PUBLIC VERSION – CONTAINS REDACTED INFORMATION

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2021-3-E

IN THE MATTER OF: **ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR DUKE ENERGY CAROLINAS, LLC (FOR POTENTIAL INCREASE OR DECREASE IN FUEL ADJUSTMENT AND GAS ADJUSTMENT)**	))))))))	**DIRECT TESTIMONY OF DEVI GLICK ON BEHALF OF THE SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY**

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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 Principal 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.

A. 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 South Carolina, Arizona, Connecticut, Florida, Indiana, Michigan, Nevada, New Mexico, North 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 South Carolina Coastal Conservation League ("CCL") and Southern Alliance for Clean Energy ("SACE").

Q. Have you testified previously before the Public Service Commission of South Carolina ("Commission")?

A. Yes, I submitted testimony in Docket Nos. 2018-1-E, 2018-2-E, and 2018-3-E.

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

A. 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 at Allen, Marshal, Cliffside and Belews Creek. In particular, I evaluate the fuel costs included in the subset of production costs that DEC used to make its unit-commitment decisions in the review period of June 1, 2020 through May 31, 2021 (i.e., the marginal production cost). I compare those to the fuel costs included in the average or full cost of production, which represent the fuel costs that the Company seeks to recover from ratepayers in this docket. 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 its actual or average unit costs had on ratepayers in the review period. 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?

A. South Carolina law requires each utility to "make every reasonable effort to minimize fuel costs" and permits the Commission to disallow cost recovery if "any decision of the utility [results] in unreasonable fuel costs."[1] DEC's incurred fuel costs, along with its other variable costs, are inputs into the Company's unit-commitment process, and are therefore directly tied to the utility's decision to operate each of its units. Comparing the level of fuel and other variable costs incurred at its coal plants to the cost to operate other units on the system in turn informs the Commission's determination of whether DEC made "every reasonable effort to minimize fuel costs."

In the past, utilities operated their coal-fired plants as baseload resources where they were not regularly turned on or off. But, in recent years, low gas prices and nearly-zero-variable-cost renewables have pushed coal generation to become marginal on many systems and therefore more costly than other resources available

[1] S.C. Code Ann. §58-27-865(F).

during many hours of the year. The practice of committing coal plants to run when there are lower-cost resources on a Company's system saddles ratepayers with avoidable excess fuel costs, should they be recovered in dockets like this one. This practice thereby allows utilities to continue operating aging and costly coal plants when there are lower-cost alternatives that can meet customers' needs.

Q. How is the remainder of your testimony structured?

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

- 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 such as DEC make daily operational decisions at coal-fired power plants. I explain the practice of uneconomic unit-commitment and outline reasons why utilities may employ this practice.
- In Section 4, I review the marginal production costs DEC uses to make its unit-commitment decisions at its coal units and quantify the excess fuel costs resulting from DEC's decisions to uneconomically commit each of its coal plants during the review period. I discuss how these costs will be imposed on DEC ratepayers if approved for recovery in this proceeding.
- In Section 5, I evaluate the actual 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 during the review period. I evaluate the economic performance of DEC's coal

units during the review period, and I compare the total average production cost of DEC units to those of other coal units around the country.

- In Section 6, I discuss and evaluate the significant deviation between the total fuel cost incurred at each unit over the course of the review period (the average production cost) and the marginal cost of production used to make unit-commitment and dispatch decisions.
- 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. I further recommend a disallowance of the $3.8 million in excess fuel costs incurred by DEC as a result of uneconomic commitment decisions over the review period.

2. FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings.

A. My primary findings are:

1. DEC regularly committed its coal units at times when it would have been less costly to serve retail ratepayers with other resources, as explained in Section 4. In each instance, the Company incurred excess fuel costs (above what it would have paid to operate lower-cost units on its system) which it seeks to recover from ratepayers in this docket.
2. During the review period, 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 5, 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.

3. DEC's reported average cost of generation at each of its four coal plants exceeded the reported cost of the marginal unit on the Company's system (system lambda) during nearly every month of the review period, as explained in Section 5. In total, during the review period, DEC incurred $174.8 million in fuel and variable costs above what the Company should have had to pay to serve the last MWh of load on its system in every hour.
4. The marginal production costs that DEC used to make unit-commitment decisions omitted approximately half of the actual or average fuel and variable costs that the Company incurred to operate its coal units during the review period. As discussed in Section 6, this omitted portion amounted to $255.0 million worth of fuel and other variable costs, approximately $242.5 million of which is fuel costs. This omission resulted in DEC committing and dispatching its coal units significantly more often than if the Company had based its commitment decisions on the actual fuel and variable costs incurred to operate each unit.
5. Even with less than half the actual fuel and variable cost reflected in the marginal production cost that it used to make its unit-commitment decisions during the review period, DEC's unit-commitment practices at its coal plants caused the Company to knowingly incur over $3.8 million in excess

fuel costs at Allen, Marshall, Cliffside and Belews Creek, as discussed in Section 4. That represents the excess fuel costs that DEC incurred at its coal plants during the months when DEC operated the units, despite its own data showing that doing so would incur excess fuel costs.

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, as discussed in Section 7.

Q. Please summarize your recommendations.

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

1. I recommend that the Commission disallow $3.8 million in excess fuel costs incurred at Allen, Marshall, Cliffside and Belews Creek as a result of imprudent commitment decisions. This represents the fuel costs incurred in excess of what the Company would have paid for fuel had it instead committed its lower-cost units that were available at the time.
2. DEC should be required to make its marginal and average production costs fully transparent to the Commission and parties. 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 into fixed and variable costs. Variable

costs should further be broken down by fuel, reagents/by products, emissions, and variable operations and maintenance ("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 clause adjustment proceedings. DEC should provide the following information as part of each fuel clause 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 that show the cost data for every unit on the system that the Company used to develop the Company's daily unit-commitment decisions.

   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 and intervening parties to calculate the actual costs incurred to operate each unit in each review period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable 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 during the review period, the Company should evaluate moving some of its plants to seasonal operation and retiring some of its units.

3. <u>Vertically Integrated Utilities in Non-Centralized Markets, Such As DEC, Control and Coordinate the Commitment and Dispatch of Their Coal-Fired Generating Units</u>

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, such as a coal-fired power plant, 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 advanced 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 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's marginal cost of production 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 (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. 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 utility is responsible for internally committing and dispatching its units and procuring energy through bilateral trades when needed. These utilities generally rely on internal processes that project the marginal production cost to operate each unit. Resources are committed based on marginal cost, with the lowest-cost resources coming online first, and progressively more expensive units being turned on until system load is met. The last unit needed to meet system load sets the system marginal cost (the system lambda). 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. While some utilities do adhere closely to efficient dispatch and commitment, others do not; as is seen with DEC, in those cases there can be a wide discrepancy between the utility's cost of operation and its operational decision. 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 units may be brought or kept online even though lower-cost resources are available to serve load.

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 limited circumstances in which a unit needs to be operated out of merit. For example, sometimes units 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. Of course, commitment decisions are not expected to always be correct given the possibility that circumstances may deviate from what utilities had projected.

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.

Additionally, 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. In these circumstances, if the utility's own contemporaneous analysis indicated that operating the unit would minimize costs, it is not necessarily an unreasonable decision. But if the high costs are part of a pattern in which the utility's forecast is consistently and systematically wrong and the utility 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 fed back into its decision-making process, with modifications incorporated when the current process is falling short.

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, regardless of how the unit's operating economics compare to that of other units on the utility's system.

Ratepayers will incur the fuel and variable costs to operate uneconomic units, even if 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 or independent power producers that operate within organized wholesale markets.[2] Those operators rely entirely on market revenues to cover their units' operating and fixed costs, providing a strong incentive to commit their units only when the market will cover the units' operating costs.

Q. Please explain why investor-owned utilities would ignore or underrepresent unit costs when making commitment or dispatch decisions.

A. 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. Doing so can decrease wear-and-tear and resulting maintenance costs,[3] but it also generally results in unnecessary operational costs well in excess of the cycling costs being avoided. This practice is also unnecessary because cycling times and costs can be, and in fact are, incorporated into utilities' (including DEC's) multi-day unit-commitment decision-making processes.[4]

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[2] *See, e.g.,* Fisher et al., *Playing with Other People's Money* (October 2019), available at https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

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

[4] DEC Response to CCL and SACE Data Request ("DR") 1-10 (d).

Second, in order to address fuel over-supply issues, utilities may artificially 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."[5]

Third, fuel or transportation contract structure and utility judgement about incurrence of O&M costs drive the categorization of utility costs as either fixed or variable. Utilities generally exclude costs associated with fixed transportation contracts (as DEC is doing here), fixed tonnage requirements, or must-take provisions of fuel contracts 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 judgement of which O&M 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 not economic over the long run (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

[5] Ind. Util. Regulatory Comm'n, Direct Testimony of John Swez, IURC Cause No. 38707-FAC 125, available at https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/d333ff64-9cd5-ea11-a813-001dd8018921/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38707%20FAC%20125%20DEI%20Direct%20Testimony%20of%20John%20D%20Swez.pdf.

disallowance. As noted by the U.S. Energy Information Administration ("EIA"), coal units that move to very low utilizations are often retired shortly thereafter because the justification for their operational costs evaporates.[6]

4. DEC INCURRED $3.8 MILLION IN AVOIDABLE FUEL COSTS AT ITS COAL PLANTS AS A RESULT OF UNECONOMIC UNIT-COMMITMENT DECISIONS DURING THE REVIEW PERIOD.

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. DEC's reported marginal cost of production at its coal plants is far lower than its average cost of production as a result of the Company inappropriately excluding certain variable costs. Nonetheless, I found that the Company incurred over $4.0 million in avoidable variable costs at its coal plants as a result of its uneconomic unit-commitment practices during the review period, $3.8 million of which were fuel costs. In other words, even accepting the Company's erroneous characterization of its marginal cost of production, DEC is still incurring avoidable fuel costs that it seeks to pass on to ratepayers.

Q. Describe DEC's 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

[6] U.S. Energy Information Administration, *As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation*, Today in Energy (September 1, 2020), available at https://www.eia.gov/todayinenergy/detail.php?id=44976.

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 1,110 MW.

Q. Please describe the different categories of costs incurred at DEC's coal plants, what costs are included in each category, and which costs are recovered in the annual fuel clause adjustment proceedings such as the current docket.

A. Table 1 provides a breakdown of all the major categories of forward-looking costs incurred by DEC at its coal plants and indicates which DEC requested to be recovered in this docket. The marginal cost of production—that is, the incremental cost of operating the unit—is composed of a subset of variable costs: the replacement cost of fuel, which is the "market price of fuel plus variable transportation costs,"[7] and the cost of reagents/byproducts, emissions, and variable O&M. DEC utilizes the marginal cost of production when making a unit-commitment decision. I discuss the marginal cost of production in this section.

Importantly, the marginal cost of production does not represent the actual or average production costs passed on to ratepayers. The actual 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 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. The average production cost

[7] DEC Response to CCL and SACE DR 1-10 (a).

provided by the Company in this docket is calculated by adding up all fuel and other variable costs incurred to operate each unit and spreading them out over the unit's total MW output.

Table 1: Categories of coal plant costs used for unit-commitment, included in actual/average production cost, and recovered in current docket

Item	Cost used in Duke's unit-commitment process (marginal production cost)	Cost included in actual / average production cost	Cost for recovery in current fuel docket
Fuel			
Fuel	Market / replacement cost of fuel	Cost of actual fuel inventory	Cost of actual fuel inventory
Fuel Transportation			
Barge transport for coal	Full cost	Full cost	Full cost
Rail transport for coal	Only variable component	Full cost (fixed and variable)	Full cost (fixed and variable)
Non-operations and maintenance variable costs			
Reagents/byproduct	Full cost	Full cost	Full cost
Emissions	Full cost	Full cost	Full cost
Operations and Maintenance (O&M)			
Variable O&M	Full cost	Full cost	None
Fixed O&M	None	None	None
Other forward-looking fixed costs			
Sustaining capital expenses	None	None	None
Taxes	None	None	None
Other fixed plant costs	None	None	None

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.[8] The Fuels and Systems Optimization Portfolio Management group is responsible for developing a unit-commitment plan (that is deciding which

[8] DEC Response to CCL and SACE DR 1-33, Attachment SACE/CCL 1.33 Joint Dispatch Agreement.

units to turn on or keep online). The Energy Control Center is responsible for operating and economically dispatching the Company's generation resources.[9] 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.[10]

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

A. DEC conducts cost-based forward-looking analysis every day using unit-commitment modeling software called GenTrader.[11] 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 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."[12] The Company adjusts the analysis throughout the day as needed. I will refer to this analysis as the "7-day forecast."[13]

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

[9] DEC Response to CCL and SACE DR 1-7.
[10] DEC Response to CCL and SACE DR 1-10 and 1-11.
[11] DEC Response to CCL and SACE DR 1-11.
[12] *Id.*
[13] In Indiana, Duke Energy produces a 7-day forecast known as the P&L or Profit and Loss Analysis.

would be a reasonable time-period), incorporating consideration of reliability as well as 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 above system lambda 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 commitment plan based on its 7-day forecast.

Q. Is there evidence that DEC is committing its coal units uneconomically?

A. Yes. The Company's data from GenTrader provided in discovery[14] shows that the Company operated its units during many sustained periods of time when its own data showed that it would be less expensive to operate other units on a marginal production cost basis. In these hours, the Company incurred excess costs that it now seeks to pass on to ratepayers.

Q. Why is it concerning that DEC is committing its coal units out of merit order so frequently during the review period?

A. Operating units out of merit order incurs unnecessary fuel and variable operational costs that are passed on to ratepayers. It is understandable that DEC may incur operational costs in excess of system marginal costs on a daily, or even weekly basis, and incur excess costs in a few hours of the day or week in order to be online during peak hours. But it is unreasonable for DEC to operate a unit at a cost that exceeds the system marginal cost over a sustained period of time. Excess costs

[14] DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

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. These costs were 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 showing up as a zero- or low-cost resource, these out of merit coal units cut the line and 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. Did you identify avoidable excess costs based on your analysis?

A. Yes, as shown in Table 2, I find that during the review period, DEC could have avoided at least $4.0 million in excess costs at its coal plants if the Company had made better unit-commitment decisions based on just the marginal cost it uses for the purposes of unit-commitment and dispatch. Specifically, these are the costs that were avoidable if DEC had turned its coal units off in the months during which each unit's production costs exceeded the system's marginal cost and instead used its lower-cost resources to meet system needs. Of the excess $4.0 million in costs, $3.8 million represents excess fuel costs.[15]

Table 2: Confidential operational costs in excess of system lambda

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	($4,003)

Source: DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

Q. On what do you base your determination that the costs incurred during the review period months when unit costs exceeded system marginal costs are avoidable?

A. DEC produced hourly data with "modeled" unit costs, system load for just DEC's part of the system, and actual system lambdas. Although the modeling occurs after the fact,[16] the modeled unit costs represent the cost information that the Company had at the time it made its unit-commitment and dispatch decisions. Any time the unit costs were projected to exceed system lambda (inclusive of start-up cost

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[15] DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

[16] DEC Response to CCL and SACE DR 1-6 (a).

considerations) over a multi-day stretch, a responsible utility manager would reduce costs to ratepayers by shutting the units down.

CCL and SACE requested the contemporaneous documentation that DEC produced at the time the Company made its daily unit-commitment decisions with all unit costs on the system, but the 7-day forecast sheets the Company provided had no cost information.[17] Without the contemporaneous documentation, the Commission will lack information critical for assessing whether DEC made "every reasonable effort to minimize fuel costs" when making its daily unit-commitment decisions.

5. DEC's Coal Plants Operated at an Average Production Cost That Exceeded the Marginal System Cost for Nearly All of the Review Period

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 during the review period. I find that each of the Company's coal-fired power plants operated at an average production cost that exceeded the marginal system cost during nearly every month in the review period.

[17] DEC Response to CCL and SACE DR 1-11(b).

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

A. In Section 4, I relied on DEC's characterization of its marginal cost of production at its coal plants, which is far lower than its average costs of production discussed in this section. I evaluated the hourly data, projections, and analysis that DEC modeled to inform its unit-commitment decisions.[18] I then calculated the excess costs DEC predictably incurred by operating its units during periods when its own projections showed it would incur operational costs in excess of system marginal cost.[19] Thus, because the process of unit-commitment and dispatch is necessarily forward-looking, Section 4 focused on DEC's projected costs.

In this section, I present analysis on how DEC's units *actually* performed during the review 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 unit's average production costs exceeded the average system lambda.[21]

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[18] DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

[19] DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

[20] DEC Response to SACE and CCL DR 1-3f, Attachment DEC Monthly Accounting Fuel Cost_Burn Detail.

[21] DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

Q. Describe Duke's utilization of its coal-fired fleet during the review period.

A. Between June 1, 2020 and May 31, 2021, each of DEC's coal-fired power plants was minimally utilized. Specifically, every unit had an annual capacity factor below 54 percent, as shown in Table 3.[22]

Table 3: Review Period Annual Capacity Factors for DEC Coal Units

Unit	Review Period Capacity Factor (%)
Allen 1	1.1%
Allen 2	1.2%
Allen 3	2.8%
Allen 4	10.8%
Allen 5	9.5%
Belews Creek 1	48.7%
Belews Creek 2	34.2%
Cliffside 5	22.9%
Cliffside 6	53.4%
Marshall 1	32.5%
Marshall 2	37.2%
Marshall 3	41.0%
Marshall 4	38.7%

Source: DEC Response to SACE and CCL Request 1-3(a), Attachment CONFIDENTIAL 2021 SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail.

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

A. I compared the hourly system lambdas[23] to the monthly average cost of generation reported by DEC at each plant.[24] As shown in Table 4, I found that during the review period of June 1, 2020 through May 31, 2021, the average cost of generation at each coal station was higher than the average system lambda during the majority of hours that each plant was online. That means that in every month during the

[22] DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail.

[23] DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices.

[24] DEC Response to SACE and CCL DR 1-3f, Attachment DEC Monthly Accounting Fuel Cost_Burn Detail.

review period, 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.

In making the decision to commit its coal units, DEC omitted nearly half of its fuel costs from the GenTrader modeling analysis. This means the marginal generation cost used by GenTrader software to make daily unit-commitment decision represents only half of the Company's actual incurred fuel costs. In total, DEC incurred $174.8 million in excess production costs by operating its coal units to meet load relative to the cost it should have incurred to meet load based on its reported system lambda (as discussed in Section 0).

Table 4: CONFIDENTIAL Average cost of generation relative to average system lambda

Year	Month	Coal-generation-weighted system lambda during hours DEC coal plants are online ($/MWh)	Average coal station cost of generation ($/MWh)			
			Allen	Marshall	Belews Creek	Cliffside
2020	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices; DEC Response to SACE and CCL DR 1-3f, Attachment DEC Monthly Accounting Fuel Cost_Burn Detail.

Q. Does the analysis reflected in Table 4 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 4 was provided by the Company and is composed of actual fuel and variable operating expenses, including all transportation expenses. The data in Table 4 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 resource options over a longer time horizon. This type of comparison requires consideration of the full forward-going costs, both fixed and variable and including sustaining capital expenditures, required to keep the plant operational. A full unit economic analysis of this type was presented by my colleague Rachel Wilson in the most recent DEC rate case proceeding before the North Carolina Utilities Commission, Docket No. E-7, Sub 1214.[25]

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.[26] Specifically, as shown in Table 5, the coal used at Allen, Belews Creek, Marshall and Cliffside cost between $2.68/MMBtu and

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[25] See N.C. Utils. Comm'n, Docket No. E-7, Sub 1214, Corrected Direct Testimony of Rachel Wilson on Behalf of Sierra Club (Public Version), available at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fd224f6a-22df-4324-b57f-dfc44b8fa6a0.

[26] Author's calculation from Energy Information Admin. Form 923, 2020.

$2.77/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.[27]

Table 5: 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	$2.77	90%
Belews Creek	$2.68	86%
Marshall	$2.53	82%
Cliffside	$2.36	75%

Source: EIA Form 923 for 2020.

6. DEC Excluded Nearly 37 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 compare 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 show how DEC excluded a significant portion of its production costs from its unit-commitment decisions.

[27] EIA Form 923 for 2020.

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

A. Yes. DEC appears to exclude 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 37 percent of actual production costs incurred at its coal plants.[28] Of the total marginal cost of production, the fuel component represents the cost DEC would pay today to replace the fuel that it burns. DEC calculates the replacement cost of coal based on [redacted][29] 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.

Q. How large is the discrepancy between DEC's actual and marginal fuel costs?

A. As shown in Table 6 below, during the review period DEC incurred $698.3 million in fuel and other production costs operating its coal fleet, but only $443.3 million in variable fuel and other operating costs were included in the Company's unit-commitment and dispatch modeling. This means that a full 37 percent of the Company's production costs, equaling $255.0 million, were excluded from DEC's unit-commitment and dispatch decision-making processes. As a result, Duke's unit-

[28] DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices; and DEC Response to SACE and CCL DR 1-3f, Attachment DEC Monthly Accounting Fuel Cost_Burn Detail.

[29] DEC CONFIDENTIAL Response to CCL and SACE DR 1-4 (b).

commitment modeling based on marginal production costs showed that its fleet provided a value of almost $80.2 million to its ratepayers during the review year, but in fact the Company actually incurred $174.8 million in actual excess production costs relative to system lambda during the review period. Of the total excess production costs incurred, approximately 95 percent, or $166 million, represents fuel costs.

The $4.0 million in excess costs discussed in Section 4 above represents the portion of the $80.2 million in value that was incurred during just the subset of months where a coal unit was on net more expensive to operate than system lambda during the hours that each unit operated. In other words, over the course of the year, the Company calculated that its coal units provide ratepayers $80.2 million in value from operating based on each unit's marginal unit costs, but during the unit's poorest performing months, the Company's own calculations indicated that $4.0 million in excess costs would be incurred from operating the units. These costs were fully avoidable if the units had been turned off during those specific months and lower-cost units had been used instead.

Table 6: Total Production Costs incurred by DEC's Coal Fleet during the review period

Cost Description	($Million)	Source
a. Total actual/average production costs passed on to ratepayers	$698.3	Average cost of generation from DEC in SACE/CCL DR 1.3(f)
b. Marginal costs used by DEC for the purpose of making unit-commitment and dispatch decisions	$443.3	Modeled unit variable costs from DEC in SACE/CCL DR 1.3(a_d_e_j)
c. Total cost of serving load met by coal units at System Lambda	$523.5	System lambda from DEC in SACE/CCL DR 1.3(b) x generation from SACE/CCL DR 1.3(a_d_e_j)
e. Cost of generation omitted from DEC's unit-commitment and dispatch decision-making process	($255.0)	(b) - (a)
d. Difference between system lambda and DEC's marginal production cost	$80.2	(c) - (b)
f. Actual excess costs incurred by DEC from operating its coal fleet during the review period that it seeks to pass on to ratepayers	($174.8)	(c) - (a)

Source: DEC Response to SACE and CCL DR 1-3a, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to SACE and CCL DR 1-3b, Attachment CONFIDENTIAL 2021 DEC SACE/CCL DR 1.3b DEC INC DEC_Prices; and DEC Response to SACE and CCL DR 1-3f, Attachment DEC Monthly Accounting Fuel Cost_Burn Detail.

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 were 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. There are two main explanations for why certain operational costs (totaling $255.0 million) were excluded from DEC's unit-commitment decision-making process: (1) the Company's rail contracts currently include both fixed and variable costs; (2) the incremental cost of fuel is based on replacement fuel costs, not purchased fuel costs, which will be different.

Q. How are DEC's rail contacts structured?

A. DEC indicated that its current rail transportation contracts include both fixed and variable costs.[30] DEC considers the fixed-cost component to be sunk and therefore excludes that component from its unit-commitment decisions.[31] DEC witness Phipps acknowledged that the current contract structure does not serve customers' interests, stating that "the Company's Fixed/Variable coal rail transportation contracts that expired on June 30, 2021 did not provide ongoing customer value in a declining burn environment."[32] Yet, DEC still operated its coal units with these

[30] DEC Response to Sierra Club DR 1-27(a).
[31] DEC Response to CCL and SACE DR 1-27(b).
[32] Docket No. 2021-3-E, Direct Testimony of Brett Phipps at 8.

costs excluded from its dispatch and commitment algorithms during the review period, and now seeks to recover the resulting excess fuel costs from its ratepayers.

The Company indicated that it is has negotiated a new rail contract with 100 percent variable pricing.[33] Accounting for these rail costs as variable will increase the marginal production cost of DEC's units, closing the gap between the units marginal and actual production costs, and making alternatives even more attractive. Transportation costs account for approximately 40 percent of the DEC's delivered cost of coal.[34]

Q. Explain how the replacement cost of fuel differs from the actual cost of fuel?

A. 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. This difference is expected to be relatively small with DEC because the Company utilized a fuel procurement strategy whereby over [redacted] of its coal supply was procured through flexible and short-term coal contracts of two years or less.[35] With short-term contracts, the coal price in the contract and the replacement price the Company would pay on the spot market should not differ significantly, and the Company can more easily adjust its purchase based on need.

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 the actual production cost of each unit, its coal units would shift higher on the supply stack. This would make

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[33] DEC Response to CCL and SACE DR 1-28 (a) and (b).

[34] Docket No. 2021-3-E, Direct Testimony of Brett Phipps at 5.

[35] DEC Response to CCL and SACE DR 1-21, CONFIDENTIAL Coal Supply Contracts Summary attachment.

alternative resources more cost-competitive on an operational basis. As a 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.

Q. What do you conclude regarding the reasonableness of DEC's fuel management and unit-commitment decisions during the review period?

A. It is reasonable to expect there will be a small difference between marginal unit costs and average unit costs based on 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 is 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.

7. Recommendations for the Commission

Q. Please summarize your recommendations.

A. I recommend that the Commission disallow $3.8 million in excess fuel costs incurred at Allen, Marshall, Cliffside and Belews Creek as a result of imprudent commitment decisions. Additionally, I recommend that DEC provide more transparency and documentation on which costs it is using for the purposes of commitment and dispatch, and how it is making its daily unit-commitment decisions.

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

A. DEC 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 into fixed and variable costs. Variable costs should further be broken down by fuel, reagents/by products, emissions, and 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 to facilitate the Commission's determination as to whether DEC made "every reasonable effort to minimize fuel costs."[36] 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.[37] 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:

1. All 7-day forecast sheets that show the cost data for every unit on the system that the Company used to develop the Company's daily unit-commitment decisions.
2. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's

[36] S.C. Code Ann.§ 58-27-865(F).

[37] Pursuant to North Carolina Utilities Commission regulations, DEC is already required to submit in fuel proceedings "at a minimum" all work papers supporting their calculations. 4 N.C. Admin. Code 11.R8-55(e)(11). The utility is also required to provide specific information, such as the "[c]ost of fuel and applicable fuel-related costs corresponding to the adjusted test period kWh generation" and "[p]rocurement practices and inventories for fuel burned," to facilitate regulatory review in fuel proceedings. 4 N.C. Admin. Code 11.R8-55(e).

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).

3. Hourly data sufficient for the Commission and intervenors to calculate the net value or excess costs that each plant actually incurred in the review period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable 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. Yes. I am recommending a disallowance of $3.8 million. This represents the excess fuel costs that DEC incurred at the Allen, Marshall, Cliffside and Belews Creek coal units as a result of sustained uneconomic operations during specific months. Specifically, the portion of fuel costs that DEC paid, above what it would have paid for fuel had it operated the lower-cost units available on its system. These excess fuel costs could have been avoided, had the Company economically committed its coal units.

Q. Does this conclude your testimony?

A. Yes.

Devi Glick, Principal Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, June 2021- Present; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.

- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

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TESTIMONY

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated August 2021

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served via first class U.S. Mail or electronic mail with a copy of the *Direct Testimony of Devi Glick* on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

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This 1st day of September, 2021.

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This 14th day of June, 2021.

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