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May 17, 2022

Via Electronic Filing

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

Re: Direct Testimony and Exhibits of Gregory M. Lander – PUBLIC VERSION
(Docket No. E-7, Sub 1263)

Dear Ms. Dunston:

Please find enclosed for filing in the above-referenced proceeding on behalf of the Sierra Club the Direct Testimony and Exhibits of Gregory M. Lander – PUBLIC VERSION. By copy of this letter, I am serving a copy of the same on the parties of record.

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

Sincerely,

s/ Gudrun Thompson

Enclosures

cc: Parties of record

PUBLIC VERSION
Confidential Information Redacted

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
Application of Duke Energy Carolinas,	)	**DOCKET NO. E-7, SUB 1263**
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 AND EXHIBITS OF
GREGORY M. LANDER

ON BEHALF OF
THE SIERRA CLUB

May 17, 2022

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Gregory M. Lander. I am President of Skipping Stone, LLC ("Skipping Stone"). As President, I lead Skipping Stone's Energy Logistics and Energy Contracting practice line. My business address is 83 Pine Street, Suite 101, Peabody, MA 01960.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from Hampshire College in Amherst, Massachusetts in 1977 with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in Citizens Energy's natural gas business in 1983. Between 1983 and 1989, I served as Manager, Vice President, President, and Chairman of Citizens Gas Supply Corporation, a subsidiary of Citizens Energy. I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, FERC Section 4 pipeline general rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, producers and industrial end-user matters, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded Trans Capacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). Between 1994 and 2002, I served as a Chairman of the Business Practices Subcommittee, along with serving on the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces.

I am currently a NAESB Board Member and have served continuously in that capacity since 1997. Skipping Stone acquired Trans Capacity in 1999, and since that time, I have led Skipping Stone's Energy Logistics and Energy Contracting practices, where I have specialized in interstate pipeline capacity issues, information, research, pricing, acquisition due diligence, and planning.

From 1984 to the present, I have maintained a deep familiarity with a wide range of pipeline transportation and contracting issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and determining what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process(es). I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on over fifty pipeline and storage mergers and acquisitions transactions, as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. HAVE YOU FILED TESTIMONY IN REGULATORY PROCEEDINGS BEFORE?

A. Last year, I pre-filed direct testimony with the North Carolina Utilities Commission ("Commission") in Docket No. G-5, Sub 635, on behalf of Haw River Assembly and in connection with Public Service Company of North Carolina, Inc.'s application filed pursuant to N.C. Gen. Stat. § 62-133.4 and Commission Rule R1-17(k)(6) for review of its gas costs. In addition, I have filed testimony and/or reports in several proceedings before FERC and other state public utility commissions, including in Maine, Massachusetts, New York, New Jersey, Missouri, California, the District of Columbia, Virginia, and South Carolina. Please refer to Exhibit GML-1 for my current curriculum vitae and Exhibit GML-2 for a full list of cases in which I have filed testimony.

II. Testimony Overview

Q. WHAT ISSUES DO YOU ADDRESS IN YOUR TESTIMONY?

A. I will address the degree to which Duke Energy Carolinas' reliance on fossil-fueled generation, specifically gas-fired generation, exposes ratepayers to significant fuel price risk, and I will provide recommendations to address and potentially mitigate ratepayers' exposure to this cost risk. First, I will briefly summarize the fossil fuel and fuel related costs Duke Energy Carolinas, LLC ("DEC" or "the Company") seeks to recover in this proceeding, with a focus on gas[1] costs. As is evident from DEC's requested fuel charge adjustment, recent high and increasingly volatile gas prices are heavily impacting DEC ratepayers' electricity costs. I will then discuss some of the strategies utilities adopt to mitigate their customers' exposure to fossil fuel price volatility. I will also highlight some of the measures DEC employed to mitigate its customers' exposure and identify the limits of such strategies, even if they are helpful in the short-term. I will then highlight how fuel-free renewable energy can help DEC mitigate its customers' exposure to fossil fuel price volatility. Lastly, I will propose certain planning and forecasting recommendations that will help DEC anticipate and respond to future gas price volatility.

[1] As used in this testimony, the term "gas" refers to methane gas produced from wells and transported by pipeline(s) to consumption sites.

III. Reliance on Fossil Fuels Exposes Ratepayers to Risk

Q. PLEASE BRIEFLY DESCRIBE THE COSTS THAT DEC SEEKS TO RECOVER IN THIS PROCEEDING.

A. The Company is seeking to collect unrecovered fuel and fuel related costs that were incurred during the 2021 calendar year ("the Test Period"), as well as estimated costs for the September 1, 2022 through August 31, 2023 billing period ("the Billing Period"). With respect to the Test Period, the Company initially sought $245 million in under-recovery. As detailed in the Company's supplemental testimony, that under-recovery grew by another $81.99 million from just the under-recovery in January 2022, with the Company's total under-recovery amounting to $326.97 million. One significant factor was the increase in gas prices last year when compared to the Company's approved 2021 price projections. From my review and analysis of the Company's discovery responses, the Company's total gas costs in 2021 were $[redacted][2] or about $[redacted] million per month on average. Accordingly, the January 2022 under-recovery was more than half the 2021 average monthly amount spent on gas – representing over a 50% increase in cost in one month.

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[2] These total gas costs were listed in the Company's response to SC-DEC 1-1. These purchases may also include purchases made by Company and re-sold (i.e., not burned). My analysis of SC-DEC 1-1 shows total purchases of [redacted] million dth for the Test Period versus a Company reported "Burn" of 189.6 Million dth. However, for the purposes of this testimony, inclusion of such purchase volumes and associated prices does not change any observations or conclusions herein.

The total fossil fuel costs used to calculate the Company's proposed fuel factor are $1.234 billion. The Company's system fuel expense for fuel factor is $1.671 billion, with fossil fuels accounting for 73.89% of the system expense.

The Company reports a gas burn of 189.6 million dth for the Test Period. With respect to the Billing Period, the Company projects that its gas burn will be 242 million MMBtu, which is a projected increase of 27% over the Company's Test Period burn. With regard to the Billing Period burn, it is not clear why DEC witness John A. Verderame states that "[t]he Company now expects projected natural gas burn volumes to be reduced based on delays in anticipated lower cost supply coming into the portfolio."[3] After all, a projected 27% increase is an increase, not a reduction.

Q. PLEASE SUMMARIZE THE IMPACT TO DEC CUSTOMERS' BILLS IF THE COMMISSION APPROVES DEC'S FUEL CHARGE ADJUSTMENT APPLICATION.

A. DEC's proposed fuel charge adjustment would result in a $9.85 increase to the monthly bill of a typical residential customer that uses 1,000 kilowatt hours of electricity each month. However, looking at just the increase in the fuel factor for residential customers, the increase from 1.5014 cents per kWh to 1.9315 in the initial filing represents a 28.6% increase in that component of residential bill charges. This is a significant increase at a time when DEC's customers

[3] Direct Testimony of John A. Verderame, page 9, lines 22-23.

are already saddled with higher grocery bills, gasoline prices, and consumer good costs due to inflation.

Q. WHAT FINANCIAL RISKS DO FOSSIL FUELS POSE TO UTILITY RATEPAYERS?

A. The primary financial risk that fossil fuels pose to utility ratepayers is significant price volatility, especially for gas. This volatility is driven by domestic as well as international supply and demand considerations, as I discuss below. Because approved fuel costs are typically passed through to ratepayers and recovered through fuel clause adjustments or "riders," like the one at issue in this proceeding, ratepayers are exposed to the risk of gas price increases.

Q: WHY DO YOU ONLY FOCUS ON THE FORECASTED IMPACT OF GAS PRICE SPIKE(S)?

A: From my review of the Company's discovery responses, DEC had 1,677 separate "Deal No." transactions recorded over the course of the Test Period and paid 689 different prices under those "deals." Prices change every day and month in the gas industry, which is reflected in the relevant daily and monthly markets. Moreover, as mentioned, ratepayers can be negatively impacted when these prices dramatically increase.

Q. PLEASE DISCUSS THE FACTORS THAT, IN YOUR VIEW, ARE CONTRIBUTING TO THE SIGNIFICANT, RECENT GAS PRICE INCREASES.

A. Fossil fuel prices, especially gas prices, are inherently volatile, and are subject to domestic—and increasingly, international—supply and demand factors.

Domestically, gas demand is the key driver. Demand for gas for power generation is relatively inelastic because there are few commercially viable substitutes other than aggressive adoption of renewable energy and storage. Indeed, given recent price volatility, even diesel oil is no longer a commercially viable substitute. Similarly, there has been slow adoption of economically viable substitutes for other gas end uses such as heating. Seasonal demand for gas is heavily weather dependent, both for heating and power generation. As Company witness Verderame notes, "stable production, lower than average storage inventory balances and seasonal weather demand" have contributed to recent gas price volatility.[4] In addition, the gas industry is capital-intensive, and it is difficult for gas suppliers to rapidly ramp up or scale down production in response to market signals.

Furthermore, in 2021, the U.S. economy, along with many other countries', finally began to recover from the economic downturn that dominated much of the beginning of the COVID-19 pandemic.[5] Resulting pent up commercial and industrial demand exerted significant upward pressure on gas prices. The U.S. is also projected to become the world's largest exporter of liquified natural gas ("LNG").[6] As domestic LNG

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[4] Direct Testimony of John A. Verderame, page 8, lines 2-3.
[5] Scott Divasino, *U.S. natgas volatility jumps to a record as prices soar worldwide*, REUTERS (Oct. 7, 2021), https://www.reuters.com/business/energy/us-natgas-volatility-jumps-record-prices-soar-worldwide-2021-10-06/.
[6] Scott Divasino, *U.S. to be world's biggest LNG exporter in 2022*, REUTERS (Dec. 21, 2021), https://www.reuters.com/business/energy/us-be-worlds-biggest-lng-exporter-2022-2021-12-21/.

suppliers struggle to construct additional LNG plants and establish additional LNG export terminal capacity, "competition for limited . . . [existing LNG] exports increases,"[7] which in turn increases gas prices. In turn, financial markets struggle to respond to these domestic and international developments, which further exacerbates price volatility. In 2021, "the wholesale spot price for natural gas at the Henry Hub in Louisiana averaged $3.89 per million British thermal units (MMBtu) in 2021," which is almost double the 2020 average.[8]

Q. HOW LONG CAN RATEPAYERS EXPECT THESE PRICE INCREASES TO PERSIST?

A. For many reasons, ratepayers can expect these price increases to persist for the foreseeable future. However, for the sake of brevity, I will highlight just three reasons. First, Europe seeks to sharply reduce its Russian gas imports, which will likely mean increased U.S. LNG exports and the construction of additional U.S. export facilities to ensure the increased flow of U.S. LNG exports. Second, Marcellus/Utica producers in Southwestern Pennsylvania have been reluctant to increase production beyond the amount necessary to keep their pipeline capacity contracts full; this is because increasing production beyond that level would exceed their takeaway capacity and

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[7] *Supra* note 5.
[8] U.S. Energy Information Admin., *U.S. natural gas prices spiked in February 2021, then generally increased through October* (Jan. 6, 2022), https://www.eia.gov/todayinenergy/detail.php?id=50778#:~:text=The%20wholesale%20spot%20price%20for,according%20to%20data%20from%20Refinitiv.

would, as a result, depress the prices they receive for the quantity of gas that exceeds their contracted takeaway capacity. Third, gas producers are using their profits from their gas sales to reduce their debts, pay shareholders dividends, or buy back stock.

IV. Risk Mitigation Strategies

Q. HOW CAN UTILITIES MITIGATE THEIR CUSTOMERS' EXPOSURE TO FOSSIL FUEL PRICE VOLATILITY?

A. Generally, utilities use hedging to help reduce volatility and to stabilize prices for a portion of their generation fuel supply. There are at least three ways in which a utility can hedge its fuel costs against price volatility. First, a utility could buy a financial instrument, such as a future on a regulated exchange. While these products do not provide the utility or the utility's customers with actual electricity, they do offer, for a limited portion of a utility's purchases, a means of either fixing a utility's purchased energy prices or offsetting the utility's energy costs with revenue from the financial product(s).

Second, a utility could purchase the option to buy a quantity of fuel over a specified time period. These transactions can be structured upfront as "costless" or "cost free" products if the utility adopts a collar strategy. Under this scenario, the utility would purchase a "call" option from a counterparty, which would then give the utility the right to purchase a specific quantity of gas at a specific price. The utility would then simultaneously sell a "put" option to that counterparty, which would give the counterparty the right to induce the Company to sell that same quantity of gas at a specific price. This collar strategy is effectively "free" and "costless" when each party agrees to set the floor and ceiling price in return for the same, offsetting payment. Accordingly, this strategy minimizes the utility's exposure to gas price increases. Should gas prices drop below the floor price of the collar, the utility will be required to buy gas at that floor price, or pay the counterparty an amount reflecting the difference between the floor price and the market price times the specified quantity. But again, this would involve only a limited portion of the utility's fuel purchases, leaving ratepayers exposed even under the most fortuitous of transactions.

Third, as discussed later in my testimony, a utility could employ "physical hedging" to protect ratepayers against the risk of fuel price volatility by procuring or self-building energy that has no fuel costs, such as wind or solar.

Q. WHAT ARE THE LIMITATIONS OF FINANCIAL HEDGING?

A. A utility cannot economically hedge its future fuel costs below forecasted prices (i.e., the prices the New York Mercantile Exchange ("NYMEX") and other exchanges present for the future period). Another limitation is that a utility must avoid "over-hedging." Said another way, a utility must ensure that it does not hedge a volume that exceeds its projected burn for the same time period the hedge would cover. At bottom, financial hedging can only reliably reduce volatility. It neither eliminates volatility nor permits a utility to secure future gas prices below forecasted, future prices.

Q. WHAT DO YOU CONCLUDE REGARDING THE IMPACT OF THE COMPANY'S HEDGING ACTIVITIES ON ITS INCURRED FUEL COSTS?

A. Based upon my review of the Company's discovery responses, I conclude that those volumes the Company chose to hedge appear to have delivered savings to the Company's customers. In addition, I conclude that even if the Company had hedged a greater portion of its purchases, it would not have fully insulated ratepayers from higher prices or volatility for the unhedged gas purchases. Importantly, these savings were only achieved because prices exceeded projections, and were largely the result of sustained commodity price increases in the Test Period when compared to the prices the sellers of those hedge products forecasted. This means that future savings might not be achieved and even losses would be realized if gas prices were stable at any level or decreased.

To further illustrate this point, when future gas prices are forecasted to be high and continue to be high relative to 2020 prices, which is currently the case, one cannot buy a hedge product below what the NYMEX indicates the price will be in the future. For instance, in mid-May 2020, the July 2022 price on the NYMEX was $2.365. In mid-May 2021, the July 2022 price on the NYMEX was $2.649. In mid-September 2021, the July 2022 price on the NYMEX increased to $3.797, and in mid-April 2022, the July 2022 price on the NYMEX had almost doubled to $6.839. As of Monday, May 16, 2022, the July 2022 price is $8.0530.

All this underscores the limits of financial hedging, which, it bears repeating, can only stabilize future prices or reduce, but not eliminate price volatility. Furthermore, as I have explained, a utility cannot economically hedge at prices below market forecasts.

Q: WHAT OTHER ASPECTS OF THE COMPANY'S HEDGING TRANSATIONS MERIT FURTHER DISCUSSION?

A: In my review of the Company's execution dates of its financial hedge transactions, I found that the latest execution date for any December 2021 Henry Hub hedge was in July 2020 and no Henry Hub hedges for any part of 2021 were executed after July 2020.

In addition, the latest hedge execution date for December 2021 Transco Zone 4 gas was in May 2021 and there were no other hedges for Transco Zone 4 gas executed after May 2021. Finally, the most recent execution date for a "costless collar" transaction was in September 2021 for December 2021.

Q: WHAT IS THE SIGNIFICANCE OF THESE DATES?

A: In mid-2020 and up through May and even September 2021, gas pricing in the U.S. and international gas markets was rather low, due in large part to depressed demand associated with the COVID-19 pandemic. The timing of those 2020 and 2021 hedge transaction executions and the value ratepayers received from them reflect the state of the gas market at the time of the executions. Put simply, the significance of these dates is that the 2020 hedges for 2021, along with the "costless collar" transactions for 2021, benefitted ratepayers precisely because gas prices increased. Hence, for the portion of the gas supply that the Company hedged, ratepayers benefitted but, for the roughly [redacted]% of supply that was purchased at the market price at the time (i.e., without offsetting hedges), ratepayers will now have to pay higher energy prices for electricity to recoup not only under-recoveries but also higher forecasted prices in the future. In short, fortuitous hedging helps, but it cannot entirely eliminate ratepayer exposure to rising and/or volatile fossil fuel prices, especially gas prices. As I discuss below however, a utility can potentially secure future energy prices through a physical hedging approach that both eliminates volatility and delivers lower prices than the NYMEX's current gas prices.

Q. YOU PREVIOUSLY DISCUSSED THE USE OF PHYSICAL HEDGING PRODUCTS TO MINIMIZE CUSTOMERS' EXPOSURE TO FOSSIL FUEL PRICE VOLATILITY. PLEASE ELABORATE.

A. Because wind and sunshine are free, there is no fuel price for wind energy and solar energy. Once wind turbine and solar panel investments have been made, the only variable costs are operations and maintenance costs, which can be fixed by contract. Conversely, investments in new gas-fired generation only fix capital costs and possibly maintenance. They do not fix energy costs and instead subject ratepayers to potential pass-throughs of fuel costs that are subject to market vagaries.

The U.S. Energy Information Administration ("EIA") released a 2022 report that estimates that the Levelized Cost of Energy ("LCOE") for different renewable energy resources.[9] The LCOE for utility scale wind, including tax credits, is $26.15 per MWh. For utility scale solar, the estimated LCOE, including tax credits, is $26.69 per MWh. Without tax credits, the LCOE is $34.92 per MWh for wind and $33.07 for solar. These estimates do not take into account financing costs, or utility returns in the event a regulated utility is making these investments. Nevertheless, these LCOE for wind and solarcompare quite favorably to the average cost per MWh for gas-generated energy, which over the January 2023 to January 2033 period has an estimated average cost to the Company of $35.01/MWh.[10] Moreover, the LCOE for Wind and Solar are not subject to the same price volatility, as they have zero fuel costs. These data points are presented in Figure GML-1, below.

[9] U.S. Energy Information Admin., Levelized Costs of New Generation Resources *in the Annual Energy Outlook 2022* 17 (2022), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[10] I calculated this figure by taking the NYMEX closing prices on May 6, 2022 for the period of January 2023 through January 2033 and averaging them. I then used the price difference between the average price per dth of the Company's delivered gas and the gas Company purchased "into the pipe" or $[redacted] per dth and added this difference (as an adder) to the NYMEX average price for only the estimated delivered gas portion of the Company's purchases (i.e., [redacted]%). Then, for this [redacted]% of the Company's purchased gas on a delivered basis, I multiplied the NYMEX price combined with the adder by 7.2 (an estimated annual average heat rate for the Company's baseload gas fired generation facilities) and multiplied that number by [redacted]%. Then for the [redacted]% of Company's purchased gas "into the pipe", I multiplied the NYMEX price (without the adder) by 7.2 and multiplied that number by [redacted]%. I then added those two amounts to get an estimated 100% of purchased gas to generate a MWh cost of $35.01/MWh on average from January 2023 through January of 2033.

<u>Figure GML-1 – Comparison of Gas, Utility Scale Wind, and Utility Scale Solar Costs[11]</u>

	Average Cost	**LCOE – Without Credits**	**LCOE – With Tax Credits**
Utility Scale Wind	N/A	$34.92/MWh	$26.15/MWh
Utility Scale Solar	N/A	$33.07/MWh	$26.69/MWh
Methane Gas	$35.01/MWh	N/A	N/A

Q. WHAT ARE SOME OF THE ADVANTAGES OF USING RENEWABLES AS PHYSICAL HEDGING PRODUCTS?

A. The Commission has previously recognized that renewable energy resources provide fuel hedging value:

> Renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a [Qualifying Facility] reduces the amount of fuel the utility otherwise would need to purchase. In doing so, the Commission acknowledged that purchasing solar power can be seen as the equivalent of buying natural gas forwards. . . . the Commission finds that the evidence in this proceeding demonstrates again that there are fuel price hedging benefits associated with renewable generation. Purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that must be purchased and, therefore, the costs that the utilities would incur toward fuel procurement. . . . The Commission agrees with Cube Yadkin that the value of the hedge is to insulate ratepayers from

[11] These figures are drawn from the EIA's 2022 LCOE of new generation resources, *see* https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf, and my calculations, *see* supra note 8.

> fuel volatility, and that the hedge value is appropriate for inclusion in avoided cost rates.[12]

Although the Commission reached these findings in the context of determining utility avoided costs, the same logic applies here to the value that physical hedges, either from the procurement or construction of renewable energy resources, provide by supplying fuel-free power to DEC ratepayers.

Q. COULD DEC HEDGE A PORTION OF ITS ENERGY NEEDS BY PROCURING OR SELF-BUILDING WIND AND SOLAR GENERATION IN LIEU OF GAS GENERATION?

A. Yes. Wind and solar resources can not only fix the costs for a large portion of the Company's energy requirements, but also immunize the Company and its customers from gas price increases and spikes. To serve as effective fuel price hedges, of course, the wind and solar energy must either be purchased on a fixed price basis or generated by utility-owned facilities. Under either circumstance, the "fuel" costs are fixed at zero.

In short, in addition to providing capacity, energy, and other services to the electric grid, renewables provide hedging value, and the Commission should encourage the Company to obtain as much of that value as possible as part of the Company's comprehensive hedging strategy.

Q. YOU MENTIONED EARLIER THAT THERE WAS SOMETHING "MISSING FROM THE COMPANY'S FUEL COST PLANNING AND FORECASTING PRACTICES." PLEASE ELABORATE.

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[12] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158, (April 15, 2020).

A: An important element that is missing from the Company's fuel cost planning and forecasting practices is an additional forecast that measures and projects the impact on consumer bills of future fuel price spikes(s) if such spike (s) were to occur in the billing period used to establish the fuel factor.

The Company's fuel factor is based upon the net effect of two elements. One is the amount of over or under recovery during the test period. At a high level, the second element is the forecasted set of prices and purchases (i.e., forecasted, total cost of fuel) for the billing period. The sum of these two numbers, again at a high level, is then divided by the number of forecasted sales in the billing period to calculate a fuel factor that is applied to each sale(s) unit.

The purpose of this forecast would be to provide the Commission with a preview of the potential impact of such projected fuel price spike(s) and help inform the Company's strategy to reduce or mitigate its customers' exposures to future, projected price spikes.

Q. WHAT SPECIFIC RECOMMENDATIONS WOULD YOU THEN PROPOSE TO IMPROVE DUKE'S FUEL COST PLANNING AND FORECASTING PRACTICES?

A. The Commission should require the Company to incorporate the impact of periodic gas fuel price spikes into the Company's forecasted fuel costs. Specifically, the Company's planning and forecasting should incorporate the frequency, duration, and magnitude of prior upward fuel price departures of 15% or greater from the average price and use this historical data to inform its projections of the frequency, duration, and magnitude of future price spikes, along with the potential impacts of these future price spikes on customers if they were to recur. For instance, the Company could use trailing ten-years price spikes as the source data. The Company should then incorporate these projected impacts and compare them with its primary projections in future fuel charge adjustment proceedings.

Q. WHAT ADDITIONAL INFORMATION WOULD YOU RECOMMEND DEC FILE IN FUTURE FUEL CHARGE ADJUSTMENT PROCEEDINGS IN LINE WITH THESE RECOMMENDATIONS?

A. I recommend that with each future fuel charge adjustment filing, the Company should provide the prior period's month by month forecasts, specifically, both the average price forecast and a forecast incorporating the impact of potential, future price spike(s). This would enable comparisons (i.e., variances) to be made and would help both the Company and the Commission determine whether these variances were because the average prices varied or because prices were volatile.

V. Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS WITH RESPECT TO DEC'S REQUESTED FOSSIL FUEL AND FUEL-RELATED COSTS.

A. The Company's under-recovery of its fuel and fuel-related costs can be attributed in part to its gas price projections being lower than the actual market prices during the Test Period. These under-projections, among other things, will have significant bill impacts for DEC ratepayers, and are partially responsible for the estimated $9.85 increase to DEC monthly residential bills, assuming the Commission approves the Company's fuel charge adjustment application.

While all fossil fuels are inherently volatile, gas is particularly so due to domestic and international demand and supply considerations. Given this, financial hedging strategies can only mitigate customer exposure to this volatility in the short term, but cannot reliably reduce fuel prices over the long-term (i.e., over the period covered by investments in fuel-free generation).

To further mitigate customer exposure to fossil fuel price volatility, I would recommend that DEC forecast the impact of periodic deviations of at least 15% or greater from average gas prices on customer bills. Specifically, I would propose that the Company use trailing ten-years data of gas price spike(s) to inform its projections on the frequency, duration, and magnitude of future price spike(s). In future fuel charge adjustment proceedings, the Company should provide month by month fuel price forecasts that include the average gas price forecast and a "15%" or greater price spike forecast. This strategy would help the Company plan its response to future gas price volatility and help the Commission evaluate the Company's volatility mitigation strategies.

Lastly, the Company should use wind and solar energy to the fullest extent possible to hedge against fossil fuel price volatility. Depending on how these assets are structured, wind and solar energy facilities can supply a large portion of the Company's generation needs at a fixed cost, with little to no exposure to fossil fuel price volatility.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Gregory M. Lander – PUBLIC VERSION on behalf of the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 17th day of May, 2022.

s/ Gudrun Thompson
Gudrun Thompson

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.
- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by

synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Designed pipeline capacity release deal integrating settlement system for firm users, including design and development for information services delivery on a transaction fee basis.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all 60 major interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and

economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 "California Energy Crisis" and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm precedent, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients' attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, and supply contract proceedings as both up-front and behind the scenes expert.

<u>Associations and Affiliations:</u>

Longest serving Member of Board of Directors for NAESB and prior to that GISB - 25 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee.

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

GML Exhibit 2: Expert Testimony of Gregory M. Lander

Name of Case	Jurisdiction	Docket Number	Date
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP04-251-000	May 3, 2004 (Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP08-426-000	May 19, 2009 (Answering Testimony) June 2, 2010 (Supplemental Answering Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP10-1398-000	June 28, 2011 (Answering Testimony) March 4, 2014 (Answering Testimony)
Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company	Massachusetts Department of Public Utilities	13-157	December 12, 2013 (Direct Testimony)
Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate	Massachusetts Department of Public Utilities	15-34	June 5, 2015 (Direct Testimony)

pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project			
Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project	Massachusetts Department of Public Utilities	15-39	June 5, 2015 (Direct Testimony)
Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A	Massachusetts Department of Public Utilities	15-48	June 5, 2015 (Direct Testimony)
Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901	Maine Public Utilities Commission	2014-00071	July 11, 2014 (Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2017-00051	August 11, 2017 (Direct Testimony)
In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service	Missouri Public Service Commission	**File No. GR-2017-0215**	September 8, 2017 (Direct Testimony) Consolidated

In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service		**File No. GR-2017-0216**	and November 21, 2017 (Surrebuttal Testimony) Consolidated
Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019. Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	California Public Utilities Commission	Application 17-10-007 Application 17-10-008	Consolidated Direct Testimony May 14, 2018 Rebuttal Testimony June 8, 2018
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia	Virginia State Corporation Commission	PUR-2018-00067	Direct Testimony June 14, 2018
Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process	California Public Utilities Commission	Application 17-10-002	Direct Testimony July 2, 2018
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2018-00065	August 13, 2018 (Direct Testimony)
In the Matter of Constellation Mystic Power, LLC Docket No. ER18-1639	Federal Energy Regulatory Commission	ER18-1639	September 4, 2018 (Cross Answering Testimony)

South Carolina Electric and Gas Company Application for Approval of Merger with Dominion Resources Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E	South Carolina Public Service Commission	Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E	September 24, 2018 (Direct Testimony)
In re: Annual Review of Base Rates for Fuel Costs of South Carolina Electric and Gas Company	South Carolina Public Service Commission	Docket 2019-2-E	March 19, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service	New York Public Service Commission	Case 19-G-0066	May 24, 2019 (Direct Testimony)
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to VA Code § 56-249.6.	Virginia State Corporation Commission	Case No. PUR-2019-00070	June 19, 2019 (Direct Testimony)
In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates	South Carolina Public Service Commission	Docket 2019-3-E	August 19, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service	New York Public Service Commission	Case-19-0309	August 30, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The KeySpan Gas East Corp. d/b/a National Grid for Gas Service	New York Public Service Commission	Case-19-0310	August 30, 2019 (Direct Testimony)

Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc.	South Carolina Public Service Commission	DOCKET NO. 2020-2-E	March 13, 2020 (Direct Testimony) March 27, 2020 (Surrebuttal Testimony)
APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY *To revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*	Virginia State Corporation Commission	Case No. PUR-2020-00031	April 30, 2020 (Direct Testimony)
Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC	South Carolina Public Service Commission	DOCKET NO. 2020-1-E	May 18, 2020 (Direct Testimony) June 2, 2020 (Surrebuttal Testimony)
In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service	District of Columbia Public Service Commission	Formal Case No. 1162	July 31, 2020 (Direct Testimony)
Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates	South Carolina Public Service Commission	DOCKET NO. 2020-3-E	August 14, 2020 (Direct Testimony)
Annual Review of Gas Costs for Public Service Company of North Carolina, Inc.	North Carolina Utilities Commission	Docket No. G-5, Sub 635	July 26, 2021 (Direct Testimony)