BEFORE THE UTILITIES COMMISSION OF NORTH CAROLINA
DOCKET NO. E-2, SUB 1300

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JULIE K. TURNER**
for Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina and Performance-Based Regulation	)	

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julie K. Turner and my business address is 411 Fayetteville Street, Raleigh, North Carolina.

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

A. I am Vice President of Carolinas Coal Generation for Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from North Carolina State University with a Bachelor of Science degree in Mechanical Engineering and received a Master's degree in Business Administration from the University of Colorado. My career began with Duke Energy (d/b/a Carolina Power & Light) in 1991 as a staff engineer at Duke Energy Progress, LLC's ("DEP" or the "Company") Harris Nuclear Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of Station Manager, first at Lee Energy Complex, followed by leading six DEP natural gas generating stations. I assumed my current role in 2020.

Q. WHAT ARE YOUR DUTIES AS VICE PRESIDENT OF CAROLINAS COAL GENERATION?

A. In this role, I am responsible for providing safe, reliable, and event-free operations of Duke Energy's coal generation fleet, which has a total system capability of approximately 9,230 megawatts ("MWs"). My responsibilities include operating and maintaining the fleet within design parameters and implementing safe work practices and procedures to ensure the safety of our employees.

Q. HAVE YOU TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before this Commission in DEP's 2019 rate case proceeding in Docket No. E-2, Sub 1219 ("2019 Rate Case").

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

A. The purpose of my testimony is to support DEP's request for a base rate adjustment. My testimony will describe the Company's Traditional/Renewable/Storage generation assets, provide operational performance results for the period of January 1, 2021 through December 31, 2021 (the "Test Period"), update the Commission on capital additions since the 2019 Rate Case, explain the key drivers impacting operations and maintenance ("O&M") expenses, and support the Traditional and Hydro capital investments included in the Company's Multi-Year Rate Plan ("MYRP"). Turner Exhibit 1 provides additional details regarding projected cost, schedule, and scope for each MYRP project, as well as the reasoning for each project as required by Commission Rule R1-17B(d)(2)j.

Q. WAS TURNER EXHIBIT 1 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. It was.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows:

I. TRADITIONAL/RENEWABLE/STORAGE FLEET

II. CAPITAL ADDITIONS

III. O&M EXPENSES

IV. PERFORMANCE

V. PROPOSED MULTI-YEAR RATE PLAN CAPITAL INVESTMENTS

VI. CONCLUSION

II. <u>TRADITIONAL/RENEWABLE/STORAGE FLEET</u>

Q. PLEASE DESCRIBE DEP'S TRADITIONAL/RENEWABLE/STORAGE GENERATION FLEET.

A. The Company's Traditional/Renewable/Storage fleet consists of 8,871 MWs of owned generating capacity, made up as follows:

Coal-fired -	3,143 MWs
Combustion Turbines -	2,408 MWs
Combined Cycle -	3,054 MWs
Hydro -	228 MWs

Solar - 35 MWs[1]

Battery Storage - 3.4 MWs

The 3,143 MWs of coal-fired generation resources represent two generating stations (Roxboro and Mayo) and a total of five units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x burners. This inventory of coal-fired assets with emission control equipment enhances the Company's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply. While DEP works toward retirement of its coal fleet, continued prudent investment in and operation of these plants is needed to ensure they are available to meet customer needs during this transition.

DEP has a total of 24 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,148 MWs of capacity. These 14 units are located at the Asheville (NC), Darlington (SC), Smith Energy (NC), and Wayne County (NC) facilities, and are equipped with water injection and/or low NO_x burners for NO_x control. The 3,054 MWs shown above as "Combined Cycle" ("CC") represent six power blocks. The HF Lee Energy Complex CC power block ("HF Lee CC") has a configuration of three CTs and one steam turbine. The

[1] This value represents the relative dependable capacity contribution to meeting summer peak demand, based on the Company's integrated resource planning metrics. The nameplate capacity of the Company's solar facilities is 141 MWs.

two power blocks located at the Smith Energy Complex ("Richmond CC") consist of two CTs and one steam turbine each. The Sutton Combined Cycle at Sutton Energy Complex ("Sutton CC") consists of two CTs and one steam turbine. The Asheville Combined Cycle ("Asheville CC") consists of two dual fuel power blocks each containing one CT and one steam turbine. The six CC power blocks are equipped with SCR equipment, and all eleven CTs have low NO_x combustors.

The Company's hydro fleet consists of 15 units providing 228 MWs of capacity and its solar fleet consists of four sites with 141 MWs of nameplate capacity, which provide 35 MWs of relative dependable capacity. The Company's battery storage fleet includes three projects that provide approximately 6.2 MWs of summer storage capacity, including the Hot Springs Microgrid project, which also provides 2 MWs alternative current ("ac") of solar PV capacity.

Q. CAN YOU COMMENT ON HOW THE COMPANY OPERATES ITS FLEET IN ORDER TO PROVIDE RELIABLE, COST-EFFECTIVE SERVICE TO CUSTOMERS?

A. Yes. While the Company's territory is spread across parts of both North Carolina and South Carolina, the system functions and is operated as an integrated whole. This system allows resources located in both states to be shared across the system in order to serve each of North Carolina's and South Carolina's customers. The Company's economic unit commitment model supports the short-term resource planning and dispatch of the DEP fleet by economically optimizing total system variable cost over a seven-day forecast period. In addition, the Company and Duke Energy Carolinas, LLC can transfer economic energy between each other to optimize the combined generation fleet to serve the Company's customers in North Carolina at the lowest cost. This approach benefits customers by increasing reliability of the system and the efficiency of system dispatch, and by providing the lowest cost energy for customers.

Q. PLEASE DESCRIBE THE CONTINUING IMPORTANCE OF THE TRADITIONAL FOSSIL FLEET TO THE CUSTOMERS OF NORTH CAROLINA.

A. The Company's North Carolina customers have benefitted from decades of reliable, cost effective electricity generated from the traditional fossil fleet. The Company's portfolio includes a diverse mix of units that, along with its nuclear capacity, allows DEP to meet the dynamics of customer load requirements in a logical and cost-effective manner. The coal fleet in particular has been a long-time contributor to resource adequacy and an invaluable resource in ensuring fuel and generation adequacy, and needed reliability in the face of long-duration extreme peak load periods during cold weather events, such as "polar vortex" cold snaps and ice storms.

Today, the Carolinas primarily rely on a mixture of nuclear, coal, natural gas, pumped storage, and increasing amounts of solar to provide the energy necessary to meet electricity demands. The diversity of the resource and fuel mix, and availability of coal generation during the transition away from coal, must be strategically managed to ensure the remaining coal fleet can reliably contribute to resource adequacy. As the Company makes plans to retire its remaining coal fired assets, and replace those assets with other resources, it is important to keep these remaining units in efficient working order to support the energy needs of our customers. Therefore, costs for these assets will continue to be incurred as appropriate and prudent to ensure that the same reliable cost effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented. Additionally, the combination of generation resources that replaces coal must be able to provide the same level of reliability that the coal units have and continue to provide. Because natural gas is critical to this resource mix, particularly during the winter months and while energy storage capacity is being developed and deployed, the Company will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix that will be needed to ensure the reliability of service to DEP customers both now and in the future.

III. CAPITAL ADDITIONS

Q. PLEASE DESCRIBE THE MAJOR TRADITIONAL/RENEWABLE/STORAGE CAPITAL PROJECTS THAT DEP HAS OR WILL HAVE BY APRIL 30, 2023 COMPLETED SINCE THE COMPANY'S LAST RATE CASE PROCEEDING.

A. Since the 2019 Rate Case, DEP has or will have by April 30, 2023, made capital investments in its Traditional/Renewable/Storage fleet totaling approximately $511 million.

Capital maintenance for the natural gas powered fleet cost approximately $323 million. These projects included, for example, major capital maintenance outages at many of the stations, Richmond CC isolation valve replacement and cooling tower rebuild, and valve maintenance at Lee CC, and were prudently undertaken in order to maintain the reliability and performance of the Company's natural gas fleet, which remains an important component of Duke Energy's strategy to achieving a cleaner energy future.

Capital maintenance of the coal units totaled approximately $117 million, and included Mayo ammonia system conversion to an aqueous ammonia system and air handling basket replacements, and a lined runoff pond and replacement of the SCR catalysts at Roxboro. These projects were undertaken in order to keep these remaining units in efficient and compliant working order to support the energy needs of DEP customers, as part of the Company's strategic management of the transition away from coal to ensure the continued reliable operation of the coal fleet during this transition.

With regard to DEP's hydro fleet, capital maintenance projects totaled approximately $70 million and included, for example, a FERC-required hydro project at Blewett Falls Hydro station to install 127 rock anchors to stabilize the concrete spillway. Other hydro capital maintenance projects included installing wicket gates and wear plates, tank access improvements, and controls replacements.

The Company has also added three battery installations to the DEP fleet at a total cost of approximately $42 million. The Asheville/Rock Hill storage project, which contributes 2 MW to the Company's summer dependable capacity, was placed in service in September 2020. The Hot Springs Microgrid project, which contributes 1.4 MW to the Company's summer dependable capacity and also includes a 2 MW solar facility, was placed in service in December 2021. The Asheville/Rock Hill and Hot Springs Microgrid projects are part of the Western Carolinas Modernization Project. The Camp Lejeune project consists of a lithium-based battery energy storage facility that contributes 2.6 MW to DEP's summer dependable capacity and is co-located with the existing Camp Lejeune solar facility. This system is expected to be placed in service in early 2023.

Q. MS. TURNER, WILL THESE CAPITAL ADDITIONS BE USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DEP'S ELECTRIC CUSTOMERS IN NORTH CAROLINA BY APRIL 30, 2023?

A. Yes. All of the capital additions listed above are commercially operational and providing electric service to customers, or will be so before April 30, 2023.

Q. IN YOUR OPINION, HAVE THE COSTS RELATED TO THE COMPANY'S CAPITAL ADDITIONS BEEN PRUDENTLY INCURRED?

A. Yes. DEP controls costs for capital projects and O&M utilizing a cost management program. The Company controls costs through routine executive oversight of project budget and activity reporting with new projects requiring approval by progressively higher levels of management depending on total project cost. The Company controls ongoing project and O&M costs through strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to drive out process improvement, and industry benchmarking to ensure best practices are being utilized.

IV. O&M EXPENSES

Q. PLEASE DESCRIBE THE O&M EXPENSES FOR THE TRADITIONAL/RENEWABLES/STORAGE FLEET.

A. For the fossil units, approximately 84% of DEP's required O&M expenditures are fuel-related for the Test Period. The majority of non-fuel expenditures are for labor costs from Company or contract resources that operate, maintain, and support the Traditional/Renewable/Storage facilities. Finally, the Company continues to be challenged by costs driven by inflationary pressures for labor and materials.

Q. HOW DOES THE COMPANY CONTROL AND MITIGATE O&M EXPENSE INCREASES? PLEASE PROVIDE EXAMPLES.

A. The Company has many efforts in place for controlling and/or minimizing costs. For example, DEP optimizes outages based on run time, which is affected by fuel market prices, weather cycles, and changes in generation resources. This optimization has provided labor and materials savings.

Duke Energy joined forces with other power companies to share best practices and learning opportunities with the Generation Networking Group ("GNG," formerly known as the Fossil Networking Group). The GNG includes Southern Company, Dominion Energy, American Electric Power, and the Tennessee Valley Authority. The Company has seen benefits associated with safety and operations based on its membership in the GNG.

The Company runs its business in a disciplined manner and continuously balances cost management with safety and reliability to generate electric service for our customers. Cost to customers is a key concern and the Company's diverse portfolio allows us to reduce overall fuel expense.

V. PERFORMANCE

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR THE DEP TRADITIONAL/RENEWABLE/STORAGE FLEET DURING THE TEST PERIOD.

A. The Company's Traditional/Renewable/Storage generating units operated efficiently and reliably during the Test Period. Several key measures are used to evaluate the operational performance depending on the generator type: (1)

equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance (*i.e.*, forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) starting reliability ("SR"), which represents the percentage of successful starts; and (4) equivalent forced outage factor ("EFOF"), which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages and forced deratings. Based on these metrics, DEP's Traditional/Renewable/Storage fleet performance was comparable in a number of areas, particularly with respect to the natural gas fleet, to the results from the North American Electric Reliability Counsel ("NERC") Generating Unit Statistical Brochure representing the period 2017-2021.

Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. For the Test Period, DEP's system total generation was approximately 59.6 million megawatt-hours ("MWHs"). The Traditional/Renewable/Storage fleet provided approximately 29.7 million MWHs, or approximately 50%, of that total. This included an approximate 11% contribution from the coal-fired stations, approximate 37% from natural gas facilities, and approximate 1% from renewable facilities, primarily hydro.

Q. IN YOUR OPINION, HAS DEP PRUDENTLY OPERATED ITS TRADITIONAL/RENEWABLE/STORAGE FLEET DURING THE TEST PERIOD?

A. Yes. The Company's performance data supports the conclusion that DEP has reasonably and prudently operated and maintained its Traditional/Renewable/Storage resources to maximize unit availability, minimize fuel costs, and provide safe and reliable service to its customers.

VI. PROPOSED MULTI-YEAR RATE PLAN CAPITAL ADDITIONS

Q. DOES THE COMPANY'S PROPOSED MYRP INCLUDE TRADITIONAL/RENEWABLE/STORAGE PROJECTS?

A. Yes. Eighty Traditional and Hydro projects are included in the Company's proposed MYRP and supported by my testimony and Turner Exhibit 1. Witness Justin LaRoche addresses solar projects included in the MYRP and Witnesses Laurel Meeks and Evan Shearer address storage projects included in the MYRP.

Q. WHAT PROCESS AND CRITERIA DID THE COMPANY USE TO SELECT THESE PROJECTS FOR INCLUSION IN THE PROPOSED MYRP?

A. The Company leveraged the project prioritization process that it typically utilizes to plan for capital projects for the Traditional and Hydro fleets to identify the projects that are proposed for the MYRP. Pursuant to this process, the Company uses a Project Prioritization ("Stack/Rank") Process to assign an initial score (0-1000) to capital projects. The scoring process factors in safety and environmental risks, economic evaluation, and unit operating priority depending on the project category. Projects required to address regulatory issues are scored as 1000 and included in the Compliance Mandate category. Project categories include:

- Compliance Mandate
- Safety
- Environmental
- Committed (In-flight and Long-Term Service Agreements)
- Growth & Strategy
- Routine Reliability (Outage and Ongoing Maintenance)
- Economic Reliability
- Infrastructure

After further evaluation, the Traditional and Hydro projects included in the proposed MYRP were identified based on their projected timing.

Q. HOW WERE THE PROJECTED COSTS FOR THE PROJECTS CALCULATED?

A. The Company's Project Management Guidelines, which include guidance for project scope development and cost estimating, were applied to the calculation of projected costs for the Traditional and Hydro MYRP projects. Cost estimates can be based on a combination of vendor quotes or budgetary estimates for labor and materials, estimates for internal labor and warehouse materials, and previous experience on similar projects. Estimates for direct costs were entered into the PowerPlan project management tool where overheads, labor loadings, and AFUDC were calculated, to produce an overall projected cost.

Q. WERE ANY OF THESE PROJECTS PRESENTED AT THE JULY 25, 2022 TECHNICAL CONFERENCE HELD IN THIS PROCEEDING?

A. No. The technical conference addressed only the Transmission and Distribution ("T&D") projects in the proposed MYRP, and none of the traditional or hydro projects are T&D.

Q. WILL ANY OF THE TRADITIONAL OR HYDRO MYRP PROJECTS REQUIRE A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FROM THE COMMISSION?

A. No.

Q. ARE ANY OF THESE PROJECTS INCLUDED IN THE CARBON PLAN?

A. None of the projects are specifically identified in the Carbon Plan, but the Carbon Plan states that "expanding the flexibility of the Companies' existing natural gas fleet in the Carolinas"[2] will be required to meet the targets of HB 951 and identifies "smaller unit flexibility projects on existing CCs"[3] as a near term action for the 2022-2024 time frame. Several traditional projects on DEP's MYRP list are considered natural gas unit flexibility projects. Notwithstanding the Carbon Plan, the Company considers these projects as a necessary part of prudent utility resource planning.

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[2] Carolinas Carbon Plan, Appendix M at p. 5, Docket No. E-100, Sub 179 (filed May 16, 2022).
[3] *Id*. at Chapter 4 at p. 10.

Q. HOW DO THE IIJA FEDERAL GRANTS FACTOR INTO YOUR PLANNING PROCESS?

A. Duke Energy is actively engaged in the ongoing implementation of the federal Infrastructure Investment and Jobs Act ("IIJA") at the state and federal levels. Duke Energy is participating in Requests for Information ("RFIs") and discussions with federal agencies. While federal agencies are making progress, they are still in the early phases of their overall IIJA implementation, with many new programs actively under development. To be clear, DEP is pursuing IIJA funding opportunities for the benefit of our customers and will ensure that customers receive that benefit. However, the projects included in this MYRP request are needed and will benefit customers regardless of whether or not IIJA funding is received. None of the cost estimates submitted with DEP's pre-filed materials assume IIJA funding is received.

Q. DID THE COMPANY CONDUCT COST BENEFIT ANALYSES ("CBA") FOR THE PROJECTS YOU ARE SUPPORTING?

A. Yes. Pursuant to the Company's Stack/Rank guidelines, a number of the projects required an economic evaluation. Specifically, projects in the Economic Reliability or Growth & Strategy categories noted above, with an estimated cost greater than $100,000, require an economic analysis in the PowerPlan project management tool. The economic evaluation models project benefits based on expected future operation of the plant, compared with the cost to implement, and estimates an internal rate of return and net present value of the project. Typical benefits may include restoring reliability to avoid future forced outages or derates, and improved heat rate.

Q. DO ANY OF THE PROJECTS OFFER PROJECTED OPERATING BENEFITS?

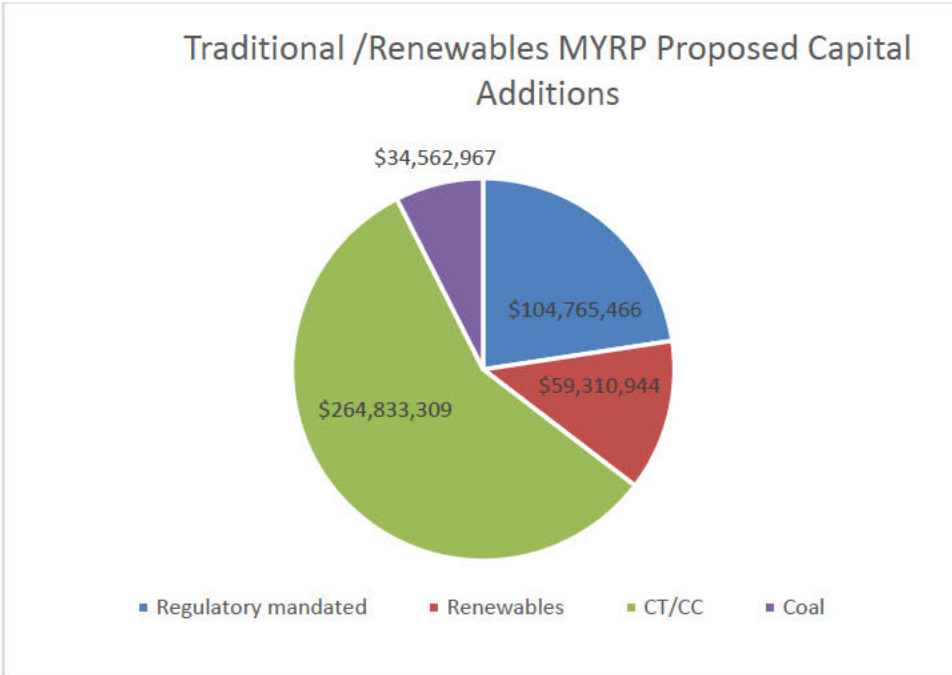
A. No quantified projected operating benefits were identified for the proposed projects. The qualitative benefits of completing the projects are that they will enable DEP to maintain safe and reliable operation of the Traditional and Hydro fleets. The specific benefits of each project are presented in further detail in Turner Exhibit 1.

Q. IN YOUR VIEW, IS THE COMPANY'S DECISION TO INVEST IN THESE PROJECTS PRUDENT, JUST, AND REASONABLE FOR THE PROVISION OF SAFE AND RELIABLE SERVICE TO CUSTOMERS AND IN THE PUBLIC INTEREST?

A. Yes. The Company has prudently and reasonably decided to invest in these projects in order to continue to provide safe, reliable, and affordable service to customers.

Q. PLEASE PROVIDE ADDITIONAL DETAIL REGARDING THE PROPOSED TRADITIONAL AND HYDRO MYRP PROJECTS AND WHY THEY ARE BEING PROPOSED FOR THE MYRP.

A. The Company proposes to spend approximately $463 million on capital investments associated with Traditional and Hydro MYRP projects over the October, 2023 through September, 2026, time period, broken down as shown below:



These projects are being undertaken to comply with regulatory requirements as well as to maintain these units in good, efficient and reliable working order. Additional discussion regarding these projects, organized by fuel technology – coal, combined cycle/combustion turbine, and hydro, is provided below. Turner Exhibit 1 provides additional details regarding projected cost, schedule, and scope for each project, as well as the reasoning for each project as required by Commission Rule R1-17B(d)(2)j.

Q. WHAT ARE THE MYRP CAPITAL INVESTMENTS THAT THE COMPANY IS PROPOSING TO MAKE AT ITS COMBINED CYCLE AND COMBUSTION TURBINE UNITS?

A. Carolinas Gas projects, including CC and CT projects, total approximately $265 million. These projects are being undertaken to ensure continued reliability of the units to provide reliable service for customers.

For example, DEP plans to conduct Hot Gas Path inspections and maintenance at all of the CT stations. These projects are scheduled according to manufacturer recommendations based on starts or run hours. They involve disassembly of the combustor and hot turbine sections of a CT and typically include replacement of parts as needed based on the inspection.

DEP also plans to upgrade the controls systems at the Smith and HF Lee Combined Cycle stations. The digital controls systems at these stations control power plant equipment during startup, unit running conditions, and shutdown to ensure proper operation while connected to the grid. The existing controls systems at these stations are obsolete and replacement parts are increasingly difficult to locate. These projects will upgrade the controls systems to the current version to maintain unit reliability.

Turner Exhibit 1 provides a full list of these and the other proposed MYRP projects for the natural gas fleet with additional details.

Q. WHAT ARE THE MYRP CAPITAL INVESTMENTS THAT THE COMPANY IS PROPOSING TO MAKE AT ITS COAL UNITS?

A. Carolinas Coal projects included in the proposed MYRP total approximately $35 million. These projects are needed to keep the active coal units in reliable operating condition while they are still providing power for our customers during the energy transition.

For example, two projects involve the replacement of turbine blades at Mayo Unit 1 and Roxboro Unit 4. These turbine blades are experiencing erosion on their leading edges. Replacing the blades will reduce the risk of potential blade detachment and damage to the low-pressure turbines and condensers.

As another example, at Mayo Unit 1 and Roxboro Units 1 and 4, the Company plans to replace a layer of the SCR catalyst in order to maintain the Department of Environmental Quality-required NO_x removal rate. Samples of each catalyst layer are taken periodically to determine each layer's remaining capacity for NO_x removal; layers are replaced when NO_x removal capability is diminished.

Turner Exhibit 1 provides a full list of these and the other proposed MYRP projects for the coal fleet with additional details.

Q. WHAT ARE THE MYRP CAPITAL INVESTMENTS THAT THE COMPANY IS PROPOSING TO MAKE AT ITS REGULATED RENEWABLE UNITS?

A. Carolinas Renewables projects total approximately $164 million. All of these projects involve the hydroelectric stations. The projects are needed to maintain these units, which have reliably provided service in some cases for over 100 years, to keep them running and meet federal regulatory requirements.

For example, a FERC-required project will be completed at Blewett Falls Hydro station. The 2015 FERC operating license for this station requires the installation of fish passage structures to accommodate the movement of American shad and American eel through the Pee Dee River.

In addition, projects at Tillery Hydro Station Units 1 and 3 will replace those units' existing turbine runners. This equipment is 90 years old and needs to be replaced with new design turbine runners that will increase capacity and meet FERC required dissolved oxygen limits.

Turner Exhibit 1 provides a complete list of these and the other proposed MYRP projects for the hydro fleet with additional details.

VII. CONCLUSION

Q. IS THERE ANYTHING YOU WOULD LIKE TO SAY IN CLOSING?

A. Yes. The Company has a proven history of experience-based, safe, reliable, and cost competitive operations of a diverse generation portfolio. The Company has been active and diligent in making the right investments that continue, and build on, DEP's solid history of safely providing reliable, efficient, and cost-effective generation, while reducing environmental impacts and ensuring compliance with state and federal regulations. Our customers reap the benefits of the Company's diverse generation assets through the economic dispatch of our energy across North Carolina and South Carolina, which dispatches lower cost energy first, saving customers money.

DEP is positioned to continue as a leader in the industry with a solid base of knowledge and experience. As the Company progresses towards retiring and replacing its coal fleet, it is critical to keep these units running in good working order to provide the dependable, low cost electricity on which our customers depend, and to maintain the efficient and reliable operation of the natural gas fleet. This base rate increase will allow the Company to continue its tradition of operational excellence and focus on safe operations and reliable generation. The MYRP projects that the Company is seeking approval of in this case will do the same over the next several years as DEP continues to transition toward a cleaner energy future.

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

A. Yes.

DUKE ENERGY PROGRESS
MYRP PROJECTS
DOCKET NO. E-2 Sub 1300

[redacted]
Attorney/Client Work Product

Line No.	MYRP Project Name	FERC Function	Project Forecasted In-Service Date	MYRP Project Description & Scope	Reason for the MYRP Project	Total Project Amount (System) Projected In-Service Costs	Projected Annual Net O&M	Projected Installation O&M
1	ACC Exhaust Gas Temperature Cooling	Other Production Plant in Service	Oct-25	Addition of an Overboard Bleed System (OBB) to improve Asheville CC Exhaust Gas Temperature Cooling Capability	Addition of an Overboard Bleed System (OBB) will reduce high exhaust gas temperatures at low load operation while maintaining emissions compliance. Extended low-load capability will in turn accommodate daytime solar generation without taking unit offline.	$ 5,209,488.01	$ -	$ -
2	ACC ST6 Generator Stator Rewind	Other Production Plant in Service	Apr-24	Rewind Asheville CC Steam Turbine 6 Generator Stator	The generator stator bar rewind with new insulation will prevent potential ground faults due to insulation cracking, thereby improving reliability of ST6.	$ 2,404,136.70	$ -	$ -
3	ACC ST8 Generator Stator Rewind	Other Production Plant in Service	Nov-24	Rewind Asheville CC Steam Turbine 8 Generator Stator	The generator stator bar rewind with new insulation will prevent potential ground faults due to insulation cracking, thereby improving reliability of ST8.	$ 2,512,567.55	$ -	$ -
4	AGP Peaker Upgrade	Other Production Plant in Service	Nov-24	GE Advance Gas Path (AGP) Peaker upgrade for Smith Combustion Turbine Unit 6.	The GE Advance Gas Path (AGP) Peaker upgrades, in which the Hot Gas Path hardware is upgraded to allow for increased flow through the turbine while maintaining current NOx and CO emissions limits, provide a 10 MW increase per unit. Upgraded parts life intervals are also extended from 900 to 1250 starts and unit ramp rate is doubled.	$ 5,872,615.81	$ -	$ -
5	AGP Peaker Upgrades	Other Production Plant in Service	Apr-24	GE Advance Gas Path (AGP) Peaker upgrade for Smith Combustion Turbine Unit 4.	The GE Advance Gas Path (AGP) Peaker upgrades, in which the Hot Gas Path hardware is upgraded to allow for increased flow through the turbine while maintaining current NOx and CO emissions limits, provide a 10 MW increase per unit. Upgraded parts life intervals are also extended from 900 to 1250 starts and unit ramp rate is doubled.	$ 5,108,235.25	$ -	$ -
6	Asheville CT HGPI Unit 5	Other Production Plant in Service	May-24	Asheville Unit 5 Combustion Turbine Hot Gas Path Inspection	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. GE 7F Gas Turbines require major maintenance at set intervals based on the number of run hours. It is projected that this unit will reach or exceed the number of run hours required to perform this maintenance in 2024.	$ 18,708,011.81	$ -	$ -
7	Asheville CT HGPI Unit 7	Other Production Plant in Service	Oct-24	Asheville Unit 7 Combustion Turbine Hot Gas Path Inspection	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. GE 7F Gas Turbines require major maintenance at set intervals based on the number of run hours. It is projected that this unit will reach or exceed the number of run hours required to perform this maintenance in 2024.	$ 18,697,259.68	$ -	$ -
8	Asheville ST Valves Unit 6	Other Production Plant in Service	Apr-24	Asheville CC Unit 6 Steam Turbine Valves Capital Maintenance	Replace capital valve components of the Asheville CC Steam Turbine 6 Valves based on Duke Turbine/Generator Services recommended maintenance interval.	$ 2,485,544.64	$ -	$ -
9	Asheville ST Valves Unit 8	Other Production Plant in Service	Oct-24	Asheville CC 8 Steam Turbine Valves Capital Maintenance	Replace capital valve components of the Asheville CC Steam Turbine 8 Valves based on Duke Turbine/Generator Services recommended maintenance interval.	$ 2,121,927.39	$ -	$ -
10	Asheville Unit 04 Generator Field Rewind	Other Production Plant in Service	Nov-24	Asheville Unit 4 Generator Field Rewind	Generator Rewind recommended by Duke Turbine/Generator Services based on inspections that show core shift/loosening.	$ 2,184,806.79	$ -	$ -
11	BLH - Fish Passage	Hydro Plant in Service	Oct-23	Addition of Fish Passage Protections at Blewett Falls Hydro Station pursuant to new FERC operating license	The new FERC operating license for Blewett Falls and Tillery hydroelectric plants requires the installation of fish passage structures to accommodate movement of American shad and American eel.	$ 104,765,466.41	$ -	$ -
12	BLH U4 Replace Turbine Runner	Hydro Plant in Service	Dec-25	Replace Turbine Runner at Blewett Falls Hydro Station, Unit 4	Original turbine runner is 100 years old, experiences cavitation during operation, and requires increasing maintenance. Replacement with a modern design turbine runner will increase output by 1.4 MW and reduce O&M maintenance costs.	$ 10,357,941.18	$ -	$ -
13	Combined Cycle Unit Flexibility Upgrade (Asheville)	Other Production Plant in Service	Nov-24	Asheville PB1 and PB 2 CC Unit Flexibility Upgrade	Install HRSG damage monitoring system to calculate real time creep and fatigue life of pressure parts (Asheville PB1 and PB2, Smith PB5)	$ 925,000.00	$ -	$ -
14	Combined Cycle Unit Flexibility Upgrade (Smith)	Other Production Plant in Service	Nov-24	Smith PB5 CC Unit Flexibility Upgrade	Install HRSG damage monitoring system to calculate real time creep and fatigue life of pressure parts (Asheville PB1 and PB2, Smith PB5)	$ 925,000.00	$ -	$ -
15	Combined Cycle Unit Flexibility Upgrade (Sutton)	Other Production Plant in Service	Sep-26	Sutton PB1 CC Unit Flexibility Upgrade	Install HRSG damage monitoring system to calculate real time creep and fatigue life of pressure parts (Sutton PB1)	$ 950,000.00	$ -	$ -
16	Darlington Unit 12 Combustion Inspection	Other Production Plant in Service	Mar-26	Darlington Unit 12 CT Combustion Inspection	Perform a standard combustion path inspection in accordance with OEM and company engineering standards. Recommended interval for a major combustion inspection is based upon a combination of operating hours and number of start/stop cycles.	$ 3,283,197.55	$ -	$ -
17	FERC BLH Raise Dam Crest	Hydro Plant in Service	Dec-24	Raise dam crest pursuant to FERC requirements at Blewett Hydro facility	FERC license requires prevention of overtopping due to wave run up during Probable Maximum Flood (PMF) event. Scope includes raising dam crest approximately 2 feet, widening dam crest, and hardening upstream face of Blewett Dam.	$ 1,076,529.27	$ -	$ -
18	HF Lee 01A LTSA HGPI	Other Production Plant in Service	Oct-25	HF Lee Unit 1A Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2025.	$ 2,645,133.60	$ -	$ -
19	HF Lee 01B LTSA HGPI	Other Production Plant in Service	Dec-25	HF Lee Unit 1B Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2025.	$ 2,630,116.51	$ -	$ -
20	HF Lee 01C LTSA HGPI	Other Production Plant in Service	Oct-25	HF Lee Unit 1C Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2025.	$ 2,629,329.60	$ -	$ -
21	HF Lee Emerson Ovation BOP Evergreen	Other Production Plant in Service	Jun-24	HF Lee CC Emerson Evergreen Balance of Plant (BOP) Controls Upgrade	Existing controls system is obsolete with parts increasingly difficult to locate. Scope is to upgrade to current version of Emerson Ovation Digital Control System to maintain unit reliability.	$ 1,143,996.64	$ -	$ -
22	HF Lee Unit 1 ST Valve	Other Production Plant in Service	Nov-25	HF Lee Unit 1 Steam Turbine Valves Capital Maintenance	HF Lee Unit 1 Steam Turbine Valve components will be replaced based on Original Equipment Manufacturer recommended maintenance interval to maintain unit reliability.	$ 3,222,795	$ -	$ -
23	Mayo 1- 1A AR Suction Piping Replacement (REL)	Steam Plant in Service	Dec-23	Replace suction piping at Mayo 1A	Mitigate failure mechanisms in pipe and valve that could cause unit to come offline for emergency repairs.	$ 307,500	$ -	$ -
24	Mayo 1 Soot blower maintenance	Steam Plant in Service	Dec-23	Replace portions of the soot blowers for Mayo 1	Replace failed and degraded soot blower components to maintain efficient heat transfer to the boiler	$ 150,000	$ -	$ -
25	Mayo 1 Soot blower maintenance	Steam Plant in Service	Dec-24	Replace portions of the soot blowers for Mayo 1	Replace failed and degraded soot blower components to maintain efficient heat transfer to the boiler	$ 150,000	$ -	$ -
26	Mayo Absorber Recycle piping lining degradation	Steam Plant in Service	Dec-24	Replace piping lining at Mayo Unit 1	Liner replacement to mitigate piping failure that would result in a 3-day unit forced outage. Mitigate pipe spool replacement costs due to failed liner.	$ 312,500	$ -	$ -
27	MLH Controls Upgrade & Automation	Hydro Plant in Service	Jul-25	Complete Marshall Hydro Controls Automation	The hydro plant has been upgraded to operate remotely from Hydro Central. This project is to incorporate remaining Programmable Logic Controllers (PLCs), control cabinets and relays that were not included in the original automation upgrade.	$ 2,949,119	$ -	$ -
28	MY00 Replace Plant Fire Header	Steam Plant in Service	Nov-25	Replace Mayo Plant Fire Water Header	Underground fire water header is in poor condition and experiences leaks. This project will replace the below ground fire piping system with above ground piping and valves to facilitate inspection and repair.	$ 2,630,365	$ -	$ -
29	MY01 Dry Bottom Ash Piping Upgrade	Steam Plant in Service	Sep-24	Replace Mayo Unit 1 Dry Bottom Ash System Piping.	Existing piping and fittings are experiencing wear resulting in frequent patching to keep system in operation. Replacing Nuvalloy I and carbon steel piping with Nuvalloy II straight pipe sections and Duracore II ceramic tile elbows will address the issue.	$ 1,419,606	$ -	$ -
30	MY01 SCR catalyst replacement	Steam Plant in Service	May-24	Mayo Unit 1 Selective Catalytic Reduction (SCR) catalyst layer replacement (NOx reduction)	SCR catalyst layer replacements maintain DEQ-required NOx removal rate based on analysis of samples of catalyst layers.	$ 2,513,214	$ -	$ -

DUKE ENERGY PROGRESS
MYRP PROJECTS
DOCKET NO. E-2 Sub 1300

[redacted]
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						Total Project Amount (System)		
Line No.	MYRP Project Name	FERC Function	Project Forecasted In-Service Date	MYRP Project Description & Scope	Reason for the MYRP Project	Projected In-Service Costs	Projected Annual Net O&M	Projected Installation O&M
31	MY01-Replace Sandbed Filters	Steam Plant in Service	Dec-24	Replace Mayo Unit 1 sandbed filters	Replace the three (3) Mayo Plant Sandbed filters. Current sandbed filters are at end of life and are in need of replacement. All make-up and raw water is processed by these filters. Material condition is poor and in need of replacement.	$ 942,079	$ -	$ -
32	MY01-Turbine LP Blade Replacement	Steam Plant in Service	May-24	Replace last stage blades on Mayo Unit 1 low pressure turbine	Both rows of last stage blades are experiencing erosion on the leading edges. Blade replacement will prevent the potential of blade detachment and possible damage to the low-pressure turbine and condenser.	$ 3,628,521	$ -	$ -
33	Richmond Unit 7 High Pressure Superheater (HPSH) Lower Header Upgrade	Other Production Plant in Service	May-25	Upgrade Richmond Unit 7 HPSH Lower Header	Existing boiler high pressure superheater (HPSH) lower headers are experiencing tube-to-header leaks due to thermal fatigue. Scope is to replace headers with Grade 91 material.	$ 1,935,195	$ -	$ -
34	Richmond Unit 8 High Pressure Superheater (HPSH) Lower Header Upgrade	Other Production Plant in Service	May-25	Upgrade Richmond Unit 8 HPSH Lower Header	Existing boiler high pressure superheater (HPSH) lower headers are experiencing tube-to-header leaks due to thermal fatigue. Scope is to replace headers with Grade 91 material.	$ 1,925,429	$ -	$ -
35	ROX4 FGD AR Pmp Piping Rubber Lining Failure	Steam Plant in Service	Dec-24	Piping lining replacement at Roxboro Unit 4	Liner replacement to mitigate piping failure that would result in a 3-day unit forced outage. Mitigate pipe spool replacement costs due to failed liner.	$ 937,500	$ -	$ -
36	Roxboro 01- Generator flexible lead potential for failure	Steam Plant in Service	Dec-25	Replace Roxboro 01 generator lead with new design lead.	General Electric identified a problem with the flexible leads which was communicated to Duke and other customers. Duke plans to replace the flexible leads with leads of updated design to mitigate risk of failure.	$ 218,750	$ -	$ -
37	Roxboro 02- Generator flexible lead potential for failure	Steam Plant in Service	Dec-23	Replace Roxboro 02 generator lead with new design lead.	General Electric identified a problem with the flexible leads which was communicated to Duke and other customers. Duke plans to replace the flexible leads with leads of updated design to mitigate risk of failure.	$ 156,250	$ -	$ -
38	Roxboro 03- Generator flexible lead potential for failure	Steam Plant in Service	Dec-23	Replace Roxboro 03 generator lead with new design lead.	General Electric identified a problem with the flexible leads which was communicated to Duke and other customers. Duke plans to replace the flexible leads with leads of updated design to mitigate risk of failure.	$ 156,250	$ -	$ -
39	Roxboro 04- Generator flexible lead failure potential	Steam Plant in Service	Dec-25	Replace Roxboro 04 generator lead with new design lead.	General Electric identified a problem with the flexible leads which was communicated to Duke and other customers. Duke plans to replace the flexible leads with leads of updated design to mitigate risk of failure.	$ 218,750	$ -	$ -
40	Roxboro 1- RX1- SCR Inlet Damper Erosion	Steam Plant in Service	Dec-24	Replace Rox 1 SCR inlet dampers	Two inlet dampers which control air flow into the SCR are being replaced due to inspection findings indicating erosion.	$ 1,250,000	$ -	$ -
41	Roxboro 2- RX02 Mill Components at End of Life	Steam Plant in Service	Dec-23	Rox 2 replace degraded components	Components degraded and need replacement	$ 1,248,750	$ -	$ -
42	Roxboro 3- ROX 3 ID Booster Fan Motor Reconditioning	Steam Plant in Service	Dec-25	Recondition Rox 3 ID Booster Fan motor based on long run time	Overhaul the fan motor (motor rewind) to improve unit reliability. Motors have run 15-16 years since last overhaul, long lead times on materials require proactive intervention.	$ 450,000	$ -	$ -
43	Roxboro 4- ROX 4 FD Fan Motor Reconditioning	Steam Plant in Service	Dec-24	Recondition Rox 4 FD Fan motor based on long run time	Overhaul the fan motor (motor rewind) to improve unit reliability. Motors have run 15-16 years since last overhaul, long lead times on materials require proactive intervention.	$ 168,750	$ -	$ -
44	Roxboro 4- ROX 4 ID Booster Fan Motor Reconditioning	Steam Plant in Service	Dec-23	Recondition Rox 4 ID Booster Fan motor based on long run time	Overhaul the fan motor (motor rewind) to improve unit reliability. Motors have run 15-16 years since last overhaul, long lead times on materials require proactive intervention.	$ 168,750	$ -	$ -
45	Roxboro 4- ROX 4 ID Fan Motor Reconditioning	Steam Plant in Service	Dec-24	Recondition Rox 4 ID Fan motor based on long run time	Overhaul the fan motor (motor rewind) to improve unit reliability. Motors have run 15-16 years since last overhaul, long lead times on materials require proactive intervention.	$ 168,750	$ -	$ -
46	ROX-Com Oxidation Air Piping Failure/Scaling - T	Steam Plant in Service	Dec-24	Rox common air piping needs replacement to avoid failure	Air piping material has corroded and will be replaced .	$ 1,250,000	$ -	$ -
47	RX01- Replace Oily Waste Separator	Steam Plant in Service	Feb-25	Replace Oily Waste Separator at Roxboro Unit 1	Existing oily waste separator is 40 years old. Scope is to replace with modern equipment to maintain reliability and provide better monitoring capabilities.	$ 945,412	$ -	$ -
48	RX01 Replace SCR Catalyst Layer	Steam Plant in Service	Nov-25	Roxboro Unit 1 Selective Catalytic Reduction (SCR) catalyst layer replacement (NOx reduction)	SCR catalyst layer replacements maintain DEQ-required NOx removal rate based on analysis of samples of catalyst layers.	$ 1,918,341	$ -	$ -
49	RX02 2A 2B Boiler Feedpump Turbine	Steam Plant in Service	May-24	Roxboro Unit 2A-2B Boiler Feedpump Turbine modifications	Based on GE Technical Information Letter (TIL) 1206, scope is to replace 5th and 6th stage rotating and stationary turbine blades with updated design that will improve performance and reduce risk of failure.	$ 1,832,875	$ -	$ -
50	RX03 CT Right Angle Gearbox Phase I	Steam Plant in Service	Dec-25	Install right-angle gearboxes on Roxboro Unit 3 cooling tower.	The seals on the existing cooling tower gearboxes are below oil level and frequently result in leaks, creating reliability and maintenance issues. Scope is to replace with new design right-angle gearboxes to prevent future oil leaks. Gearboxes will be replaced in phases in groups of 4 until all 16 are replaced.	$ 1,711,658	$ -	$ -
51	RX04 4A & 4B Boiler Feedpump Turbine	Steam Plant in Service	May-24	Roxboro Unit 4A-4B Boiler Feedpump Turbine modifications	Based on GE Technical Information Letter (TIL) 1206 scope is to replace 5th and 6th stage rotating and stationary turbine blades with updated design that will improve performance and reduce risk of failure.	$ 2,423,431	$ -	$ -
52	RX04 CT Right Angle Gearbox Phase I	Steam Plant in Service	Dec-25	Install right-angle gearboxes on Roxboro Unit 4 cooling tower.	The seals on the existing cooling tower gearboxes are below oil level and frequently result in leaks, creating reliability and maintenance issues. Scope is to replace with new design right-angle gearboxes to prevent future oil leaks. Gearboxes will be replaced in phases in groups of 4 until all 16 are replaced.	$ 1,711,658	$ -	$ -
53	RX04 LP rotor L-0 blade replacement	Steam Plant in Service	May-24	Replace last stage blades on low pressure turbines of Roxboro Unit 4	Previous inspections revealed erosion on leading edge of last stage buckets on both Low-Pressure A and Low-Pressure B rotors. Blade replacement will prevent the potential of blade detachment and possible damage to the low-pressure turbines and condensers.	$ 3,585,387	$ -	$ -
54	RX04-Catalyst Replacement	Steam Plant in Service	Dec-24	Roxboro Unit 4 Selective Catalytic Reduction (SCR) catalyst layer replacement (NOx reduction)	SCR catalyst layer replacements maintain DEQ-required NOx removal rate based on analysis of samples of catalyst layers.	$ 1,987,922	$ -	$ -
55	Smith CC PB4 Emerson Evergreen	Other Production Plant in Service	Apr-25	Upgrade Smith CC Power Block 4 Emerson Evergreen Controls	Existing controls system is obsolete with parts increasingly difficult to locate. Scope is to upgrade to current version of Emerson Ovation Digital Control System to maintain unit reliability.	$ 914,989	$ -	$ -
56	Smith CC PB4 Toshiba to Emerson Controls	Other Production Plant in Service	Jun-25	Upgrade controls from Toshiba to Emerson for Smith CC Power Block 4	Controls hardware/software upgrade will provide current version system that is fully supported by Emerson. Upgrading from Toshiba to Emerson will make the system compatible with other Duke Energy sites, resulting in O&M savings for support.	$ 1,634,850	$ -	$ -
57	Smith CC PB5 Emerson Evergreen	Other Production Plant in Service	May-24	Upgrade Smith CC Power Block 5 Emerson Evergreen Controls	Existing controls system is obsolete with parts increasingly difficult to locate. Scope is to upgrade to current version of Emerson Ovation Digital Control System to maintain unit reliability.	$ 1,086,424	$ -	$ -
58	Smith CC U10 SCR Dual Catalyst	Other Production Plant in Service	Nov-23	Smith Unit 10 Selective Catalytic Reduction (SCR) catalyst layer replacement (NOx and CO reduction)	SCR catalyst layer replacements maintain DEQ-required NOx removal rate based on analysis of samples of catalyst layers.	$ 2,073,239	$ -	$ -
59	Smith CC U9 SCR Dual Catalyst	Other Production Plant in Service	Nov-23	Smith Unit 9 Selective Catalytic Reduction (SCR) catalyst layer replacement (NOx and CO reduction)	SCR catalyst layer replacements maintain DEQ-required NOx removal rate based on analysis of samples of catalyst layers.	$ 2,070,456	$ -	$ -
60	Smith CT 4 HGPI Unit	Other Production Plant in Service	Apr-24	Smith Unit 4 Combustion Turbine Hot Gas Path Inspection	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. GE 7F Gas Turbines require major maintenance at set intervals based on the number of run hours. It is projected that this unit will reach or exceed the number of run hours required to perform this maintenance in 2024.	$ 10,851,222	$ -	$ -

DUKE ENERGY PROGRESS
MYRP PROJECTS
DOCKET NO. E-2 Sub 1300

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Attorney/Client Work Product

Line No.	MYRP Project Name	FERC Function	Project Forecasted In-Service Date	MYRP Project Description & Scope	Reason for the MYRP Project	Total Project Amount (System) Projected In-Service Costs	Projected Annual Net O&M	Projected Installation O&M
61	Smith CT 6 HGPI	Other Production Plant in Service	Oct-24	Smith Unit 6 Combustion Turbine Hot Gas Path Inspection	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. GE 7F Gas Turbines require major maintenance at set intervals based on the number of starts. It is projected that this unit will reach or exceed the number of starts required to perform this maintenance in 2024.	$ 10,397,662	$ -	$ -
62	Smith CT exhaust frame replacement	Other Production Plant in Service	Apr-24	Replace the exhaust frame on Smith Combustion Turbine Unit 4	Existing exhaust frame has cracking issues affecting reliability. Replacement exhaust frame will also accommodate 10MW increase from GE Peaker Upgrades.	$ 1,369,534	$ -	$ -
63	Smith CT Unit 10 LTSA HGPI	Other Production Plant in Service	Oct-23	Smith Unit 10 Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2023.	$ 17,564,146	$ -	$ -
64	Smith CT Unit 7 HGPI and Compressor Replacement	Other Production Plant in Service	Dec-25	Smith Unit 7 Combustion Turbine Hot Gas Path Inspection & Compressor Rotor End-of-Life replacement.	Simple Cycle GE 7FA Heavy Frame Gas Turbines require major maintenance intervals based on starts. Smith Unit 7 is predicted to reach the required starts for a Hot Gas Path Inspection at the end of 2025. Compressor rotor will also be replaced due to rotor wheel dovetail cracking.	$ 26,022,465	$ -	$ -
65	Smith CT Unit 8 HGPI and Compressor Replacement	Other Production Plant in Service	Dec-25	Smith Unit 8 Combustion Turbine Hot Gas Path Inspection & Compressor Rotor End-of-Life replacement.	Simple Cycle GE 7FA Heavy Frame Gas Turbines require major maintenance intervals based on run hours. Smith Unit 8 is predicted to reach the required run hours for a Hot Gas Path Inspection at the end of 2025.	$ 19,589,774	$ -	$ -
66	Smith CT Unit 9 LTSA HGPI	Other Production Plant in Service	Oct-23	Smith Unit 9 Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2023.	$ 17,494,604	$ -	$ -
67	Smith U10 Rotor Replacement LTSA Adder	Other Production Plant in Service	Nov-23	Smith Unit 10 Rotor Replacement	Based on industry failures of the air separator in similar units, scope is to install a new rotor with an upgraded air separator.	$ 5,940,671	$ -	$ -
68	Smith U9 Rotor Replacement LTSA Adder	Other Production Plant in Service	Nov-23	Smith Unit 9 Rotor Replacement	Based on industry failures of the air separator in similar units, scope is to install a new rotor with an upgraded air separator.	$ 5,940,671	$ -	$ -
69	Smith Unit 6 Exhaust Frame Replacement	Other Production Plant in Service	Nov-24	Replace the exhaust frame on Smith Combustion Turbine Unit 6	Existing exhaust frame has cracking issues affecting reliability. Replacement exhaust frame will also accommodate 10MW increase from GE Peaker Upgrades.	$ 1,245,435	$ -	$ -
70	SNCC Lake Makeup System	Other Production Plant in Service	May-24	Sutton Combined Cycle Lake Makeup Pump Controls	Existing pump controls are obsolete with reliability issues. Scope is to remove existing lake makeup pump control system and install new motor control center, transformer, and enclosure.	$ 1,174,046	$ -	$ -
71	Sutton CT Unit 01A LTSA HGPI Unit 01A	Other Production Plant in Service	May-26	Sutton Unit 1A Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2026.	$ 16,937,409	$ -	$ -
72	Sutton CT Unit 01B LTSA HGPI	Other Production Plant in Service	May-26	Sutton Unit 1B Combustion Turbine Hot Gas Path Inspection under Long Term Service Agreement (LTSA)	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. Siemens 501F Gas Turbines require major maintenance at set intervals based on run hours. It is projected that this unit will reach run hours required to perform this maintenance in 2026.	$ 16,937,439	$ -	$ -
73	TL U1 Life Extension	Hydro Plant in Service	Sep-25	Tillery Unit 1 Life Extension Project	Existing turbine runner is 90 years old and needs to be upgraded. New design turbine rotor will increase capacity by 2.1 MW and meet FERC required Dissolved Oxygen limits. Currently, the FERC Dissolved Oxygen limits are being met with an oxygen injection system at an approximate O&M cost of $350K per year. This system will be eliminated with the new design rotor.	$ 16,251,263	$ -	$ -
74	TL U1-4 Replace Controls	Hydro Plant in Service	Aug-25	Replace Tillery GE 9070 Controls on Units 1-4	Existing GE 9070 Controls hardware is obsolete and no longer manufactured by GE. Replace with modern GE control system to maintain reliability.	$ 1,758,392	$ -	$ -
75	TL U3 Replace Turbine Runner	Hydro Plant in Service	Aug-24	Replace Tillery Unit 3 Turbine Runner	Existing turbine runner is 90 years old and needs to be upgraded. New design turbine rotor will increase capacity by 8.7 MW and meet FERC required Dissolved Oxygen limits. Currently, the FERC Dissolved Oxygen limits are being met with an oxygen injection system at an approximate O&M cost of $300K per year. This system will be eliminated with the new design rotor.	$ 17,651,473	$ -	$ -
76	Wayne CT Unit 11HGPI and Combustion Inspection	Other Production Plant in Service	Jun-24	Wayne County Unit 11 Combustion Turbine Hot Gas Path Inspection (HGPI) and Combustion Inspection	Perform a standard hot gas path inspection in accordance with OEM and company engineering standards. GE 7FA Simple Cycle Heavy Frame Gas Turbines require major maintenance at set intervals based on the number of starts. It is projected that this unit will reach or exceed the number of starts required to perform this maintenance in 2024.	$ 18,068,486	$ -	$ -
77	WT Powerhouse Roof Replacement	Hydro Plant in Service	Dec-23	Walters Hydro Powerhouse Roof Replacement	Roof leaks currently must be diverted off critical generator equipment. Replacement will ensure no rain ends up on critical equipment as well as office spaces.	$ 966,127	$ -	$ -
78	WT Replace Intake Derrick	Hydro Plant in Service	Dec-25	Replace Intake Derrick Crane at Walters hydroelectric facility	Existing intake derrick crane has reached the end of its service life (worn gears) and needs to be replaced to maintain unit reliability.	$ 2,516,165	$ -	$ -
79	WT Upgrade Intake Hoist System	Hydro Plant in Service	Dec-25	Upgrade Intake Hoist System at Walters hydroelectric facility	Current intake gate is cumbersome to operate manually and in an emergency it could pose a safety issue when lowering the head gate. Upgrades will address by allow backup manual lowering capability.	$ 2,964,976	$ -	$ -
80	WT Water & Fire Protection Tanks	Hydro Plant in Service	Oct-23	Walters Hydro Potable Water & Fire Protection Tanks	Current holding tanks and associated piping need attention due to leakage. Project will install complete tank liners with addition of manways, and replace potable water feed line, potable water supply line, fire water supply and feed lines.	$ 2,818,958	$ -	$ -
	TOTALS					**$ 463,472,687**	**$ -**	**$ -**