COVER SHEET

TO REDACTED, PUBLIC VERSION
OF RESPONSIVE TESTIMONY OF
DEVI GLICK ON BEHALF OF SIERRA CLUB

APRIL 27, 2022

CONFIDENTIAL INFORMATION REDACTED—SUBJECT TO PROTECTIVE ORDER IN OKLAHOMA CORPORATON COMMISSION IN CAUSE NO. 202100164

BEFORE THE
OKLAHOMA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	**CAUSE NO. PUD 202100164**
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

*****PUBLIC, REDACTED VERSION*****

RESPONSIVE TESTIMONY

OF

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TABLE OF CONTENTS

LIST OF EXHIBITS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

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

Q Please describe Synapse Energy Economics.

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

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

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Arkansas, Arizona, Connecticut, Florida, Indiana, Michigan, Nevada, New Mexico, North Carolina, Ohio, South Carolina, Wisconsin, Virginia, and Texas. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

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

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Oklahoma Corporation Commission ("Commission" or "OCC")?

A No.

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

A In this proceeding, I evaluate the historical and forward-looking economics of Oklahoma Gas and Electric Company ("OG&E" or "The Company") coal units, namely Sooner Generating Station ("Sooner"), Muskogee Generating Station Unit 6 ("Muskogee 6"), and River Valley Power Station ("River Valley"). I also assess the adequacy of the analysis the Company has performed to justify the continued operation of its coal units, and the respective retirement years for the units that the Company is currently projecting and using for depreciation.

Q How is your testimony structured?

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

In Section 3, I provide an overview of OG&E's coal fleet and outline the test-year expenses that the Company is requesting to recover in this current docket.

In Section 4, I review the analysis and procurement efforts—or lack thereof—that OG&E has conducted to justify continuing to invest in and operate its coal-fired power plants, and to project that the units will operate through the mid to late 2040s.

In Section 5, I evaluate the respective historical economic performances of the Sooner, Muskogee 6, and River Valley coal plants, and I calculate the costs incurred and value provided to OG&E by each during recent years.

In Section 6, I use the Company's own data to evaluate each unit's projected economic performance over the next decade under different assumptions and sensitivities. I discuss the market and regulatory risks that the Company faces over the next decade in continuing to operate its coal plants. I also present alternative resource options that the Company should consider in evaluating the economics of its coal resources.

In Section 7, I outline best practices in resource planning and resource procurement that OG&E should be using to ensure it is serving customers with the lowest-cost portfolio of resources while maintaining system reliability.

Q What information do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of OG&E witnesses. I also rely on other publicly available documents and data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. OG&E incurred hundreds of millions of dollars in costs in excess of each plant's value at Sooner, Muskogee 6, and River Valley over the past five full calendar years (2017–2021).
2. OG&E is likely to continue to incur hundreds of millions of dollars in costs in excess of each plant's value at Sooner, Muskogee 6, and River Valley by continuing to operate and invest in each of the plants over the next decade (2022–2031).
3. OG&E has incurred over $500 million in capital expenditures for environmental compliance projects at Sooner, Muskogee 6, and River Valley over the past five years, and it may need to spend hundreds of millions more on capital projects needed to comply with environmental regulations over the next ten years. Compliance with the U.S. Environmental Protection Agency's ("EPA") recently proposed ozone "good neighbor" rule, for one, could require the utility to spend tens to hundreds of millions of dollars in compliance costs.
4. Since at least 2016, and probably since 2014, OG&E has not performed any modeling or economic analysis to assess the reasonableness of continued

operations and investment at Sooner, Muskogee 6, and River Valley relative to alternative resources; nor has it performed any modeling or economic analysis to identify optimal retirement dates and potentially more economic replacement options for these coal units. Rather, OG&E's recent modeling exercises have hard-coded 2040s retirement dates for the coal units, simply assuming that they are long-term economic resources. This is inconsistent with prudent utility practices of periodically conducting robust economic analysis that incorporates regular changes in market and regulatory forces, to test the cost-effectiveness of the utility's current and planned portfolio against potential alternatives.

5. Each of OG&E's coal units appears likely to be uneconomic when compared to market alternatives, according to my historical analysis. This means that OG&E's failure to assess alternatives and to model optimal retirement/replacement years are not merely theoretical shortcomings of process. Rather, the Company's approach is economically imprudent, has harmed ratepayers, and will continue to do so absent action from the Company or the Commission.

Q Please summarize your recommendations.

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

1. The Commission should require OG&E to conduct a full retirement study of its coal fleet that identifies the optimal retirement date for each of its coal-fired power plants, and the optimal future resource mix to meet projected load. This analysis should test critical sensitivities around increased capital and operating expenses needed to comply with current and foreseeable environmental regulations, gas prices, load growth, and carbon dioxide prices. As part of the study, OG&E should be required to issue an all-source request for proposals ("RFP") and to use its results,

which will best reflect up-to-date market data, in the Company's retirement study.

2. The Commission should require OG&E to prepare this study and present the results publicly as part of a docketed proceeding. This proceeding should commence, and the study should be completed, prior to or in connection with the Company's 2024 Integrated Resource Plan ("IRP"). Further, this proceeding should include robust procedures for meaningful scrutiny of the Company's analysis, such as stakeholder intervention, discovery, testimony, and witness examination. In addition, the proceeding should culminate in a binding Commission ruling about the reasonableness of both the Company's planning process and the substance of the resource plan itself, including unit retirement dates.
3. The Commission should signal that in future dockets it will not be inclined to approve cost recovery by OG&E of any capital investments of more than $1 million at the Company's coal units without prior Commission approval. The Commission should retain this position, unless and until the Company issues an all-source RFP and conducts the retirement analysis needed to demonstrate the prudence of continuing to invest in its coal fleet.

3. OG&E'S THREE COAL-FIRED POWER PLANTS

Q Describe OG&E's coal-fired fleet.

A OG&E fully owns and operates five coal-fired units across three power plants. These units all burn out-of-state coal from the Powder River Basin.[1]

[1] U.S. EIA form 923, 2021.

First, Sooner Generating Station is a two-unit power plant located near Red Rock, Oklahoma. Units 1 and 2 are both 569 MW[2] and were built in 1979 and 1980, respectively.

Second, Muskogee Generating Station Unit 6 is located near Fort Gibson, Oklahoma. It is a 572 MW unit[3] and was built in 1984.

Last, River Valley Power Station is a two-unit power station located in Le Flore County, Oklahoma. Units 1 and 2 are 175 MW each[4] and were built in 1991. OG&E purchased River Valley in May 2019 from AES Shady Point, LLC.[5] Prior to 2019, OG&E purchased the power from the plant under a power purchase agreement ("PPA").[6]

Q Describe the major air pollution controls installed at each plant.

A Sooner has a circulating dry scrubber flue-gas desulfurization ("FGD") system that OG&E installed to control sulfur dioxide ("SO_2") emissions; an activated

[2] OG&E Response to SC 3-1
[3] *Id*.
[4] *Id.*
[5] *See* Cause No. PUD 201800159, *In the Matter of Oklahoma Gas & Electric Company for Commission Preapproval Pursuant to 17 O.S. Section 286(C) for Acquisition of Capacity through Asset Purchase*; *see also, e.g.*, Selene Balasta, *OG&E completes purchase of 146-MW Okla. gas-fired plant*, S&P global, available at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/ia7gyyjor0slv3wdngstvq2.
[6] OG&E Response to SC 8-5.

carbon injection system ("ACI") to control mercury emissions; and low NO_x (nitrogen oxides) burners and overfire air technology to control NO_x emissions.[7]

Muskogee 6 has no SO_2 control system; has an ACI system to control mercury emissions; and uses combustion controls for NO_x emissions.[8]

River Valley has a dry sorbent injection ("DSI") system for SO_2 emissions (which is less effective but also less costly than an FGD system); a baghouse to control mercury emissions; and uses combustion controls to control NO_x emissions to a common stack.[9]

None of OG&E's coal units are equipped with selective catalytic reduction ("SCR") technology,[10] which is the current state of the art for controlling NO_x emissions.[11]

Q When does OG&E plan to retire each of these plants?

A Sooner Units 1 and 2 and are scheduled to retire in 2044 and 2045, respectively; Muskogee 6 is schedule to retire in 2049; and River Valley is scheduled to retire in 2048.[12] The Sooner and Muskogee 6 units will be 65 years old at their scheduled retirement dates, and River Valley will be 57 years old. OG&E uses these projected retirement dates for planning and for depreciation purposes.

[7] U.S. EIA Form 860; OG&E Response to SC 6-1(a).
[8] *Id.*
[9] *Id.*
[10] OG&E Response to SC 6-1(b).
[11] *See, e.g.*, *Proposed Rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, U.S. EPA, 87 Fed. Reg. 20036, 20042 (Apr. 6, 2022).
[12] Direct Testimony of John J. Spanos, Exhibit JJS-2, page III-7.

Q Is it common to see retirement dates this late in the 2040s for coal-fired power plants?

A No, these dates in the mid to late 2040s are highly unusual. Very few coal plants have retirement dates this far into the future, and I know of no other utility that is planning to keep its entire coal fleet online through the mid-2040s. This anomaly is all the more glaring without any robust retirement analysis to justify the plan.

Q What is the test year for this rate case?

A OG&E is using a historical test year of October 1, 2020–September 30, 2021.

Q What power plant operations and maintenance ("O&M") expenses and capital expenditures did OG&E include in the test year?

A OG&E test-year O&M expenses associated with its solid-fuel fleet totaled $83.8 million, and its test-year capital expenditures totaled $50.3 million, as shown below in Table 1.[13]

Table 1: Test-year (October 1, 2020–September 30, 2021) O&M expenses and capital expenditures by plant

Unit	Sustaining capital expenditures (million)	O&M (million)
Sooner 1	$17.7	$32.0
Sooner 2	$1.0	
Muskogee 6	$5.1	$26.4
River Valley 1	$21.7	$25.4
River Valley 2	$4.9	
Total	**$50.3**	**$83.8**

Source: OG&E Response to SC 1-3(d); OG&E Response to AG 1-16, Attachment 1.

[13] OG&E Response to SC 1-3(d); OG&E Response to AG 1-16, Attachment 1.

Q What is the remaining undepreciated balance for each plant?

A OG&E has over $1 billion in undepreciated plant balances remaining at its aging coal fleet, as shown in Table 2 below.[14] Nearly three-quarters of the balance is for Sooner, about 20 percent is for Muskogee 6, and the remainder is for River Valley.

Table 2: Remaining plant balance at OG&E's coal plants as of September 30, 2021

Unit	Total (millions)
Sooner 1	$499.9
Sooner 2	$273.0
Muskogee 6	$219.3
River Valley 1	$45.0
River Valley 2	$17.7
Total	**$1,054.9**

Source: OG&E Response to SC 5-1.

Q Is it concerning that OG&E has such a large undepreciated balance on its coal fleet?

A Yes. In recent years, OG&E has invested substantially in Sooner and Muskogee 6, including on costly emissions control technology required to comply with new environmental regulations. Most significantly among them was the half-billion-dollar FGD scrubber for Sooner. OG&E conducting modeling in 2014 to justify the investment but was denied preapproval based on that record in 2015.[15] In

[14] OG&E Response to SC 5-1.

[15] Cause No. PUD 201400229, *In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization and Cost Recovery.*

2019, after the project was completed, the Company did not conduct new modeling, yet did receive approval for cost recovery of the project.[16] That investment and others have contributed to the large current balance.

In the eyes of a utility, a large undepreciated balance is a barrier to retirement. OG&E has an incentive to keep the plants online because, if it retires any of the units early, it risks not recovering the remaining undepreciated balance. But to keep the plants online, the Company will need to continue investing in O&M as well as any necessary future major capital expenditures. If future environmental regulations require large capital investments or increased O&M, and the Company opts to continue investing in the plants rather than retiring them, those expenses will further inflate the undepreciated plant balance and make early retirement even more of a challenge. Then, when the plants do inevitably retire before the mid to late 2040s, the Company will be left with significant stranded assets.

It is very concerning that, since at least 2016—and probably since the 2014 modeling presented in both Cause Nos. PUD 201400229 and PUD 201800140—OG&E has not conducted any modeling or robust analysis to evaluate whether it is economic to keep investing in its coal capacity.[17] Without analysis of forward-going costs, OG&E cannot defend its operating assumption that operating and investing in its coal fleet indefinitely is the lowest-cost option for ratepayers.

[16] Cause No. PUD 201800140, *In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.*

[17] *See, e.g.*, OG&E Responses to SC 1-6, SC 5-2.

Q Is OG&E guaranteed recovery of the full undepreciated plant balance at its coal plants if any of them retire early?

A No, I don't believe so. I am not a lawyer, but my understanding is that if the Company does not demonstrate that continued investment and operation of a plant is prudent relative to alternatives, and the resource is shown to be not used and useful, then OG&E is not guaranteed full recovery of any undepreciated plant balance when it retires the plant. The decision on whether and to what extent to allow recovery of undepreciated balance is left to the Commission. I believe there is also theoretically the option of securitization, which I understand would need legislative approval, to facilitate at least some cost recovery of otherwise stranded assets.

Q Are you suggesting that the Commission should disallow the remaining undepreciated balances at all its coal plants when each one retires?

A No, not necessarily. I am asserting that OG&E has not performed the analysis necessary to demonstrate that continued investment in its coal fleet is the prudent and least-cost option to provide reliable power to ratepayers. Specifically, the Company has not performed any recent analysis to show any of the following: (1) whether the plants have been operating economically historically, (2) whether the plants are projected to continue to operate economically relative to market alternatives; (3) whether continued operation of and investment in the coal plants is the least-cost option for ratepayers, even with future risks of incurring high environmental compliance costs (among other factors); and (4) whether the scheduled retirement dates are the optimal retirement dates for the coal plants.

Q Is there precedent for disallowing or limiting the recovery of costs for a plant that is retired early?

A Yes. For one example, in Southwestern Electric Power Company's ("SWEPCO") most recent rate case in Texas, PUC Docket No. 51415, the Public Utility Commission of Texas's ("PUCT") final order allowed SWEPCO to place the undepreciated plant balance for the Dolet Hills Power Plant into a regulatory asset after the plant retires; but it also rejected the Company's request to earn a rate of return on its investment once the plant retired.[18] OG&E knows that the utility has the burden of proof to demonstrate that continued investment in its resources is reasonable and in the best interest of ratepayers.

4. FOR THE BETTER PART OF A DECADE, OG&E HAS FAILED TO ASSESS THE REASONABLENESS OF CONTINUING TO OPERATE ITS COAL PLANTS OR OF THEIR PROJECTED RETIREMENT DATES—AND SHOULD TIMELY ADDRESS THAT FAILURE WITH ROBUST, TANGIBLE, AND TIMELY ANALYSIS.

Q Has OG&E conducted any modeling in at least the past five years to assess the cost of continuing to operate its coal fleet or to determine an optimal retirement date for any of its coal plants?

A No. OG&E has not conducted any modeling of the cost of continuing to operate its coal fleet or optimal retirement dates for any of its coal plants since at least 2016, as OG&E confirmed in discovery.[19] The last analysis of which I am aware

[18] PUCT Docket No. 51415, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Final Order (Jan. 14, 2022) at ¶¶ 44-65.
[19] OG&E Responses to SC 1-6 and SC 5-2.

is the 2014 retire / convert / upgrade analysis that was prepared to evaluate whether to install a scrubber at the Sooner and Muskogee plants.[20]

Q Did OG&E study the near-term retirement of any of its coal plants as part of its most recent IRP?

A No. OG&E did not evaluate or study the economics or retirement dates of any of its coal plants as part of its 2021 IRP.[21] Instead, the Company identified retirement dates in its Depreciation Study and used those dates as an input for the IRP process.[22] The Depreciation Study did not evaluate unit-level forward-going economics relative to potential alternatives in the market.

Q How does OG&E determine retirement dates as part of its Depreciation Study, if not using resource economics?

A OG&E identified the depreciable life span for each unit based on a narrow analysis that evaluates plants in isolation from the larger system in which they operate. Specifically, OG&E said this about the Depreciation Study:

> The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major

[20] *See supra*, footnotes 15-16 & accompanying text.

[21] *See, e.g.*, OG&E Responses to SC 2-1(b) and SC 5-2; *see also* Public Meeting on OG&E 2021 IRP (Sept. 16, 2021), exchange at ~1:06–1:11, available through OCC website at: https://www.zoomgov.com/rec/play/Q3L6Ip35irf2FDpuL4dSGi-1sanPN8n32Avwyxs0IsJYqWcHd4gqIBrgnMpyEmaTuBGEiMbbRruYbVfv.3w6ji--LCfUrRrgH?startTime=1631803591000E.

[22] OG&E Response to SC 2-1(b).

> refurbishing, discussions with management personnel concerning the probable long-term outlook for the units….[23]

It is concerning that OG&E is continuing to use the same, limited methodology it has used for decades to project unit retirement dates. Even more concerning is that this methodology relies on units' generic manufacturer useful lives and on staff's internal intuitions. OG&E does not use robust modeling informed by current data inputs and multiple sensitivities to determine unit retirement dates.

While that might have been reasonable decades ago when replacement options were more limited, and coal-fired power's comparative economics were strong, it is not reasonable to do so today. The Company has access to many resource options in the market today, including solar PV, wind, battery storage, demand-side management, gas, and firm energy and capacity purchases. These resources can, independently or in combination with other resources, provide the energy, capacity, and other grid services that OG&E needs to replace aging coal resources. Moreover, announced retirements of coal-fired power plants have become ubiquitous in recent years, with industry trends plainly illustrating the underlying comparative resource economics that support retirement and replacement with less expensive resource combinations.

The question of whether to operate or retire a unit today, or in the near or medium term, should not focus on how long a power plant could remain active as a matter of operational capability or book life; rather, it should focus on how much it will cost going forward (including any capital costs as well as operating costs) relative to the costs of alternatives that might replace it. The analysis should also consider

[23] OG&E Response to SC 2-1(a).

how the risks of continuing to operate the plant compare to the risks inherent to other resource options.

Since at least 2016, and probably since 2014, OG&E has not systematically analyzed the costs or risks associated with keeping its coal fleet online relative to alternatives. And the Company has indicated that it has no definite plans to do so in the foreseeable future.[24]

Q Has OG&E issued an all-source RFP to properly consider alternatives to continuing to operate its coal plants?

A OG&E issued an all-source RFP in 2018 and received ninety-four distinct proposals from nineteen different bidders for a total of 6,400 MW of capacity. The bids were from both existing and new generating facilities, and covered a range of resource types including coal, natural gas, wind, solar, and batteries. The proposals also covered a range of locations, specifically twenty-six different locations within a 350-mile radius of Oklahoma City.[25]

But despite this high level of participation in the all-source RFP, none of these resources were considered for replacement of any of OG&E's coal plants. As noted above, this is because the Company simply hard-coded in the retirement dates for its coal units in its recent modeling.

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[24] *See, e.g.*, OG&E Responses to SC 2-1(b) and SC 5-2; Public Meeting on OG&E 2021 IRP, exchange identified *supra* in footnote 21.

[25] OG&E Response to SC 5-08; Direct Testimony of Leon Howell in Cause No. PUD 201800159, at 7:1-8.

Q Is the decision by OG&E to keep operating its coal plants without robustly assessing alternatives consistent with how other utilities in the region and across the country are treating resource planning around their coal assets?

A No. For one, another large investor-owned utility in Oklahoma, Public Service Company of Oklahoma ("PSO"), has committed to retiring the last of its coal units by 2026.[26] Further, PSO does not plan on building any new gas—only solar—over the next 10 years, in combination with increases in demand-side resources such as demand response, energy efficiency, and distributed generation.[27] Given that OG&E's neighboring Oklahoma utility is planning to be *entirely* out of coal four years from now, it is unclear how OG&E can defend the need to keep *five coal units* online through the next decade, let alone until the mid to late 2040s, absent any evidence of the underlying economics of such a decision.

Since 2012, over 100 GW (100,000 MW) of coal capacity in the United States has retired. In 2022 alone, coal-fired power is expected to account for 85 percent of electric generation capacity retirements, and another 57 GW (57,000 MW) has announced retirement dates before 2030.[28]

[26] PSO Final 2021 IRP (distributed to stakeholders via email on Oct. 29, 2021; not posted by PSO online or posted yet by the OCC on its website; voluminous and available upon request) at 41, 48.

[27] *Id* at 126.

[28] U.S. EIA. *Coal will account for 85% of U.S. electric generating capacity retirements in 2022*. January 11, 2022. Available at https://www.eia.gov/todayinenergy/detail.php?id=50838#.

Q Are you proposing that OG&E retire all its coal plants and replace the capacity and energy with alternative resources immediately, or even necessarily in the next few years?

A No, not necessarily. I recognize that OG&E cannot instantly replace the energy and capacity from 2 GW of coal-fired generation overnight; nor would it want to. It takes time to plan for a plant shut-down, to procure replacement resources, to construct replacements, and to get them grid-operational. But OG&E needs to evaluate and understand the economics of each unit relative to alternatives to understand when each unit should be economically retired.

The Company should identify which units are most costly or will likely require the most costly or risky investments to stay online, and which are less costly and risky. OG&E should identify an optimal order to retire and (as necessary) replace each unit, and an optimal and feasible retirement date for each based on the availability of market alternatives.

5. OG&E'S COAL PLANTS INCURRED HUNDREDS OF MILLIONS OF DOLLARS IN COSTS IN EXCESS OF THEIR VALUE FROM 2017–2021.

Q Please summarize your findings on the economic performance of the Sooner, Muskogee, and River Valley plants in recent years.

A I find that Sooner, Muskogee 6, and River Valley have incurred costs in excess of the value of their energy and capacity over the past five years. In all my calculations, I relied on projected unit costs provided by the Company, the cost of resource purchases provided by the Company, historical and projected market prices provided by the Company, and the cost of alternative resource options from the National Renewable Energy Laboratory ("NREL"). I also evaluated a number of sensitivities including (1) using the Southwest Power Pool's ("SPP") Cost of New Entry ("CONE") as a proxy for value of capacity in the region,[29] (2) removing the impact of winter storm Uri, (3) removing the cost associated with FGDs, and (4) adding potential future costs associated with SCRs. I also evaluated the cost of alternative resources going forward to compare the cost that OG&E is currently paying to operate its coal fleet, to the cost of replacement resources available on the market.

Q Describe how the Company has been operating its coal-fired power plants over the past five years.

A Over the last six years (three years for River Valley), OG&E operated the Sooner, Muskogee 6, and River Valley plants at a collective average capacity factor of around 40 percent.[30] But, OG&E expects the units' combined average capacity factor to [redacted] over the next five years, and [redacted] over the next ten years.[31]

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[29] In SPP, CONE is calculated based on the revenue needed to cover the capital and fixed costs of a hypothetical gas-burning peaking facility. This is a conservative estimate because unless a region is capacity constrained, then capacity can generally be procured for less than the cost of buildings an entirely new peaking plant.

[30] OG&E Response to SC 4-8; U.S. EIA Form 923 for River Valley generation prior to May 2019.

[31] OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

Figure 1: CONFIDENTIAL historical and projected capacity factors for OG&E's coal plants

[redacted]

Source: OG&E Response to SC 4-08; EIA Form 923 for River Valley generation prior to May 2019; OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

Q Are there any market or regulatory factors to consider when evaluating the historical performance of OG&E's plants between 2017 and 2021?

A Yes, there are several things to consider regarding specific costs incurred and revenues earned during this time period.

First, in February of 2021, winter storm Uri swept through the region. It knocked out power for days for many households and businesses and sent locational marginal prices ("LMPs") in the region to highly anomalous, record levels. Any plants that were able to remain online during this time earned enormous revenues. Sooner (although it did experience some downtime during the storm due to freezing[32]), Muskogee, and River Valley (which was also offline for part of the storm) earned combined energy market revenues in February 2021 that were 42 times higher than average for a February (based on the average of OG&E's revenues over the prior five February's).[33]

Second, OG&E installed a circulating dry scrubber FGD system on Sooner, finishing the work in 2019, to control SO_2 emissions. This project cost $515 million, over 60 percent of which was incurred in the 2017–2021 timeframe. This is not a cost that the Company regularly incurs, but it is representative of the cost and risk that environmental compliance costs can and will continue to impose on fossil-fuel power plants. And it does represent a cost that the Company will recover, and ratepayers will pay, over the remaining life of the plant (absent securitization or some future disallowance by the Commission).

Q Is it reasonable for OG&E to plan around the assumption that another extraordinary market price spike, like the one associated with winter storm Uri, will deliver high revenue and offset unit spending?

A No. It would be imprudent for OG&E to plan its system around the assumption that another anomalous catastrophe will deliver record market revenues and offset standard costs and losses. The alignment of environmental, infrastructural, and market conditions that caused the price spikes during winter storm Uri is unusual,

[32] Cause No. PUD 202100072, *In the Matter of the Application of Oklahoma Gas and Electric Company for a Financing Order Pursuant to the February 2021 Regulated Utility Consumer Protection Act Approving Securitization of Costs Arising from the Winter Weather Event of February 2021,* Direct Testimony of Robert Doupe (June 18, 2021), at 10-11.

[33] OG&E Response to SC 1-17.

and those abnormal circumstances are unlikely to happen again, at least not to that extent. While there is still a lot of operational preparation to do in the region, efforts to winterize generation resources, adjust capacity accreditation, firm-up fuel supplies, and adjust market pricing rules have all been occurring or are in the works in the aftermath of that catastrophe.[34] Further, the economic risks that exist under normal (or at least less abnormal) weather circumstances that lead to operational costs, including compliance with future environmental regulations—are much more likely to be realized than the conditions seen in February 2021.

Q Is it reasonable for OG&E to plan around the assumption that the FGD costs were highly anomalous, and it is not likely to incur costs of that nature again the near future?

A No. While costs of this magnitude are not incurred every year, it is likely that OG&E will have to incur other substantial environmental costs in the future to comply with future environmental regulations. For example, EPA recently proposed a new regional haze rule that could require OG&E to install SCR or selective non-catalytic reduction ("SNCR") technology on its coal plants.[35] This would cost OG&E tens to hundreds of millions of dollars in compliance. I will further discuss this risk in Section 6 below.

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[34] *See* Preparing for the Big Chill, OCC website (collecting presentations), available at: https://oklahoma.gov/occ/divisions/public-utility/consumer-services/preparing-for-the-big-chill-2021.html; *see also, e.g.*, Runyon, Jennifer, "On Year after Uri: Texas energy experts weigh in on grid reforms," Power Grid International (Feb. 2, 2022), available at: power-grid.com/td/one-year-after-uri-texas-energy-experts-weigh-in-on-grid-reforms/#gref.

[35] 87 Fed. Reg. 20036.

Q Taking into account these factors, describe the economic performance of OG&E's power plants over the past five years.

A All three coal plants incurred costs (variable and fixed) well in excess of their energy revenue and the value of their capacity in every year between 2017 and 2020, as shown in Table 3 below. In 2021, each coal plant earned positive revenues in excess of its value.

Table 3: Historical net costs/value of OG&E's coal fleet relative to the market value of each units' energy and capacity, 2017–2021 ($2022 million)

<table>
<tr><th></th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th></tr>
<tr><td>Sooner 1&2</td><td>($247)</td><td>($124)</td><td>($66)</td><td>($70)</td><td>$253</td></tr>
<tr><td>Muskogee 6</td><td>($121)</td><td>($77)</td><td>($88)</td><td>($67)</td><td>$71</td></tr>
<tr><td>River Valley 1&2</td><td>($47)</td><td>($59)</td><td>($11)</td><td>($32)</td><td>$22</td></tr>
<tr><td>Total</td><td>($415)</td><td>($260)</td><td rowspan="2">($164)</td><td rowspan="2">($169)</td><td rowspan="2">$346</td></tr>
<tr><td>Total without FGDs at Sooner</td><td>($203)</td><td>($151)</td></tr>
</table>

Source: Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 04-08; OG&E Response to SC 8-05; OG&E Response to AG 13-7; U.S. EIA Form 923 for River Valley generation prior to May 2019.

In total, OG&E's coal plants incurred $661 million in costs in excess of their value over the past five years, as shown in Table 4 below. When adjusting for (*i.e.*, removing) the anomalous energy market revenues from 2021, as well as the cost of the FGD controls incurred in 2017 and 2018, excess costs increase just slightly to $686 million.

Table 4: Total historical revenue 2017–2020 and 2017–2021 ($2022 million)

	2017–2021		**2017–2020 (exclude 2021)**		**2017–2020 (exclude 2021& FDG)**	
	Total	**Annual Average**	**Total**	**Annual Average**	**Total**	**Annual Average**
Sooner 1&2	($254)	($51)	($506)	($127)	($185)	($46)
Muskogee 6	($282)	($56)	($353)	($88)	($353)	($88)
River Valley 1&2	($126)	($25)	($148)	($37)	($148)	($37)
Total	($661)		($1,007)		($686)	

Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 04-08; OG&E Response to SC 8-5; OG&E Response to AG 13-7; U.S. EIA Form 923 for River Valley generation prior to May 2019.

Q Explain how you calculated the values displayed in Table 3 and Table 4.

A I calculated the net revenues in Table 3 and Table 4, above, using the Company's own data on unit costs and revenues, supplemented by a small amount of public data.

For costs, OG&E provided historical fuel costs[36] and total O&M costs[37] by plant for each historical year between 2017–2021. The Company also provided historical sustaining capital expenditures and environmental capital expenditures for the period 2017–2021.[38] I added the capital expenditure costs to the fuel and O&M costs to get total unit costs. For River Valley, OG&E did not have cost data for the years prior to its purchase of the plant (2017 and 2018). But OG&E did provide the energy and capacity charges it paid to the prior owner in these years.[39]

[36] OG&E Response to SC 1-10, Attachment 3.
[37] OG&E Response to SC 1-10, Attachment 2.
[38] OG&E Response to SC 1-10, Attachment 4.
[39] OG&E Response to SC 8-5.

I used these charges to represent the variable and non-variable costs incurred to operate the maintain the units in these years.

For revenues, OG&E provided energy and ancillary market revenues[40] from selling the energy from each unit into the SPP market. SPP does not have a capacity market, and therefore the Company earned no capacity market revenues over the years 2017–2021. I instead valued capacity based on the cost the Company could pay to purchase a new capacity resource during this time. Because OG&E actually did purchase new capacity during this time period, specifically the River Valley and the Frontier power plants, I used the purchase price OG&E paid, the MW of capacity of the units combined, and the years the plants will provide capacity to OG&E to find the total capacity value of the plants.[41] I summed this capacity value with the energy and ancillary revenues to get total unit revenues.

Finally, I calculated the difference in each year between unit costs and revenues to produce the net revenues at each plant, shown in Table 3.

Q Looking at each plant individually, how did Sooner Units 1 and 2 perform in recent years?

A As shown in Table 3 and Table 4, at Sooner, OG&E incurred costs in excess of value on a forward-looking[42] basis over the past five years (2017–2021), totaling

[40] OG&E Response to SC 1-17, Attachment 1.

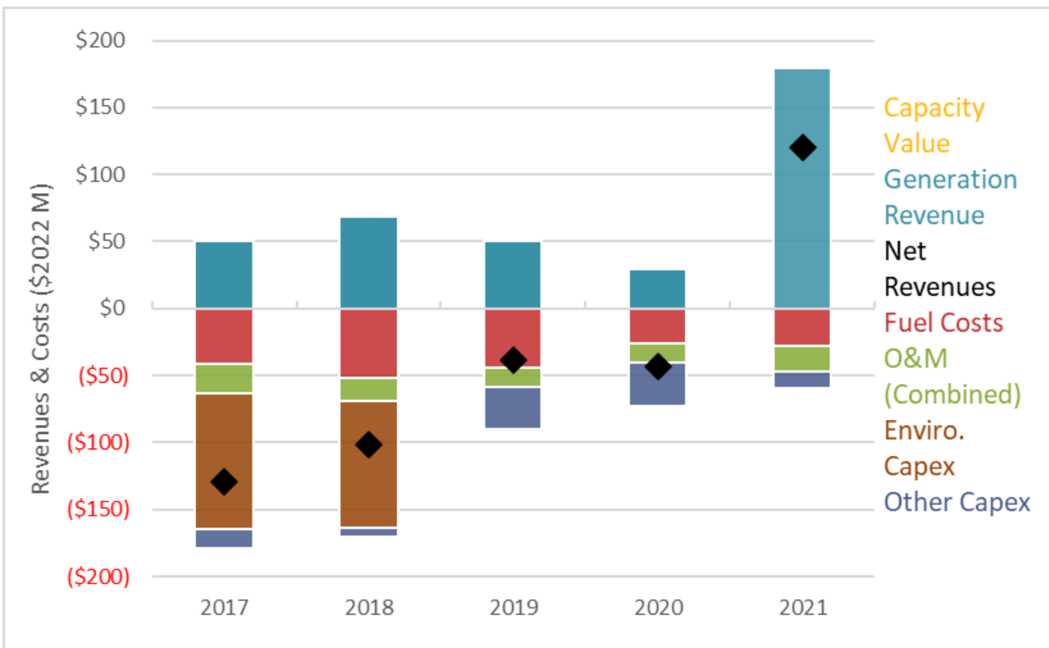
[41] OG&E Response to AG 13-7(e).

[42] Forward-looking cost analysis looks at all costs incurred due to the continued operation of the plant, and therefore could be avoided by the retirement of the plant. All capital and fixed costs that had already been incurred, such as prior capital investments and fixed operating costs, are excluded from this analysis. This is because the decision to retire or operate the plant has no impact on whether or not they are incurred.

$254 million ($2022) at Sooner Units 1 and 2. This works out to an average of $51 million in excess costs relative to the market every year.

Figure 2 below shows the breakdown in costs and revenue for just Unit 1 (which is representative of the costs and revenues incurred at Unit 2 as well). There are two defining features of this data in Figure 2, as discussed above: (1) OG&E earned the majority of its energy market revenue in 2021 during winter storm Uri, (2) OG&E incurred substantial cost (specifically $321 million across both plants) to install scrubbers at Sooner in 2017 and 2018.

Figure 2: Annual costs and revenue for Sooner Unit 1, 2017–2021



Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 8-5; OG&E Response to AG 13-7.

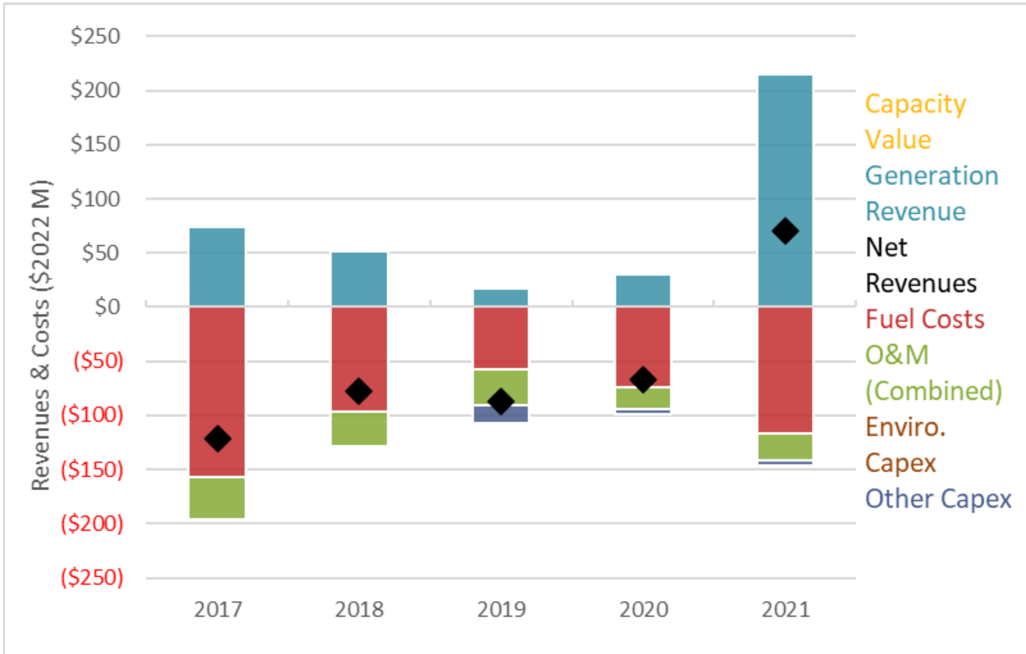
If we omit the scrubber costs (under "Enviro. Capex."), the plant appears to have excess value of $68 million over the past five years. But, as with all capital expenditures that the Company incurs each year, the project costs must be covered by the unit's energy market revenue and any capacity value over the lifetime of the project, as I will detail below.

Excluding both the extraordinary revenues earned in 2021 and the scrubber costs from 2017 and 2018, OG&E excess costs drop just to $185 million over the four-year period from 2017–2020, for an average of $46 million in excess costs per year. This demonstrates how poorly the unit has performed relative to the market value of the unit's energy and capacity in recent years. And it shows that without the record market prices that resulted from winter storm Uri, and the highly anomalous revenue that the Company earned as a result, Sooner would have incurred substantial excess costs relative to the market over the past five years.

Q How did Muskogee 6 perform in recent years?

A Figure 3 below shows the historical cost breakdown at Muskogee 6. Specifically, OG&E incurred costs in excess of market value on a forward-looking basis over the years 2017–2021 totaling $282 million ($2022). This works out to an average of $56 million excess costs each year. Excluding 2021—the year of the anomalous Uri storm, from which lessons have been learned, and in response to which reforms have begun to be implemented—Muskogee 6's performance drops to total losses relative to the market of $353 million between 2017–2020 for an average of $88 million in losses per year.

Figure 3: Annual costs and revenue for Muskogee Unit 6, 2017–2021

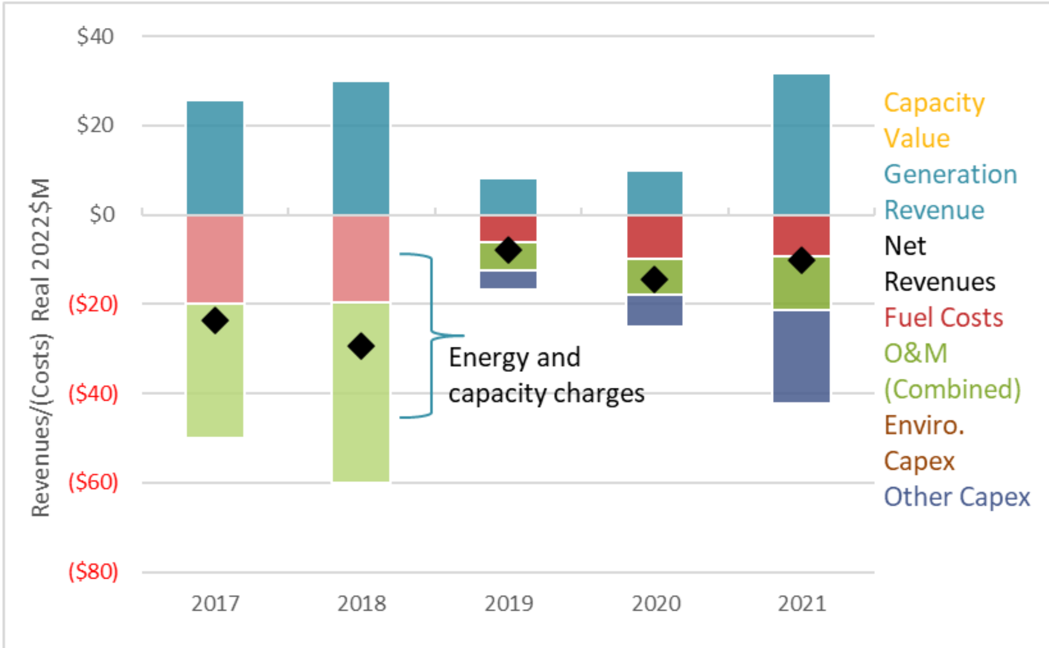


Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 8-5; OG&E Response to AG 13-7.

Q How did River Valley perform in recent years?

A Figure 4 below shows the historical cost breakdown at River Valley Unit 1 (whose performance is comparable to that of Unit 2). OG&E purchased River Valley in May of 2019, so for 2017 and 2018, I used Company data on the cost that OG&E paid to the prior owner for the plant's energy and capacity. For 2019–2021, I used Company data on operational costs and revenues. Based on this, I find that OG&E incurred costs in excess of market value at River Valley on a forward-looking basis over the years 2017–2021 to a total of $126 million ($2022). This works out to an average of $25 million in excess costs each year. Excluding 2021, River Valley's performance drops with costs exceeding value of $148 million from 2017–2020 for an average of $37 million in excess costs per year.

Figure 4: Annual costs and revenue for River Valley Unit 1, 2017–2021



Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 4-08; OG&E Response to SC 8-5; OG&E Response to AG 13-7; U.S. EIA Form 923 for River Valley generation prior to May 2019.

Q Explain why you added the full cost of each expenditure in the year it was incurred instead of annualizing the costs over the remaining life of the plant?

A I expensed the full cost of each capital expenditure in the year it was incurred because this approach is more robust against early retirements, but I do present alternative annualization assumptions later in the next section. In years where large projects are undertaken, capital expenditures will likely exceed the resources' total revenues and value; but the reverse is also true. And over a multi-year timeframe, if the plant is operating economically, the total costs incurred and total energy revenues earned and capacity value should, at the very least, net out. If they do not—meaning that the plant's total fixed and variable costs consistently sum to more than its total energy market revenues and capacity value—then continuing to invest in the plant is not in ratepayers' interest on a forward-going basis.

In contrast, the Company typically annualizes capital expenditures (based on the utility's cost of capital) and spreads the costs out over the remaining economic life of the plant. This approach is reasonable with projects where there is a reasonable degree of certainty that the plant will operate through its planned retirement date. But it is dangerous with aging resources that we know are likely to retire early—in line with a strong, widespread, accelerating trend across the country.[43] A project might look economic when spread out over 20 years, with 20 years of energy market revenues and capacity value to balance it out. But if it has to be recovered over only five or ten years instead (with only five to ten years of revenue and value as well) it suddenly becomes clear how expensive and uneconomic it was to invest in the plant.

[43] *See supra* footnote 28 & accompanying text; *see also, e.g.*, Darren Sweeney, *et al.*, *More than 23 GW of coal capacity to retire in 2028 as plant closures accelerate*, S&P Global, available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/more-than-23-gw-of-coal-capacity-to-retire-in-2028-as-plant-closures-accelerate-68709205 ("Under price pressure from renewable power and a national move away from high-emission fuels, utilities plan to shutter 51 GW of coal power from 2022 through 2027, according to S&P Global Market Intelligence analysis. But in 2028 alone, retirements will jump by 23 GW, and that doesn't include the retirements of the 1,700-MW Conemaugh and 1,700-MW Keystone coal-fired power plants in Pennsylvania that were reported by media."); Rebecca J. Davis, *et al.*, *Coal-Fired Power Plant Retirements in the U.S.*, Working Paper 28949, June 2021, National Bureau of Economic Research, at 4, available at: https://www.nber.org/papers/w28949 ("Figure 1 displays the location of the coal-fired generators that have retired between 2010-2019. They represent 473 generators with a nameplate capacity of nearly 80 thousand MWs.").

This is exactly what we are seeing now at other plants in the region. Examples include the Dolet Hills coal plant in Louisiana and Pirkey power plant in Texas, both of which participate in SPP and happen to be at least partially owned by American Electric Power Company ("AEP") subsidiary SWEPCO. Major capital investments at the two plants were justified based on the assumption that the costs were going to be recovered over the remaining decades of the plants' lives (despite clear indications that both plants were already uneconomic). Now that the plants are both retiring, SWEPCO ratepayers are exposed to hundreds of millions in incurred capital expenditures with no incoming revenue or value in exchange.[44] As I will discuss in the next section, this is what I expect will happen at OG&E's coal plants if the Company continues to invest in these plants.

6. OG&E'S PROJECTIONS LIKELY UNDERESTIMATE THE COST TO OPERATE ITS COAL FLEET, AND WE FIND THAT UNDER MORE REASONABLE ASSUMPTIONS, ITS COAL PLANTS ARE LIKELY TO INCUR COSTS IN EXCESS OF THEIR VALUE OVER THE NEXT DECADE

Q How does the Company project it will operate its coal plants over the next decade?

A OG&E has performed no recent analysis on the projected economic performance of its coal fleet; therefore, I had to conduct my own analysis using available Company data. The most recent data available on expected unit costs, performance, and revenues were from its 2021 IRP, where OG&E hard-coded the

[44] PUCT Docket No. 51415, *Application of Southwestern Electric Power Company for Authority to Change Rates.*

retirement dates in for each of its coal units.[45] OG&E's modeling shows its coal fleet operating at [redacted] combined average capacity factor from 2022–2031, as noted above. This represents [redacted] current operational levels. These results indicate that there are lower-cost options that the Company can use to serve load, and that OG&E's coal plants are relatively more expensive and less competitive than market energy and other Company resources. The plants' economics will be further threatened if OG&E has to install costly equipment to comply with future environmental regulations, such as the newly proposed Good Neighbor Rule poised to require reductions in NO_X emissions.

Q Did you evaluate the forward-going economics of OG&E's power plants, inclusive of both fixed and variable costs and the full value of each plant's energy and capacity?

A Yes, I evaluated the forward-looking value of each power plant in several ways. The goal of these pieces of analysis is to demonstrate the high level of uncertainty and also the high level of risk OG&E faces in continuing to operate its power plants without conducting robust economic retirement analysis.

First, I evaluated the total value of each plant using conservative capacity value assumptions and calculated a break-even capacity value for each plant. I then factored in the possibility that the Company will have to install SCR or SNCR technology at each plant to control NO_X emissions and comply with the currently

[45] OG&E Response to SC 1-12(a), OG&E Final 2021 IRP at 17. For its IRP modeling, OG&E relies on PROMOD® software to simulate the SPP IM and project hourly nodal LMPs. The PCI GenTrader® software than uses the LMPs to determine production costs and market revenues for these generators. A revenue requirement model combines all the costs components into the estimated 30-year net present value of customer costs.

proposed Good Neighbor Rule, and I evaluated the impact of this risk on the economics of each plant.

Second, I evaluated the economics of each plant assuming that all capital costs will be depreciated over the remaining life of the plant instead of expensed in the year they are incurred. I also imposed an arbitrary but illustrative retirement date of 2031, to show the impact on unit economics if the Company continues to plan around retirement dates in the mid to late 2040s but ends up retiring a plant early.

Finally, I evaluated the cost of alternative resources to benchmark against the cost that OG&E is projected to spend to keep its coal plants online.

Q Starting with the first analysis you discuss, what did you find regarding each plant's economic performance under a different capacity price and capacity factor assumption?

A Using the conservative, high measure of SPP CONE[46] to represent the capacity value of each resource, and assuming all of OG&E's modeling assumptions from its IRP are accurate (which I do not), I find that the best-case scenario is that the market value of the plants could exceed their costs by [redacted] on an NPV basis over the next decade.[47]

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[46] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No.1 – Attachment AA Resource Adequacy – Attachment AA Section 14. Cost of New Entry. Available at: https://spp.org/documents/58599/cone-effective%207-1-2018.pdf

[47] Calculated based on OG&E Response to SC 1-14, Attachment 1; OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

CONE is defined as "the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future recovery over its economic life."[48] The CONE values are calculated based on the cost to build a new natural gas-fired peaking facility in SPP.[49] This is a conservative capacity value estimate because, unless a region is capacity constrained, capacity can generally be procured for less than the cost of building an entirely new peaking plant.

Q Given this finding, do you think it likely that OG&E's coal plants will continue to provide value to OG&E ratepayers over the next few decades?

A No. The finding that OG&E's coal plants may continue to provide substantial value to the Company represents the best-case scenario—a scenario that assumes the highest capacity value possible, assumes retirement dates well over two decades into the future, and assumes extremely low future capital investments and environmental compliance costs. All of those assumptions are concerning and unlikely to materialize.

It is implausible to assume that a fleet of aging coal plants that has incurred substantial costs in recent years will somehow become more economic in the long term—even as their equipment ages, renewables and battery storage penetration increase on the grid, and generation resources face increased environmental

[48] PJM Cost of New Entry, The Brattle Group. April 2018. Available at: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[49] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No.1 – Attachment AA Resource Adequacy – Attachment AA Section 14. Cost of New Entry. Available at: https://spp.org/documents/58599/cone-effective%207-1-2018.pdf.

constraints. Given each plant's poor economic performance over the past five years, it is unclear how OG&E can expect that the plants will transform into net revenue generators as their utilization drops.

Q Do you have any concerns with any of the input costs or revenues provided by OG&E?

A Yes, several. First, the Company relied on low cost assumptions around base sustaining capital expenditures. These assumptions are inconsistent with its historical spending, and with industry-leading estimates for sustaining capital expenditures ("capex").

Second, the Company has not evaluated the risk associated with future environmental compliance costs. For instance, OG&E admitted that the Company has neither prepared any estimation of what it would cost to install and operate SCR on its coal plants, nor tracked those costs generally in the industry.[50] This means OG&E has likely substantially understated future environmental capital expenditure costs.

Third, OG&E assumed that the capacity factor of each coal unit would increase substantially in the late 2020s and early 2030s and, as a result, the coal fleet's energy market revenues would increase. The assumption that each plant's utilization would increase as it aged is both unsubstantiated and concerning, in that it inflates future energy revenue projections.

Finally, OG&E assumed that each plant operates through the mid or late 2040s and did not test any early retirement dates. This means the Company assumes that any capital expenditures it incurs to keep the coal plants operating will be spread

[50] OG&E Response to SC 6-1; OG&E Response to SC 8-7.

out over the remaining decades, with accompanying decades of revenue to cover the cost. It also means the Company is not considering how to ramp down spending in the event of an early retirement and it is not evaluating the cost and feasibility of alternatives.

Q Explain your concerns with OG&E's sustaining capex assumptions for its coal plants looking forward?

A OG&E's forward-looking sustaining and environmental capital expenditure assumptions for each unit are very low, meaning OG&E is likely underestimating the cost to operate its coal plants on a forward-looking basis. The Company's estimates are also out of line with historical spending at the units and industry standard estimates put out by the U.S. Energy Information Administration ("EIA"). They also are not supported by detailed, itemized cost data, and they do not include costs to comply with likely future environmental regulations.

Specifically, as shown below in Table 5, OG&E's projected capex spending at Sooner, Muskogee 6, and River Valley over the next decade is between 20 and 40 percent lower than OG&E's historical average annual spending at each plant (d excluding the historical FGD costs at Sooner). This means that OG&E is projecting that it will spend around $19.4 million less annually on capital expenditures to maintain its coal plants than it spent historically. When FDG costs are added into the historical cost comparison at Sooner, projected forward-going costs drop to only one-quarter of historical costs, for an annual difference across the fleet of $62.4 million. Note that I included 2022 costs in the historical bucket because some have already been incurred or are in progress, and the Company provided a high level of detail for 2022 cost estimates.

I also looked at industry-standard estimates for annual capex spending produced by the firm Sargent & Lundy for the EIA. I found OG&E's actual spending at Sooner and River Valley over the past 5 years was substantially higher than Sargent & Lundy projected (spending at Muskogee 6 was lower than Sargent & Lundy projected). This means that if historical spending at Sooner and River Valley is indicative of future costs trends, then we can expect to see capex at Sooner and River Valley continue to exceed industry average estimates.

Table 5 below summarizes the cost comparisons discussed above.

Table 5: Historical capex spending vs. OG&E's projected future capex spending at the Company's coal plants ($2021 Million)

	Sooner	**Muskogee 6**	**River Valley**	**Total**	**Delta from projected**
Historical average annual capex spending (millions)					
Average of 2017–2022* actual spending	$30.1 ($73.1 with FGD)	$8.2	$14.6	$53.0 ($95.9 with FGD)	$19.4 ($62.4 with FGD)
OG&E's projected average forward-going annual capex spending					
Average of 2023*–2031 projected spending	$18.4	$6.9	$8.3	$33.5	n/a
EIA / Sargent & Lundy estimates of annual sustaining capex for steam coal plant					
Sargent and Lundy report based on plant size, age, and FGD status	$25.5	$12.1	$9.5	$47.1	$13.6

Source: Calculations based on OG&E Response to SC 1-14, Attachment 1; OG&E Response to Sierra Club 1-10, Attachment 4; Sargent & Lundy Consulting, prepared for U.S. EIA, Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.
**Note: 2022 costs were grouped with the historical costs rather than projected costs because many associated projects are already in progress, and the Company provided a high level of detail around the total costs expected in 2022.*

Q What impact do the Company's capex assumptions have on assumed cost to continue operating the plant over the planning horizon?

A OG&E has estimated the forward-going costs to operate the three plants in its coal fleet at around $218 million on an NPV basis over the years 2023–2031, as shown in Table 6 below. The Company's estimate is around $159 million lower on an NPV basis over the years 2023–2031 than what I would project based on OG&E's recent historical spending at its coal plants (and $380 lower when including historical FGD costs in its historical benchmark). The Company's estimate is also about $85 million lower over the years 2022–2031 than what I would project based on Sargent & Lundy's industry study for EIA.

Table 6: Total capex spending at OG&E's coal plants over the time period (2023*–2031) using original and updated assumptions (Million)

Capex data source	Total NPV	NPV Delta from OG&E projection
OG&E projected sustaining capex for its coal plants (2023*–2032)	$217.6	n/a
Estimate of sustaining capex for OG&E's coal plants based on EIA formulas	$302.4	$84.8
Extrapolation of OG&E historical capex spending at its coal plants	$376.5 ($682.0 inc. FGD)	$158.9 ($379.7 inc. FGD)

*Source: Calculations based on OG&E Response to SC 1-14, Attachment 1; OG&E Response to Sierra Club 1-10, Attachment 4; Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. *See note to Table 5, above, regarding grouping 2022 with historical costs rather than projected costs, for capex.*

Table 6 shows that OG&E is likely underestimating future capital costs needed to maintain its coal-fired power plants by tens to hundreds of millions of dollars over the next decade. The high end of that range includes the FDG cost at Sooner, and while a future investment of that magnitude may not be likely, it is possible that a large investment could be required in the future to comply with future environmental regulations—for instance, the recently proposed Good Neighbor Rule. Additionally, while it is reasonable that the Company will seek to minimize spending as each plant's utilization drops, there are baseline investments required to keep the plants functional and reliably available when needed.

Q What are some of the future risks and factors that OG&E has not considered that could impact the cost to continue to operate its coal fleet?

A There are a number of reasonably foreseeable potential future regulations that would further weaken the comparative economics of coal-fired generation. One possibility is an effective constraint or cost on carbon emissions, with EPA indicating that it is currently working on a regulation to replace the Clean Power Plan.[51]

Most concrete, however, as I have already referenced several times, is the new EPA Proposed Rule under the Clean Air Act that could obligate OG&E to install and operate SCR or SNCR to reduce NO_x emissions at each of its coal units (or else to purchase costly emissions credits to simulate such reductions), if the coal units are to operate in the year 2026 and beyond.[52] This Proposed Rule is intended

[51] *See, e.g.*, U.S. EPA, "Climate Change Regulatory Actions and Initiatives," https://www.epa.gov/climate-change/climate-change-regulatory-actions-and-initiatives ("EPA is actively developing a strategy for achieving meaningful reductions in [carbon dioxide] emissions from existing power plants, building on the lessons of EPA's prior efforts and informed by engagement with a broad range of stakeholders.").

[52] 87 Fed. Reg. 20036 (Apr. 6, 2022); *see, e.g.*, *id.* at 20039 ("These EGU emissions reductions are scheduled to begin in the 2026 ozone season based on the feasibility of control installation for EGUs in 22 states that remain linked to downwind nonattainment and maintenance receptors in that year. These 22 states are: … Oklahoma …. The additional emissions reductions required for these states are based primarily on the potential retrofit of additional post-combustion controls for NOx on most coal steam EGUs and a portion of oil/gas steam EGUs that are currently lacking such controls."); *id.* at 20080 ("The EPA proposes that a strategy of retrofitting new SCR on a fleetwide, regional scale is available by, but no earlier than, the 2026 ozone season."); *see also,*

to reduce Oklahoma's (among other states') contribution to non-attainment of National Ambient Air Quality Standards ("NAAQS") for ozone in downwind states, and under provisions sometimes also referred to as the "Transport Rule," in addition to the "Good Neighbor Rule." If finalized in materially the same form as proposed, this rule could require OG&E to spend tens to hundreds of millions of dollars, as discussed below, in upfront capital costs to install SCR/SNCR at each of its coal units, plus considerable increased annual O&M to operate that technology, unless the units retire by 2026.

Q Has OG&E performed any analysis to evaluate the cost and risk of installing SCR?

A No. OG&E has indicated that it has not performed any analysis, to date, to know how much installing and operating SCR would cost at any of its coal units.[53] Indeed, beyond not performing any study of possible costs on its own specific units, OG&E indicated that it "has not tracked industry costs," and so is not able to provide a generic estimate.[54] I am able to provide approximate figures using industry estimates produced for NREL.

e.g., EPA Fact Sheet, EPA's Proposed "Good Neighbor" Plan to Address Ozone Pollution – Overview, at 1 ("The proposed emissions budgets would initially be set at the level of reductions achievable through immediately available measures, including consistently operating emissions controls already installed at power plants. Starting in 2026, the budgets would be set at levels achieved by the installation of modern and cost-effective selective catalytic reduction (SCR) controls at the approximately 30 percent of large coal-fired power plants in the covered states that do not now have them."), available at https://www.epa.gov/system/files/documents/2022-03/fact-sheet_2015-ozone-proposed-good-neighbor-rule.pdf.

[53] OG&E Response to SC 6-1(c).

[54] OG&E Response to SC 8-7.

I find that if OG&E is required to install SCR or controls on any of its plants, it will cost the Company hundreds of millions of dollars in initial capital expenditure costs, and then incur ongoing fixed O&M ("FOM") and variable O&M ("VOM") costs, as shown in Table 7 below. Even with the less stringent SNCR, it will still cost OG&E tens of millions of dollars to comply with the Good Neighbor Rule, if it is finalized materially as currently proposed.

Table 7: Capital and O&M costs for SCR and SNCR technology ($2022 Million)

	SCR			**SNCR**		
	Capex ($million)	**FOM ($/kw-yr)**	**VOM ($/MWh)**	**Capex ($million)**	**FOM ($/kW-yr)**	**VOM ($/MWh)**
Sooner 1&2	$434	$2.40	$2.25	$28	$ 0.42	$1.37
Muskogee 6	$218	$1.20	$1.27	$14	$ 0.21	$1.03
River Valley 1&2	$164	$5.23	$2.28	$13	$ 0.61	$0.86
Total	$816			$55		

Source: Calculations done using the EPA's Retrofit Cost Analyzer available here: https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

This could result in NO_X compliance costs of $365 million on an NPV basis from 2025–2031, assuming all plants have to install SCRs and the cost is depreciated over each plant's remaining lifetime as currently projected by OG&E, as shown in Table 8 below. And that cost could grow to $721 million if the controls are installed and then the plants were to retire in 2031 (arbitrary but illustrative). These costs are large enough to cancel out all potential value calculated based on OG&E's optimistic future projections, even under an otherwise best-case scenario for the coal units.

Table 8: NPV for SCR and SNCR assuming installation in 2025 ($2022 Million)

	2031 depreciation		Lifetime depreciation	
Plant	**SCR**	**SNCR**	**SCR**	**SNCR**
Sooner 1&2	$387	$31	$203	$19
Muskogee 6	$190	$13	$91	$7
River Valley 1&2	$145	$12	$71	$6
Total	**$721**	**$56**	**$365**	**$32**

Source: Calculations based on the EPA's Retrofit Cost Analyzer available here: https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

It is currently unclear whether each plant will in fact have to install SCR, but it is concerning that OG&E has not performed any analysis that considers the implications of future environmental compliance costs. The proposed rule is new, but other utilities, including Entergy Texas, have already assessed whether specific plants will be required to install controls and have estimated the costs associated with compliance with the rule.[55]

Q Explain your concerns with OG&E's capacity factor assumptions.

A As discussed above, OG&E's IRP data shows that it expects the utilization of each of its coal plants [redacted]. Higher utilization means higher energy market revenues and also higher operational costs. But given OG&E's current projections that its plants will be utilized [redacted].[56] This has likely

[55] PUCT Docket No. 52487, *Application of Entergy Texas, Inc. to ament its certificate of convenience and necessity to construct Orange County Advanced Power Station.* Rebuttal Testimony Abigail Weaver, at 38:12-19.

[56] OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

resulted in an overestimation of energy market revenues and underestimation of variable costs by tens of millions of dollars.

Q Explain your concern with OG&E's assumption that the coal plants will each operate into the mid to late 2040s.

A OG&E assumes that its coal plants will each operate for longer than two more decades from now. This means that the Company can assume that any investments it makes in the plants will be paid off over that more-than-two-decade timeframe, and also will have that long timeframe's worth of revenues to cover the costs. This has the impact of making large investments look relatively small, and thus more favorable, than if the Company instead assumed it had only, say, ten years to pay off an investment and ten years of market revenues to offset the costs. Below I will show results of a sensitivity where I assumed that the plant retires in ten years, at the end of 2031.

Q What do you conclude regarding the economic status of the Sooner, Muskogee 6, and River Valley Units?

A I find that, despite OG&E's data initially showing that its coal plants are projected to perform well, under more reasonable assumptions is it likely that the plants actually will incur costs in excess of their value to operate over the next decade.

Specifically, OG&E has potentially underestimated base capital costs by as much as $159 million; underestimated future environmental compliance costs by as much as $365 million to $721 million, if SCRs are required; and overestimated energy revenues by tens of millions of dollars over the next decade. There is a large range of costs implied here, and also some level of uncertainty, but OG&E has the data and the wherewithal necessary to narrow this range of costs and assess the likelihood of each of the costs being incurred. But, the Company has failed to do so.

Q Your analysis in the beginning of this section evaluated costs the year they are incurred without including depreciation expenses. Why is this analysis an important compliment to depreciation analysis?

A Both depreciation analysis and the original analysis presented above are important in understanding the economics of the Company's coal fleet. Regardless of how costs are spread out, on net, the plants value must exceed costs for it to be economic. The main difference is that the original analysis shows the overnight cost of project, as if the project had been paid off all at once, whereas the depreciation analysis shows financed costs spread out over multiple years.

Specifically, the original analysis discussed above shows the forward-looking costs and values expected to be incurred and earned over the next decade. This analysis allows us to quickly compare the value coming in and costs going out to determine, on net, whether the plants' projected costs and values are expected to balance out over the next decade. This is especially important when a plant's retirement date has not been economically set, and there is uncertainty around the economics of continuing to operate a plant.

The depreciation analysis, on the other hand, begins with an assumption about how long the plant will continue to operate and shows the ratepayer impact of continuing to operate the plant, and recover all investments, over that assumed timeline. It is sensitive to retirement date assumptions but most closely represents how costs are passed on to ratepayers.

Q Have you conducted any analysis where you evaluate the costs with financing and spread out over a longer time to more closely approximate the costs ratepayers are likely to see?

A Yes. To conduct this analysis, I first selected a starting year and a depreciation timeline. I selected 2017 as the starting point, to align with my historical analysis, and selected an arbitrary (but illustrative) date of 2031 as a retirement date. I set a requirement for the analysis that all costs incurred in the subsequent years from 2017–2031 had to be paid off by the 2031 retirement date.

I found that using all of OG&E's original assumptions and the cost of the Frontier and River Valley purchase to represent the value of capacity, the costs required to maintain OG&E's coal plants were $360 million in excess of the value of the plants over the last five years (2017–2021), as shown in Table 9. Once again, this cost difference from what I calculated above does not reflect a change in the cost to operate or maintain the plants, but rather the distribution of the FGD costs over the 15 years from 2017–2031.

Table 9: Historical cost and value of OG&E's coal fleet assuming depreciation through 2031 ($2022 Million)

	Depreciation through 2031		Original (year of expensing)	
	2017 to 2020	2017 to 2021	2017 to 2020	2017 to 2021
Sooner 1&2	($226)	($8)	($506)	($254)
Muskogee 6	($334)	($262)	($353)	($282)
River Valley 1&2	($134)	($94)	($148)	($126)
Total	($690)	($360)	($1,007)	($661)

Source: Synapse calculations based on OG&E Response to SC 1-10, Attachment 2; OG&E Response to SC 1-10, Attachment 3; OG&E Response to SC 1-10, Attachment 4; OG&E Response to SC 1-17, Attachment 1; OG&E Response to SC 04-08; OG&E Response to SC 8-5; OG&E Response to AG 13-7; U.S. EIA Form 923 for River Valley generation prior to May 2019.

Looking forward, and switching to CONE to value capacity, the projected excess value for the plants dropped substantially to [redacted] over the next decade, compared with [redacted] when the FGD scrubber costs had not been amortized and spread out, as shown in Table 10 below. But as discussed above, these projections are still based on optimistic, best-case scenario projections. And additional base capex costs, or SCR compliance costs will outstrip the projected value.

Table 10: CONFIDENTIAL NPV Projected cost and value of OG&E's fleet assuming depreciation 2022–2031 ($2022 millions)

[redacted]

Source: Synapse calculations based on OG&E Response to SC 1-14, Attachment 1; OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

Q Given your findings with this screening analysis, would full capacity expansion and production cost modeling by OG&E be valuable?

A Yes. Full capacity expansion and production cost modeling by OG&E with allowance retirement of coal units within the modeling framework would further improve on both these analysis by utilizing optimization logic and detailed system cost and revenue data and full consideration of alternatives.

Q Did OG&E conduct any recent analysis on the cost of alternatives relative to the cost of its coal fleet?

A No. As discussed above, in its 2021 IRP, OG&E hard-coded in the retirement dates for its coal fleet and therefore did not test alternatives to running the coal units until the mid to late 2040s.

Q Did you conduct any analysis on the cost of alternative resources relative to the costs OG&E will incur to operate its coal fleet?

A Yes, I evaluated the cost to build, maintain, and operate alternative resource options over the next ten years. Specifically, I looked at solar PV, battery storage, wind, and paired storge and solar resources. The goal of this exercise was not to identify a precise portfolio or resources to replace any of OG&E's coal plants, but rather to evaluate the cost-competitiveness of alternative resources.

Looking at Sooner 1 as an example, I found that a combination of solar PV and battery storage installed in 2025 could most cost-effectively supply the same quantity of firm capacity as the plant. Specifically, I found that 400 MW of solar PV and 288 MW of 4-hour duration battery storage can provide the same firm capacity as Sooner 1 (516 MW) for a slightly lower NPV ($2.53 million lower NPV) over the period 2022–2031. Even more important than the lower cost is the lower risk inherent with solar PV, battery storage, and other replacement options—particularly the lower ongoing capital costs required to maintain the resources, and the essentially non-existent risk that future environmental regulations will impose additional costs on the operation of the unit. I calculated the resource cost estimates based on cost data provided by NREL,[57] and the average energy prices that OG&E projects it will receive for the energy from its coal plants during each year from 2025–2031.[58]

7. BEST PRACTICES IN UTILITY MANAGEMENT DICTATE THAT OG&E SHOULD BE REGULARLY EVALUATING THE ECONOMICS OF ITS COAL PLANTS, IDENTIFYING FUTURE RISKS AND COSTS, AND CONSIDERING THE COST-EFFECTIVENESS OF THEIR EARLY RETIREMENT/REPLACEMENT

Q How should OG&E be evaluating the optimal future retirement dates and replacement portfolios for its coal units?

A OG&E should be regularly evaluating the economics of operating its coal plants relative to the cost of alternatives. These evaluations should occur at least every time OG&E prepares an IRP, and additionally whenever there may arise any potentially game-changing market or regulatory developments (*e.g.*, the newly proposed Good Neighbor Rule, when finalized). This process should involve two fundamental components: (1) up-to-date resource cost data, and (2) robust modeling. The results should then be presented to the Commission and to stakeholders in a transparent, adversarial proceeding in which OG&E's methods and plans can be scrutinized and their consistency with ratepayers' interests can be judged.

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[57] NREL Annual Technology Baseline. Available at https://atb.nrel.gov/electricity/2021/data.

[58] OG&E Response to SC 1-11, CONFIDENTIAL Attachment 1.

For the first component, OG&E should be issuing all-source RFPs to test the market and to have the most up-to-date resource cost data to use as inputs into its modeling. OG&E issued an RFP in 2018 but did not use the cost data it obtained from this process in its next IRP in 2021.[59] Instead, the Company included only the specific projects it had already selected in the IRP as resources and relied on generic cost data to represent the cost of other resource options.

For the second component, as part of each IRP, at least, and anytime it contemplates a major investment at an existing plant, the Company should complete modeling using industry-standard production cost and capacity expansion modeling. This modeling should compare the cost of continuing to operate the unit relative to the cost of retiring the unit and replacing it with a portfolio of alternatives. OG&E should not be hard-coding in retirement dates for its coal plants.

The results of that analysis should be presented transparently in a docket capable of robust scrutiny of the Company's analysis. This docket should include an adversarial process with discovery and testimony by the Company, as well as intervening stakeholders, witness examination, and argumentation. It should culminate with a ruling by the Commission—ideally a binding one, but at least something advisory that would signal the Commission's inclinations about future cost recovery requests—concerning the reasonableness of the Company's resource plans and unit retirement dates.

Q Does this conclude your testimony?

A Yes.

[59] OG&E Response to SC 7-02(b).

EXHIBIT DG-1

TO THE RESPONSIVE TESTIMONY OF DEVI GLICK

ON BEHALF OF SIERRA CLUB

CAUSE NO. PUD 202100164

RESUME OF DEVI GLICK

Devi Glick, Principal Associate

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PROFESSIONAL EXPERIENCE

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

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

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

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

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

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

Associate

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

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

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

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

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

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

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

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

EDUCATION

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

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

PUBLICATIONS

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Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

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Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

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Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

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Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina

Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Last updated April 2022

BEFORE THE
OKLAHOME CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	**CAUSE NO. PUD 202100164**
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

AFFIDAVIT OF DEVI GLICK
IN SUPPORT OF RESPONSIVE TESTIMONY ON BEHALF OF SIERRA CLUB

Commonwealth of)
Massachusetts)

Affiant Devi Glick, being first duly sworn, states that the prepared Responsive Testimony of Devi Glick on Behalf of Sierra Club (including its associated exhibit), filed herewith on Wednesday, April 27, 2022, constitutes the responsive testimony of Affiant in the above-captioned case. Affiant further states that she would give the answers set forth in her Responsive Testimony if asked the questions propounded therein. Affiant further states that her statements are true and correct to the best of her knowledge.

Devi Glick
Devi Glick

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Devi Glick on this 26 th day of April, 2022.

Notary Public

Notary ID No.: 1812882

My Commission expires:

JENNIFER MARUSIAK
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 29, 2022