SOUTHERN ENVIRONMENTAL LAW CENTER

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May 18, 2020

Via Electronic Filing

Ms. Kim Campbell
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

Re: In the Matter of: Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities; Docket No. E-7, Sub 1228

Dear Ms. Campbell:

Enclosed for filing in the above captioned docket is the Direct Testimony of John Rosenkranz on behalf of the Sierra Club. Duke Energy Carolinas, LLC's Response to Sierra Club Data Request 1-8 is attached as Exhibit 2 to Mr. Rosenkranz's testimony. The Response was marked as confidential when produced by Duke Energy Carolinas during discovery and has been left unaltered in this submission. However, on May 14, 2020 Duke Energy Carolinas' counsel, Jack Jirak, confirmed via electronic email that the Response was marked as confidential in error. Therefore, we are filing Exhibit 2 as a public document despite the document being marked as confidential.

Please let me know if you have any questions about this filing.

Sincerely,

s/Tirrill Moore

TM
Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1228

In the Matter of: Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))))	**DIRECT TESTIMONY OF JOHN A. ROSENKRANZ ON BEHALF OF THE SIERRA CLUB**

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is John A. Rosenkranz. I am Principal with North Side Energy, LLC. My business address is 56 Washington Drive, Acton, MA 01720.

Q. Please describe your professional background and experience.

A. I have more than 30 years of experience in the areas of natural gas supply planning, utility regulation, and gas and electric project development. I have been an independent consultant since 2006. Previously, I was responsible for negotiating and managing long-term natural gas supply and transportation contracts for power generation, and prepared market and rate studies for interstate pipeline and gas storage projects. I received a BA degree in economics from George Washington University, and completed all course and examination requirements for a doctorate in economics at Northwestern University. My Experience Statement is attached as Exhibit 1.

Q. Have you previously testified before the North Carolina Utilities Commission?

A. No, I have not.

Q. Have you testified before other state, provincial, or federal regulators?

A. Yes. I have testified before the Maine Public Utilities Commission, the New Hampshire Public Utilities Commission, the Massachusetts Department of Public Utilities, the Arizona Corporation Commission, and the Ontario Energy Board. I have also submitted testimony in proceedings before the New Jersey Board of Public Utilities and the Federal Energy Regulatory Commission.

Q. Please describe your experience with natural gas supply for electricity generation.

A. From 2000 to 2006, I was responsible for negotiating gas transportation and storage services agreements for new gas-fired generation facilities developed by Calpine Corporation in the U.S. and Canada. From 2006 to 2016, I advised the Ontario Power Authority on power generators' proposals to contract for gas transportation and storage services that would be eligible for cost reimbursement under electricity purchase contracts.

Q. Please describe your experience with utility gas cost recovery proceedings.

A. Over the last decade, I have reviewed natural gas utility cost recovery filings as a consultant to the Maine Public Advocate and New Jersey Division of Rate Counsel.

Q. On whose behalf are you sponsoring testimony in this proceeding?

A. I am testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to examine whether the information that Duke Energy Carolinas ("DEC") provided with its February 2020 application in this case is adequate to support the requested cost recovery. I evaluate DEC's filing based first, on whether DEC has met the minimum reporting requirements set out in Commission Rule R8-55, and second, on whether the information provided by DEC is sufficient to make a determination as to whether the test period natural gas supply costs were reasonable and prudently incurred.

Q. Please summarize your findings and recommendations.

A. From 2011 to 2019, DEC's fuel and fuel-related costs for natural gas supply increased from approximately $50 million to more than $400 million per year, and DEC entered into new long-term commitments for interstate gas transportation services. However, even though natural gas costs now account for a much larger share of DEC's fuel and fuel-related costs, the data that DEC provides to support the recovery of gas supply costs appears not to have changed.

Based on the information provided, it is not possible to determine whether DEC's test period fuel and fuel-related costs were reasonable and prudently incurred. DEC should expand the information on natural gas supply quantities and costs that it includes with the annual fuel cost adjustment application. At a minimum, DEC should provide: (a) details on the sources and uses of natural gas, (b) a full description of the gas transportation and storage services used to supply DEC plants, and the associated fixed reservation charges, and (c) net revenues from natural gas sales and the transportation capacity releases. DEC should also be prepared to provide daily gas use data for each plant, and daily scheduled quantities for each firm gas transportation service.

Q. Please explain how your testimony is organized.

A. Section II describes the natural gas supply costs that DEC is seeking to recover in this proceeding. Section III addresses DEC's commitments to gas transportation services, and explains why it is important for DEC to actively manage these services to reduce customer costs. In Section IV I examine the natural gas supply quantity and cost information that DEC provided to support test period cost recovery, and make recommendations concerning the additional information that DEC should provide.

II. ANNUAL FUEL CHARGE ADJUSTMENT

Q. What is the purpose of the annual fuel charge adjustment?

A. North Carolina electric public utilities that use fossil fuels to generate electricity for retail electric service are permitted to adjust their rates each year to reflect changes in the cost of fuel and fuel-related costs. The fuel cost adjustment is based on the projected costs for the billing period, and actual costs that were over-recovered or under-recovered during the test period. The utility has the burden of proof to show that test period costs were reasonable and prudently incurred.

For DEC, the test period is the calendar year prior to the year in which the application is filed, and the billing period is the twelve-month period starting September 1 of the year in which the application is filed.

Q. What are the fuel and fuel-related costs?

A. N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 define "cost of fuel and fuel-related costs" to mean the cost of fuel burned and the cost of fuel transportation, adjusted for any net gains or losses from sales of fuel and other fuel-related costs components.

Q. How does DEC currently use natural gas?

A. DEC consumed natural gas at seven generating stations during the 2019 test period. This includes three combined-cycle ("CC") plants (Buck, Dan River, and W.S. Lee), three combustion turbine ("CT") plants (Lincoln, Rockingham, and Mill Creek), and a steam plant that co-fires natural gas with coal (Cliffside). The three combined-cycle plants accounted for 81 percent of DEC's total natural gas consumption (Table 1). Natural gas used in combustion turbines and gas for co-firing each accounted for just under 10 percent of the total. DEC also used natural gas for commissioning the Clemson combined heat and power ("CHP") plant.

Table 1: Natural Gas Use at DEC Plants, Calendar 2019[1]

	Plant Type	Gas Burned (BBtu)	Percent
1	Combined Cycle	99,790.5	80.6%
2	Combustion Turbine	12,167.4	9.8%
3	Steam (Co-Firing)	11,792.8	9.5%
4	Other Steam & CHP	20.0	<0.1%
5	Total	123,770.7	100.0%

Natural gas use for the September 1, 2020 to August 31, 2021 billing period is projected to reach 201,900 BBtu.[2] DEC attributes the expected increase of 63 percent from the 2019 test period to the start of co-firing at the Belews Creek

[1] 2019 Monthly Fuel Reports, Docket No. E-7, Sub 1198.
[2] Natural gas quantities are shown as million British Thermal Units (MMBtu) and billion Btu (BBtu).

and Marshall generating stations, and an expected increase in generation from the Lincoln combustion turbines.[3]

Q. What portion of test period fuel and fuel related costs were related to natural gas?

A. DEC proposes to recover $405 million for natural gas supply costs incurred during the 2019 test period. As is shown in Table 2, these costs account for 23 percent of the total reported fuel and fuel related costs of $1,750 million. By comparison, natural gas supply costs for calendar 2011 were $51 million, which was less than three percent of the total.

Table 2: Natural Gas Costs vs. Total Fuel Costs, 2011 and 2019

	Plant Type	Calendar 2011[4] (000)	Calendar 2019[5] (000)
1	Combined Cycle	$9,668.2	$322,366.7
2	Combustion Turbine	$41,155.6	$40,328.3
3	Steam	-	$42,380.5
4	Combined Heat and Power	-	$54.7
5	Total Natural Gas Costs	$50,823.8	$405,130.2
6	Total Fuel & Fuel-Related Costs	$1,918,301.0	$1,750,175.4

Q. How do the Duke Energy utilities manage natural gas supplies for their North Carolina and South Carolina plants?

A. The responsibility for managing natural gas supplies for the DEC and DEP power plants is divided into two categories. The first category involves decisions to enter into long-term arrangements with intrastate and interstate transporters to connect generating plants to a source of natural gas supply. These commitments are made by the individual utility. For DEC, these

[3] Direct Testimony of Brett Phipps, page 7.
[4] McManeus Exhibit 8, Docket No. E-7, Sub 1002 (March 7, 2012).
[5] McGee Exhibit 6, Schedule 2.

commitments include contracts with local distribution companies (“LDCs”), long-term contracts with Transcontinental Gas Pipe Line Company (“Transco”) for interstate gas transportation, and commitments for future gas transportation service with Atlantic Coast Pipeline (“ACP”).

The second category involves decisions to acquire shorter-term gas supply resources, buy natural gas, and optimize the value of gas supply resources under contract. Under the “Asset Management and Delivered Supply Agreement” that was implemented in January 2013, DEC, as the designated Asset Manager, manages these activities on a combined basis for both DEC and DEP.[6] DEP assigns its gas transportation and storage assets to DEC, and the total costs are allocated between the two utilities.

III. NATURAL GAS TRANSPORTATION AND STORAGE SERVICES

Q. How is natural gas delivered to the DEC generating stations?

A. With the exception of the Cliffside generating station, which is connected to Public Service of North Carolina, and the Clemson CHP plant, which is connected to Fort Hill Natural Gas Authority, the DEC generating stations are connected to the Piedmont Natural Gas distribution system.[7] DEC has agreements with the connecting LDCs to receive gas from Transcontinental Gas Pipe Line Company (“Transco”) and redeliver the gas to the plant. These agreements specify the quantity of gas that the LDC is obligated to receive and redeliver on any day.

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[6] Phipps Exhibit 1, p. 1.
[7] DEC Response to Sierra Club Data Request 1-8, attached as Exhibit 2.

Q. Does DEC also hold long-term contracts for interstate transportation and storage services?

A. Yes. During the test period DEC had long-term contracts with Transco for 151,560 MMBtu/day of firm gas transportation service (Table 3). This pipeline capacity allows DEC to buy gas at various points along the pipeline, and deliver the gas to the LDCs in North Carolina and South Carolina that connect to the DEC generating plants.[8] DEC also holds a long-term contract for firm storage service with Mississippi Hub Storage, which connects with Transco in Simpson County, MS.[9]

Table 3: DEC Long-Term Transportation Contracts on Transco[10]

	Contract Number	Quantity (MMBtu/day)	Start Date	Expiration Date
1	9109922	60,000	5/1/2011	4/30/2031
2	9139583	16,560	7/1/2017	10/31/2017[11]
3	9172961	75,000	3/1/2016	1/31/2023
4	Total	151,560		

Q. Is all of the natural gas used at DEC plants transported on contracts held by DEC or DEP?

A. No. Because there is a market for natural gas delivered at Transco meters in North Carolina and South Carolina, DEC has a choice to either source gas at points outside the market area and contract for interstate pipeline capacity, or buy "delivered" gas. During calendar 2019, of the 308,682.3 BBtu of natural gas purchased for DEC and DEP plants, 151,171.6 BBtu (49 percent) was delivered by gas suppliers at pipeline delivery meters in North Carolina and

[8] DEC has other interstate gas transportation agreements for biogas used at its Dan River plant.
[9] Mississippi Hub Index of Customers report, at http://www.gasnom.com/ip/mississippihub/.
[10] Transco Index of Customers Report, at http://www.1line.williams.com/Transco/index.html.
[11] After the end of the contract term this became an "evergreen" contract that DEC can terminate, subject to the applicable notice provisions.

South Carolina.[12] The remaining 156,510.7 BBtu, or 428,796 MMBtu/day, was transported using interstate pipeline capacity under contract to DEC or DEP.

Q. Does DEC have other commitments for interstate pipeline capacity?

A Yes. DEC has committed to 272,250 MMBtu/day of firm transportation service on ACP. ACP is a proposed new pipeline that would connect gas supply areas in West Virginia to markets in Virginia and North Carolina. DEC's parent company, Duke Energy, has a 47 percent ownership interest in ACP.[13] The ACP capacity would increase the amount of interstate pipeline capacity held by DEC under long-term contracts by 180 percent, from 151,560/MMBtu per day to 423,810 MMBtu/day.

Q. What is the status of the ACP project?

A. ACP had originally proposed a start date of November 1, 2018. In the Quarterly Status Report filed on February 17, 2020 in Docket No. E-7, Sub 1062, DEC states that ACP is now expected to go into service in early 2022, and the construction cost for the project is estimated to be approximately $8 billion. This is an increase of more than 50 percent from the $5.14 billion estimate in ACP's Federal Energy Regulatory Commission ("FERC") certificate application.[14]

Q. Has the Commission determined that DEC's decision to commit to ACP service is prudent?

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[12] DEC Response to Sierra Club Data Request 1-5, attached as Exhibit 3.

[13] Duke Energy Security and Exchange Commission Form 10-K for 2019, p 18.

[14] Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, FERC Docket No. CP15-554, September 18, 2015.

A. No, it has not. The Commission's order accepting the DEC and DEP affiliate agreements with ACP makes clear that the recovery of ACP costs in rates will be addressed in a future proceeding.

> …for ratemaking purposes, the authorizations to pay compensation provided by this Order do not constitute approval of the amount of compensation paid pursuant to the Agreements, and the authority granted by this Order is without prejudice to the right of any party to take issue in a future proceeding with any provision of the Agreements and with DEC's and DEP's management of their pipeline capacity resources.[15]

Q. How do long-term contracts for gas transportation service, such as DEC's commitments with Transco and ACP, create risks for utility customers?

A. Long-term contracts with interstate pipelines commit the contracting party (the "shipper") to pay a fixed monthly charge to reserve pipeline capacity over the term of the agreement. The monthly reservation charge may be based on a negotiated rate that is fixed over the term, or on the tariff rate approved by FERC, which is subject to change. If the value of the capacity falls, either because the market price of natural gas at the receipt point(s) listed in the gas transportation agreement declines relative to the market price at the delivery point(s), or because there is an increase in the tariff rate, the cost of holding capacity on the pipeline may exceed the cost savings obtained from buying gas in an upstream market.

Q. How do utilities manage gas transportation contracts to mitigate these risks?

A. There are three mechanisms that electric and gas utilities can use to obtain additional value from firm transportation capacity, and mitigate their customers' exposure to fixed pipeline charges.

[15] "Order Accepting Affiliate Agreements, Allowing Payment Thereunder and Granting Limited Waiver of Code of Conduct", N.C.U.C. Docket No. E-2, Sub 1052 (October 29, 2014), at 6.

Third-Party Sales – The utility uses the firm transportation service to buy natural gas at pipeline receipt points where prices are relatively low, and resell gas at delivery points where prices are relatively high. The margin recovered on behalf of customers is the difference between the sales price and the purchase price, minus the variable pipeline transportation cost.

Capacity Release - FERC rules allow a shipper holding firm transportation capacity on interstate pipelines to temporarily resell its rights to a replacement shipper. The payments made by the replacement shipper are credited to the releasing shipper by the pipeline.

Asset Management Arrangements ("AMAs") – An AMA combines a capacity release with a gas sales transaction. The utility releases pipeline capacity to a natural gas supplier (the "Asset Manager") and has rights to buy delivered gas from the Asset Manager at a defined price. The Asset Manager makes a negotiated payment to the utility to the use the pipeline capacity over the term of the AMA.

Q. Is contracting for firm gas transportation service a one-time decision that need not be revisited?

A. No, it is not. A utility should continually re-evaluate its commitments to firm gas transportation services as fuel requirements and gas and electric market conditions charge. Precedent agreements for new pipelines and pipeline expansion projects generally include a right to terminate if major project milestones are not met by the dates specified in the agreements. In addition, after service starts, the utility can choose whether or not to renew or extend the service when the initial term expires.

IV. REPORTING REQUIREMENTS

Q. Does the DEC fuel cost adjustment application include the information needed to support the recovery of test period natural gas supply costs?

A. No. The information provided by DEC is not adequate to support a determination as to whether the gas fuel and fuel-related costs were reasonable and prudently incurred.

Q. What information is DEC supposed to include with the fuel cost filings?

A. Commission Rule R8-55(e) defines the <u>minimum</u> information and data requirements for the annual fuel cost adjustment application.[16] This information includes:

- Procurement practices and inventories for fuel burned;
- The cost of fuel burned;
- Net gains or losses resulting from sales of fuel or other fuel-related costs components; and
- The monthly fuel report for the last month in the test period and information required by Rule R8-52 which has not already been filed.

Commission Rule R8-52 requires electric utilities to file a Monthly Fuel Report that includes:

[16] "Each electric public utility, at a minimum, shall submit to the Commission for the purposes of investigation and hearing the information and data in the form and detail as set forth below:"

- Details of cost of fuel burned;
- Details of cost of fuel transportation;
- Details of fuel consumption and inventories; and
- Details of net gains or losses resulting from sales of fuel or other fuel-related costs components.

Q. Did DEC provide the required information with its application?

A. No. The main source of natural gas supply and cost information in the DEC filings is the "Fuel and Fuel Related Cost Report," which shows gas use and the total allocated gas supply cost by plant, by month. The report does not break out gas purchase costs from gas transportation costs, or show any difference between the costs of natural gas purchased and the costs of natural gas burned.

Q. What other natural gas information is missing from the DEC reports?

A. DEC did not provide "details of cost of fuel transportation" or "inventories of fuel burned." This would include information describing the natural gas transportation and storage services under contract, the fixed and variable costs paid for gas transportation and storage, gas storage balances, and how costs were allocated between DEC and DEP.

DEC also failed to provide "details of net gains or losses resulting from sales of fuel or fuel-related cost components." This would include the total revenues and net margins from sales of natural gas sale, and revenue from gas transportation capacity release.

Q. What additional information should DEC include with the annual fuel adjustment application?

A. DEC has the obligation to show that test period natural gas supply costs were reasonable and prudently incurred. In particular, DEC must demonstrate that the gas supply resources under contract were necessary to obtain a reliable supply fuel for electricity generation at a reasonable cost, and that gas supply resources were prudently managed to reduce the costs charged to electricity customers. To make this demonstration, DEC should augment the annual fuel adjustment application to include the following information:

1. DEC should include a table showing the sources and uses of natural gas for each month. "Sources" would include total gas purchased and gas withdrawn from storage. "Uses" would include gas retained by transporters, gas injected into storage, gas used for power generation, and third-party sales. This information will allow the Commission, the Public Staff, and intervenors to see how DEC procured and managed natural gas supplies during the test period.

2. DEC should provide a table listing all firm transportation and storage contracts, both long-term and short term, held by DEC or DEP that were in effect during the test period. For each transportation agreement, DEC should identify the contract holder, the transporter, contract number, rate schedule, contract quantity, daily quantity entitlement at each receipt point, daily quantity entitlement at each delivery point, contract start date, contract expiration date. This will identify the natural gas supply resources that are

currently available, and the duration of existing commitments to pipeline and storage services.

3. DEC should report the reservation charges paid for firm transportation and storage services, by month. This information is needed to quantify DEC customers' exposure to fixed natural gas supply costs.

4. DEC should report the sales quantity, revenue and margin from third-party sales, and the revenue from the capacity release and AMA transactions. This will show the extent to which DEC was able to offset fixed transportation and storage costs using capacity optimization transactions.

5. The testimony supporting the fuel cost adjustment request should include a narrative identifying the changes to natural gas supply resource commitments that occurred during the test period, or are expected to occur during the billing period. This testimony should explain how decisions to enter into new long-term contracts for firm transportation or storage service, or extend the term of an existing agreements (including evergreen contracts), will benefit customers.

Q. Does the fact that the DEC and DEP natural gas supply assets are managed on a combined basis affect how this information should be reported?

A. Yes. Natural gas quantities and costs should be provided on a combined basis, with worksheets showing how quantities and costs are allocated. Because DEC uses the gas supply resources under contract to DEC and DEP to meet the fuel requirements for all plants, the current reporting, which only presents gas use and total allocated gas supply costs for DEC-owned plants, does not demonstrate that these gas supply resources were actually needed, or show whether DEC is prudently managing these assets to reduce the costs charged to customers.

Q. What other information should DEC be prepared to provide, if requested?

A. DEC should be prepared to provide daily gas use for each DEC and DEP plant.[17] To assess the need for firm transportation capacity to supply DEC and DEP plants, it is important to see both average and peak daily use, and when during year gas use is highest. Because the value of firm gas delivery is likely to be higher for a baseload generating plant without alternate fuel capability, and lower for a dual-fueled peaking plant, it is important to see which plants are using gas each day. DEC should also be prepared to provide the daily scheduled quantities for each firm interstate transportation agreement to show how these resources are being utilized.

Q. Does this complete your testimony?

A. Yes, it does.

[17] Sierra Club Data Request 1-11 asked for the maximum daily gas consumption for each plant over the test period. DEC objected on the grounds that the information "is not readily available and production of the requested information would be unduly burdensome." Because natural gas transporters measure the gas delivered at each meter, and electricity generators keep track of fuel use at their facilities, DEC should be expected to have ready access to daily gas consumption data for each of its plants.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of John A. Rosenkranz on behalf of the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of May, 2020.

s/ Gudrun Thompson

Gudrun Thompson

JOHN A. ROSENKRANZ
56 Washington Drive
Acton, MA 01720
(617) 755-3622
jrosenkranz@verizon.net

PROFESSIONAL EXPERIENCE

North Side Energy, LLC, Acton, MA 2006 – Present
PRINCIPAL

Consultant to energy companies, government agencies and natural gas consumers. Project areas include:
- Gas distribution company resource planning and procurement practices.
- Fuel supply for power generation and electric-gas interface issues.
- Natural gas transmission and storage cost allocation.
- Market studies and avoided cost analysis.

Calpine Corporation, Boston, MA 2000 – 2006
DIRECTOR, GAS ORIGINATION

Developed and implemented fuel supply plans for gas-fired power plants in the Northeast U.S. and Eastern Canada. Negotiated and managed contracts with natural gas suppliers and transporters.
- Testified on the availability of natural gas supply and pipeline delivery capacity to support the permitting of a gas-fired power plant in the Midwest.
- Supported arbitration cases to enforce long-term natural gas contracts.

PG&E Gas Transmission, Boston, MA and Portland, OR 1997 – 1999
DIRECTOR, BUSINESS DEVELOPMENT

Identified and managed development projects and investment opportunities involving natural gas pipelines, underground storage and LNG peaking plants.
- Project manager for a natural gas storage feasibility study in the Pacific Northwest.
- Owner representative and management committee member for the Iroquois Gas Transmission System and Portland Natural Gas Transmission System partnerships.

MANAGER, PROJECT DEVELOPMENT – J. Makowski Company, Boston, MA 1992 – 1997
Supervised a team that provided project management and marketing support for natural gas pipeline and storage projects. Conducted regional gas market studies for internal projects and outside clients.

VICE PRESIDENT - EnerPro, Inc., Chicago, IL 1990 – 1992
Consultant to gas distribution companies. Helped clients define gas portfolio objectives, draft requests for proposals, evaluate suppliers, and negotiate long-term gas purchase contracts.

MANAGER, GAS MODELING GROUP - Planmetrics, Inc., Chicago, IL 1986 – 1990
Provided consulting support to gas distribution companies on gas dispatch modeling and cost forecasts.

ADVISORY ECONOMIST - Chicago Board of Trade, Chicago, IL 1983 – 1986
Researched commodity markets for futures and options trading potential. Prepared a natural gas futures trading proposal that was submitted to the Commodity Futures Trading Commission.

EDUCATION

Graduate study in Economics - Northwestern University**,** Evanston, IL
Completed all course and examination requirements for Ph.D.

Bachelor of Arts, Economics - George Washington University, Washington, DC

RECENT REGULATORY PROCEEDINGS

Natural Gas Supply Planning and Cost of Gas

National Grid Denial of Service Investigation
Case #: New York Public Service Commission Case 19-G-0678
Client: Eastern Environmental Law Center
Scope: Comments on National Grid Long-Term Capacity Report

Liberty Utilities (EnergyNorth) Proposed Transportation Agreement with Tennessee Gas Pipeline
Case #: New Hampshire PUC Docket 14-380
Client: Pipe Line Awareness Network for the Northeast, Inc.
Scope: Testimony on alternatives to a proposed long-term pipeline transportation contract.

Liberty Utilities (EnergyNorth) Granite Bridge Project
Case #: New Hampshire PUC Docket 17-198
Client: Pipe Line Awareness Network for the Northeast, Inc.
Scope: Testimony on proposed intrastate pipeline and LNG peaking facility.

Berkshire Gas Company 2016 Integrated Resource Plan
Case#: Massachusetts DPU Docket 16-103
Client: Town of Montague
Scope: Testimony on alternatives for ending moratorium on new gas service.

Berkshire Gas Company Long Term Contract Approval
Case#: Massachusetts DPU Docket 15-178
Client: Town of Montague
Scope: Testimony on alternatives to a proposed long-term gas transportation contract.

Bangor Natural Gas Company Request for Contract Approvals
Case#: Maine PUC Docket 2019-00105
Client: Maine Public Advocate
Scope: Testimony on proposed long-term gas transportation contracts.

Northern Utilities, Inc. Integrated Resource Plans
Case #: Maine PUC Dockets 2015-00018 and 2011-00526
Client: Maine Public Advocate
Scope: Prepare discovery requests and participate in technical conferences.

Northern Utilities, Inc. Cost of Gas Factor Cases
Case #: Annual, 2012 to present.
Client: Maine Public Advocate
Scope: Review cost of gas filings. Prepare discovery requests and participate in technical conferences.

South Jersey Gas Company Basic Gas Supply Service Reviews
Case #: Annual. 2013 to present
Client: New Jersey Division of Rate Counsel
Scope: Draft discovery requests, prepare written report, and support settlement negotiations.

Elizabethtown Gas Capacity Management Plan
Case#: New Jersey BPU Docket GO13040272
Client: New Jersey Division of Rate Counsel
Scope: Prepare discovery requests and participate in settlement negotiations.

Cost Allocation and Rates

Union Gas 2014 Rate Case
Case #: Ontario Energy Board Case EB-2013-0365
Client: Canadian Manufacturers & Exporters and other consumer groups
Scope: Testimony recommending changes to the allocation of transmission costs.

Northern Utilities Approval of Affiliated Interest Transaction
Case #: Maine PUC Dockets 2011-00302, 2012-00393, and 2013-00259
Client: Maine Public Advocate
Scope: Review proposed contract with pipeline affiliate. Examine rate implications for sales customers.

Granite State Gas Transmission, Inc. Rate Case
Case #: FERC Docket No. RP10-896
Clients: Maine Public Advocate and MPUC Staff
Scope: Review rate case application. Participate in settlement negotiations.

Maritimes & Northeast Rate Case
Case #: FERC Docket No. RP04-360
Client: Calpine Corporation
Scope: Testimony on distance-based rates.

Natural Gas Markets

Merger of The Southern Company and AGL Resources, Inc.
Case #: New Jersey BPU Docket GM15101196
Client: New Jersey Division of Rate Counsel
Scope: Testimony on potential affiliate preference in asset management arrangement.

Union Gas 2016 Dawn Parkway Expansion Project
Case #: Ontario Energy Board Case EB-2014-0261
Client: Canadian Manufacturers & Exporters and other consumer groups
Scope: Testimony on market developments that may reduce Northeast U.S. companies' demand for Canadian gas transportation services.

Ontario Natural Gas Market Review
Case #: Ontario Energy Board Cases EB-2014-0289 and EB-2010-0199
Client: Canadian Manufacturers & Exporters and other consumer groups
Scope: Written and oral submissions on natural gas market issues.

Enbridge Gas Distribution GTA Project
Case #: Ontario Energy Board Case EB-2012-0451
Client: Green Energy Coalition
Scope: Prepare discovery requests on the need for a proposed expansion project.

Portland Natural Gas Transmission System Rate Case
Case #: FERC Docket RP10-729
Client: Maine Public Advocate
Scope: Rebuttal testimony on the market risks faced by the pipeline.

Natural Gas for Power Generation

New Jersey Natural Gas Service Agreement for Red Oak Power
Case #: New Jersey BPU Docket GO13010059
Client: New Jersey Division of Rate Counsel
Scope: Prepare discovery requests and participate in settlement negotiations.

Ontario Integrated Power System Plan
Case #: OEB Case EB-2007-0707
Client: Ontario Power Authority
Scope: Report on the implications of increased gas-fired power generation for the Ontario gas market.

Natural Gas Electricity Interface Review
Case #: OEB Case EB-2005-0551
Client: Association of Power Producers of Ontario
Scope: Written evidence on power generators' gas service needs. Expert witness at hearing.

Greenfield Energy Centre Leave to Construct
Case#: Ontario Energy Board Case EB-2005-0441
Client: Greenfield Energy Centre
Scope: Witness supporting application to construct a gas supply pipeline.

Rulemakings

Storage and Transportation Access Rules
Case #: Ontario Energy Board Case EB-2008-0052
Client: Ontario Energy Board Staff
Scope: Report on transporter and storage operator conduct and reporting requirements in other jurisdictions. Assist in drafting proposed rules and reviewing intervenor comments.

Guidelines for Pre-Approval of Long-Term Gas Supply Contracts
Case #: Ontario Energy Board Case EB-2008-0280
Client: Ontario Energy Board Staff
Scope: Assist Board Staff in evaluating policy options.

CONFIDENTIAL

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1228
Fuel and Fuel-Related Cost Proceeding
Test Year Ended December 31, 2019
SIERRA CLUB Data Request No. 1-8
Date Sent: 5/4/2020
Requested Due Date: 5/4/2020

REQUEST:

Reference: Phipps Exhibit 1, page 1. For each Duke Energy Carolinas plant that burned natural gas during the test period, please identify the gas transporter(s) connected to the plant. For plants with direct connections to an interstate pipeline, please identify the transporter deliver meter.

CONFIDENTIAL RESPONSE:

Please see the CONFIDENTIAL attachment.

2020 DEC SC DR 1-8
CONFIDENTIAL NG Tr

Response provided by:
Tiffany Weir, Regulatory Strategy Manager

Duke Energy Carolinas, LLC **CONFIDENTIAL**
Sierra Club 1-8 - Natural Gas Pipeline Firm Gas Transportation Agreements (Intrastate and Interstate)
Test Period: 1/1/19-12/31/19

Plant	Meter Number*	Interconnect
Belews Creek	Duke VAD (9004742)	Piedmont
Buck	Duke VAD (9004742)	Piedmont
Cherokee (Tolled)	07334	Transco
Clemson CHP	1006669	Fort Hill NGA
Cliffside	PSNC VAD (1006608)	PSNC
Dan River	Duke VAD (9004742)	Piedmont
Lincoln	Duke VAD (9004742)	Piedmont
Mill Creek	Duke VAD (9004742)	Piedmont
Rockingham	Duke VAD (9004742)	Piedmont
WS Lee CC	Duke VAD (9004742)	Piedmont
WS Lee CT	Duke VAD (9004742)	Piedmont

*Note, most DEC natural gas plants do not directly connect to interstate pipelines. For these plants, DEC uses a single Transco VAD.

<u>Duke Energy Carolinas, LLC</u>
Docket No. E-7, Sub 1228
Fuel and Fuel-Related Cost Proceeding
Test Year Ended December 31, 2019
SIERRA CLUB Data Request No. 1-5
Date Sent: 5/4/2020
Requested Due Date: 5/4/2020

<u>REQUEST</u>:

Reference: Phipps Exhibit 1, page 1, and Phipps Exhibit 2, page 2. For each month of the test period, please break out the total gas purchase quantity in Exhibit 2 to show: (a) the gas quantity that was transported to plants using a Duke Energy Carolinas or Duke Energy Progress long term firm transportation agreement, (b) the gas quantity that was transported to plants using a shorter term pipeline capacity purchase, and (c) the gas quantity that was delivered to plants by the gas seller.

<u>RESPONSE</u>:

DR 1-5 requests information that is not reasonably available as it relates to tying the gas purchase quantity in Exhibit 2 to (a) the gas quantity that was transported to plants using a Duke Energy Carolinas or Duke Energy Progress long term firm transportation agreement, (b) the gas quantity that was transported to plants using a shorter term pipeline capacity purchase, and (c) the gas quantity that was delivered to plants by the gas seller.

Please see the attached Excel file showing the total natural gas purchases by month as well as the total 3rd party delivered natural gas purchases together with the daily firm long term and short term capacity available by month to transport non-3rd party delivered gas supply to the Transco Duke VAD referenced in DR 1-8.

PDF
2020 DEC SC DR 1-5
Natural Gas Purchase

Response provided by:
Tiffany Weir, Regulatory Strategy Manager

Duke Energy Carolinas, LLC
Sierra Club 1-5 - Total gas purchase quantity, 3rd party delivered gas & available transportation capacity
Test Period: 1/1/19-12/31/19

Note: E-7 Sub 1228- 2020 DEC NC Fuel - Phipps Exhibit 2 presents gas receipts by DEC Generating Stations only, excluding receipts by DEP Generation Stations and DEP tolling facilities as they are outside the scope of the DEC fuel proceeding and DEC tolling Facilities as they are reviewd as purchased power expense. The following is a breakout of actual gas purchases for the test period 1/1/2019-12/31/2019. DEC is the face to the market and purchases natural gas supply and transportation for both DEC and DEP on a combined basis. Given this, the purchased and available transportation capacity below are for DEC and DEP combined and the costs/volumes are allocated based on actual burns according to the NCUC AMA approved methodology. The exception to this are gas purchase contracts for NC REPS requirements.

	Total Monthly Purchases (Mbtu/Month)	Monthly 3rd Party Deliveries (Mbtu/Month)	Contracted Long Term Transportation Capacity (Mbtu/day)	Contracted Short Term Transportation Capacity (Mbtu/day)
Jan-19	27,116,131	16,502,867	434,560	0
Feb-19	26,803,938	16,688,277	434,560	0
Mar-19	23,163,935	9,301,002	434,560	45,239
Apr-19	21,521,450	9,048,041	434,560	30,000
May-19	22,851,291	8,867,692	434,560	70,000
Jun-19	25,207,732	11,786,761	434,560	70,000
Jul-19	29,036,804	15,660,366	434,560	70,000
Aug-19	29,523,737	15,105,607	434,560	70,000
Sep-19	28,945,719	15,303,090	434,560	70,000
Oct-19	25,758,461	10,991,992	434,560	30,000
Nov-19	23,074,372	10,120,869	434,560	18,779
Dec-19	25,678,758	12,795,044	434,560	18,779