BEFORE THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

In Re: Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC (For Potential Increase or Decrease in Fuel Adjustment)	)	Docket No. 2022-3-E

CORRECTED DIRECT TESTIMONY AND EXHIBITS
OF RONALD J. BINZ

ON BEHALF OF
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, AND UPSTATE FOREVER

September 8, 2022

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

A: My name is Ronald J. Binz. I am a Principal with Public Policy Consulting, a firm specializing in energy policy and regulatory matters. I primarily provide regulatory consulting services to public sector and private sector clients in the energy and telecommunication industries. My business address is 333 Eudora Street, Denver, Colorado 80220-5721.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: I am testifying on behalf of the South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), and Upstate Forever.

Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE, AND EDUCATIONAL BACKGROUND.

A: I have been involved in energy regulation since 1979. From 1995 to 2006, and from 2011 to the present, I have served as a principal of Public Policy Consulting. My focus in recent years has been on performance-based regulation and energy regulatory policy, including integrated resource planning (IRP), clean technology, smart grid, and climate issues.

From 2007 to 2011, I was Chairman of the Colorado Public Utilities Commission ("Colorado PUC"). In that capacity, I helped implement Colorado's vision for a "New Energy Economy" and its 30% Renewable Energy Portfolio Standard, participated in the Governor's Climate Action Plan, rewrote the Colorado PUC's IRP rules, and improved the Colorado PUC's operations. As Chair, I presided over implementation of the Colorado Clean Air-Clean Jobs Act, examining proposals of electric utilities to reduce pollutants from their fleets of coal fired power plants. I also presided over the modification and approval of an electric utility resource plan, which involved the early closure of two coal power plants and added a substantial amount of new wind capacity and additional energy efficiency savings.

In addition to my experience as a commissioner, I have held a number of positions in the field of energy and utility regulation, with a focus on protecting consumer interests. From 1984 to 1995, I was first director of the Colorado Office of Consumer Counsel, Colorado's (new at the time) state-funded utility consumer advocate office. During my tenure, the office was a party to more than two hundred legal cases before the Colorado PUC, FERC, FCC, and the courts. I negotiated rate settlement agreements with utilities, regularly testified before the Colorado General Assembly, and presented to professional business and consumer organizations on utility rate matters,

From 1996-2003, I served as President and Policy Director of the Competition Policy Institute, an independent non-profit organization based in Washington, D.C., advocating for state and federal policies to advance competition in the energy and telecommunications markets for consumers' benefit.

From July 2011 to July 2013, I was Senior Policy Advisor at the Center for the New Energy Economy ("CNEE") at Colorado State University. Founded by former Colorado Governor Bill Ritter, CNEE assists policymakers, governors, regulators, and other decision-makers in developing roadmaps to accelerate the nationwide development of a new energy economy.

Since the start of my career in 1979, I have participated in more than 150 regulatory proceedings before the Federal Energy Regulatory Commission, the Federal Communications Commission, the U.S. Supreme Court, the Eighth Circuit, Tenth Circuit, and D.C. Circuit Courts of Appeal, state and federal district courts, and state regulatory commissions in California, Colorado, Georgia, Hawai‘i, Idaho, Maine, Massachusetts, Missouri, Montana, New York, North Dakota, Rhode Island, North Carolina, South Carolina, Texas, Utah, Washington, Wyoming, and the District of Columbia. I have filed testimony in more than sixty proceedings before these bodies, addressing technical and policy issues in electricity, natural gas, telecommunications, and water regulation. I have also testified before U.S. House and Senate Committees sixteen times.

I have authored or co-authored numerous publications on energy and regulatory matters, including *Risk-aware Planning and a New Model for the Utility-Regulator Relationship* (July 2012).[1]

My educational background includes an M.A. degree in Mathematics from the University of Colorado (1977), course requirements met for Ph.D., graduate coursework toward an M.A. in Economics from the University of Colorado (1981-1984), and a B.A. with Honors in Philosophy from St. Louis University (1971).

A copy of my professional resume, which includes my employment history, education, Congressional testimony, selected regulatory testimony,

[1] Ron Binz & Dan Mullen, *Risk-Aware Planning and a New Model for the Utility-Regulator Relationship* (2012), http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf, attached as **Exhibit RJB-2**.

reports and publications, and professional associations and activities, is attached as **Exhibit RJB-1** to this testimony.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I testified before the Public Service Commission of South Carolina ("Commission") in several proceedings involving the abandonment of V.C. Summer Units 2 and 3 and the merger of Dominion Energy and South Carolina Electric & Gas, specifically Docket Nos. 2017-370-E, 2017-305-E, and 2017-207-E.

Q: WHAT IS THE FOCUS OF YOUR CURRENT WORK?

A: Since leaving the Colorado PUC in 2011, much of my work has focused on the related topics of "the new utility business model" and "a new regulatory model" that can enable necessary utility business innovation, given the structural changes and headwinds in the utility sector. These changes include the increased prevalence (and cost effectiveness) of renewable and distributed energy resources, the demand for reduced carbon emissions, and the need to mitigate upward rate pressure due to the replacement of aging grid infrastructure in the upcoming decades. Relatedly, I led "Utilities 2020," a fifteen-month long project that brought together regulators and industry leaders to develop and promote discussion and proposals regarding these topics.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

In my testimony, I plan to provide the following:

- A review of the Duke Energy Carolinas ("DEC") fuel charge adjustment filing, proposed fuel factors and rates, and the resulting impact on DEC customers;
- An explanation of the drivers of DEC's proposed fuel rider increase, primarily fuel cost volatility and increasing prices;
- An explanation of how the utility business model shields utilities from fuel price fluctuations, incentivizes suboptimal utility resource selections, and shifts risk to customers— creating a "moral hazard."
- A review of how this "moral hazard" factors into past, current, and future Commission proceedings involving Duke Energy, including IRPs, avoided cost, certificate of public convenience and necessity, and other proceedings; and
- An explanation of why the Commission should not take a siloed approach to these various proceedings and should instead institute a "risk aware" framework for evaluating fuel cost risk in DEC's annual fuel proceedings and other interrelated dockets.

Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A: I reviewed DEC's fuel charge adjustment application, DEC witness testimony, relevant provisions of South Carolina law, portions of the discovery adduced in the case, and selected testimony from other Commission proceedings.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A: I offer four findings and recommendations for the Commission's consideration:

- The price of gas is inherently volatile and in recent months has spiked to levels not seen since 2008. The Commission must consider these facts when making decisions about planning and resource acquisitions. These proceedings impact each other and should not be viewed in isolation.
- High and volatile gas prices drive up the cost of essential electric utility services, straining households' finances and making budgeting difficult. The fuel cost increase sought in this case is higher than recent inflation in the U.S. economy.
- Although its plans are still in flux, Duke Energy has in recent IRP proceedings proposed to build significant amounts of new gas generation in the near future. The fuel charge adjustment mechanism makes that decision appear to Duke Energy to be less risky than it actually is. The risk will not impact Duke Energy because the fuel adjustment mechanism will very efficiently compensate Duke for its prudent gas purchases, no matter how much the price fluctuates or how much it increases. All the risk of higher gas prices is transferred to consumers. This is a classic case of a "moral hazard."
- Solar generation paired with storage (solar plus storage) can be treated as a dispatchable resource and is now cost competitive with gas combustion turbines. Further, solar plus storage carries no fuel price risk or volatility.

Regulators should consider the benefits of low-risk, low-cost alternatives when deciding whether to approve new gas power plants.

OVERVIEW OF DEC'S FUEL COST ADJUSTMENT APPLICATION

Q: WHAT DOES THIS PROCEEDING CONCERN?

A: DEC has come before the Commission to request approval of its fuel and fuel-related costs to be included in customer rates for the Billing Period (October 1, 2022, to September 30, 2023). These costs incorporate DEC's forecast for its gas prices. At the same time, DEC is requesting recovery of a large under-recovered amount of fuel costs for the Review Period (June 1, 2021, to May 31, 2022) and the Estimated Period (June 1, 2022, to September 30, 2022). The combined adjustments, both new year and old year, will raise residential consumer bills by 13.2%, a substantial increase by any measure. Commercial and Industrial electric customers will see even larger percentage increases: 18.3% and 24.4%, respectively.

This case presents the Commission with an opportunity to examine the predictable (and predicted) results of gas price volatility, the main contributor to the higher rates the Commission is being asked to approve. As discussed in greater detail below, the fuel cost adjustment ("FCA") is a regulatory creation that obscures the risks that reliance on gas-fired generation poses to ratepayers. Further, volatile and increasing gas prices should factor into the Commission's review of other important proceedings that have or will come before the Commission.

Q. HOW DOES THE MAGNITUDE OF THIS PROPOSED INCREASE TO THE FUEL RIDER COMPARE WITH OTHER RATE INCREASES FROM THE COMPANY?

A: This is the steepest annual increase in the fuel rider over the past decade by far. **Table 1** below shows that without adjusting for inflation, this is the highest overall fuel rider for residential customers over the past ten years.

Table 1: DEC Fuel Cost Increases 2013-2022

	Sep. 2013-Oct. 2014	**2014-2015**	**2015-2016**	**2016 - 2017**	**2017-2018**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2022-2023**
Total Base Fuel Cost Component (cents/kWh)	2.0144	2.3474	2.1447	1.5877	1.727	1.9648	2.1166	1.5025	1.8123	3.3464
Total Residential Fuel Billing Factors (cents/kWh)	2.0653	2.4318	2.2843	1.689	1.8769	2.1094	2.2896	1.6102	1.9607	3.5222
Residential 1,000 kWh ($)	20.65	24.32	22.84	16.89	18.77	21.09	22.90	16.10	19.61	35.22
Change ($)		3.67	(1.48)	(5.95)	1.88	2.33	1.80	(6.79)	3.51	15.6[illegible]

In addition, DEC's proposed 13.2% increase to residential customer bills is larger than the rate increases approved in DEC's two most recent rate cases. In 2013, the Commission approved a 10.16% increase for residential bills,[2] and a 3.7% increase to residential rates in DEC's 2018 rate case.[3]

Q: IS THE FUEL INCREASE IN THIS PROCEEDING UNEXPECTED?

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[2] Order No. 2013-661 at 27 (Sep. 18, 2013), Docket No. 2013-59-E, https://dms.psc.sc.gov/Attachments/Order/fa22cddb-155d-141f-230669a786584c40.

[3] DEC Witness Pirro Compliance Exhibit 4 (May 14, 2019) Docket No. 2018-319-E, https://dms.psc.sc.gov/Attachments/Matter/199dcf83-5461-4dd4-855a-8e73d85de108.

A: No. While unprecedented, DEC's proposed increase is not unexpected: it is a function of (1) the inherent volatility of natural gas prices and (2) flaws in the utility business model that shield utilities from this risk.

FUEL COST VOLATILITY AND RISING PRICES

Q: WHAT IS "VOLATILITY"?

A: In everyday usage, "volatile" means the tendency to change quickly and perhaps unpredictably. We might speak of someone's personality being "volatile" or the Dow Jones Industrial Average exhibiting "volatility." For commodities like gas or coal, "volatility" describes how quickly the price of the commodity changes over time. The term has loose, informal meanings. But it also has technical, economic meanings. In finance the term is well-defined and can be measured. Officially, "volatility" is the standard deviation of changes in value of a variable over time.

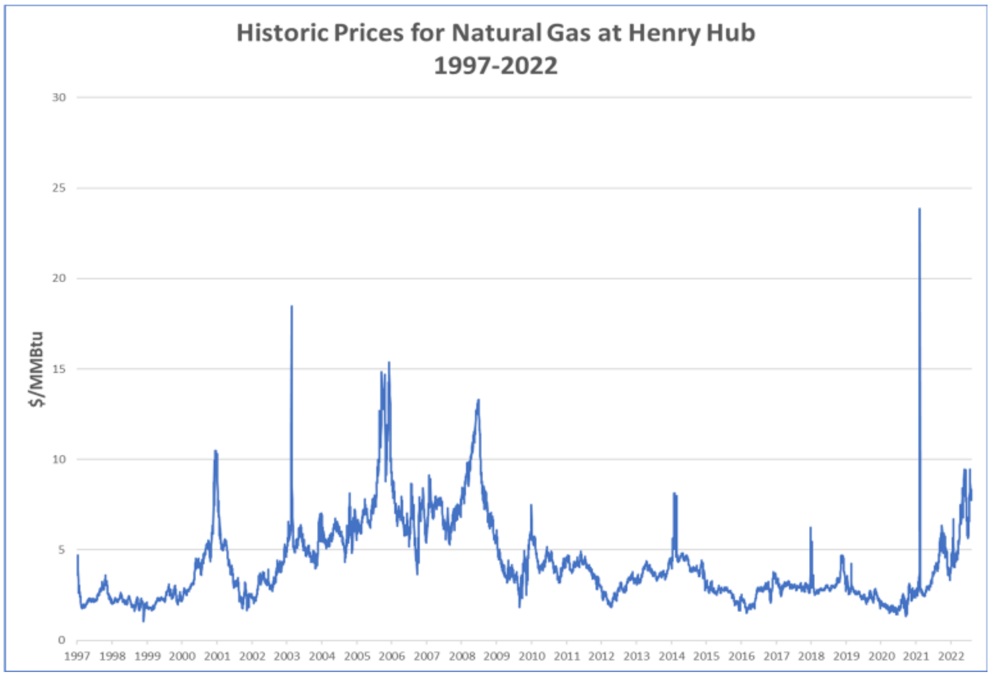
Q: DOES VOLATILITY MEAN THAT PRICES ARE INCREASING?

A: Not necessarily. Volatility measures the rate of price changes, both up and down. A slowly rising price might have low volatility; a downward trending price may or may not be volatile. Further, prices that are very volatile in one period might not be volatile in another period. However, in recent months, the prices of both natural gas and coal resources have been volatile *and* increasing.

Q: PLEASE SHOW THE RECENT HISTORY OF GAS PRICES.

A: The graphs in **Figure 1** and **Figure 2** below[4] show gas prices and the volatility of those prices. First, **Figure 1** shows daily gas prices reported at the Henry Hub from 1997 to date.

Figure 1: Henry Hub Natural Gas Spot Price



It is clear from the graph in **Figure 1** that gas prices fluctuated throughout most of the timeline depicted. I remember well the peak gas price achieved on July 2, 2008: I was Chairman of the Colorado PUC, and the Colorado PUC began warning customers about the high gas prices heading into the heating season, only to see the price descend quickly as U.S. shale gas production came online. The other notable recent needle peak occurred during winter storm Uri in February

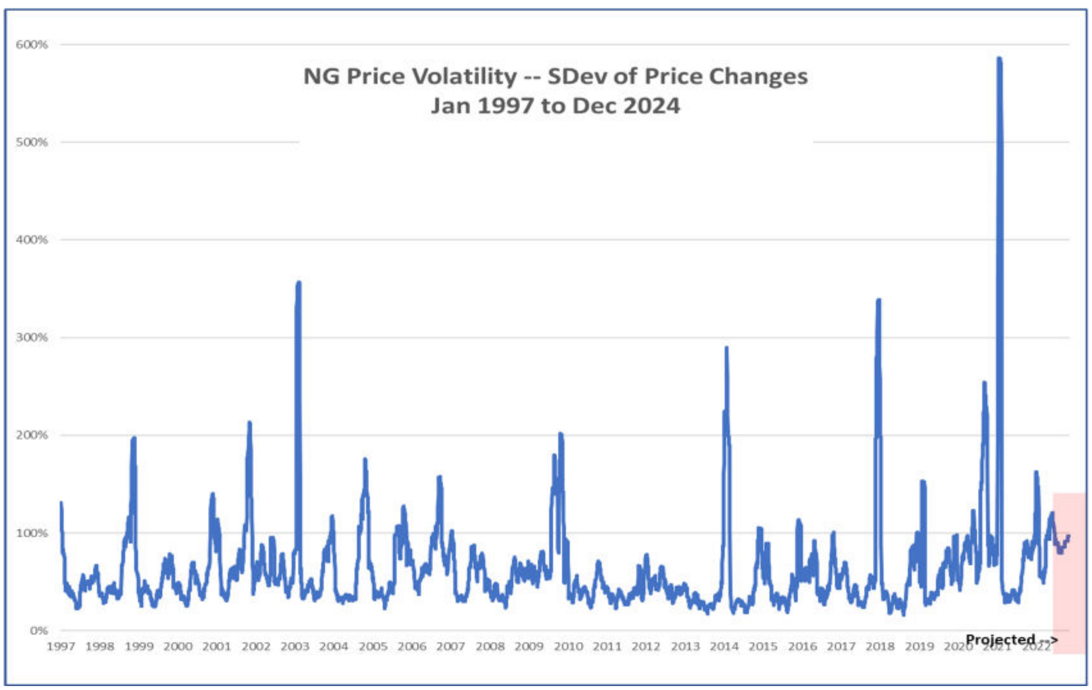
[4] The data for these graphs are derived from U.S. Energy Administration historic natural gas prices. *See Natural Gas: Henry Hub Natural Gas Spot Price*, U.S. Energy Information Admin., https://www.eia.gov/dnav/ng/hist/rngwhhdD htm (last visited Aug. 22, 2022).

2021, when freezing weather, snow, ice, and tornadoes racked the country, creating a power crisis in Texas.

Q: WHAT ABOUT PRICE VOLATILITY DURING THE SAME PERIOD?

A: **Figure 2** shows the price volatility (not the prices) during the period January 1997 to December 2024. Historic volatility is calculated directly from historic prices using a formula familiar in economics and finance. Future volatility, which is referred to as imputed volatility, is derived from the prices of publicly traded financial option contracts. Calculating future volatility in this way works because financial options are often used to reduce or eliminate price risk for a commodity. Option prices demonstrate how much volatility commodity traders are expecting.

Figure 2: Natural Gas Price Volatility, Henry Hub Spot Prices



Q: WHAT DO THESE FIGURES SHOW?

A: The main takeaway from these figures is this: after a period of relatively stable gas prices and low volatility in 2011 to 2020, the price of gas is now much more volatile and has achieved price levels not seen in fifteen years. As I will discuss later, these circumstances—higher prices and greater volatility—have broad implications for many future decisions facing the Commission.

Q: WHAT IS DRIVING THESE INCREASES IN NATURAL GAS PRICES?

A: That is a complex question. On balance, it is primarily a result of supply and demand pressures. The U.S. economy has snapped back following its decline during the worst of the economic recession caused by COVID-19, which has spurred demand for additional production of gas. Russia's invasion of Ukraine adds pressure to international gas prices because Europe is moving away from Russian natural gas supply. Finally, inflation is world-wide, not simply in the US, as many seem to think.[5] This inflation affects all industries; natural gas production and transportation are no different. Importantly, though, these factors are outside utilities' control, and utilities likewise have limited ability to protect customers from price risks outside of reducing their reliance on gas resources.

Q: DEC WITNESS VERDERAME CLAIMS IN HIS DIRECT TESTIMONY THAT ADDITIONAL GAS INFRASTRUCTURE IS NEEDED TO REDUCE GAS PRICES IN THE SOUTHEAST. ARE NATURAL GAS PRICES IN THE SOUTHEAST BEING DRIVEN UP BY LACK OF PIPELINE CAPACITY?

A: No. Utilities in the southeast are purchasing gas at market prices like everyone else. Recall that, in this case, DEC witness Verderame uses futures prices from Henry Hub in this to forecast natural gas prices for the billing year.[6] There is no

[5] "U.S. inflation rate is in the middle of the pack globally." Axios. June 13, 2022. Available at https://www.axios.com/2022/06/13/inflation-rates-around-world-us-china-eu-japan.

[6] *Id.* at 9, lines 17-22.

separate pricing hub for North and South Carolina. The current debates about the need for pipelines in the Southeast are driven mainly by the question of how much pipeline capacity is needed for *future* gas deliveries—not as a tool to lower a global commodity price.[7] The cancellation of the Atlantic Coast Pipeline was due to a combination of reasons, chief among them that scaled back demand forecasts for natural gas by Dominion, combined with ballooning costs of the project. Duke was a partner in the project and continues (like Dominion) to predict a need for more natural gas generation.[8] But Duke's outlook presupposes that new gas generation is the least cost resource. New, lower prices for solar plus storage will challenge Duke's assessment of that course. I will return to this question later.

Q: WHAT FUTURE PRICE FOR GAS DID WITNESS VERDERAME USE IN HIS MODELING OF NEW GAS COSTS?

A: According to his testimony, DEC used a price of $6.76/MMBtu for the billing period gas costs. He derived that from the prices in the futures market for gas at Henry Hub. But this price may be too low. As of this writing, the average future price of gas at Henry Hub for the period October 1, 2022, to September 30, 2023, is 15% higher, at $7.37/MMBtu.

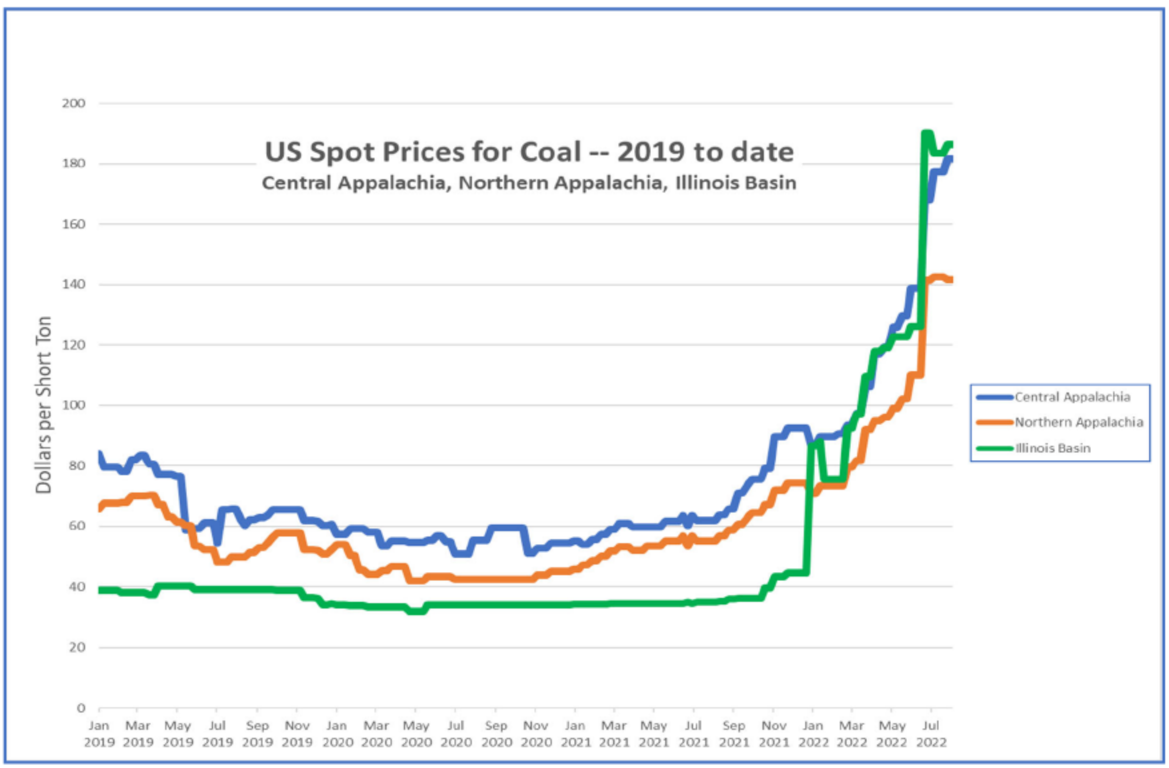
[7] Intervenors have also highlighted how utilities have failed to adequately to account for *risks* to the reliability or usefulness of those resources if pipeline capacity is unable to be expanded. This testimony did not claim that surer access to additional pipeline capacity would lessen the risks associated with *gas price volatility*. For example, even if Duke had additional pipeline access to gas from the Marcellus region, the price of gas in that region is up, so Duke would merely have access to more gas at the current higher price, which it could then pass to customers through the fuel rider. *See, e.g.,* Revised Surrebuttal Testimony of Kevin Lucas at 27-29 (April 23, 2022) Docket Nos. 2019-224-E and 2019-225-E, https://dms.psc.sc.gov/Attachments/Matter/54bdfd65-194f-4a89-83b6-3779fca90ebc (noting that one of the risks associated with new gas generation, in addition to the cost and risk of fuel expenses, was the "reliability and cost risk arising from uncertainty about Duke's ability to secure firm natural gas transportation to its current and potentially expanded fleet of gas generating facilities").

[8] DEC Modified 2020 IRP at 9-11 (Aug. 27, 2021), Docket Nos. 2019-224-E and 2019-225-E, https://dms.psc.sc.gov/Attachments/Matter/81fe90b2-7966-4435-b14a-6a79549bfa33.

Q. ARE COAL MARKETS ALSO SUBJECT TO PRICE VOLATILITY?

A: Yes, all commodity-based resources, like gas and coal, expose customers to price volatility. For many years, the spot market for thermal coal was relatively boring. Although unregulated, the price of coal used for electricity generation moved up and down in small increments. All that changed in 2020 when the spot price of coal began to climb. Now, similar to the gas market, the price of coal has awakened after years of hovering around the price of $50/ton. As of this writing, coal prices were at record high levels. **Figure 3** below tracks the spot prices of coal in the three US mining regions where Duke purchases coal.

Figure 3: U.S. Coal Spot Prices January 2019 to July 2022



Q: WHY HAVE COAL PRICES RISEN SHARPLY?

A: There is undoubtedly a mix of causes, both domestic and foreign. In his testimony, DEC Witness Verderame notes the increase and volatility of coal prices and offers an extensive list of factors that have driven the price to record levels.[9] I have no quarrel with his list of factors.

In his Exhibit 1, Witness Verderame explains the Company's coal purchasing practices and notes that DEC's supply portfolio includes contracts of various lengths and also purchases in the spot market. The contracts undoubtedly cushion the price shock that would occur if DEC were fully dependent on the spot market for coal. In Exhibit 2, Witness Verderame shows that DEC's exposure to the spot market has averaged about 30% for each the twelve-month periods that ended May 2022 and May 2021.

Q: HOW DO THESE DEVELOPMENTS ULTIMATELY AFFECT ELECTRIC CONSUMERS?

A: As mentioned earlier, DEC's fuel charge adjustment application, if approved, would raise the average residential customer's bill by 13.2%, or about $15.76 per month. But this percentage obscures the actual change in fuel costs because it refers to all residential revenues, not the fuel portion. The overall percentage change in fuel costs is much higher than this average bill increase. The previous residential fuel billing factor was 1.9607 cents/kWh in DEC's 2021 fuel docket.[10] The new proposed residential fuel cost is 3.5222 cents/kWh. This means that

[9] Direct Testimony of John A. Verderame at 6-7 (Aug. 1, 2022), Docket No. 2022-3-E.

[10] Supplemental Testimony of Bryan L. Sykes at 6 (Aug. 18, 2021) Docket No. 2021-3-E, https://dms.psc.sc.gov/Attachments/Matter/9bd35886-c957-4948-8734-8b6c48ef74f9.

from the last fuel case to this one, the fuel costs passed customers actually increased by 79.6%.

In obvious fashion, higher gas prices raise electricity costs for consumers. To put the projected 13.2% average increase in residential customer bills in perspective, the U.S. inflation rate peaked in June this year at 9.1%.[11] In other words, the DEC fuel cost increase is ***4.7% points higher*** than the June 2022 inflation rate, which has drawn sharp complaints from the public. But this 13.2% increase is only for the items covered by the cost adjustment, fuel, and fuel-related costs. Inflation affects all businesses. The Commission should expect that DEC will seek higher rates, as the inflated costs of all the non-fuel costs (e.g., operation and maintenance expenses and labor costs) are booked.

Increasing, unpredictable energy costs can wreak havoc with household budgets, as electricity is one of the largest household expenses.[12] Volatile energy costs affect low-income household to a greater degree.[13]

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[11] Consumer Price Index, https://www.bls.gov/cpi/ (last visited Aug. 22, 2022).

[12] Ariel Drehobl et al., *How High are Household Energy Burdens: An Assessment of National and Metropolitan Energy Burden across the United States* 9 (2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf (providing that the median national energy burden is 3.1%).

[13] According to 2019 data compiled by the University of North Carolina at Chapel Hill, South Carolinians that live below 50% of the federal poverty line face an average energy burden of 37%; in fact, all South Carolinians living below 200% of the federal poverty level face an average energy burden exceeding what is considered affordable. UNC-Chapel Hill, Convergence of Climate-Health Vulnerabilities, Energy Poverty (2019), https://convergence.unc.edu/vulnerabilities/energy-poverty/ (last accessed Aug. 26, 2022. South Carolina is one of the five states with the highest low-income energy burdens in the country. U.S. Dept. of Energy, Office of Energy Efficiency & Renewable Energy, *Low-Income Household Energy Burden Varies Among States — Efficiency Can Help In All of Them* (Dec. 2018), https://www.energy.gov/sites/prod/files/2019/01/f59/WIP-Energy-Burden_finalv2.pdf.

The rising and volatile cost of gas had another troubling effect for DEC's customers. The total cost of fuel requested in this case from the South Carolina jurisdiction is $705 million, of which $215 million is a true up of under-recovered fuel costs through September 30, 2022. As explained in DEC witness Sigourney Clark's testimony, the base fuel rates during the Review Period and Estimated Period under collected actual fuel costs, resulting in the $215 million,[14] added to projected fuel costs for the 12-month Billing Period. This means that, due to the volatility of gas prices, customers *underpaid* their fuel costs in the Review Period and will now *overpay* their actual fuel costs in the Billing Period. Thus, rates for fuel in 2023 will be 44% higher[15] than the actual projected cost.

Q: IN YOUR OPINION, ARE FOSSIL FUEL PRICES LIKELY TO STABILIZE OR DECLINE IN THE NEAR FUTURE?

A: It is difficult to speculate on the future price of gas. The forward price in the futures market is probably the best tool for projecting close-in price changes. As mentioned earlier, those prices, above $9.00 per MMBtu for delivery through February 2023, seem to indicate that gas prices will remain high through the coming winter.[16] It's unclear what is likely to happen after that. However, it's easier to predict that the volatility of gas prices will continue.

Q: ARE PURPA-RELATED COSTS A SUBSTANTIAL DRIVER OF THE PROPOSED INCREASE IN THE FUEL RIDER?

[14] Direct Testimony of Sigourney Clark, p. 9 lines 5-7 (July 29, 2022), Docket No. 2022-3-E.

[15] *Id.,* Exhibit 1 at p. 2 (line 3 total ($705 million) divided by line 2 total ($489 million) = 1.44, or a 44% increase).

[16] See CME Group, Henry Hub Natural Gas Quotes, https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html (last accessed Aug. 26, 2022).

A: No, they are not. First, in the absence of the purchased power supplied from PURPA facilities, the fuel increase may have been even greater because Duke would have had to rely on additional fossil fuel generation. Second, capacity-related costs (which include PURPA-related cost) comprise only 4.5% of the proposed increase, compared with the contribution of increased fuel costs, at 95.0% of the proposed increase.[17] Although the PURPA-related expenses are small, we might expect them to get smaller in the future. The cost of procuring solar and storage resources is becoming more cost effective, particularly with the passage of the federal Inflation Reduction Act and the potential implementation of competitive procurement of renewable energy in South Carolina.

Q: **PLEASE EXPLAIN.**

A: The Commission has recently issued an order requiring Duke Energy to propose a program for the competitive procurement of renewable energy resources.[18] I have a lot of experience in this area. Like South Carolina, Colorado is a "vertically integrated" utility state in which utilities own their own generation, outside of organized markets. Beginning in the mid-1990s, Colorado began to use competitive bidding to choose PURPA-affected generation projects. As the years passed, competitive bidding was applied to renewable energy projects (PURPA-affected or not) that utilities began to purchase to meet renewable energy targets. By 2016 the system and the market had matured into a remarkable combination where the utilities were swamped with very low-cost wind, solar, and storage

[17] *See* Direct Testimony of Sigourney Clark, Exhibit 1, lines 3, 6, 13 (July 29, 2022), Docket No. 2022-3-E.

[18] Colorado Public Utilities Commission. "Xcel Energy. 2016 Electric Resource Plan (ERP); 120-day Report" Docket No. 16A-0396E, June 2018.

projects. Anyone will tell you that the process has been a resounding success. Two figures show how successful competitive bidding can be.

Figure 4 below provides a summary from Xcel Energy's 2016 Colorado IRP. The prices listed in this table are the ***median*** price for the bids in each category. As we will see, the eventual contracted prices were even lower than the median bids. These very low prices, especially for solar + storage, surprised many in the utility world and have become the expectation for bids in many states.[19]

Figure 5 lists the prices of the actual contracted solar and solar + storage resources scheduled to be in service in 2022. Note also that the Commission received **430** bids for a desired **eleven** projects. Also note that these are "all-in" prices, including, where necessary, transmission links.

Figure 4: Xcel Colorado 2016 IRP Bid Results[20]

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

[19] *See* Trabish, H.K., June 2021, *Xcel's Record-Low-Price Procurement Highlights Benefits of All-Source Competitive Solicitations*, UtilityDive.com, available at https://tinyurl.com/y4d4re5c.

[20] Colorado PUC Proceeding No. 16A-0396E, Xcel Colorado 2016 Electric Resource Plan, All Source Solicitation 30-Day Report (Public Version) at 9, available at https://cdn.arstechnica.net/wp-content/uploads/2018/01/Proceeding-No.-16A-0396E_PUBLIC-30-Day-Report_FINAL_CORRECTED-REDACTION.pdf.

Turning to **Figure 5** below, the actual contracted prices for wind are some of the lowest ever reported (e.g., \$10.68/MWh) and the solar + storage prices (e.g., \$30.32/MWh) are lower cost than any new fossil generation that could be built in Colorado.

Figure 5: Contracted Prices from Xcel Energy Colorado 2016 All-Source RFP[21]

Bid ID	Project Name	Bidder Name	In-Service Year	Nameplate Capacity (MW)	Storage (MW)	Storage (MWh)	Structure	Contract Term (yr)	45 DAY LEC ($/MWh)	45 DAY LCC ($/kW-mo)
W602	Bronco Plains Wind	NextEra	2020	300			PPA	25	$ 10.68	$ -
W192	Cheyenne Ridge	Tradewind	2020	500			Build-Own Transfer		$ 16.53	$ -
W301	CO_Green_162	Avangrid	2020	162			PPA	20	$ 14.16	$ -
W090	Mountain Breeze	Leeward	2020	169			PPA		$ 18.00	$ -
S430	Owl Canyon PV	Coronal	2022	75			PPA		$ 22.53	$ -
S085	Hartsel Solar	Adani	2022	72			PPA	25	$ 26.84	$ -
X647	Thunder Wolf	NextEra	2022	200	100	400	PPA	25	$ 30.32	$ -
X427	Piccadilly Solar + Storage	Coronal	2022	110	50	100	PPA		$ 30.33	$ -
X645	Neptune	NextEra	2022	250	125	500	PPA	25	$ 31.35	$ -
G215	Manchief Gas Combustion Turbine	Atlantic	2022	301			Existing Asset Sale		$ -	$ 1.50
G065	Valmont Gas Plant 2022	SW Generation	2022	82			Existing Asset Sale		$ -	$ 2.43

In summary, I congratulate the Commission for further examining competitive bidding and encourage the Commission to ensure these programs are robust. I'm confident that the Commission will find competitive procurement to be a less costly and more efficient way to acquire low-cost solar resources and reduce customer exposure to fuel risk.

[21] Presentation from Colorado PUC Engineer Bob Bergman to Michigan PUC (Feb. 2021), slide 8, https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/comp-proc/Feb_18_Competative_Procurement_Presentation_.pdf?rev=c0dfd06533714ee9991658e2f8c145f2. Note that the last two rows regarding the Manchief Gas CT and the Valmont Gas Plant only reflect capacity costs, not the all-in costs for operating those facilities (i.e. the values exclude energy costs, including fuel costs).

<u>FUEL COST RISKS AND THE UTILITY BUSINESS MODEL</u>

Q: IN SOUTH CAROLINA, HOW DO UTILITIES RECOVER FUEL COSTS THEY INCUR?

A: As with many states, South Carolina employs a "fuel cost adjustment" mechanism. S.C. Code Ann. § 58-27-865 sets forth the procedures and requirements for annual fuel cost proceedings in which the utility seeks to recover its "fuel costs," a category that includes "the cost of fuel, cost of fuel transportation, and fuel costs related to purchased power," S.C. Code Ann. § 58-27-865(A)(l) (2015). Section 58-27-865(B) directs " each electrical utility which incurs fuel cost for the sale of electricity to submit to the Commission and to [ORS]... its estimates of fuel costs for the next twelve months" and further provides that "the [C]ommission [] direct each company to place in effect in its base rate an amount designed to recover, during the succeeding twelve months, the fuel costs determined by the [C]ommission to be appropriate for that period."

Conversely, S.C. Code Ann. § 58-27-865(F) permits the Commission to "disallow recovery of any fuel costs that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs." In assessing any potential disallowance, the Commission must "giv[e] due regard to reliability of service, economical generation mix, generating experience of comparable facilities, and minimizations of the total cost of providing service." S.C. Code Ann. § 58-27-865(F).

Q: IS THIS TYPE OF FUEL COST RECOVERY MECHANISM COMMON?

A: Yes. Fuel cost adjustments ("FCAs") first originated in the mid-1970s.[22] Before that time, fuel costs were included in base rates and the levels remained fixed until the next rate case when total rates, including the cost of fuel, would be reset. Fuel costs were relatively stable and there usually was not a "true-up" mechanism.

All of that changed with the 1973 Arab Oil Embargo, which caused market prices for generation fuels to become much more volatile.[23] Because of rapidly increasing fuel prices, many utilities were forced to file "pancaked" rate cases, with new cases filed before the pending ones were settled. Indeed, I witnessed this and other developments firsthand in my role as a consulting utility rate analyst. These pancaked rate cases led to proposals to defer fuel costs that were above the levels included in base rates, and then collect those deferred amounts at a later date, oftentimes in the following month. FCAs helped to address these issues and lighten the regulatory load by mitigating the need for frequent rate cases.

Unsurprisingly, there was a lot of resistance among customer groups and consumer advocates to FCAs. Those opponents argued that FCAs were "single issue ratemaking," that they were overly generous to the utilities, that they relieved much of the pressure on the utilities to be efficient and shifted all fuel cost risk to customers. Despite this opposition, FCAs became a feature of most state regulatory systems, often enshrined in enabling legislation, as in the case of

[22] S&P Global Market Intelligence, *RRA Regulatory Focus: Adjustment Clauses, a state by state overview* 2 (2017), https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf.

[23] *Id.*

South Carolina. In the decades following the adoption of FCAs, numerous other “adjustment clauses” were adopted across the country: for pension benefits, inflation tracking, changes in labor costs, environmental compliance costs, and capital investment, to name a few.

The array of adjustment clauses has transformed cost-of-service regulation in a way that changes a utility’s incentives and removes the main pressure on utilities to become and remain efficient as business firms: pressure from cost changes.

Q: IN DEC’S PRESS RELEASE ANNOUNCING THE PROPOSED RATE INCREASE IN THIS PROCEEDING, THE COMPANY HIGHLIGHTED THAT IT DOES NOT EARN A PROFIT ON THE FUEL COSTS IT INCURS. DO YOU VIEW THIS CLAIM AS MISLEADING?

A: Yes. While electric utilities do not make a profit on the fuel they purchase, they *do* make a profit on the power plants that burn that fuel. Under cost-of-service regulation, the companies’ profit margin is calculated as a rate-of-return multiplied by the rate base. Thus, under cost-of-service regulation, adding a plant to rate base is a primary means through which electric utilities can grow and increase their earnings. It is well understood that this creates a capital expenditure bias or “capex bias” that can lead utilities to invest in hard assets when other approaches (demand response, energy efficiency, purchased power) might be of lower cost to customers. As a simple analogy, a car salesman wants to earn a higher commission (i.e., return) and is more likely to push buyers towards expensive cars (large capital investments); if a car buyer is choosing between an expensive gas guzzler (such as a gas plant) and a less expensive, fuel-efficient car (renewables or efficiency), the salesman is motivated to try and sell the former, because only the buyer has to pay for gas (fuel costs). If the car salesman had to pay for any of the gas needed to run the cars he sells, his motivation may instead be to sell cars that cost less to operate over time and are less susceptible to risks associated with gas prices.

A generic FCA, like the one at issue in this case thus plays a role in the utility's preference to grow its rate base. From the utility's perspective, operating a natural gas plant will build its rate base and is not risky because there is no way the utility will collect less than its reasonable and prudently incurred cost for fuel, no matter how much the price changes. Indeed, as demonstrated in the intricate calculations in DEC's exhibits, fuel charge adjustment applications are designed to recover exactly every fuel dollar spent, no more, no less.

For this reason, it is fair to say that the certainty of fuel cost recovery in combination with the capex bias presents a "moral hazard," inducing utilities to invest in fossil-fueled generation even when other solutions (energy efficiency, demand response, power purchases) are cheaper for its customers.[24] In contrast, a competitive company, like the industrial customers DEC serves, must consider the risk inherent when sourcing its supply and cannot expect that they will be fully compensated for those expenditures.

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[24] *See generally* Mark Thoma, *Explainer: What is Moral Hazard*, CBS News (Nov. 22, 2013), https://www.cbsnews.com/news/explainer-moral-hazard/. (defining moral hazard primarily in regard to the 2008 financial crisis and health care markets). Generally speaking, moral hazard refers to a situation in which one party engages or is incentivized to take more risk because they are "insured" against that risk or at least perceive themselves to be insured against that risk.

Q: HOW DOES THIS "MORAL HAZARD" IMPACT OTHER REGULATORY PROCEEDINGS BEFORE THIS COMMISSION?

A: As the Commission has seen in recent IRP and avoided cost proceedings, utilities often set fuel cost forecasts too low, and the Commission has in recent orders required utilities to improve those forecasts.[25] Relying on low fuel price forecasts has the effect of making fuel-dependent resources look more cost-effective over the long term than fixed price alternatives, like solar and storage, making energy efficiency investments seem less cost-effective, and reducing the avoided cost rates paid to small power producers under PURPA.

Each of these examples has the potential to result in less investment in renewable resources, more investment in fossil fuel resources,[26] and ultimately, a larger rate base on which the utility can earn a return. However, as we are seeing now, those fuel-based resources also increase utility customers' exposure to fuel costs which the utility itself gets to treat as "zero."

Q: THE FUEL COST RISK TO CUSTOMERS CREATED BY THIS "MORAL HAZARD" HAS NOW MATERIALIZED IN THE FORM OF A PROPOSED

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[25] *See* Order No. 2022-329 at 17 (May 2, 2022) Docket No. 2021-88-E (requiring modifications to Dominion Energy S.C.'s avoided cost fuel forecast); Order No. 2020-832 at 67, 70-71 (Dec. 23, 2020) Docket No. 2019-226-E (requiring Dominion Energy S.C. to amend its natural gas forecasts because it relied on forecasts that were overly low and inconsistent with industry-standard market models); Order No. 2021-447 at 17 (June 28, 2021) Docket Nos. 2019-224-E and 2019-225-E (requiring Duke to modify its 2020 IRPs because its natural gas forecasting method "rel[ied] too heavily on forward contract prices determined at a market low point and maintained for over 10 years in the forecast period" and "commit[ed] Duke to large-scale buildouts of natural gas generation assets, at the expense of renewables and storage.").

[26] *See* Revised Direct Testimony of Anthony Sandonato, Ex. AMS-1 at 52-53 (Mar. 4, 2021) Docket Nos. 2019-224-E and 2019-225-E, https://dms.psc.sc.gov/Attachments/Matter/7a5c3678-6ac1-4f70-84aa-c096effb9990 (explaining that is important to review the accuracy of gas price forecasts because "low gas price forecasts could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives").

13.2% INCREASE TO RESIDENTIAL BILLS. HAS THE COMMISSION HEARD TESTIMONY REGARDING THIS POSSIBILITY IN PAST COMMISSION PROCEEDINGS?

A: Yes. While utilities have advocated for lower gas price forecasts and new gas generation,[27] intervenors before this Commission have regularly highlighted the potential impact to customers of investing in natural gas resources and the need to hedge those risks through investment in fuel-free resources.

To provide just a few examples, the risk of gas price volatility to customers—with specific reference to the fuel rider—was raised by intervenors in both of the 2020 IRP proceedings before this Commission. For example, at Dominion Energy South Carolina's 2020 IRP hearing, Carolinas Clean Energy Business Association ("CCEBA")[28] Witness Kenneth Sercy explained that

> natural gas prices…are [] costs that flow through the fuel rider [.] In a utility regulation, we call those "pass-through costs" because the company passes their cost through, straight to ratepayers. So if the company spends $250 million on natural gas one year, ratepayers pay $250 million. If the company has to spend $350 million next year because gas prices went up, ratepayers pay $350 million. I mean ratepayers are 100 percent exposed to these risks that we're talking about[.][29]

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[27] *See, supra* note 25; *infra* note 39; *see also* Order No. 2021-447 at 63 (June 28, 2021) Docket Nos. 2019-224-E and 2019-225-E (concluding that "Duke's natural gas forecasting methodology, as set forth in the IRPs, risks reversing that progress [of coal retirement] by over-committing to natural gas generation as a result of low forecasts of gas prices").

[28] CCEBA was formerly known as the Solar Business Alliance.

[29] *South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated (See also Docket No. 2021-9-E*), Hearing Tr. Vol. 3 at 653-657, Docket. No. 2019-226-E.

While Mr. Sercy was discussing Dominion Energy South Carolina, the same pass-through structure applies to DEC's fuel costs.

Likewise, CCL, SACE, and Upstate Forever, along with other clean energy intervenors, observed in comments on Duke 2020 Modified IRP that Duke's proposed buildout of natural gas prices "could expose Duke's customers to major bill increases in future years. By contrast, the price for new renewable generation is often locked in through long-term contracts, offering a hedge against volatile fossil fuel prices."[30] In same Duke 2020 IRP Proceeding, CCEBA Witness Kevin Lucas also provided in depth testimony on gas price volatility[31] and continually highlighted risk to customers associated with new gas resources.[32] The Commission heard similar testimony about fuel cost risk, and specifically

[30] Comments of CCL, SACE, Upstate Forever, Natural Resources Defense Council, Sierra Club & CCEBA in response to Duke Modified 2020 IRPs at 21 (Oct. 26, 2021) Docket Nos. 2019-224-E and 2019-225-E.

[31] Revised Direct Testimony of Kevin Lucas at 75, lines 4-13 (April 22, 2021) Docket Nos. 2019-224-E and 2019-225-E, https://dms.psc.sc.gov/Attachments/Matter/6e87a450-4930-4981-bd3a-145e957527aa ("The natural gas industry is a sprawling, complex sector of the economy. Natural gas is used not only by the electric sector for electricity generation but used heavily in residential and commercial buildings for space and water heating and by industry as fed stocks for many products. Production, transmission, and storage of natural gas involves an entire other set of market participants, and there is a vibrant commodity market where traders and speculators seeks profits on natural gas financial derivatives. Demand for natural gas is highly depended on weather and storage capacity, leading to major swings in prices during extreme weather events that affect demand or natural disasters that impact supply. Because the market is affected by myriad factors, many of which are unknowable more than a few days out, daily prices are highly volatile.").

[32] Revised Surrebuttal Testimony of Kevin Lucas at 3, line 9-14 (April 23, 2021) Docket Nos. 2019-224-E and 2019-225-E, https://dms.psc.sc.gov/Attachments/Matter/54bdfd65-194f-4a89-83b6-3779fca90ebc ("[Duke Witness] Mr. Snider fails to address the reality that an unreasonably-low natural gas price forecast could cause the model to favor new natural gas over other resources such as additional renewables and storage, placing the risk of stranded asset and fuel price changes squarely on the Company's customers while providing Duke's shareholders with a bloated capital investment plan for unnecessary fossil generation.").

how PPAs provide a valuable hedge against fuel volatility, in the most recent avoided cost proceedings.[33]

Even as early as 2013, in DEC's last proceeding seeking approval to build a combined cycle facility, intervenors CCL and SACE submitted testimony recommending that "the Commission ensure that DEC and [Duke Energy Progress] have exhausted cost-effective opportunities to defer or avoid the additional [natural gas combined cycle] plants through lower-cost lower-risk resources."[34] CCL and SACE further recommended in that proceeding that the Company solicit proposals to build solar facility at or near the proposed combined cycle units to "provid[e] a cost-effective hedge against the risk to customers of future increases in natural gas prices," explaining that "[i]f natural gas fuel prices

[33] Direct Testimony of Jon Downey at 11, lines 13-19 (Sep. 11, 2019) Docket No. 2019-185-E, https://dms.psc.sc.gov/Attachments/Matter/2c34e20f-b126-4628-a654-946bd6c0ca4a, ("As a resource, solar is stable and predictable and represents a meaningful hedge against historically volatile fuel prices. While natural gas prices currently enjoy historically low prices, recent history and future projections indicate that this is temporary. The added regulatory risks associated with a future price on carbon, coal ash storage and clean-up requirements, and a tightening of fracking regulations suggests that volatility in fossil fuel markets is an omnipresent reality"); Direct Testimony of Hamilton Davis at 11, lines 10-18 (Sep. 11, 2019) Docket No. 2019-185-E, https://dms.psc.sc.gov/Attachments/Matter/a64c495e-7fd6-4fe3-8551-d656c091e24e ("[W]hen natural gas prices rise, those increasing costs will be passed along directly to ratepayers. And while utilities may have some limited ability to shift dispatch from gas-fired to coal-fired resources, doing so could further expose customers to uneconomic coal generation. So, while fixed PPAs for solar and storage resources do create some cost risk for customers, they also provide a hedge against volatility and increases in fuel costs…This risk-hedge is especially valuable in an era of historically low natural gas prices, which are reflected in the avoided energy rates paid to SPPs and which lock in these low energy rates for the term of the PPA."); *Dominion Energy South Carolina, Incorporated's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)*, Hearing Tr. at Vol. 4, 160-161, Docket No. 2021-88-E ("[W]hat if [] fuel prices go high than we are thinking they will? What if there are greenhouse gas regulations' And those [] costs are all on customers, right? They all flow through the fuel – the fuel rider, and they all go straight to customers. Customers are exposed to them.")

[34] Joint Direct Testimony of Hamilton Davis and John D. Wilson at 4 (Dec. 10, 2013) Docket 2013-392-E, https://dms.psc.sc.gov/Attachments/Matter/b0cd9424-155d-141f-23c329aafd8b7b6d.

spike temporarily due to market disruption, the impact on the fuel cost recovery rates would be mitigated by solar power generation."[35]

Today solar + storage provides the same hedge at a much lower cost—the passage of the Inflation Reduction Act may further reduce costs due to its extension and expansion of available clean energy tax credits.[36] Notably, and in a contrast to testimony in recent fuel proceedings,[37] the Commission rejected CCL and SACE's recommendation in the 2013 proceeding in part because it considered the "fuel proceeding" a more appropriate forum to consider which fuel source can be dispatched most cost-effectively.[38]

Q: YOU MENTIONED EARLIER THAT THE FUEL PRICE RISK AND VOLATILITY ISSUES UNDERSCORED BY DEC'S REQUESTED RIDER INCREASE HAVE IMPLICATIONS FOR CURRENT AND FUTURE DUKE PROCEEDINGS BEFORE THE COMMISSION. CAN YOU ELABORATE?

A: In Duke Energy's most recent IRP proceeding, Duke Energy selected a preferred portfolio in its Modified IRP that retired Duke's coal plants and replaced that capacity with substantial amounts of new gas generation. The portfolio approved

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[35] *Id.* at 7, 20.

[36] *See* Forbes, *Inflation Reduction Act Benefits: Clean Energy Tax Credits Could Double Deployment (*Aug, 23, 2022), https://www.forbes.com/sites/energyinnovation/2022/08/23/inflation-reduction-act-benefits-clean-energy-tax-credits-could-double-deployment/?sh=371df6c86727\.

[37] *See, e.g.,* Direct Testimony of James J. McClay at 6, lines 1-8 (May 25, 2022) Docket No. 2022-1-E, https://dms.psc.sc.gov/Attachments/Matter/37531f01-ce4a-4bd7-99c3-1159fc5dad6b.

[38] Order No. 2014-546 at 5-6 (July 30, 2014) Docket No. 2013-392-E, https://dms.psc.sc.gov/Attachments/Order/51008b87-155d-141f-230a6845c299fd60.

by the Commission in Order No. 2022-332 keeps Duke's existing coal plants online but still adds a significant amount of gas (though slightly less than Duke's selection) over the planning horizon.[39]

Given the volatility, cost, and risks associated with both coal and gas resources, continuing to rely on coal generation and "doubling down" on gas additions would expose ratepayers to the very same risk of "rate shock" they face in this proceeding. This exposure to rate shock due to fuel price spikes with increased gas generation is only compounded by the significant risk of stranded assets with the construction of gas facilities. On the other hand, solar plus storage—a proven, mature technology—is increasingly cost-competitive with new gas generation and has no fuel price risk.

ROLE OF THE COMMISSION

Q: WHAT IS THE COMMISSION'S ROLE IN PROTECTING CUSTOMERS FROM THESE FUEL RISKS IN THE CONTEXT OF THIS AND OTHER RELATED PROCEEDINGS?

A: Historically, the Commission has treated FCA proceedings as limited in scope. The timing is quite abbreviated, and the Commission has used the proceedings only to verify the accuracy of the utility's accounting. However, these fuel cost proceedings present the Commission with a natural opportunity to examine fuel prices and consider the regulatory incentives at play. The Commission must

[39] In Duke Energy's Modified 2020 IRP, Duke selected as its preferred portfolio C1, which proposed an additional 9,600 MW of incremental gas additions over the planning period for DEC and DEP combined (5,200 MW for DEC alone). The Commission in Order No. 2022-332 approved portfolio A2 from Duke's Modified 2020 IRP, which involves adding 7,950 MW of new gas additions for DEC/DEP over the planning period (3,500 MW for DEC). DEC Modified 2020 IRP at 10-11 (Aug. 27, 2021) Docket No. 2019-224-E, https://dms.psc.sc.gov/Attachments/Matter/81fe90b2-7966-4435-b14a-6a79549bfa33.

recognize the effects these FCA proceedings have on a utility's incentives and consider that when making decisions about the utility's cost recovery, rates, and resource acquisition in these and other types of proceedings.

Q: WHAT ARE THE DANGERS OF VIEWING FUEL PROCEEDINGS IN A SILO?

A: As stated earlier, the fuel risk that customers are exposed to—and the resulting rate increases when those risks inevitably come to bear—are the result of multiple decisions made in a variety of different dockets, including IRPs, energy efficiency proceedings, rate cases, avoided cost dockets, and many others.[40] Ignoring the interrelatedness of the various dockets may expose customers to cost burdens in fuel proceedings that could have been prevented through more risk aware regulation in the other proceedings.

Q: HOW SHOULD THE COMMISSION EVALUATE AND SEEK TO MINIMIZE CUSTOMER RISK IN ITS DECISIONS?

A: This is a complicated, but critically important question. I recommend that the Commission adopt a "risk aware" approach to its regulatory decision-making. Shortly after I left the Colorado PUC in 2011, I was the lead author on a report called "Practicing Risk Aware Electricity Regulation: What Every State Regulator Needs to Know." The report was well-received by the regulators I know and, in my view, remains relevant to state regulation today. That is because regulators, for years to come, will be faced with billion-dollar decisions about changes to the

[40] These proceedings include, for example, all dockets that address utilities' planned retirement or investment in fossil fuel resources, investment in renewable resources or demand-side resources, and rate design policies that affect customers' ability to invest in rooftop solar or make energy efficiency investments.

generation fleet needed to sharply reduce carbon emissions in the utility sector. The paper evaluates the risk of various supply-side and demand-side resources by utilities and recommends best practices for regulators that wish to be "risk aware." I have attached the "Risk Aware" report to my testimony as **Exhibit RJB-2**.

Q: CAN YOU GIVE AN EXAMPLE OF WHEN RISK AWARE REGULATON SHOULD BE APPLIED?

A: Yes. I have pointed out the intrinsic bias created by FCAs that recover changes in volatile fuel costs and therefore obscure the associated risk. As a result, facilities that burn fuel are seemingly put on the same footing as other resources like energy efficiency and renewable energy whose costs are known at the beginning and have no fuel risk. The following figure is an excerpt from the Risk Aware report in which we summarize seven strategies regulators can use to minimize these risks.[41] Several of these strategies apply directly to the South Carolina PUC.

[41] *See* **Exhibit RJB-2** at 38, 38-47; for a more detailed chart summarizing these strategies, *see* p. 10.

Figure 6: "Risk Aware" Report–Seven Strategies for Regulators to Minimize Risk

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Of these seven strategies, I would highlight two, especially at this time. First, there is no substitute for a robust planning process. During my time on the Colorado PUC, the IRP was the proceeding in which the most important and far-reaching decisions were made. The Colorado process was very interactive with many participants. The Commission took an active hand in ensuring that the utility prepared multiple scenarios, some of which were specified by the Commission. Intervenors prepared resource portfolios that could be actively compared to the utility's preferred portfolios. The Commission specified details of the competitive selection process that followed. Finally, the Commission required an independent evaluator to keep an eye on that process. As mentioned before, the Colorado Xcel IRP produced many resource bids and led to plant additions at very low cost.

The second strategy I would highlight is for Commissions to operate in an active mode, taking the initiative and not deferring excessively to the regulated companies, especially on "big picture" issues. This is sometimes called operating in "legislative mode" in contrast to the alternative of operating in the "judicial" role. But commissioners are not simply judges, waiting for matters in dispute to be brought to them. Times like these require the Commission to lead, not simply preside,[42] and indeed the South Carolina General Assembly has granted the Commission broad ratemaking authority.[43] Of course, utilities need to be free to run their businesses, but it is the regulator's role to provide guidance that serves consumer interests by recognizing and reducing risk, among other things.

Q: CAN UTILITIES ALSO BE RISK AWARE?

A: Yes, I can offer one example of a utility being risk aware. In 2004, Xcel Energy ("Xcel") led the campaign against a 10% renewable portfolio standard ("RPS") on the Colorado ballot, predicting that consumer prices would go up sharply. During my tenure on the Commission, Xcel began to transition away from coal generation (60% of its resources), adding more variable generation to its fleet. That marked a significant shift in its approach.

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[42] *See especially*, Scott Hempling. "Preside or Lead: The Attributes and Actions of Effective Regulators". Silver Spring, Maryland (2013), available for download at https://tinyurl.com/5bpfj4sf.

[43] S.C. Code Ann. § 58-5-210; S.C. Code Ann. § 58-27-140; *see also Duke Energy Carolinas, LLC v. S.C. Off. of Regulatory Staff*, 434 S.C. 392, 406 (2021) ("[T]he General Assembly has designated the PSC as the 'expert' in regulating rates and services of public utilities in the state."); *see also id*. at 405 (citing *Fed. Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (finding that a public utilities commission is not bound to the use of any single formula or combination of formulae in determining rates, and that determining whether a rate is "just and reasonable" depends on the total impact from a rate adjustment)).

The citizen ballot measure and state RPS legislation initially pushed Xcel to begin adding renewable energy. But Xcel has gone beyond those requirements on its own. The Company's approach has evolved into a full-blown corporate strategy that Ben Fowke, its former CEO, dubs "steel for fuel." Xcel argues that it is more profitable to own zero-fuel-cost resources like wind and solar generation (steel) instead of merely passing through the huge variable fuel costs of their fossil fleet (fuel) with no opportunity for earnings.[44] The rising price and volatility of gas and coal, combined with very low prices for solar and wind, and decreasing costs for storage, have validated Mr. Fowke's vision.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A: My findings and recommendations are summarized below:

- The price of gas is inherently volatile and in recent months has spiked to levels not seen since 2008. The Commission must consider these facts when making decisions about planning and resource acquisitions. These facts are interrelated and should not be viewed in isolation.
- High and volatile gas prices drive up the cost of essential electric utility services, straining households' finances and making budgeting difficult. The fuel cost increase sought in this case is the largest rate increase from DEC since at least 2013 and higher than recent inflation in the U.S. economy.

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[44] Gavin Bade, *DEEP DIVE 'Steel for fuel': Xcel CEO Ben Fowke on his utility's move to a renewable-centric grid*, Utility Dive (July 11, 2017), https://www.utilitydive.com/news/steel-for-fuel-xcel-ceo-ben-fowke-on-his-utilitys-move-to-a-renewable-c/446791/.

- Although its plans are still in flux, Duke Energy proposes to build significant amounts of new gas generation in the near future. The fuel charge adjustment mechanism makes that decision appear to Duke Energy to be less risky than it actually is. Duke Energy will not feel the risk because the fuel adjustment mechanism will very efficiently compensate Duke Energy for its prudent gas purchases, no matter how the price fluctuates or how high it goes. All the risk of higher gas prices is transferred to consumers. This is a classic case of a "moral hazard."
- Solar generation paired with storage (solar plus storage) can be treated as a dispatchable resource and is now cost competitive with gas combustion turbines. Further, solar plus storage carries no fuel price risk or volatility. Regulators should consider this when deciding whether to approve new gas power plants.
- The Commission should not view these fuel proceedings in a "silo" and should instead carefully consider how the utility business model affects utilities' incentives across multiple proceedings and how the Commission's individual decisions in these separate dockets will cumulatively affect customer risk. I recommend that the Commission practice "risk aware" regulation in evaluating and making decisions regarding DEC's resource mix, rates, and other choices that affect customer risk, the consequences of which are often realized in annual fuel proceedings such as this one.

Q: DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A: Yes.