VERIFICATION

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

The undersigned, Brad Daniel, Director, Generation Dispatch and Operations, 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.

Brad Daniel, Affiant

Subscribed and sworn to before me by Brad Daniel on this 10 day of October, 2023.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

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

The undersigned, Jim McClay, Manager Director Natural Gas Trading, 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.

Jim McClay

Jim McClay, Affiant

Subscribed and sworn to before me by Jim McClay on this 20 day of October 2023.

ELIZABETH NEECE
Notary Public - State of Georgia
Coweta County
My Comm. Expires Aug. 3, 2027

NOTARY PUBLIC

My Commission Expires: 08/03/2027

VERIFICATION

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

The undersigned, Kimberly A. Hughes, Director, Coal Origination, 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.

Kimberly A Hughes

Kimberly A. Hughes, Affiant

Subscribed and sworn to before me by Kimberly A. Hughes on this 18th day of October, 2023.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

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

The undersigned, Libbie S. Miller, Rates & Regulatory Strategy 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.

Libbie S. Miller

Libbie S. Miller Affiant

Subscribed and sworn to before me by Libbie S. Miller on this 9TH day of OCTOBER, 2023.

Adele M Frisch

NOTARY PUBLIC

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

My Commission Expires: 1/5/2024

VERIFICATION

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

The undersigned, Scott Burnside, Director - Unit Commitment and Post Analysis, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests are true and correct to the best of his knowledge, information and belief.

Scott Burnside

Scott Burnside, Affiant

Subscribed and sworn to before me by Scott Burnside on this 17th day of October, 2023.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

KyPSC Case No. 2022-00012
TABLE OF CONTENTS

DATA REQUEST	WITNESS	TAB NO.
STAFF-DR-02-001	Brad Daniel …….....………….	1
STAFF-DR-02-002	Brad Daniel …….....………….	2
STAFF-DR-02-003	Brad Daniel …….....………….	3
STAFF-DR-02-004	Brad Daniel ……....………….	4
STAFF-DR-02-005	Brad Daniel …….....………….	5
STAFF-DR-02-006	Brad Daniel …….....………….	6
STAFF-DR-02-007	Brad Daniel …….....………….	7
STAFF-DR-02-008	Brad Daniel …….....………….	8
STAFF-DR-02-009	Brad Daniel …….....………….	9
STAFF-DR-02-010	Jim McClay …….....………….	10
STAFF-DR-02-011	Jim McClay …….....………….	11
STAFF-DR-02-012	Jim McClay …….....………….	12
STAFF-DR-02-013	Libbie Miller …….....………….	13
STAFF-DR-02-014	Kimberly Hughes ......…………	14
STAFF-DR-02-015	Kimberly Hughes ......…………	15
STAFF-DR-02-016	Kimberly Hughes ......…………	16
STAFF-DR-02-017	Kimberly Hughes ......…………	17

STAFF-DR-02-018	Libbie Miller ……......………….	18
STAFF-DR-02-019	Libbie Miller ……......………….	19
STAFF-DR-02-020	Brad Daniel ……......………….	20
STAFF-DR-02-021	Brad Daniel ……......………….	21
STAFF-DR-02-022	Brad Daniel ……......………….	22
STAFF-DR-02-023	Scott Burnside Brad Daniel Libbie Miller ……......………….	23
STAFF-DR-02-024	Libbie Miller Scott Burnside ….......………….	24

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-001

REQUEST:

Refer to the Direct Testimony of Brad Daniel (Daniel Direct Testimony), page 5, lines 5–8. Explain the nature of Duke Kentucky's security constrained unit commitments.

RESPONSE:

Security-constrained economic dispatch is an optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the generation fleet and transmission system. In Duke Energy Kentucky's case, as a member of PJM, PJM performs the security constrained economic commitment and least-cost security constrained economic dispatch process that simultaneously optimizes energy and reserves for all generation in its footprint in determining which assets to commit and dispatch. PJM is responsible for commitment and dispatch of all its system resources via their security constrained unit commitment and least-cost economic dispatch model. Therefore, Duke Energy Kentucky follows commitment and dispatch signals provided by PJM.

Even though PJM is ultimately responsible for commitment of generators, the Company also can and does utilize Must Run offer status in order to commit units as most efficiently as possible, such as to ensure the unit to be committed from an offline state and to avoid uneconomic unit cycling. Once a unit is committed online, PJM's least-cost security constrained economic dispatch process directs a generators output through locational marginal price (LMP). When the unit is online and the unit's incremental cost offer price is greater than the LMP, under the fundamentals of economic dispatch, PJM will generally dispatch the output of the unit down between the economic maximum of the unit and economic minimum of the unit. Alternatively, when the unit is online and the unit's incremental cost offer price is less than LMP, under the fundamentals of economic dispatch, PJM will generally dispatch the output of the unit up between the economic minimum of the unit and economic maximum of the unit.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-002

REQUEST:

Refer to Daniel Direct Testimony, page 5, lines 9–10. Explain how each locational marginal price (LMP) is applied to specific generation units and to the utility. For example, the Day-Ahead LMP is used to select specific generation units available for dispatch the next day and the Real-Time LMP is used to govern actual available unit dispatch and explain whether the hourly energy price paid by market participants.

RESPONSE:

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved real-time security constrained economic dispatch program solution. Each generator receives its own nodal LMP, which is paid to Duke Energy Kentucky by PJM. The Day-Ahead and Real-Time markets are separate and distinct markets. The Day-Ahead market is a forward looking market focused on an operational planning horizon of the next day. Day-Ahead LMP is utilized to select resources for commitment and dispatch for the next operating day. Day Ahead LMP is issued at hourly granularity for the following day’s 24 hour operating period. If a generating unit is selected for commitment and/or dispatch by the Day-Ahead model, the unit receives a day-ahead award, which comprises the unit loading for a given hour and the corresponding day-ahead LMP the unit is paid.

The real time market functions as a balancing market between generation and load focused on updated real-time conditions. Real time LMP is issued every 5 minutes and is used to govern individual generator set points via PJM's security constrained unit commitment and least-cost economic dispatch model. If a unit does not receive a day-ahead award and is called upon to generate in the real-time, the unit will receive real-time LMP. If a unit receives a day-ahead award and is called on to generate more than its day-ahead award in the real-time, the unit will retain its day-ahead price up to the amount of its day ahead award and then be paid the real-time LMP for any generation above the day-ahead awarded amount.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-003

REQUEST:

Refer to Daniel Direct Testimony, page 7, lines 12–21. Explain both the operational timing and the economic rationale of a generation unit being dispatched, then placed into reserve shutdown for a period of time, then being dispatched again.

RESPONSE:

The Company submits updated supply offers to PJM each day by 1100 EPT. When a unit is available, the commitment decision for an available unit is between either a Must Run or Economic commitment status offer. There are operational differences between Economic and Must Run offers, mainly in how the unit is committed into the market. When offering a unit in the Day-Ahead market with Must Run status, the unit will receive a Day Ahead Award greater than or equal to the unit's minimum dispatchable load up to its maximum dispatchable load. When the Company offers the unit to PJM in the Day-Ahead market with an Economic status, the Company is allowing PJM to determine the commitment decision for the unit, whether the unit is in an already online state or an offline state. Day-Ahead awards are issued each day at 1330 EPT. Day-Ahead Awards notify the Company the commitment status and the day-ahead scheduled loading of a generating unit. Once a unit is committed online, either via Must Run or Economic status, the unit will be economically dispatched between its economic minimum and maximum load by PJM.

Commitment decisions involve many different inputs, including the initial state of the unit (on or off), expected revenue from operation of the unit, operating cost of the unit including replacement fuel cost, unit startup up cost, unit startup up time, risk around cycling off-line, minimum up and down times, the need to perform any required unit testing, weather and system reliability conditions and other factors. When available, Duke Energy Kentucky's coal unit, East Bend, is typically offered into the PJM Day-Ahead Market with a Must Run offer status to best optimize the unit's availability for dispatch in PJM. There could be times that warrant offering the East Bend unit with an Economic status. If revenues from running the unit are expected to be less than the units' variable costs, the unit can potentially be offered as Economic to PJM to allow PJM to determine the commitment decision for the unit. If East Bend was offered by the Company with an Economic status to PJM in the Day-Ahead Market and the unit was committed by PJM, the unit would dispatch the same in the Real-Time Market as it would when the unit was offered to PJM with a Must Run status in the Day-Ahead Market. In each case in the Real-Time market, PJM will economically dispatch the unit between its economic minimum and maximum load. If East Bend was offered by the Company with an Economic status in the Day-Ahead Market to PJM and the unit was not committed by PJM the unit would be de-committed offline and go into Reserve Shutdown once its Day-Ahead award ended or remain off-line in an already de-committed status. From its offline state, the unit would remain offline at least until it met its minimum downtime obligation and until committed by PJM either economically or for system reliability reasons or committed by the Company into Must Run status. Typically, when the East Bend unit is de-committed from the market in order to reinstate the unit into the market, the Company will commit the unit Must Run to be able to most efficiently and best optimize the unit's availability for dispatch in PJM. When considering whether to offer the East Bend unit as Economic to PJM, the Company considers the impact and risk of cycling the unit especially over short time periods in order to maintain a commitment strategy that best maximizes a generating unit's margin in the market while also best minimizing customer costs over time.

When available, the Company's Woodsdale units are typically offered with an Economic status into the Day-Ahead Market unless there is an operational necessity to commit the unit as Must Run, such as for unit testing. This is mainly due to the higher marginal cost to operate combustion turbine units compared to market prices as well as more flexible operating characteristics compared to coal unit, especially when it comes to cycling. Therefore, the Woodsdale units are able to run for shorter time periods to meet commitment awards from PJM, cycle offline into reserve shutdown and be committed and dispatched again after shorter shutdown periods.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-004

REQUEST:

Refer to Daniel Direct Testimony, page 8, lines 11–14. If energy can be purchased in either the Day-Ahead or the Real-Time markets, explain which energy price is the final purchase price paid by the utility when there are differences in the hourly energy prices or whether there is an hourly reconciliation between the two.

RESPONSE:

Duke Energy Kentucky offers all of its available generation and bids its forecasted demand into the Day-Ahead market. For generation cleared in the day-ahead market the Company is paid day-ahead LMP and for demand cleared in the day-ahead market the Company pays day-ahead LMP. The Real-Time Energy Market functions as a balancing market between generation and load in real-time. The Company pays or is paid the real-time LMP based on differences of unit loadings or demand values in real-time compared to the day-ahead cleared unit loading or demand value.

Hypothetical example A: The Company's East Bend unit receives a Day-Ahead (DA) award in a given hour for 400 MW with a DA LMP of $30/MWh. In the Real-Time (RT) East Bend is dispatched to 410 MW while the RT LMP is $35/MWh. In this case, PJM pays Duke Energy Kentucky 400 MWh * $30/MWh = $12,000 for the DA award. PJM also pays Duke Energy Kentucky an additional 10 MWh *$35/MWh = $350 for the extra 10 MW produced real-time.

Hypothetical example B: The Company's procures 400 MW of load in a given hour with a DA LMP of $30/ MWh. In the Real-Time, the Company's load is 410 MW while the RT LMP is $35/ MWh. In this case, Duke Energy Kentucky pays PJM 400 MWh * $30/MWh = $12,000 for the DA award. Duke Energy Kentucky also pays PJM an additional 10 MWh *$35/MWh = $350 for the extra 10 MW of demand in real-time.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-005

REQUEST:

Refer to Daniel Direct Testimony, page 9, lines 22–23 and page 10, lines 1–11. When the East Bend unit is committed as “must run”, the marginal cost of the unit is lower than the market price and the unit will run between its minimum and maximum load. Explain the circumstances governing the commitment of the unit in economic run status and whether the unit will run.

RESPONSE:

In circumstances when the market price of power drops below the unit offer and the generators’ market costs are expected to exceed the forecasted market revenues over an appropriate time period, the unit could be offered to PJM with an Economic status. If East Bend was offered by the Company with an Economic status to PJM in the Day-Ahead Market and the unit was committed by PJM, the unit would dispatch the same in the Real-Time Market as it would when the unit was offered to PJM with a Must Run status in the Day-Ahead Market. In both cases, once the unit reaches its minimum dispatchable load, in the Real-Time market PJM will economically dispatch the unit between its economic minimum and maximum load. However, if East Bend was offered by the Company with an Economic status in the Day-Ahead Market to PJM and the unit was not committed by PJM the unit would ramp off-line (if already in an on-line state) and/or remain off-line until or unless committed by PJM either economically or for system reliability reasons. The Company could also self-commit the unit in the Real-Time Market or offer the unit with a

Must Run status in the Day Ahead Market to ensure the unit's commitment with a Day-Ahead award.

Offering a unit with an Economic commitment status, at all times, includes risks that can either cause the unit to not be started when it is economic to operate or cause excessive cycling costs and shutdown the unit when it is economic to leave the unit on-line. This is due to the planning horizon of the PJM Day-Ahead market (24 hours) in relationship to the unit's practical minimum up time, minimum down time, and/or startup time. As a base-load coal-fired generator, East Bend cannot respond quickly to changes in power prices on an hourly or daily basis when a unit is cycled off as a result of an Economic commitment offer. For this reason, PJM may not call upon the units in the Day-Ahead Market because they cannot power up quickly enough in an offline state, even if it is otherwise economic to operate. In addition, unit cycling and resulting performance must be considered. For example, if the units were frequently cycled from off-line to on-line, the risk of error, damage, and unit degradation will increase. Failed start-up due to risks of thermal cycling could occur in this scenario, resulting in additional cost of repair, lost energy margins during the time that the unit was off-line for repair, and any additional PJM charges, *i.e.*, potential capacity performance charges. These factors are prudently evaluated when considering de-commitment for East Bend.

PERSON RESPONSIBLE: Brad Daniel

STAFF-DR-02-006

REQUEST:

Refer to Daniel Direct Testimony, page 12, lines 6–7. Explain whether Duke Kentucky has filed its updated back-up supply plan with the Commission.

RESPONSE:

The Company sought approval of its back-up supply plan in Case No. 2021-00086. The Company had requested approval of its hedging strategy through May 31, 2024. By Order dated November 30, 2021, the Commission approved the Company's plan through May 31, 2022. The Company again sought approval of a proposed a power hedging strategy in Case No. 2022-00372 and proposed a comprehensive hedging strategy utilizing the PJM AD Hub financial forward power markets that have available financial products to hedge exposures for monthly, weekly, and daily terms. The Company proposed to expand customer exposure price risk mitigation to include scheduled outages/derates, forced generation outages/derates and time periods where market prices are lower than operating the Company's owned generation assets. On October 12, 2023, the Commission issued its decision in Case No. 2022-372 and denied the Company's request to implement a comprehensive hedging plan that included hedging of purchased power and forced outages. The Commission authorized the Company to only hedge scheduled outages.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-007

REQUEST:

Refer to Daniel Direct Testimony, page 14, lines 6–8.

a. Explain whether the financial hedges are a PJM members-only financial product and if so, how the market for these instruments functions and whether they are zone specific.

b. Explain whether Duke Kentucky's financial hedging plan has been filed with the Commission and provide the cite. If not, provide a copy and explain the rationale governing the length of the hedge and how the size of the hedge is determined.

RESPONSE:

a. The Company utilizes InterContinental Exchange ("ICE") to conduct financial hedging activities. ICE is a clearinghouse comprised of market-wide entities and is not limited to PJM members-only. Essentially, ICE matches market bidders and sellers for specific financial contracts, which provides market participants' access to more liquid markets to effectively manage market price risk. Duke Energy Kentucky enters into financial futures contracts at PJM AD Hub, which is an aggregation of Locational Marginal Price (LMP) nodes defined by PJM most representative of generation and load characteristics of Duke Energy Kentucky generators and load.

b. Duke Energy Kentucky’s financial hedging plan was covered under the Company’s back-up supply plan which, by Commission order, expired May 31, 2022. The Company requested Commission approval of a comprehensive hedging program as part of its application in Case No. 2022-00372, that, among other things, included scheduled and forced outages, and for purchased power. On October 12, 2023 the Commission issued its decision in Case No. 2022-00372 that among other things, denied the Company’s request to also hedge economic power purchases and forced outages, but approved hedging for scheduled outages.

PERSON RESPONSIBLE: Brad Daniel

STAFF-DR-02-008

REQUEST:

Refer to Daniel Direct Testimony, page 14, lines 10–17. Explain whether the non-native sales to PJM, which occur when the units' dispatched generation is greater than Duke Kentucky's native load, is automatic or at Duke Kentucky's direction or discretion.

RESPONSE:

Non-native sales to PJM are essentially a function of Company generation compared to company load. When the amount of Duke Energy Kentucky generation online is greater than Duke Energy Kentucky demand, the Company will have non-native sales to PJM. The Company offers its generating units to PJM regardless of their anticipated allocation to Native or Non-Native load, and the Company does not attempt to offer generators differently based on the expectation of a generator's allocation to Native or Non-Native load.

PERSON RESPONSIBLE: Brad Daniel

STAFF-DR-02-009

REQUEST:

Refer to Daniel Direct Testimony, page 19, lines 21–23. If not already answered, when the unit is committed as "must run" and is operating at its minimum load, explain the parameters for Duke Kentucky's decision to go into reserve shutdown. Include in the response whether the decision parameters are according to PJM policy and requirements or are left up to the utilities generally.

RESPONSE:

Referring to Daniel Direct Testimony, page 19, lines 21–23, this response is focused on the commitment of the Company's East Bend coal unit. As discussed in response to STAFF-DR-02-005, in circumstances when the market price of power drops below the unit offer and the generators' market costs are expected to exceed the forecasted market revenues over an appropriate time period, the unit could be offered to PJM with an Economic status. The Company controls the offer status of the unit to PJM and PJM controls the commitment requirement through its Day-Ahead award notification process. PJM issues Day-Ahead Awards each day to notify the Company the commitment status and the day-ahead scheduled loading of a generating unit modeled by PJM. If a Day-Ahead award is issued by PJM (Economic or Must-Run), the commitment is financially binding between the Company and PJM. If a Day-Ahead Award is not issued, there is no binding Day-Ahead financial commitment between the Company and PJM. Starting from an online state, if East Bend was offered by the Company with an Economic status in the Day-Ahead

Market to PJM and the unit was not awarded a day-ahead commitment status by PJM the unit would either be de-committed offline and go into Reserve Shutdown once its Day-Ahead award ended or the Company could decide to self-commit the unit in the Real-Time market. As a matter of practice if the Company were to offer the unit as Economic to PJM and not receive a Day-Ahead award, the unit would be de-committed and go into Reserve Shutdown once its Day-Ahead award ends. There could be times the unit is self-committed into the Real-Time market as part of unit startup prior to its Day-Ahead award.

As also discussed in STAFF-DR-02-005, offering a unit with an Economic commitment status, at all times, includes risks that can either cause the unit to not be started when it is economic to operate or cause excessive cycling costs and shutdown the unit when it is economic to leave the unit on-line. This is due to the planning horizon of the PJM Day-Ahead market (24 hours) in relationship to the unit's practical minimum up time, minimum down time, and/or startup time. As a base-load coal-fired generator, East Bend cannot respond quickly to changes in power prices on an hourly or daily basis when a unit is cycled off as a result of an Economic commitment offer. For this reason, PJM may not call upon the unit in the Day-Ahead Market because the unit cannot power up quickly enough in an offline state, even if it is otherwise economic to operate. In addition, unit cycling and resulting performance must be considered. For example, if the units were frequently cycled from off-line to on-line, the risk of error, damage, and unit degradation will increase. Failed start-up due to risks of thermal cycling could occur in this scenario, resulting in additional cost of repair, lost energy margins during the time that the unit was off-line for repair, and any additional PJM charges, i.e., potential capacity performance charges. These factors are prudently evaluated when considering de-commitment into Reserve Shutdown for East Bend.

The Company takes these and several other factors into consideration when determining daily unit offers into the PJM energy and ancillary services market, with the goal of portfolio management strategy being to maximize generating units' margin and to ultimately minimize customer costs. The Company conducts a daily morning meeting with station and dispatch personnel to discuss topics including but not limited to market conditions, weather conditions, unit availability, unit parameters, and any scheduled or potential unit maintenance issues to determine inputs for its generating offers to PJM for the following day. The Company also constructs a daily profit and loss analysis that compares the unit's expected revenue to the incremental cost of the unit and provides an expected daily unit margin for the next three weeks based on expected market prices and expected unit variable costs. This profit and loss analysis provides company personnel insight to forecast expected margin of generating units, determine expected commitment status of its generating units and to communicate market risk factors to station personnel pertaining to any potential maintenance issues impacting a generating unit. Each of the factors discussed are considered parameters for the Company's commitment decision and any potential de-commitment into reserve shutdown.

PERSON RESPONSIBLE: Brad Daniel

STAFF-DR-02-010

REQUEST:

Refer to the Direct Testimony of Jim McClay, (McClay Direct Testimony), page 4, lines 15–16. Explain any synchronization and market clearing timing issues between the PJM Day-Ahead energy market and the natural gas supply market. Include in the response how Duke Kentucky deals with issues, if any, and its suggestions on how to eliminate any issues between these different markets.

RESPONSE:

PJM issues generation awards and dispatches in both the day ahead and real time. The Day Ahead dispatch is awarded at 1:30 pm for the next power day which begins 12:00am - 12:00am. The gas day is from 10:00am-10:00am which overlaps the power day. The gas market is more liquid in the morning timeframe when gas suppliers are actively selling gas to end users for the next gas day beginning 10:00am the following day. Gas purchases made after 2:00pm are considered "intraday" and subject to market liquidity. The mismatch in gas procurement and PJM day ahead power notifications forces the end users with marginally economical units to wait until PJM awards before a gas quantity can be calculated and procured. Intraday power dispatches, which can occur any time during the day or night, must rely on the intraday gas market or depending on pipeline conditions and restrictions, utilize gas from the pipeline which may be subject to penalty. The gas market and pipeline scheduling rely on NAESB scheduling deadlines to nominate gas for delivery on the pipelines. All gas for the existing gas day must be procured and scheduled prior to the NAESB scheduling deadline at 8:00pm.

In order to manage the differences between the power day awards and ideal timing of next day gas market supply procurement, the Company enters into physical gas supply enabling agreements (NAESB Agreements) with multiple gas suppliers to ensure natural gas can be procured at a competitive market price to meet the needs of the Company's gas generation fleet. When purchasing firm natural gas to meet day ahead and intra-day dispatch schedules, Duke Energy actively solicits bids from gas suppliers and purchases from the lowest cost supplier. A competitive solicitation with multiple counterparties ensures Duke Energy Kentucky is capturing the lowest market price gas for its customers. If gas in not available or volumes are cut by the supplier, Woodsdale has 72 Full load burn hours of onsite fuel oil to deliver its power commitments. Synchronizing the gas and power day would be one way to eliminate timing issues, another would be to establish a 24 hour gas market with additional NAESB deadlines to schedule the procured gas. At a minimum, change intraday PJM notifications to coordinate and allow enough time to procure gas supply (1-2 hours) prior to the NAESB deadline that aligns with future dispatch schedules.

PERSON RESPONSIBLE: Jim McClay

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-011

REQUEST:

Refer to McClay Direct Testimony, page 6, lines 11–13. Explain whether the Duke Energy Ohio Kentucky (DEOK) PJM Zone is the same thing as the PJM locational delivery area. If not, explain the differences.

RESPONSE:

PJM Locational Delivery Area (LDA) is a broader term. As mentioned in the testimony "PJM divides the RTO into multiple sub-regions called locational delivery areas (LDA) in order to model the locational value of generation." Duke Energy Ohio Kentucky (DEOK) PJM Zone is one of the LDAs.

PERSON RESPONSIBLE: Jim McClay

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-012

REQUEST:

Refer to McClay Direct Testimony, page 7, lines 1–19. Explain the reasons for the DEOK Zone being constrained and the actions that Duke Kentucky are taking or plan to take to alleviate the constraint(s).

RESPONSE:

Although no official reports are available on why DEOK Zone became constrained, empirical evidence pointed to coal generation unit retirements in the past 10 years that drastically reduced available generation capacity in the zone. As a result, the zone relied on imports to cover capacity shortfall, which leads to constraints in some years due to transmission limitations. One of the benefits of being an FRR entity in PJM is that only a certain percentage of capacity used in a FRR plan must come from within the zone. The rest can come from other zones. This percentage varies from year to year. It gives the Company more flexibility to manage capacity cost for the customers. The Company will continue to evaluate overall value of being an FRR entity or a RPM participant for the benefits of customers.

PERSON RESPONSIBLE: Jim McClay

STAFF-DR-02-013

REQUEST:

Refer to the Direct Testimony of Libbie S. Miller, (Miller Direct Testimony), page 4, lines 14–23 and page 5, line 1. The 2023 and 2024 projected average fuel prices are much higher than the proposed base fuel rate. Explain how the economic conditions and outlook today are different than they were at the time of the October 2022 forecast.

RESPONSE:

The economic conditions and outlook of the Company are different than they were when the Company's fuel forecast was prepared in October 2022. As Witnesses Hughes, McClay, and Daniel state in their Direct Testimonies, there was significant volatility in the coal, natural gas, and PJM power markets in 2022. The theme from the three witnesses is the markets saw extreme upward pressure from external market conditions that resulted in significantly higher commodity costs by late summer and early fall of 2022 – the same time the 2023-2024 fuel forecast was developed. By the time commodity costs had begun to soften in early 2023, the 2023-2024 fuel forecast was completed. Reviewing actual fuel costs from January 2023 through July 2023 supports the notion of more stable markets in 2023 than in 2022.

PERSON RESPONSIBLE: Libbie Miller

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-014

REQUEST:

Refer to Duke Kentucky's response to Commission Staff's First Request for Information (Staff's First Request), Item 2f. Explain whether the coal price is the delivered price of coal and provide the equivalent price in $/MMBtu.

RESPONSE:

The coal price provided in response to STAFF-DR-01-002(f) is the contracted commodity price per ton. As discussed in response to STAFF-DR-01-036 Duke Energy Kentucky's coal purchase contracts do not include transportation costs. However, the Company's contracted transportation costs are included in the evaluation to determine the total delivered cost of coal purchased. Duke Energy Kentucky procures coal FOB barge and is directly responsible for arranging the barge transportation from the delivery point proposed by the supplier to the plant.

Please see STAFF-DR-02-014 Attachment for the equivalent price in $/MMbtu.

PERSON RESPONSIBLE: Kimberly Hughes

Duke Energy Kentucky
Case No. 2023-00012- Staff Second Set Data Requests

Coal purchased November 1, 2020 - October 31, 2022

Vendor	Contract #	Purchased Tonnage	$/ton	$/Mmbtu
Alliance Coal LLC	DEK 34704	162,395	$55.00	*$2.18*
Central Coal Co	DEK 34495	57,825	$33.90	*$1.51*
Central Coal Co	DEK 34725	20,286	$44.00	*$1.96*
Alliance Coal LLC	DEK 34466	263,998	$39.00	*$1.55*
Case Coal Sales LLC	DEK 35111	1,543	$118.00	*$5.09*

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-015

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Items 1 and 2.

a. Explain why Duke Kentucky would enter into a long term contract with Case Coal Sales, LLC (Case Coal Sales) for such a small amount of coal.

b. Explain why the coal purchase price from Case Coal Sales is far out of line with other long term contract prices.

c. Explain when the other listed long term contracts expire.

RESPONSE:

a. Duke Energy solicited the market on May 19, 2022 with a Term Request for Proposal due by June 1, 2022 for coal to be delivered over the period of July 1, 2022 through December 31, 2025. Case Coal offered coal in response to the solicitation for delivery over the period of July 1, 2022 through March 31, 2024. The tons procured from Case Coal as a result of this solicitation were distributed on an approximate ratable schedule over the proposed term.

b. The coal purchase price from Case Coal varies in comparison to the other long term contract prices provided in response to Staff's First Request Items 1 and 2 due to the time frame in which the coal was solicited and procured. The other long term contracts were executed as a result of earlier solicitations and prior to the increase in global coal demand and subsequently rising coal prices in response to higher natural gas prices, overall declining domestic coal inventories and a strong export market receiving record high prices for coal overseas.

c. Please see STAFF-DR-02-015 Attachment for the long term contracts expiration dates.

PERSON RESPONSIBLE: Kimberly Hughes

Duke Energy Kentucky
Case No. 2023-00012- Staff second Set Data Requests
Coal purchased May 1, 2022 - October 31, 2022

Vendor	Purchase Tonnage	Purchase Type	Contract #	Filed with Commission	Expiration Dates	If no, Explain why
Alliance Coal LLC	162,395	Contract	DEK 34704	3/8/2022	1/31/2023	
Central Coal Co	57,825	Contract	DEK 34495	6/4/2021	1/31/2023	
Central Coal Co	20,286	Contract	DEK 34725	3/8/2022	12/31/2023	
Alliance Coal LLC	263,998	Contract	DEK 34466	6/4/2021	12/31/2025	
Case Coal Sales LLC	1,543	Contract	DEK 35111	4/4/2023	3/31/2024	

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-016

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 4. Item 4b states that only one bid was selected for term purchase and the attachment shows that two bids were selected. Explain whether one or two bids were selected and the length of the contract(s).

RESPONSE:

As a result of the Term Request for Proposal solicited in May 2022, Duke Energy Kentucky executed one agreement with Iron Senergy for coal to be delivered over a two year period. The attachment shows each year ranked by delivered costs for evaluation purposes but was considered as one bid.

PERSON RESPONSIBLE: Kimberly Hughes

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-017

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 4 attachment and Item 5 Attachment. Explain the rationale of purchasing Alliance coal on the basis of an oral solicitation at a higher price when a greater amount of Alliance coal from the same location was not purchased at a lower price as a result of the long term contract solicitation.

RESPONSE:

Duke Energy solicited the market in May 2022 with a spot solicitation to procure additional coal to support inventory levels and meet projected coal burns during the third and fourth quarter of calendar year 2022. Increased demand for coal both domestically and internationally as a result of high natural gas prices and overall declining inventory levels resulted in scarce availability of additional coal supply and significantly increased pricing over this period. In response to the spot solicitation, Alliance offered coal from the Tunnel Ridge mine for delivery over the period of July 1, 2022 through December 31, 2022, which Duke Energy Kentucky procured.

Duke Energy solicited the market again in late May 2022 in the form of a written term solicitation for coal to be delivered over the period of July 1, 2022 through December 31, 2025. Alliance submitted an offer for coal from the Tunnel Ridge mine in response to the Term Solicitation for deliveries to begin January 1, 2023. Duke Energy Kentucky evaluated this proposal in comparison to the other bids submitted and an alternative lesser cost coal bid was selected for the time period being considered.

PERSON RESPONSIBLE: Kimberly Hughes

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-018

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 25 Attachment. To the extent that Duke Kentucky forecasts customer growth and increases in energy demand over the next two years per its Integrated Resource Plan, explain how those forecasts and any more recent forecasts compare to the static total sales number.

RESPONSE:

In choosing the February 2022 rate as the proposed base fuel rate, the Company looked at fuel costs and sales together as a whole in the form of a rate, with less emphasis on the specific components (i.e., costs and sales) of the fuel rate. The Company reviewed the total native fuel rate in the 2-year review period, 2-year forecasted period, and actuals after the end of the review period from November 2022 through July 2023. As discussed in my testimony, the Company was of the opinion that the 2-year forecasted rates were not representative of rates going forward; therefore, the analysis in choosing a new base fuel rate focused more on the actual rates once that decision was made. The February 2022 static sales came in lower than the average and median 2-year forecasted sales amounts. However, the February 2022 static sales were more in line with the average and median sales of the two-year review period (November 2020 – October 2022) and with actuals after the end of the review period from November 2022 through July 2023.

PERSON RESPONSIBLE: Libbie Miller

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

STAFF-DR-02-019

REQUEST:

State whether any PJM costs were included in Duke Kentucky's monthly Fuel Adjustment Clause (FAC) filings during the period under review. If yes, provide the amount of the costs by month and by type of cost.

RESPONSE:

Please see STAFF-DR-02-019 Attachment for PJM costs by month and type of cost.

PERSON RESPONSIBLE: Libbie Miller

Type of Cost	PJM BLI	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021
1230-Inad Inter	1230	$ (99.70)	$ (1,089.12)	$ 689.84	$ (2,245.58)	$ (19.17)	$ 467.10	$ (366.05)	$ (1,482.35)	$ (4,433.01)	$ (7,970.58)	$ (1,619.05)	$ 1,601.10
1250-Meter Err Cor	1250	$ 3.74	$ (2,753.10)	$ 28.73	$ 6,854.84	$ 16.19	$ (82.75)	$ 119.60	$ (497.47)	$ (2.32)	$ (32.93)	$ 81.03	$ (2.11)
1340-Regulation	1340	$ (38,734.16)	$ (39,903.80)	$ (32,036.63)	$ (51,802.26)	$ (46,909.96)	$ (43,048.13)	$ (45,061.05)	$ (54,600.04)	$ (53,884.31)	$ (84,085.71)	$ (72,555.07)	$ (99,355.54)
1360-Synch Reserve	1360	$ (19,244.17)	$ (16,783.93)	$ (11,190.38)	$ (16,142.92)	$ (16,400.81)	$ (10,886.37)	$ (30,070.49)	$ (21,698.56)	$ (17,659.91)	$ (32,060.98)	$ (26,142.03)	$ (64,408.85)
1370-Operating Resrv	1370	$ (2,670.25)	$ (2,414.53)	$ (3,428.68)	$ (4,262.86)	$ (12,624.53)	$ (3,577.98)	$ (2,948.84)	$ (6,559.66)	$ (2,898.72)	$ (5,548.72)	$ (9,290.54)	$ (2,121.24)
1375-Bal Opr Rsrv	1375	$ (23,886.48)	$ (28,565.98)	$ (15,795.99)	$ (32,577.00)	$ (15,542.28)	$ (49,291.69)	$ (18,760.60)	$ (38,580.22)	$ (66,275.73)	$ (77,969.62)	$ (12,108.19)	$ (30,790.34)
1378-Reactive Servic	1378	$ -	$ (8.57)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10.03)	$ -
1500-FTR Shortfall	2211	$ 994.56	$ (557.09)	$ 87.65	$ 489.18	$ (48,554.76)	$ (3,378.38)	$ 16,900.46	$ (0.01)	$ (0.09)	$ (2,624.54)	$ (14,016.51)	$ (3,277.99)
1500-Mthly FTR Prem	1500	$ 0.28	$ (0.08)	$ 0.14	$ 0.16	$ (0.12)	$ 0.27	$ 0.13	$ 0.25	$ 0.17	$ 0.19	$ 0.22	$ (0.01)
2215-Bal Trns Cng Cr	2215	$ (66,891.65)	$ (57,418.42)	$ (144,896.89)	$ (224,776.75)	$ (111,553.75)	$ (113,221.78)	$ (68,292.62)	$ (84,595.22)	$ (15,975.11)	$ (84,619.87)	$ (38,485.12)	$ (77,369.47)
2220-Tran Loss	2220	$ 60,166.49	$ 98,042.71	$ 115,840.20	$ 203,164.48	$ 81,354.72	$ 68,122.15	$ 89,414.50	$ 138,150.24	$ 193,998.89	$ 208,449.37	$ 154,826.46	$ 177,697.17
2340-Lost Opp. Cost	2340	$ 0.19	$ 153.11	$ -	$ -	$ -	$ 995.18	$ -	$ 6,933.43	$ 1,808.67	$ 17,511.91	$ 594.49	$ 386.76
2360-Synch Reserve	2360	$ 1,249.51	$ 14,785.35	$ 13.03	$ 52.63	$ 7,502.35	$ 5,720.15	$ 6,395.01	$ 10,104.64	$ 7,646.48	$ 23,387.51	$ 1,323.98	$ 25,668.70
2370-DA Op Rsrv Cr	2370	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2375-Bal Opr Rsrv Cr	2375	$ 109,083.08	$ 79.52	$ -	$ 44,877.33	$ 39,178.40	$ 180,477.73	$ 47,629.38	$ 166,547.83	$ 367,103.51	$ 293,937.80	$ 29,292.19	$ 199,682.73
2510-ARR	2510	$ 279,788.70	$ 289,114.99	$ 313,799.98	$ 261,136.12	$ 289,114.99	$ 279,788.70	$ 289,114.99	$ 289,179.00	$ 315,327.35	$ 300,474.32	$ 285,502.50	$ 308,328.48
FTR	2211	$ (4,003.02)	$ (28,426.43)	$ (47,417.29)	$ 407,731.48	$ 702,175.59	$ 26,889.69	$ 354,696.35	$ 176,650.48	$ 225,408.96	$ 287,788.75	$ 119,989.70	$ 49,778.42
PJM Annual FTR Prem	1500	$ (266,902.81)	$ (275,799.56)	$ (275,799.56)	$ (249,109.28)	$ (275,799.57)	$ (266,902.80)	$ (275,799.56)	$ (283,648.67)	$ (293,103.62)	$ (293,103.62)	$ (283,648.68)	$ (293,103.62)
PJM Mthly FTR Prem	2500	$ 72,598.83	$ (14,190.79)	$ (5,399.10)	$ (10,887.96)	$ 76,328.95	$ 168,105.63	$ 37,247.61	$ (16,420.88)	$ (1,651.37)	$ (48,396.29)	$ (18,870.34)	$ 33,092.37
Reg.Supply	2340	$ 1,716.15	$ 5,835.17	$ -	$ -	$ -	$ 4,397.96	$ -	$ 17,687.31	$ 13,508.71	$ 122,064.46	$ 18,844.76	$ 18,791.27
PJM Yrly Cong Uplift	1218/2218	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,379.40)	$ -	$ -	$ -	$ -	$ -
Total PJM Costs		$ 103,169.29	$ (59,900.56)	$ (105,504.95)	$ 332,501.62	$ 668,266.25	$ 244,574.69	$ 396,839.43	$ 297,170.10	$ 668,918.55	$ 617,201.44	$ 133,709.77	$ 244,597.83
Congestion & Losses		$ 121,636.94	$ 57,200.95	$ 249,611.93	$ 683,277.08	$ 1,972,522.11	$ 641,916.98	$ 714,642.00	$ 303,505.08	$ 553,043.89	$ 667,847.12	$ 211,136.93	$ 210,174.76
Net Fuel Related RTO Billing Line Items		$ (18,467.65)	$ (117,101.52)	$ (355,116.88)	$ (350,775.46)	$ (1,304,255.87)	$ (397,342.29)	$ (317,802.57)	$ (6,334.98)	$ 115,874.65	$ (50,645.68)	$ (77,427.16)	$ 34,423.07

Type of Cost	PJM BLI	November 2021	December 2021	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022
1218-Planning Period Congestion Uplift	1218	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,920.86)	$ -	$ -	$ -	$ -	$ -
1230-Inad Inter	1230	$ 1,094.00	$ 1,368.58	$ 345.04	$ 473.93	$ 1,587.28	$ 5,850.13	$ 2,073.28	$ 3,664.63	$ (2,956.13)	$ 5,652.60	$ 10,503.91	$ 5,375.14
1250-Meter Err Cor	1250	$ 90.53	$ (33.03)	$ 134.09	$ 17.49	$ (18.78)	$ 11.14	$ 21.56	$ 106.41	$ (194.02)	$ (78.03)	$ (69.13)	$ (32.33)
1340-Regulation	1340	$ (129,377.35)	$ (72,625.86)	$ (178,918.37)	$ (77,257.56)	$ (70,074.56)	$ (127,136.09)	$ (114,166.13)	$ (151,497.84)	$ (162,684.38)	$ (180,694.47)	$ (119,276.88)	$ (103,365.78)
1360-Synch Reserve	1360	$ (65,749.94)	$ (31,966.59)	$ (26,785.63)	$ (16,703.53)	$ (10,563.24)	$ (28,576.27)	$ (55,725.40)	$ (103,248.05)	$ (60,925.01)	$ (81,465.46)	$ (16,450.89)	$ (26,358.03)
1370-Operating Resrv	1370	$ (3,799.88)	$ (7,590.52)	$ (3,168.68)	$ (2,043.16)	$ (2,113.99)	$ (2,581.66)	$ (11,050.56)	$ (20,746.83)	$ (52,432.50)	$ (37,702.23)	$ (31,828.58)	$ (1,329.08)
1375-Bal Opr Rsrv	1375	$ (34,600.18)	$ (18,672.35)	$ (43,815.01)	$ (13,034.30)	$ (17,588.36)	$ (23,155.00)	$ (35,423.44)	$ (46,670.87)	$ (73,041.82)	$ (85,765.11)	$ (28,018.72)	$ (37,235.99)
1500-FTR Shortfall	2211	$ (19,086.69)	$ (4,760.42)	$ 19,060.88	$ 1,242.23	$ 2,520.06	$ 73.73	$ 13,279.24	$ (42,867.89)	$ 42,638.04	$ (0.34)	$ 2,623.99	$ (8,520.40)
1500-Mthly FTR Prem	1500	$ 0.21	$ 0.31	$ 0.31	$ 0.04	$ 0.14	$ 0.11	$ 0.09	$ (0.04)	$ (0.04)	$ (0.05)	$ 0.05	$ 0.08
2215-Bal Trns Cng Cr	2215	$ (160,552.56)	$ (48,593.81)	$ (642,038.65)	$ (234,445.21)	$ (185,209.93)	$ (270,498.56)	$ (365,489.42)	$ (240,691.59)	$ (215,516.46)	$ (265,073.97)	$ (174,302.39)	$ (179,307.36)
2218-Planning Period Congestion Uplift	2218	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,734.92	$ -	$ -	$ -	$ -	$ -
2220-Tran Loss	2220	$ 183,842.15	$ 128,483.82	$ 351,907.07	$ 197,995.03	$ 131,880.48	$ 154,403.89	$ 257,878.50	$ 320,624.23	$ 462,871.46	$ 468,825.63	$ 301,508.82	$ 176,337.49
2340-Lost Opp. Cost	2340	$ 57,770.40	$ 874.73	$ 1,339.10	$ -	$ 15,580.38	$ 3,070.93	$ 7,447.41	$ 23,759.82	$ 28,875.97	$ 12,517.78	$ 4,194.12	$ 41.40
2360-Synch Reserve	2360	$ 79,707.95	$ 18,781.60	$ 15,471.89	$ -	$ 31,630.61	$ 33,595.52	$ 28,384.13	$ 207,240.73	$ 215,854.14	$ 122,448.91	$ 8,443.68	$ 20,891.62
2370-DA Op Rsrv Cr	2370	$ 106.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 749.62
2375-Bal Opr Rsrv Cr	2375	$ 460,421.85	$ 99,217.06	$ 49,374.09	$ 0.30	$ 18,206.02	$ 65,210.18	$ 32,565.10	$ 300,245.05	$ 897,150.02	$ 636,512.18	$ 88,543.26	$ 794,788.14
2510-ARR	2510	$ 281,742.00	$ 300,850.35	$ 304,780.22	$ 258,587.28	$ 323,878.39	$ 280,839.90	$ 304,871.67	$ 421,638.60	$ 435,893.79	$ 435,823.73	$ 420,417.30	$ 434,431.21
FTR	2211	$ 132,243.67	$ 46,396.72	$ (68,961.81)	$ 33,157.81	$ 88,221.19	$ 108,098.73	$ 171,070.10	$ 1,637,403.03	$ 772,594.53	$ 577,372.21	$ 638,282.03	$ 154,132.89
PJM Annual FTR Prem	1500	$ (283,648.66)	$ (293,103.63)	$ (293,103.63)	$ (264,738.76)	$ (293,103.63)	$ (283,648.66)	$ (293,103.62)	$ (319,348.46)	$ (329,993.41)	$ (329,993.40)	$ (319,348.46)	$ (329,993.38)
PJM Mthly FTR Prem	2500	$ (21.35)	$ (11,799.97)	$ (19,755.50)	$ (8,647.40)	$ 26.39	$ (203.95)	$ (32.78)	$ (6,533.10)	$ -	$ -	$ 70,319.31	$ 387,108.94
Reg.Supply	2340	$ 142,570.10	$ 11,192.31	$ 98,794.51	$ -	$ 12,240.22	$ 8,131.06	$ 39,956.52	$ 103,179.13	$ 170,904.67	$ 240,026.17	$ 9,755.67	$ 70,194.89
Total PJM Costs		$ 642,753.06	$ 118,019.28	$ (435,340.07)	$ (125,395.81)	$ 47,098.67	$ (76,514.86)	$ (19,629.69)	$ 2,086,256.95	$ 2,129,038.85	$ 1,518,406.16	$ 865,297.09	$ 1,357,909.07
Congestion & Losses		$ 213,804.06	$ 324,513.25	$ 75,242.43	$ 361,910.24	$ (5,553.48)	$ 254,302.81	$ 565,803.29	$ 1,255,810.17	$ 1,757,141.78	$ 1,152,322.93	$ 1,029,063.02	$ 76,269.13
Net Fuel Related RTO Billing Line Items		$ 428,949.00	$ (206,493.97)	$ (510,582.50)	$ (487,306.05)	$ 52,652.15	$ (330,817.67)	$ (585,432.98)	$ 830,446.78	$ 371,897.07	$ 366,083.23	$ (163,765.93)	$ 1,281,639.94

STAFF-DR-02-020

REQUEST:

Explain how Duke Kentucky's generating units are bid into PJM's energy market and the implications for the manner in which the units are run when the unit's bid in price is greater than the hourly locational marginal pricing (LMP). For example, if the unit is bid in as "must run" and its bid in price is greater than the hourly LMP, explain whether the unit is ramped down to its economic minimum output level or whether it is run at some level greater than that for some other reason such as balancing or voltage support.

RESPONSE:

Duke Energy Kentucky offers its units to PJM's energy and ancillary service market for commitment and dispatch purposes based on variable production costs used for the calculation of incremental cost, no-load cost, and startup cost. These costs are comprised of the market price of fuel and emissions plus variable operation and maintenance costs. For purposes of clarification, "commitment" means the decision to start a generator that is offline or to maintain online output from a generator that is already online and "dispatch" means the decision to operate an already committed generator at a certain megawatt output level. Once a unit has been committed and online above its economic minimum load, Duke Energy Kentucky predominantly follows PJM dispatch signals between its economic minimum load and economic maximum load. There are times in which the Company will "self-schedule" a generator's output with PJM under circumstances that are required for safety, testing, plant operational requirements, or reliability reasons. During these circumstances, the unit would be dispatched at a specific loading level and would not be at the discretion of PJM for economic dispatch. When the unit is online and the unit's incremental cost offer price is greater than the LMP, under the fundamentals of economic dispatch, PJM will generally dispatch the output of the unit down between the economic maximum of the unit and economic minimum of the unit. Alternatively, when the unit is online and the unit's incremental cost offer price is less than the LMP, under the fundamentals of economic dispatch, PJM will generally dispatch the output of the unit up between the economic minimum of the unit and economic maximum of the unit. As mentioned above, there are times in which the Company will "self-schedule" a generator's output with PJM under circumstances that are required for safety, testing, plant operational requirements, or reliability reasons. During these circumstances the unit would not be at the discretion of PJM for economic dispatch. The Company also can and does "self-schedule" the unit as Must Run in order to commit the unit as most efficiently as possible, such as to ensure the unit to be committed from an offline state and to avoid uneconomic unit cycling.

Additionally, PJM co-optimizes Energy and Ancillary Services; thus, the Company's generators also offer ancillary service products such as regulation, synchronized and non-synchronized reserves or day-ahead scheduling reserves, in addition to energy. Additionally, the Company's generators can also supply black start and reactive reserve where applicable.

PERSON RESPONSIBLE: Brad Daniel

Duke Energy Kentucky
Case No. 2023-00012
STAFF Second Set of Data Requests
Date Received: October 5, 2023

PUBLIC STAFF-DR-02-021
(As to Attachments only)

REQUEST:

In an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible, for the period under review and when the units are available to run,

a. Provide the bid status (i.e. economic dispatch, must-run, etc.), by day, of Duke Kentucky's generating units into PJM's day ahead market. Explain the reason for each bid status.

b. Provide the price per MWH, by day, of Duke Kentucky's generating units bid into PJM's day ahead market and the corresponding LMP indicating whether or not the unit cleared the market.

c. In a separate spreadsheet Tab, provide a graphical representation of the information in part b. above.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachments only)

a. Please see STAFF-DR-02-021(a) Confidential Attachment that provides the bid status (i.e. economic dispatch, must-run, etc.), by day, of Duke Energy Kentucky's generating units into PJM's day ahead market and the reason for each bid status.

b. Please see STAFF-DR-02-021(b) Confidential Attachment for the price per MWH, by day, of Duke Energy Kentucky's generating units' bid into PJM's day ahead market with the following information: Day Ahead offer price pair quantities by unit, startup and no load costs by unit, the hourly Day-Ahead LMP by unit, and the hourly DA award for each unit.

c. Please see STAFF-DR-02-021(c) Confidential Attachment.

PERSON RESPONSIBLE: Brad Daniel

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-021(a)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-021(b)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-021(c)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

STAFF-DR-02-022

REQUEST:

Explain how often PJM denies a request made by Duke Kentucky to place a generating unit in maintenance outage. Also provide a general description for how often PJM denies other entities request to place a generating unit in maintenance outage in the Duke Kentucky's region.

RESPONSE:

PJM as a matter of practice does not deny requests made by Duke Energy Kentucky to place a generating unit into maintenance outage unless the maintenance outage will impact grid reliability. PJM's Operating Manual 10 covers Pre-Scheduling Operations, including Generation Outage reporting and scheduling. According to Manual 10, section 2.1 PJM only rejects outage requests when they affect the reliability of the PJM RTO. Concurrently, the Company proactively schedules maintenance outages when grid reliability is not at risk. The Company had no instances during the review period in which a Maintenance Outage request was denied by PJM. PJM also has discretion to approve a Maintenance Outage then recall it due to grid reliability concerns. The Company had no instances during the review period in which an approved Maintenance Outage was recalled by PJM. Company personnel are not able to view other entities outage requests in PJM's eDART (Dispatcher Application and Reporting Tool) generation outage request tool and is unable to comment on how often PJM denies other entities request to place a generating unit in maintenance outage in the Duke Energy Kentucky’s region.

PERSON RESPONSIBLE: Brad Daniel

STAFF-DR-02-023

REQUEST:

For the two-year period under review, provide each instance an error or misreport was made by Duke Kentucky on its FAC form A rate sheet filing. For each instance provide:

a. An explanation on the error that occurred and why the error was made.

b. Duke Kentucky's actions taken to correct for the error and to ensure future similar errors do not occur.

c. Revised FAC form A rate sheets showing the actual fuel related expenses and sales as correctly calculated pursuant to 807 KAR 5:056.

RESPONSE:

<u>Error #1</u>

a. In expense month September 2022, the "Non-Native Sales Including Interchange Out" line on Schedule 3 was incorrectly reported at 6,510,510 kWh when it should have been reported as 5,742,130 kWh. As a result, the Sales on Line 2 of Schedule 1 was incorrect and caused the FAC rate on line 4 to be calculated at a rate of $0.036071 instead of the correct rate of $0.035933. The supporting schedules provided to complete the filing inadvertently contained an incorrect number due to a manual input error of the source data.

b. The Company found the error during preparation of STAFF-DR-01-013 Attachment in the review process in Case No. 2023-00012. Corrections were made in the FAC filing for expense month September 2023 as a prior period adjustment on Schedule 5, line 13. Details of the correction are on Schedule 7 – Prior Period Adjustments of the same September 2023 filing. To ensure the error is not repeated, Company personnel have started comparing the non-native sales kWh that are manually input into the supporting schedules for the filing to an independent database within the Company's network of systems.

c. Please see STAFF-DR-02-023 Attachment for the correction. Schedule 7 – Error #1, page 1, shows the before and after view and dollar impact of the correction. Schedule 7 – Error #1, page 2, shows the original Schedules 1 and 3. Schedule 7 – Error #1, page 3, shows the revised Schedules 1 and 3.

<u>Error #2</u>

a. In expense month March 2021, as reported on Schedule 6-RTO Resettlements Fuel Cost Schedule in the FAC filing for July 2021 expense month, the "'Fuel (substitute cost during Forced Outage(a)" line on Schedule 6 was reported at -$5,213.31. The error was partially a result of a query tool incorrectly calculating the MWh of East Bend station derated energy that was replaced by Woodsdale station generation and power purchased from PJM and natural gas purchases and consumption recorded on the books for Woodsdale station were negative due to reversal of the prior month estimate and prior month actual true-ups.

b. The Company corrected the MWh of derated energy at East Bend by making a code change in the query tool. The Company made the correction in the FAC filing for expense month January 2023 as part of the prior period adjustment on Schedule 2, line H and Schedule 7. To ensure the error is not repeated going forward, the Company will check the hours each month in the circumstances when East Bend is derated and Woodsdale is making up part of the shortfall generation and will also check for negative gas purchases and consumption in the same month. If the combination of these two circumstances occurs in the same month, then further analysis will be performed to ensure no negative derate dollar amounts appear in the FAC. The Company reviewed all months in this 2-year review period (November 2020 – October 2022) plus the months after the 2-year review period (November 2022 – July 2023) to ensure this error did not occur again. No additional errors were found.

c. Please see STAFF-DR-02-023 Attachment for the correction. Schedule 7 – Error #2, page 4, shows the original, revised, and adjusted dollar impact of the correction.

Error #3

a. In expense month July 2022, as reported on Schedule 6-RTO Resettlements Fuel Cost Schedule in September 2022, the "Economy Purchases" line on Schedule 6, Section B, was incorrectly reported at $12,042,718.61 when it should have been reported at $10,423,646.85. The error was a result of an incorrect load reconciliation submitted to PJM for the Duke Energy Ohio and Kentucky (DEOK) zone for one day, July 7, 2022. The error impacted the load for all users of the DEOK zone, including Duke Energy Kentucky load. Due to the error, Duke Energy Kentucky's load purchased from PJM was overstated for July 7. 2022. It was corrected at PJM with a Miscellaneous Bilateral Transaction on the December 2022 PJM invoice which was booked in January 2023.

b. The Company made the correction in the FAC filing for expense month January 2023 as part of the prior period adjustment on Schedule 2, line H and Schedule 7. Duke Energy has implemented two new checkpoints into the reconciliation process to prevent this type of error in the future. First, the Company implemented a monthly report that checks for any discrepancies between internal load schedules and PJM preliminary load schedules. Secondly, during monthly close out for PJM settlement a manual check is performed comparing internal load schedules versus external load schedules.

c. Please see STAFF-DR-02-023 Attachment for the correction. Schedule 7 – Error #3, page 5, shows the original, revised, and adjusted dollar impact of the correction.

<u>Error #4</u>

a. In expense month July 2021, as reported on Schedule 6-RTO Resettlements Fuel Cost Schedule in November 2021, a temporary, non-FAC, reconciling entry was made in the CXL system in order to tie CXL to PJM settlement statements. Once the issue causing the discrepancy was identified and investigated, the reconciling entry was removed, and the transactions were entered into CXL with all of the appropriate data to be included in the FAC filing.

b. The Company made the adjustment in the FAC filing for expense month February 2022 as part of the prior period adjustment on Schedule 2, line H and Schedule 7. The controls the Company currently have in effect worked to identify the discrepancy. However, it took longer than the normal resettlement update process to determine the cause of the discrepancy.

c. Please see STAFF-DR-02-023 Attachment for the correction. Schedule 7 – Error #4, page 6, shows the original, revised, and adjusted dollar impact of the correction.

PERSON RESPONSIBLE: Scott Burnside – Errors #1, #2 and #4 (a & b)
Brad Daniel – Error #3 (a & b)
Libbie Miller – Errors #1, #2, #3, & #4 (c)

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTION
OVER OR (UNDER) RECOVERY SCHEDULE 5

	Expense Month: September 2022		**Original September 2022 Over/(Under) Recovery**	**Revised September 2022 Over/(Under) Recovery**	**Adjustment**
			Original FAC Filing Expense Month: November 2022	**Updated in FAC Filing Exp Month: September 2023**	**Over/(Under) Dollars ($) [(a)]**
1	FAC Rate Billed ($/kWh)	(+)	0.036071	0.035933	(0.000138)
2	Retail kWh Billed at Above Rate	(x)	262,704,024	263,712,934	1,008,910
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$ 9,475,996.86	$ 9,475,996.86	$ -
4	kWh Used to Determine Last FAC Rate Billed	(+)	321,177,184	321,895,620	718,436
5	Non-Jurisdictional kWh included in Line 4	(-)	-	-	-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)		321,177,184	321,895,620	718,436
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$ 11,585,182.20	$ 11,566,675.31	$ (18,506.89)
8	Over or (Under) (Line 3 - Line 7)		$ (2,109,185.34)	$ (2,090,678.45)	$ 18,506.89
9	Total Sales (Schedule 3, Line C)	(-)	296,154,378	296,154,378	-
10	Kentucky Jurisdictional Sales	(+)	296,154,378	296,154,378	-
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)		1.00000	1.00000	-
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$ (2,109,185.34)	$ (2,090,678.45)	$ 18,506.89
13	Amount Over or (Under) Recovered in prior filings	(-)	$ -	$ -	$ -
14	Total Company Over or (Under) Recovery		$ (2,109,185.34)	$ (2,090,678.45)	$ 18,506.89

Note: [(a)] Correction of the September 2022 FAC rate billed on line 1 due to non-native sales reported as 6,510,510 kWh instead of the correct kWh of 5,742,130 on Schedule 3.
See page 2 of 6 for original schedules and page 3 of 6 for revised schedules.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE 1

Expense Month: September 2022 **Original Schedule 1**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel Fm (Schedule 2, Line K)		$ 19,743,252.39		
2	Sales Sm (Schedule 3, Line C)	÷	321,177,184		0.061472
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.036071

DUKE ENERGY KENTUCKY
SALES SCHEDULE 3

Expense Month: September 2022 **Original Schedule 3**

			Kilowatt-Hours Current Month
A.	Generation (Net)	(+)	171,048,000
	Purchases Including Interchange-In	(+)	178,967,520
	Sub-Total		350,015,520
B.	Pumped Storage Energy	(+)	-
	Non-Native Sales Including Interchange Out	(+)	6,510,510
	System Losses (343,505,010 KWH times 6.5%) [(a)]	(+)	22,327,826
	Sub-Total		28,838,336
C.	Total Sales (A - B)		321,177,184

Note: (a) Average of prior 12 months.

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE 1

Expense Month: September 2022 | **Revised Schedule 1**

Line No.	Description		Amount		Rate ($/kWh)
1	Fuel Fm (Schedule 2, Line K)		$ 19,743,252.39		
2	Sales Sm (Schedule 3, Line C)	÷	321,895,620	(a)	0.061334
3	Base Fuel Rate (Fb/Sb) per PSC Order in Case No. 2021-00057			(-)	0.025401
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)				0.035933

DUKE ENERGY KENTUCKY
SALES SCHEDULE 3

Expense Month: September 2022 | **Revised Schedule 3**

			Kilowatt-Hours Current Month
A.	Generation (Net)	(+)	171,048,000
	Purchases Including Interchange-In	(+)	178,967,520
	Sub-Total		350,015,520
B.	Pumped Storage Energy	(+)	-
	Non-Native Sales Including Interchange Out	(+)	5,742,130 [b]
	System Losses (344,273,390 KWH times 6.5%) [a]	(+)	22,377,770
	Sub-Total		28,119,900
C.	Total Sales (A - B)		321,895,620

Note: (a) Average of prior 12 months.
(b) Corrected non-native sales from 6,510,510 kWh to 5,742,130 kWh discovered during the preparation of Case No. 2023-00012 data requests

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE 6

Expense Month: March 2021

		Original March 21 S105	Revised March 21 S105	Adjustment
		Exp Month: July 2021	Updated in Exp Month: January 2023	March 2021 Settlement Update Dollars ($) [b]
A. Company Generation				
Coal Burned	(+)	$ 6,489,966.27	$ 6,489,966.27	$ -
Oil Burned	(+)	118,040.26	118,040.26	-
Gas Burned	(+)	(21,000.00)	(21,000.00)	-
Net Fuel Related RTO Billing Line Items	(-)	(1,291,401.06)	(1,291,401.06)	-
Fuel (assigned cost during Forced Outage [a])	(+)	31,259.18	31,259.16	(0.02)
Fuel (substitute cost during Forced Outage [a])	(-)	(5,213.31)	-	5,213.31
Sub-Total		$ 7,914,880.08	$ 7,909,666.75	$ (5,213.33)
B. Purchases				
Economy Purchases	(+)	$ 723,925.85	$ 723,925.85	$ -
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	36,985.48	36,985.14	(0.34)
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ 686,940.37	$ 686,940.71	$ 0.34
C. Non-Native Sales Fuel Costs		$ 687,053.01	$ 687,053.01	$ -
D. Total Fuel Costs (A + B - C)		$ 7,914,767.44	$ 7,909,554.45	$ (5,212.99)
E. Total Fuel Costs Previously Reported		$ 7,872,159.07	$ 7,872,159.07	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ 42,608.37	$ 37,395.38	$ (5,212.99)

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Corrected derate calculations for March 2021 expense month

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE 6

Expense Month: July 2022

		Original July 22 S105	Revised July 22 S105	Adjustment
		Exp Month: November 2022	Updated in Exp Month: January 2023	July 2022 Settlement Update Dollars ($) [b]
A. Company Generation				
Coal Burned	(+)	$ 7,226,972.27	$ 7,226,972.27	$ -
Oil Burned	(+)	128,605.31	128,605.31	-
Gas Burned	(+)	2,102,900.00	2,102,900.00	-
Net Fuel Related RTO Billing Line Items	(-)	232,614.12	232,614.12	-
Fuel (assigned cost during Forced Outage(a))	(+)	446,583.98	446,583.98	-
Fuel (substitute cost during Forced Outage(a))	(-)	343,509.32	343,509.32	-
Sub-Total		$ 9,328,938.12	$ 9,328,938.12	$ -
B. Purchases				
Economy Purchases	(+)	$ 12,042,718.61	$ 10,423,646.85	$ (1,619,071.76)
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	1,424,109.13	1,424,109.13	-
Less purchases above highest cost units	(-)	-		-
Sub-Total		$ 10,618,609.48	$ 8,999,537.72	$ (1,619,071.76)
C. Non-Native Sales Fuel Costs		$ 542,362.92	$ 542,362.92	$ -
D. Total Fuel Costs (A + B - C)		$ 19,405,184.68	$ 17,786,112.92	$ (1,619,071.76)
E. Total Fuel Costs Previously Reported		$ 18,880,363.52	$ 18,880,363.52	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ 524,821.16	$ (1,094,250.60)	$ (1,619,071.76)

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Refund for incorrect load reconciliation affecting power purchased on July 7, 2022

DUKE ENERGY KENTUCKY
PRIOR PERIOD CORRECTIONS
FUEL COST SCHEDULE 6

Expense Month: July 2021

		Original July S105	Revised July S155	Adjustment
		Exp Month: November 2021	Updated in Exp Month: February 2022	July 2021 Settlement Update Dollars ($) [b]
A. Company Generation				
Coal Burned	(+)	$ 6,938,910.49	$ 6,938,910.49	$ -
Oil Burned	(+)	172,053.68	172,053.68	-
Gas Burned	(+)	386,994.80	386,994.80	-
Net Fuel Related RTO Billing Line Items	(-)	99,974.37	107,490.13	7,515.76
Fuel (assigned cost during Forced Outage(a))	(+)	523,616.42	524,128.57	512.15
Fuel (substitute cost during Forced Outage(a))	(-)	43,150.77	43,150.77	-
Sub-Total		$ 7,878,450.25	$ 7,871,446.64	$ (7,003.61)
B. Purchases				
Economy Purchases	(+)	$ 3,140,078.34	$ 3,193,160.07	$ 53,081.73
Other Purchases	(+)	-		
Other Purchases (substitute for Forced Outage[a])	(-)	$ 979,882.60	$ 980,721.31	$ 838.71
Less purchases above highest cost units	(-)	-		
Sub-Total		$ 2,160,195.74	$ 2,212,438.76	$ 52,243.02
C. Non-Native Sales Fuel Costs		$ 308,671.15	$ 296,920.52	$ (11,750.63)
D. Total Fuel Costs (A + B - C)		$ 9,729,974.84	$ 9,786,964.88	$ 56,990.04
E. Total Fuel Costs Previously Reported		$ 9,848,865.42	$ 9,848,865.42	$ -
F. Prior Period Adjustment		$ -	$ -	$ -
G. Adjustment due to PJM Resettlements		$ (118,890.58)	$ (61,900.54)	$ 56,990.04

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Corrected a discrepancy between PJM and the Company's internal systems

STAFF-DR-02-024

REQUEST:

For each month of the review period, provide the total amount of fuel related cost that occurred during a forced outage that was disallowed pursuant to 807 KAR 5:056, or that Duke Kentucky was unable to collect via any other means.

RESPONSE:

Please see STAFF-DR-02-024 Attachment for disallowed FAC costs due to forced outages and for FAC costs not collected via any other means.

PERSON RESPONSIBLE: Libbie Miller
Scott Burnside

Type of Cost		November 2020	December 2020	January 2021	Febrauary 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021
Fuel (assigned cost during Forced Outage[a])	(+)	$ 51,016.98	$ -	$ 875,049.67	$ -	$ 31,259.16	$ 198,176.59	$ -	$ 46,701.10	$ 524,128.57	$ 1,814,872.94	$ 1,060,259.05	$ -
Fuel (substitute cost during Forced Outage[a])	(-)	$ -	$ -	$ 53,679.27	$ -	$ -	$ 25,639.52	$ -	$ -	$ 43,150.77	$ -	$ 3,681.48	$ -
Other Purchases (substitute for Forced Outage[a])	(-)	$ 52,901.22	$ -	$ 1,213,596.94	$ -	$ 36,985.14	$ 286,050.21	$ -	$ 91,956.78	$ 980,721.31	$ 3,555,798.70	$ 1,782,944.50	$ -
Total Disallowed FAC Costs Due to Forced Outages		$ (1,884.24)	$ -	$ (392,226.54)	$ -	$ (5,725.98)	$ (113,513.14)	$ -	$ (45,255.68)	$ (499,743.51)	$ (1,740,925.76)	$ (726,366.93)	$ -
Purchases Above Highest Cost Units Not Recovered by Duke Energy Kentucky		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Type of Cost		November 2021	December 2021	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 22
Fuel (assigned cost during Forced Outage[a])	(+)	$ -	$ 123,617.55	$ 11,241.72	$ 271,590.96	$ -	$ -	$ 953,898.36	$ 362,992.49	$ 446,583.98	$ 317,710.07	$ 11,122.19	$ -
Fuel (substitute cost during Forced Outage[a])	(-)	$ -	$ -	$ -	$ 4,970.62	$ -	$ -	$ 56.42	$ 62,290.34	$ 343,509.32	$ 42,787.80	$ -	$ -
Other Purchases (substitute for Forced Outage[a])	(-)	$ -	$ 190,400.08	$ 27,556.86	$ 649,303.60	$ -	$ -	$ 3,029,095.63	$ 1,209,768.10	$ 1,424,109.13	$ 1,166,538.20	$ 39,271.27	$ -
Total Disallowed FAC Costs Due to Forced Outages		$ -	$ (66,782.53)	$ (16,315.14)	$ (382,683.26)	$ -	$ -	$ (2,075,253.69)	$ (909,065.95)	$ (1,321,034.47)	$ (891,615.93)	$ (28,149.08)	$ -
Purchases Above Highest Cost Units Not Recovered by Duke Energy Kentucky		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,918.65	$ -	$ -	$ -	$ -

Notes:
[a] Forced Outage as defined in 807 KAR 5:056