STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1321

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 2021 annual fuel and fuel-related rider proceeding in Docket No. E-2, Sub 1272 and DEC's 2023 annual fuel and fuel-related rider proceeding application in Docket No. E-7, Sub 1282.

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, 2022 through March 31, 2023 ("test period") versus the period April 1, 2021 through March 31, 2022 ("prior test period"), and describe changes projected for the billing period of December 1, 2023 through November 30, 2024 ("billing period"). Additionally, I will discuss the proposed changes to; 1) the fuel cost proxy percentage calculation used to approximate the actual fuel cost component of a power purchase when the actual fuel cost component is unavailable or unidentified as a component of the price paid for energy under a power purchase contract and 2) the Company's implemented enhancements optimizing the independent 3rd party spot market coal prices used in its daily economic unit commitment and dispatch process to better reflect the market replacement price of coal given the inelasticity of coal supply.

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING A CHANGE TO THE FUEL COST PROXY PERCENTANGE CALCULATION.

A. The most recent proxy percentage was established during the 2008 fuel proceeding, through an analysis of off-system sales from calendar year 2007. Since the 2008 fuel proceeding, the proxy has not been updated. Due to increasing fuel commodity prices and a changing resource mix, the Company and the Public Staff have agreed that the fuel proxy established in the 2008 fuel proceeding no longer represents a reasonable approximation of the fuel cost portion of power purchases 14 years later. Furthermore, both the Company and the Public Staff consider it reasonable to continue to use the accepted methodology of using the fuel component of the Companies' off-system sales as a reasonable basis for approximating fuel costs associated with power purchases when actual fuel costs are unavailable or unidentified as a component of the price paid for energy under a power purchase contract. Therefore, the Company and the Public Staff have reached agreement that, per the attached Stipulation (Swez Exhibit 4), for future fuel proceedings starting with the Company's 2023 annual fuel rider proceeding, an annual compilation of actual total fuel and fuel-related costs as a component of total short-term off-system sales revenue is an appropriate basis for estimating fuel costs on power purchases when the actual fuel component is unavailable or unidentified as a component of the price paid for energy under a power purchase contract.

Q. PLEASE EXPLAIN THE CHANGE IN THE FUEL COST PROXY PERCENTAGE CALCULATION.

A. For the Company's annual fuel rider proceedings filed during 2023 through 2027, if actual fuel cost for a power purchase is unavailable or the fuel cost component is unidentified under a power purchase contract, the Company shall assume that the fuel cost was in a range between 75% to 85%, the exact percentage to be determined by the parties beginning with a composite calendar year 2022 review of short-term off-system sales, inclusive of Southeast Energy Exchange Market ("SEEM") sales (applied to the test year purchases under review in 2023 fuel proceedings) through a composite calendar year 2026 review of short-term off-system sales (applied to the test year purchases under review in 2027 fuel proceedings). The Company will propose a composite total fuel cost to total energy cost ratio, based on DEP's and DEC's combined short-term off-system sales for the calendar year. Such composite, in accordance with the terms of the Stipulation, shall be no greater than 85%, but no less than 75%. For each of the above-specified fuel proceeding test years, the Company will assess the prior calendar year composite proxy percentage to be used by both DEP and DEC, consistently for the full test periods of the subsequent annual fuel rider proceeding, despite the three-month difference in end date between DEP's and DEC's twelve-month test periods. To the extent that the analysis of annual composite short-term off-system sales indicates that the actual fuel and fuel-related component of such sales revenue falls outside the range of 75% to 85%, the composite proxy percentage will be adjusted accordingly to reflect either the minimum or maximum of the range.

Q. HAS THE COMPANY AND THE PUBLIC STAFF REACHED A STIPULATION IN THIS MATTER?

A. Yes, as of January 5, 2023, the Company and the Public Staff entered into a Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others. The executed Stipulation is attached as Swez Exhibit 4.

Q. YOUR TESTIMONY INCLUDES FOUR 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. Swez Exhibit 4 sets out the executed Stipulation between the Public Staff and the Company entered into January 5, 2023.

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. To ensure that the rapidly rising cost and limited availability of incremental replacement coal was adequately reflected in the unit commitment model inputs, in late 2021, the Company began meeting weekly to review the independent 3rd party spot coal market price input against the next seven and thirty day expected coal burns and deliveries to determine which input price, domestic bid, offer or export was the most reflective of the current market supply availability conditions.

Q. DOES THE COMPANY BELIEVE THIS MANUAL APPROACH TO REFLECTING MARKET SUPPLY CHAIN DYNAMICS IN THE FORECASTED FUEL PRICES IS THE BEST APPROACH OVER THE LONG TERM GIVEN THE INELASTICITY OF COAL SUPPLY?

A. No. The Company has been working on an updated model-driven approach that incorporates a coal price input that reflects the realities of the inelasticity of coal supply and the Company's need to manage within inventory bounds while minimizing customer costs and ensuring fuel security. Given the inability of the coal supply chain to respond timely to changes in demand, along with the transition of the domestic utility generation fleet away from coal as baseload generation, the Company recognized there was a need to enhance the existing unit commitment and dispatch coal price input process to reflect longer term coal market realities and operational risks over time. This enhanced approach—which the Company is calling "dynamic dispatch"—reflects an optimized coal price input 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. The dynamic dispatch process will generate an optimized coal price input for unit commitment and dispatch that minimizes system cost over the near-term fuel planning horizon while integrating the forward-looking forecasted coal delivery plan and inventory balances into the current coal price input process for updating weekly coal prices for unit commitment and dispatch.

Q. HOW DOES THE COMPANY DETERMINE THE OPTIMIZED COAL PRICE INPUT TO USE IN UNIT COMMITMENT AND DISPATCH?

A. To determine the optimized coal price input, the Company starts from the current stochastic fuel burn projection across a near-term fuel procurement horizon (typically 12 to 18 months ahead), that is based on current market pricing and is independent of station inventory considerations. From these initial coal burn scenarios, a mean optimized burn and inventory forecast is generated for each coal and dual fuel operating station based on 100 simulations of burn projections and the Companies' forecasted coal deliveries. If the stochastic simulations result in projected coal inventories which fall below station minimum or exceed maximum storage limits, a series of further optimization steps is performed. First, the model assesses whether contractual inventory management options (such as re-balancing deliveries between stations, exercising "flex" provisions in contracts, deferring a limited volume of contracted deliveries, or accelerating deliveries) can alleviate the inventory constraints. If those options are unable to alleviate the inventory constraints, then coal price inputs are optimized to bring projected inventories within limits at impacted coal plants.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S STOCHASTIC PRODUCTION COST MODEL.

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 give the Company not only expected fuel burns, but also the range of fuel burns and the probability associated with each range.

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. DOES DYNAMIC DISPATCH IMPACT THE COMPANY'S INTERGRATED RESOURCE PLANNING PROCESS?

A. No, dynamic dispatch is optimizing the spot coal price input for the existing fleet.

Q. WHEN DOES THE COMPANY EXPECT TO TRANSITION TO THIS DYNAMIC DISPATCH METHODOLOGY?

A. The Company implemented this optimized coal input price process effective May 15, 2023. The implementation of the coal price adjustment is timely, as current coal inventory projections are forecasted to exceed station capabilities due to a dramatic decline in coal burns resulting from a warmer than expected winter and low natural gas prices. The Company has utilized its available commercial options, and dynamic dispatch is now the most effective option to manage coal supply and coal inventories within reliability and safety limits while maintaining longer term fuel security for customers.

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 $95.13 per ton, compared to $84.26 per ton in the prior test period, representing an increase of approximately 13%. The cost of delivered coal includes an average transportation cost of $33.34 per ton in the test period, compared to $35.15 per ton in the prior test period, representing a decrease of approximately 5%. The Company's average price of gas purchased for the test period was $8.15 per Million British Thermal Units ("MMBtu"), compared to $5.44 per MMBtu in the prior test period, representing an increase of approximately 50%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 2.4 million tons, compared to a coal burn of 2.9 million tons in the prior test period, representing a decrease of 16%. The Company's natural gas burn for the test period was 179.6 million MBtu, compared to a gas burn of 174.6 million MBtu in the prior test period, representing an increase of approximately 3%.

Changes in coal and natural gas burns were primarily driven by the relationship of coal commodity prices during 2022 relative to natural gas prices in the same period, as record high coal commodity prices off-set higher natural gas costs, reducing gas to coal generation switching.

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) continued uncertainty regarding proposed and imposed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) increased demand in global markets for both steam and metallurgical coal; (5) tightened access to investor financing; (6) continued shifts in production from thermal to metallurgical coal as producers move away from supplying declining electric generation to take advantage of increasing demand from industry; and, (7) continued labor and resource constraints further limiting suppliers' operational flexibility. In addition, the coal supply chain experienced significant challenges throughout 2021 and 2022 as historically low utility stockpiles combined with rapidly increasing demand for coal, both domestically and internationally, made procuring additional coal supply increasingly challenging. Producers were largely unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices to record levels by late 2021 and limited coal supply availability. Continued labor and resource constraints, including the threat of a rail strike in the fourth quarter of 2022, caused prices to remain elevated over the course of 2022. Going into winter 2022 (December 2022 through February 2023), coal commodity costs remained at historically high levels but began to soften in response to rapidly declining natural gas prices and an overall lack of winter weather demand. Despite current market conditions, coal producers are seeing the inflationary impacts of rising costs associated with mining operations including, but not limited to, labor and equipment costs putting additional pressure on their ability to respond to changes in market demand.

Long-term declines in demand for coal in the utility sector has 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 adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios. In 2022, the Company experienced escalated delivery delays created by rail transportation labor and resource shortages, increasing the average cycle time from mine to plant and decreasing actual rail deliveries versus scheduled deliveries by approximately 30%. With the threat of a potential Class I rail strike averted in early December 2022, the Company has seen delivery improvements by its rail transportation service providers.

With respect to natural gas, the nation's natural gas supply has grown significantly as producers enhanced production techniques, enhanced efficiencies, and lowered production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in 2022, such dynamics were influenced primarily by growth in export demand, stable production, lower than average storage inventory balances and domestic demand. Gas production's slow response to rising prices and the uncertainty of future coal deliveries placed continued stress on gas storage replenishment through much of 2022, keeping upward pressure on gas prices into the latter half of 2022. However, beginning in January 2023, moderate weather, increasing inventory storage balances and growing production have caused natural gas prices to sharply decline.

There is a growing need for natural gas pipeline infrastructure, but gas production—particularly in low-cost regions such as Appalachia—is constrained because 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 while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico is highly uncertain.

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 13, 2023, DEP's coal burn projection for the billing period is 2.5 million tons, compared to 2.4 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 $108.60 per ton for the billing period compared to $95.13 per ton in the test period. This increase in delivered costs is primarily driven by increased coal commodity costs due to limited coal supply and increased domestic and international demand. This includes an average projected total transportation cost of $30.11 per ton for the billing period, compared to $33.34 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 197.5 million MBtu, which is an increase from the 179.6 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $3.34 per MMBtu, compared to $6.26 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.

The net increase in DEP's overall burn projections for the billing period versus the test period is primarily driven by increases in projected load over the period.

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. As of July 1, 2022, the Company has implemented the Fuels and Related Equipment and Services Management and Supply Agreement (the "DECFM Agreement") between DEP and DEC, meaning DEC is the commercial face to the market for coal, reagents, and related transportation in the Carolinas. This agreement provides for an increasingly flexible fuel procurement strategy along with increased real-time logistical flexibility resulting in increased operational and cost efficiencies for customers.[1]

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, the Company procures long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the

[1] North Carolina Utilities Commission Docket No. E-7, Sub 1258 & Docket No. E-2, Sub 1282 Order Accepting Affiliate Agreement issued January 24, 2022.

ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it 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 Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's 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.