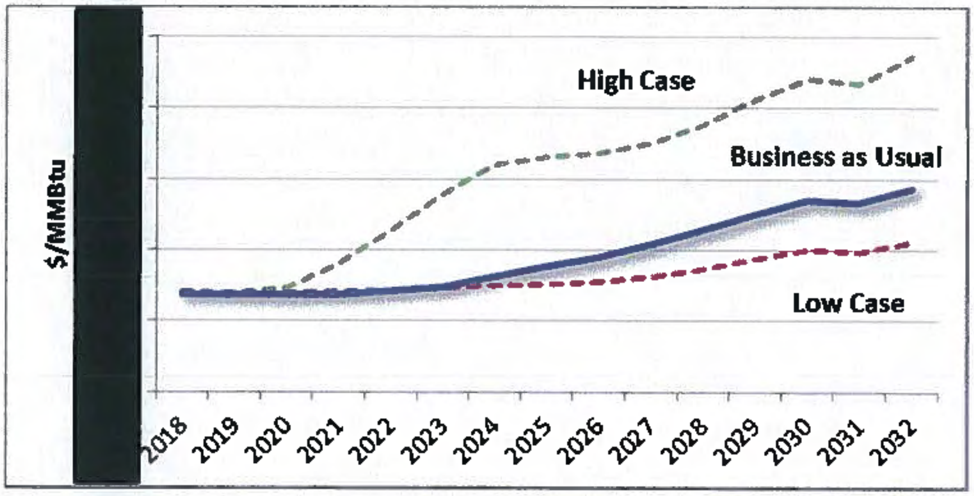
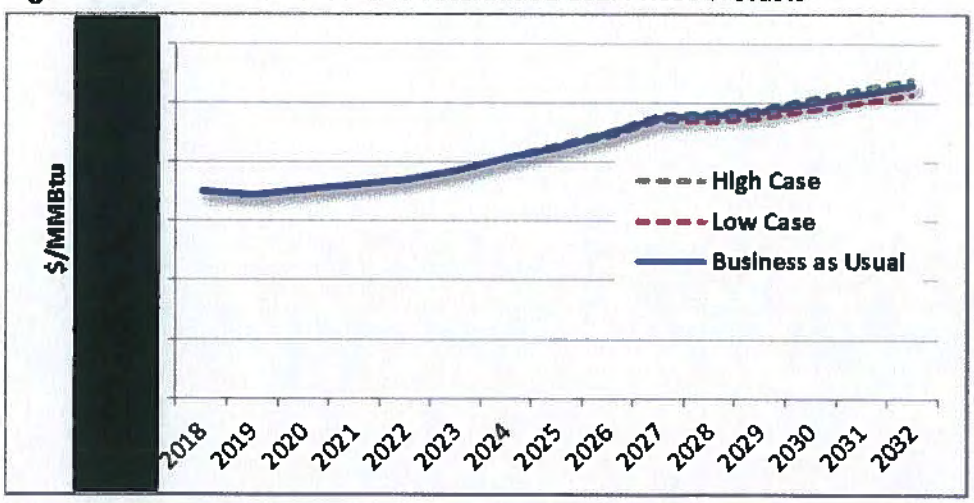


Figure 4.6: Business as Usual and Alternative Coal Price Forecasts



C. 2018 POWER PRICE FORECASTS

As was described in section 3D, power prices are a function of the assumed fuel and carbon price assumptions. Additionally, changes in the RTO generation fleet are modeled utilizing PROMOD.

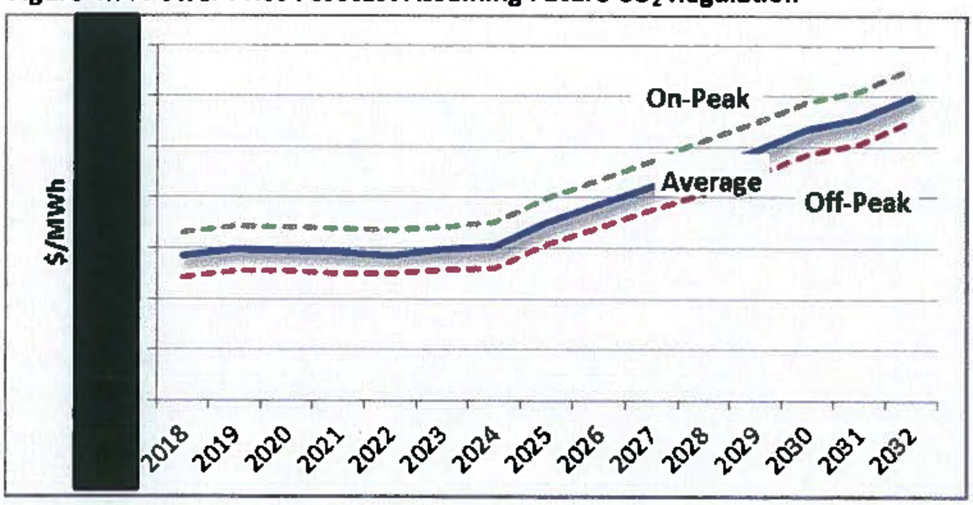
PROMOD Expansion Plans

Generation expansion plans were developed for the Eastern Interconnect for two scenarios; a carbon constrained future and a future with no new carbon legislation or regulation. These expansion plans were input into PROMOD and hourly energy prices were developed to simulate the PJM power price for DEK. 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 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 retiring coal units in both scenarios.

PROMOD Expansion Plan assuming future CO_2 regulation

The expansion plan assuming future CO_2 regulation shows a strong emphasis on Solar PV and Wind representing [redacted]% of new capacity additions, with CC and CT making up the remaining [redacted]% through the early 2030s. The total load and peak demand grows an average of [redacted]% and [redacted]% per year respectively through 2032 in this Scenario. The resulting DEK power price forecast is displayed in Figure 4.7 below.

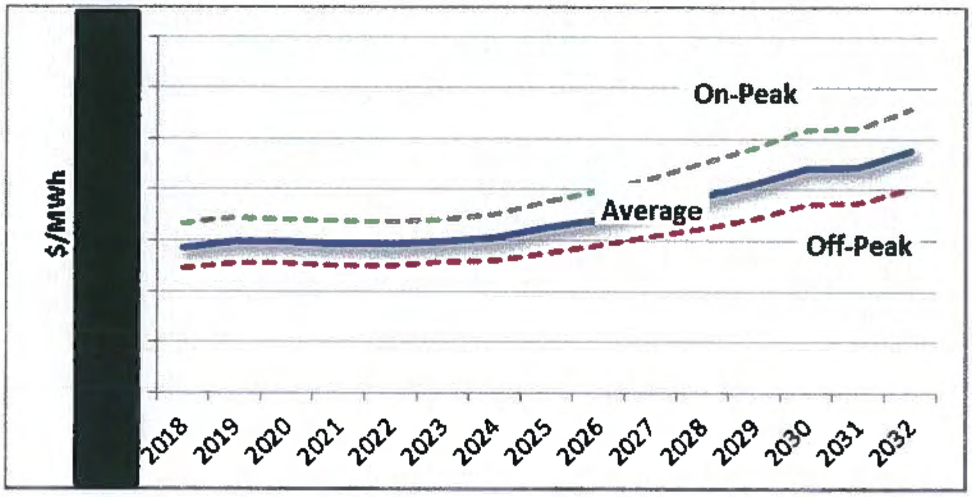
Figure 4.7: Power Price Forecast Assuming Future CO_2 Regulation



PROMOD Expansion Plan assuming no future CO_2 regulation

This expansion plan assuming no future CO_2 regulation shows a balanced approach in capacity additions between Solar PV and Wind representing [redacted]% and CC and CT making up the remaining [redacted]% through the early 2030s. The total load and peak demand grows an average of [redacted]% per year for each through 2032 in this Scenario. The resulting DEK power price forecast is displayed in Figure 4.8 below.

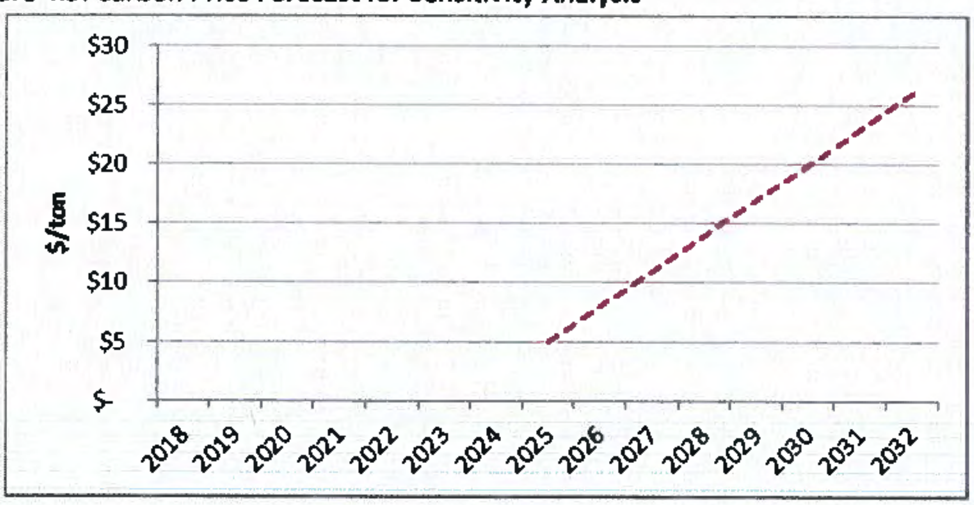
Figure 4.8: Power Price Forecast Assuming No Future CO_2 Regulation



D. A PRICE ON CARBON EMISSIONS

As discussed in Section III.D, Duke Energy 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 $3/ton/year in some sensitivity analyses for the purposes of the 2018 IRP.

Figure 4.9: Carbon Price Forecast for Sensitivity Analysis



E. SUPPLY-SIDE RESOURCE OPTIONS CONSIDERED FOR INCLUSION IN 2018 IRP

The supply-side resources not eliminated on technical or commercial availability grounds are listed in the table below. In some cases, models were allowed to select fractional units in order to better assess the timing of new resource needs and the optimal resource type, regardless of size.

Table 4.1: Supply-Side Resource Options

DESCRIPTION	SUMMER CAPACITY (MW)	TYPICAL CAPACITY FACTOR	OVERNIGHT CAPITAL COST ($/kW)	COST ESCALATION FACTOR
Nuclear	2,234	90%	[redacted]	2.5%
Ultra-Supercritical Pulverized Coal	850	70%		2.5%
Integrated Coal Gasification Combined Cycle	620	70%		1.7%
Combined Cycle Gas Turbine, 2x1	706	70%		1.3%
Simple Cycle Gas Turbine	215	10%		1.3%
Reciprocating Engine	17	10%		1.7%
Wind	150	35%		1.7%
Solar PV, Single-Axis Tracker	1.8[a]	25%		-2.7% / 1.9%[c]
Battery Storage, 4-hour Lithium Ion	4[b]	15%		-3.9% / 1.9%[c]

(a) nameplate capacity is 5 MW, solar contribution to peak is 35% of nameplate capacity in summer

(b) nameplate capacity is 5 MW, battery contribution to peak is 80% of nameplate capacity

(c) capital costs for solar PV and battery technologies are forecast to continue to decline for ten years before beginning to increase

V. MODEL RESULTS AND SENSITIVITY ANALYSIS

A. INTRODUCTION

This section describes the modeling results for a portfolio optimized for business as usual conditions, as well as the changes that would occur in response to a variety of alternative assumptions. The results of this sensitivity analysis are presented in the form of answers to several hypothetical questions about the future.

B. OPTIMIZED PORTFOLIO UNDER BUSINESS AS USUAL CONDITIONS

Table 5.1: Modeling Assumptions for a Business as Usual Future

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Most Likely	Most Likely	Most Likely	Suspended

Assuming current conditions are indicative of the future and our expectations for what is most likely to occur in term of load and fuel prices prove accurate, the optimized DEK generation fleet would remain essentially unchanged over the planning period. East Bend 2 would continue to generate low cost energy and the gas-fired peaking facility, Woodsdale, would be a reliable source of additional capacity, providing energy when economic to do so. The PVRR of the portfolio optimized for business as usual conditions is $1,493 million (this does not include existing rate base or any future investment in transmission and distribution). Figure 5.1 below summarizes the energy mix for the DEK system under this set of assumptions.

Figure 5.1a: Generating Capacity Mix and Cumulative PVRR Under BAU Future

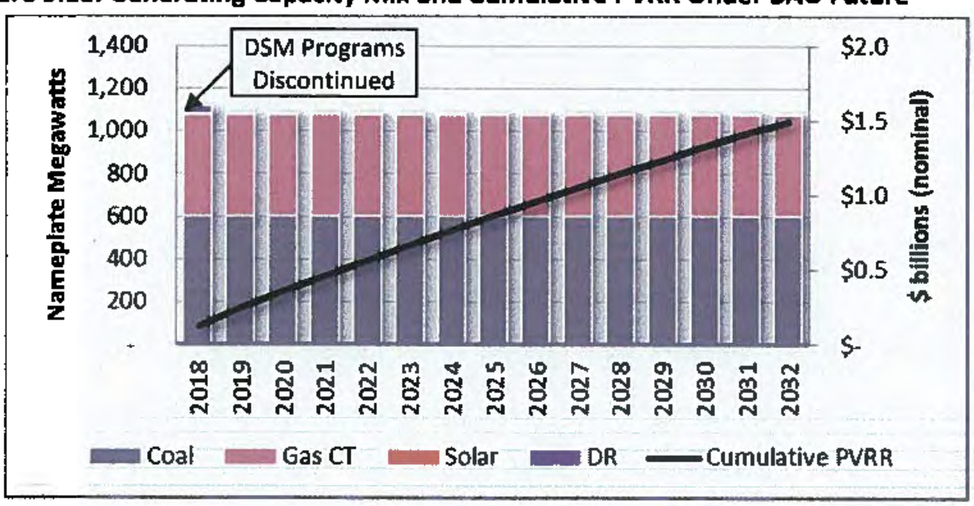
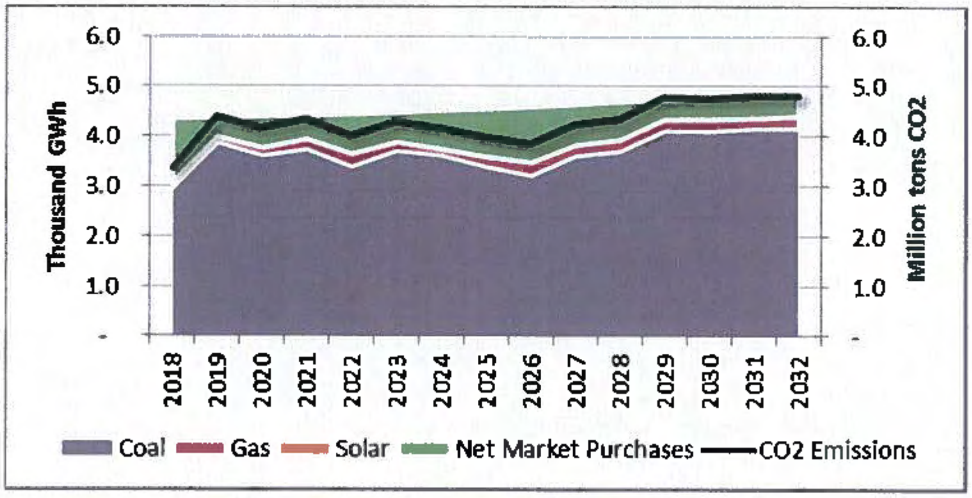


Figure 5.1b: Annual Energy Mix and CO_2 Emissions Under BAU Future



TAKEAWAY: The DEK generation fleet, as it exists today, is well-positioned economically for the continuation of current trends into the future. Gradually improving gas prices combined with persistently low coal prices and no legislative action to curb carbon emissions would create an environment in which East Bend 2 would continue to operate profitably throughout the planning period. However, should conditions change, heavy reliance on East Bend 2 carries risks associated with potential future carbon regulation or persistently low gas prices putting downward pressure on power prices.

C. SENSITIVITY ANALYSIS & ALTERNATIVE PORTFOLIOS

As part of the planning process, we performed extensive sensitivity analysis to gauge the degree of risk associated with future deviations from our business as usual forecasts for fuel prices, load, and a direct cost associated with carbon emissions. The analysis is described below in the form of several questions exploring the impacts of those deviations. The questions are grouped together under common themes.

Carbon Tax and Additional Investment in Renewables.

The Company considers it possible if not likely that policy imposing a cost on carbon emissions will be enacted at some point over the planning horizon. Investing in renewables in the near term could help reduce exposure to carbon-related risk and moderate impact to customers during the transition.

1. *How would the DEK generation fleet change if a CO_2 tax was enacted?*

Table 5.2: Modeling Assumptions for a BAU Future with the Addition of a Carbon Tax

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	Yes	Most Likely	Most Likely	Most Likely	Suspended

This question contemplates a cost associated with carbon emissions as described in Section IV.D. If a CO_2 tax is enacted in the future (starting in 2025 for the purposes of this analysis), the immediate impact would be a reduction in East Bend 2's capacity factor and an increase in market purchases to replace the lost energy. Expenditures at East Bend 2 would be substantially reduced to reflect its more limited role, but the facility would still retire earlier than it would in a world without a price on carbon and be replaced with natural gas-fired combined cycle capacity. With the addition of a new combined cycle to the fleet, market purchases would be eliminated and the Company could even become a net seller into the marketplace to the extent that the additional capacity exceeded system needs. CO_2 emissions would fall as the energy mix shifted away from coal, but the earlier retirement and replacement of East Bend 2, together with increased costs associated with purchased power, would result in an estimated $254 million (17%) increase in PVRR for the system over business as usual conditions.

Figure 5.2a: Generating Capacity Mix and Cumulative PVRR for a Carbon Tax Portfolio

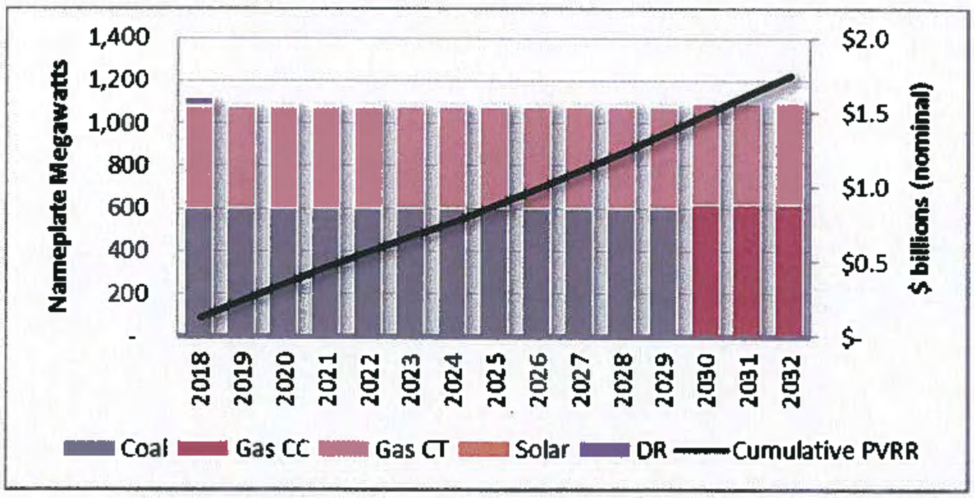
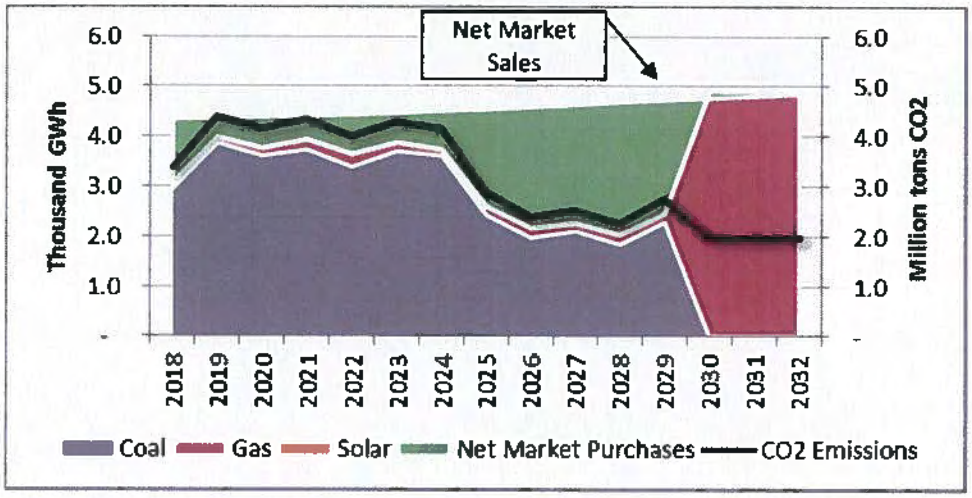


Figure 5.2b: Annual Energy Mix and CO_2 Emissions for a Carbon Tax Portfolio



2. *What would the impact be of adding near term renewables to the generation fleet?*

Table 5.3: Modeling Assumptions for BAU Portfolio with Additional Solar and Battery Storage

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Most Likely	Most Likely	Most Likely	Suspended

A steady increase in the amount of solar PV capacity (10 MW per year) and battery storage (2 MW per year) on the DEK system would not significantly change the operation of East Bend 2 or Woodsdale over the planning period in a business as usual future. However, the additional renewable energy would reduce and eventually eliminate energy purchases from the market and would reduce CO_2 emissions by an average of one thousand tons per year over the planning period. The additional solar and battery storage capacity would increase the PVRR for the system by approximately $64 million (4%) over the planning period under business as usual conditions.

Figure 5.3a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio with Additional Solar and Battery Storage

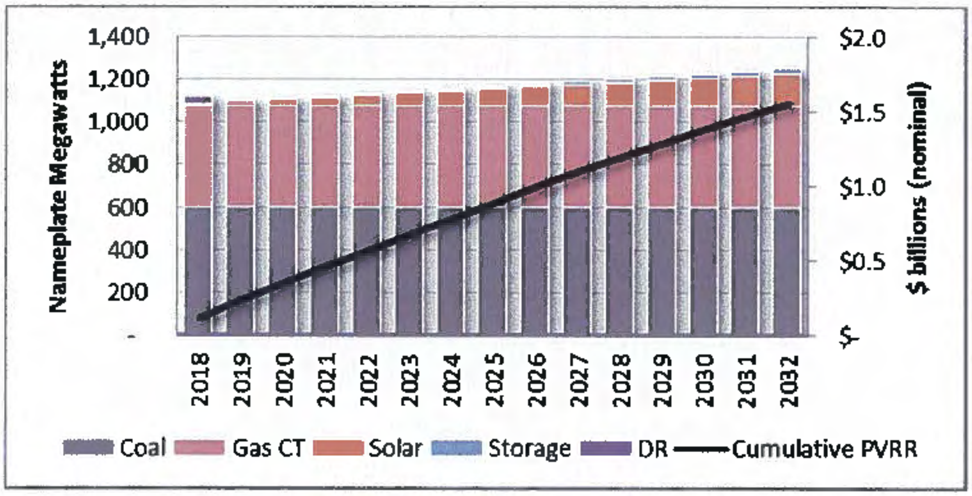
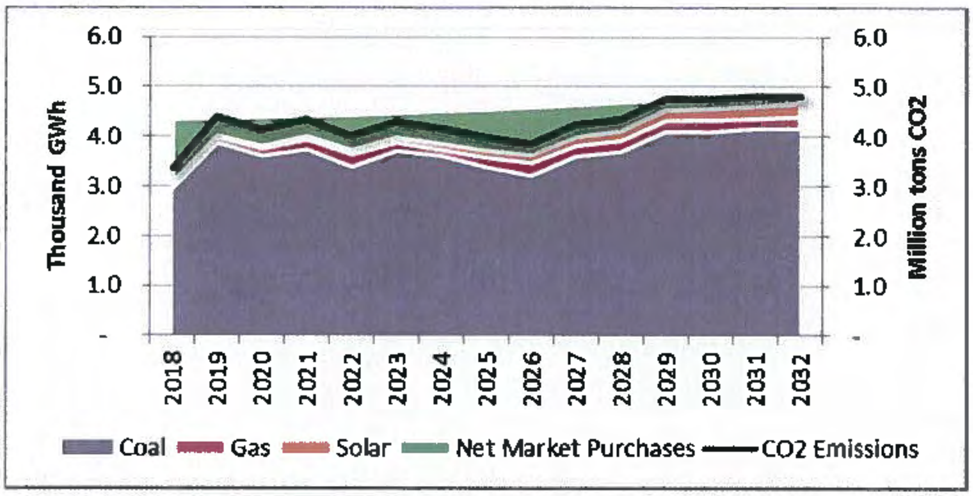


Figure 5.3b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio with Additional Solar and Battery Storage



TAKEAWAY: A CO_2 tax would have an immediate impact on operations at East Bend 2 and would eventually force the retirement of the station earlier than would otherwise be considered. It would also increase DEK's reliance on energy purchased from the market while driving up the cost of that energy through the imposition of additional operating expenses on all fossil generators. If the Company were to continue to add small amounts of solar capacity each year, these risks could begin to be mitigated.

Alternative Load Forecasts and Reinstatement of DSM Programs.

Given the inherent uncertainty in forecasting, it is prudent to consider futures in which demand is higher or lower than what is considered most likely. Along similar lines, the reinstatement of the Company's DSM programs would result in a decrease in the load served by generation.

3. *What would be the impact to the DEK generation fleet if load grew faster than expected?*

Table 5.4: Modeling Assumptions for BAU Portfolio with Faster than Expected Load Growth

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Most Likely	Most Likely	High	Suspended

Faster than expected load growth would result in a higher level of energy purchases from the market through most of the planning period and would finally result in the need for additional capacity late in the period. The Company would meet this need with the addition of a small amount of combined cycle capacity in 2032. Because the additional energy need would be met with purchases from the market, the Company's own CO_2 emissions would be very similar to those under the most likely load assumptions prior to the addition of the new combined cycle capacity. Increased energy purchases and the required capacity addition would result in a PVRR increase of approximately $37 million (2%) over the most likely load portfolio, but of course that requirement would be spread over a larger volume of sales.

Figure 5.4a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio with Higher than Expected Load

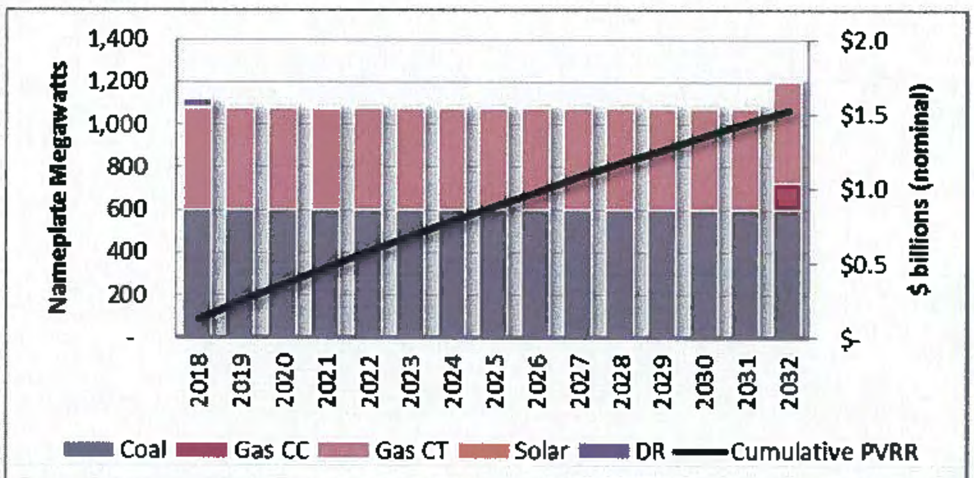
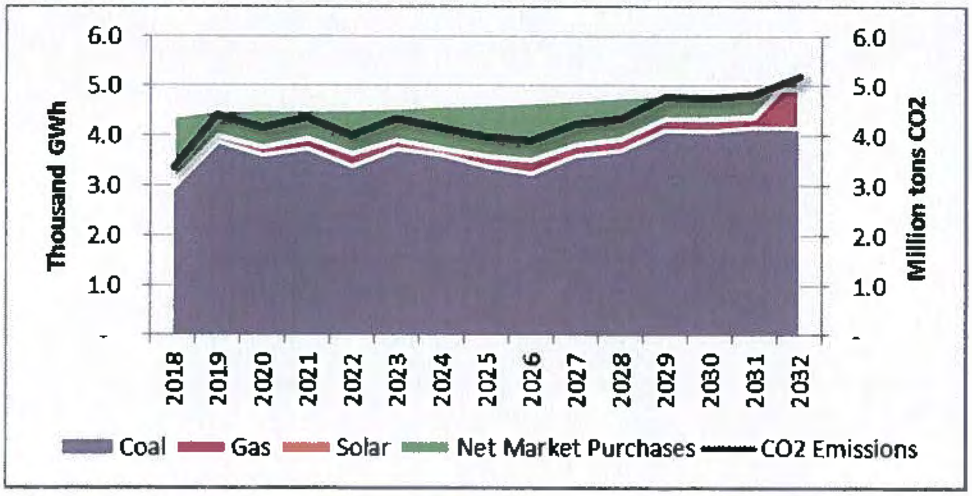


Figure 5.4b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio with Higher than Expected Load



4. *What would be the impact to the DEK generation fleet if load grew more slowly than expected?*

Table 5.5: Modeling Assumptions for BAU Portfolio with Slower than Expected Load Growth

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Most Likely	Most Likely	Low	Suspended

If load grew more slowly than expected, the Company would reduce energy purchases from the PJM market. As a result, PVRR would decrease by approximately $34 million from the most likely load case. CO_2 emissions would remain relatively constant as the output of East Bend 2 and Woodsdale are dependent on market dispatch rather than the exact level of DEK load.

Figure 5.5a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio with Lower than Expected Load

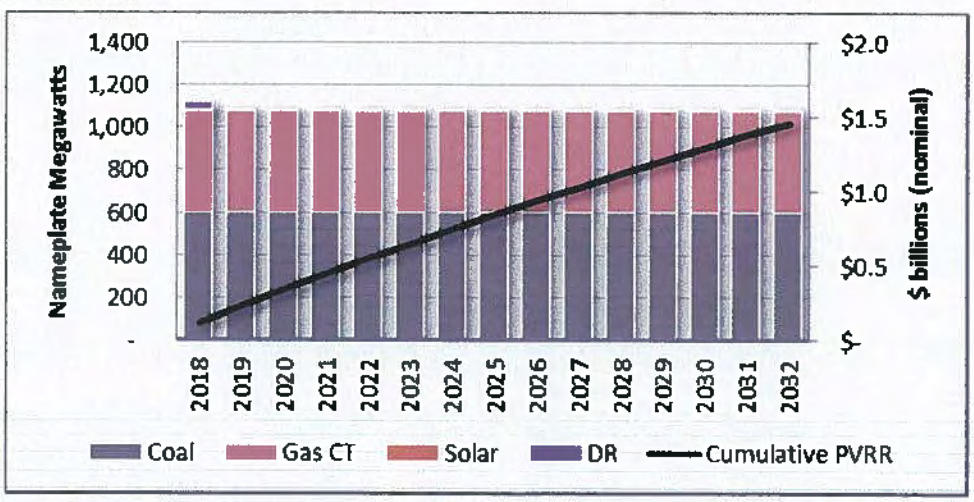
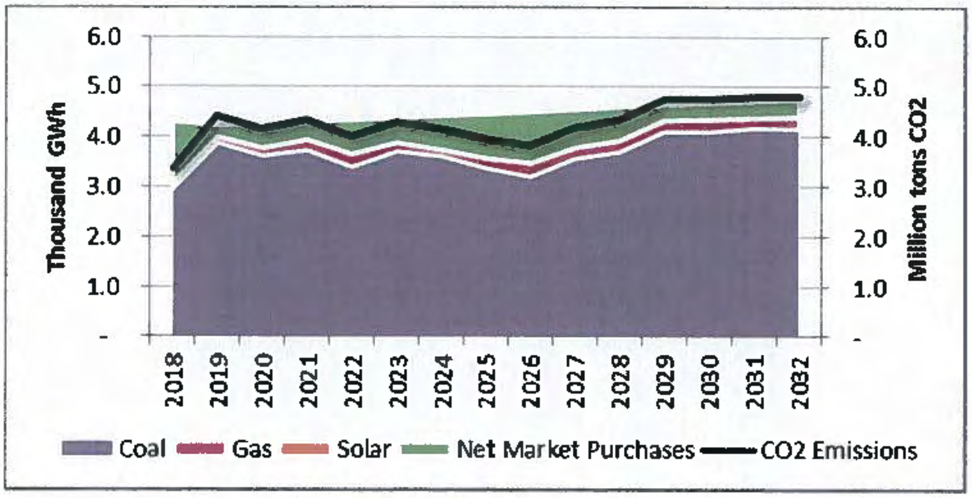


Figure 5.5b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio with Lower than Expected Load



5. *How would the DEK generation fleet change under a BAU scenario if the DEK DSM programs were reinstated?*

Table 5.6: Modeling Assumptions for BAU Portfolio with the Reinstatement of DSM Programs

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Most Likely	Most Likely	Most Likely	Reinstated

Similar to a lower load scenario, the reinstatement of DSM programs (both DR and EE) would result in reduced need for energy purchased from the market. This represents DSM Case #2 as discussed in Section II.B. As a result, the system PVRR would be $29 million (2%) higher with the reinstatement of DSM programs in a business as usual future.

Figure 5.6a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio with DSM Programs Reinstated

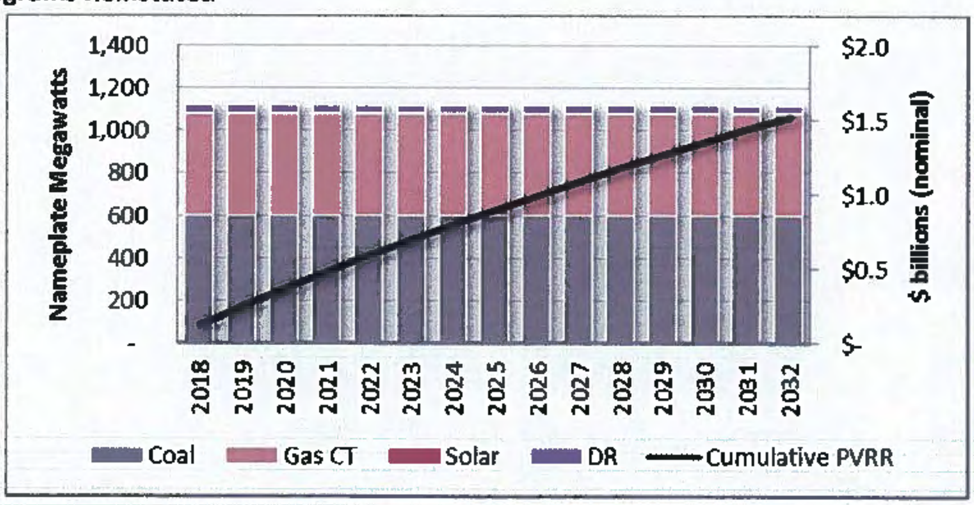
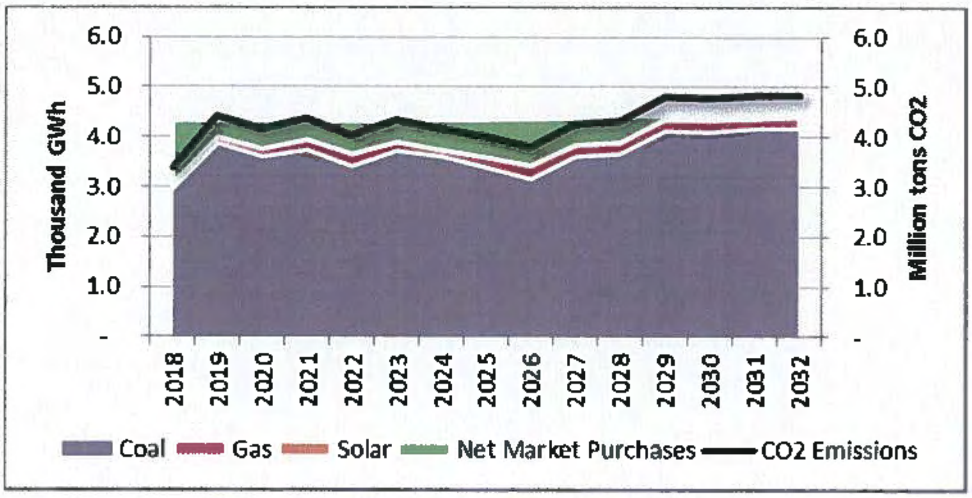


Figure 5.6b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio with DSM Programs Reinstated



TAKEAWAY: Load growth above or below the expected rate would result in the addition or reduction in energy purchases from the market, and higher than expected load would create a need for additional generating resources towards the end of the planning period. The reinstatement of DSM programs would help customers in managing energy consumption and satisfy PJM requirements.

Alternative Fuel Price Forecasts.

Fuel prices above or below the expected values could change the relative competitiveness of different resource options.

6. *How would the business as usual portfolio change if fuel prices were to be higher than expected?*

Table 5.7: Modeling Assumptions for BAU Portfolio in High Fuel Price Environment

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	High	High	Most Likely	Suspended

As discussed in Section IV.B, there is a much greater degree of uncertainty around future gas prices than the future price of coal. Therefore, a high fuel price environment is one with much higher gas prices but with coal prices close to the expected trajectory. For this reason, high fuel prices would increase the competitiveness of coal assets relative to gas and increase the capacity factor of East Bend 2, displacing energy that would otherwise have been purchased from the market. With East Bend 2 economically dispatched in more hours, market purchases would be displaced but carbon emissions would increase. Overall, the system PVRR in a high fuel price environment is $37 million (2%) higher than it would be if our expected fuel price forecasts are correct, but East Bend 2 provides a strong hedge against higher gas prices.

Figure 5.7a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio in High Fuel Price Environment

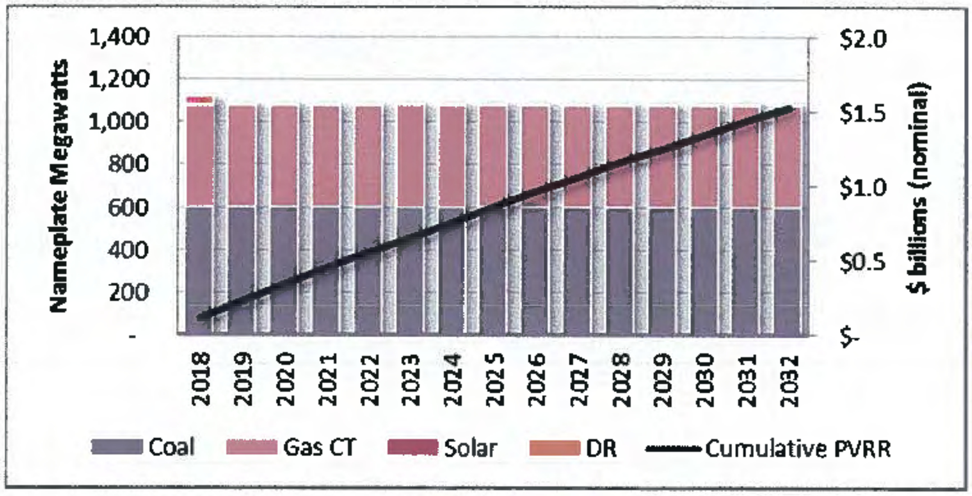
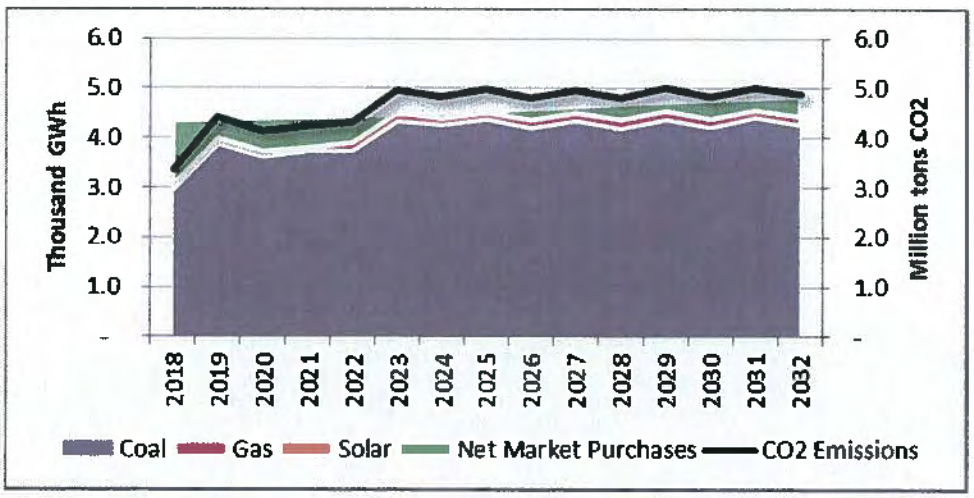


Figure 5.7b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio in High Fuel Price Environment



7. *How would the business as usual portfolio change in fuel prices were to be lower than expected?*

Table 5.8: Modeling Assumptions for BAU Portfolio in Low Fuel Price Environment

	CO_2	GAS PRICE	COAL PRICE	LOAD	DSM
ASSUMPTION	None	Low	Low	Most Likely	Suspended

A low fuel price environment would be one in which gas prices stay low relative to coal. In this case, East Bend 2 runs economically in fewer hours and DEK relies more heavily on the market for low cost energy. In the low fuel price environment, the PVRR for the system would be approximately \$51 million (3%) lower than if our expected fuel price forecasts are correct, and carbon emissions would fall by an estimated 1.3 million tons per year on average.

Figure 5.8a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio in Low Fuel Price Environment

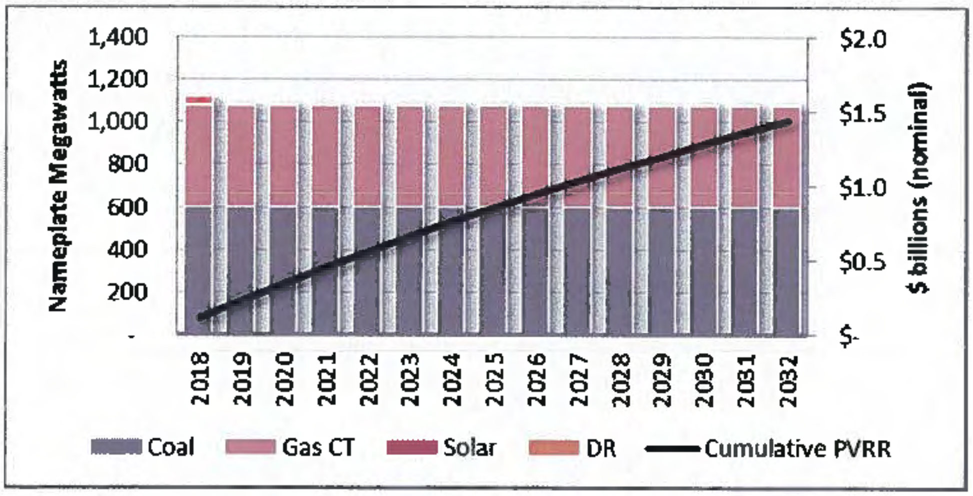
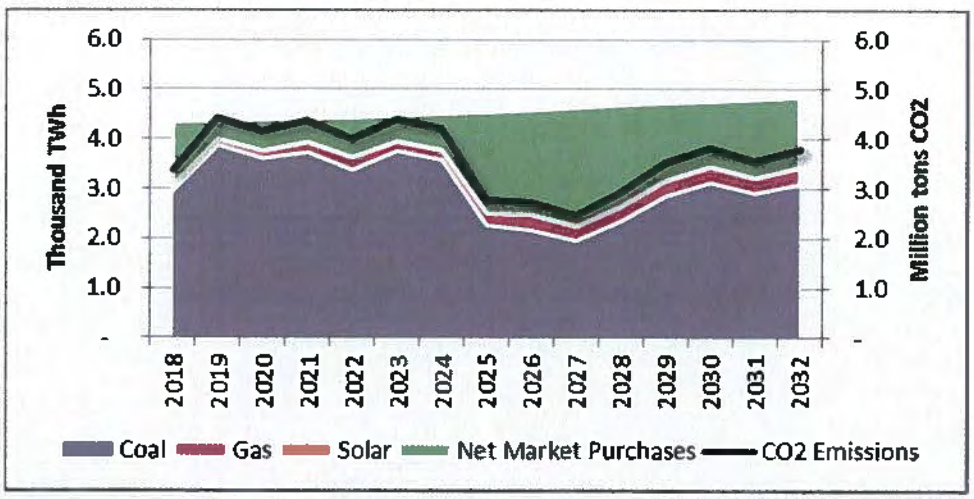


Figure 5.8b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio in Low Fuel Price Environment



TAKEAWAY: East Bend 2, an efficient, well-controlled coal unit, effectively shields DEK customers from the negative impacts of high gas prices. In a low gas price environment, generation from East Bend 2 would be displaced by low cost energy purchased from the market and customers would still benefit from lower prices.

VI. 2018 INTEGRATED RESOURCE PLAN

A. PLAN OVERVIEW

The preferred portfolio for the 2018 DEK IRP includes the addition of renewable resources over time and continued operation of East Bend 2 and Woodsdale station. This plan is the result of extensive analysis that began with the assessment of business as usual conditions, and incorporated evaluations of the probability and impact of several factors that could drive changes to the portfolio.

The Company made its selections based on its expectations for near-term market stability and the promulgation over time of increasingly restrictive carbon regulations. It is hard to envision a long-term future that does not include an increasing role for renewable generation and storage. In anticipation of that trend, a measured program that increases the amount of renewable resources on the system is prudent. This will allow us to learn firsthand the issues and challenges associated with the growing presence of intermittent resources on the system and be better prepared for larger investments in renewables as costs continue to decline and the likelihood of CO_2 regulation increases.

This is a robust plan that does not commit the utility to a large future spend and will allow us to quickly pivot in response to changes in the market or regulatory landscape. For ease of reference, the evolution of the generation fleet and energy mix is copied from Section V and provided below:

Figure 6.1a: Generating Capacity Mix and Cumulative PVRR for BAU Portfolio with Additional Solar and Battery Storage

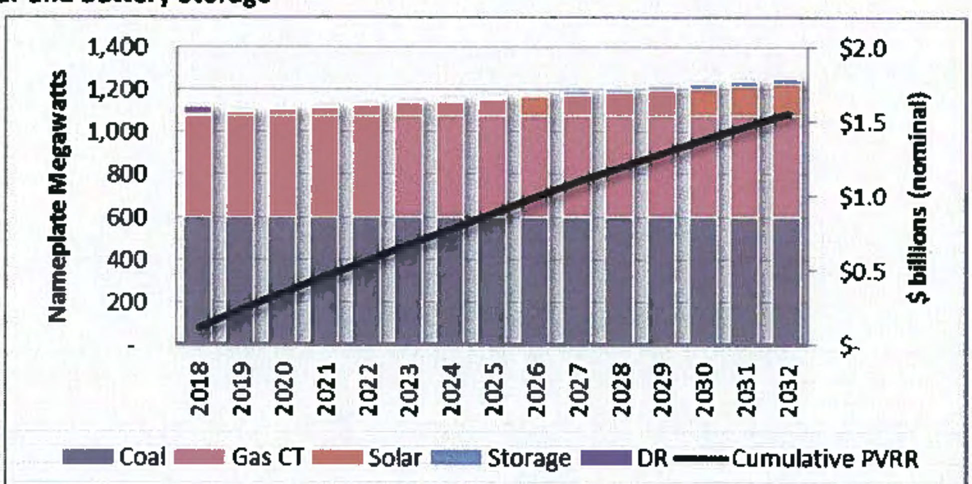
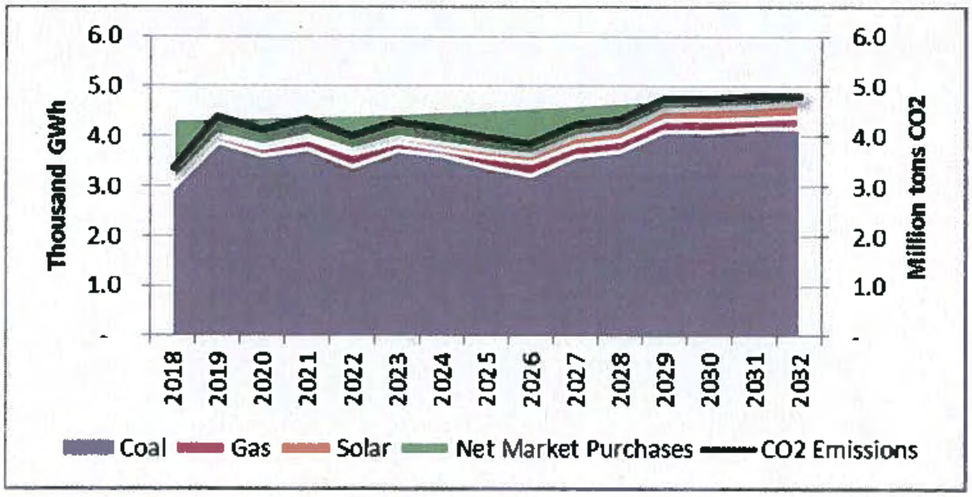


Figure 6.1b: Annual Energy Mix and CO_2 Emissions for BAU Portfolio with Additional Solar and Battery Storage



The inclusion of additional renewable energy resources in the plan will help diversify the portfolio to mitigate downside risk from any future regulation imposing a price on carbon emissions and help to lessen the impact to customers if East bend 2 is forced to retire.

The portfolio is also well-positioned for future fuel prices that are above or below our expectations, with East Bend 2 providing a strong hedge against higher gas prices and access to the PJM allowing customers to take advantage of low-cost energy resulting from lower gas prices.

If load growth exceeds or fails to meet expectations, or if the Company's DSM programs are reinstated, new resource additions can be accelerated or delayed in response.

In addition to the analysis presented in Section V, operating and cost data can be found in Appendix A.

B. KEY VARIABLES TO MONITOR AHEAD OF 2021 IRP

As part of its normal business planning process, Duke Energy Kentucky updates its long-term generation resource plan at least annually. In doing so, each of the model variables are updated with the prevailing information at that time.

In terms of impact, the following variables have potentially the greatest impact on the DEK 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 is a factor that undermines the competitiveness of the East Bend 2 unit 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 expected to continue decreasing which increases the competitiveness of these resources. 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 system and PJM footprint, the need for resources that can provide grid support increases. As the demands on the grid increase while more coal units retire, there will be a greater role for battery storage 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 DEK generation fleet is well positioned from a regulation standpoint, but the potential enactment of a cost on carbon could have a negative impact on East Bend 2 and a to a lesser extent Woodsdale station. As a straight CO_2 tax on carbon emissions, the impact would be to 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 but the timeline for such regulation is likely beyond the next five years.

Changes in Load Forecasts

Forecasts of customer loads are frequently monitored and modeled as described in Appendix A. In general, load growth greater than expectation tends to accelerate additions to the resource 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.

APPENDIX A – FINANCIAL & OPERATING PROJECTIONS OVER PLANNING PERIOD

Response to Rule Section 8(3)(b) 1 through 11

Table A.1 Existing and Planned Electric Generating Facilities

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	Unknown	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	Dec, 2017	Unknown	PV	Sunlight	None	1.4	0
Crittenden Solar		Existing	Grant County, KY	Dec, 2017	Unknown	PV	Sunlight	None	1.0	0
Solar 2019		Planned	TBD	2019	Unknown	PV	Sunlight	None	3.5	0
Solar 2020		Planned	TBD	2020	Unknown	PV	Sunlight	None	3.5	0
Solar 2021		Planned	TBD	2021	Unknown	PV	Sunlight	None	3.5	0
Solar 2022		Planned	TBD	2022	Unknown	PV	Sunlight	None	3.5	0
Solar 2023		Planned	TBD	2023	Unknown	PV	Sunlight	None	3.5	0
Solar 2024		Planned	TBD	2024	Unknown	PV	Sunlight	None	3.5	0
Solar 2025		Planned	TBD	2025	Unknown	PV	Sunlight	None	3.5	0
Solar 2026		Planned	TBD	2026	Unknown	PV	Sunlight	None	3.5	0
Solar 2027		Planned	TBD	2027	Unknown	PV	Sunlight	None	3.5	0
Solar 2028		Planned	TBD	2028	Unknown	PV	Sunlight	None	3.5	0
Solar 2029		Planned	TBD	2029	Unknown	PV	Sunlight	None	3.5	0
Solar 2030		Planned	TBD	2030	Unknown	PV	Sunlight	None	3.5	0
Solar 2031		Planned	TBD	2031	Unknown	PV	Sunlight	None	3.5	0
Solar 2032		Planned	TBD	2032	Unknown	PV	Sunlight	None	3.5	0
Storage 2019		Planned	TBD	2019	Unknown	Li-ion	Electricity	None	1.6	1.6
Storage 2020		Planned	TBD	2020	Unknown	Li-ion	Electricity	None	1.6	1.6
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
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

Fuel Storage: East Bend station has storage capacity for 500,000 tons of coal and 500,000 gallons of fuel oil. DEK is in the process of installing a fuel oil storage system at Woodsdale station with a capacity of 2 million gallons.

Response to Rule Section 8(3)(b)12

Table A.2 Actual and Projected Cost and Operating Information for Base Year and Each Forecast Year

	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
East Bend																	
Availability	%	88%	[redacted]														
Capacity Factor	%	81%															
Average Heat Rate	Btu/kWh	11,153															
Fuel Cost	$/MMBtu	$1.93															
Variable O&M	$ million	$34															
Fixed O&M + Maintenance Capital	$ million	$22															
Woodsdale																	
Availability	%	81%	[redacted]														
Capacity Factor	%	4%															
Average Heat Rate	Btu/kWh	31,765															
Fuel Cost	$/MMBtu	$4.52															
Variable O&M	$ million	$4.8															
Fixed O&M + Maintenance Capital	$ million	$37															
Walton & Crittenden Solar																	
Availability	%	*	[redacted]														
Capacity Factor	%	*															
Average Heat Rate	Btu/kWh	*															
Fuel Cost	$/MMBtu	*															
Variable O&M	$ million	*															
Fixed O&M + Maintenance Capital	$ million	*															
Future Solar Facilities (10 MW nameplate capacity added each year)																	
Availability	%	n/a	n/a	[redacted]													
Capacity Factor	%	n/a	n/a														
Average Heat Rate	Btu/kWh	n/a	n/a														
Fuel Cost	$/MMBtu	n/a	n/a														
Variable O&M	$ million	n/a	n/a														
Fixed O&M + Maintenance Capital	$ million	n/a	n/a														
Total Capital Cost	$ million	n/a	n/a														
	$/kW	n/a	n/a														

*Facilities commenced commercial operation in mid-December 2017, so base-year operating data are not available

Responses to Rule Section 8(4)(a)&(b)

Table A.3 Resource Capacity (Summer/Winter), Retirements, Reserve Requirement and Reserve Margin

SUMMER MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Peak Load	841	848	853	858	863	868	873	881	886	895	902	910	918	924	931	939
Capacity from:																
Existing Generating Resources	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
Demand Response Resources	34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Utility-Owned Resources*	0	2	6	9	13	16	70	23	27	30	34	37	41	44	48	51
Purchases (Sales) from (to) Third Parties	0	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	0	0
Reserve Requirement	956	964	970	976	982	986	993	1,001	1,008	1,017	1,025	1,035	1,043	1,050	1,058	1,067
Capacity Excess (Deficit)	154	114	112	110	107	106	103	98	95	89	85	78	74	70	65	60
Reserve Margin	32%	27%	27%	26%	26%	26%	25%	25%	24%	24%	23%	22%	22%	21%	21%	20%
WINTER MW	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Peak Load	706	730	733	734	737	741	748	751	757	764	773	779	784	789	796	801
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	1,164	1,164
Demand Response Resources	34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Utility-Owned Resources*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases (Sales) from (to) Third Parties	0	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	0	0
Reserve Requirement	803	830	834	835	838	843	851	854	861	869	879	886	891	897	905	910
Capacity Excess (Deficit)	395	334	330	329	326	321	313	310	303	295	285	278	273	267	259	254
Reserve Margin	70%	60%	59%	59%	58%	57%	56%	55%	54%	52%	51%	49%	49%	48%	46%	45%

Note: solar contribution to peak capacity is 35% of nameplate in summer and 0% in winter

Table A.4 Planned Annual Generation

Gigawatt Hours	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Forecast Energy Requirements	4,891	4,345	4,365	4,388	4,409	4,432	4,465	4,512	4,541	4,586	4,632	4,690	4,730	4,765	4,802	4,848
Energy from Existing and Planned Resources																
Coal	4,270	2,960	3,871	3,608	3,736	3,387	3,707	3,610	3,384	3,211	3,602	3,697	4,102	4,095	4,160	4,161
Gas	13	94	113	146	202	252	167	120	195	259	214	225	222	239	203	238
Solar	-	12	31	49	68	86	104	123	141	159	178	196	214	233	251	270
Energy Purchased from the PJM Market	608	1,279	350	585	405	708	488	661	823	959	642	575	195	202	192	183

Responses to Rule Section 8.(4)(c)

Table A.5 Annual Fuel Requirements

Fuel Requirements	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal																
Thousand Tons	2,01[redacted]	[redacted]														
Thousand MMBtu	47,62[redacted]	[redacted]														
Gas																
Mcf	40[redacted]	[redacted]														
MMBtu	42[redacted]	[redacted]														

Responses to Rule Section 9

Table A.6 Financial Information: Revenue Requirements (Present Value, Annual, and per Kilowatt Hour)

PVRR	$1,557 million
Discount Rate	6.52%
Inflation Rate	2.50%

Annual Revenue Requirements ($ millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Nominal	$124	$126	$131	$138	$142	$152	$162	$168	$178	$190	$187	$194	$204	$213	$222
Real 2018$	$124	$123	$125	$128	$129	$134	$140	$141	$146	$152	$146	$148	$151	$154	$157

Revenue Requirements per Kilowatt Hour

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Nominal	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.05
Real 2018$	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03

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

APPENDIX B – LOAD FORECAST

1. 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.

Service Area Economy

The service area economy is described by employment, income, inflation, production, and output measures, forecasts of which are provided by Moody's Analytics. 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. Demographic projections include population and households for the Duke Kentucky territory. This information is an input to the energy and peak load forecast models.

Electric Energy Forecast

The forecast methodology recognizes that the use of energy is dependent upon key economic factors such as income, production, energy prices, 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 are a means of representing economic behavior using statistical methods, such as regression analysis.

The Duke Energy Kentucky sales forecast is developed by separately forecasting the energy requirements for each customer group. These groups include the 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 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 kWh energy usage per customer.

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

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

Commercial Sector. Commercial electricity usage is a function of median household income, total employment, real electricity price, 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) and the impacts of real electricity prices, electric price relative to alternate fuels, and weather.

Governmental Sector. The Company uses the term Other Public Authorities (OPA) to indicate those customers involved and/or affiliated with federal, state or local government. The OPA sector comprises sales to schools, government facilities, airports, and water pumping stations. Electricity sales to OPA customers are a function of real governmental output, the real price of electricity, 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 street lights is associated with the population of the service area. The efficiency of the street lights 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 Load at Generation. The forecast of total system generation (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 statistically adjusted end-use 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. 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 August 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 generation is "weather normalized" by design.

2. ASSUMPTIONS

Macroeconomic

It is generally assumed that the Duke Energy Kentucky service territory economy will tend to react much like the national economy over the forecast period. Duke Energy Kentucky uses long-term forecasts of the national, state, and PMSA economy prepared as prepared by Moody's Analytics. No major wars, economic disruptions, energy embargoes are assumed during the forecast period. If minor conflicts and/or energy supply shocks such as hurricanes occur, the long-range path of the overall forecast would not be dramatically altered. Adjustment of the scenario from the Moody's "Baseline" to the Moody's "Consensus" scenario allowed for some projections to be brought down into the very center of the range of alternative forecast providers.

Economic weakness was a pressing concern during the early years of this decade, and frustration with the unevenness and weakness of the recovery led to a series of policy changes. Since the fourth quarter of 2013, economic growth—nationally and locally—has been consistently moderate. The ultimate outcome in the near term is dependent upon the success of the economy sustaining this recent trend of moderate growth in the face of federal policy uncertainty in monetary policy, fiscal policy, and health policy.

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

Local

Forecasts of employment, local population, gross product, and inflation are key indicators of economic and demographic trends. The majority of employment growth over the forecast period occurs apart from manufacturing, for which Moody's Analytics forecasts continued declines in employment over the long-term.

Duke Energy Kentucky is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and 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 2014 to 2034, Duke Energy Kentucky's service area population is expected to increase at an annual average rate below 0.4%, while nationally, population is expected to grow at an annual rate of 0.6%.

The residential sector has the most existing customers and new customers 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.

Other Forecast Drivers

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 Analytics.

Pricing Policy. Duke Energy Kentucky's electric tariffs for residential customers have a seasonal pattern. In Kentucky, an inverted rate (a block rate structure in which price increases as usage increases) is currently provided for residential customers and a time of day rate is used for all large commercial and industrial customers. The seasonal characteristic motivates conservation during summer months when demand upon electric facilities is greatest.

Year End Residential Customers. Table B.1 provides historical and projected total year end residential customers for the entire service area.

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.

TABLE B.1
DUKE ENERGY KENTUCKY SYSTEM
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
2013	121,661	13,689	378	431	956
2014	122,287	13,826	373	433	950
2015	122,962	13,873	371	441	958
2016	124,307	13,932	371	446	958
2017	125,796	13,710	365	447	956
2018	126,891	13,643	361	452	961
2019	127,276	13,722	358	456	970
2020	127,896	13,755	356	461	974
2021	128,525	13,789	353	467	983
2022	129,187	13,827	351	472	994
2023	129,871	13,859	348	478	1,004
2024	130,573	13,879	346	485	1,013
2025	131,327	13,894	343	492	1,021
2026	132,073	13,910	341	499	1,030
2027	132,791	13,925	338	506	1,039
2028	133,477	13,941	336	514	1,048
2029	134,126	13,957	334	522	1,057
2030	134,759	13,972	331	530	1,067
2031	135,350	13,987	329	539	1,075
2032	135,911	14,003	327	548	1,082
2033	136,441	14,019	324	557	1,088
2034	136,953	14,036	322	567	1,094
2035	137,470	14,053	320	578	1,100
2036	137,961	14,070	318	589	1,107
2037	138,419	14,087	315	600	1,113
2038	138,842	14,107	313	612	1,120

NOTE: 2018 AND BEYOND FIGURES REPRESENT AVERAGE TWELVE MONTH FORECAST

3. DATABASE DOCUMENTATION

Economic Data

The major groups of data in the economic forecast are employment, demographics, income, production, inflation and prices. National and local values (which represent the Cincinnati MSA) for these concepts are available from Moody's Analytics 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 Analytics. Employment series are available for manufacturing and several non-manufacturing sectors.

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

Income. Local income data series are obtained from Moody's Analytics. 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.

Personal Consumption Expenditure Index (PCE). The PCE is obtained from Moody's Analytics.

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.

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 Analytics. 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 used in the 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 residential 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 monthly basis using temperature data. The degree day series are required 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.

TABLE B.2
DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
ANNUAL ENERGY (MWh)

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY	INTER DEPARTMENT	COMPANY USE	TOTAL COMSUMPTION	LOSSES AND UNACCOUNTED FOR	NET ENERGY FOR LOAD
2013	1,475,280	1,464,916	812,309	15,362	291,293	873	720	4,060,754	279,049	4,339,803
2014	1,492,141	1,475,129	833,447	15,274	292,526	954	551	4,110,023	330,878	4,440,901
2015	1,433,925	1,474,267	810,877	15,120	290,332	804	736	4,026,062	101,696	4,127,757
2016	1,442,859	1,479,344	804,352	15,264	290,494	757	694	4,033,764	232,802	4,266,566
2017	1,444,667	1,458,606	801,895	15,077	278,079	1,136	684	4,000,144	264,837	4,264,981

DUKE ENERGY
WEATHER NORMALIZED PEAKS (MW)

	SUMMER PEAK (MW)	WINTER PEAK (MW)
2013	881	830
2014	889	808
2015	880	770
2016	905	776
2017	926	735

* partial data available for winter 2017

DUKE ENERGY KENTUCKY
RECORDED PEAKS (MW)

	SUMMER PEAK (MW)	WINTER PEAK (MW)
2013	869	860
2014	837	799
2015	814	739
2016	877	733
2017	841	706

* partial data available for winter 2017

Forecast Data

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

Load Research and Market Research Efforts

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

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

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

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

4. MODELS

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

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, 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.

Relationships Between Specific Techniques

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

Alternative Methodologies

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

Methodology Enhancements

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

The statistically adjusted end-use 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 incorporates the impacts from appliance end-use saturation and efficiency trends.

Computer Software

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

5. FORECASTED DEMAND AND ENERGY

On the following pages, the loads for Duke Energy Kentucky are provided. Forecast data are 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.

Service Area Energy Forecasts

Table B.3a contains the energy forecast for Duke Energy Kentucky's service area. Before implementation of any new EE programs or incremental EE impacts, residential use for the twenty-year period of the forecast is expected to increase an average of 1.1 percent per year; Commercial use, 0.7 percent per year; and Industrial use, 0.6 percent per year. The summation of the forecast across all sectors and including losses results in a growth rate forecast of 0.8 percent for Net Energy for Load. As seen in Table B.3b, the impact of the current Low-Income DSM programs (DSM Case #1 as discussed in Section II.B) on these numbers is de minimis.

TABLE B.3a
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
BEFORE EE

Year	(1) Rural and Residential	(2) Commercial	(3) Industrial	(4) Steet-Hwy Lighting	(5) Sales for Resale[a]	(6) Other	(7) (1+2+3+4+5+6) Total Consumption	(8) Losses and Unaccounted For[b]	(9) (7+8) Net Energy for Load
2013	1,465,361	1,454,627	808,831	15,362	0	291,017	4,035,198	277,293	4,312,491
2014	1,479,746	1,459,944	827,408	15,274	0	291,336	4,073,709	327,954	4,401,663
2015	1,445,887	1,477,900	812,522	15,120	0	292,528	4,043,958	102,148	4,146,106
2016	1,451,682	1,494,014	810,977	15,264	0	293,918	4,065,855	234,654	4,300,509
2017	1,395,234	1,450,924	800,034	15,077	0	278,593	3,939,861	260,845	4,200,706
2018	1,456,030	1,470,677	801,550	15,212	0	283,046	4,026,515	319,254	4,345,770
2019	1,456,128	1,479,231	812,845	15,115	0	281,550	4,044,869	320,712	4,365,581
2020	1,468,493	1,488,389	815,032	15,051	0	280,597	4,067,563	322,512	4,390,075
2021	1,475,084	1,494,626	818,995	14,991	0	283,262	4,086,958	324,050	4,411,008
2022	1,486,479	1,502,662	819,282	14,936	0	285,820	4,109,179	325,812	4,434,991
2023	1,501,967	1,510,977	824,211	14,866	0	288,340	4,140,361	328,285	4,468,646
2024	1,525,847	1,521,787	830,736	14,784	0	290,964	4,184,119	331,755	4,515,873
2025	1,538,617	1,528,102	837,185	14,725	0	293,251	4,211,880	333,956	4,545,836
2026	1,558,651	1,539,044	846,207	14,659	0	295,952	4,254,512	337,337	4,591,849
2027	1,581,098	1,552,439	850,254	14,583	0	299,056	4,297,430	340,740	4,638,170
2028	1,609,686	1,569,518	854,775	14,499	0	302,557	4,351,035	344,991	4,696,026
2029	1,629,609	1,582,679	856,667	14,406	0	305,646	4,389,008	348,003	4,737,010
2030	1,647,606	1,592,497	858,385	14,332	0	308,236	4,421,055	350,544	4,771,599
2031	1,666,188	1,602,525	862,015	14,247	0	310,839	4,455,814	353,300	4,809,114
2032	1,691,305	1,615,474	864,050	14,153	0	313,558	4,498,540	356,688	4,855,228
2033	1,707,733	1,623,734	869,808	14,051	0	316,279	4,531,605	359,310	4,890,915
2034	1,729,600	1,634,648	876,827	13,945	0	319,261	4,574,281	362,695	4,936,975
2035	1,752,787	1,646,134	883,064	13,836	0	322,166	4,617,987	366,160	4,984,148
2036	1,779,610	1,659,250	889,789	13,722	0	324,727	4,667,098	370,055	5,037,153
2037	1,797,303	1,668,141	897,719	13,600	0	327,171	4,703,934	372,976	5,076,910
2038	1,819,485	1,679,222	905,940	13,472	0	329,553	4,747,672	376,444	5,124,117

(a) Sales for resale to municipals.

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

TABLE B.3b
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)[a]
AFTER EE (Case #1)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
							(1+2+3+4+5+6)		(7+8)
	Rural and			Steet-Hwy	Sales for		Total	Losses and	Net Energy
Year	Residential	Commercial	Industrial	Lighting	Resale[b]	Other	Consumption	Unaccounted For[c]	for Load
2013	1,465,361	1,454,627	808,831	15,362	0	291,017	4,035,198	277,293	4,312,491
2014	1,479,746	1,459,944	827,408	15,274	0	291,336	4,073,709	327,954	4,401,663
2015	1,445,887	1,477,900	812,522	15,120	0	292,528	4,043,958	102,148	4,146,106
2016	1,451,682	1,494,014	810,977	15,264	0	293,918	4,065,855	234,654	4,300,509
2017	1,395,234	1,450,924	800,034	15,077	0	278,593	3,939,861	260,845	4,200,706
2018	1,455,709	1,470,677	801,550	15,212	0	283,046	4,026,195	319,229	4,345,424
2019	1,455,212	1,479,231	812,845	15,115	0	281,550	4,043,953	320,640	4,364,592
2020	1,466,980	1,488,389	815,032	15,051	0	280,597	4,066,049	322,392	4,388,441
2021	1,472,970	1,494,626	818,995	14,991	0	283,262	4,084,844	323,882	4,408,726
2022	1,483,762	1,502,662	819,282	14,936	0	285,820	4,106,462	325,596	4,432,058
2023	1,498,646	1,510,977	824,211	14,866	0	288,340	4,137,040	328,021	4,465,061
2024	1,521,922	1,521,787	830,736	14,784	0	290,964	4,180,194	331,443	4,511,637
2025	1,534,088	1,528,102	837,185	14,725	0	293,251	4,207,351	333,597	4,540,948
2026	1,553,653	1,539,044	846,207	14,659	0	295,952	4,249,514	336,941	4,586,455
2027	1,575,748	1,552,439	850,254	14,583	0	299,056	4,292,079	340,316	4,632,395
2028	1,603,986	1,569,518	854,775	14,499	0	302,557	4,345,335	344,539	4,689,874
2029	1,623,561	1,582,679	856,667	14,406	0	305,646	4,382,960	347,523	4,730,483
2030	1,641,214	1,592,497	858,385	14,332	0	308,236	4,414,663	350,037	4,764,700
2031	1,659,638	1,602,525	862,015	14,247	0	310,839	4,449,263	352,781	4,802,044
2032	1,684,754	1,615,474	864,050	14,153	0	313,558	4,491,989	356,169	4,848,158
2033	1,701,183	1,623,734	869,808	14,051	0	316,279	4,525,054	358,791	4,883,845
2034	1,723,050	1,634,648	876,827	13,945	0	319,261	4,567,730	362,175	4,929,906
2035	1,746,236	1,646,134	883,064	13,836	0	322,166	4,611,437	365,641	4,977,078
2036	1,773,060	1,659,250	889,789	13,722	0	324,727	4,660,547	369,536	5,030,083
2037	1,790,753	1,668,141	897,719	13,600	0	327,171	4,697,384	372,457	5,069,840
2038	1,812,935	1,679,222	905,940	13,472	0	329,553	4,741,122	375,925	5,117,047

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

System Seasonal Peak Load Forecast

Table B.4a 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 predominant ones historically. Projected growth in the summer peak demand from 2018 to 2038 is 0.8 percent. Projected growth in the winter peak demand is 0.7 percent. Including the expected impacts of low-income EE programs does not appreciably change the forecasts.

TABLE B.4a
DUKE ENERGY KENTUCKY SYSTEM
SEASONAL PEAK LOAD FORECAST (MEGAWATTS)
BEFORE EE
INTERNAL LOAD[a]

	SUMMER			WINTER[d]		
			PERCENT			PERCENT
YEAR	LOAD	CHANGE[b]	CHANGE[c]	LOAD	CHANGE[b]	CHANGE[c]
2013	869			860		
2014	837	(32)	-3.7%	799	(61)	-7.1%
2015	814	(23)	-2.7%	739	(60)	-7.5%
2016	877	63	7.7%	733	(6)	-0.8%
2017	841	(36)	-4.1%	706	(27)	-3.7%
2018	848	7	0.8%	730	24	3.4%
2019	853	5	0.6%	733	3	0.5%
2020	858	5	0.6%	734	1	0.1%
2021	863	5	0.6%	737	3	0.4%
2022	868	4	0.5%	741	4	0.5%
2023	873	6	0.7%	748	7	1.0%
2024	881	7	0.8%	751	3	0.4%
2025	886	6	0.6%	757	6	0.8%
2026	895	8	0.9%	764	7	0.9%
2027	902	7	0.8%	773	9	1.2%
2028	910	9	1.0%	779	6	0.7%
2029	918	7	0.8%	784	5	0.6%
2030	924	6	0.7%	789	5	0.7%
2031	931	7	0.8%	796	7	0.9%
2032	939	8	0.8%	801	4	0.6%
2033	946	7	0.7%	807	6	0.8%
2034	954	8	0.9%	814	7	0.9%
2035	962	8	0.9%	822	8	1.0%
2036	971	9	0.9%	828	5	0.6%
2037	980	9	0.9%	834	7	0.8%
2038	989	9	0.9%	842	7	0.9%

(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.

TABLE B.4b
DUKE ENERGY KENTUCKY SYSTEM
SEASONAL PEAK LOAD FORECAST (MEGAWATTS)[a]
AFTER EE (Case #1)
INTERNAL LOAD[b]

	SUMMER			WINTER[d]		
YEAR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
2013	869			860		
2014	837	(32)	-3.7%	799	(61)	-7.1%
2015	814	(23)	-2.7%	739	(60)	-7.5%
2016	877	63	7.7%	733	(6)	-0.8%
2017	841	(36)	-4.1%	706	(27)	-3.7%
2018	848	7	0.8%	730	24	3.4%
2019	853	5	0.6%	733	3	0.5%
2020	858	5	0.6%	734	1	0.1%
2021	863	5	0.6%	737	3	0.4%
2022	868	4	0.5%	741	4	0.5%
2023	873	6	0.7%	748	7	1.0%
2024	881	7	0.8%	751	3	0.4%
2025	886	6	0.6%	757	6	0.8%
2026	895	8	0.9%	764	7	0.9%
2027	902	7	0.8%	773	9	1.2%
2028	910	9	1.0%	779	6	0.7%
2029	918	7	0.8%	784	5	0.6%
2030	924	6	0.7%	789	5	0.7%
2031	931	7	0.8%	796	7	0.9%
2032	939	8	0.8%	801	4	0.6%
2033	946	7	0.7%	807	6	0.8%
2034	954	8	0.9%	814	7	0.9%
2035	962	8	0.9%	822	8	1.0%
2036	971	9	0.9%	828	5	0.6%
2037	980	9	0.9%	834	7	0.8%
2038	989	9	0.9%	842	7	0.9%

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

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.

Load Factor

The table below contains 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, Table B.3a, and the annual peak, Table B.4a, before EE.

TABLE B.5
DUKE ENERGY KENTUCKY
SYSTEM LOAD FACTORS

Year	Load Factor
2013	57.4%
2014	60.0%
2015	58.1%
2016	56.0%
2017	57.7%
2018	61.0%
2019	60.8%
2020	60.9%
2021	60.5%
2022	60.7%
2023	60.7%
2024	60.8%
2025	60.8%
2026	60.8%
2027	61.0%
2028	61.1%
2029	61.1%
2030	61.1%
2031	61.1%
2032	61.2%
2033	61.2%
2034	61.2%
2035	61.2%
2036	61.3%
2037	61.2%
2038	61.2%

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.

Table B.6a provides the high, low, and most likely before EE forecasts of electric energy and peak demand for the service area. Table B.6b provides similar information after implementation of the Low-Income EE programs (DSM Case #1 as described in section II.B).

TABLE B.6a
DUKE ENERGY KENTUCKY SYSTEM
RANGE OF FORECASTS
ECONOMIC BANDS

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) BEFORE EE			PEAK LOAD FORECAST (MW) INTERNAL[a] BEFORE EE, BEFORE DR		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2018	4,303	4,346	4,388	840	848	856
2019	4,228	4,366	4,503	827	854	880
2020	4,254	4,390	4,526	833	859	884
2021	4,297	4,411	4,525	841	864	886
2022	4,333	4,435	4,537	848	868	889
2023	4,372	4,469	4,565	854	874	894
2024	4,423	4,516	4,609	863	881	900
2025	4,454	4,546	4,637	869	887	905
2026	4,500	4,592	4,684	877	896	914
2027	4,546	4,638	4,731	884	903	921
2028	4,603	4,696	4,789	893	912	930
2029	4,642	4,737	4,832	900	919	938
2030	4,676	4,772	4,867	906	925	944
2031	4,713	4,809	4,905	913	932	951
2032	4,758	4,855	4,953	920	940	960
2033	4,792	4,891	4,990	927	947	967
2034	4,837	4,937	5,037	935	955	976
2035	4,883	4,984	5,085	943	963	984
2036	4,935	5,037	5,139	952	972	993
2037	4,973	5,077	5,180	960	981	1,003
2038	5,019	5,124	5,229	968	990	1,012

(a) Excludes controllable load.

TABLE B.6b
DUKE ENERGY KENTUCKY SYSTEM
RANGE OF FORECASTS[a]
ECONOMIC BANDS

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD) AFTER EE (Case #1)			PEAK LOAD FORECAST (MW) INTERNAL[b] AFTER EE (Case #1)		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2018	4,303	4,345	4,388	840	848	856
2019	4,227	4,365	4,503	827	853	879
2020	4,253	4,388	4,524	833	858	884
2021	4,295	4,409	4,523	841	863	886
2022	4,330	4,432	4,534	847	868	888
2023	4,368	4,465	4,562	854	873	893
2024	4,418	4,512	4,605	862	881	899
2025	4,449	4,541	4,633	868	886	904
2026	4,494	4,586	4,679	876	895	913
2027	4,540	4,632	4,725	883	902	920
2028	4,596	4,690	4,783	892	910	929
2029	4,636	4,730	4,825	899	918	937
2030	4,669	4,765	4,860	905	924	943
2031	4,706	4,802	4,898	912	931	950
2032	4,751	4,848	4,946	919	939	959
2033	4,785	4,884	4,983	925	946	966
2034	4,830	4,930	5,030	933	954	974
2035	4,876	4,977	5,078	941	962	983
2036	4,928	5,030	5,132	950	971	992
2037	4,966	5,070	5,173	958	980	1,001
2038	5,012	5,117	5,222	967	989	1,011

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

Monthly Forecast

Tables B.7a and B.7b 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.

TABLE B.7a
DUKE ENERGY KENTUCKY SYSTEM
NET MONTHLY ENERGY AND PEAK FORECAST
BEFORE EE

YEAR 0	2018	ENERGY, MWH	PEAK, MW
January		401,045	728
February		352,355	695
March		338,874	641
April		310,668	566
May		334,725	714
June		385,458	814
July		426,955	848
August		410,022	844
September		362,402	814
October		320,440	623
November		328,513	601
December		374,311	692
YEAR 1	2019		
January		392,584	730
February		354,104	697
March		340,867	644
April		312,774	569
May		337,232	717
June		388,662	818
July		430,728	854
August		413,530	849
September		365,170	818
October		322,751	627
November		330,799	603
December		376,379	694

TABLE B.7b
DUKE ENERGY KENTUCKY SYSTEM
NET MONTHLY ENERGY AND PEAK FORECAST
AFTER EE (Case #1)

YEAR 0	2018	ENERGY, MWH	PEAK, MW
January		401,040	728
February		352,346	695
March		338,862	641
April		310,655	566
May		334,707	714
June		385,430	814
July		426,917	848
August		409,982	844
September		362,367	814
October		320,406	623
November		328,471	601
December		374,244	692
YEAR 1	2019		
January		392,512	730
February		354,036	697
March		340,805	644
April		312,719	569
May		337,172	717
June		388,576	818
July		430,624	853
August		413,430	849
September		365,087	817
October		322,676	627
November		330,711	603
December		376,244	694

TABLE B.8a
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	2018	Residential	Commercial	Industrial	Lighting	Resale[a]	Other	Consumption	Unaccounted For[b]	Net Energy for Load
January		159,199	122,227	64,950	1,323	0	23,887	371,586	29,459	401,045
February		127,742	113,366	61,955	1,299	0	22,111	326,473	25,883	352,355
March		112,264	114,135	63,147	1,259	0	23,175	313,981	24,893	338,874
April		89,867	112,230	63,201	1,257	0	21,290	287,846	22,823	310,668
May		97,107	118,776	69,238	1,251	0	23,761	310,133	24,592	334,725
June		125,723	134,294	70,817	1,249	0	25,057	357,139	28,319	385,458
July		156,194	142,569	70,575	1,249	0	25,001	395,589	31,366	426,955
August		140,303	137,696	74,632	1,248	0	26,021	379,901	30,121	410,022
September		112,936	128,381	68,351	1,248	0	24,863	335,779	26,623	362,402
October		88,422	116,574	66,483	1,250	0	24,169	296,898	23,542	320,440
November		105,865	111,581	63,757	1,326	0	21,850	304,378	24,135	328,513
December		140,408	118,847	64,442	1,254	0	21,862	346,813	27,498	374,311
YEAR 1	2019									
January		152,050	121,194	65,376	1,323	0	23,802	363,745	28,839	392,584
February		128,248	113,921	62,547	1,281	0	22,096	328,092	26,012	354,104
March		112,726	114,820	63,861	1,253	0	23,168	315,827	25,040	340,867
April		90,269	112,943	64,091	1,245	0	21,247	289,796	22,978	312,774
May		97,644	119,605	70,287	1,243	0	23,676	312,456	24,776	337,232
June		126,613	135,299	72,013	1,240	0	24,943	360,107	28,554	388,662
July		157,352	143,741	71,897	1,241	0	24,854	399,085	31,643	430,728
August		141,353	138,859	75,849	1,240	0	25,849	383,151	30,379	413,530
September		113,612	129,336	69,479	1,241	0	24,676	338,344	26,827	365,170
October		88,897	117,426	67,510	1,243	0	23,963	299,039	23,712	322,751
November		106,427	112,427	64,682	1,319	0	21,642	306,496	24,303	330,799
December		140,936	119,660	65,254	1,247	0	21,633	348,729	27,650	376,379

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

TABLE B.8b
DUKE ENERGY KENTUCKY SYSTEM
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
AFTER EE (Case #1)

		(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	2018	Residential	Commercial	Industrial	Lighting	Resale[a]	Other	Consumption	Unaccounted For[b]	Net Energy for Load
January		159,194	122,227	64,950	1,323	0	23,887	371,581	29,459	401,040
February		127,733	113,366	61,955	1,299	0	22,111	326,464	25,882	352,346
March		112,252	114,135	63,147	1,259	0	23,175	313,969	24,893	338,862
April		89,854	112,230	63,201	1,257	0	21,290	287,833	22,822	310,655
May		97,091	118,776	69,238	1,251	0	23,761	310,116	24,590	334,707
June		125,696	134,294	70,817	1,249	0	25,057	357,113	28,317	385,430
July		156,159	142,569	70,575	1,249	0	25,001	395,553	31,363	426,917
August		140,266	137,696	74,632	1,248	0	26,021	379,864	30,118	409,982
September		112,903	128,381	68,351	1,248	0	24,863	335,746	26,621	362,367
October		88,391	116,574	66,483	1,250	0	24,169	296,866	23,539	320,406
November		105,825	111,581	63,757	1,326	0	21,850	304,339	24,132	328,471
December		140,346	118,847	64,442	1,254	0	21,862	346,750	27,493	374,244
YEAR 1	2019									
January		151,983	121,194	65,376	1,323	0	23,802	363,678	28,834	392,512
February		128,185	113,921	62,547	1,281	0	22,096	328,029	26,007	354,036
March		112,668	114,820	63,861	1,253	0	23,168	315,769	25,035	340,805
April		90,218	112,943	64,091	1,245	0	21,247	289,745	22,974	312,719
May		97,589	119,605	70,287	1,243	0	23,676	312,401	24,771	337,172
June		126,533	135,299	72,013	1,240	0	24,943	360,028	28,548	388,576
July		157,255	143,741	71,897	1,241	0	24,854	398,988	31,636	430,624
August		141,260	138,859	75,849	1,240	0	25,849	383,058	30,372	413,430
September		113,535	129,336	69,479	1,241	0	24,676	338,267	26,820	365,087
October		88,828	117,426	67,510	1,243	0	23,963	298,970	23,706	322,676
November		106,346	112,427	64,682	1,319	0	21,642	306,415	24,297	330,711
December		140,811	119,660	65,254	1,247	0	21,633	348,604	27,640	376,244

(a) Sales for resale to municipals.

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

APPENDIX C – 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 (SO2) 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 has also been 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. In particular, potential ongoing reductions of the Ozone NAAQS (coupled with eventual loss of the Miami Fort 6 emission allowances five years after retirement) may lead to additional reductions in NOx emission allocations, 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 3.D and 4.D 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 ohserved 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, hut 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 recently 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 existing dry bottom ash pond. The ash pond will undergo closure per CCR Rule requirements. Additionally, Duke Energy Kentucky has recently developed a new lined 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.

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

1. INTRODUCTION

The following section applies to DSM Cases #1 and #2 as described in section II.B of this document. Prior to the suspension of programs as ordered by the PSC, Duke Energy Kentucky offered the following DSM[7] programs that have been developed in conjunction with the DSM Collaborative:

- Program 1: Residential Smart $aver® Energy Efficient Residences Program
- Program 2: Residential Smart $aver® Energy Efficient Products Program[8]
- Program 3: Residential Energy Assessments Program (Residential Home Energy House Call)
- Program 4: Energy Efficiency Education Program for Schools Program
- Program 5: Low Income Services Program
- Program 6: Residential Direct Load Control- Power Manager® Program
- Program 7: Smart $aver® Prescriptive Program
- Program 8: Smart $aver® Custom Program
- Program 9: Smart $aver® Energy Assessments Program
- Program 10: Peak Load Manager (Rider PLM) - PowerShare® Program
- Program 11: Low Income Neighborhood Program
- Program 12: My Home Energy Report Program
- Program 13: Small Business Energy Saver Program
- Program 14: Non-Residential Pay for Performance[9]
- Program 15: Power Manager® for Apartments
- Program 16: Power Manager® for Business

[7] 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 (Michie 2007).
[8] The Smart $aver® Residential Energy Efficient Products Program and the Energy Efficient Residences Program are individual measures that are part of a single and larger program referred to and marketed as Residential Smart $aver.® For ease of administration and communication with customers the two measures have been divided into separate tariffs even though they are a single program.
[9] Marketed as Smart $aver® Performance

Table D.1a Projected Demand Side Management Impacts – Case #1

			DR Impacts - MW				Total DSM Impacts - MW
Year	EE Impacts - MWh	EE Impacts - MW	Power Share	Power Manager for Business	Power Manager	Total	Total
2018	594	0.1	0.0	0.0	0.0	0.0	0.1
2019	1,190	0.2	0.0	0.0	0.0	0.0	0.2
2020	1,789	0.3	0.0	0.0	0.0	0.0	0.3
2021	2,391	0.4	0.0	0.0	0.0	0.0	0.4
2022	2,995	0.5	0.0	0.0	0.0	0.0	0.5
2023	3,599	0.6	0.0	0.0	0.0	0.0	0.6
2024	4,203	0.7	0.0	0.0	0.0	0.0	0.7
2025	4,807	0.8	0.0	0.0	0.0	0.0	0.8
2026	5,411	0.9	0.0	0.0	0.0	0.0	0.9
2027	6,015	1.0	0.0	0.0	0.0	0.0	1.0
2028	6,619	1.1	0.0	0.0	0.0	0.0	1.1
2029	7,223	1.1	0.0	0.0	0.0	0.0	1.1
2030	7,827	1.2	0.0	0.0	0.0	0.0	1.2
2031	8,431	1.2	0.0	0.0	0.0	0.0	1.2
2032	9,035	1.2	0.0	0.0	0.0	0.0	1.2

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

Table D.1a Projected Demand Side Management Impacts – Case #2

			DR Impacts - MW				Total DSM Impacts - MW
Year	EE Impacts - MWh	EE Impacts - MW	Power Share	Power Manager for Business	Power Manager	Total	Total
2018	25,590	2.5	19.6	0.0	14.5	34.2	36.7
2019	49,635	6.4	18.9	0.7	14.7	34.2	40.6
2020	75,497	10.2	18.9	1.6	14.9	35.4	45.6
2021	101,231	14.0	14.0	2.7	15.0	31.8	45.8
2022	126,780	17.8	14.0	3.8	15.2	33.0	50.8
2023	152,329	21.4	14.0	3.8	15.2	33.0	54.4
2024	177,879	20.1	14.0	3.8	15.2	33.0	53.1
2025	203,428	23.0	14.0	3.8	15.2	33.0	56.0
2026	228,977	25.8	14.0	3.8	15.2	33.0	58.8
2027	254,527	28.6	14.0	3.8	15.2	33.0	61.6
2028	280,076	31.0	14.0	3.8	15.2	33.0	64.0
2029	305,625	33.5	14.0	3.8	15.2	33.0	66.5
2030	331,174	35.6	14.0	3.8	15.2	33.0	68.6
2031	356,724	36.9	14.0	3.8	15.2	33.0	69.9
2032	382,273	37.0	14.0	3.8	15.2	33.0	70.0

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

2. CURRENT DSM PROGRAM DESCRIPTIONS

Program 5: Low Income Services Program

The Weatherization program portion of Low Income Services helps the Company's income-qualified customers reduce their energy consumption and lower their energy cost. This program specifically focuses on Low Income Home Energy Assistance Program (LIHEAP) customers that meet the income qualification level (*i.e.*, income below 150% of the federal poverty level).

This program uses the LIHEAP intake process as well as other community outreach initiatives to improve participation. The program provides direct installation of weatherization and energy-efficiency measures and educates Duke Energy Kentucky's income-qualified customers about their energy usage and other opportunities to reduce energy consumption and lower energy costs.

Program 11: Low Income Neighborhood Program

The Duke Energy Kentucky Residential Neighborhood Program takes a non-traditional approach to serving income-qualified areas of the Duke Energy Kentucky service territory by directly installing energy efficiency measures in customer homes. The program engages targeted customers with personal interaction in a familiar setting while ultimately reducing energy consumption by installing energy efficient measures and educating customers on ways to manage and lower their energy bills.

Examples of direct installed measures include energy efficient 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. Targeted low income neighborhoods qualify for the program if at least 50% of the households are at or below 200% of the federal poverty guidelines. 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 the majority of 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.

3. SUSPENDED DSM PROGRAM DESCRIPTIONS

Programs 1 and 2: Residential Smart \$aver® Program

The Residential Smart \$aver Program is offered under two separate tariffs, Residential Smart \$aver® Energy Efficient Residences and Residential Smart \$aver® Energy Efficient Products.

The Residential Smart \$aver® Energy Efficient Residences program offers customers a variety of energy conservation measures designed to increase EE in their homes. The Program utilizes a network of contractors to encourage the installation of high efficiency equipment and the implementation of energy efficient home improvements. There are equipment and services incentives for:

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

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.

Program 3: Residential Energy Assessments Program

The primary goal for the Residential Energy Assessments Program (Home Energy House Call (HEHC)) is to empower customers to better manage their energy usage and cost. Duke Energy Kentucky partners with several key vendors to administer the program which an energy specialist completes a 60 to 90 minute walk through assessment of the home and analyzes energy usage to identify energy savings opportunities. The Building Performance Institute (BPI) Building certified energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The program targets Duke Energy Kentucky residential customers that own a single family home with at least four months usage history and have electric water heater and/or electric heat, or central air.

Program 4: Energy Efficiency Education Program for Schools

The Energy Efficiency Education Program for Schools offers two educational interactions: 1) an in depth classroom curriculum through the National Energy Education

Development (NEED) project; and 2) a live theatrical production by The National Theatre for Children (NTC).

Program 6: Residential Direct Load Control - Power Manager Program

The Power Manager program reduces 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.

Program 7: Smart $aver® Prescriptive Program

The Smart $aver® Non-residential Prescriptive Incentive Program provides incentives to commercial and industrial consumers for installation of bigh 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. This program offers incentives for:

- Lighting
- HVAC
- Pumps/Motors/Variable Frequency Drives
- Energy Star Food Service Products
- Information Technology Process Equipment and Water Conservation

The eligible measures, incentives and requirements for both equipment and customer eligibility are listed in the applications posted on Duke Energy's website for each technology type.

Program 8: Smart $aver® Custom Program

The purpose of this program is to encourage the installation of high efficiency equipment in new and existing nonresidential 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.

Program 9: Smart $aver® Energy Assessments Program

The purpose of this program is to assist customers with the evaluation of energy usage within a specific building(s) and to provide recommendations for energy savings projects. The program may provide up to a 50% subsidy for an energy efficiency audit completed in partnership with a Duke Energy contracted professional engineering organization or a third-party engineering firm of the customer's choice. This program is jointly implemented within the Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Carolinas territories to reduce administrative costs and leverage resources.

Program 10: 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 this Rider, specifying the terms and conditions under which the customer agrees to reduce usage.

Program 12: My Home Energy Report Program

The My Home Energy Report (MyHER Report) 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. The MyHER Report is delivered in printed or online form to targeted customers with desirable characteristics who are likely to respond to the information. The printed reports are distributed up to 12 times per year; however delivery may be interrupted during the off-peak energy usage months in the fall and spring. Currently to qualify to receive the MyHER Report, customers must be living in a single metered, single family home with 13 months usage history.

The Company has also developed a MyHER program for multifamily dwellings that was available in January 2017.

Program 13: 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.

Program 14. Smart $aver® Non-Residential Performance Incentive Program (Formerly filed as Pay for Performance) [10]

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 are included in the contract with the Customer.

Program 15. Power Manager® for Apartments[10]

Power Manager® for Apartments is a residential load control program focused on Apartment Complexes/Communities. It is used to reduce electricity demand by controlling residential air conditioners and when available, electric water heaters during periods of peak demands. A load control device is attached to the outdoor air conditioning unit and water heater of participating customers. This enables Duke Energy Kentucky to cycle central air conditioning systems off and on when the load on Duke Energy Kentucky's system reaches peak levels during the cooling season. In addition, this program enables Duke Energy Kentucky to cycle the electric water heaters off when the load on the system reaches peak levels—any time of year.

Duke Energy Kentucky received approval to offer this program however realizing the IT investment relative to the small impacts and the overall desire to control overall program costs the Company has decided not to offer the program. Program spending during the July 2016 – June 2017 timeframe were costs of specifying the information technology project to implement the program changes to the billing system, as well as, some equipment purchases in anticipation of launching the program.

The results of this program have not been included in the Case 1 analysis.

Program 16. Power Manager® for Business[10]

Power Manager® for Business is a non-residential program that provides business customers with the opportunity to participate in demand response, earn incentives and realize optional energy efficiency benefits. This program is designed as a flexible offer that provides small-to-medium size business customers with options on device types as well as level of demand response participation. Customers first select the type of device from two available options: thermostat or switch.

[10] Programs approved in Case No. 2016-00289.

Customers who opt for the thermostat will have the ability to manage their thermostat remotely via computer, tablet or smartphone. The thermostat comes with presets designed to help the business manager/owner set an efficient schedule that works for their business. This realizes additional benefits in the form of EE impacts/savings. Customers then select one of three levels of summer demand response (DR) participation, and earn an incentive based upon that selection.

Both thermostat and switch customers have the same DR participation options and receive the same DR incentives.

Response to Section 8 (3)(e)4

Table D.2a: Expected Case Energy Efficiency Program Costs - Case #1

Energy Efficiency and DSM Programs	Year 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential															
Energy Efficiency Education Program for Schools	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Income Neighborhood	$ 401,885	$ 284,589	$ 295,908	$ 427,313	$ 319,397	$ 326,688	$ 334,154	$ 341,674	$ 349,394	$ 357,489	$ 365,920	$ 374,522	$ 383,207	$ 391,975	$ 400,925
Low Income Services	$ 750,077	$ 745,013	$ 746,858	$ 747,768	$ 749,193	$ 766,295	$ 783,808	$ 801,447	$ 819,556	$ 838,542	$ 858,320	$ 878,497	$ 898,868	$ 919,435	$ 940,428
My Home Energy Report	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power Manager®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Energy Assessments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Smart Saver®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power Manager® for Apartments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Residential	$ 1,151,962	$ 1,029,602	$ 1,042,767	$ 1,175,081	$ 1,068,590	$ 1,092,982	$ 1,117,962	$ 1,143,122	$ 1,168,950	$ 1,196,031	$ 1,224,240	$ 1,253,019	$ 1,282,074	$ 1,311,410	$ 1,341,353
Non-Residential															
Power Manager® for Business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PowerShare®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Small Business Energy Saver	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Saver Prescriptive®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Saver® Custom	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Saver® Non Residential Performance Incentive Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Non-Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Energy Efficiency and DSM Programs	$ 1,151,962	$ 1,029,602	$ 1,042,767	$ 1,175,081	$ 1,068,590	$ 1,092,982	$ 1,117,962	$ 1,143,122	$ 1,168,950	$ 1,196,031	$ 1,224,240	$ 1,253,019	$ 1,282,074	$ 1,311,410	$ 1,341,353

Note: Program costs beyond 2022 are estimated using the same Consumer Price Index forecast as used in the IRP modelling

Table D.2b: Expected Case Energy Efficiency Program Costs - Case #2

Energy Efficiency and DSM Programs	Year 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential															
Energy Efficiency Education Program for Schools	$ 258,765	$ 211,642	$ 195,285	$ 307,622	$ 220,550	$ 225,584	$ 230,740	$ 235,933	$ 241,263	$ 246,853	$ 252,675	$ 258,615	$ 264,611	$ 270,666	$ 276,846
Low Income Neighborhood	$ 401,885	$ 284,589	$ 295,908	$ 427,313	$ 319,397	$ 326,688	$ 334,154	$ 341,674	$ 349,394	$ 357,489	$ 365,920	$ 374,522	$ 383,207	$ 391,975	$ 400,925
Low Income Services	$ 750,077	$ 745,013	$ 746,858	$ 747,768	$ 749,193	$ 766,295	$ 783,808	$ 801,447	$ 819,556	$ 838,542	$ 858,320	$ 878,497	$ 898,868	$ 919,435	$ 940,428
My Home Energy Report	$ 826,643	$ 771,280	$ 728,541	$ 829,524	$ 781,011	$ 798,840	$ 817,097	$ 835,486	$ 854,363	$ 874,156	$ 894,773	$ 915,807	$ 937,043	$ 958,484	$ 980,369
Power Manager®	$ 829,058	$ 786,959	$ 709,393	$ 835,290	$ 803,748	$ 822,095	$ 840,884	$ 859,807	$ 879,234	$ 899,603	$ 920,821	$ 942,467	$ 964,321	$ 986,387	$ 1,008,908
Residential Energy Assessments	$ 343,997	$ 256,033	$ 236,883	$ 158,618	$ 260,525	$ 266,472	$ 272,562	$ 278,696	$ 284,993	$ 291,595	$ 298,473	$ 305,488	$ 312,573	$ 319,725	$ 327,025
Residential Smart Saver®	$ 2,433,446	$ 2,213,477	$ 1,697,918	$ 1,520,893	$ 1,325,190	$ 1,355,441	$ 1,386,419	$ 1,417,620	$ 1,449,650	$ 1,483,234	$ 1,518,217	$ 1,553,906	$ 1,589,939	$ 1,626,319	$ 1,663,452
Power Manager® for Apartments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Residential	$ 5,843,871	$ 5,268,992	$ 4,610,787	$ 5,026,729	$ 4,459,614	$ 4,561,414	$ 4,665,663	$ 4,770,663	$ 4,878,453	$ 4,991,471	$ 5,109,200	$ 5,229,302	$ 5,350,561	$ 5,472,991	$ 5,597,953
Non-Residential															
Power Manager® for Business	$ 149,660	$ 210,701	$ 256,789	$ 288,388	$ 329,805	$ 337,338	$ 345,047	$ 352,812	$ 360,784	$ 369,142	$ 377,849	$ 386,731	$ 395,699	$ 404,753	$ 413,994
PowerShare®	$ 950,951	$ 896,482	$ 761,680	$ 981,971	$ 1,012,555	$ 1,035,669	$ 1,059,339	$ 1,083,179	$ 1,107,653	$ 1,133,313	$ 1,160,044	$ 1,187,313	$ 1,214,845	$ 1,241,642	$ 1,271,015
Small Business Energy Saver	$ 971,649	$ 845,668	$ 739,068	$ 632,880	$ 573,461	$ 586,551	$ 599,957	$ 613,459	$ 627,319	$ 641,852	$ 656,991	$ 672,435	$ 688,028	$ 703,771	$ 719,840
Smart Saver Prescriptive®	$ 1,966,785	$ 1,531,661	$ 1,524,901	$ 1,644,917	$ 1,630,687	$ 1,667,912	$ 1,706,031	$ 1,744,425	$ 1,783,838	$ 1,825,165	$ 1,868,213	$ 1,912,130	$ 1,956,469	$ 2,001,236	$ 2,046,929
Smart Saver® Custom	$ 594,067	$ 680,603	$ 679,386	$ 817,266	$ 835,764	$ 854,842	$ 874,380	$ 894,057	$ 914,258	$ 935,438	$ 957,501	$ 980,010	$ 1,002,734	$ 1,025,679	$ 1,049,097
Smart Saver® Non Residential Performance Incentive Program	$ 102,307	$ 307,736	$ 566,136	$ 740,585	$ 742,362	$ 759,308	$ 776,661	$ 794,140	$ 812,083	$ 830,896	$ 850,494	$ 870,487	$ 890,672	$ 911,052	$ 931,853
Total Non-Residential	$ 4,735,418	$ 4,472,851	$ 4,530,960	$ 5,116,007	$ 5,124,634	$ 5,241,619	$ 5,361,415	$ 5,482,072	$ 5,605,936	$ 5,735,808	$ 5,871,092	$ 6,009,105	$ 6,148,446	$ 6,288,132	$ 6,432,729
Total Energy Efficiency and DSM Programs	$ 10,579,290	$ 9,741,844	$ 9,141,747	$ 10,142,736	$ 9,584,251	$ 9,803,033	$ 10,027,078	$ 10,252,734	$ 10,484,388	$ 10,727,279	$ 10,980,292	$ 11,238,407	$ 11,499,008	$ 11,761,123	$ 12,030,681

Note: Program costs beyond 2022 are estimated using the same Consumer Price Index forecast as used in the IRP modelling

Response to Section 8 (3)(e)5

Table D.3a: Expected Case Energy Efficiency Avoided Costs - Case #1

Section 8(3)(e)5
Energy Efficiency and Demand Response Avoided Costs
Case #1

Energy Efficiency and DSM Programs	Year 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential															
Energy Efficiency Education Program for Schools	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Income Neighborhood	$ 127,772	$ 134,391	$ 140,125	$ 145,170	$ 150,191	$ 153,430	$ 156,666	$ 159,970	$ 163,400	$ 166,910	$ 170,737	$ 174,816	$ 179,059	$ 183,448	$ 188,186
Low Income Services	$ 224,662	$ 232,868	$ 239,819	$ 245,878	$ 251,869	$ 257,394	$ 263,125	$ 269,018	$ 275,208	$ 281,635	$ 288,510	$ 295,851	$ 303,581	$ 311,608	$ 320,251
My Home Energy Report	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power Manager®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Energy Assessments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Residential Smart Saver®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Power Manager® for Apartments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Residential	$ 352,434	$ 367,259	$ 379,944	$ 391,048	$ 402,059	$ 410,824	$ 419,791	$ 428,988	$ 438,609	$ 448,545	$ 459,247	$ 470,666	$ 482,640	$ 495,055	$ 508,437
Non-Residential															
Power Manager® for Business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PowerShare®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Small Business Energy Saver	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Smart Saver Prescriptive®	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Saver® Custom	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Smart Saver® Non Residential Performance Incentive Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Non-Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Energy Efficiency and DSM Programs	$ 352,434	$ 367,259	$ 379,944	$ 391,048	$ 402,059	$ 410,824	$ 419,791	$ 428,988	$ 438,609	$ 448,545	$ 459,247	$ 470,666	$ 482,640	$ 495,055	$ 508,437

Note: Avoided costs beyond 2022 are estimated using the estimated annual growth rate computed by Avoided Cost component

Table D.3b: Expected Case Energy Efficiency Avoided Costs - Case #2

Section 8(3)(e)5
Energy Efficiency and Demand Response Avoided Costs
Case #2

Energy Efficiency and DSM Programs	Year 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential															
Energy Efficiency Education Program for Schools	$ 205,114	$ 222,907	$ 237,741	$ 243,285	$ 250,839	$ 256,360	$ 271,931	$ 277,497	$ 283,291	$ 289,254	$ 295,582	$ 302,569	$ 309,916	$ 317,897	$ 325,649
Low Income Neighborhood	$ 127,772	$ 134,391	$ 140,125	$ 145,170	$ 150,191	$ 153,430	$ 156,665	$ 159,970	$ 163,400	$ 166,910	$ 170,737	$ 174,816	$ 179,059	$ 183,448	$ 188,186
Low Income Services	$ 224,662	$ 232,868	$ 239,819	$ 245,878	$ 251,869	$ 257,394	$ 263,125	$ 269,018	$ 275,208	$ 281,635	$ 288,510	$ 295,851	$ 303,581	$ 311,608	$ 320,251
My Home Energy Report	$ 973,303	$ 1,061,008	$ 1,133,943	$ 1,171,051	$ 1,222,214	$ 1,248,767	$ 1,277,368	$ 1,302,845	$ 1,332,919	$ 1,357,246	$ 1,382,896	$ 1,411,553	$ 1,449,792	$ 1,474,888	$ 1,509,858
Power Manager®	$ 1,834,797	$ 1,947,885	$ 2,059,084	$ 2,171,460	$ 2,294,179	$ 2,339,119	$ 2,396,007	$ 2,453,707	$ 2,512,689	$ 2,571,620	$ 2,635,880	$ 2,699,183	$ 2,763,532	$ 2,828,727	$ 2,895,233
Residential Energy Assessments	$ 303,387	$ 317,312	$ 322,254	$ 329,122	$ 335,850	$ 343,265	$ 350,928	$ 358,875	$ 367,176	$ 375,863	$ 385,138	$ 395,026	$ 405,430	$ 416,229	$ 427,837
Residential Smart Saver®	$ 3,344,948	$ 1,960,174	$ 2,679,310	$ 1,676,979	$ 1,330,886	$ 1,339,118	$ 1,358,448	$ 1,388,612	$ 1,420,357	$ 1,453,347	$ 1,488,746	$ 1,526,649	$ 1,566,640	$ 1,608,196	$ 1,653,087
Power Manager® for Apartments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Residential	$ 7,013,983	$ 6,876,546	$ 6,813,285	$ 5,883,946	$ 5,806,007	$ 5,837,856	$ 6,074,472	$ 6,213,520	$ 6,355,081	$ 6,497,874	$ 6,647,480	$ 6,807,647	$ 6,977,880	$ 7,140,492	$ 7,320,102
Non-Residential															
Power Manager® for Business	$ 90,986	$ 120,215	$ 139,410	$ 144,904	$ 157,515	$ 160,963	$ 164,419	$ 167,947	$ 171,603	$ 175,340	$ 179,385	$ 183,672	$ 188,123	$ 192,719	$ 197,652
PowerShare®	$ 1,655,542	$ 1,805,977	$ 1,519,861	$ 1,894,320	$ 1,939,666	$ 1,986,363	$ 2,034,704	$ 2,083,748	$ 2,133,884	$ 2,185,668	$ 2,239,585	$ 2,292,400	$ 2,347,115	$ 2,402,566	$ 2,459,139
Small Business Energy Saver	$ 2,158,948	$ 1,969,389	$ 1,757,677	$ 1,321,288	$ 1,401,895	$ 1,430,894	$ 1,460,797	$ 1,491,261	$ 1,523,943	$ 1,557,982	$ 1,594,312	$ 1,633,500	$ 1,674,649	$ 1,717,509	$ 1,764,475
Smart Saver Prescriptive®	$ 4,567,835	$ 4,829,015	$ 5,072,183	$ 5,304,149	$ 5,541,791	$ 5,664,317	$ 5,790,983	$ 5,922,450	$ 6,059,886	$ 6,203,786	$ 6,357,641	$ 6,521,819	$ 6,694,690	$ 6,874,204	$ 7,067,346
Smart Saver® Custom	$ 1,274,952	$ 1,586,630	$ 1,957,987	$ 2,336,989	$ 2,730,439	$ 2,787,266	$ 2,847,465	$ 2,909,757	$ 2,974,898	$ 3,043,248	$ 3,116,505	$ 3,185,647	$ 3,279,617	$ 3,367,082	$ 3,462,449
Smart Saver® Non Residential Performance Incentive Program	$ 271,654	$ 1,081,018	$ 2,136,639	$ 2,895,798	$ 2,964,941	$ 3,026,649	$ 3,092,018	$ 3,159,660	$ 3,230,395	$ 3,304,615	$ 3,384,163	$ 3,470,103	$ 3,561,285	$ 3,656,261	$ 3,759,819
Total Non-Residential	$ 10,288,918	$ 11,372,244	$ 12,582,757	$ 14,097,449	$ 14,736,247	$ 15,056,452	$ 15,390,388	$ 15,734,829	$ 16,093,803	$ 16,470,643	$ 16,870,593	$ 17,297,141	$ 17,745,478	$ 18,210,342	$ 18,710,879
Total Energy Efficiency and DSM Programs	$ 17,274,902	$ 18,248,789	$ 19,395,042	$ 20,008,395	$ 20,542,254	$ 20,959,808	$ 21,464,860	$ 21,948,348	$ 22,448,649	$ 22,968,517	$ 23,518,082	$ 24,104,788	$ 24,723,428	$ 25,350,834	$ 26,030,981

Note: Avoided costs beyond 2022 are estimated using the estimated annual growth rate computed by Avoided Cost component

APPENDIX E – RESPONSE TO 2014 IRP STAFF COMMENTS

Load Forecasting

Staff has no specific criticisms of Duke Kentucky's forecasting methodologies or the results of its forecasts of energy use and peak demands. Staff notes that as it has refined its forecasting approach beginning with the 2011 forecast included in its prior IRP, the Company's forecast results have heen more accurate relative to actual energy use and peak demand. For its next IRP, Staff makes the following recommendations concerning Duke Kentucky's energy and demand forecasts:

RECOMMENDATION:

- The impact of existing and future environmental regulations on the price of electricity and other economic variables continues to be a subject of great interest in the electric utility industry. Accordingly, the effects of such regulations should continue to be examined as a part of Duke Kentucky's load forecast and sensitivity analysis.

RESPONSE:

- Duke Energy Kentucky always consider how inputs to our forecast might be modified by these types of policies. On the generation side, altering the projected generation mix is an impact of these, with scenarios managed in light of different implied futures vis-à-vis a tax or "price" being applied to Carbon emissions. In past versions of the forecast, the downward pressure of this cost being made explicit resulted in load growth lagging behind a baseline until after 2030. On the demand side, please reference the next answer regarding consumer behavior as a response to price changes.

RECOMMENDATION:

- The potential for future increases in electricity prices due to stricter environmental regulations to be large enough to affect consumer behavior and energy consumption continues to exist. An updated analysis/discussion of how such price increases may impact the elasticity of customer demand should be included in the next IRP.

RESPONSE:

- Regarding the impact of new environmental regulations on consumer behavior: the EIA projections for efficiency and penetration of the end uses that are core to our methodology already encapsulate the average projected case. Economic theory suggests that when consumers make different choices, they respond either to changes in relative prices, or to changes in their own incomes. With respect to prices, the fixed parameter for price elasticity used in the residential usage model was -0.08, implying that about a 12% increase in the effective "price" of energy would be required to reduce usage by 1%. This estimate is in-line with results from industry studies and estimates based on the DEK history for sales and price; models for customers of other classes show more responsiveness to price, as would be expected for businesses concerned with their bottom lines. With respect to income, our provided high/low economic scenarios incorporate the changes in personal income that are projected under either short-term growth in excess of forecast or under a moderate recession.

RECOMMENDATION:

- Weather continues to have an impact on Duke Kentucky's forecasting. In its forecasting discussion, Duke Kentucky should identify the period it uses for weather normalization in its forecasting models and explain how Duke Kentucky determined that this period is reasonable.

RESPONSE:

- Regarding Weather Normalization, since the previous IRP filing, Duke energy has standardized all jurisdictions around the use of a thirty-year weather normalization period. The motivations for this were: 1. Reducing the year-to-year variability of the portion of the forecast attributable to normal weather; 2. Approaching the standard used by the plurality of companies in our industry as measured by industry surveys conducted by data vendors such as ITRON; and 3. Increasing the sample size for estimation of normal weather in order to reduce standard errors. Intuitively, using recent data is informative, but so is having a larger sample for calculations, particularly for a measurement of something as variable year-to-year as weather. For the forecast used in this IRP, weather data from years 1987-2016 was used to calculate normal weather.

DSM and EE

While the Commission Staff is generally pleased with the DSM efforts of Duke Kentucky, the following recommendations should be addressed in its next IRP:

RECOMMENDATION:

- Duke Kentucky should include all environmental costs, including, but not limited to, costs of carbon, as they become known, in future benefit/cost analysis.

RESPONSE:

- The inputs used in the DSMore software to evaluate the cost effectiveness of the current DSM programs include the expected impact of carbon prices and other environmental costs as part of the Avoided Production Costs.

RECOMMENDATION:

- Duke Kentucky should monitor its DSM charges in order to prevent large over/(under) collections of DSM charges.

RESPONSE:

- The annual program update filing captures the DSM charges and minimizes the amount of adjustments to prior period collection of DSM charges. In the filings made since the last IRP filing in 2014, additional processes have been implemented to minimize the amounts of over-collection of DSM charges.

RECOMMENDATION:

- Duke Kentucky should continue to aggressively review other cost-effective DSM/EE programs and measures for all customer classes (residential, commercial, and industrial) to include in its DSM portfolio.

RESPONSE:

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

Supply-Side Resources and Environmental Compliance

The Staff considers the supply-side resource assessment of this IRP reasonable, considering that, for the planning period of this IRP, Duke Kentucky maintains a 13.7 percent reserve margin. Miami Fort 6 is retired and therefore is not a component in the power supply resources. Tbe supply-side resources encompass a variety of options considered to meet customers' energy needs. These options include conventional, advanced technology, and renewable generating units.

Staff believes, however, that several issues should be addressed in greater detail in the next IRP. Staff's discussion and recommendations are included below:

1. ***Renewables and Distributed Generation***

RECOMMENDATION:

- 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, including cogeneration, and the specific benefits that these technologies may bring to our customers. Business development personnel bave engaged DEK'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 DEK generating fleet. Inquiries have been made but no customers have indicated interest at this time. DEK will continue to promote CHP and evaluate Duke owned CHP co-located at customers sights as opportunities arise.

RECOMMENDATION:

- In addition, Duke Kentucky should continue to provide information related to customers' net metering statistics and activities.

RESPONSE:

- As of May 31, 2018, Duke Energy Kentucky had 72 net metering customers with cumulative connected capacity of 1.24 MW. All this capacity is supplied by inverter-based photovoltaic (PV) generation. Of these 72 customers that are net metered, 60 are single-family residential, 3 are multi-unit residential, 4 are schools, and 5 are commercial businesses. The largest PV system, at 0.39 MW, is at one of the schools. Except for two of the other schools and two commercial business, all the other customers have generating capacities less than 10 kW.

2. Generation Efficiency

RECOMMENDATION:

- Continue providing discussion of options considered in the IRP, especially improvements to and more efficient utilization of existing facilities.

RESPONSE:

- Duke Energy Kentucky evaluates efficiency impacts during the capital project development and approval process. Efficiency impacts are evaluated along with reliability and cost impacts to determine the most prudent capital spend. As mentioned in the 2014 IRP, Duke Energy evaluated the installation of a high pressure dense pack turbine for the 2018 outage but the project was not financially prudent. Since the 2014 IRP filing several projects have been installed or are planned for installation in the near term to improve unit efficiency. A temporary test lime injection system was installed in 2016 that has provided roughly a 1% improvement in heat rate. The permanent system is planned for installation in 2019 and we expect increased efficiency improvements after that installation. During the 2018 Planned Outage several improvements were made to the circulating water/condenser system. One loop of the condenser was retubed, cooling tower distribution headers were replaced, and the coating in the Circulating Water piping was replaced. This is anticipated to improve heat rate roughly 1-1.5%. Since the last IRP filing improvements to the Secondary Air Heater have also been made with replacement seals as well as adjustments to sealing surfaces to reduce bypassing the heat exchanger.

3. Compliance Planning

RECOMMENDATION:

- Compliance issues, actions, and plans relating to current and pending environmental regulations should be included in the next IRP, as these are of utmost importance in deciding future utility actions.

RESPONSE:

- Please see Appendix C for discussion of environmental compliance planning.

4. Other Issues

RECOMMENDATION:

- Duke Kentucky should provide an update on the Miami Fort 6 retirement, its facilities ' status, any razing and/or property restoration involved in its shuttering situation, and any issues affecting environmental compliance.

RESPONSE:

- DEK is currently in receipt of bids to support the removal of Asbestos Containing Materials from Unit 6. This includes the boiler furnace, gas/air ducts, precipitator and process piping systems. We are anticipating work to begin late summer and complete by end of 1st Qtr 2019. Tenant debris and other remnant materials from decommissioning will be removed from the unit/building as well during this period.

RECOMMENDATION:

- Concerning recent reports on Duke Energy's coal ash ponds in North Carolina, and the fact that substantial fines have been paid for spills, etc., Duke Kentucky should provide a discussion of the status, inspections and any other pertinent information about the condition of similar ponds at the East Bend Station, unless a circumstance of a critical nature requires expedited notification to the Commission prior to its next IRP filing.

RESPONSE:

- Duke Energy Kentucky has one coal ash pond at the East Bend Station and one FGD pond. The coal ash pond is halfway through the closure process. The CCR material is being completely excavated during the closure process and is being transported to a landfill onsite at East Bend. Duke Energy continues to work with the Kentucky Department for Environmental Protection (KDEP) during the closure process and no environmental issues are expected during the closure process. The FGD pond closure is near is scheduled to be completed by the end of 2018. This material is being excavated and transported to the landfill onsite. Dam inspections continue to be performed on the both ponds, including weekly, monthly, and annual inspections. During these inspections, no substantial issues have been identified. Additionally, no fines have been levied related to the East Bend ash pond, nor are any expected.

Integration and Plan Optimization

RECOMMENDATION:

- Unless otherwise addressed before filing its next IRP, Duke Kentucky should report on the effectiveness of its recently approved back-up power supply plan and discuss whether it intends for its future plans to include insurance products or other means to address its concentration of supply.

RESPONSE:

- As of May 31, 2018, it has been 12 months since the beginning of the most recent approved Back-up Power Supply Plan, which commenced June 1, 2017. From realized forced outage cost and realized planned outage hedging results we conclude that the Back-up Power Supply Plan has been fairly effective thus far.
- During the 12-month period, the Company incurred $2,162,641 in purchased power cost during forced outages and derates in excess of East Bend unit's generation cost. This amount is lower than the average annual forced outage cost of $4,270,090 for the 11 calendar years from 2007 through 2017.
- Since early March 2018, East Bend 2 unit has been in an extended planned outage. In fact, it was the biggest planned outage in the station's history with a total spend of

approximately \$90,000,000 - \$100,000,000. The outage included maintenance and enhancement work on turbine, generator, boiler, cooling tower, and other areas. Financial hedges were purchased in advance to mitigate price volatility during the period of the planned outage. As of May 31, 2018, the hedges had realized a profit of approximately \$3.1 million, providing DEK customers protection from volatile spot power market prices. As the outage has extended into June in order to complete all work, the final realized hedging results may see a small variance from the current \$3.1 million amount.

- As part of the analysis performed for the Back-up Power Supply Plan the Company evaluated forced outage insurance products. While recognizing these products could provide various levels of protection, the Company didn't find a suitable product that provided both good coverage and fair value for its forced outage risk. Because of the major overhaul this spring, East Bend unit 2 is expected to see performance improvement. While some underwriters give some consideration for recent unit enhancement, insurance products traditionally were priced off historical outage data. As a result, the Company believed it's unlikely to obtain properly priced insurance coverage at this point and therefore won't seek coverage for the near future. However, the Company will continue to reevaluate its operational situation and risk management needs and may revisit insurance products at some point.

APPENDIX F – CROSS REFERENCE TO IRP RULE REQUIREMENTS

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CONFIDENTIAL PROPRIETARY TRADE SECRET

2018 INTEGRATED RESOURSE PLAN RESPONSE TO SECTION 8(3)(a) IS BEING FILED UNDER THE SEAL OF A MOTION FOR CONFIDENTIAL TREATMENT