BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2013-1-E

In the Matter of	)	**DIRECT TESTIMONY OF**
Annual Review of Base Rates	)	**JOSEPH A. MILLER, JR. FOR**
for Fuel Costs for	)	**DUKE ENERGY PROGRESS, INC.**
Duke Energy Progress, Inc.	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Miller, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am General Manager of Strategic Engineering for Duke Energy Business Services, LLC ("DEBS"), which is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Progress, Inc. ("DEP" or "the Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana or "PSI") in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam 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 Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and Investments Engineering in 2010, and was named to my current role in July 2012 following the merger between Duke Energy and Progress Energy, Inc.

Q. WHAT ARE YOUR DUTIES AS GENERAL MANAGER OF STRATEGIC ENGINEERING?

A. My responsibilities include environmental compliance planning and strategy, fuel flexibility, assessment of new technology developments, and analysis of plant retirements and new fossil generation for the Company's fleet of fossil and hydroelectric ("hydro" and collectively, "fossil/hydro") facilities.

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

A. Yes. I testified before this Commission in Duke Energy Carolinas, LLC's 2012 annual fuel proceeding in Docket No. 2012-3-E. I have also testified on behalf of Duke Energy in proceedings before other state commissions, most recently in January 2013.

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

A. The purpose of my testimony is to (1) describe DEP's generation portfolio and changes made since the prior year's filing, as well as those expected in the near term, (2) discuss the performance of DEP's fossil/hydro facilities during the period of March 1, 2012 through February 28, 2013 (the "review period"), (3) provide information on significant outages that occurred during the review period, and (4) discuss DEP's environmental compliance efforts.

Q. PLEASE DESCRIBE THE COMPANY'S FOSSIL/HYDRO GENERATION PORTFOLIO.

A. The Company's fossil/hydro generation portfolio consists of 9,365[1] megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	4,095 MWs
Hydro -	225 MWs
Combustion Turbines -	3,041 MWs
Combined Cycle Turbines -	2,004 MWs

The coal-fired fleet consists of four generating stations and a total of ten units. These units are equipped with emission control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NOx"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). In addition, nine coal-fired units are equipped with low NOx burners. This inventory of coal-fired assets with emission control equipment employed enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the best cost options for coal supply.

The Company has a total of 36 simple cycle combustion turbine ("CT") units, of which 14 are considered the larger group, providing approximately 2,241 MWs of capacity. These 14 units are located at Asheville, Darlington, Richmond County, and Wayne County. Within the fleet of 36, 14 units have NOx control equipment. The 2,004 MWs shown as "Combined Cycle Turbines" ("CC")

[1] As of 4/1/2013 – includes retirements for early 2013.

represent three power blocks. The Lee Energy Complex has a configuration of three CTs and one steam turbine, and Richmond County has two power blocks consisting of two CTs and one steam turbine. Within these power blocks, the seven CTs are equipped with low NOx burners, SCR equipment, and carbon monoxide volatile organic compound catalysts. The steam turbines do not combust fuel and, therefore, do not require NOx controls. Additionally, DEP's hydro fleet consists of 15 units providing approximately 225 MWs of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO PORTFOLIO SINCE DEP'S 2012 FUEL FILING?

A. Changes within the portfolio include the addition of a combined cycle facility providing 920 MWs of capacity at the Lee Energy Complex ("Lee CC"), which went in-service on December 31, 2012, and is located in Goldsboro, North Carolina. Also within the review period, DEP retired coal-fired units 5 and 6 at Cape Fear, Units 1, 2 and 3 at Lee, and Unit 1 at Robinson. These coal retirements in September and October 2012 reduced capacity by 875 MWs, retiring units that began commercial operations from between 1951 and 1962. The CT fleet was reduced by a total of 144 MWs with the October 2012 and March 2013 retirement of units at Cape Fear and Lee that all began commercial operation between 1968 and 1971. A combination of criteria went into the decisions to retire these units, including the economics of meeting environmental controls and the obsolescence of equipment.

Q. ARE OTHER CAPACITY CHANGES EXPECTED WITHIN THE FOSSIL/HYDRO PORTFOLIO BY THE END OF THE BILLING PERIOD?

A. Yes, another combined cycle facility is under construction in New Hanover County, North Carolina (the "Sutton CC"). The Sutton CC will provide an additional 625 MWs of capacity and is scheduled to be in service by December 2013. Also at the Sutton facility, coal-fired Units 1, 2 and 3 that began operation in 1954, 1955, and 1972, respectively, are scheduled for retirement by the end of 2013.

Q. WHAT ARE DEP'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/HYDRO FACILITIES?

A. The primary objective of DEP's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEP's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model. Like safety, environmental compliance is a "first principle" and DEP works very hard to achieve high level results.

The Company achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power options for DEP's customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

Q. WHAT HAS BEEN THE HEAT RATE OF DEP'S COAL UNITS DURING THE REVIEW PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the average heat rate for the coal fleet was 10,856 Btu/kWh. The most active units at Asheville, Mayo, Roxboro, and Sutton achieved a heat rate of 10,844 Btu/kWh and the most efficient two units were Roxboro Units 1 and 2, achieving heat rates of 9,551 and 10,204 respectively. The Roxboro units provided the majority (62.5%) of coal-fired generation for DEP.

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

A. For the review period, DEP's total system generation was 60,246,019 MW hours ("MWHs"), of which 32,498,898 MWHs, or approximately 54%, was provided by the fossil/hydro fleet. The breakdown includes a 34% contribution from the coal-fired stations, approximately 19% contribution from gas facilities, and approximately 1% from hydro facilities.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEP'S FOSSIL/HYDRO FLEET DURING THE REVIEW PERIOD.

A. The Company's coal-fired generating units operated efficiently and reliably during the review period. The Company uses two key measures to evaluate the operational performance of coal-fired generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power, if needed. Equivalent availability is not affected by the manner in which the unit is dispatched or by the system demands; however, it is impacted by planned and unplanned (*i.e.*, forced) outage time. Capacity factor 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. Capacity factor is affected by the dispatch of the unit to serve customer needs.

The Company's coal-fired units achieved results of 91.05% equivalent availability factor and 46.65% capacity factor over the review period. During the 2012 peak summer season (June through August 2012), the fleet achieved results of 97.04% equivalent availability factor and 62.32% capacity factor. Utilizing the North American Electric Reliability Council's ("NERC") Generating Availability Report[2] ("NERC Report"), the Company's coal fleet compares very well with availability of the units to operate as needed. The most recently published NERC Report represents the period 2007 through 2011 and indicates an average equivalent availability factor of 83.45% for all North American coal plants. The Company's

[2] Typically, the Company obtains this figure from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company utilized the published NERC Report.

capacity factor reflects the generation fleet dispatch impact of historically low natural gas pricing, as discussed by Company witness Weintraub.

The Company's most active CTs located at Asheville, Darlington, Richmond County, Lee, and Wayne County were available as needed in this time period, with a 98.75% starting reliability, outperforming the average of 97.42% reported in the above referenced NERC Report. The Richmond CC facility reported a capacity factor of 73.02% for the review period which also outperformed the NERC Report average of 40.36%. As noted previously, the Lee CC facility began commercial operation in December 2012 and has performed well as a baseload unit in its first two months of operation, achieving a capacity factor of 80.18%, which is also above the NERC average.

With an overall availability factor of 97.89%, the hydroelectric fleet had strong operational performance during the review period, and also exceeded the NERC reported average availability factor of 85.22%.

These performance results are indicative of safe, high quality operations, and management efforts.

Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEP FOSSIL/HYDRO FACILITIES DURING THE REVIEW PERIOD.

A. In general, planned maintenance outages for all fossil and hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this review period to inspect and maintain plant equipment. The most significant outages occurred in the spring of 2012. Mayo Unit 1 entered a maintenance outage for a turbine flow guide and blading inspection which resulted in the need to complete significant repairs to the flow guides and blading. The Company took advantage of the outage time and performed additional maintenance efforts to ensure on-line reliability once the unit was fully repaired and back in service. These additional maintenance items included performing air heater washes for boilers, fuel handling maintenance and repairs, scrubber maintenance, rewiring of several power supplies, and a boiler feed pump thrust bearing replacement. Also in the spring, Roxboro Unit 1 entered a planned maintenance outage which involved major inspections on the boiler and turbine, and maintenance on the scrubber. More significant projects included coal burner replacements, generator stator rewind, condenser coating, and replacements for the economizer inlet header, scrubber damper, and waterwall tubing.

For the CT fleet, the most significant outages occurred at Darlington, Cape Fear, and Wayne County facilities. The Darlington Unit 12 outage was the most significant due to turbine blade failure and subsequent damage. This event began in August of 2011 and is currently on schedule to complete in May 2013. Restoration of this unit involves extensive major work in the inlet, compressor, combustor, turbine, and exhaust sections of the unit. A generator stator rewind was required along with installation of a new generator rotor, and refurbishment of compressor diaphragms, pumps, motors, and valves. Other major restoration work included installation of water injection modification components, refurbishment of blade rings and seal housings, a new exhaust cylinder and exhaust rake, along with replacement of cable and conduit in the exhaust section, installation of refurbished journal bearings, and a new CT rotor and bearings. In addition to restoration, the Company is improving blade path thermocouples, generator controls, modifying exhaust bearing tunnels, and installing new instrumentation to provide improved information and control for operators.

Cape Fear Unit 4 experienced an outage resulting from a bearing failure that was deemed uneconomical for repair given the retirement schedule for the unit. An outage at Wayne County involved Unit 1 which exhibited a high vibration trip in June 2012. Disassembly and inspection indicated damage to the mid-compressor case which required refurbishment. Other components, including combustion and turbine hardware and rotor, were also refurbished. The Company installed enhanced compressor blades to increase the compressor reliability. Testing, tuning, and alignments were performed, and the unit was returned to service in December 2012. Substation maintenance, switchyard upgrades and tie-ins, and control room upgrades resulted in planned outages at Blewett, Wayne County, and Weatherspoon.

There were planned outages for major turbine work for CC units at Richmond County in the fall of 2012 and maintenance outages in February 2013 for the new Lee CC facility. Within the hydro fleet, significant planned outages included the Blewett Hydro Unit 5, which began a turbine gate rebuild, and Marshall Unit 2, which included a generator turbine inspection and headgate gearbox replacement.

Q. ARE EMISSION-REDUCING CHEMICALS NEEDED FOR USE WITH EMISSION-CONTROL EQUIPMENT AT THE COAL-FIRED STATIONS?

A. Yes. As discussed above, DEP has installed pollution control equipment on coal-fired units in order to meet various current federal, state, and local reduction requirements for NO_x and SO_x emissions. Each of these technologies requires the presence and consumption of specific chemicals which act as reagents in order for the chemical reaction to occur that greatly reduces the NO_x or SO_x emissions. The SCR technology that DEP currently operates uses ammonia or, in the case of Ashville, urea, which is converted to ammonia for NO_x removal, and the scrubber technology employed by DEP uses crushed limestone for SO_2 removal. Organic acid (often referred to as "DBA" or "dibasic acid") can also be used with the scrubber technology for additional SO_2 removal. In addition, DEP also uses magnesium hydroxide and calcium carbonate as reagents to mitigate increased SO_x and reduce slag formation in the boiler, which, if allowed to build, can significantly impair plant generation. This use of magnesium hydroxide and calcium carbonate allows DEP to meet increasing environmental standards and manage boiler slag formation in a cost efficient manner.

Additionally, DEP is testing the use of other emission-reducing reagents, including, but not limited to, activated carbon, calcium bromide, and re-emission chemicals in order to meet present and future state and federal emission requirements. New advancements in the environmental control arena provide DEP with new and improved emission-reducing chemical opportunities (such as the aforementioned chemicals) that the Company can use to comply with its federal and state environmental obligations, which are ever-increasing. In order to meet these obligations in the least cost manner while continuing to provide reliable electric generation to our customers, DEP continually tests these new and improving emissions-reducing chemicals at its coal-fired plants with the hopes of eventually using them to more efficiently reduce emissions.

The quantity of chemicals consumed in these emission-reduction processes varies depending on the generation output of the unit, the chemical constituents in the coal being burned, and the level of emission reduction required. Station operators monitor each of these parameters to ensure that the equipment is being operated in an efficient and effective manner.

SCR equipment is also an integral part of the design of the Lee CC Station and will likewise be employed at Sutton CC. Similar to coal-fired SCR equipment, the specific purpose is to reduce NO_x from the flue gases to meet environmental regulations. Aqueous ammonia (19% solution of NH_3) is introduced in the flue gas in the presence of a catalyst and excess oxygen for NO_x removal. The Company's current forecast does not anticipate the need for ammonia at the CC facilities for environmental compliance in the near term.

Q. HOW DOES DEP MANAGE THE COSTS OF THESE EMISSION-REDUCING CHEMICALS?

A. The Company's objectives in procuring emission-reducing chemicals and managing the resulting by-products are to provide the stations with the most effective total cost solution for operation of the unit, understand the technical capabilities of the equipment, assess emission-reducing chemical input and by-product output over the long-term, analyze the markets for those chemicals and by-products, and look for leverage opportunities with the chemical purchases and by-product sales contracts between stations and with other Duke Energy subsidiary operations. Overall, DEP is managing the impacts of all chemicals used to reduce emissions, favorable or unfavorable, as a result of changes to fuel mix and/or changes in coal burn (as discussed by Company witness Weintraub) due to competing fuels. Company witness Babcock provides the cost information for DEP's chemical use and forecast.

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

A. Yes, it does.