STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1341

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOHN D. SWEZ**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, and my business address is 525 S. Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC ("DEC"). In that capacity, I lead the organization responsible for Power Trading on behalf of Duke Energy's regulated utilities including Duke Energy Progress, LLC ("Duke Energy Progress," "DEP," or the "Company") and DEC (collectively, the "Companies"), as well as generation dispatch on behalf of Duke Energy's regulated utilities in Indiana, Ohio, and Kentucky.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Master of Business Administration degree from the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held various engineering positions with the Company or its affiliates in the generation dispatch or power trading departments. In 2003, I assumed the position of Manager, Real-Time Operations. On January 1, 2006, I became the Director of Generation Dispatch and Operations with responsibility for (i) generation dispatch; (ii) unit commitment; (iii) 24-hour real-time operations; and (iv) plant communications related to short-term generation maintenance planning for Duke Energy's regulated utilities in Indiana, Ohio, and Kentucky. During the period 2010-2017, I also managed the DEC Generation Dispatch function. I assumed my current role on November 1, 2019. Finally, I am a registered Professional Engineer licensed in the States of North Carolina and Indiana.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. Yes. I testified in support of DEP's 2023 and 2021 annual fuel and fuel-related rider proceeding in Docket No. E-2, Sub 1321 and Docket No. E-2, Sub 1272, respectively and in DEC's 2024 and 2023 annual fuel and fuel-related rider proceeding application in Docket No. E-7, Sub 1304 and Docket No. E-7, Sub 1282, respectively.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the period April 1, 2023 through March 31, 2024 ("test period") versus the period April 1, 2022 through March 31, 2023 ("prior test period"), and describe changes projected for the billing period of December 1, 2024 through November 30, 2025 ("billing period").

Q. YOUR TESTIMONY INCLUDES THREE EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Swez Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Swez Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and Swez Confidential Exhibit 3, which summarizes the annual fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month.

Q. PLEASE PROVIDE A SUMMARY OF DEP'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of DEP's fossil fuel procurement practices is set out in Swez Exhibit 1.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO UNIT COMMITMENT AND DISPATCH OF ITS GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS.

A. Both DEP and DEC perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to meet system requirements economically and reliably. The model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time. Inputs to the model include, but are not limited to, the following: (1) forecasted customer energy demand; (2) the latest forecasted fuel prices, reflective of market supply chain dynamics; (3) variable transportation rates; (4) planned maintenance and refueling outages at the generating units; (5) generating unit performance parameters; (6) reliability constraints such as units run to maintain day-ahead planning reserves or units required to run for transmission or voltage support; (7) expected market conditions associated with power purchases and off-system sales opportunities; and (8) projected variable renewable resource contributions (i.e. solar). The production cost model produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real time adjustments due to changing system conditions, including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Q. PLEASE EXPLAIN HOW THE COMPANY'S FORECASTED FUEL PRICES ARE REFLECTIVE OF MARKET SUPPLY CHAIN DYNAMICS.

A. Incremental fuel replacement prices are a key input in determining the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. As energy market price volatility, fuel inventory supply chain constraints, and shifting dynamics in the market fuel resource mix continue to impact fuel inventories and fuel reliability, the Companies' recognized a need to enhance the unit commitment and dispatch coal price input process to reflect longer term coal market realities and operational risks over time. This enhanced optimized coal price input approach—which the Company calls "dynamic dispatch"—reflects an approach that aligns spot coal market prices with longer term supply, delivery, and inventory planning to cost effectively reduce volatility in seasonal and annual fuel inventories.

Q. IS THE COMPANY CHANGING THE ECONOMIC UNIT COMMITMENT AND DISPATCH METHODOLOGY?

A. The unit commitment and dispatch process described above is not changing. The enhanced dynamic dispatch process is providing the economic unit commitment and dispatch production cost model with an optimized spot coal price input to use if needed to maintain projected inventories within limits at impacted coal plants. The use of this optimized spot coal price input maintains least cost economics by calculating incremental adjustments needed over a longer time horizon to maintain plant inventories within safety and reliability limits, while minimizing fuel security risk and total long term system costs for customers. The dynamic dispatch process also proactively reduces the need for more reactive approaches such as uneconomic unit commitment and dispatch and contractual buyouts.

Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE TEST PERIOD.

A. The Company's average delivered cost of coal per ton for the test period was \$116.38 per ton, compared to \$95.13 per ton in the prior test period, representing an increase of approximately 22%. The cost of delivered coal includes an average transportation cost of \$41.23 per ton in the test period, compared to \$33.34 per ton in the prior test period, representing an increase of approximately 24%. The Company's average price of gas purchased for the test period was \$5.41 per Million British Thermal Units ("MMBtu"), compared to \$8.15 per MMBtu in the prior test period, representing a decrease of approximately 34%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 2.7 million tons, compared to a coal burn of 2.4 million tons in the prior test period, representing an increase of 12%. The Company's natural gas burn for the test period was 164.5 million MBtu, compared to a gas burn of 179.6 million MBtu in the prior test period, representing a decrease of approximately 8%.

Changes in coal and natural gas burns were primarily driven by the relationship of coal commodity prices during 2023 relative to natural gas prices in the same period, as rapidly declining coal commodity prices used for the dispatch and commitment of the Company's units became more competitive with natural gas costs, increasing gas-to-coal generation fuel switching between the Company's combustion turbines and its coal generation units.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. Coal markets continue to experience a high degree of market volatility due to a number of factors, including: (1) the inability of coal suppliers to respond timely to changes in demand; (2) natural gas price volatility; (3) increased uncertainty regarding proposed and imposed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) global demand for both steam and metallurgical coal; (5) tightened access to investor financing; (6) continued shifts in production between thermal and metallurgical coal as producers move away from supplying declining utility sector demand to take advantage of industrial demand; and (7) continued labor and resource constraints further limiting suppliers' operational flexibility.

Over the course of 2023 and the first quarter of 2024, published coal market curves declined from the historically elevated levels in 2022 in response to low natural gas prices and overall lack of coal generation demand. Despite the decline in published coal market prices, the impacts of rising production costs on individual mining operations may result in higher coal contract prices than market publications imply. The Company is watching this trend closely for potential impacts on long term supplier viability and contracting costs.

Long-term declines in demand for coal in the utility sector have also driven rail transportation providers to modify their business models to be less dependent on coal related transportation revenues. Although rail transportation providers are required to provide rail service, the Company's rail transportation providers have limited resources to quickly adapt to significant changes in scheduling demand resulting from the Company's burn volatility. In 2023, the Company saw improvement in deliveries by its rail transportation providers following the delivery constraints experienced in 2022.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years as producers enhanced production techniques and efficiencies, resulting in lowered production costs. Natural gas prices are reflective of the dynamics between supply and demand factors. In 2023 and first quarter of 2024, market dynamics were primarily influenced by robust production, and growth in inventory storage balances which caused natural gas prices to sharply decline.

There remains a growing need for natural gas pipeline infrastructure, as gas production—particularly in low-cost regions such as Appalachia—is constrained as pipeline infrastructure permitting and regulatory process approval efforts are increasingly challenged, delaying planned pipeline construction and commissioning timing.

Over the longer-term planning horizon, natural gas supply has the ability to respond to changing demand related to power generation, liquefied natural gas exports, and pipeline exports to Mexico. However, it is increasingly uncertain whether the pipeline infrastructure needed to supply power generation will be available.

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. Based on the most recently completed forecast for use in this filing, which used market prices as of April 11, 2024, DEP's coal burn projection for the billing period is 3.9 million tons, compared to 2.7 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $102.80 per ton for the billing period compared to $116.38 per ton in the test period. This decrease in delivered costs is primarily driven by declining coal commodity costs resulting from decreasing domestic demand. This includes an average projected total transportation cost of $31.34 per ton for the billing period, compared to $41.23 per ton in the test period. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of Central Appalachian coal DEP is able to purchase and deliver and the non-Central Appalachian coal DEP is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads which may not occur despite DEP's strong contract compliance monitoring process; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEP's current natural gas burn projection for the billing period is approximately 163.4 million MBtu, which is a decrease from the 164.5 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $3.43 per MMBtu, compared to $2.44 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S MODELING PROCESS RELATED TO FORECASTING FUEL COSTS?

A. Yes, starting in 2023 the Fleet Analytics Stochastic Tool "FAST" model outputs are being used as part of the process to forecast future fuel costs. Since late 2020, the Company has used the outputs from the FAST model as the basis for its fuel procurement planning process.

Q. PLEASE PROVIDE AN OVERVIEW OF STOCHASTIC MODELING CAPABILITIES.

A. The stochastic model uses historic weather information to simulate numerous scenarios of future weather and commodity prices. For each of these scenarios, system load and commodity prices (gas, coal, oil and power) are all calculated in a correlated manner using historical correlations with each other and with weather.

The resulting forecasts of this stochastic model give the Company not only expected fuel burns, but also the range of fuel burns and the probability associated with each range.

Q. WHAT STEPS IS DEP TAKING TO ENSURE A COST-EFFECTIVE RELIABLE FUEL SUPPLY?

A. The Company continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. With respect to coal procurement, the Company's procurement strategy includes: (1) having an appropriate mix of term contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to forward market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels. Additionally, the Company negotiates coal transportation contracts that support secure, reliable deliveries.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. DEP continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. DEP monitors and makes adjustments as necessary to its natural gas hedging program to ensure it remains appropriate based on market conditions and the Company's fuel procurement strategy.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to DEP and DEC's generating facilities. Given the Companies' limited amount of contracted firm interstate transportation, DEC purchases shorter term firm interstate pipeline capacity as available from the capacity release market for use by DEP and DEC. The Companies' firm transportation ("FT") provides the underlying framework for the Companies to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Companies access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the FT allows the Companies to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Companies to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Companies' customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.