**COMMONWEALTH OF KENTUCKY**
**BEFORE THE PUBLIC SERVICE COMMISSION**

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| In the matter of: | : | |
| ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY | : | CASE NO. 2024-00326 |

## KENTUCKY COAL ASSOCIATION'S POST-HEARING COMMENTS

The Kentucky Coal Association (KCA) intervener in this action respectfully submits the following post-hearing comments in this matter:

### Summary

This is a supplement to KCA's February 28, 2025, comments on the IRP.

This supplemental testimony focuses on the following issues:

- Changes in Federal regulatory policy;
- The continued uncertainty with respect to load growth upon which the IRP is forecasting;
- The failure to include a proposed data center tariff in the IRP that would protect traditional customers from the financial consequences associated with their default;
- Additional information supporting KCA's earlier conclusions about the fuel price forecasts used in the IRP; and
- The financial consequences and rate impact of the preferred plan.

A summary of the findings are as follows:

- Given the issues KCA raised in its initial IRP comments combined with the items raised in these comments, the IRP cannot be relied upon for supporting a Certificate of Public Convenience and Necessity (CPCN).
- The Companies' forecast load growth is not firm as while there are Data Center prospects, the Companies have not entered into any agreements to provide electrical service.
- The Companies are just beginning to negotiate a Data Center Rate with the Commission. The filing made by the Companies on May 30, 2025 does not adequately protect traditional ratepayers if there is a default.
- The outlook for CCGT's has changed since the filing of the IRP due to many factors including cost inflation, tariffs, supply chain constraints, and increased CCGT demand.

The Companies acknowledged they will be challenged to meet the construction dates put forward in their IRP. The Companies need to re-evaluate the cost and timing of the preferred plan given these changes.

- KCA recommends the Companies incorporate third party fuel price forecasts into the analysis. Intercompany mathematical correlation of the Companies historical coal to gas purchases to forecast fuel price for long range planning should be compared to industry accepted third party forecasts to determine reasonableness and support credibility of the fuel price assumptions used by the Companies.
- The Companies acknowledge that their parent, PPL Inc., is committed to net-zero carbon emissions by 2050. The Companies have not incorporated this commitment in their analyses. The analyses for carbon emitting sources should address the 2050 net-zero commitment by assuming closure of carbon emitting assets, the purchase/cost of carbon offsets beyond 2050, and/or PPL's commitment to not seek recovery of stranded and replacement costs.

**Changes in Federal Regulatory Policy**

The Trump Administration is moving forward with changes to a number of regulations on utility power plants. On June 11, 2025, the Environmental Protection Agency (EPA) announced the proposed repeal of the 2024 MATS rule amendments, the 2015 New Source Performance Standards (NSPS) for new coal plants which required new coal plants to be equipped with Carbon Capture and Sequestration (CCS), and the 2024 Carbon Pollution Standards (GHG Rule). The EPA provides two alternative proposals for repealing the rules, seeking public comment on both. The primary proposal eliminates all federal GHG requirements for fossil power plants by asserting these sources do not "significantly contribute" to harmful air pollution. The alternative proposal reinterprets what qualifies as the "best system of emission reduction" (BSER), revoking many elements of the 2024 rule while retaining the 2015 NSPS. Legal challenges are expected under both proposals, and a final rule is anticipated by year-end. However, compliance with the 2024 GHG rule timelines is unlikely since both proposals repeal the rule.

| Feature | Primary Proposal | Alternative Proposal |
|---|---|---|
| 2015 Coal GHG NSPS | Repealed | Retained |
| 2024 GHG Rule | Fully repealed | Mostly repealed |
| BSER definitions | Not required; no significant contribution finding (SCF) for EGUs | CCS deemed not adequately demonstrated or cost-effective; 40% co-firing deemed illegal "generation shifting", inefficient, and infrastructure-limited |
| 2009 Endangerment Finding | Reinterpreted to exclude stationary sources like EGUs | Not addressed |
| Regulatory Implications | No replacement needed unless a new sector-specific SCF is issued | Future rulemaking under Section 111(d) is still likely required for existing EGUs |

The 2024 Mercury and Air Toxics (MATS) proposed rolls back (1) the stricter filterable particulate matter (fPM) limit (0.010 → 0.030 lbs/MMBtu), (2) the lower mercury (Hg) limit for lignite-fired EGUs (1.2 → 4.0 lbs/TBtu), and (3) the PM Continuous Emission Monitoring System (CEMS)-only compliance requirement, restoring monitoring flexibility. EPA justifies the repeal under Clean Air Act Section 112(d)(6), citing cost-effectiveness concerns, limited environmental benefit, and unrepresentative data supporting the 2024 standards. If finalized, the rule would re-establish the more flexible and less stringent 2012 MATS framework, aligning with recent deregulatory efforts.

| Requirement | 2024 MATS Amendment (To Be Repealed) | 2012 MATS Standard (To Be Reinstated) |
|---|---|---|
| fPM Limit (Coal EGUs) | 0.010 lbs/MMBtu | 0.030 lbs/MMBtu |
| Hg Limit (Lignite-Fired EGUs) | 1.2 lbs/TBtu | 4.0 lbs/TBtu |
| fPM Monitoring Method | PM CEMS only | Quarterly stack tests, CPMS, or PM CEMS |
| Low Emitting EGU (LEE) Program | Eliminated | Reinstated |

Both rules will have a 45-day comment period following their publication in the Federal Register. In both instances, EPA indicated it plans to publish final rules before the end of the year. Given the proposed time frame, decisions should not be made regarding compliance with the existing rules at this time.

**Uncertainty with Respect to Load Growth**

The Companies continue to believe that their load growth increase will be substantial. However, the uncertainties related to the cost of new generation as a result of increased demand and tariffs, delays in the supply chain, and competition from other utilities for data center projects places material risk upon existing rate payers, if the load growth needed to support the generation buildout does not materialize.

A reported speech given by NextEra CEO, John Ketchum, at the March 2025 CERA Conference reflect these concerns. [1]

> *A backlog in gas turbine manufacturing could slow the growth of gas in the power sector, according to NextEra Energy, one of the largest power plant builders in the U.S.*
>
> *The explosive growth of data centers has raised expectations that the U.S. will see a surge in gas consumption. Some forecasts see electricity used for data centers tripling by 2028.*

[1] https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/

*At the CERAWeek conference in Houston in mid-March, oil and gas executives talked excitedly about the growth prospects for gas provided by the AI boom. There was wide speculation that gas would account for much of the new electricity demand.*

*But not everyone saw it that way.*

*"There is a lot of demand for gas turbines right now. You have to get in a long line. It has pushed the prices up," NextEra Energy CEO John Ketchum said at CERAWeek. NextEra built 16 gigawatts of gas-fired power over the past two decades, and operates a fleet of 26 GW of gas capacity. It also builds renewable energy.*

*"**We built our last gas-fired facility in 2022, at $785/kW. If we wanted to build that same gas-fired combined cycle unit today…$2,400/kW," he said. "The cost of gas-fired generation has gone up three-fold."*** (emphasis added)

*Not only are gas turbine costs shooting up, but the backlog of orders means that they are hard to come by in the near-term. On top of that, gas plants can take several years to build.*

*"When you look at gas as a solution…you're really looking at 2030 or later," Ketchum said.*

***Ketchum said that the U.S. will need 460 gigawatts of additional capacity by 2030, but gas can only account for roughly 75 GW, or 16 percent, of that total.*** (emphasis added)

These concerns are being echoed by others. A recent article in the New York Times raised concerns that there will not be enough affordable capacity in the near term to meet this demand.[2]

…

*But turning natural gas into electricity requires giant metal turbines that are increasingly difficult to secure. Companies that haven't already reserved this equipment, which can weigh as much as a large airplane and cost hundreds of millions of dollars, are facing waits of three or four years, about twice as long as just a year earlier.*

***The cost of building gas power plants has also soared** — so much so that in some parts of the country, solar panels and batteries are likely to be cheaper, energy executives and consultants said. **By some estimates, it now costs two or three times as much to build a gas-fired power plant as it did a few years ago.*** (emphasis added)

***The challenge of securing enough gas turbines is one of the clearest examples of how booming investment in artificial intelligence is reshaping the electric power industry, overwhelming suppliers and upending longstanding notions of what makes sense financially.*** (emphasis added)

...

[2] https://www.nytimes.com/2025/04/08/business/energy-environment/gas-turbines-power-plants.html

*GE Vernova, the biggest manufacturer of large gas turbines in the world, is among those betting that the recent flurry of interest in gas power will last. The company, formed last year in the breakup of General Electric, is spending more than $160 million to overhaul its gas turbine plant on the edge of Greenville, S.C.*

*By the end of next year, the 1.5-million-square-foot factory is expected to churn out about 35 percent more gas turbines. The building is a whirring, beeping expanse of partly automated assembly lines interspersed with metal turbine components.*

…

*As sales of turbines climbed, so did wait times and prices. It takes about four months for GE Vernova to assemble the turbines used in power plants. But that clock starts only after the company has received all the components, like the dense metal fins that catch hot air inside the turbine, causing a rotor to spin.*

***These days, the backlog is so severe as to be reminiscent of the snarled supply chains of the pandemic, which constrained production of cars, medical devices and much more.*** (emphasis added)

*Between those delays and the time it takes to build a power plant, a company starting from scratch today would probably not have a new gas plant running before 2030. Other critical electrical equipment like transformers is also harder to get.*

...

*Generally speaking, building a gas power plant can now be about as expensive as installing solar panels paired with batteries, according to Rystad, when including tax credits that apply to renewable energy and storage. One big factor is that gas turbines now cost about 50 percent more than they did just 10 months ago, according to the investment bank Jefferies.*

***"We're in this weird no man's land where it's very profitable to run a plant and it's clear we're going to need more electricity," Mr. Noffsinger of McKinsey said of gas plants. But in some markets, he added, it is unclear whether building new ones will make financial sense.*** (emphasis added)

...

*Joseph Dominguez, who runs the country's largest nuclear power plant operator, is among those who question how big the gas power boom will ultimately be. His company, Constellation Energy, struck a $16.4 billion deal in January to buy Calpine, which owns many gas power plants.*

Utility Dive, an industry publication, stated in a recent article that only "a fraction of proposed data centers will get built. Utilities are wising up".[3] Utility Dive quotes Astrid Atkinson, a former Google senior director of software engineering and now co-founder and CEO of grid optimization software provider Camus Energy, saying "(c)onservatively, you're seeing five to 10 times more interconnection requests than data centers actually being built."

The Companies projected anemic demand growth in the previous IRP. The current IRP has electricity demand growth at an accelerated rate. This acceleration in demand is underpinned by the addition of Data Centers, however, to date they have no signed commitments from any Data Center to provide electrical service. KCA supports the Companies' efforts to supply growing electrical demand and support economic development, however, the Commission should require more certainty in the projections of load growth before approving any generation buildout. This is consistent with the Companies "no regrets" policy which works in both directions, i.e., do not regret over-building and do not regret under-building. At a minimum, it is reasonable to conclude that no coal plants should be retired, including Mill Creek Unit 2, until there is greater clarity as to load requirements, costs of new generation, and regulatory requirements.

The Companies have only recently applied to the Commission for a Data Center tariff. Without a clear understanding of rates, rate structure, and the impact of Data Center rates to other customer classes, it is difficult to make judgments about the probability of any of the Data Center prospects coming to fruition and the impact to rate making.

**Failure to Propose a Data Center Tariff in the IRP**

During the IRP proceedings, the Companies indicated that they planned to consider Data Centers as commercial load despite the fact they are expected to have high capacity factors and need to receive generation support from the utility. In other words, the capacity dedicated to the Data Center may not be available to serve traditional load and therefore will provide limited benefits, if any, to the traditional customers.

On May 30, 2025, the Companies filed cases 2025-00013 and 2025-00014 which included a request for an Extremely High Load Factor Rate (EHLF – the Data Center Tariff) noting that EHLF customers have "different service characteristics and potential financial impacts to the Companies and their other customers to require a separate rate schedule and terms and conditions of service. In particular, because any one or just a few such customers could require the Companies to acquire additional generation resources to supply their needs and the needs of existing customers, increased minimum billing demands, extended contract terms, and enhanced collateral requirements are appropriate for such customers."

[3] https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/

The Companies' proposal is a step in the right direction, however, the proposed collateral requirements do not provide adequate protection for existing rate payers.

The Companies' EHLF proposed tariff states:

**All collateral is due at the signing of the electric service agreement. If there is an adverse change to the customer's or its guarantor's creditworthiness, the customer or its guarantor must provide the Companies the increased collateral requirement (i.e., the 24 months' value) within three business days after written notice from the Companies.** (emphasis added)

The Commission is currently dealing with this issue in a tariff filing by EKPC for what it refers to as Rate Data Center (RDC) tariff.[4] EKPC notes in its filing that its proposal is "the culmination of **many months of efforts** to understand the nature and characteristics of data centers, how they impact utilities and what guidelines should be put in place to assure that commercial relationships are fair, just and reasonable without giving rise to undue discrimination either in favor of, or in opposition to, this new category of load. At its heart, this proposed tariff recognizes that the demand for data centers is real, immense and accelerating in growth. EKPC and its Owner-Member distribution cooperatives recognize the value that data centers, artificial intelligence and other technology-dependent commerce has for the Commonwealth of Kentucky and our nation. To that end, the RDC **is designed to assure that risks are appropriately identified, characterized and allocated between new data center load and traditional residential, commercial and industrial loads**." (emphasis added)

EKPC recently applied to the Commission for approval of a Rate Data Center Power (DCP). EKPC notes in its cover letter that even though "its proposed tariff is lengthy and complex, it is not comprehensive." [5] EKPC further states "that a one-size-fits-all approach is not prudent" and "the terms and conditions of service to specific data centers will necessarily have key distinctions and nuances that a tariff cannot adequately foresee or anticipate. Accordingly, Rate DCP provides a broad set of guidelines that will be taken into account in the drafting of specific and unique special contracts …"

While KCA appreciates the complexity of developing a Data Center Tariff, the Companies' proposal should specifically address concerns over a counter-party failure and/or abandonment of the Data Center during the term of its agreement. Accelerating limited collateral requirements under such circumstances does not adequately address this concern.

**Correlated Fuel Price Forecasts**

KCA continues to believe that the Companies' fuel price forecasts undermine the validity of the Companies' analysis. The Companies' performance as discussed below demonstrates the Companies' success in procuring coal in a diversified portfolio that has greatly limited market

[4] Case No. 2025-00140

[5] https://psc.ky.gov/pscscf/2025%20cases/2025-00140//20250430_East%20Kentucky%20Power%20Cooperative,%20Inc.%20Tariff%20Filing.pdf

price movements and volatility.[6] The Companies' modeling assumes coal prices are correlated to natural gas prices. KCA has pointed out to the Companies that projecting coal prices in this manner is not a standard industry practice. The Companies have declined to consider alternatives and have taken the position that this methodology has been accepted by the Commission in the prior CPCN filing and therefore the Companies have no obligation to revisit this matter. KCA believes all assumptions need to be validated in the IRP and other cases where fuel price forecasting is required.

In the IRP proceeding on May 14, 2025, Company Witness Schram stated that coal prices under contracts are tied to the price of natural gas via price adjustment provisions in the coal contracts.[7]

KCA conducted a complete review of the Companies' coal procurements in 2020 through 2024 that show that this is not the case. The Companies buy coal on both a spot and contract basis. The spot purchases are defined as a purchase for a year or less. While the spot purchases typically are quality adjusted based upon actual delivered quality, they are at a fixed price with **no** escalation. The contract purchases range from over one year typically with volumes and prices set for the entire contract period. All contract purchases are adjusted for delivered quality based upon the quality specifications in the agreement. Term contracts also provide for recovery of costs related to governmental impositions.

In Kentucky, utilities which recover their fuel costs through a fuel adjustment clause are required to submit copies of each fossil fuel purchase contract.[8] These contracts are available on the Commission website.[9]

The contracts have standard terms and conditions with some variation presumably as a result of negotiations between the Companies and the producers. For example, some contracts state tonnage as a specific amount per year while others provide a range. Another example relates to pricing. In some contracts, pricing is established per year while in other contracts pricing is tied to cumulative tons shipped under the contract.

The coal contract commitments made between 2020 and YTD 2025 are summarized below for the years 2021 through 2030. This table does not include spot purchases which are under contracts one year or less, deliveries under term contracts made in 2019 or earlier, or subsequent contract amendments changing volumes. Regardless, there is sufficient information in this exhibit that confirms the portfolio procurement strategy. The spot purchases including one-year contracts are not relevant to the position the Companies have adopted regarding escalators as the prices in the spot purchases are not adjusted directly or indirectly by the prevailing price of natural gas.

[6] It is unclear why the Companies do not acknowledge that and take the credit they deserve.
[7] Witness Schram, VR, 5/14/2025, 9:42 AM, 44:50.
[8] https://apps.legislature.ky.gov/law/kar/titles/807/005/056/
[9] https://psc.ky.gov/WebNet/FuelContracts

| | Quantity (000 Tons) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Contract | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| J20006 | 330 | 330 | 330 | 330 | | | | | | |
| J21002 | 250 | 250 | 250 | 750 | 750 | | | | | |
| J21004 | 2,500-3,000 | 3,000-3,500 | 3,000-3,500 | 1,000-2,500 | | | | | | |
| J21009 | 240-560 | 360-840 | 360-840 | 0-540 | | | | | | |
| J21010 | 500-600 | 500-700 | 500-700 | 1,000-2,000 | 200-1,000 | | | | | |
| J21011 | 300 | 500-600 | 2000-2500 | 2000-2500 | 1100-2200 | | | | | |
| J23001 | | | 500-600 | 500-600 | 500-600 | 0-300 | | | | |
| J23002 | | | 250 | 500 | 500 | 1,000 | 1,000 | | | |
| J23003 | | | 500 | 500 | | | | | | |
| J23004 | | | 500 | 500 | 1,000 | 1,000 | | | | |
| J23005 | | 0-150 | 550-850 | 550-850 | 550-850 | | | | | |
| J24007 | | | | 150 | 500-600 | 750-950 | 1,000-1.200 | 500-1000 | | |
| J25001 | | | | | 2,000-2,400 | 2,000-2,400 | 2,000-2,400 | 2,000-2,400 | 2,000-2,400 | 0-2,000 |
| J26001 | | | | | | 350 | 600 | 600 | 600 | |
| Range | 4120-5040 | 4940-6370 | 10820-13700 | 7230-10870 | 6,100-9,900 | 5,100-6,000 | 3,600-4,200 | 3,100-4,000 | 2,600-3000 | 0-2,000 |

Notably, the volume ranges in the contracts provide significant protection for ratepayers should markets change.

The contract pricing in almost all coal procurements is fixed in the contracts for the entire term which effectively eliminates natural gas pricing as the basis for the escalated prices in the vast majority of contracts. KCA's review found only a few contracts that had prices tied to escalators. As discussed below, there was no material impact of natural gas pricing in these escalators.

In J20006 and J23002, there are adjustments for changes in the price of # 2 Diesel Fuel related to trucking obligations in those agreements, the base cost of which is laid out in the agreement. According to EIA, the price of diesel fuel is tied to the cost of purchasing crude oil, refining costs, distribution and marketing costs, and taxes, **not** the price of natural gas.[10]

In J23003, most of the price is tied to changes in the Producer Price Index (PPI) for Bituminous UG Coal (PCU21211221212110). The PPI for underground bituminous coal is tied primarily to equipment costs, not natural gas prices. If the PPI for Surface Mining had been used, there would be a greater connection as the use of natural gas in explosives is substantial in surface mines. Further this agreement is only for two years and accounts for less than five percent of the purchases and burn.

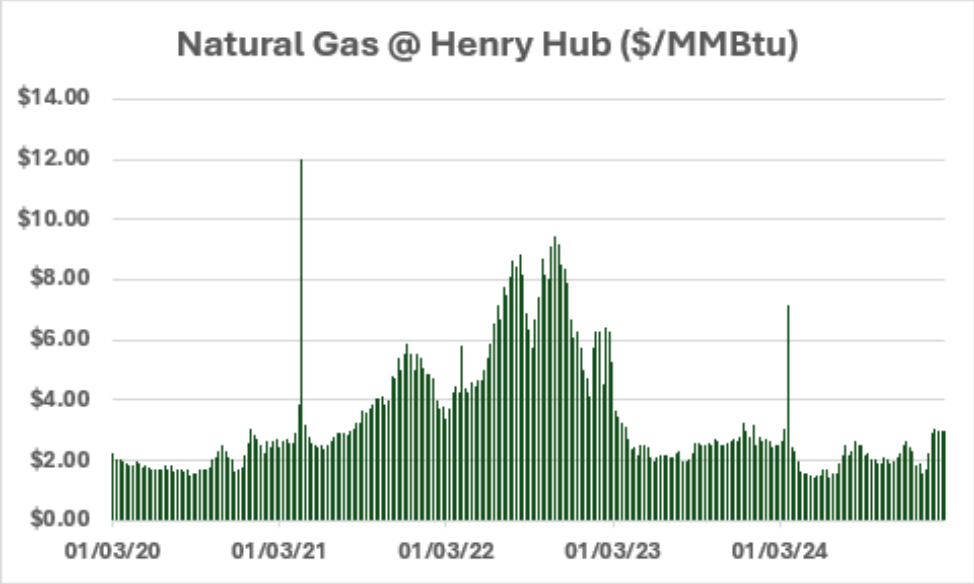
Finally in J25001, only the last three years of the six-year contract provides for price adjustments based upon changes in labor and benefit costs. While the indices and procedures for determining the adjustments are laid out in the agreement, it is worth noting that the adjustments can move in either direction and most importantly are capped at $2.50 per ton per year or about five percent of the contract price. About 75 percent of the indices are tied to labor and equipment costs. Less than 20 percent are tied to power and commodity costs. Therefore, even if power and commodity costs doubled, the impact on pricing would be less than $0.50 per ton and would not materially influence the actual price of the coal.

[10] https://www.eia.gov/energyexplained/diesel-fuel/factors-affecting-diesel-prices.php

The review KCA conducted confirmed KCA's belief that Companies do an excellent job in procuring coal in part due to the use of a diversified procurement portfolio. The diversification ensures that the Companies are not overly exposed to the market in any one year. It also serves to assure the availability of future supplies for the Companies' coal facilities which the Companies raised as a concern related to continued coal use.

Another way to confirm that natural gas prices and coal prices are not linked in the manner suggested by the Companies is to review pricing for natural gas and coal.

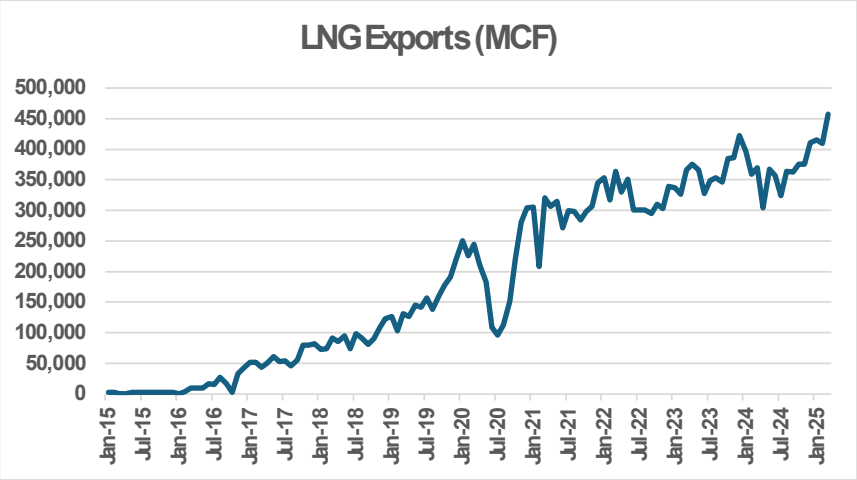
Henry Hub natural gas prices for the 2020-2024 period compared to the purchase price of coal delivered to the Companies' stations are below. Henry Hub refers to the spot price of natural gas at the Henry Hub in Erath, Louisiana. Henry Hub is the official delivery location for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The prices set at Henry Hub are considered the benchmark for the entire North American natural gas market.




As can be seen, natural gas prices are more volatile than coal prices. In fact, gas prices are often affected daily by weather conditions and delivery issues. As seen above, there was an extended period during COVID and post-COVID when prices soared. The increase was due to growth in demand for liquefied natural gas (LNG) due in part to the war in Ukraine, natural gas supply shortages, and coal supply shortages as coal companies did not initially resume coal production post-COVID as utilities were living off of high inventory levels.

In recent years, natural gas prices have been increasingly influenced by LNG exports which as shown below soared post-COVID.[11] Significant growth continues to be forecast as noted in KCA's earlier IRP comments.

[11] Despite requests, the Companies provided no indications that the growth in natural gas by other sectors such as LNG was considered in developing coal prices for the CPCN.



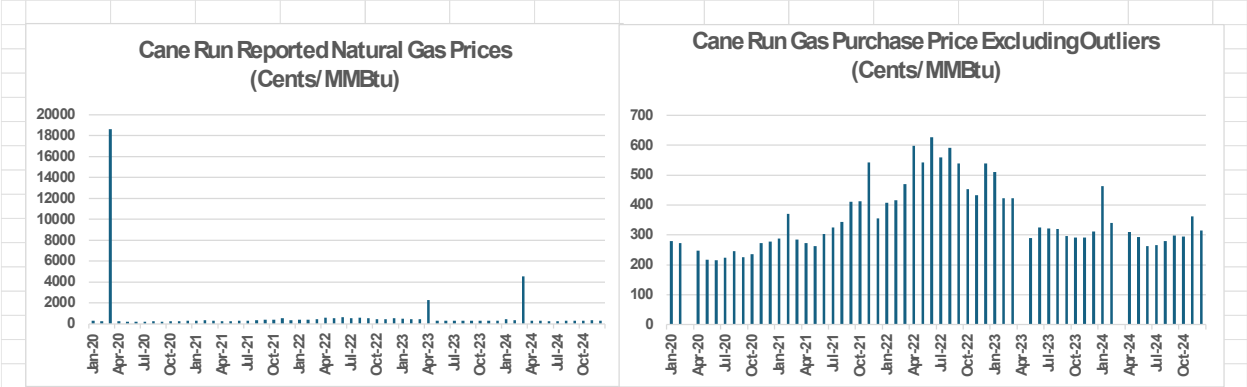

Source: EIA https://www.eia.gov/dnav/ng/hist/n9133us2m.htm

The prices for natural gas purchases for Cane Run are volatile. KCA reviewed the natural gas filings for the Companies for the period 2020 and beyond. As can be seen from Attachment 1 (below), KCA's review of the Commission website produced **no** purchase agreements during the referenced period although some NAESB agreements which do not have specific volumes or pricing were filed for some of the suppliers.[12] KCA could not verify the Companies' assertions that gas was purchased through a portfolio strategy akin to how coal was purchased.

KCA's focused on the gas purchase prices filed on a monthly basis with EIA on Form 923.

Reported purchases for Cane Run are summarized below. The first chart includes all months during the 2020 to 2024 period in which there were reported purchases. The second chart excludes the three outlier months in which prices were orders of magnitude greater thereby masking the significant volatility. To state the obvious, using a forecast of the monthly purchase prices for natural gas would be very difficult because of the volatility.

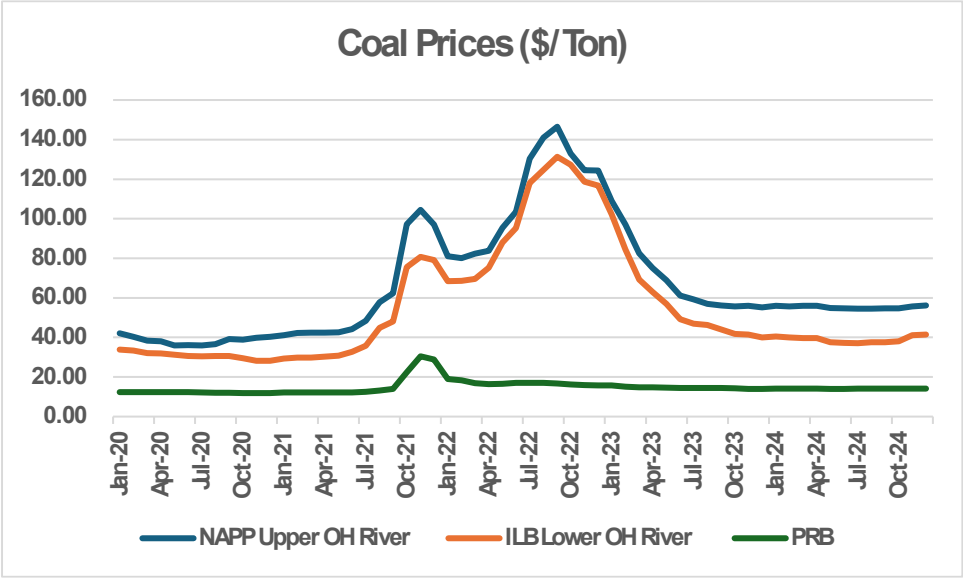
[12] Other Kentucky utilities do file their natural gas purchases with the Commission. Examples can be found at https://psc.ky.gov/PSC_WebNet/FuelContracts/Kentucky%20Power%20-%20KP/DTE%20Energy%2011-14-24_01.pdf; https://psc.ky.gov/PSC_WebNet/FuelContracts/Kentucky%20Power%20-%20KP/DTE%20Energy%206-21-23.pdf; https://psc.ky.gov/PSC_WebNet/FuelContracts/Big%20Rivers%20Electric%20Corporation%20-%20BREC/Cima%20Energy%206-5-25.pdf;




Source: EIA Form 923

Coal demand has declined over the last 20 years as a considerable number of domestic coal power plants were closed and very few new ones were built. That being said, coal production has not disappeared with over 200 million tons being produced east of the Mississippi and about 400 million produced in the west. Further, there are ample coal reserves should demand increase.

The Companies burn three types of coal: Illinois Basin High Sulfur, Northern App High Sulfur, and Powder River Basin. Market prompt year spot pricing for these coals over the 2020 to 2024 period are shown below.

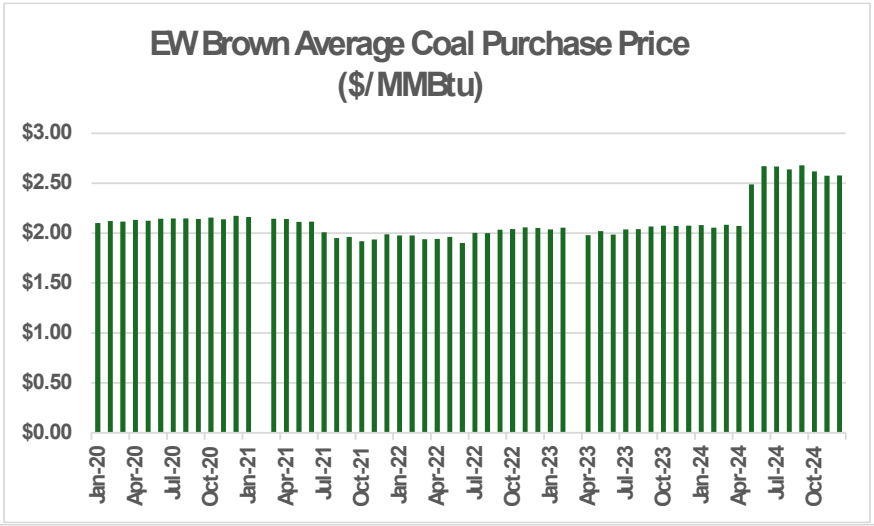



Source: Coaldesk

Prompt year coal spot prices from these regions going into COVID had been relatively flat. There was an initial bump in pricing during early COVID which was not sustained and then a significant increase in pricing from mid-2022 through the first half of 2023. The reasons for the significant bump were increased demand due to COVID recovery, a delayed response from the

coal industry in restarting idled production, and higher gas prices due to strong global pricing resulting in part from the war in Ukraine. Once demand and supply were balanced in the market, coal prices fell albeit not to pre-COVID levels as a result of inflationary cost pressures.

The success of the Companies' coal procurement strategy can be seen in their reported coal purchase costs during this period by comparing the Companies EIA Form 923 reported coal prices to the prompt year spot price for each of the coal types shown above. Pricing at EW Brown was flat during the 2020 to H1 2024. Pricing at Ghent, Mill Creek, and Mill Creek was also relatively flat with a slight increase in the second half of 2022 and modest increases in price compared to 2020 and 2021 in 2023 and YTD 2024. Pricing at all four plants increased modestly during this period consistent with the post-COVID recovery prices which were slightly higher than the pre-COVID numbers.


EW Brown Average Coal Purchase Price
($/MMBtu)
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
Jan-22
Apr-22
Jul-22
Oct-22
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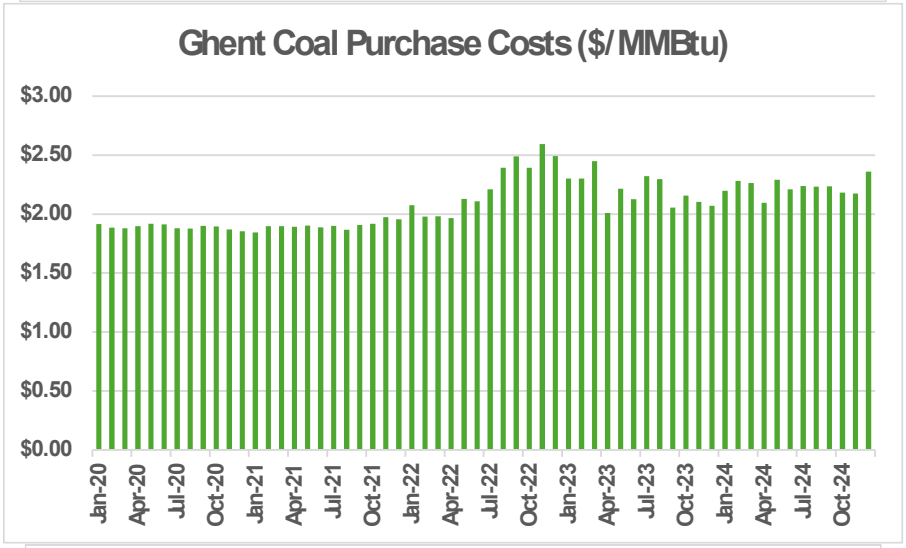
Oct-24


Ghent Coal Purchase Costs ($/MMBtu)
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
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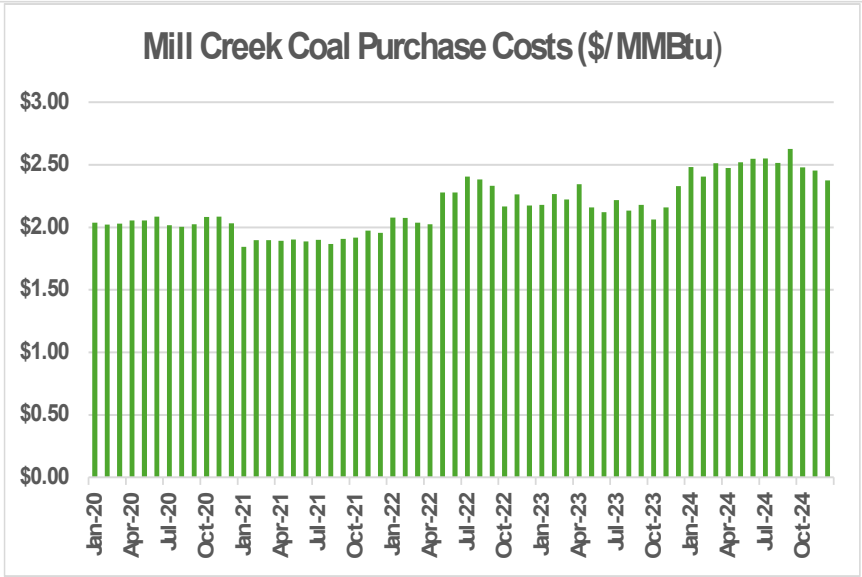
Apr-24
Jul-24
Oct-24


Mill Creek Coal Purchase Costs ($/MMBtu)
$3.00
$2.50
$2.00
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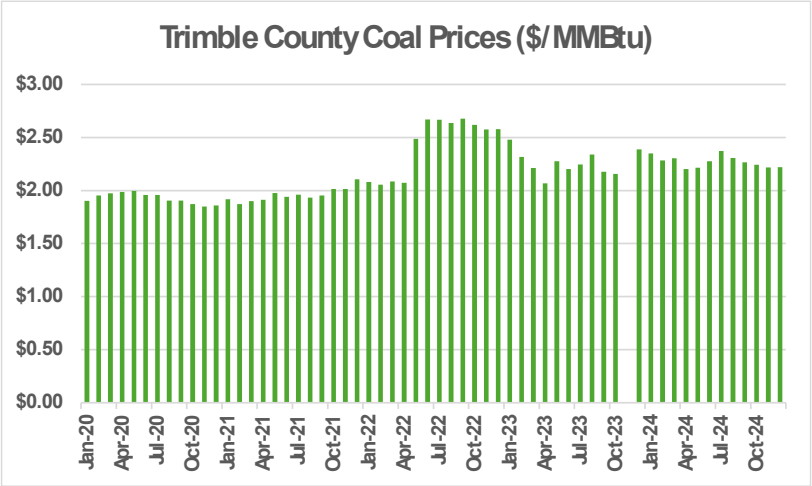
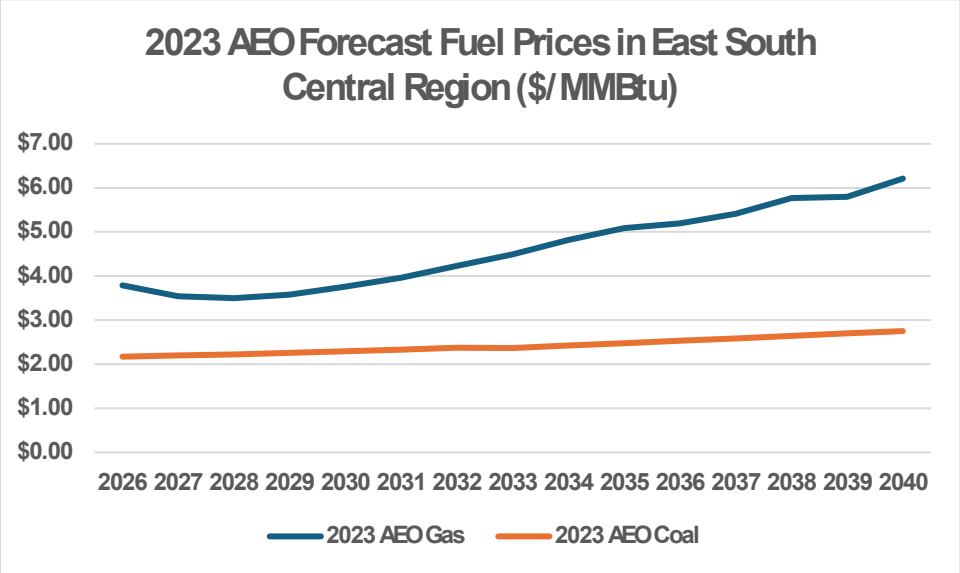


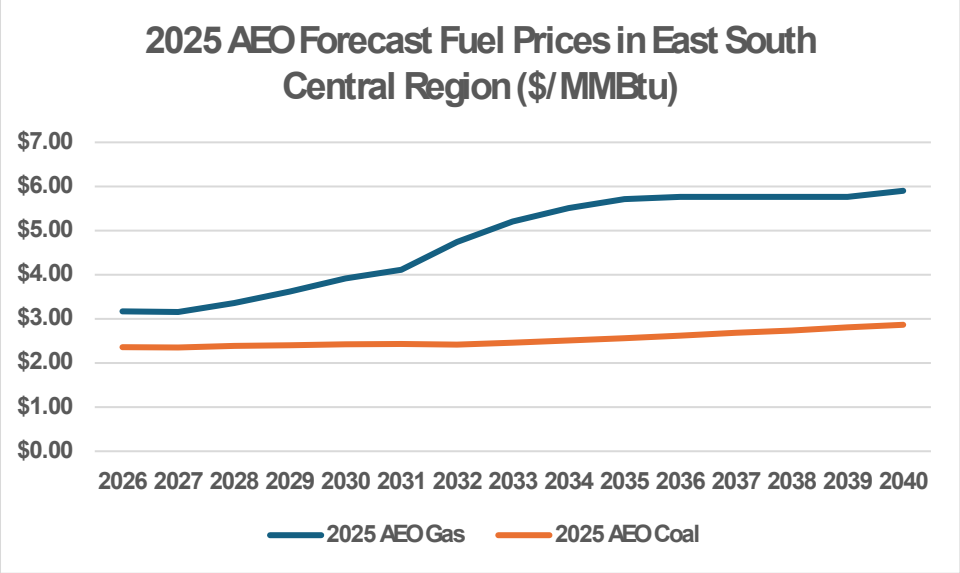

Source: EIA Form 923

EIA prepares an Annual Energy Outlook (AEO) with multiple scenarios and outlooks for the U.S. as a whole as well as regional outlooks. These forecasts support KCA's opinion about the non-linkage between coal and natural gas prices.

The region most relevant to the Companies is the East South Central Region. The annual forecasts in 2023 and 2025 show changes in the Reference Case outlook for natural gas prices during the period 2029 through 2037 period. Both the 2023 and 2025 AEO forecasts shown natural gas prices to be considerable higher than coal prices. That being said, the 2025 AEO has considerably higher gas prices during the 2029 to 2037 period reflecting increased natural gas demand from Data Centers and exports of both LNG overseas and pipeline gas to Mexico. The coal price outlook is effectively the same in both cases. It is obvious, EIA does not correlate its coal price forecast to its natural gas price forecast.[13]

[13] Annual Energy Outlook - U.S. Energy Information Administration (EIA) (Select Table 3.6) https://www.eia.gov/outlooks/archive/aeo23/tables_ref.php; Annual Energy Outlook - U.S. Energy Information Administration (EIA) (Select Table 3.6) https://www.eia.gov/outlooks/aeo/tables_ref.php




**PPL's Commitment to Net-Zero Carbon Emissions by 2050**

The Companies have chosen to ignore PPL's commitment to net zero carbon emissions by 2050.[14] This is consequential in their analyses with respect to costs. In order to achieve net zero carbon emissions by 2050, PPL must shut down all generation producing carbon, retrofit them with CCS, convert to green hydrogen, or purchase carbon offsets.

Carbon offsets are tradable "rights" or certificates linked to activities that lower the amount of carbon dioxide ($CO_2$) in the atmosphere. By buying these certificates, a buyer can continue emitting $CO_2$ emissions as the equivalent $CO_2$ emissions are reduced elsewhere. These options

[14] https://filecache.investorroom.com/mr5ir_pplweb2/1207/PPL_2024_Annual_Report.pdf page 13.

are costly and not reflected in the IRP. The Companies while acknowledging PPL's commitment chose to not include a net zero carbon emissions by 2050 scenario in its analysis.

The Companies indicated in the IRP that CCGT's would come online no sooner than 2030 and would be depreciated over 40 years, suggesting an operation life of the CCGT through 2070.

## Attachment 1. Reported Purchases of Natural Gas by Vendor[15]

| | Natural Gas Purchases 1/1/24-5/28/25 | Agreements Filed with KYPSC between 1/1/17 and YTD | | |
|---|---|---|---|---|
| Vendor | Total Volume (MMBtu) | Kentucky Utilities | Louisville Gas & Electric | |
| BP Energy Company | 537,570 | 0 | 0 | |
| CIMA ENERGY, LP | 42,500 | 0 | 0 | |
| Castleton Commodities Merchant Trading L.P. | 137,398 | 0 | 0 | |
| Chesapeake Energy Marketing, L.L.C. | 40,462 | 0 | 0 | |
| Colonial Energy, Inc. | 306,113 | 0 | 0 | |
| Columbia Gas of Kentucky, Inc. | 2,441 | 0 | 0 | |
| Concord Energy LLC | 6,448 | 0 | 0 | |
| ConocoPhillips Company | 60,133 | 0 | 0 | |
| Constellation Energy Generation, LLC | 112,942 | NAESB 5/26/13 | 0 | |
| DTE Energy Trading, Inc. | 4,532,898 | 0 | 0 | |
| EDF Trading North America, LLC | 37,300 | 0 | 0 | |
| Eco-Energy Natural Gas, LLC | 243,297 | 0 | 0 | |
| Expand Energy Marketing LLC | 20,000 | 0 | 0 | |
| Hartree Partners, LP | 39,600 | NAESB 2/1/19 | NAESB 2/1/19 | |
| J. Aron & Company LLC | 26,500 | 0 | 0 | |
| Koch Energy Services, LLC | 516,697 | NAESB 3/29/21* | NAESB 3/29/21* | Amended 5/1/22 |
| MIECO LLC | 56,200 | 0 | 0 | |
| Macquarie Energy LLC | 19,931 | 0 | 0 | |
| NJR Energy Services Company, LLC | 127,100 | NAESB 4/1/09 | NAESB 4/1/09 | |
| NRG Business Marketing LLC | 20,600 | 0 | 0 | |
| NextEra Energy Marketing, LLC | 1,444,277 | 0 | 0 | |
| Ovintiv Marketing Inc. | 57,600 | NAESB 5/15/20 | NAESB 5/15/20 | |
| Radiate Energy LLC | 78,802 | NAESB 2/28/22 | NAESB 2/28/22 | |
| Sequent Energy Management LLC | 478,878 | 0 | 0 | |
| Shell Energy North America (US), L.P. | 554,200 | 0 | 0 | |
| Southwest Energy, L.P. | 3,775,812 | NAESB 3/29/18 | NAESB 3/29/18 | |
| Spire Marketing Inc. | 131,300 | 0 | 0 | |
| Spotlight Energy, LLC | 354,094 | NAESB 11/4/20 | NAESB 11/4/20 | |
| Symmetry Energy Solutions, LLC | 48,600 | 0 | 0 | |
| Tenaska Marketing Ventures | 28,831,400 | 0 | 0 | |
| Tennessee Valley Authority | 18,761 | 0 | 0 | |
| TotalEnergies Gas & Power North America, Inc. | 92,300 | 0 | 0 | |
| Twin Eagle Resource Management, LLC | 607,539 | 0 | 0 | |
| Uniper Global Commodities North America LLC | 196,300 | 0 | 0 | |
| United Energy Trading, LLC | 38,921 | 0 | 0 | |
| Vitol Inc. | 2,296,460 | 0 | 0 | |
| Wells Fargo Commodities, LLC | 27,000 | NAESB 6/14/17 | NAESB 6/14/17 | |
| | | | | |
| **Grand Total** | 45,918,374 | | | |

Respectfully submitted,

*/s/Matt Malone*
Matthew R. Malone (90508)
Aaron D. Reedy (90523)
Hurt, Deckard & May PLLC
201 E. Main Street; Suite 1402
Lexington, Kentucky 40507

[15] https://psc.ky.gov/WebNet/FuelContracts

(859) 254-0000 (office)
(859) 254-4763 (facsimile)
mmalone@hdmfirm.com
areedy@hdmfirm.com

Counsel for the Petitioner,
**KENTUCKY COAL ASSOCIATION**

## CERTIFICATE OF SERVICE

I hereby certify that KCA's June 16, 2025 electronic filing is a true and accurate copy of KCA's pleading and Read 1st Document to be filed in paper medium; that the electronic filing has been transmitted to the Commission on June 16, 2025; that an original and one copy of the filing will not be delivered to the Commission based on pandemic orders; that there are currently no parties excused from participation by electronic service; and that, on June 16, 2025 electronic mail notification of the electronic filing is provided to all parties of record:

*/s/Matt Malone*
ATTORNEY FOR KCA