COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of Duke Energy Kentucky,	)	
Inc.'s Integrated Resource Plan	)	Case No. 2021-00245
	)	

PETITION OF DUKE ENERGY KENTUCKY, INC. FOR CONFIDENTIAL TREATMENT OF INFORMATION CONTAINED IN ITS RESPONSES TO COMMISSION STAFF'S AND SIERRA CLUB'S FIRST SET OF DATA REQUESTS

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), pursuant to 807 KAR 5:001, Section 13, respectfully requests the Commission to classify and protect certain information provided by Duke Energy Kentucky in its Responses to Commission Staff (Staff)'s First Request for Information and Sierra Club (Sierra)'s First Request for Information both issued on October 1, 2021. The information that Duke Energy Kentucky seeks confidential treatment on generally includes: (1) information related to operations and management (O&M) costs, projected fuel and environmental compliance forecasted costs, forecasted power market prices, and projected capacity and resource alternative capital costs; (2) supply side screening curves and resource evaluations; and (3) third party owned and licensed modeling tools. The information which the Company is requesting to remain confidential includes the attachments to items 38, 39, and 41 of Staff's First Request for Information and the attachments to items 2 and 4 of Sierra's First Request for Information.

The public disclosure of the information described would place Duke Energy Kentucky at a commercial disadvantage as it manages its business in the wholesale power markets, negotiates contracts with various suppliers and vendors, and could potentially harm

Duke Energy Kentucky's competitive position in the marketplace, to the detriment of Duke Energy Kentucky and its customers. Moreover, to the extent the requested information is subject to licensing agreements, disclosure of the information would be in violation of such agreements and could put the Company in an adverse legal position to the detriment of its customers.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878 (1)(c). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the commercial information would permit an unfair advantage to competitors of that party. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The information regarding power production costs that Duke Energy Kentucky wishes to protect from public disclosure - including supply side screening curves, projected costs of fuel and various compliance and other O&M expenses, capital costs, power market prices, and projected capacity cost - as identified in the responses. This information was developed internally by Duke Energy Kentucky personnel, is not on file with any public agency, and is not available from any commercial or other source outside Duke Energy Kentucky. The aforementioned information is distributed within Duke Energy Kentucky only to those employees who must have access for business reasons. If publicly disclosed, this information setting forth Duke Energy Kentucky's costs of operation, strategies for managing its operations in the wholesale power markets, including projected prices, expected need for fuel and allowances and projected capacity could give competitors

an advantage in bidding for and securing new resources. Similarly, disclosure would afford an undue advantage to Duke Energy Kentucky's vendors and suppliers as they would enjoy an obvious advantage in any contractual negotiations to the extent they could calculate Duke Energy Kentucky's requirements, how it values certain resources, and what Duke Energy Kentucky anticipates those requirements to cost. Finally, public disclosure of this information, particularly as it relates to supply-side alternatives, would reveal the business model Duke Energy Kentucky uses - the procedure it follows and the factors and inputs it considers - in evaluating the economic viability of various generation related projects. Public disclosure would give Duke Energy Kentucky's contractors, vendors and competitor's access to Duke Energy Kentucky's cost and operational parameters, as well as insight into its contracting practices. Such access would impair Duke Energy Kentucky's ability to negotiate with prospective contractors and vendors and could harm Duke Energy Kentucky's competitive position in the power market, ultimately affecting the costs to serve customers.

3. Duke Energy Kentucky requests confidential protections for certain third-party data contained in its responses. Duke Energy Kentucky used certain confidential and proprietary data consisting of confidential information belonging to third parties who take reasonable steps to protect their confidential information, such as only releasing such information subject to confidentiality agreements. Duke Energy Kentucky used forecasts of various commodities and inputs such as power market data and fuel price forecasts (coal prices and gas prices) developed by independent third parties, ABB and IHS Markit, subject to confidentiality restrictions. Burns and McDonnell provided operating specifications and costs for potential future generating units, and Moody's Analytics provided economic forecasts, both subject to confidentiality agreements. Duke Energy Kentucky is contractually

bound to maintain such information confidential. Moreover, this information is deserving of protection to protect Duke Energy Kentucky's customers. If allowance brokers or equipment vendors knew Duke Energy Kentucky's forecasted emissions and fuel prices, by station or otherwise, such brokers or vendors would have an unfair advantage in negotiating future emission allowance or emission control equipment sales, to the detriment of Duke Energy Kentucky and its customers. Furthermore, if competitors of Duke Energy Kentucky knew such forecasts, they could have an advantage in competing for new business against Duke Energy Kentucky.

4. The information contained in its responses include various forecasts depicting the Company's view of power prices, facility operations, and fuel consumption respectfully. This information is considered proprietary to Duke Energy Kentucky and depicts its views of operations in the future. The Company would be placed at a competitive disadvantage if such information is released publicly as it would provide the competitors and potential counterparties and vendors for Duke Energy Kentucky with a competitive advantage that would prevent the Company from having the ability to manage its costs. It would also allow such counterparties and/or competitors to make decisions regarding pricing they otherwise would not have done, thereby making Duke Energy Kentucky and, in turn, its customers pay more than they otherwise would absent such information.

5. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, with the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

6. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally accepted as confidential or proprietary.'" *Hoy v. Kentucky Industrial Revitalization Authority*, Ky., 904 S.W.2d 766, 768 (Ky. 1995).

7. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and eleven copies without the confidential information included.

8. Duke Energy Kentucky respectfully requests that the Confidential Information be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

9. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc. respectfully requests the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

/s/Rocco D'Ascenzo
Rocco O. D'Ascenzo (92796)

Deputy General Counsel
Duke Energy Business Services LLC
139 East Fourth Street, 1303-Main
Cincinnati, Ohio 45202
Phone: (513) 287-4320
Fax: (513) 287-4385
E-mail: rocco.d'ascenzo@duke-energy.com
Counsel for Duke Energy Kentucky, Inc.

CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on October 22, 2021; and, that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

John G. Horne, II
The Office of the Attorney General
Utility Intervention and Rate Division
700 Capital Avenue, Ste 118
Frankfort, Kentucky 40601
John.Horne@ky.gov

Matthew E. Miller
Sierra Club
2528 California Street
Denver, CO 80205
matthew.miller@sierraclub.org

/s/Rocco D'Ascenzo
Rocco D'Ascenzo

VERIFICATION

STATE OF North Carolina)
) SS:
COUNTY OF Mecklenburg)

The undersigned, Adam Nygaard, Director Renewables Business Development, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Adam Nygaard
Adam Nygaard, Affiant

Subscribed and sworn to before me by Adam Nygaard, on this 22 day of October, 2021.

DONALD E MEGAHAN III
Notary Public
Mecklenburg Co., North Carolina
My Commission Expires June 19, 2024

NOTARY PUBLIC

My Commission Expires: 6-19-2024

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Alan Mok, Financial Market Manger - MW, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Alan Mok, Affiant

Subscribed and sworn to before me by Alan Mok on this 20th day of October, 2021.

NOTARY PUBLIC

AIDAN N ABBINANTE NOTARY My Commission Expires August 29th, 2025 PUBLIC MECKLENBURG COUNTY, NC

My Commission Expires: August 29th, 2025

VERIFICATION

STATE OF INDIANA)
) **SS:**
COUNTY OF HENDRICKS)

The undersigned, Andrew Taylor, Manager Products & Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Andrew Taylor, Affiant

Subscribed and sworn to before me by Andrew Taylor on this 18 day of October, 2021.

SEAL
NOTARY PUBLIC, STATE OF INDIANA
HENDRICKS COUNTY
JOHN DELOUGHERY
COMMISSION NUMBER 678735
MY COMMISSION EXPIRES MARCH 13, 2024

NOTARY PUBLIC

My Commission Expires: 3/13/24

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Benjamin Passty, Lead Load Forecasting Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Benjamin WB Passty
Benjamin Passty Affiant

Subscribed and sworn to before me by Benjamin Passty on this 8th day of October, 2021.

DEBORAH STROUD
Notary Public - North Carolina
Iredell County
My Commission Expires Aug 23, 2026

Deborah Stroud
NOTARY PUBLIC

My Commission Expires: August 23 2026

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Brian Bak, Manager DSM Analytics, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Brian Bak, Affiant

Subscribed and sworn to before me by Brian Bak, on this 21st day of Oct., 2021.

NOTARY PUBLIC

My Commission Expires:

ANDREW J. DUMOND
NOTARY PUBLIC, STATE OF OHIO
HAMILTON COUNTY
My Commission Expires 7/16/2022

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, Bruce L. Sailers, Manager Rates & Regulatory Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Bruce L. Sailers, Affiant

Subscribed and sworn to before me by Bruce L. Sailers, on this 13th day of October, 2021.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC
STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF ~~OHIO~~ Kentucky)

) **SS:**

COUNTY OF ~~HAMILTON~~ Boone)

The undersigned, Derek Picklesimer, Sr. Environmental Specialist, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Derek Picklesimer, Affiant

Subscribed and sworn to before me by Derek Picklesimer, on this 18th day of October, 2021.

NOTARY PUBLIC

Kim Angel

KYNP4993

My Commission Expires:

April 5, 2024

KIM ANGEL
COMM. EXP. 04/05/24
NOTARY PUBLIC
COMM #: KYNP4993
STATE AT LARGE, KENTUCKY

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Donald E. Broadhurst, Regional SVP Customer Delivery, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Donald E. Broadhurst, Affiant

Subscribed and sworn to before me by Donald E. Broadhurst, on this 21st day of October, 2021.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John D. Swez, Managing Director, Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 6 day of October, 2021.

Mary B Vicknair

NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, J. Michael Geers, Manager Environmental Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

J. Michael Geers

J. Michael Geers, Affiant

Subscribed and sworn to before me by J. Michael Geers, on this 19th day of OCTOBER, 2021.

Ruth M. Loccisano

NOTARY PUBLIC

My Commission Expires: 06-18-2022

NOTARIAL SEAL STATE OF OHIO

RUTH M. LOCCISANO
Notary Public, State of Ohio
My Commission Expires 06-18-2022

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF ~~MECKLENBURG~~ SL)
Lincoln

The undersigned, Scott Park, Director IRP & Analytics-Midwest, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Scott Park, Affiant

Subscribed and sworn to before me by Scott Park on this 11 day of October 2021.

Sheila Lemoine
NOTARY PUBLIC

Sheila Lemoine
Notary Public
Lincoln County
North Carolina
My Commission Expires 7/21/2024

My Commission Expires:

July 21, 2024

G.S. § 10B-41 NOTARIAL CERTIFICATE FOR ACKNOWLEDGMENT

Lincoln County, North Carolina

I certify that the following person(s) personally appeared before me this day, each acknowledging to me that he or she signed the foregoing document: Tim Duff

Date: October 11, 2021

Sheila Lemoine
Notary Public
Lincoln County
North Carolina
My Commission Expires 7/21/2024

Sheila Lemoine

Official Signature of Notary

Sheila Lemoine, Notary Public

My commission expires: July 21, 2024

I signed this notarial certificate on October 11, 2021 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Lincoln County
Stated physical location of principal during video notarization: Mecklenburg County

This certificate is attached to a Verification signed by Scott Park on October 11, 2021.

To VERIFICATION

STATE OF NORTH CAROLINA)
) SS:
COUNTY OF ~~MECKLENBURG~~)
Lincoln

The undersigned, Tim Duff, GM Grid Strategy Enablement, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Tim Duff, Affiant

Subscribed and sworn to before me by Tim Duff on this 7th day of Octo 2021.

Sheila Lemoine
NOTARY PUBLIC

Sheila Lemoine
Notary Public
Lincoln County
North Carolina
My Commission Expires 7/21/2024

My Commission Expires:
July 21, 2024

G.S. § 10B-41 NOTARIAL CERTIFICATE
FOR ACKNOWLEDGMENT

Lincoln County, North Carolina

I certify that the following person(s) personally appeared before me this day, each acknowledging to me that he or she signed the foregoing document: Tim Duff

Date: October 7, 2021

Sheila Lemoine

Official Signature of Notary

Sheila Lemoine
Notary Public
Lincoln County
North Carolina
My Commission Expires 7/21/2024

Sheila Lemoine, Notary Public

My commission expires: July 21, 2024

I signed this notarial certificate on October 7, 2021 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Lincoln County
Stated physical location of principal during video notarization: Union County

This certificate is attached to a Verification signed by Tim Duff on October 7, 2021.

VERIFICATION

STATE OF INDIANA)
) **SS:**
COUNTY OF)

The undersigned, Timothy Hohenstatt, Director Transmission Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Timothy Hohenstatt, Affiant

Subscribed and sworn to before me by Timothy Hohenstatt, on this 20TH day of OCTOBER, 2021.

PAULA MCGOWAN ROSEMAN
Seal
Notary Public – State of Indiana
Hendricks County
My Commission Expires Mar 17, 2025

NOTARY PUBLIC

My Commission Expires: 3-17-25

VERIFICATION

STATE OF OHIO)
) SS:
COUNTY OF HAMILTON)

The undersigned, Tony Platz, Manager Asset Management, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Tony Platz, Affiant

Subscribed and sworn to before me by Tony Platz, on this 20th day of October, 2021.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF OHIO	)	
	)	SS:
COUNTY OF HAMILTON	)	

The undersigned, Trisha Haemmerle, Senior Strategy & Collaboration Manager, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Trisha Haemmerle, Affiant

Subscribed and sworn to before me by Trisha Haemmerle on this 19th day of October, 2021.

E. Minna Rolfes

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

KyPSC Case No. 2021-00245
TABLE OF CONTENTS

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-001

REQUEST:

Refer to the Integrated Resource Plan (IRP), Section 1, page 5. Duke Kentucky states that it must anticipate the potential for changes in environmental policy. Explain whether the modeling used for this IRP includes Duke Energy's environmental initiatives. If so, explain how the initiative were factored into the modeling.

RESPONSE:

Modeling for this IRP did not include any Duke Energy-specific environmental initiatives. The phrase "potential changes in environmental policy" refers to regulatory changes with which the company would be obliged to comply. In this IRP, the policy change that was modeled was a federally-imposed price on carbon emissions beginning in 2025, which was included in several IRP scenarios.

PERSON RESPONSIBLE: Scott Park

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-002

REQUEST:

Refer to the IRP, Section 1, page 6, Figure 1.4. Explain the drivers of the negative one percent rate impact predicted for 2022 under the 2021 IRP portfolio.

RESPONSE:

The primary driver of the predicted negative one percent rate impact predicted for 2022 under the 2021 IRP portfolio is the fact that projected retail sales volume in MWh increases faster than total retail revenue requirement in dollars, leading to a decline in the projected per unit cost of energy in $/MWh.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-003

REQUEST:

Refer to the IRP, Section 1, pages 7-8. Explain which project Duke Kentucky is developing that will add value to the system and community.

RESPONSE:

This is an overarching objective that as part of the CPCN process, the company will develop projects that add value to the system and community.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-004

REQUEST:

Refer to the IRP, Section 1, page 8. Discuss the PJM zone separation history.

RESPONSE:

Regarding the PJM Base Residual Auction (BRA) results, there have been two years that the DEOK zone cleared higher in the Reliability Pricing Model (RPM) BRA auction than the "Rest of RTO":

- In the 2020/2021 BRA, the DEOK zone separated, clearing at $130/MW-Day while the Rest of RTO cleared at $76.53/MW-Day.
- In the 2022/2023 BRA, the DEOK zone separated, clearing at $71.69/MW-Day while Rest of RTO cleared at $50/MW-Day.

Beginning with the 2020/2021 capacity auction, PJM imposed a Minimum Internal Resource Requirement for the FRR load obligation for the Company's FRR plan. A minimum percentage of resources that are committed in Company's FRR plan must be inside the DEOK zone. The percentages are as follows:

Delivery Year	Minimum Internal Resource Requirement
2020/2021	41.7%
2021/2022	44.7%
2022/2023	33.9%
2023/2024	32.6%

PERSON RESPONSIBLE: John Swez

STAFF-DR-01-005

REQUEST:

Refer to the IRP, Section 2B, page 9.

a. Explain whether Duke Kentucky's current PJM reserve margin is 8.7 percent (UCAP). If not, provide Duke Kentucky's current reserve margin requirement, and explain the rationale for setting an 8.7 percent minimum reserve margin for this IRP's modeling.

b. Explain how increasing levels of renewable penetration throughout the PJM region might affect future reserve margin requirements.

c. If increasing levels of renewable penetration generally affects the PJM reserve margin requirements, explain whether this is accounted for in the modeling or if the 8.7 percent reserve was persistent throughout the model years.

RESPONSE:

a. The IRP just assumed that the most recent reserve margin requirement from PJM is a reasonable estimate of the future reserve margin requirement but understand that it is subject to change.

b. Rather than changing future reserve margin requirements, increasing levels of renewable penetration in PJM are more likely to decrease the capacity value (contribution to peak) of future wind or solar resources. The actual impacts are difficult to predict, and will depend on, among other factors, the amount and locations of each resource type added, evolution of renewable energy technology, deployment of energy storage resources, and so on.

In PJM's 2020 Reserve Requirement Study (RRS) (see link below), which sets PJM's pool wide capacity reserve margin level, PJM began to use the Effective Load Carrying Capability (ELCC) study to address the capacity accreditation of the renewable resources. PJM states that this change has a negligible impact on the Forecasted Pool Requirement (FPR) which is the parameter used to calculate the Reliability Requirement (and the demand curve) for the RTO in RPM (see link below). Capacity resources compete to meet this reliability requirement using the UCAP values from the ELCC study (for renewable resources) and the UCAP values calculated using GADS data (non-ELCC, traditional resources). Note that ELCC is a supply side issue, not a demand side issue.

https://www.pjm.com/-/media/committees-groups/committees/mc/2020/20201119/20201119-cac-2-2020-installed-reserve-margin-study-results-report.ashx

https://insidelines.pjm.com/capacity-reserve-needs-shrink-with-increased-generator-efficiency/

c. As discussed in the response to 5(b), the Company does not expect the 8.7% reserve margin requirement to change as a result of additional renewable energy deployment.

PERSON RESPONSIBLE: Scott Park – a., b., c.
John Swez – b.

STAFF-DR-01-006

REQUEST:

Refer to the IRP, Section 2, pages 13-14. Explain how Duke Kentucky balanced its evaluation of the near term cost of the 12 portfolios against the longer terms costs and how much emphasis Duke Kentucky put on the near term costs versus the longer term costs in the selection of the 2021 IRP portfolio.

RESPONSE:

A near term rate impact view and a longer term PVRR analysis are both important metrics. The long term PVRR sets a strategic direction and it should be kept in mind that a long term PVRR is predicated on not only fuel and power market forecasts being perfectly accurate as well as the resource mix evolving exactly as prescribed. Solving to minimize PVRR helps a strategic direction and it should recognize that external factors will change and that a portfolio that is adaptable is preferred. The forecasted rate impact has value in that it is what customers will experience as well as the variability is less than the long term PVRR analysis. In summary, long term PVRR sets a direction while the rate impact gives insight of a specific path.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-007

REQUEST:

Refer to the IRP, Section 3B Power Prices, pages 20-29.

a. For any of the expansion plans, explain whether Duke Kentucky is aware of any known or anticipated nuclear generation unit retirements in the PJM region.

b. Explain whether the Encompass model was allowed to add new nuclear generation capacity. If so, explain whether it is realistic to make such assumptions.

c. Explain whether the existing nuclear capacity is capable of producing the forecast generation.

RESPONSE:

a. Please see STAFF-DR-01-007(a) Attachment. According to the PJM Independent Market Monitor (IMM) state of the Market Report for 2020:

   - As of 12-31-2020, of the 184,236.8 MW of RPM installed capacity, nuclear generation in PJM was 32,285.4 MW, or 17.5% (Table 5-3, page 286).
   - There are 1,786.5 MW of planned Nuclear unit retirements in PJM starting in January 2021 and later (Table 12-6, page 581).
   - As of December 31, 2020, there are 4,163.9 MW of generation that have requested retirement after December 31, 2020, of which 1,794.5 MW (43.1 percent) are located in the ComEd Zone. Of the generation requesting retirement in the ComEd Zone, 1,786.5 MW (99.6 percent) are nuclear units (page 68 and page 569).

- Finally, it should be noted that nuclear unit retirements are fluid and subject to change.

https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol2.pdf

b. New nuclear generation was included as an option for selection by the EnCompass model. This included both conventional nuclear technology and emerging small, modular reactor (SMR) technology. While the inclusion of these resources as potential options for model selection is reasonable, their failure to be selected (with the exception of one SMR unit, selected in 2035 in the scenario with both high gas prices and a price on carbon emissions) indicates that they are not economic options for Duke Energy Kentucky customers at this time. Please see IRP Chapter 4 and confidential Appendix E for additional details on screening of supply-side resource options.

c. Duke Energy Kentucky does not have existing nuclear capacity.

PERSON RESPONSIBLE: John Swez – a.
Scott Park – b., c.

Plant	Area	Units	Commissioned	Planned Retirement Date
Oyster Creek:1	PJM-EMAAC	1	12/1/1969	9/17/2018
Three Mile Island:1	PJM-EPA	1	8/1/1974	9/20/2019
Dresden Generating Station:2	PJM-COMED	1	6/1/1970	11/1/2021
Dresden Generating Station:3	PJM-COMED	1	11/1/1971	11/1/2021
Perry:1	PJM-ATSI	1	11/1/1987	3/18/2026
Quad Cities Generating Station:1 (PJM-COMED)	PJM-COMED	1	12/1/1972	12/14/2032
Quad Cities Generating Station:2 (PJM-COMED)	PJM-COMED	1	12/1/1972	12/14/2032
Calvert Cliffs Nuclear Power Plant:1	PJM-SWMAAC	1	5/1/1975	7/31/2034
Donald C Cook:1	PJM-AD	1	8/1/1975	10/25/2034
Beaver Valley:1	PJM-AD	1	9/1/1976	1/29/2036
Calvert Cliffs Nuclear Power Plant:2	PJM-SWMAAC	1	4/1/1977	8/13/2036
PSEG Salem Generating Station:1	PJM-EMAAC	1	6/1/1977	8/13/2036
Davis Besse:1	PJM-ATSI	1	11/1/1977	4/22/2037
Donald C Cook:2	PJM-AD	1	7/1/1978	12/23/2037
PSEG Salem Generating Station:2	PJM-EMAAC	1	10/1/1981	4/18/2040
LaSalle Generating Station:1	PJM-COMED	1	8/1/1982	4/17/2042
TalenEnergy Susquehanna:1	PJM-EPA	1	6/1/1983	7/17/2042
LaSalle Generating Station:2	PJM-COMED	1	4/1/1984	12/16/2043
TalenEnergy Susquehanna:2	PJM-EPA	1	2/1/1985	3/23/2044
Limerick:1	PJM-EMAAC	1	2/1/1986	10/26/2044
Byron Generating Station:1	PJM-COMED	1	9/1/1985	10/31/2044
PSEG Hope Creek Generating Station:1	PJM-EMAAC	1	12/1/1986	4/11/2046
Braidwood Generation Station:1	PJM-COMED	1	7/1/1988	10/17/2046
Byron Generating Station:2	PJM-COMED	1	8/1/1987	11/6/2046
Beaver Valley:2	PJM-AD	1	11/1/1987	5/27/2047

Braidwood Generation Station:2	PJM-COMED	1	10/1/1988	12/18/2047
Limerick:2	PJM-EMAAC	1	1/1/1990	6/22/2049
Surry:1	PJM-DOM	1	12/1/1972	5/25/2052
Surry:2	PJM-DOM	1	5/1/1973	1/29/2053
Peach Bottom:2	PJM-EMAAC	1	7/1/1974	8/8/2053
Peach Bottom:3	PJM-EMAAC	1	12/1/1974	7/2/2054
North Anna:1	PJM-DOM	1	6/1/1978	4/1/2058
North Anna:2	PJM-DOM	1	12/1/1980	8/21/2060

STAFF-DR-01-008

REQUEST:

Refer to the IRP, Section 3C, page 30.

a. Explain the basis for Duke Kentucky setting the carbon pricing at $5/ton beginning in 2025. If legislative initiatives influenced Duke Kentucky's carbon pricing, provide citations to the legislation.

b. For select scenarios, the carbon price of $5/ton begins in 2025 and increases $5/ton/year. Explain whether the scenarios with carbon regulation have the carbon price increasing at this rate over the entire forecast period such that by 2035 the price of carbon would be $55/ton.

RESPONSE:

a. The carbon tax assumption is used to reflect the impact of various policies that are being discussed, recognizing that the actual carbon regulation itself could be very different in form.

b. This is correct. The price of carbon in select scenarios begins at $5/ton and increases at $5/ton/year throughout the period, reaching $55/ton by 2035.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-009

REQUEST:

Refer to the IRP, Section 3D, page 31, Figure 3.8 – PJM Power Prices.

a. Provide the units for the axis – Average of Power Price.

b. Explain the meaning of NCL in the scenario titles.

RESPONSE:

a. The unit for the y-axis of the chart in Figure 3.8 is $/MWh.

b. NCL in the scenario titles stand for "No Carbon Law" and it indicates that these scenarios do not include regulation imposing a price on carbon emissions.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-010

REQUEST:

Refer to the IRP, Section 4A, page 34. Explain whether the selection of fractional unit indicates a partial ownership or partnership in a full unit. If so, explain whether Duke Kentucky assumes that a partnership is guaranteed for the purposes of modeling.

RESPONSE:

The selection of fractional units in IRP modeling is useful for identifying the optimal type and timing of new resource additions with additional granularity for the purposes of IRP analysis. This analysis includes no explicit assumptions regarding future partnerships or ownership structures for fractional units.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-011

REQUEST:

Refer to the IRP, Section 4A, Figure 4.1, page 35.

a. Explain whether the capacity factors listed for solar and wind are specific to Kentucky.

b. Explain why summer capacity and not winter capacity or both were not modeled.

c. Explain whether the solar PV listed in the table is utilized by the Encompass model with the presumption that Duke Kentucky will own and build the generation.

d. Explain whether the possibility of utilizing a solar power purchase agreement arrangement in the modeling. If not, explain why not.

e. Explain why only 4-hour lithium batteries were modeled and whether there are lithium ion batteries being installed that are greater than 10 MW or with a capability beyond four hours.

f. Explain and list the multiple ways in which battery storage was utilized in the Encompass modeling.

g. Refer also to Figure 6.5, page 53. Figure 4.1 lists a combined cycle gas turbine 2X1 unit (CC) at 1,157 MW summer capacity. Figure 6.5 lists only 45 MW being added in 2027. Explain how only 45 MW of CC capacity can be added.

RESPONSE:

a. Yes, they are specific to Kentucky.

b. We have summer and winter modeled. Reserve margin is applied in all months. Solar does not receive any contribution to peak in the winter. Wind gets the same contribution to peak in winter as it does in summer.

c. Yes, we have the model setup to assume that the PV will be built and owned by Duke Energy Kentucky.

d. In order to ensure apples-to-apples comparison of future resource options, all resources were assumed to be utility-owned for IRP modeling purposes. Actual ownership and/or contract specifics would be determined at the time of resource procurement.

e. As of today, four hour batteries are the best resource for storage when one considers the requirements of PJM as well as the cost of the batteries themselves. Longer duration batteries come with greater expense and in general, the current environment doesn't warrant longer duration storage.

f. The EnCompass model is setup to allow Duke Energy Kentucky to build and own its own standalone battery sites. The dispatch for these batteries are optimized by the model.

g. In the lower table of Figure 6.5, the rows for solar and CC are swapped. For resource selection purposes, the company allows for the selection of fractional shares of units as it better identifies what the system needs. Given the size of the utility, this is particularly important. At the CPCN process, the transactability of fractional ownership will be evaluated based on the needs of the utility at that time as well as the needs of neighboring utilities.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-012

REQUEST:

Refer to the IRP, Section 4B, pages 36-37, and Section 6B, Figures 6.1 and 6.2, pages 44 and 46.

a. Confirm that the only assumptions Duke Kentucky changed in the various scenarios is carbon pricing and the price of natural gas. If not, explain what other assumptions were changed from one scenario to the other.

b. Page 36 lists the Woodsdale station units at 462 MW, and Figures 6.1 and 6.2 list Woodsdale at 564 MW. Reconcile the difference.

c. On page 36, solar generation is listed at 6.8 MW for installed capacity, but is not included in the unforced capacity figures because it is connected at the distribution level. Figures 6.1 and 6.2 do not list the existing 6.8 MW of solar capacity and only show solar additions. Explain the discrepancy.

d. Refer to Figure 6.1. Explain whether Duke Kentucky is building and owning the wind generation or acquiring the capacity through a power purchase agreement.

e. Refer to Figure 6.1. Explain the meaning of SMR.

f. The title of Figure 6.2 indicates that the results assume no carbon regulation. However, the data in the tables reference that there is carbon regulation. Explain the discrepancy.

g. Refer to Figure 4.1, page 35. Solar capacity is cost modeled at 50 percent of nameplate capacity. Explain whether the solar capacity listed in Figures 6.1 and 6.2 represents nameplate capacity or 50 percent of nameplate capacity.

RESPONSE:

a. Yes, carbon regulation and gas prices were the only variables changed in the scenario analysis. This was done due to both factors having the greatest impact on the selection of resources.

b. Woodsdale Station has a summer capacity of 462 MW (page 36) and a winter capacity of 564 MW (Figures 6.1 and 6.2).

c. Resources at the distribution level are below the threshold of PJM capacity construct and as such are not put in the resource category but are reflected as a reduction in load.

d. All resources are modeled as utility-owned assets for the purposes of the IRP analysis. Actual ownership specifics would be determined at the time of resource procurement.

e. SMR stands for "small, modular reactor," an emerging nuclear energy technology with enhanced cost, safety, and operational flexibility characteristics.

f. The table headings in Figure 6.2 should read, or order of appearance, "Ref w/o CO2 (High Gas)," "Ref w/o CO2 (Base Gas)," "Ref w/o CO2 (Low Gas)."

g. Solar capacity listed in Figures 6.1 and 6.2 is expressed in nameplate MW.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-013

REQUEST:

Refer to the IRP, Section 4B, Figure 4.2 page 37.

a. Explain whether the 44.08 percent of total energy purchases represents the sum of hourly market purchases that are more economical that what can be generated by Duke Kentucky's existing generation portfolio. If not, explain the nature of the purchases.

b. Explain whether the level of energy purchases is expected to continue over the IRP forecast period. If so, at what annual levels?

RESPONSE:

a. 44.08% of energy delivered to Duke Energy Kentucky customers in 2020 was purchased on the PJM market. Energy may be purchased for a variety of economic and technical reasons subject to constantly changing conditions.

b. Please see IRP Figure 6.8 for projected energy market purchases for each potential portfolio over the planning period.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-014

REQUEST:

Refer to the IRP, Section 5, pages 39-41. Provide a table showing anticipated demand-side management (DSM) participation customer counts throughout the IRP planning period. Also provide the participation broken down by program.

RESPONSE:

The Company does not forecast participation in our DSM programs on the basis of individual customers but rather the number of units of each DSM measures. For example, in the case of a lighting measure, a single customer account could have multiple units installed at one location. Accordingly, the Company does not possess the necessary data to answer this specific question.

PERSON RESPONSIBLE: Brian Bak

STAFF-DR-01-015

REQUEST:

Refer to the IRP Section 6B, Figures 6.1-6.5, pages 44-53.

a. Explain whether the capacity positions listed in the various scenarios represent summer capacity values.

b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity projections.

RESPONSE:

a. The capacity values listed in Figures 6.1 - 6.5 represent winter capacity values for fossil units and nameplate capacity values for renewable energy units.

b. Please see STAFF-DR-01-015(b) Attachment.

PERSON RESPONSIBLE: Scott Park

15. Refer to the IRP, Section 6B, Figures 6.1–6.5, pages 44–53.
b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity

Demand Forecast	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898

Ref w/ CO2 (High Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar									5	55	105	155	205	225	250
Wind											35	85	135	185	235
CT															232
CC														121	121
SMR															114
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1169	1219	1304	1404	1504	1695	1516
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	36%	40%	49%	60%	70%	90%	69%

Ref w/ CO2 (Base Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar					5	5	45	50	55	80	90	110	160	175	185
CC							484	484	484	484	484	484	484	484	605
TOTAL	1164	1164	1164	1164	1169	1169	1093	1098	1103	1128	1138	1158	1208	1223	1354
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	28%	28%	28%	30%	30%	32%	37%	37%	51%

Ref w/ CO2 (Low Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	0	0	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar														20	70
CT					580	580	580	580	580	580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1144	1144	1144	1144	1144	1144	1144	1144	1144	1164	1214
Reserve Margin (ICAP)	43%	42%	39%	39%	34%	34%	34%	33%	33%	31%	31%	30%	29%	31%	35%

Figure 6.1: Optimized Portfolios for Scenarios with Carbon Regulation

ENERGY. KENTUCKY

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

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

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

15. Refer to the IRP, Section 6B, Figures 6.1–6.5, pages 44–53.

b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity

Demand Forecast	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898

Ref No CO2 (High Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar											20	70	120	170	180
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1184	1234	1284	1334	1344
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	34%	36%	40%	45%	50%	50%

Ref No CO2 (Base Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	34%	33%	32%	32%	31%	30%

Ref No CO2 (Low Gas)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	0	0	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT					580	580	580	580	580	580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144	1144
Reserve Margin (ICAP)	43%	42%	39%	39%	34%	34%	34%	33%	33%	31%	31%	30%	29%	29%	27%

Figure 6.2: Optimized Portfolios for Scenarios without Carbon Regulation

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

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

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

15. Refer to the IRP, Section 6B, Figures 6.1–6.5, pages 44–53.
b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity

Demand Forecast	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898

Transitional A	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
FDR															605
Solar	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150
Battery	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30
Wind				40	50	60	70	80	90	100	110	120	130	140	150
TOTAL	1176	1188	1200	1252	1274	1296	1318	1340	1362	1384	1406	1428	1450	1472	1499
Reserve Margin (ICAP)	44%	45%	44%	49%	50%	52%	54%	56%	58%	59%	61%	62%	64%	65%	67%

Transitional B	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
FDR															363
Solar	25	55	85	125	165	205	235	265	295	325	350	380	415	450	500
Battery	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30
Wind				65	105	145	180	215	250	285	315	350	390	430	470
TOTAL	1191	1223	1255	1362	1444	1526	1593	1660	1727	1794	1851	1918	1995	2072	1927
Reserve Margin (ICAP)	46%	49%	50%	62%	70%	79%	86%	94%	101%	106%	112%	118%	125%	133%	115%

Figure 6.3: Transitional Portfolios

TRANSITIONAL A	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
FDR															605
Solar	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150
Battery	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30
Wind				40	50	60	70	80	90	100	110	120	130	140	150
TOTAL	1176	1188	1200	1252	1274	1296	1318	1340	1362	1384	1406	1428	1450	1472	1499

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

15. Refer to the IRP, Section 6B, Figures 6.1–6.5, pages 44–53.
b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity

Demand Forecast	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898

EB2 Gas Conversion	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
EB2 Gas Conversion										600	600	600	600	600	600
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1214	1264	1314	1349
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	34%	33%	38%	43%	48%	50%

EB2 Retire / CC replacer	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
CC										611	611	611	611	611	611
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1175	1175	1225	1275	1325	1360
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	35%	35%	39%	44%	49%	51%

EB2 Retire / CT replacer	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar												50	100	150	185
CT										580	580	580	580	580	580
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1144	1144	1194	1244	1294	1329
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	31%	31%	36%	41%	45%	48%

EB2 Retire / Ren replace	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar			40	140	240	340	440	540	640	740	840	940	1040	1140	1240
CT										232	232	232	232	232	232
Battery										150	150	150	150	150	150
Wind				45	95	145	195	245	295	345	345	345	345	345	345
TOTAL	1164	1164	1204	1349	1499	1649	1799	1949	2099	2031	2131	2231	2331	2431	2531
Reserve Margin (ICAP)	43%	42%	44%	61%	76%	93%	111%	127%	144%	133%	144%	154%	163%	173%	182%

Figure 6.4: East Bend 2 Replacement Portfolios

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

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

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

DUKE ENERGY. KENTUCKY

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

15. Refer to the IRP, Section 6B, Figures 6.1–6.5, pages 44–53.

b. Update the Figures to show the demand and reserve margins that corresponds to the annual forecasted capacity projections.

Demand Forecast	815	822	836	840	851	853	854	857	860	870	874	879	885	890	898

Low Cost Renewables (No CO2 Reg)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	36%	36%	35%	34%	33%	32%	32%	31%	30%

Low Cost Renewables (w/ CO2 Reg)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
East Bend 2	600	600	600	600	600	600	0	0	0	0	0	0	0	0	0
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar							45	50	55	80	130	180	215	235	255
CC							484	484	484	484	484	484	484	484	484
TOTAL	1164	1164	1164	1164	1164	1164	1093	1098	1103	1128	1178	1228	1263	1283	1303
Reserve Margin (ICAP)	43%	42%	39%	39%	37%	37%	28%	28%	28%	30%	35%	40%	43%	44%	45%

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

Low Cost Renewables in Reference w/No CO_2 Reg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Bend 2	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164	1164

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

STAFF-DR-01-016

REQUEST:

Refer to the IRP, Section 6C, Figures 6.3-6.4, pages 48 and 51.

a. Explain the type of resource FDR represents in Figure 6.3 and how it was priced.

b. Provide a more thorough explanation of what assumptions were changed from what level to achieve the various results in Figures 6.3 and 6.4.

c. Identify which scenario results the portfolios in Figures 6.3 and 6.4 should be compared to. For example, should the portfolios be compared to Figure 6.2 base case or to some other portfolio.

RESPONSE:

a. While preserving the technology decision to a future date that is closer to a decision point, the FDR was modeled using the specs and costs of a Combine Cycle.

b. The portfolios in Figures 6.3 and 6.4 were not optimized for any one particular scenario and were derived a plausible other portfolios that would be worth evaluating, as such the only differences in assumptions for each of these portfolios are those detailed in the Figures themselves.

c. Please see IRP Figures 6.6 - 6.8 for portfolio comparisons. In this IRP, the term portfolio refers to the resources available to serve customers, while the term scenario refers to the economic, regulatory, technical and other factors that influence utility operations. A portfolio may be optimized for a given scenario (the Optimized Portfolios) or may be constructed to evaluate a specific resource decision or to perform well across a variety of potential future scenarios (the Alternate Portfolios). Regardless of how they are constructed, portfolio performance should always be evaluated under the same scenario if the results are to be comparable (for example, to determine which portfolio would be least cost under a scenario with high gas prices and no carbon regulation).

PERSON RESPONSIBLE: Scott Park

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-017

REQUEST:

Refer to the IRP, Section 6C, page 49. Provide amount the capacity factor of East Bend 2 would be reduced if it was converted to a gas burning facility.

RESPONSE:

Under a conversion to natural gas, the change in the units capacity factor would be dependent on the price of natural gas versus the cost of coal to the unit, plus changes to the units heat rate, variable O&M, and emissions rate. Since the changes in the unit heat rate, variable O&M, and emissions rate tend to be smaller in comparison to the larger relative change possible within natural gas markets, East Bend's change in capacity factor after conversion to natural gas is mostly tied to the cost of natural gas. With most scenarios envisioned where the price of natural gas would be higher than the cost of coal delivered to the unit, thus the statement was made in the IRP that "...variable costs of such a unit would be higher. This would reduce the capacity factor of the unit and cause Duke Energy Kentucky to become reliant on the market to supply its customers with energy."

PERSON RESPONSIBLE: John Swez

STAFF-DR-01-018

REQUEST:

Refer to the IRP, Section 6D, page 52.

a. Explain why it is over simplistic to conduct a single variable sensitivity analysis, and explain whether there is value in isolating a single variable's effects on a portfolio.

b. Explain Duke Kentucky's qualitative or quantitative rational for setting the capital cost reduction at 20 percent.

c. Provide a more thorough explanation (including the timing) of how more solar and wind generation enters the PJM market, the resources will have a depressive impact on the hourly PJM power prices which will have an effect on Duke Kentucky's renewable generation additions. Include in the explanation how the assumption of decreasing price of renewables over time differs from the costs represented in Figure 4.1 on page 35 and assumed in the other scenarios.

RESPONSE:

a. Single variable sensitivity analysis is overly simplistic because of the interconnectedness of a variety of market and operational factors. For instance, lower than expected costs for new renewable resources may lead to increased adoption of renewables across the PJM market, which could impact future hourly energy prices as well as the capacity value of incremental renewable energy additions, all of which could influence future Duke Energy Kentucky resource decisions. However, these correlations can be difficult to quantify and incorporating this complexity in the IRP sensitivity analysis could pose a substantial challenge. Evaluating the impact of changing a single variable like the cost of new renewable energy resources can provide insight into the sensitivity of modeling results to changes in that input assumption.

b. It is believed that 20% is a plausible and meaningful sensitivity to represent a reasonable technological innovation and also result in a meaningful change in the resource plans.

c. It is agreed that in general, holding all else constant, as renewable energy resources such as solar and wind generation enter the PJM market that these resources have a depressive impact on the hourly PJM power prices. This is due to the fact that these resources tend to have very low (and in some cases negative) variable cost offers since they have no fuel costs, low variable O&M, no emissions cost, and produce renewable energy credits (REC). Thus, depending on how the market participant considers the value of these REC's in the units offer, the unit could even be offered with a negative offer price. However, energy markets are a combination of many factors, including customer demand, generating unit additions and retirements, commodity prices, and availability of generators, so this relationship may not be as precise as one would imagine.

PERSON RESPONSIBLE: Scott Park – a., b., c.
John Swez – c.

STAFF-DR-01-019

REQUEST:

Refer to the IRP, Section 6E, pages 55 and 56.

a. Given how close Present Value Revenue Requirements (PVRR) are for the portfolios plotted in Figure 6.6, provide a chart that shows the numerical values.

b. Explain whether a similar analysis was performed with the Low, High, and Base Gas Price cases.

RESPONSE:

a. Please see STAFF-DR-01-019(a) Attachment.

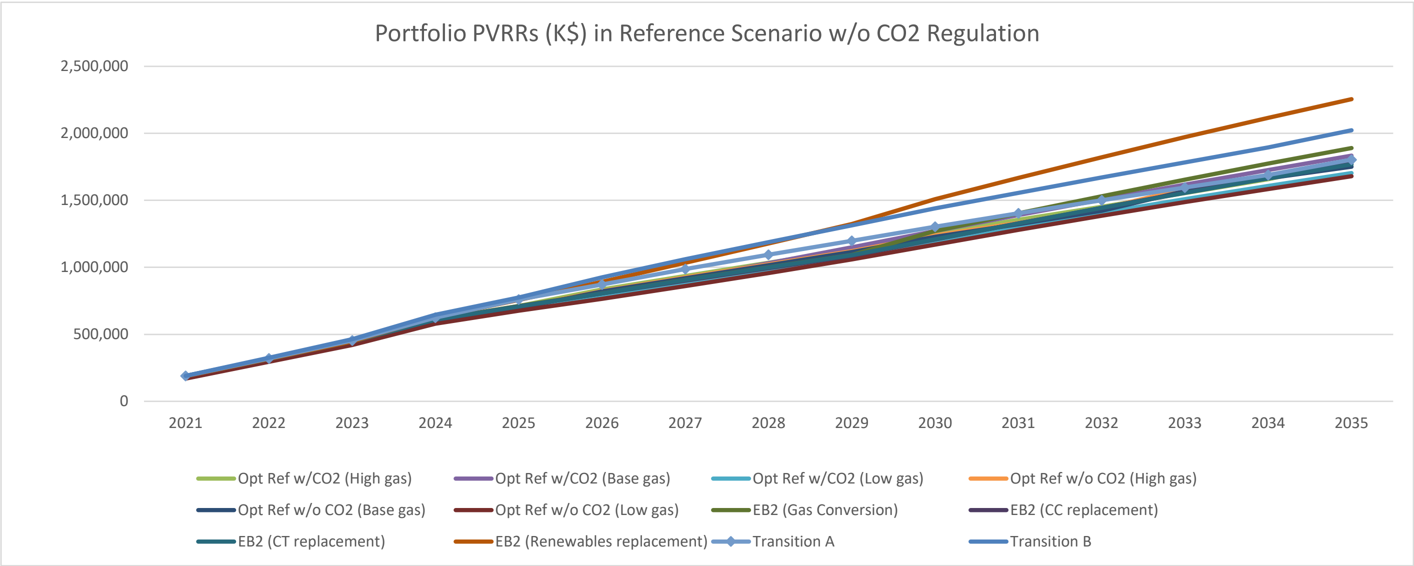
b. This analysis assumed the base gas forecast; high and low cases for this sensitivity were not performed. In general, high gas prices improve the economics of renewables whereas low gas prices have the opposite effect.

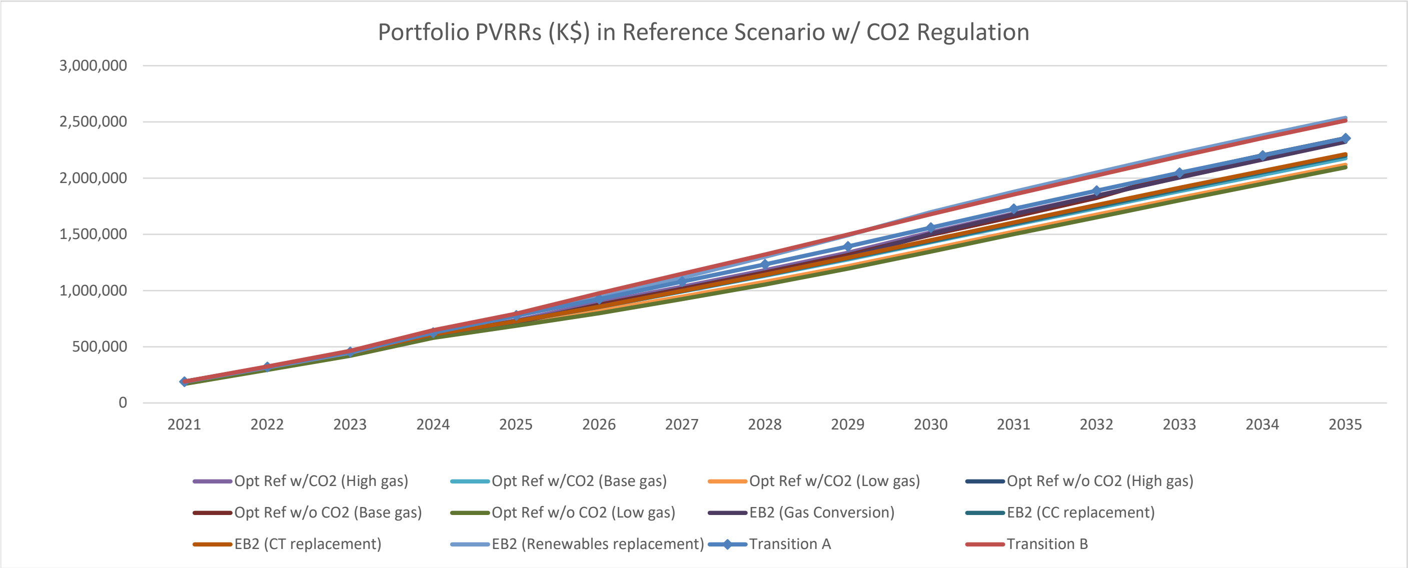
PERSON RESPONSIBLE: Scott Park

Ref w/o CO2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Opt Ref w/CO2 (High gas)	188,366	313,852	443,629	606,980	711,697	835,800	936,330	1,034,906	1,134,243	1,253,709	1,354,692	1,452,253	1,553,816	1,658,233	1,789,662	
Opt Ref w/CO2 (Base gas)	188,317	315,323	444,567	602,770	702,533	800,309	915,191	1,030,864	1,149,177	1,271,360	1,390,813	1,505,120	1,618,201	1,726,588	1,833,695	
Opt Ref w/CO2 (Low gas)	189,482	319,108	444,275	601,767	699,320	788,446	883,735	979,825	1,081,988	1,191,850	1,301,957	1,407,469	1,509,697	1,607,874	1,703,774	
Opt Ref w/o CO2 (High gas)	172,954	300,525	430,397	593,760	699,106	824,101	924,887	1,022,281	1,120,832	1,238,552	1,332,558	1,437,338	1,586,411	1,686,445	1,778,036	
Opt Ref w/o CO2 (Base gas)	172,312	298,926	429,646	592,304	696,787	820,362	919,605	1,015,794	1,114,350	1,228,786	1,321,652	1,422,359	1,568,384	1,663,894	1,751,013	
Opt Ref w/o CO2 (Low gas)	169,784	294,537	420,659	579,050	676,623	765,844	861,149	957,173	1,059,486	1,169,346	1,279,461	1,384,903	1,487,254	1,584,966	1,680,129	
EB2 (Gas Conversion)	188,829	318,454	448,047	611,504	711,444	807,526	906,784	1,001,262	1,093,322	1,271,476	1,403,734	1,530,379	1,654,961	1,774,508	1,890,380	
EB2 (CC replacement)	189,370	317,328	449,274	607,921	708,332	805,103	901,138	994,689	1,085,972	1,207,302	1,327,719	1,444,485	1,559,897	1,671,524	1,779,044	
EB2 (CT replacement)	189,014	316,080	447,031	609,313	708,639	805,741	904,932	998,845	1,091,068	1,210,439	1,328,862	1,443,271	1,555,554	1,663,717	1,768,941	
EB2 (Renewables replacement)	188,161	316,559	446,744	628,474	757,484	892,412	1,034,469	1,177,986	1,323,307	1,508,292	1,668,076	1,821,796	1,971,537	2,115,632	2,255,204	
Transition A	190,100	320,788	454,139	624,960	760,442	872,823	987,336	1,093,659	1,198,279	1,303,882	1,403,523	1,501,029	1,596,058	1,689,009	1,803,902	
Transition B	190,009	325,660	463,843	645,841	775,781	925,961	1,060,217	1,187,687	1,313,679	1,440,714	1,555,843	1,670,451	1,783,106	1,894,784	2,023,062	

Ref w/CO2																
Opt Ref w/CO2 (High gas)	188,488	315,927	447,177	612,635	734,832	891,355	1,033,733	1,180,122	1,336,523	1,518,064	1,684,991	1,844,485	2,007,318	2,169,003	2,328,472	
Opt Ref w/CO2 (Base gas)	190,029	317,592	448,743	606,947	725,794	856,218	990,752	1,130,420	1,276,652	1,429,777	1,583,189	1,733,200	1,883,183	2,029,525	2,176,591	
Opt Ref w/CO2 (Low gas)	189,482	319,108	444,275	601,767	709,662	821,488	945,855	1,076,574	1,217,374	1,368,675	1,523,096	1,674,114	1,824,791	1,971,602	2,118,102	
Opt Ref w/o CO2 (High gas)	172,954	300,525	430,397	593,760	715,892	873,131	1,015,784	1,161,567	1,317,188	1,497,130	1,659,234	1,827,588	2,041,479	2,202,083	2,354,913	
Opt Ref w/o CO2 (Base gas)	172,312	298,926	429,646	592,304	714,448	871,234	1,013,481	1,159,253	1,314,793	1,494,624	1,656,666	1,824,881	2,038,852	2,199,629	2,353,358	
Opt Ref w/o CO2 (Low gas)	169,784	294,537	420,659	579,050	686,936	798,849	923,240	1,053,925	1,194,816	1,346,106	1,500,545	1,651,514	1,802,322	1,949,127	2,095,912	
EB2 (Gas Conversion)	188,829	318,454	448,047	611,504	729,359	858,192	1,000,114	1,143,723	1,293,432	1,506,130	1,676,459	1,841,888	2,006,385	2,165,226	2,322,785	
EB2 (CC replacement)	189,370	317,328	449,274	607,921	725,231	854,863	994,018	1,136,551	1,285,765	1,438,623	1,593,755	1,747,217	1,900,755	2,051,222	2,198,906	
EB2 (CT replacement)	189,014	316,080	447,031	609,425	726,139	856,360	998,424	1,141,787	1,291,557	1,447,635	1,606,037	1,760,676	1,914,707	2,063,853	2,212,140	
EB2 (Renewables replacement)	188,161	316,559	446,744	628,474	773,549	937,798	1,116,042	1,300,783	1,491,682	1,697,094	1,877,096	2,049,905	2,218,134	2,379,347	2,535,529	
Transition A	189,589	320,221	453,937	625,348	777,432	922,826	1,078,198	1,232,053	1,392,845	1,560,156	1,726,588	1,887,065	2,046,572	2,200,752	2,354,167	
Transition B	190,723	324,636	463,908	647,346	793,872	975,189	1,148,591	1,319,843	1,497,211	1,679,804	1,854,670	2,024,173	2,192,208	2,355,364	2,511,753	

2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050





STAFF-DR-01-020

REQUEST:

Refer to the IRP, Section 6E, pages 58 and 59.

a. Given how close CO_2 reductions are for the portfolios plotted in Figure 6.7, provide a chart that shows the numerical values.

b. Describe the 2005 CO_2 Emission of Duke Kentucky that are used in Figure 6.7 as a comparison to future reductions.

RESPONSE:

With regards to the Duke Energy Kentucky IRP, Section 6E, pages 58 & 59:

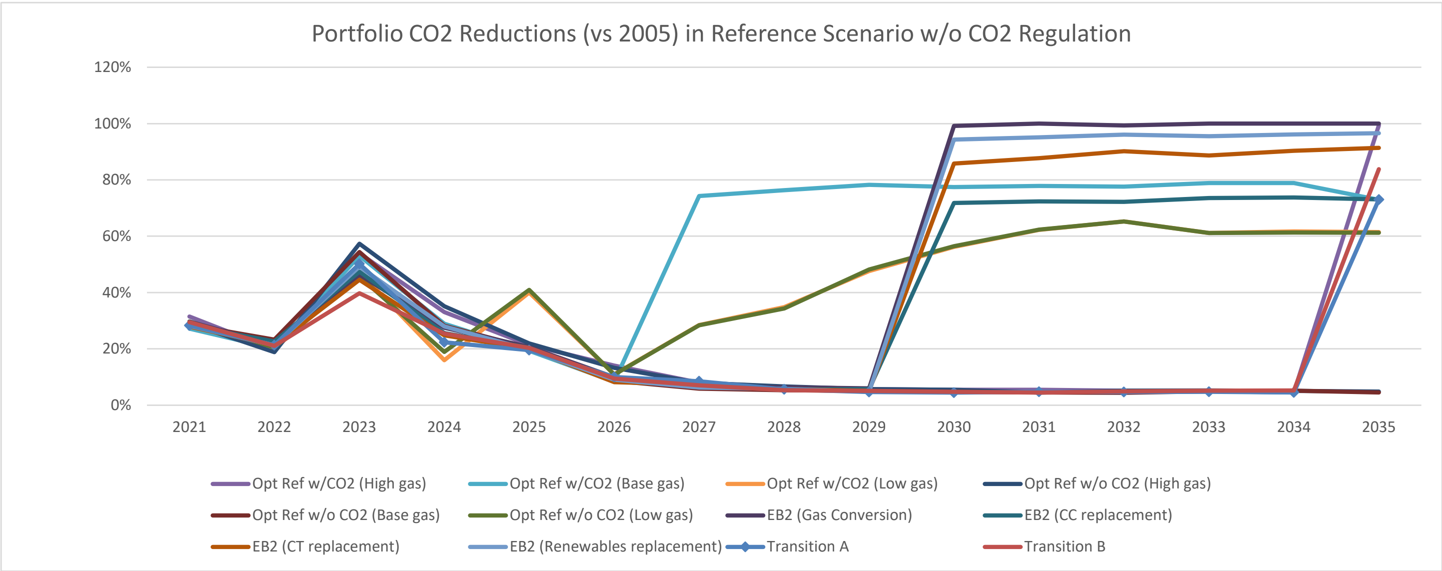
a. Please see STAFF-DR-01-020(a) Attachment.

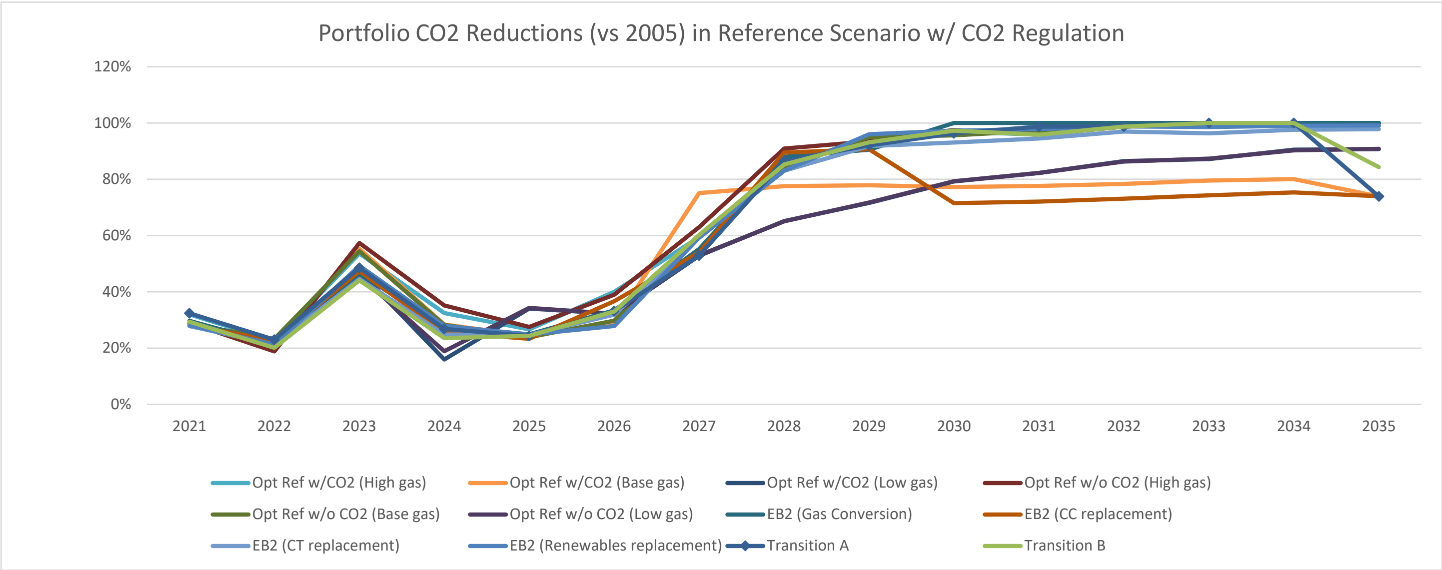
b. Please see STAFF-DR-01-020(b) Attachment to see the details behind the 2005 CO2 emission baseline.

PERSON RESPONSIBLE: Scott Park

CO2 (Tons)

Ref w/o CO2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Opt Ref w/CO2 (High gas)	32%	20%	54%	33%	21%	14%	8%	6%	6%	6%	5%	5%	5%	5%	99%
Opt Ref w/CO2 (Base gas)	27%	20%	53%	29%	19%	8%	74%	76%	78%	77%	78%	78%	79%	79%	73%
Opt Ref w/CO2 (Low gas)	30%	20%	47%	16%	40%	11%	28%	35%	48%	56%	62%	65%	61%	62%	61%
Opt Ref w/o CO2 (High gas)	29%	19%	57%	35%	22%	13%	8%	7%	6%	6%	4%	5%	5%	5%	5%
Opt Ref w/o CO2 (Base gas)	29%	23%	54%	28%	20%	9%	6%	5%	5%	5%	4%	4%	5%	5%	5%
Opt Ref w/o CO2 (Low gas)	30%	21%	46%	19%	41%	11%	28%	34%	48%	56%	62%	65%	61%	61%	61%
EB2 (Gas Conversion)	30%	21%	46%	28%	21%	10%	7%	6%	6%	99%	100%	99%	100%	100%	100%
EB2 (CC replacement)	28%	23%	47%	26%	20%	9%	7%	6%	6%	72%	72%	72%	74%	74%	73%
EB2 (CT replacement)	28%	21%	45%	25%	20%	8%	7%	6%	5%	86%	88%	90%	89%	90%	91%
EB2 (Renewables replacement)	28%	21%	49%	28%	20%	9%	6%	6%	5%	94%	95%	96%	95%	96%	97%
Transition A	28%	21%	50%	22%	20%	10%	9%	6%	5%	4%	5%	5%	5%	4%	73%
Transition B	30%	21%	40%	25%	20%	9%	7%	5%	5%	5%	4%	5%	5%	5%	84%
Ref w/CO2															
Opt Ref w/CO2 (High gas)	32%	23%	54%	32%	27%	40%	59%	86%	94%	97%	96%	100%	100%	99%	99%
Opt Ref w/CO2 (Base gas)	28%	22%	55%	28%	24%	29%	75%	78%	78%	77%	78%	78%	80%	80%	74%
Opt Ref w/CO2 (Low gas)	30%	20%	47%	16%	34%	32%	53%	65%	72%	79%	82%	86%	87%	90%	91%
Opt Ref w/o CO2 (High gas)	29%	19%	57%	35%	28%	39%	63%	91%	93%	98%	96%	99%	100%	100%	100%
Opt Ref w/o CO2 (Base gas)	29%	23%	54%	28%	24%	30%	60%	85%	95%	96%	97%	99%	100%	100%	100%
Opt Ref w/o CO2 (Low gas)	30%	21%	46%	19%	34%	32%	53%	65%	72%	79%	82%	86%	87%	90%	91%
EB2 (Gas Conversion)	30%	21%	46%	28%	25%	33%	55%	88%	91%	100%	100%	100%	100%	100%	100%
EB2 (CC replacement)	28%	23%	47%	26%	23%	37%	54%	90%	91%	71%	72%	73%	74%	75%	74%
EB2 (CT replacement)	28%	21%	45%	25%	25%	32%	59%	83%	92%	93%	94%	97%	96%	98%	98%
EB2 (Renewables replacement)	28%	21%	49%	28%	25%	28%	59%	83%	96%	97%	98%	99%	99%	99%	99%
Transition A	32%	23%	48%	27%	24%	33%	53%	87%	92%	96%	99%	99%	100%	100%	74%
Transition B	29%	20%	44%	24%	24%	33%	60%	85%	93%	97%	96%	99%	100%	100%	84%


Portfolio CO2 Reductions (vs 2005) in Reference Scenario w/o CO2 Regulation
120%
100%
80%
60%
40%
20%
0%
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Opt Ref w/CO2 (High gas)
Opt Ref w/CO2 (Base gas)
Opt Ref w/CO2 (Low gas)
Opt Ref w/o CO2 (High gas)
Opt Ref w/o CO2 (Base gas)
Opt Ref w/o CO2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B


Portfolio CO2 Reductions (vs 2005) in Reference Scenario w/ CO2 Regulation
120%
100%
80%
60%
40%
20%
0%
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Opt Ref w/CO2 (High gas)
Opt Ref w/CO2 (Base gas)
Opt Ref w/CO2 (Low gas)
Opt Ref w/o CO2 (High gas)
Opt Ref w/o CO2 (Base gas)
Opt Ref w/o CO2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B

				2005	2005	2005	2005
FACILITY_NAME	UNITID	Fuel	Ownership	CO2 Tons	Ownership Share CO2	Total MWhrs	Ownership Share MWhrs
East Bend	2	Coal	100%	3,665,437	3,665,437	3,566,682	3,566,682
Miami Fort	6	Coal	100%	1,191,914	1,191,914	1,138,334	1,138,334
Woodsdale	CT 1-6	Gas	100%	54,475	54,475	45,658	45,658
TOTALS				**4,911,826**	**4,911,826**	**4,750,674**	**4,750,674**
				Coal =			4,705,016
				Gas =			45,658

Note: Miami Fort 6 has been retired

STAFF-DR-01-021

REQUEST:

Refer to the IRP, Section 6E, page 60. Explain whether Duke Kentucky is aware of any discussions regarding market purchases counting toward emissions in future regulation or reporting standards.

RESPONSE:

At this time there are no carbon regulations in place that include options for market purchases (e.g. allowances, offsets, etc.) that would contribution to compliance.

PERSON RESPONSIBLE: Michael Geers

STAFF-DR-01-022

REQUEST:

Refer to the IRP, Section 6E, pages 61 and 62.

a. Given how close Market Purchases as percent of Total Load are for the portfolios plotted in Figure 6.7, provide a chart that shows the numerical values.

b. Explain whether a similar analysis was performed with the Low, High, and Base Gas Price cases.

RESPONSE:

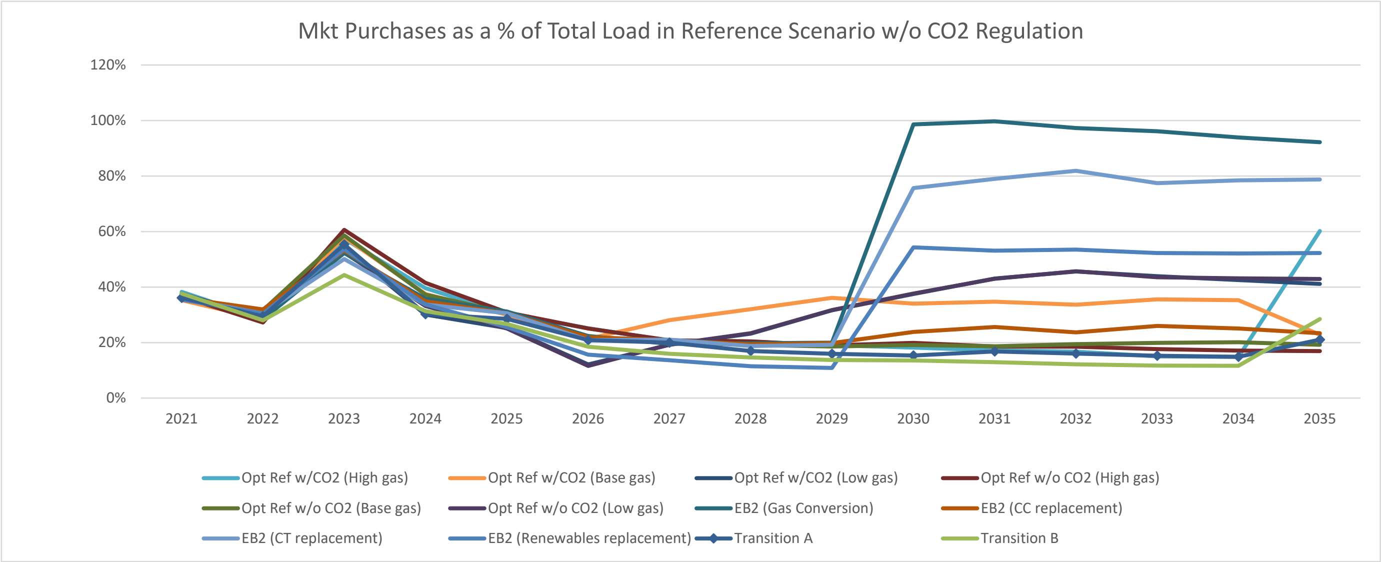
a. Please see STAFF-DR-01-022(a) Attachment. Figure 6.7 shows carbon reduction for all of the portfolios. Figure 6.8 shows market purchases. The vertical axis is divided such that the level of market purchases can be seen for each portfolio and is within a reasonable level of variability in these metrics due to changes in load, unit performance, gas and power prices.

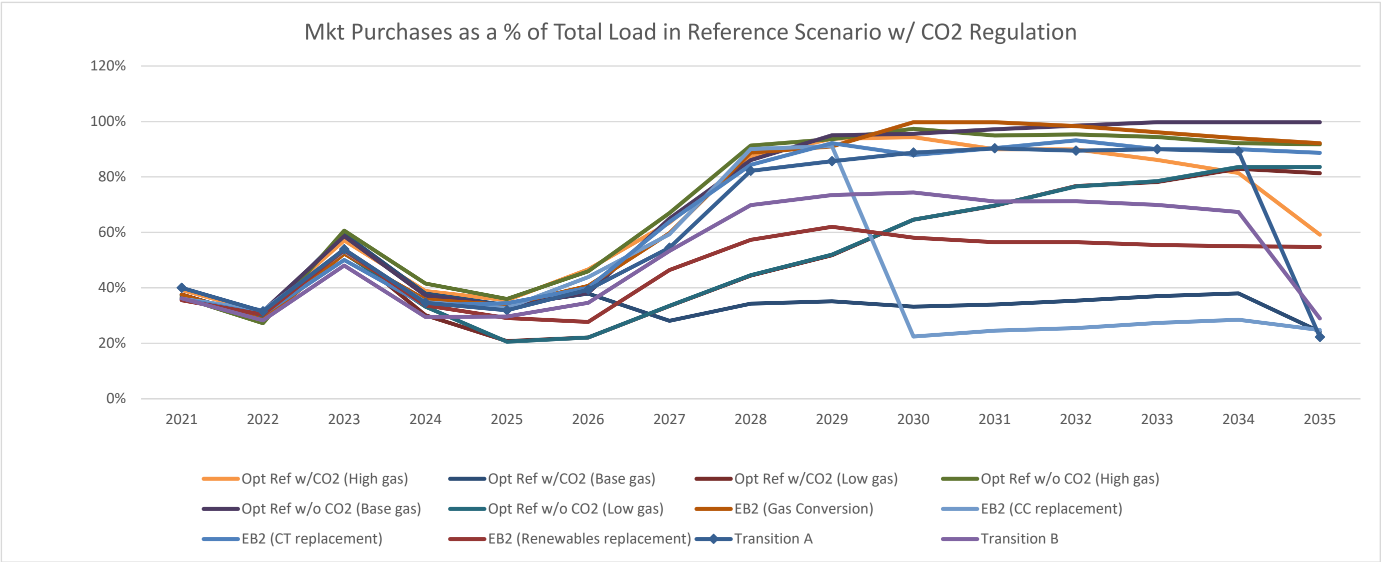
b. The IRP did not include data on the portfolio performance in the high and low gas scenarios. The charts that show portfolio performance in the Reference cases with and without CO2 regulation assume the base gas forecast.

PERSON RESPONSIBLE: Scott Park

Purchases (GWh)

Ref w/o CO2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Opt Ref w/CO2 (High gas)	38%	28%	57%	40%	30%	25%	21%	20%	19%	18%	17%	17%	15%	15%	60%
Opt Ref w/CO2 (Base gas)	35%	28%	58%	37%	30%	21%	28%	32%	36%	34%	35%	34%	36%	35%	23%
Opt Ref w/CO2 (Low gas)	38%	29%	54%	30%	25%	12%	19%	23%	32%	38%	43%	46%	44%	43%	41%
Opt Ref w/o CO2 (High gas)	37%	27%	61%	42%	31%	25%	21%	20%	19%	20%	19%	18%	18%	17%	17%
Opt Ref w/o CO2 (Base gas)	36%	32%	59%	37%	31%	22%	20%	19%	19%	19%	19%	19%	20%	20%	19%
Opt Ref w/o CO2 (Low gas)	37%	30%	52%	33%	25%	12%	19%	23%	32%	38%	43%	46%	44%	43%	43%
EB2 (Gas Conversion)	38%	28%	52%	36%	31%	22%	20%	20%	20%	99%	100%	97%	96%	94%	92%
EB2 (CC replacement)	36%	32%	53%	35%	31%	22%	21%	19%	20%	24%	26%	24%	26%	25%	23%
EB2 (CT replacement)	36%	31%	50%	34%	31%	21%	21%	19%	19%	76%	79%	82%	77%	78%	79%
EB2 (Renewables replacement)	36%	30%	54%	34%	26%	16%	14%	11%	11%	54%	53%	53%	52%	52%	52%
Transition A	36%	29%	55%	30%	29%	21%	20%	17%	16%	15%	17%	16%	15%	15%	21%
Transition B	38%	28%	44%	31%	27%	19%	16%	15%	14%	14%	13%	12%	12%	12%	28%
Ref w/CO2															
Opt Ref w/CO2 (High gas)	39%	31%	57%	39%	36%	47%	64%	87%	94%	94%	90%	90%	86%	81%	59%
Opt Ref w/CO2 (Base gas)	36%	30%	59%	38%	34%	38%	28%	34%	35%	33%	34%	35%	37%	38%	24%
Opt Ref w/CO2 (Low gas)	38%	29%	54%	30%	21%	22%	33%	44%	52%	65%	70%	77%	78%	83%	81%
Opt Ref w/o CO2 (High gas)	37%	27%	61%	42%	36%	46%	67%	91%	94%	97%	95%	95%	94%	92%	92%
Opt Ref w/o CO2 (Base gas)	36%	32%	59%	37%	33%	38%	65%	86%	95%	96%	97%	98%	100%	100%	100%
Opt Ref w/o CO2 (Low gas)	37%	30%	52%	33%	21%	22%	34%	45%	52%	65%	70%	77%	78%	84%	84%
EB2 (Gas Conversion)	38%	28%	52%	36%	34%	41%	60%	89%	91%	100%	100%	98%	96%	94%	92%
EB2 (CC replacement)	36%	32%	53%	35%	33%	44%	59%	90%	91%	22%	25%	26%	27%	29%	25%
EB2 (CT replacement)	36%	31%	50%	34%	34%	40%	64%	84%	92%	88%	90%	93%	90%	90%	89%
EB2 (Renewables replacement)	36%	30%	54%	34%	29%	28%	46%	57%	62%	58%	56%	56%	55%	55%	55%
Transition A	40%	32%	54%	35%	32%	39%	54%	82%	86%	89%	90%	89%	90%	89%	22%
Transition B	36%	28%	48%	30%	30%	35%	53%	70%	73%	74%	71%	71%	70%	67%	29%


Mkt Purchases as a % of Total Load in Reference Scenario w/o CO2 Regulation
120%
100%
80%
60%
40%
20%
0%
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Opt Ref w/CO2 (High gas)
Opt Ref w/CO2 (Base gas)
Opt Ref w/CO2 (Low gas)
Opt Ref w/o CO2 (High gas)
Opt Ref w/o CO2 (Base gas)
Opt Ref w/o CO2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B


Mkt Purchases as a % of Total Load in Reference Scenario w/ CO2 Regulation
120%
100%
80%
60%
40%
20%
0%
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Opt Ref w/CO2 (High gas)
Opt Ref w/CO2 (Base gas)
Opt Ref w/CO2 (Low gas)
Opt Ref w/o CO2 (High gas)
Opt Ref w/o CO2 (Base gas)
Opt Ref w/o CO2 (Low gas)
EB2 (Gas Conversion)
EB2 (CC replacement)
EB2 (CT replacement)
EB2 (Renewables replacement)
Transition A
Transition B

STAFF-DR-01-023

REQUEST:

Refer to the IRP, Section 7, page 65. Explain in greater detail how the lessons learned from the portfolios developed and tested in the previous sections culminate into the 2021 IRP Portfolio.

RESPONSE:

When we look at the optimized portfolios to get a better understanding of how the changes in the two biggest drivers (CO2 regulation and gas prices) affect the portfolio, the first observation is that East Bend 2 retires within the next 15 years in situations when there is either carbon regulation or low gas prices. Given the probability of either or both of the outcomes happening, the Company feels it is prudent to begin preparing by bringing in the retirement of East Bend 2 to 2035. Furthermore, when East Bend 2 does retire, the system will need a resource that can provide higher levels of dispatchable energy that would likely be, given today's technology, a combined cycle. But, given the amount of time between now and 2035, it is important to identify the system's need and maintain technology type flexibility until we get closer to that date. Lastly, the addition of renewables help to decarbonize and diversify the fleet over time, both of which reduces the risk to future carbon regulation.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-01-024

REQUEST:

Refer to the IRP, Section 7, Figure 7.1, page 65.

a. Confirm that Figure 7.1 is the same as the Transitional A portfolio in Figure 6.3, page 48.

b. If not answered previously, explain whether Duke Kentucky has begun installing battery capacity, whether the installation requires a Certified of Public Convenience and Necessity (CPCN), and whether it will be installed in conjunction with additional solar capacity.

c. If not already answered, explain whether the listed solar capacity is installed nameplate or 50 percent of nameplate per PJM and whether it includes the existing 6.8 MW of solar capacity.

d. Explain whether the new wind capacity will be built and owned by Duke Kentucky and whether the capacity will reside in Kentucky or out of state.

RESPONSE:

a. Confirmed.

b. The Company has not installed battery capacity. The Company files CPCNs for construction projects that are not considered ordinary extensions in the usual course of business.

c. The solar capacity listed in Figure 7.1 represents nameplate capacity and excludes the 6.8 MW of existing solar capacity.

d. This will be determined once a specific project has been identified.

PERSON RESPONSIBLE: Scott Park – a., c., d.
Legal – b.

STAFF-DR-01-025

REQUEST:

Refer to the IRP, Section 7B, page 69. Explain the requirements relevant to Duke Kentucky in PJM's Capacity Performance requirement.

RESPONSE:

Beginning in 2020, all capacity in the RPM must be Capacity Performance compliant, including capacity included as part of an FRR Plan. Capacity performance resources must be capable of sustained, predictable operation that provides energy and reserves during performance assessment hours throughout the Delivery Year. Capacity performance resources are subject to non-performance assessments during emergency conditions throughout the entire Delivery Year and are required to be available to PJM during periods of high load demand or system emergency or face substantial non-performance assessments. Conversely, over-performance will be rewarded with performance-based bonuses.

PJM Capacity Performance compliance does not have a strict or bright line set of guidelines. PJM's rules do not provide specific eligibility requirements or qualifications that a generation resource must meet in order to qualify as a Capacity Performance resource. Instead, the Capacity Performance resources are those that to the extent they cleared in the RPM auction or are otherwise committed as a capacity resource, are obligated to deliver energy during the relevant Delivery Years as scheduled or dispatched during the Performance Assessment Hours. The best a utility can do is manage the risks and make appropriate and prudent investments to maintain and, if possible, enhance the reliability of its assets to reduce the likelihood of the asset not being able to perform when called upon during a PJM-determined event. The Capacity Performance rules provide broad discretion on the part of PJM and the IMM to challenge generators as being Capacity Performance compliant. That said, there are some minimum strategies that Duke Energy Kentucky has taken in terms of ensuring there is a reliable source of fuel, and maintaining regular and proactive maintenance schedules and activities. The Company believes that East Bend meets the minimum requirements of a Capacity Performance resource in that it is a coal fired facility with a significant reserve of fuel stored on-site. Additionally, the Company has taken proactive steps to invest in the maintenance of East Bend through "asset hardening" strategies designed to reduce the possibility, likelihood, and duration of forced outages. Additionally, in addition to the same strategies as East Bend, as the Commission is aware, the Company added oil as a back-up fuel at Woodsdale and the site is now a CP resource.

PERSON RESPONSIBLE: John Swez

STAFF-DR-01-026

REQUEST:

Refer to the IRP, Appendix B, pages 76-77.

a. Explain how Duke Kentucky transformed the primary metropolitan statistical area (PMSA) economic data from Moody's Analytics (Moody's) to its Kentucky service territory.

b. Provide a list of economic variables obtained from Moody's that were used in the various customer class demand forecasts.

c. Explain whether Duke Kentucky used Moody's Baseline or Consensus forecast scenarios and what transformations, if any, were applied to the data.

RESPONSE:

a. The Company does not need to perform an adjustment on economic data for this purpose. Exposing variation in electric sales to variation in economic indicators for a region that approximates the region in which the company conducts business is appropriate, as the estimation process is designed to attribute a causal relationship from how the variables co-move.

b. Variables for State of Kentucky: Total Employment, Real GDP – Government, Real GDP – Manufacturing, Employment – Manufacturing, Number of Households, Real Median Household Income; VARIABLES for Cincinnati MSA: Total Employment, Number of Households, Real Median Household Income

c. The company used Moody's "Consensus Forecast" series as a way to try to better capture the many risks in this fragile economic moment.

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-01-027

REQUEST:

Refer to the IRP, Appendix B, Pages 81-82, and Figure B-Oc, page 88.

a. Explain how each of the economic variables was derived.

b. Explain why there are two Cooling statistical adjusted end-used (SAE) variable in the residential usage per customer model as opposed to using one or the other and whether there are multicollinearity issues.

c. Explain the qUPC_SAE_Res.prre2014q3 variable in the Qtrly Residential Usage Per Customer model.

d. Explain the qUPC_SAE_COM.Covid variable in the Qtrly Commercial Usage Per Customer model.

e. Explain the qSales_SAE_Inc.MFG_ren variable in the Quarterly Industrial Sales model.

f. Explain why the qSales_SAE_Inc.Price variable in the Quarterly Industrial Sales model which is insignificant was let in the model.

RESPONSE:

a. Economic variables are downloaded directly from our data vendor—Moody's analytics. To the extent that transformations are necessary, they are scaled such that the values for a recent year, often 2019, are 100.

b. The two cooling variables represent SAE terms that are calculated for different temperature/degree day bases, one at 60 degrees and one at 70 degrees. Both terms perform well in the model, showing a high degree of statistical significance—and other model statistics are improved when we add the 70-degree base term—so there aren't multi-collinearity concerns.

c. The purpose of this variable—which indicates earlier observations of the model through the end of the year 2014—is to properly account for excess sales not readily explained by the other predictors. Without it, the early errors would lead to other problematic model statistics.

d. This variable was used to capture a sales deficit in recent observations during the time when COVID-related shutdowns and business disruptions were reducing activity by commercial customers.

e. This variable was used to acknowledge early observations in which Industrial customers used more energy than explained by the existing economic variables; the name was chosen informally and meant to refer to a time when it seemed that manufacturers were recovering from the devastating downturn of 2008.

f. The price variable was included in the industrial model despite its high standard error because the sign and elasticity of the coefficient aligned with how we'd expect industrial customers to behave, and the company occasionally receives requests for calculation of alternative scenarios or hypotheticals involving alternative price outlooks. We accept that the high standard error is problematic, but the model is maintained in this way to prepare for other obligations or requests for information of this type.

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-01-029

REQUEST:

Refer to the IRP, Appendix B, page 84.

a. Explain in detail the weather normalization period used by Duke Kentucky. Discuss the reasoning for using the weatherization period and whether it is the same or different from what the other Duke affiliates are using.

b. Explain whether Duke Kentucky considered 20-year normal weather. If so, explain why it was not applied in the IRP.

RESPONSE:

a. Duke Energy calculates "normal weather" based on average daily temperatures over a rolling thirty year period, ending with the most recent complete calendar year prior to the computation of the forecast. This 30-year period is identical across all Duke Energy affiliates.

b. As an institution, Duke Energy has considered other time periods, although we do not perform calculations for an alternative normal period for any applications. An advantage of the 30-year period is minimizing the variance of sample-based statistics by using more sample data. Shifting to a 20-year normal would imply an increase in the error of estimates of more than 20%, as well as higher variation attributed to changes in normal weather in each reporting period.

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-01-030

REQUEST:

Refer to the IRP, Figure B-0b, page 86, and Figure B-5, page 103. Confirm that Figure B-0b should list the same load factor information as listed in Figure B-5.

RESPONSE:

Confirmed.

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-031

REQUEST:

Refer to the IRP, Appendix B, Figure B-0c, pages 88-89, Figure B-1 page 96, and Figure B-2, pages 98-99.

a. Confirm that dividing column (1) in Figure B-2a by column 1 in Figure B-1 yields residential MWh use per customer per year.

b. Confirm that dividing column (2) in Figure B-2a by column 2 in Figure B-1 yields commercial MWh use per customer per year.

c. Explain the meaning of column (6) in Figure B-2a.

d. Comparing the two tables in Figure B-2,confirm that there were no MWhs attributable to EE programs for years 2015-2017 for residential and 2015 for commercial customer classes.

e. Provide an updated Figure B-2 showing the MWhs per year of EE that is subtracted to arrive at column 9, "NetEnergy for load." If the numbers do not match the MWh numbers in Figure 5-2 page 41, explain why.

RESPONSE:

a. Confirmed.

b. Confirmed.

c. The "Other" column refers to a sum of usage by Governmental customers (sometimes referred to as "OPA"), interdepartmental usage, and energy used within the Duke system (commonly called "Company Use".

d. Indeed no adjustment to the historical sales data was made for UEE program achievements for 2015-2017 residential sales and for 2015 commercial sales.

e. Please see STAFF-DR-01-039 Attachment for an updated Figure B-2a including a column showing Total UEE Achievements. The numbers used to compute figure 5.2 represent an anticipated drop in sales, which can be less than the forecast amount of UEE programs because the diversity of programs can mean they are not additive in the modeling. The Company follows a process for modeling the UEE after the transmission of the UEE forecast to the IRP team, and diversity of programs means that the drop in load is not as drastic as the sum of program activities.

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-01-032

REQUEST:

Refer to the IRP, Appendix A. Transmission and Distribution Forecast. Response 5.(4) on page 69 states that there are currently no transmission system projects planned or in progress. With the recent increased number of merchant plants application in Kentucky, explain whether or not Duke Kentucky anticipates a need for either an upgrade or additional transmission.

RESPONSE:

The impact of any merchant generation project or projects on the Duke Energy Kentucky transmissions system and any need for upgrades will depend on the exact location and size of the merchant project(s). At this time, Duke Energy Kentucky is not aware of any projects which may impact the Duke Energy Kentucky system. All proposed interconnections will be evaluated by PJM and/or the transmission coordinator for the region in which the merchant project is located. If any impacts to the Duke Energy Kentucky system are found, the Company will evaluate and propose any needed upgrades to comply with our responsibilities as a member of PJM.

PERSON RESPONSIBLE: Timothy J. Hohenstatt

STAFF-DR-01-033

REQUEST:

Refer to the IRP, Appendix A, Transmission and Distribution Forecast page 70. Explain if there are any distribution upgrades planned that are in response to an increase in residential distributed energy from resources such as roof top solar, batteries, or electric vehicles.

RESPONSE:

None of the distribution upgrades are in response to an increase in residential distributed energy from resources such as roof top solar, batteries, or electric vehicles.

PERSON RESPONSIBLE: Tony Platz

STAFF-DR-01-034

REQUEST:

Refer to the IRP, Appendix B, Figure B-3b, page 100, and Figure B-4a, page 101.

a. Provide an updated Figure B-4a table showing separately the amounts of energy efficiency (EE) and demand response (DR) that can be subtracted from seasonal peak loads in Figure B-3b to obtain the peak loads in Figure B-4a. If the numbers do not match the Total DSM Impacts MW numbers in Figure 5-2 page 41, explain why.

b. Confirm that the peak load forecasts in Figure B-4a are the peak loads used to calculate the required PJM reserve margins. If not, explain which peak load forecasts are utilized and why.

RESPONSE:

a. Please see STAFF-DR-01-034 Attachment for the requested figures. Load Forecasting performed the calculations in the figures in Appendix B, while table 5-2 was prepared based on calculations that accounted for diversity across sources of demand mitigation, or different amounts of demand side management than are registered because of participation estimates.

b. PJM prepares its own load forecast which they use for this function.

PERSON RESPONSIBLE: Benjamin W. Passty

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

				SUMMER			WINTER[d]		
	YEAR	EE	DR	LOAD	CHANGE[b]	PERCENT CHANGE[c]	LOAD	CHANGE[b]	PERCENT CHANGE[c]
-5	2015			814			739		
-4	2016			877	63	7.7%	733	(6)	-0.8%
-3	2017			841	(36)	-4.1%	797	64	8.7%
-2	2018			857	16	1.9%	821	24	3.0%
-1	2019			849	(8)	-0.9%	742	(79)	-9.6%
0	2020			809	(40)	-4.7%	678	(64)	-8.6%
1	2021	-2	-32	783	(26)	-3.2%	726	48	7.1%
2	2022	-4	-33	789	6	0.8%	740	14	1.9%
3	2023	-6	-33	803	14	1.8%	739	(0)	-0.1%
4	2024	-9	-33	807	4	0.5%	755	16	2.1%
5	2025	-11	-33	818	11	1.4%	751	(4)	-0.5%
6	2026	-13	-33	819	1	0.1%	750	(1)	-0.2%
7	2027	-15	-33	821	2	0.2%	747	(3)	-0.4%
8	2028	-17	-33	824	3	0.3%	748	1	0.1%
9	2029	-19	-33	827	3	0.3%	760	12	1.6%
10	2030	-21	-33	837	10	1.3%	760	0	0.0%
11	2031	-23	-33	841	3	0.4%	761	1	0.1%
12	2032	-25	-33	846	6	0.7%	757	(4)	-0.5%
13	2033	-27	-33	852	5	0.6%	757	(1)	-0.1%
14	2034	-28	-33	857	5	0.6%	767	10	1.3%
15	2035	-29	-33	865	8	0.9%	784	18	2.3%
16	2036	-25	-33	878	13	1.6%	790	6	0.7%
17	2037	-25	-33	886	8	0.9%	789	(1)	-0.1%
18	2038	-25	-33	898	12	1.4%	795	5	0.7%
19	2039	-25	-33	909	10	1.2%	794	(1)	-0.1%
20	2040	-25	-33	917	8	0.9%	816	22	2.7%

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

0.0

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-035

REQUEST:

Refer to the IRP, Appendix B, Figure B-3a, page 99, and Figure B-4a, page 101.

a. Explain how the peak forecasts were derived.

b. Provide the amounts of Demand Resource or controllable load that is subtracted from the seasonal peak forecasts.

RESPONSE:

a. The peak forecasts are estimated from models that predict monthly peak demand—adding back any relevant demand response—as a function of transformations of the monthly forecast for MWH. Base load, heating, and cooling terms are computed by adding together the model output for the class models. EIA data—packaged by ITRON—for the end uses active at the moment of peak are also applied to transform the data, and the model is optimized using the same procedures and intercept-shifters as with the models for energy.

End Use	Heating	Cooling	Base Load
Energy Included	Residential Heating Commercial Heating	Residential Cooling Commercial Cooling	Residential/Commercial Residual
			Industrial OPA SL/CU/ID

b. The forecast for MW peak has Demand response deducted according to the following annual schedule:

Year	Winter DR	Summer DR
2021	7.5 MW	31.8 MW
2022-later	7.5 MW	33 MW

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-01-036

REQUEST:

Refer to the IRP, Appendix B, Figure B-5, page 103. Explain why the peak volumes in column 2 do not exclude the demand resource volumes.

RESPONSE:

While there are exceptions, it is the most frequent practice of Load Forecasting to transmit forecasts before anticipated UEE program achievements are deducted, leaving other parts of the organization to calculate the extent to which Demand Response and UEE programs will reduce load. For an updated version of the referenced table that presents MWH and MW that are in alignment, please see STAFF-DR-01-036 Attachment.

PERSON RESPONSIBLE: Benjamin W. Passty

LOAD FACTOR CALCULATIONS, DEK

	1	2	3
	Volume	Peak	Load Factor
2015	4,043,958	814	56.7%
2016	4,065,855	877	52.8%
2017	3,939,861	841	53.5%
2018	4,158,382	857	55.4%
2019	4,081,160	849	54.9%
2020	3,842,705	809	54.1%
2021	3,982,499	815	55.8%
2022	4,055,840	822	56.3%
2023	4,145,164	836	56.6%
2024	4,171,713	840	56.5%
2025	4,253,309	851	57.0%
2026	4,265,258	853	57.1%
2027	4,291,767	854	57.3%
2028	4,321,772	857	57.4%
2029	4,351,378	860	57.8%
2030	4,424,639	870	58.0%
2031	4,450,677	874	58.2%
2032	4,487,687	879	58.1%
2033	4,525,193	885	58.4%
2034	4,554,395	890	58.4%
2035	4,596,744	898	58.4%
2036	4,657,360	911	58.2%
2037	4,688,398	919	58.2%
2038	4,736,299	931	58.1%
2039	4,784,633	942	58.0%
2040	4,825,014	950	57.8%

STAFF-DR-01-037

REQUEST:

Refer to the IRP, Appendix B, page 87, and Figure B-5, page 103. Confirm that Figure B-5 contains the load factor calculations and not the high, low, and most likely forecasts before EE.

RESPONSE:

I confirm that Figure B-5 contains the load factor calculations and not the high, low, and most likely forecasts before EE.

PERSON RESPONSIBLE: Benjamin W. Passty

PUBLIC STAFF-DR-01-038
(As to Attachment only)

REQUEST:

Refer to the IRP, Appendix B, pages 86-87, and Figure B-5, page 103, Figure B-4b, page 102, and Figure B-2a, page 97.

a. Confirm that the load factor calculations in Figure B-5 are taken from Figure B-4b and Figure B-2a.

b. For the volumes taken from Figure B-2a, explain why column 7 "total Consumption" was used and not net column 9, "Net Energy for Load."

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

a. Confirmed that they are taken from the named Figures.

b. The company uses load that we meter for certain business purposes as well. A version of the calculation that uses Net Energy for Load is provided in STAFF-DR-01-038 Confidential Attachment.

PERSON RESPONSIBLE: Benjamin W. Passty

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-01-038 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

PUBLIC STAFF-DR-01-039
(As to Attachment only)

REQUEST:

Refer to the IRP, Appendix B Figure B-2a, page 97. Provide an updated table showing the MWhs per year of EE that is subtracted to arrive at column 9 “Net Energy for load.”

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

Please see STAFF-DR-01-039 Confidential Attachment.

PERSON RESPONSIBLE: Benjamin W. Passty

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-01-039 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

STAFF-DR-01-040

REQUEST:

Refer to the IRP, Appendix B, page 87, and Figure B-6, page 104.

a. Confirm that the peak load forecast in the “most likely” column matches the peak load forecast in Figure B-4b.

b. The most likely peak load forecast excludes EE. If not answered above, explain why demand resources were not also subtracted from the peak load forecasts and that the forecast.

RESPONSE:

a. Confirmed.

b. The Company frequently follows internal process in which load forecasting output is conveyed without deducting EE or DR. The scenarios all referenced are comparable and can be treated identically.

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

PUBLIC STAFF-DR-01-041
(As to Attachment only)

REQUEST:

Refer to the IRP, Appendix B, page 87, and Figure B-6, page 104.

a. Provide a copy of the Moody's discussion of the assumptions driving its base forecast, and what changes were made for the optimistic and pessimistic scenarios.

b. Explain whether Duke Kentucky made any adjustments to the Moody's data or assumptions to make its own high and low sensitivity forecasts listed in Figure B-6. If so, explain each of the changes.

c. Explain in detail how Duke Kentucky made its high and low energy and demand forecasts.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

a. Please see STAFF DR-01-041 Confidential Attachment for *confidential* reports provided by Moody's analytics.

b. No adjustments were made to data received from Moody's.

c. During the 2018 IRP process, Duke Energy Kentucky used Moody's scenarios to estimate a range—from high ("Stronger near-term rebound") to low ("Moderate recession")—for the peak energy forecast based on exposing the estimated forecast models to the scenario data. That range was centered around the existing baseline forecast. Scalars from the midpoint to low (and from midpoint to high) were brought forward to the 2021 IRP calculations.

PERSON RESPONSIBLE: Benjamin W. Passty

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-01-041 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

STAFF-DR-01-042

REQUEST:

Refer to Section C, Energy Efficiency and Demand Side Management in general. Discuss whether Duke Kentucky plans to continue providing the variety of DSM programs in the future if load reduction is unnecessary.

RESPONSE:

Duke Energy Kentucky plans on offering customer a variety of DSM programs in the future, as long as the DSM programs are found to be cost effective and the Commission continues to approve the programs operations.

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-043

REQUEST:

Refer to Case No. 2017-00427.[1] In this case Duke Kentucky filed testimony in support of its DSM portfolio, particularly in support of the direct impact the DSM programs have on Duke Kentucky's participation in PJM.

a. Provide any updates regarding DSM impacts to Duke Kentucky's participation in PJM as an FRR entity.

b. On page 9 of the final Order, the Commission noted that Duke Kentucky relies on the PowerShare and Power Manager as a capacity resource in Duke Kentucky's FRR plan.

   1) Explain what actions, if any, Duke Kentucky is taking to increase participation in these two DSM programs to avoid additional capacity purchases to meet Duke Kentucky's PJM requirements.

   2) Provide the annual amount of PowerShare capacity directly modeled into the FRR construct and, if different, in the IRP.

   3) Provide the annual amount of from the Power Manager DSM Program that is embedded in the FRR plan and, if different, in the IRP.

RESPONSE:

a. Beginning with the 2020/2021 Delivery Year, PJM required all FRR resources to be Capacity Performance (CP) resources. One of the requirements is that the

[1] Case No. 2017-00427, *Electronic Annual Cost Recovery Filing for Demand Side Management by Duke Energy Kentucky, Inc.* (Ky. PSC Oct. 15, 2018).

resource must meet their CP commitment to delivery energy whenever PJM determines they are needed to meet system emergences. Beginning 2020/2021, the Company began to use DSM programs in the FRR Plan only if they are available throughout the year. Consequently, the types of the DSM programs available for FRR use has been reduced from "seasonal/limited and annual" to just "annual" DSM. Thus, the Company has been committing less DSM resource in its FRR plan. However, the Company commits all available "annual" DSM programs in its FRR plan to offset the capacity load obligation.

b. PowerShare and Power Manager

1) Duke Kentucky is reviewing and making modifications where necessary, including recent elimination of some program options, to ensure compatibility with PJM capacity resource types.

2) PowerShare FRR and IRP MW values:

PowerShare:

Calendar Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IRP MW	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2

Planning Year	20/21	21/22	22/23	23/24*	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35
FRR MW	3.5	3.5	3.5	-	-	-	-	-	-	-	-	-	-	-	-

* FRR is only available through 2022/2023 planning year. MW value as determined by PJM capacity performance rules

3) Power Manager FRR and IRP MW values:

Power Manager:

Calendar Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IRP MW	6.9	6.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0

Planning Year	20/21	21/22	22/23	23/24*	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35
FRR MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Power Manager is a summer-only program and does not receive FRR MW under PJM capacity performance rules

PERSON RESPONSIBLE: John Swez – a.
Andy Taylor/Trish Haemmerle – b.(1)
Brian Bak – b.(2), b.(3)

STAFF-DR-01-044

REQUEST:

Confirm that Duke Kentucky relies on the utility total cost score for cost-effectiveness and inclusion in Duke Kentucky's DSM portfolio.

RESPONSE:

Duke Energy Kentucky analyzes the cost-effectiveness of all of its energy efficiency and demand response programs through the four accepted cost effectiveness tests: the UCT (Utility Cost Test), TRC (Total Resource Cost), RIM (Rate Impact Measure), and the PCT (Participant Cost Test). The Commission has historically focused on the TRC test as the determinant cost effectiveness test for inclusion in the Company's DSM portfolio.

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-045

REQUEST:

Regarding DSM programs in general, explain whether Duke Kentucky models saturation points of each program. If so, explain how Duke Kentucky explores alternatives and solutions to DSM program saturations.

RESPONSE:

The Company does not explicitly model saturation points of each DSM program; however, program staff continuously evaluate program performance as well as customer adoption and retention trends. Stakeholder engagement through the DSM Collaborative and feedback from third party experts performing Evaluation, Measurement and Verification studies assists program staff in their ongoing efforts to maximize customer adoption and program effectiveness.

PERSON RESPONSIBLE: Brian Bak

STAFF-DR-01-046

REQUEST:

Refer to page 138 of the IRP. Regarding the Peak Time Rebate Pilot Program, provide any studies that Duke Kentucky has performed regarding the possibility of converting the PTR Pilot to a Price Responsive Demand Program that is recognized in PJM.

RESPONSE:

Duke Energy Kentucky has not performed a study on converting the PTR Pilot program to a PJM Price Responsive Demand (PRD) resource. When available, the Company plans to review the PTR Pilot results and assess potential changes to the pilot to improve cost effectiveness, including possible transition to a PRD resource.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-047

REQUEST:

Refer to Duke Kentucky's Low Income Services DSM Program. Explain whether Duke Kentucky has evaluated a program that would assist in paying for health and safety repairs so that the Federal Department of Energy's Weatherization Assistance Program measures can be completed.

RESPONSE:

Duke Energy Kentucky has not evaluated a EE/DSM program that would focus on assisting to paying for health and safety repairs. An energy efficiency program that funds Health and Safety repairs will not produce energy savings that would lead to utility system benefits. The Company's existing approved Weatherization Program allows for "limited structural improvements that effect health, safety and energy up to $150."

PERSON RESPONSIBLE: Tim Duff

STAFF-DR-01-048

REQUEST:

Explain whether the modeled DSM impacts should be revised due to the COVID-19 impact. If so, provide an update.

RESPONSE:

The Company does not believe the forecasted DSM impacts modeled in the IRP require further revision as these impacts are anticipated to be short-lived and will not materially change the long range forecasts. Historical DSM likely does include some reduction in impact, predominantly due to inability to perform in-home energy audits, but these effects are not anticipated to persist over the IRP planning period.

PERSON RESPONSIBLE: Brian Bak

STAFF-DR-01-049

REQUEST:

Refer to the IRP, Appendix D, Environmental Regulations. Provide a list and corresponding explanation of any environmental regulation changes that impact Duke Kentucky.

RESPONSE:

In reference to the IRP, Appendix D, Environmental Regulations, the following is a list, with corresponding explanation, of environmental regulation changes that could impact Duke Energy Kentucky to the best of the Company's knowledge at this time.

Air-Related Environmental Regulations

Cross-State Air Pollution Rule (CSAPR)

The April 2021 revision to the Cross-State Air Pollution Rule has resulted in more stringent NOx emissions requirements for 12 states including Kentucky to implement the 2008 National Ambient Air Quality Standard (NAAQS) for ozone. The emissions reductions began with the 2021 summer ozone season and will be fully implemented in 2024. East Bend's existing SCR accommodated the new CSAPR requirements during the 2021 ozone season and should continue to accommodate them when CSAPR is fully implemented in 2024. To date EPA has not initiated a further rule making related to the 2015 ozone NAAQS.

Cincinnati Regional Ozone Non-Attainment

The Greater Cincinnati area continues to be in non-attainment with the 2015 ozone NAAQS. Ambient air quality monitoring results for the Cincinnati area during the 2021 ozone season are not available at this time. Continued non-attainment with the standard may result in additional state level regulation such as short-term NOx emissions rate limits or other requirements. However, neither Ohio nor Kentucky have implemented any such requirements at this time.

Mercury and Air Toxics Standard (MATS)

The USEPA under the previous administration conducted a risk-and-technology review (RTR) of the 2011 MATS rule and found no "residual" health risks from power plants' air toxics and no new control technologies are available that would warrant tightening the standards. It also determined that contrary to the original 2011 rule, that regulation under Section 112 of the Clean Air Act was not "appropriate or necessary", but the administration left the MATS rule requirements in place. EPA is now developing a proposed rule that is expected to revise the previous administration's "appropriate and necessary" determination. EPA may also reconsider the MATS limits. The impacts of EPA's actions are not known at this time.

Affordable Clean Energy Rule (ACE)

On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated EPA's Affordable Clean Energy (ACE) power plant greenhouse gas rule. At this time EPA has not proposed a new rule for the regulation of power plant greenhouse gases.

Water-Related Environmental Regulations

Effluent Limitation Guidelines (ELG)

As discussed in IRP, Appendix D, Duke Energy Kentucky has completed a multitude of work to assist with the compliance of the federal Coal Combustions Residuals Rule (CCR Rule) and the Steam Electric Effluent Limitations Guidelines (ELG), including installation of a dry bottom ash management system and on-site water management equipment installation in order to enable the cessation of all CCR waste and water flows to and from the former bottom ash pond. Duke Energy does anticipate further environmental regulatory changes to the ELG which may impact Duke Energy Kentucky in the future.

On April 12, 2019, the Fifth Circuit issued its opinion in Southwestern Elec. Power Co. v. EPA, ordering EPA to reconsider parts of its 2015 Effluents Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("2015 ELG Rule"). The opinion resolves a challenge brought by environmental groups regarding the rule's effluent limitation guidelines for "legacy" wastewater and for combustion residual leachate from landfills or settling ponds. The Spring 2021 "Agency Rule List" states that for leachate (EO 12866) a rulemaking would be proposed in September 2022 and a final rule in September 2023. It is possible that revised leachate limitations could be included with the effort to reconsider the 2020 Steam Electric Effluent Limitations Guidelines Reconsideration Rule (2020 ELG Rule) instead of a separate rulemaking with a similar schedule.

Duke Energy Kentucky's East Bend Generating Station has two landfills from which leachate is generated. The East Bend Generating Station may need to implement additional technology to manage landfill leachate depending on EPA's forthcoming rule.

It is anticipated, due to the amount of leachate generated by the landfills, that onsite leachate treatment would most likely be needed.

On July 26, 2021 the EPA announced that it is initiating another rulemaking to address elements of the 2020 ELG Rule after a science-based review under Executive Order 13990. The focus of this rulemaking is reviewing FGD wastewater treatment technology (EPA's announcement stated that the Agency "will evaluate whether [membrane treatment systems] should serve as the basis for the 'best available technology economically achievable'"), reviewing bottom ash transport water provisions, and review of subcategories. On September 14, 2021 the EPA published the "Preliminary Effluent Guidelines Program Plan 15" document stating that a proposed rulemaking would be developed during Fall 2022. Based on this schedule, a final rule could be published in Summer/Fall 2023. This document states that elements of the 2020 ELG Rule were to be reviewed with the focus on FGD wastewater treatment using membranes.

East Bend Station is forecasted to install an additional wastewater system in the early-2030's. This would allow East Bend to comply with the anticipated changes in the ELG mentioned above and is consistent with the Company's IRP statement in Appendix D "…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…"

Waste-Related Environmental Regulations

Federal Coal Combustion Residuals Rule (CCR Rule)

As discussed in IRP, Appendix D, Duke Energy Kentucky has completed a multitude of work to assist with the compliance of the federal CCR Rule, including installation of a dry bottom ash management system and on-site water management equipment installation in order to enable the cessation of all waste and water flows from the former bottom ash pond.

In addition, the ash pond completed certified closure per CCR Rule requirements and has been converted to two lined retention basins to manage water flows. Additionally, Duke Energy Kentucky has recently developed a new lined cell at the on-site landfill footprint at East Bend Station that is designed to accept and safely manage the CCR from East Bend Unit 2, including the bottom ash, and flyash-fixated FGD product (calcium sulfite) for years to come. Ongoing routine future landfill cell development costs were included in the analysis in this IRP.

The EPA continues to revise the CCR Rule and has identified several potential rulemakings on it's Spring Regulatory Agenda and in Long Term Actions. The anticipated rulemaking which has potential to affect East Bend Generating Station the most is the establishment of a federal CCR Rule permit process. The EPA is required to establish the federal permit process for all CCR units (CCR landfills and CCR impoundments) for Indian Country and for states in which the state has not adopted the CCR Rule through the process identified through the WIIN Act. Kentucky has not adopted the CCR Rule through this process, and it is not expected to do so before an EPA permit process is launched. When EPA finalizes the federal permit program, which is on the EPA agenda for January 2022, East Bend Generating Station will be required to comply with that program for the two coal ash landfills at that site. Other than costs incurred developing and submitting permit applications, it is unclear whether additional costs will be incurred related to this potential regulatory change. EPA has not provided enough information to determine the full impact of a final permit program. Since Duke Energy Kentucky already complies with the CCR Rule, the effect of a permit rule could be minimal.

PERSON RESPONSIBLE: Mike Geers

STAFF-DR-01-050

REQUEST:

Refer to the IRP, page 158. Explain whether any of Duke Kentucky customers indicated an interest in a Combined Heat and Power project since the filing of the IRP.

RESPONSE:

To the best of the Company's knowledge, there have not been any indications from customers directly nor opportunities identified by the company to deploy a Combined Heat and Power project in Kentucky.

PERSON RESPONSIBLE: Adam Nygaard

Duke Energy Kentucky
Case No. 2021-00245
STAFF First Set Data Requests
Date Received: October 1, 2021

STAFF-DR-01-051

REQUEST:

Recently, natural gas prices have seen a significant increase. Explain the impact this will have on Duke's generation portfolio.

RESPONSE:

The recent run up in gas prices appear to be more of a short term phenomenon and would not necessarily impact the selection of resources over the planning period of the IRP. If this higher level of gas prices are sustained, the result would lessen the likelihood of adding gas resources (all else being equal) and favor renewable additions as well.

PERSON RESPONSIBLE: Scott Park