BEFORE THE NORTH CAROLINA UTILITES COMMISSION

DOCKET NO. E-7, SUB 1250

IN THE MATTER OF	)	
APPLICATION OF DUKE ENERGY	)	
CAROLINAS, LLC PURSUANT TO	)	**DIRECT TESTIMONY OF**
N.C.G.S. § 62-133.2 AND	)	**DEVI GLICK ON BEHALF OF**
COMMISSION RULE R8-5	)	**THE SIERRA CLUB**
RELATING TO FUEL AND FUEL-	)	
RELATED CHARGE ADJUSTMENTS	)	
FOR ELECTRIC UTILITIES	)	

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant

economics, utility resource needs, and solar valuation before state utility regulators in North Carolina, Arizona, Connecticut, Florida, Indiana, Michigan, New Mexico, South Carolina, Texas, Wisconsin, and Virginia. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club.

Q Have you testified previously before the North Carolina Utilities Commission ("Commission")?

Yes, I submitted testimony in Docket No. E-100, Sub 158, the 2018 biennial proceeding regarding avoided cost rates.

Q What is the purpose of your testimony in this proceeding?

My testimony addresses the analysis and decision-making processes Duke Energy Carolinas' ("DEC" or the "Company") uses to commit (turn on, keep on, or turn off) and dispatch (turn up or down once a unit is committed) its coal-fired power plants. In particular, I evaluate the production costs that DEC reported and used to make its unit commitment decisions in 2020 (the marginal production cost) and compare those to the fuel costs the Company seeks to recover from ratepayers in this docket (the average or full cost of production). I explain how the significant discrepancy between the marginal and average cost of production is driving DEC's uneconomic commitment of its coal plants and evaluate the impact DEC's underrepresentation of unit costs had on ratepayers in 2020. Finally, I outline recommendations for improving the transparency and functioning of the Company's unit commitment process to better serve ratepayers.

Q Why is the issue of unit commitment relevant to this fuel clause adjustment proceeding?

North Carolina law says that the utility can recover the "reasonable costs of fuel and fuel-related costs prudently incurred during the test period."[1] DEC's incurred fuel costs are directly tied to the operation of each of its units, and thus its unit-

[1] N.C. Gen. Stat.§ 133-2(d).

commitment decisions and practices inform the Commission's determination whether those costs were reasonable and prudently incurred.

While in the past utilities operated their coal-fired plants as baseload resources with little thought given to whether the plants should be turned on or off, in recent years low gas prices and nearly zero-variable cost renewables have pushed coal generation to become marginal and uncompetitive during many hours of the year. The practice of committing coal plants to run when it is not economic to do so saddles ratepayers with avoidable fuel costs, recovered in this docket, and thereby allows utilities to continue operating aging and costly coal plants when there are lower cost alternatives that can meet customers' needs.

Q You've addressed the full 'production' cost of DEC's generating units, which includes variable operations and maintenance costs. Why is the full production cost relevant to a proceeding that only seeks recovery of fuel costs?

The operation of the Company's generation units is governed by the full production cost of those units, which includes both fuel and non-fuel variable costs. While the Company only seeks recovery of its incurred fuel costs in this docket, whether or not the Company prudently incurred those fuel costs can only be assessed by evaluating how the Company operated its generating units.

Q How is the remainder of your testimony structured?

In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I define the terms "unit commitment" and "dispatch" and describe how electric utilities make daily operational decisions at coal-fired power plants.

In Section 4, I evaluate the fuel and other production costs incurred by DEC (which, if determined to be reasonable and prudently incurred, would normally be passed on to ratepayers) to operate its coal-fired power plants in the 2020 test year. I compare the production cost of DEC units to those of other coal units around the country.

In Section 5, I review the marginal production costs the Company uses to make its unit commitment decisions at its coal units and evaluate the significant deviation between the average production cost incurred at each unit over the course of the test year, and the marginal cost of production used for the purposes of making unit commitment and dispatch decisions.

In Section 6, I explain the practice of uneconomic unit commitment, outline reasons why utilities may utilize this practice, and discuss the impacts this practice has on DEC's ratepayers. I evaluate the economic performance of DEC's coal units during the 2020 test year. I discuss the costs that uneconomic commitment practices will impose on ratepayers if approved for recovery in this proceeding. I quantify the customer net revenue losses resulting from the Company's decisions to "must-run" each of its coal plants during the test year.

In Section 7, I outline recommended reporting requirements for future fuel charge adjustment dockets that will allow the Commission to evaluate whether the Company's unit-commitment practices are causing the Company to incur fuel costs unreasonably or imprudently.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. During the 2020 test year, DEC's coal units had some of the highest fuel costs among all coal units in the country, yet DEC continued to incur costs in operating and maintaining the units. As explained in Section 4, Allen, Marshall, Cliffside and Belews Creek ranked in the top 75th – 90th percentile for most expensive fuel costs in 2020 among all United States coal-fired power plants.
2. During the 2020 test year, DEC's reported average cost of generation at each of its four coal plants exceeded the system lambda (marginal cost of energy) during nearly every month, with only two exceptions – Allen and Cliffside in the month of December 2020. Other than these two instances, the average cost of generation exceeded the system lambda for all plants in all months, as explained in Section 4. In total, DEC's units incurred $233 million in variable costs above system lambda. This means that during the

test year, many of DECs coal plants failed to pass the lowest bar of economic performance a large portion of the time.

3. DEC omitted from its unit commitment decisions approximately $263 million worth of fuel and variable costs (approximately $250 million of which is fuel costs), representing over 40 percent of those costs at its coal units, thus allowing the units to commit and dispatch significantly more than they would if the units' full variable production cost was reflected.

4. DEC regularly committed its coal units at times when its marginal production costs exceeded the system lambda, even when it would have been less costly to serve captive retail customer load with other resources. This means that those unit commitments were uneconomic, yet DEC seeks to pass those excess costs on to ratepayers in this docket.

5. During the 2020 test year, DEC's unit-commitment practices at its coal plants caused the Company to incur avoidable excess costs of $8.5 million at Allen, Marshall, Cliffside, and Belews Creek based on the Company's reported marginal variable production costs for those units.

6. DEC did not adequately report and describe its fuel cost accounting and unit-commitment practices in its fuel charge adjustment application. The Company should have included documentation of its daily decision-making process and its reasoning for frequent uneconomic commitment.

Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations:

1. I recommend that the Commission examine DEC's production cost accounting, its unit commitment process that relies on its production costs, and the operational decisions and incurred costs that result, and scrutinize such costs carefully for potential disallowance in future proceedings.
2. DEC's should be required to provide full transparency into the Company's marginal and average production costs. Specifically, DEC should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:
    a. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down by the following categories:
        i. Fixed costs
        ii. Variable costs
            1. Fuel
            2. Reagents/ by products
            3. Emissions
            4. Variable O&M
    b. Marginal production cost of each unit used for making unit commitment and dispatch decisions, broken down by the same

components listed directly above. For any production costs Excluded from DEC marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit commitment decisions.

3. The Commission should require DEC to provide a detailed report describing its daily unit-commitment decisions and practices as part of future fuel charge adjustment proceedings. DEC should provide the following information as part of each fuel charge adjustment filing, to inform the Commission's review of its unit-commitment practices and determination whether DEC's fuel- and fuel-related costs for those units were reasonably and prudently incurred:

   a. All 7-day forecast sheets used to develop the Company's daily unit-commitment decisions and marginal cost.

   b. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).

   c. Hourly data sufficient for the Commission to calculate the net revenues that each plant actually incurred in each test year period,

including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, system lambdas, day-ahead commitment status, and actual outages.

4. Given the low capacity factor at which DEC's coal fleet operated in 2020—extremely low, in the case of some units—the Company should evaluate moving some of its plants to seasonal operation and retiring some of its units.

3. DEC CONTROLS AND COORDINATES THE COMMITMENT AND DISPATCH OF ITS COAL-FIRED GENERATING UNITS.

Q Please summarize this section.

A In this section, I define the concepts of unit commitment and dispatch and explain how dispatchable power plants operate in DEC's system. I define the practice of uneconomic unit commitment by regulated, vertically integrated utilities like DEC and discuss the impacts this practice can have on ratepayers, if utilities are permitted to pass along the avoidable excess costs that result.

Q Please explain the terms "unit commitment" and "dispatch."

A Unit commitment is the process by which a utility decides if a long-lead time generating unit, generally steam boilers, should be operational for the following day. Commitment is the decision to either keep the unit online, bring a unit online that is not currently generating, or bring offline ("de-commit") a unit that is

currently online. Unit commitment decisions are distinct from "dispatch" decisions, which are the decisions to incrementally increase or decrease a unit's generation. Fast-start units like combustion turbines or battery storage can generally be dispatched from idle (or "blackstart") and do not need to be committed ahead of time. However, large steam boilers require a clear commitment, and once committed to operate, must run at a minimum level of output.

Q How does the process of unit-commitment occur?

A The process of unit commitment requires that the operator look forward to determine if a long-lead time unit is likely to operate economically over the next few days. To make this determination, the operator will compare the costs of starting and operating a particular unit with the costs of all other units on its system to determine whether that unit should be online the next day. When a unit is committed economically, the unit is reasonably expected to be lower cost than the marginal cost of energy, called "system lambda," over the next day or days. When a unit is committed uneconomically, the operator has decided to operate that unit at its economic minimum, which is the lowest MW output that a unit can safely and efficiently maintain, even though that unit's marginal costs of production are projected to be higher than the system lambda.

Q In this testimony, you refer to "average costs" of production and DEC's reported "marginal cost" of production. Can you briefly explain what you

mean by these two terms, which variable costs are included in each, and why they are relevant to this proceeding?

A Each of DEC's coal-fired power plants has a specific set of costs incurred to operate the unit. The cost of production is composed of fixed costs, which are incurred regardless of whether and how a unit is operated, and variable costs, which are incurred based on usage. Variable costs include fuel, reagents/byproducts emissions, and variable O&M.

When making a unit commitment decision, DEC utilizes the marginal cost of production. The marginal cost of production is calculated based on the replacement cost of fuel, which is the "market price of fuel plus variable transportation costs,"[2] and the cost of reagents/byproducts, emission, and variable O&M. This cost represents the incremental cost of operating the unit.

But the marginal cost of production does not represent the actual production costs passed on to ratepayers. The average production cost represents the cost to operate each unit (that is actually passed on to ratepayers) spread out over the unit's MW output. This includes the cost of the fuel that was actually burned (or paid out) and all associated transportation costs, regardless of contract structure. Reagent / byproduct, emissions, and variable O&M costs are also included.

[2] Duke Energy Carolinas Response to Sierra Club Request 1-8.

Q Please describe how dispatchable power plants are generally committed and operated by electric utilities like DEC that operate outside of organized wholesale markets.

A In a non-centralized market, the unit commitment process is completely dictated by the utility. The utility is responsible for internally committing and dispatching its units, and procuring energy through bilateral trades when needed, and generally does so on a variable cost basis within operational constraints. These utilities generally use internal systems that project the marginal production cost to operate each unit and calculates the cost of the marginal unit in the system, called "system lambda." Resources are committed based on cost, with the lowest-cost resources coming online first, and progressively more expensive units being turned on until system load is met. Both the unit-commitment and dispatch processes should be based on economics and should generally ensure customers are served by the lowest-cost resources while maintaining reliability.

Q In practice, are all power plants actually committed by electric utilities in that way?

A No. Utilities may ignore marginal cost when making operational decisions or simply consider only a portion of the unit's actual cost in making commitment and dispatch decisions. The result is that utilities keep units online and operating when it otherwise would not operate. Some utilities do adhere closely to efficient dispatch and commitment, but others do not, and can exhibit a wide discrepancy between the cost of operation and operational decision, as is seen with DEC.

There are a variety of reasons why utilities ignore or underrepresent unit costs, and the practice varies widely

First, for inflexible units with long start-up and shut-down times, such as coal-fired power plants, utilities regularly force units to stay online in order to avoid unit cycling costs. Utilities have historically tried to avoid cycling of coal plants because it can result in wear-and-tear that increases maintenance costs.[3] But, while continuous operation of coal units can reduce cycling costs, it generally results in the incursion of unnecessary operational costs well in excess of the cycling costs being avoided. Cycling times and costs can be incorporated into multi-day unit commitment decision-making processes.

Second, in order to address fuel over-supply issues, utilities sometimes explicitly adjust how fuel costs are accounted for in their dispatch. Specifically, they may lower the marginal cost of a unit for the purposes of keeping a unit online to burn excess fuel. This is generally done when it is cheaper to burn the coal at a loss than to store the coal or cancel a fuel contract. Duke Energy Indiana refers to this process as a 'coal price decrement.'[4]

Third, there are structural and company decisions relating to fuel contracts, transportation contracts, and operations and maintenance ("O&M") that

[3] *See* Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. NARUC, January 2020. Accessible at https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.

[4] Direct Testimony of John Swez, IURC Cause No. 38707-FAC 125.

drive the utility's categorization of costs. Specifically, utilities that sign coal contracts with fixed tonnage requirements or must-take provisions of fuel contracts often categorize some of their fuel costs as fixed, and therefore exclude them from unit dispatch and commitment decisions. This practice effectively locks ratepayers into paying a portion of fuel costs, often without any formal approval from the regulatory commission. Utility treatment of O&M costs– specifically, utility judgement of what costs are truly variable and predictable based on unit operations, and which are truly fixed—also varies widely.

Q Are there any reasons why a utility might be incentivized to operate a unit more often than it should be from a cost perspective?

A Yes. A utility that receives a return of and on assets in the rate base may have an incentive to show that aging units are still "used and useful" despite the substantial capital and fixed expense required to keep them online. A unit that is neither economic over the long-run (i.e. relative to replacement options) and does not provide economic service on a short-term basis may be perceived as not used or useful and at risk for disallowance. As noted by the Energy Information administration, coal units that move to very low utilizations are often retired shortly thereafter,[5] because the justification for their operational costs evaporates.

[5] As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation. September 1, 2020. Accessible at https://www.eia.gov/todayinenergy/detail.php?id=44976

4. DEC'S COAL FLEET OPERATED AT AN AVERAGE PRODUCTION COST THAT EXCEEDED THE MARGINAL SYSTEM COST FOR NEARLY ALL OF 2020.

Q Please summarize this section.

A In this section, I review the actual generation costs that were passed on to ratepayers as a result of DEC's operation of its coal-fired units in the test year 2020. I find that the Company's four coal-fired power plants all operated at an average production cost that exceeded the marginal system cost during nearly every month in 2020 (the exception was one month at each Allen and Cliffside).

Q Describe DECs coal-fired power stations.

A The Company has four coal-fired power stations: Allen, Marshall, Cliffside, and Belews Creek. Allen consists of five units (Units 1-5) and has a total capacity rating of 1,130 MW. Marshall consists of four units and has a total capacity rating of 2,078 MW. Cliffside consists of two units, Units 5 and 6, which have capacity ratings of 546 and 849 MW respectively. Belews Creek consists of two units, Units 1 and 2, which each have a capacity rating of 1,100 MW.[6]

[6] Duke Energy Carolinas, Application in the Fuel Charge Adjustment Proceeding. Exhibit 6, Schedule 10.

Q Describe Duke's utilization of its coal-fired fleet in 2020.

A In 2020, each of Duke's coal-fired power plants was minimally utilized. Specifically, every unit with the exception of Cliffside 6 (56.6 percent) had an annual capacity factor below 39 percent, as shown in Table 1. The five Allen units had the worst performance, operating at between a 1.1 percent and 10.8 percent capacity factor.[7]

Table 1: 2020 Annual Capacity Factors for DEC Coal Units

Unit	2020 Capacity Factor (%)
Allen 1	1.1%
Allen 2	1.2%
Allen 3	2.8%
Allen 4	10.8%
Allen 5	9.4%
Belews Creek 1	28.1%
Belews Creek 2	27.5%
Cliffside 5	22.8%
Cliffside 6	56.6%
Marshall 1	25.9%
Marshall 2	28.9%
Marshall 3	36.1%
Marshall 4	38.2%

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL Attachment; DEC Application in the Fuel Charge Adjustment Proceeding (Exhibit 6, Schedule 10)

[7] Duke Energy Carolinas Response to Sierra Club 1-3a, CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; Duke Energy Carolinas, Application in the Fuel Charge Adjustment Proceeding. Exhibit 6, Schedule 10. Disclosed publicly with agreement of DEC counsel.

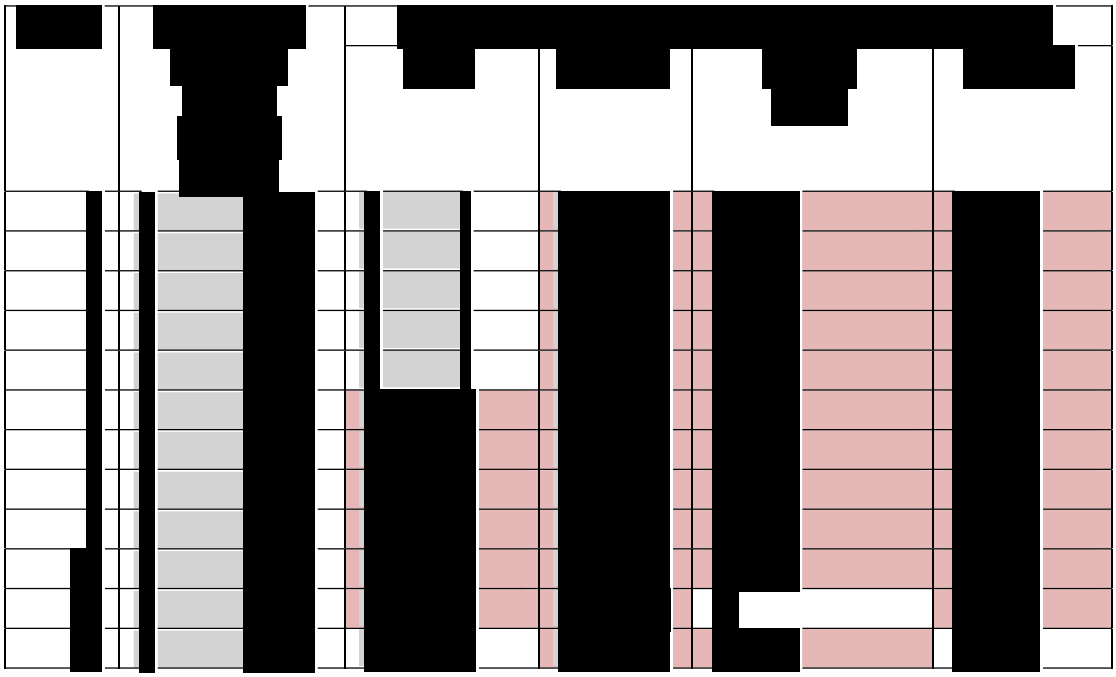
Q Please summarize your analysis of the economic performance of DEC's units in 2020 based on the Company's actual cost data.

A I reviewed data reported by DEC on the average cost of generation for each plant by month and the hourly system lambdas. I compared the monthly average system lambda[8] to the monthly average cost of generation at each plant.[9] As shown in Table 2, I found that during the test year of 2020 the average cost of generation at each coal station was higher than the average system lambda, with the exception of one month each at Allen and Cliffside. That means that in every month of 2020, nearly all of DEC's coal-fired power plants were operating at an average cost above the marginal cost of electricity on its system, when there were lower cost resources available to serve load. DEC did this by underrepresenting the marginal production cost used for the purposes of making unit commitment decision. In total, DEC total production costs were $233 million more than the cost of serving load met by the coal units at the system lambda (as discussed in section 5).

[8] Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC.

[9] Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j, CONFIDENTIAL Attachment.

Table 2: CONFIDENTIAL Average Cost of Generation relative to Average System Lambda ($/MWh)



Source: Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC; Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j, CONFIDENTIAL Attachment.

Q Why do you compare the average cost of generation to the marginal system cost when DEC makes unit commitment decisions based on marginal unit costs?

A It is reasonable to expect there will be a small difference between marginal unit costs and average unit costs based on (1) the delta between fuel and market prices at the time contracts were signed and the present, as well as truly unavoidable fixed/ sunk production costs. But a responsible utility manager should seek to minimize the portion of average costs that falls into these categories and are therefore omitted from the unit commitment process. Specifically, this can be done by (1) securing fuel and transportation contracts that are flexible and have

minimal locked-in or must-take provisions; (2) carefully reviewing the costs of fuel contracts relative to alternatives, including reduced operation and retirement of the plant, prior to signing any new fuel contracts; and (3) carefully reviewing O&M costs to break-out the variable costs associated with predictive and preventative maintenance from those that are truly fixed.

Q Does the analysis reflected in Table 2 represent the total costs incurred by ratepayers as a result of DEC operating and maintaining its coal plants?

A No. The monthly Average Cost of Generation displayed in Table 2 was provided by the Company and is composed of actual fuel and variable operating expenses, and excludes from consideration any of the large fixed costs of maintaining those units which are passed on to customers. These costs are not the same as those used by the Company for the purpose of making unit commitment decisions. As I will discuss in depth in section 5, there is a significant and unexplained discrepancy between the average production costs DEC seeks to pass on to ratepayers in this docket and the marginal production costs DEC uses to make unit commitment and dispatch decisions.

The data in Table 2 simply show whether the units pass the lowest bar of providing value to ratepayers on an hourly basis. It says nothing about whether the plant is the lowest-cost resource available to serve customer load (relative to alternatives) based on the full forward-going costs (both fixed and variable)

required to keep the plant operational. A full unit economic analysis of this type was presented by my colleague Rachel Wilson in Docket No. E-7, Sub 1214.

Q Do the coal units "pass the lowest bar of providing value to ratepayers on an hourly basis"?

A According to the values reported by the Company, no.

Q How do the fuel costs at DEC's coal units compare to those of other coal plants across the country?

A Allen, Marshall, Cliffside and Belews Creek have some of the highest fuel costs among coal plants in the country.[10] Specifically, as shown in Table 3, the coal used at Allen, Belews Creek, Marshall and Cliffside cost between $2.38/MMBtu and $2.81/MMBtu during the 2020. This puts these plants in the 75th to 90th percentile of most expensive solid fuel in the country. Allen, for example, has a fuel cost higher than 90 percent of comparable coal plants nationwide. Even the DEC coal plant with the lowest fuel cost in this analysis, Cliffside, is more expensive than 75 percent of comparable plants nationwide.[11]

[10] Author's calculation from EIA Form 923, 2020.

[11] EIA Form 923, 2020.

Table 3: DEC's coal unit costs relative to other solid-fuel plants in the U.S. in 2020

Plant	Fuel Cost ($/MMBtu)	Percentile of most expensive solid-fuel plants
Allen	$2.81	90%
Belews Creek	$2.68	86%
Marshall	$2.52	81%
Cliffside	$2.38	75%

Source: EIA Form 923 for 2020.

5. DEC EXCLUDED OVER 40 PERCENT OF THE PRODUCTION COSTS INCURRED AT ITS COAL UNITS FROM ITS UNIT COMMITMENT AND DISPATCH DECISION-MAKING PROCESS

Q Please summarize this section.

A In this section I review the production costs that DEC seeks to pass on to ratepayers, the marginal production costs DEC models in making its daily unit commitment and dispatch decisions, and DEC's marginal system cost. I find that DEC excluded a significant portion of its production costs from its unit commitment decisions, and the justifications provided by the Company only explain a small portion of the omitted costs.

Q Do you have any concerns with the unit-commitment data DEC has provided?

A Yes, DEC appears to be excluding a significant portion of its actual fuel and variable operating costs from the marginal cost of production that it uses to make its unit-commitment decisions. Specifically, the Company's reported marginal

cost of production omits over 40 percent of actual production costs incurred at its coal plants.[12]

The Company's marginal fuel costs represent the cost DEC would pay today to replace the fuel that it burns. DEC calculates the replacement cost of coal based on "[redacted][13]

Actual fuel costs, however, represent the cost of the fuel that DEC actually uses for generation at each plant. The Company seeks to recover actual fuel expenses from ratepayers in this docket.

As shown in Table 4 below, in 2020 DEC incurred $597 million in fuel and other production costs operating its coal fleet. But only $333 million in variable fuel and other operating costs were included in the Company's unit commitment and dispatch modeling. This means that a full 40 percent of the Company's production costs, equaling $263 million, were excluded from DEC's unit commitment and dispatch decision-making processes. As a result, Duke's unit commitment modeling showed that its fleet provided a value of almost $31

[12] Analysis based on data from Duke Energy Carolinas Response to Sierra Club Request 1-3(a) CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; Duke Energy Carolinas Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices; and Duke Energy Carolinas Response to Sierra Club Request 1-3(f) CONFIDENTIAL 2021 SCDR 1.3f_j.

[13] Duke Energy Carolinas Response to Sierra Club Request CONFIDENTIAL 1-17.

million in production costs to its ratepayers in 2020, but in fact the Company actually incurred $233 million in excess production costs relative to system lambda in 2020. Of that total, approximately 95 percent, or $221 million, represents fuel costs.

Table 4: Total Production Costs incurred by DEC's Coal Fleet in 2020 ($Million)

Cost Description	($Million)	Source
a. Production costs passed on to ratepayers	$597	Average Cost of Generation from DEC in SC 1.3(f)&(j)
b. Unit variable costs used by DEC for the purpose of making unit commitment and dispatch decisions	$333	Modeled unit variable costs from DEC in SC 1.3(a)
c. Total cost of serving load met by coal units at System Lambda	$364	System lambda from DEC in SC 1.3(b) x generation from SC 1.3(a)
e. Cost of generation omitted from DEC's unit commitment and dispatch decision-making process	($263)	(b) - (a)
d. Difference between system lambda and DEC's incomplete modeled unit production costs	$31	(c) - (b)
f. Actual operational losses incurred by DEC and passed on to ratepayers from operating its coal fleet in 2020	($233)	(c) - (a)

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices; DEC Response to Sierra Club Request 1-3(f) CONFIDENTIAL 2021 SCDR 1.3f_j. Disclosed publicly with agreement of DEC counsel.

Q How does this discrepancy in reported fuel costs impact the Company's unit-commitment decision-making?

A As discussed above, DEC makes unit commitment decisions based on each unit's marginal production cost, also known as the incremental operating costs. Lower operating costs therefore put the unit lower on the supply curve and make it more likely that a unit will be committed. If the marginal production costs used for making unit-commitment decisions and market offer curves represent only a portion of the actual cost of fuel, then a unit will appear more economic than it actually is, and the unit will be over-committed and over-dispatched as a result.

Full (actual) fuel costs are still typically passed on to ratepayers either through the fuel charge adjustment process or through base rates (for the non-fuel variable component), regardless of what cost is used to make unit-commitment decisions. But these costs will be higher than if the plant was committed and operated based on its actual fuel cost. For this reason, the Commission should be concerned about which fuel costs the Company is using for different purposes and how those costs are calculated.

Q What accounts for the difference between DEC marginal and actual fuel costs at its coal plants?

A DEC provided several explanations for why certain of its operational costs are considered fixed and therefore excluded from its unit commitment decision-making process. But none of the Company's explanations account for the sheer

magnitude of costs $225 million in costs excluded from its commitment modeling.

First, DEC indicated that its current rail transportation contracts include both fixed and variable costs. The fixed cost component is considered by DEC to be sunk and therefore excluded from its unit commitment decisions.[14] But, fixed transportation costs accounted for only 0.2 percent of total fuel costs incurred in December 2020, according to the Company's December 2020 fuel report.[15] The Company indicated that in the contract it is about to sign, these rail costs will instead be fully variable. While in theory, accounting for these rail costs as variable will increase the marginal production cost of DECs units slightly, closing the gap between the units marginal and actual production costs, and making alternatives even more attractive, in reality these costs have only a small impact on total production cost.

Second, the incremental cost of fuel DEC models represents the replacement cost of fuel, not the cost the Company has paid for its current fuel supply. But, because DEC utilized a fuel procurement strategy that relied on relatively flexible and short-term coal purchases this delta should be minimized.

[14] Duke Energy Carolinas Response to Sierra Club Request 1-22.

[15] Exhibit 6, Schedule 7 to Duke Energy Carolinas Application in Docket No. E-7, Sub 1250.

Indeed, in 2020, just over [redacted] of DEC's coal supply came from contracts of two years or fewer.[16] With short-term and spot contracts, the coal price in the contract and the replacement price the Company would pay on the spot market should not differ significantly. Additionally, with short-term and spot contracts, the Company has more flexibility to adjust its purchase based on need (compared with long-term contracts that tend to contain a minimum annual take). Short-term contracts should not lock ratepayers into significant fixed costs.

Third, DEC selected a buy-out option for some of its coal contracts instead of accepting delivery of the fuel and running the units for the purpose of burning off the coal. The Company's own analysis indicated that this option was projected to save ratepayers $22 million in 2020.[17] The $24.8 million in costs associated with this buy-out are also included in the fuel costs passed on to ratepayers.[18,19]

Q How would DEC's system be impacted if the Company updated its marginal production costs to include underrepresented costs?

A If DEC updated its marginal costs to represent a larger portion of the production cost of each unit, its coal units would shift higher on the supply stack. This would make alternative resources more cost-competitive on an operational basis. As a

[16] Duke Energy Carolinas Response to Sierra Club Request 1-18, CONFIDENTIAL Coal Supply Summary attachment.

[17] Direct Testimony of J, Verderame, Page 6.

[18] Duke Energy Carolinas Response to Sierra Club Request 1-21, 2021 DEC PSDR 3-1d CONFIDENTIAL Carolinas Decrement Analysis Documents.

[19] Direct Testimony of J. Verderame, Page 5.

result, the output of DEC's coal-fired units would be expected to decrease substantially. System lambdas would also likely increase, to more accurately reflect the true system lambda. This increase in system lambdas may lead to an increase in the valuation of alternative new resources.

6. DEC INCURRED $8.5 MILLION IN AVOIDABLE UNIT COSTS AT ITS COAL PLANTS AS A RESULT OF UNECONOMIC UNIT COMMITMENT DECISIONS.

Q Please summarize this section.

A In this section I review the marginal cost of production that DEC uses for the purposes of making unit commitment and dispatch decisions. I find that, even with DEC modeling marginal costs that omit over 40 percent of its actual variable production costs, DEC still incurred nearly $8.5 million in avoidable operational costs at its coal plants during these months as a result of these uneconomic unit commitment practices.

Q How does the analysis in this section differ from the analysis presented in section 4 above?

A In Section 4, I present analysis on how DEC's units *actually* performed during the test year period using data available after the fact (*i.e.,* the average cost of

generation[20] that DEC incurred by operating its coal units uneconomically rather than turning them off). I show the total excess costs that DEC seeks to pass on to ratepayers during the months where the units average production costs exceeded the average system lambda.[21]

In contrast, in this section, I evaluate the hourly data, projections, and analysis that DEC modeled to inform its unit commitment decisions.[22] I identify the periods of time when the Company projected it would incur operational costs in excess of the system marginal cost[23] by operating its units, but yet still opted to operate its coal units and then predictably incurred significant net losses. I then calculate the excess costs that DEC seeks to pass on to ratepayers.

In this section I am relying on DEC's characterization of its marginal cost of production at its coal plants, which as I note above are far lower than—its average costs of production. Even relying on the company's characterization of

[20] This number is slightly higher than the [redacted] million contract-buy out cost calculated by DEC on Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j CONFIDENTIAL Attachment.

[21] Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC.

[22] DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

[23] DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

marginal costs of production, I still find that the Company self-commits its coal units out of merit on a regular basis.

Q What does it mean to operate a unit "out of merit" or "uneconomically"?

A When a utility operates a unit without regard for the unit's marginal cost, the unit is said to be committed "out of merit" order. This is generally done by the utility applying a "must-run" status to the unit, thereby forcing the unit to operate with a power output no less than its minimum operating level—no matter how the unit's operating economics compare to that of other units on the utility's system. Ratepayers incur the fuel and variable costs to operate the unit, regardless of whether there were lower cost resource options available to meet system needs.

This practice is common among investor-owned utilities, such as DEC, that are able to pass fuel costs directly on to ratepayers. It is much less common among merchant plants / independent power producers that operate within organized wholesale markets.[24] These operators rely entirely on market revenues to cover their units' operating and fixed costs. This provides a strong incentive to

[24] *See, for example,* Playing with Other People's Money. Sierra Club, October 2019. Accessible at https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

them to only commit their units when the market will cover the unit's operating costs.

Q How does DEC operate its system?

A DEC operates its system with Duke Energy Progress based on the terms of a Joint Dispatch Agreement.[25] The Fuels and Systems Optimization Portfolio Management group (Unit Commitment) is responsible for developing a unit commitment plan (that is deciding which units to turn on or keep online). The Energy Control Center (ECC) is responsible for operating and economically dispatching the Company's generation resources.[26] In deciding which units to commit and dispatch, the Company calculates the marginal production cost for each unit based on the market replacement cost of fuel, reagents/byproduct costs, emissions, and other variable O&M costs incurred at that particular unit.[27]

Q What tools does DEC have to inform its unit-commitment decisions?

A DEC conducts cost-based forward-looking analysis everyday using a unit commitment modeling software called GenTrader.[28] Forecasted customer demand, fuel and emission market prices, contractual obligations, unit costs and parameters, and planned unit outage information are all input into the model. The

[25] Duke Energy Carolinas Response to Sierra Club Request 1-28, Attachment SC 1.28.
[26] Duke Energy Carolinas Response to Sierra Club Request 1-5.
[27] Duke Energy Carolinas Response to Sierra Club Request 1-8.
[28] *Id*.

model outputs "a unit commitment plan that is utilized to dispatch the generation fleet to minimize production costs while ensuring reliability over the 7-day forecast period."[29] The Company adjusts the analysis throughout the day as needed. I will refer to this analysis as the "7-day forecast."[30]

Q How should DEC be using the results of its cost-based analysis to inform unit-commitment decisions?

A Except in the case of unit testing or other extenuating circumstances, DEC should elect to commit its units only if it expects the unit to operate at below system lambda over a reasonable near-term time period (the Company's 7-day forecast period would be a reasonable time-period), incorporating consideration of reliability, start-up and shut-down costs and times. Conversely, the Company should take a unit offline if the Company projects it will operate at a cost that exceeds system lambda. Operating the units otherwise would predictably result in higher costs that could have been avoided. Therefore, the Company should document any deviations between its final commitment decision and the decision based on its 7-day forecast.

[29] Duke Energy Carolinas Response to Sierra Club Request 1-9.

[30] In Indiana, Duke Energy produces a 7-day forecast known as the P&L or Profit and Loss Analysis.

Q Should a utility always commit its units to minimize costs to ratepayers based purely on the basis of marginal costs?

A Not necessarily. There are certainly circumstances, although limited, in which a unit needs to be operated out of merit. For example, units sometimes need to be brought or kept online for testing purposes or in anticipation of a reliability need. These decisions may be made regardless of costs. Aside from these exceptions, utilities are expected to use accurate cost information and robust processes to make commitment decisions, but they are not expected to never operate a unit uneconomically or to always be right based on perfect hindsight.

First, given the inflexibility of coal units, it can sometimes make sense to leave a unit online for short periods of time, even when there are lower cost resources available, in order to be available to provide electricity during hours of high demand. But even so, the unit must be projected to be economic overall across a multi-day or week period of time.

Second, if system demand or the availability (or cost) of alternative energy opportunities differs significantly from what the utility projected, the utility's commitment decisions may not minimize costs to ratepayers during a multi-day period. If the utility's own contemporaneous analysis indicated that operating the unit would minimize costs, it is not necessarily an imprudent decision. But, if the high costs are part of a pattern in which the utility is consistently and systematically wrong and has neglected to modify its decision-making process,

the entire process may not be robust or prudent. The accuracy of the utility's daily unit-commitment decision-making process should itself be a feedback into its decision-making process, with modifications incorporated when the current process is falling short.

Q Why is it concerning that DEC is self-committing its coal units out of merit order so frequently?

A Operating units out of merit order incurs unnecessary fuel and variable operational costs that are passed on to ratepayers. These costs are likely avoidable if the units were instead committed and dispatched based on economics.

In addition, when a unit is committed out of merit, it shows up on the supply curve as a zero- or low-cost resource, but ratepayers still incur the full cost to operate the resources. By artificially cutting the line, and showing up as a zero- or low-cost resource, these out of merit coal units displace lower cost resources that were previously below the margin. This has a price suppressive effect, and results in a system lambda that is below the marginal cost of energy on DEC's system. The coal unit is still operating above system lambda and those full unit costs are being passed on to ratepayers. Beyond the direct ratepayer impact, this has important implications for how avoided costs are calculated.

Q Why is it notable that DEC incurred costs in excess of system lambda at many of its units over many months during the test year period?

A As discussed above, it is understandable that DEC may incur operational costs in excess of system marginal costs on a daily or even weekly basis as a result of the longer start-up and shut-down costs associated with coal units. These units may accept a "loss" in a few hours of the day or week in order to be online during peak hours. But it is not reasonable or prudent for DEC to operate a unit at a cost that exceeds the system marginal cost over a sustained period of time. Excess costs incurred as a result of this operational decision are avoidable through better unit-commitment decisions and indicate that DEC is either (1) not using robust and complete input data to inform its unit-commitment decisions, or (2) ignoring the results of its unit-commitment analysis.

Q Did you identify avoidable losses based on your analysis?

A Yes, as shown in Table 5, I find that in 2020, DEC could have avoided at least $8.5 million in operational costs at its coal plants if the Company had made better unit-commitment decisions. Specifically, these are the costs that are avoidable if DEC had turned its coal units off in the months when each unit's production costs exceeded the system's marginal cost and instead used its lower cost resources to meet system needs.

Table 5: Operational costs in excess of system lambda ($Million)

Plant	Avoidable Operational Costs ($000)
Allen 1	[redacted]
Allen 2	[redacted]
Allen 3	[redacted]
Allen 4	[redacted]
Allen 5	[redacted]
Belews Creek 1	[redacted]
Belews Creek 2	[redacted]
Cliffside 5	[redacted]
Cliffside 6	[redacted]
Marshall 1	[redacted]
Marshall 2	[redacted]
Marshall 3	[redacted]
Marshall 4	[redacted]
Total	**$(8,463)**

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

Confidential Exhibit DG-2 shows the monthly break-down, by unit, of monthly production costs relative to system lambda. In the months where the values are positive, the unit on net has a lower production cost then the marginal system cost. In months where the values are negative, the unit on net has a higher production cost than the system marginal cost.

Q What evidence do you have that the costs incurred during the months in 2020 when unit costs exceeded system marginal costs are avoidable?

A DEC provided hourly data with "modeled" unit costs and load and actual system lambdas. Although the modeling occurs after the fact,[31] the modeled costs represent the cost information that the Company had at the time it made its units commitment and dispatch decisions. Any time the unit costs were projected to exceed system lambda (inclusive of start-up cost considerations) over a multi-day stretch, a responsible utility manager would reduce costs to ratepayers if the units were shut down.

We asked multiple times for the contemporaneous documentation that DEC produced at the time that they made their daily unit commitment decisions, but they only provided the loading reports, not their 7-day forecast sheets.[32] Without the contemporaneous documentation, the Commission will lack critical information to assess the reasonableness and prudence of the Company's daily unit commitment decisions.

[31] Duke Energy Carolinas Response to Sierra Club Request 3-2.

[32] Duke Energy Carolinas Response to Sierra Club 1-9(b); Duke Energy Carolinas Response to Sierra Club Request 3-1.

7. RECOMMENDATIONS FOR THE COMMISSION

Q Please summarize your recommendations.

A I recommend that the Commission examine closely DEC's production cost accounting, its unit commitment process that relies on its production costs, and the operational decisions and incurred costs that result, and carefully scrutinize these costs for potential disallowance in future proceedings.

Q What do you recommend to address the discrepancy in production costs used to make unit commitment decision and the actual costs passed on to ratepayers?

A DEC's should be required to provide full transparency into the Company's marginal and average production costs. Specifically, DEC should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:

1. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down by the following categories:
    a. Fixed costs
    b. Variable costs
        i. Fuel
        ii. Reagents/ by products
        iii. Emissions
        iv. Variable O&M.

2. Marginal production cost of each unit used for making unit commitment and dispatch decisions, broken down by the same components listed directly above. For any items not included in DEC marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit commitment decisions.

Q What information do you specifically recommend that DEC provide in each fuel cost adjustment filing to allow a review of the prudence of its unit-commitment practices?

A The utility filings in this docket are insufficient and do not meet the filing requirements for this proceeding outlined in Commission Rule R8-55(e).[33] I recommend that DEC compile and file as workpapers with its annual fuel cost adjustment application a detailed report describing its daily unit-commitment decisions and practices as part of future fuel charge adjustment proceedings. DEC should provide the following information as part of each annual fuel charge adjustment application, to inform the Commission's review of its unit-commitment practices and determination whether DEC's fuel- and fuel-related costs for those units were reasonably and prudently incurred:

a. All 7-day forecast sheets used to develop the Company's daily unit-commitment decisions and marginal cost.

[33] NCUC Rule R8-55(e).

b. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).

c. Hourly data sufficient for the Commission to calculate the net value or excess costs that each plant actually incurred in each test year period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, system lambdas, day-ahead commitment status, and actual outages.

Q What other recommendations do you have for the Commission?

A I recommend that the Commission direct DEC to conduct a new retirement study of each unit in the Company's fleet. I acknowledge that the Company conducted retirement analyses for its 2020 Integrated Resource Plans at the direction of the Commission. However, DEC should be required to evaluate the continued operation of each of its coal units based on economics, from both a short-term operational, and long-term planning perspective.

Q Are you recommending a disallowance in this docket relating to DEC's uneconomic commitment practices at any of its coal units?

A Not at this time. As discussed in Section 6, $8.5 million represents the net operational losses that DEC incurred at its coal units as a result of sustained uneconomic operations during specific months. These losses could have been avoided, had the Company economically committed its coal units. While I am not recommending a disallowance at this time, I do recommend that the Commission direct DEC to evaluate the economics of continuing to maintain and operate the units relative to alternative resources to meet system capacity and energy needs while maintaining reliability.

Q Does this conclude your testimony?

A Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list who have signed a confidentiality agreement have been served with the *Corrected* Direct Testimony of Devi Glick –*Public Version* on behalf of the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 1st day of June, 2021.

s/ Gudrun Thompson