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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JIM O'CONNOR. CHAIRMAN
NICK MYERS
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ANNA TOVAR
KEVIN THOMPSON

IN THE MATTER OF THE APPLICATION OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	Docket No. E-01933A-22-0107 **SIERRA CLUB'S NOTICE OF FILING OF DIRECT TESTIMONY OF DEVI GLICK**

Pursuant to the Rules of Practice and Procedure of the Arizona Corporation Commission ("Commission") and the Administrative Law Judge's July 29, 2022 procedural order in this matter, Sierra Club hereby provides notice of its filing of the attached Direct Testimony of Devi Glick in Docket No. E-01933A-22-0107. Ms. Glick's testimony contains information designated by Tucson Electric Power Company ("TEP") as confidential and competitively sensitive confidential information, which is redacted in the attached public

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version of the testimony. Confidential and competitively sensitive confidential versions of Ms. Glick's testimony have been provided to the Hearing Division and to TEP. TEP has represented to Sierra Club that it will provide the confidential version of Ms. Glick's testimony to all parties that have signed TEP's protective agreement in this matter (including Exhibit A of that agreement pertaining to confidential information). Sierra Club understands that TEP will provide the competitively sensitive confidential version of Ms. Glick's testimony to Commission Staff, to the Residential Utility Consumer Office ("RUCO"), and to any other party that requests the competitively sensitive confidential version, provided that party has signed Exhibit B of TEP's protective agreement regarding competitively sensitive confidential information.

RESPECTFULLY SUBMITTED this 11th day of January, 2023.

/s/ Patrick Woolsey

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By: */s/ Maddie Lipscomb*

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA FOR RELATED APPROVALS.	DOCKET NO. E-01933A-22-0107

Direct Testimony
of
Devi Glick

PUBLIC VERSION

On Behalf of
Sierra Club

January 11, 2023

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal 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, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other 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 10 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Attachment 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 Arizona Corporation Commission ("Commission" or "ACC")?

A Yes. I submitted reply testimony in Docket No. E-01933A-19-0028, Tucson Electric Power Company's ("TEP" or "the Company") prior rate case. I also participated on behalf of Sierra Club in TEP's 2020 Integrated Resource Planning ("IRP") process.

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

A In this proceeding, I evaluate the economic performance of TEP's coal plants at the Springerville Generating Station ("Springerville") and the Four Corners Generating Station ("Four Corners") and evaluate their likely economic performance going forward. I review the sufficiency of the analysis the Company completed to justify continuing to operate the plants and including operations and maintenance ("O&M") and sustaining capital costs in its proposed test-year spending at the plants. I also review the Company's load forecast, and the measures it is taking to manage peak and secure new resources moving forward.

Finally, I outline recommendations for the Company and the Commission to transition its resource procurement and planning to a rolling model rather than focusing procurement purely on filling firm capacity needs.

Q How is your testimony structured?

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

In Section III, I describe Springerville Units 1 and 2 and Four Corners and discuss TEP's requested test-year spending at each plant. I also summarize the Company's load forecast and near-term procurement efforts.

In Section IV, I summarize my analysis on the economic performance of each coal unit based on data I received from TEP. I review the most recent analysis the Company completed to justify continued operation of the plants and inclusion of the associated O&M and sustaining capital costs in test-year spending. I discuss the major changes that have occurred since TEP completed its most recent economic analysis, and outline the avoided costs associated with retirement and replacement with alternatives.

In Section V, I summarize TEP's current resource procurement efforts and its peak-management and firm capacity needs. I explain the need for TEP to switch to a rolling procurement model in order to accelerate its transition to clean energy resources, rather than focusing on just procuring resources when it identifies a firm capacity need.

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

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of TEP's witnesses. I also rely on public information from other ACC proceedings and other publicly available documents.

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. TEP's ongoing O&M and sustaining capital spending at the Springerville and Four Corners coal plants, which TEP is asking to include in test-year spending in this rate case, are not economically justified.
2. The analysis that TEP used to support the ongoing operations of and spending at Springerville Units 1 and 2 and Four Corners is nearly two-and-a-half years old, relies on outdated assumptions that pre-date the federal Inflation Reduction Act ("IRA") and current market conditions, and substantially understates the risk associated with continued reliance on its coal plants.
3. The cost to operate and maintain Springerville Units 1 and 2 and Four Corners substantially exceeds the cost of alternatives, including clean energy resources.
4. TEP can avoid substantial unnecessary capital expenditures and O&M costs at Springerville Units 1 and 2 and Four Corners by retiring the plants earlier than the Company's current retirement dates.
5. TEP has not taken sufficient action to implement and invest in peak-management programs, technologies, and resources on its system.
6. TEP's current resource planning approach of waiting until it has a capacity need to procure new resources may have worked well in the past when utilities relied primarily on large, centralized legacy fossil units, but it is not well matched with the resources needed for a clean energy transition.

Q Please summarize your recommendations.

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

1. The Commission should disallow all test-year O&M and capital expenditure spending at Four Corners on the basis that the plant has incurred costs above market prices in recent years, the plant is uneconomic relative to alternatives, and TEP has failed to conduct any analysis as part

of either this docket or the prior 2020 IRP docket to evaluate the cost of retirement relative to replacement with alternatives.

2. The Commission should require that TEP seek and obtain pre-approval for investments at Springerville or Four Corners above $1 million (on a whole-plant basis) that TEP intends to include in its rate base. The Commission should require that TEP justify any such investment over alternatives.

3. The Commission should make clear to TEP that, in the future, it will not allow test-year O&M and capital spending at Springerville Units 1 and 2 without analysis performed within one year of the rate case application that demonstrates that it is still reasonable to maintain the units relative to alternatives.

4. The Commission should require TEP to move away from a planning model that procures resources only in response to firm capacity needs and instead transition to a rolling model that brings on new clean energy resources that can lower energy costs as they become available. This will facilitate a clean energy transition and protect ratepayers from volatile fuel and market prices, project delays, and legacy unit breakdowns.

III. TEP'S RATE CASE APPLICATION INCLUDES TEST-YEAR SPENDING FOR SPRINGERVILLE UNITS 1 AND 2 AND FOR FOUR CORNERS, A PROJECTION OF RAPIDLY INCREASING PEAK DEMAND, AND A PLAN TO BRING ONLINE NEW FIRM CAPACITY RESOURCES OVER THE NEXT FEW YEARS

Q Please provide an overview of TEP's coal-fired power plants.

A TEP has two coal-fired power plants. Springerville is a four-unit coal-fired power station located near Springerville, Arizona. TEP operates all four units and owns Units 1 and 2. Unit 1 is 387 megawatts ("MW") and went into service in 1985. Unit 2 is 406 MW and went into service in 1990. The other two units are owned by Tri-State Generation and Transmission (Unit 3) and Salt River Project (Unit 4) and do not serve TEP load.[1]

Four Corners is a two-unit (Units 4 and 5) coal-fired power station located near Farmington, New Mexico. Units 4 and 5 are each 770 MW and went into service in 1969 and 1970 respectively. The plant is operated by Arizona Public Service ("APS") and co-owned by APS, Salt River Project Agricultural Improvement and Power District ("SRP"), Public Service Company of New Mexico, and TEP. TEP has a 7 percent ownership share, equivalent to 110 MW.[2]

Q What is TEP requesting in this docket related to Springerville Units 1 and 2 and Four Corners?

A TEP is seeking approval to include in rates its costs to operate and maintain Springerville Units 1 and 2 and Four Corners. This includes capital expenditures and O&M costs incurred during the test year.

Q What test-year costs for the Springerville and Four Corners coal plants is TEP requesting to include in rates?

A As shown in Table 1 below, TEP is requesting to place approximately $55 million in capital expenditures into its rate base, and nearly $73 million in O&M costs into rates. These costs were incurred at Springerville Units 1 and 2 and at Four Corners during the test year ending December 31, 2021.

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[1] Tucson Electric Power, *2020 Integrated Resource Plan* at 93 (June 26, 2020), *available at* https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf [hereinafter "TEP 2020 IRP"].

[2] *Id*. at 95.

Table 1.Test-year sustaining capital expenditures and operations & maintenance costs

Plant	Sustaining capital expenditures ($Millions)	Operations & maintenance costs ($Millions)
Springerville Units 1 & 2	$46.1	$61.3
Four Corners	$8.8	$11.4
Total	**$54.9**	**$72.6**

Source: TEP Response to SC DR 1-03(a), Attachment SC 1.03a.xlsx; TEP response to SC DR 1-03(c), Attachment SC DR 1.03 and 1.05 Summary.xlsx. All public discovery responses referenced in this testimony are compiled and available within Attachment DG-2 ["Attach. DG-2"].

Q What is the undepreciated balance at each plant?

A The plant balances for Springerville Units 1 and 2 and TEP's share of Four Corners were [redacted] million and [redacted] million respectively at the beginning of the test year (2021), inclusive of common plant and coal-handling balances.[3]

For Springerville 1 and 2, the Company's current rates, set during the prior rate case in 2018, reflect retirement years of 2045 and 2050. As part of this rate case, TEP proposes to move each retirement year as set in rates up by eight years to more closely align cost recovery with the plant's operational timeline, which now calls for the units to retire 18 years earlier, in 2027 and 2032 respectively.[4] By accelerating depreciation and paying off more of the balance while the units are still online, the plant balance at retirement would be reduced from $640 million to $540 million[5] by the time the units retire in 2027 and 2032.

[3] TEP Response to Sierra Club Request ["SC DR"] 1-08(d), Attachment SC 1.08d and e-Confidential.xlsx. All confidential discovery responses referenced in this testimony are compiled and available within Attachment DG-3 ["Attach. DG-3"].

[4] *See* Direct Testimony of Susan Gray at 7:7-11 [hereinafter "Gray Direct"].

[5] *Id*. at 11:14-17.

Q Has TEP committed to a retirement date for each coal plant?

A Yes. As shown in Table 2 below, TEP plans to retire all coal by 2032. Specifically, it plans to retire Springerville Unit 1 in 2027 and Unit 2 in 2032. The Company plans to switch to seasonal operation at Springerville Units 1 and 2 in 2023 and 2024 respectively.[6] APS plans to switch Four Corners to seasonal operations in 2023,[7] and retire the plant at the end of July 2031 when its coal contract ends.[8]

Table 2. Retirement and seasonal operations dates for TEP coal plants

Plant	Year switching to seasonal operation	Retirement year
Springerville Unit 1	2023	2027
Springerville Unit 2	2024	2032
Four Corners	2023	2031

Source: Bakken Direct at 6:25-7:2; Gray Direct at 9:24-10:13.

Q Does TEP have any near-term resource needs?

A Yes, TEP has seen a 5.7 percent increase in peak demand since the end of the last test year (2018). The Company projects that over the next five years, peak load will increase by over 1.5 percent annually while energy sales are expected to remain the same or decline.[9] The Company claims that it needs more firm capacity resources and demand-side peak-management solutions to address its increasing peak load.

[6] Direct Testimony of Erik Bakken at 6:27-7:1 [hereinafter "Bakken Direct"].
[7] *Id*. at 6:25-27.
[8] Gray Direct at 9:25-10:1.
[9] *Id*. at 3:8-9.

Q What near-term resource procurement efforts has TEP made?

A TEP has brought online 465 MW of new renewables and 60 MWh of battery storage since the Company's last rate case.[10] This includes the 250 MW Oso Grande Wind project which came online in December 2020. TEP is requesting to add Oso Grande to base rates in this docket.[11]

In addition, the Company issued an all-source request for proposals (RFP) in April 2022 for 250 MW of renewables and energy efficiency resources. This could include new wind, solar photovoltaics ("PV"), energy efficiency, and demand response.[12] The RFP also seeks 300 MW of a firm capacity resource that can be called on at any time. This includes 4-hour energy storage and demand response.[13] The evaluation for both procurements is currently ongoing.

Q What are TEP 's carbon dioxide ("CO_2") reduction and renewable energy goals?

A TEP has a goal to reduce CO_2 emissions 80 percent below 2005 levels by 2035 and serve 70 percent of retail load with cost-effective renewables by 2035. This is up from serving only 21 percent of retail load with renewables in 2021.[14] To achieve this goal, TEP must reduce its reliance on fossil fuels, retire its coal plants, and build out substantial new renewable capacity.

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[10] Bakken Direct at 2:8-12.

[11] Gray Direct at 2:16-19.

[12] Direct Testimony of Dallas Dukes at 5:3-7 [hereinafter "Dukes Direct"].

[13] *Id*. at 3:8-13.

[14] Bakken Direct at 3:3-8.

IV. THE ECONOMIC AND OPERATIONAL PERFORMANCE OF SPRINGERVILLE UNITS 1 AND 2 AND FOUR CORNERS HAS BEEN DECLINING AND ARE LIKELY TO BECOME RISKIER AND MORE COSTLY GOING FORWARD, BUT TEP HAS PROVIDED NO CURRENT ANALYSIS TO JUSTIFY ITS CONTINUED RELIANCE ON THE PLANTS

i. My analysis indicates that continuing reliance on Springerville Units 1 and 2 and Four Corners is risky and not the least-cost option for TEP ratepayers

Q What are the utilization levels of Springerville Units 1 and 2 and Four Corners in recent years?

A TEP's utilization of Springerville Units 1 and 2 and Four Corners has been relatively high over the past few years. As shown in Table 3 below, between 2019 and 2022, Springerville Units 1 and 2 operated at relatively high capacity factors ranging between 59 and 70 percent in three out of the four years. The exceptions were 2021 for Unit 1, where its utilization dropped to 37 percent, and 2022 for Unit 2, where its capacity factor dropped to 40 percent. Four Corners has operated at between a 56 and 73 percent capacity factor in each of the past four years.[15]

Table 3. Historical capacity factors 2019–2022

	2019	2020	2021	2022*
Springerville 1	70%	62%	37%	64%
Springerville 2	67%	59%	67%	40%
Four Corners	66%	56%	59%	73%

Source: U.S. Energy Information Administration Form 923, 2019-2022 (2022 data only through September), available at https://www.eia.gov/electricity/data/eia923/ [hereinafter "U.S. EIA Form 923"].

[15] U.S. EIA Form 923, 2019-2022 data.

Q How reliable have Springerville Units 1 and 2 and Four Corners been in recent years?

A The reliability of TEP's coal fleet has been lacking. As shown in Confidential Table 4 and Confidential Table 5 below, each of TEP's coal units has had a high forced outage rate during at least one of the last four years. In fact, Four Corners Units 4 and 5 had a high forced outage rate in every year between 2019 and 2021 (data was not yet available for 2022) with its equivalent forced outage rates[16] ranging from [redacted]. Springerville performed better overall but had an equivalent forced outage rate of [redacted] at Unit 1 in 2021 and an equivalent availability of only [redacted] at Unit 2 in 2022 (equivalent forced outages rates were not available for 2022).

These outages rates are much higher than the national average as reported by the North American Electric Reliability Corporation ("NERC"), which was around 7.25 percent across all grid resources for the five years between 2017 and 2021. According to the same study, outage rates at coal units averaged around 10 percent nationally, which was worse than during the prior five-year study period, and part of a pattern of worsening fleet performance.[17] These high outage rates are concerning because, as discussed later in this section and in Section V, gas and market prices are currently high, meaning the short-term replacement resources that TEP has to rely on in the event of outages are very expensive for TEP's ratepayers.

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[16] The Equivalent Forced Outage Rate measures the percentage of time that a unit was unavailable during only the hours that it was expected to be available. This means it excludes hours when the unit was planned to be offline.

[17] 2020 State of Reliability, North American Electric Reliability Corporation (July 2020), *available at* https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

Confidential Table 4. Equivalent availability factors

	2019	2020	2021	2022*
Springerville 1	[redacted]	[redacted]	[redacted]	[redacted]
Springerville 2	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners Unit 4	[redacted]	[redacted]	[redacted]	(no data yet)
Four Corners Unit 5	[redacted]	[redacted]	[redacted]	(no data yet)

Source: Attach. DG-3, TEP Response to SC DR 1-13, Attachment SC 1.13 a-f Data from 2019-2021-Confidential.xlsx; Attach. DG-3, TEP Response to Staff DR 1-15, Attachment STF 1.15 Aval and perf Gen units – Confidential.xlsx.

Notes: The Equivalent availability factor measures the percentage of time that a unit was available during all the hours in that period. This includes hours in which the unit was planned to be unavailable. Notably, the EAFs that TEP provided in response to Staff 1-15 are slightly different than the EAFs TEP provided in response to SC 1-13, but the difference has no impact on my analysis.

Confidential Table 5. Equivalent forced outage rate for TEP's coal units 2019–2021

	2019	2020	2021
Springerville 1	[redacted]	[redacted]	[redacted]
Springerville 2	[redacted]	[redacted]	[redacted]
Four Corners Unit 4	[redacted]	[redacted]	[redacted]
Four Corners Unit 5	[redacted]	[redacted]	[redacted]

Source: Attach. DG-3, TEP Response to SC DR 1-13, Attachment SC 1.13 a-f Data from 2019-2021-Confidential.xlsx.

Q Describe Four Corners' recent financial performance.

A As shown in Confidential Table 6 below, at Four Corners between 2019 and 2021, the plant's variable costs (fuel and variable O&M) exceeded the value of the revenues that plant would earn in the market, based on prices at the Palo Verde hub, by several million dollars each year. Given Four Corners' high operational costs, and the fact that TEP could purchase energy from the market at a lower cost than it spent to operate the units, it is concerning that APS continued to operate the plant at such a high level.

Confidential Table 6. Costs and market value of Four Corners 2019–2021

($2020 Million)	**2019**	**2020**	**2021**
Fuel costs	[redacted]	[redacted]	[redacted]
Estimated total variable cost	[redacted]	[redacted]	[redacted]
Total O&M costs	[redacted]	[redacted]	[redacted]
Sustaining (non-environmental) capital expenditures	[redacted]	[redacted]	[redacted]
Environmental capital expenditures	[redacted]	[redacted]	[redacted]
Total Cost	[redacted]	[redacted]	[redacted]
Energy market value (Palo Verde hub)	[redacted]	[redacted]	[redacted]
Net energy margin	[redacted]	[redacted]	[redacted]

Source: Attach. DG-2, TEP Response to SC DR 1-13 (j) and (k); Attach DG-3, TEP Response to SC DR 1-13, Attachment SC 1.13 a-f-Data from 2019-2021-Confidential.xlsx.

Q Describe Springerville's recent financial performance.

A Springerville Units 1 and 2 performed better financially than Four Corners (which is admittedly a low bar) and did not incur costs in excess of their market value. But as discussed above, both units also experienced high outage rates in at least one recent year. Specifically, Unit 1 had an equivalent availability factor of only [redacted] percent in 2021, and Unit 2 had an equivalent availability factor of around [redacted] percent in 2022 based on the data available to date. Confidential Table 7 shows TEP's estimates of the net replacement cost of power costs at Springerville during Unit 1 and 2's unplanned outages from 2019–2022. Of the [redacted] million in net costs incurred, [redacted] were attributed to unplanned outages at Unit 1 during 2021.

Confidential Table 7. Net replacement cost of power from Springerville Units 1 and 2 due to forced outages from 2019–2022

($Million)	**2019**	**2020**	**2021**	**2022**	**Total**
Springerville 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Springerville 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Attach. DG-3, TEP Response to Staff DR 1-15, Attachment STF 1.15 – Forced Outages_2019-2022-Confidential.xlsx.

Q Explain the methodology you used to evaluate the unit's historical performance.

A I relied on TEP data provided in discovery, as well as public data where referenced by TEP. To calculate the Four Corners historical unit costs and market value shown in Confidential Table 6 above, I found TEP's historical fuel costs[18] and total O&M costs[19] as reported in FERC Form 1. TEP also provided historical capital expenditures for environmental[20] and non-environmental[21] items which I added to the total cost. To calculate the estimated total variable cost, I applied a 10 percent adder[22] to TEP's reported fuel costs to account for variable O&M costs. I had to rely on a simplifying assumption to represent variable O&M ("VOM") costs because TEP didn't provide historical O&M costs broken down into variable and fixed cost categories. To calculate the energy revenue based on Palo Verde Market Hub prices I relied on TEP's actual Palo Verde market price data reported in its 2020 IRP for 2019 data,[23] the Company's 2020 forecast for 2021 data,[24] and the Company's 2021 forecast for 2022 data.[25] I calculated the net energy margin based on the difference between the estimated total variable cost and total projected energy revenues.

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[18] Attach. DG-2, TEP Response to SC DR 1-13 (i).

[19] Attach. DG-2, TEP Response to SC DR 1-13 (g) and (h).

[20] Attach. DG-2, TEP Response to SC DR 1-13 (j).

[21] Attach. DG-2, TEP Response to SC DR 1-13 (k).

[22] This assumption is based on my experience reviewing variable unit costs across tens of coals plants across over a dozen states. In my expert experience, a 10 percent adder for variable O&M costs is a reasonable assumption.

[23] TEP 2020 IRP, Chart 34 – Palo Verde (7x24) Market Price Sensitivities.

[24] Attach. DG-3, TEP Response to SC DR 1.11, Attachment SC 1.11 Palo Verde Forward Price – Confidential.xlsx.

[25] *Id.*

Q Describe the projected financial performance of Springerville and Four Corners over the next five to ten years.

A On a forward-going basis, Springerville is projected to have a levelized cost of energy ("LCOE") of around $45/MWh and Four Corners is projected to have an LCOE of $65/MWh (excluding the cost of the coal contract) over the next decade, as shown in Table 8 below. These costs are inclusive of all fuel, O&M, and capital costs (environmental and otherwise) required to operate and maintain the plants. For reasons discussed further below and in Section IVii, these cost estimates likely understate the actual future cost to operate each unit.

Table 8. LCOE of TEP's coal plants 2022–2032

Resource	LCOE ($/MWh)
Four Corners*	$65.48
Springerville Unit 1	$45.26
Springerville Unit 2	$46.55

Source: Synapse calculations based on TEP Response to SC DR 1.14, Attachments SC 1.14-1.xlsx, SC 1.14-1-Revised.xlsx, and SC 1.14-2.xlsx.

Q Explain the methodology you used to calculate the projected LCOE of TEP's coal plants.

A I once again relied on TEP data provided in discovery. For each unit I added up TEP's projected fuel costs,[26] fixed O&M,[27] variable O&M,[28] environmental capital expenditures ("capex"),[29] and non-environmental capex[30] for its share of the plant for each year between 2022 and 2032. I then calculated the net present value of the total costs using TEP's nominal weighted average cost of capital

[26] Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1.14-1-Revised.xlsx.
[27] Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1-14.2 Revised.xlsx.
[28] *Id.*
[29] *Id.*
[30] *Id.*

("WACC") of 7.31 percent.[31] I divided that by the net present value of TEP's projected generation from each unit[32] over the same time period to get the LCOE's shown in Table 8 above.

Q Do you have any concerns with the data that TEP provided?

A Yes. I am concerned that the data and projections the Company provided were developed based on the assumption that the cost to operate the plants in the future will be similar to the costs that TEP incurred in the past. This is not likely to be true based on two major factors: the cost of coal and a switch to seasonal operations.

First, the coal prices that TEP relied on likely understate the future cost and risk of continuing to rely on coal. TEP's coal costs have gone up around 27 percent over the last year after remaining virtually flat for the prior five years, as shown in Figure 1 below. And more broadly, across the United States, as I discuss in Section IVii and show in Figure 3, coal prices in many parts of the country have increased dramatically this year. It is unclear if they will rebound, when they will rebound, or by how much.

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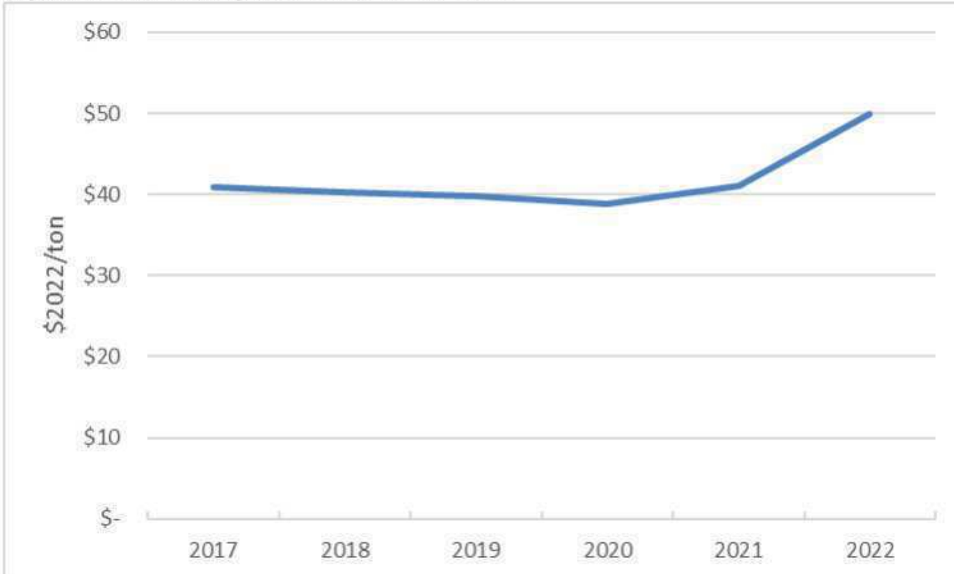
[31] Tucson Electric Power Company Application at 8, Docket No. E-01933A-22-0107 (June 17, 2022), *available at* https://edocket.azcc.gov/search/document-search/item-detail/299689 [hereinafter "TEP Application"].

[32] Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1.14-2 Revised.xlsx.

Figure 1. TEP average cost of coal 2017–2022



Source: Calculated based on U.S. EIA Form 923 Fuel Receipts data 2017–2022.

Second, I am concerned that the data TEP provided does not fully reflect a switch to seasonal operations at both Four Corners and Springerville in 2023 and 2024. Confidential Figure 2 below shows the Company's projected generation data for each plant.[33] Specifically, this figure shows that TEP expects Four Corners to continue to operate with approximately the same annual output over the next decade as it has historically. But the plant currently operates year-round, and therefore is unlikely to generate the same quantity of energy when it switches to seasonal operations in 2023. For Springerville, TEP did assume a downturn in utilization as the units switch to seasonal operations, but the utilization levels for Units 1 and 2 match in 2023, when Unit 1 is expected to switch to seasonal operations, while Unit 2 is still expected to operate year-round until 2024.

[33] Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1.14-1.xlsx.

Confidential Figure 2. TEP recent historical and projected capacity factors for coal-fired units

[redacted]

Source: Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1.14-1.xlsx; Attach. DG-3, TEP Response to SC DR 1-13, Attachment SC 1.13 a-f-Data from 2019-2021-Confidential.xlsx.

Q Why is it concerning that TEP provided operational projections that do not match its stated operational plan at each unit?

A These assumptions are concerning for three reasons. First, TEP is providing out-of-date data to intervenors and may itself be relying on out-of-date data for planning purposes. Second, and more specifically, a switch to seasonal operations impacts not just output but also operations and maintenance costs, capital investments, and replacement resource decisions. This switch should directly lead to lower fuel and variable costs and should also impact planning around long-term spending on O&M and sustaining capital expenditures. It is unclear if and how TEP considered this.

Finally, lower generation levels at each plant also mean that there are fewer MWh to recover the units' fixed costs. Therefore, TEP should be carefully tracking and evaluating all spending, and taking all measures possible to minimize unnecessary spending at its coal plants. At Springerville, which TEP owns and operates, TEP can take direct action and control to provide oversight and limit spending. At Four Corners, where TEP only has partial ownership, the Company still has an obligation to exercise oversight and act in collaboration with APS and the plant's other co-owners to minimize costs to ratepayers.

Q How does the cost to operate TEP's existing coal plants compare with the cost of alternative resources?

A At $45 to $65/MWh, the costs to operate TEP's existing coal plants are very high relative to the cost of alternatives as shown in Competitively Sensitive Confidential Table 9 and Confidential Table 10 below. Solar PV is currently being built in the region for between $15 to $30/MWh, and wind for [redacted] Paired solar PV plus battery storage projects are being built for between $24.50 and $30/MWh for the solar PV and between $5.36 and $10.99/kW-month for the battery storage. TEP also just brought online the 247 MW Oso Grande Wind project, which cost approximately $1,435/kW.[34]

Competitively Sensitive Confidential Table 9. Recent solar PV and wind PPAs in the Southwest

Resource	Utility/ owner	State	Project size (MW)	$/MWh	Commercial operation date
AZ Solar 1	Central Arizona Project	AZ	30	$24.99	12/2020
Borderlands Wind	TEP	NM	100	[redacted]	12/2021
Buena Vista 2 Solar	El Paso Electric	NM	20	$23.38	6/2023
AZ Solar 2	Central Arizona Project	AZ	20	Low $30's	12/2023
Hecate 1 Solar	El Paso Electric	NM	100	$14.99	6/2024
Hecate 2 Solar	El Paso Electric	NM	50	$18.93	6/2024

Source: TEP Response to Staff DR 4.097, Attachment Amendment STF 4.097 TEP Borderlands PPA Wind 100 MW, Amend No. 1, 01-19-17 Signed COMPETITIVELY SENSITIVE CONFIDENTIAL.pdf (All competitively sensitive confidential discovery responses referenced in this testimony are compiled and available within Attachment DG-4 ["Attach. DG-4"]); El Paso

[34] Attach. DG-2, TEP Response to Staff DR 4.003, Attachment STF 4.003 Oso Grande Plant-in-Service.xlsx.

Electric Company, Amended Application for Approval of Amendments to Four Purchased Power Agreements, Dockets No. 19-00099-UT & 19-00348-UT at 8-10 (NM Pub. Reg. Comm'n Nov. 14, 2022) (describing Buena Vista 2 Solar, Hecate 1 Solar, and Hecate 2 Solar)[hereinafter "EPE Amended Application in NM PRC Case No. 19-00099-UT;"]; John Fitzgerald Weaver, Arizona delivers solar at half price of existing coal generation, PV Magazine Australia (June 12, 2018), available at https://www.pv-magazine-australia.com/2018/06/12/arizona-delivers-solar-at-half-price-of-existing-coal-generation/ *(describing AZ Solar 1 and AZ Solar 2)*

Confidential Table 10. Recent solar PV + battery energy storage system (BESS) projects

Resource	**Utility/ owner**	**State**	**Project size (MW)**	**Price**	**Commercial operation date**
Wilmot solar PV + battery storage	TEP	AZ	Solar: 100 BESS: 30	[redacted]	5/2021
Buena Vista 1 solar PV + battery storage	El Paso Electric	NM	Solar: 100 BESS: 50	Solar: \$24.49/MWh BESS: \$5.36/kw-month	6/2023
Carne solar PV + battery storage	El Paso Electric	NM	Solar: 130 BESS: 65	Solar: \$29.96/MWh BESS: \$10.99/kw-month	5/2025
Box Canyon	Southwest Public Power Agency	AZ	Solar: 300 BESS: 600 MWh	Not public	2025

Sources: Attach. DG-4, TEP Response to Staff DR 4.097, Attachment STF 4.097_TEP NextEra (Wilmot) PPA full execution version signed 092917_COMPETITIVELY SENSITIVE CONFIDENTIAL.pdf; El Paso Electric Company's Amended Application for Approval of its 2022 Renewable Energy Act Plan and Sixth Revised Rate No. 38-RPS Cost Rider, Docket No. 22-00093-UT at 2 (NM Pub. Reg. Comm'n Nov. 18, 2022)(describing Carne solar PV + battery storage) [hereinafter "EPE Amended Application in NM PRC Case No. 22-00093-UT"]; EPE Amended Application in NM PRC Case No. 19-00099-UT at 2, 13 (describing Buena Vista 1 solar PV + battery storage); Ryan Kennedy, *BrightNight to meet one third of Arizona utility's peak demand with solar and storage project,* PV Magazine (July 19, 2022), *available at* https://pv-magazine-usa.com/2022/07/19/brightnight-to-meet-one-third-of-arizona-utilitys-peak-demand-with-solar-and-storage-project/ *(describing Box Canyon).*

Q How do these costs compare to the costs for alternatives that TEP modeled during its 2020 IRP?

A Table 11 below shows the costs that TEP modeled in its prior IRP. Comparing TEP's projects from its IRP to the costs reported for actual projects in the region, as shown in Competitively Sensitive Confidential Table 9 and Confidential Table

10 above, we can see that TEP's cost assumptions are high and not in line with actual industry cost data. TEP indicated that it has issued an RFP as part of its next IRP process. The Company should be regularly issuing RFPs and requests for information ("RFIs") to ensure it always has accurate market data and relies on these data as the basis of its new resource cost assumptions.

Table 11. TEP 2020 IRP new renewable cost assumptions

Resource	LCOE ($/MWh) $2022
Energy efficiency	$18.26
Solar PV (SAT)	$33.64
New Mexico wind	$37.49
Solar PV (fixed tilt)	$37.49
Arizona wind	$61.51
Natural gas CC (baseload)	$58.63
8-hour battery	$163.40
4-hour battery	$182.62

Source: TEP 2020 IRP.

Q Do the costs shown in the tables above reflect the near-term impact of inflation and supply chain challenges?

A Yes, some of the recent numbers do reflect the near-term impact of inflation and supply chain challenges. For instance, the prices for the Hecate and Buena Vista projects reflect recent PPA amendments that the developers requested which delay the online date and increase the project cost (in the case of Buena Vista) to account for supply chain challenges and inflation. The price for the Carne project also reflects a recent price update that the developer requested to cover cost increases due to inflation.

Q How does the cost of a clean energy portfolio compare to the cost of continuing to rely on TEP's aging coal resources?

A The *Arizona Coal Plant Valuation Study* (attached as Attachment DG-5) conducted by Strategen (on behalf of Sierra Club) in September of 2019 found substantial cost savings from replacing Four Corners and Springerville with alternative portfolios of resources consisting of a combination of solar PV plus storage, market energy, and wind.

In the time since this report was published there have been substantial changes in the market that will, on net, substantially improve the economics of clean energy alternatives, as evidenced by the examples listed above. Most notably, the Inflation Reduction Act ("IRA") passed Congress in August 2022, extending tax credits for solar PV and wind, and adding critical new tax credits for battery storage. I discuss the IRA in more detail in Section IVii below.

Q Can clean energy portfolios paired with market energy provide the same level of reliability as TEP currently gets from its fossil-fuel power plants?

A Yes, if deployed correctly, clean energy resources (including renewables, battery storage, demand-side management programs, and transmission build-out) paired with market energy, can provide the same if not better reliability than TEP's fossil plants. TEP's coal plants have all faced reliability challenges in recent years, as shown by the forced outage rates discussed above. Additionally, as outlined in detail below in Section IVii, TEP has faced increasing challenges procuring the coal it needs to run each plant at full capacity. Specifically, TEP had to de-rate both San Juan and Springerville in 2022 because either the coal mine or the railroad transporting the coal were unable to supply the contracted quantity.[35] If a plant does not have a firm and certain fuel supply, then it cannot be relied on to provide its full firm capacity and should be de-rated. And while the plants were de-rated in the past, TEP's projections show no future de-rating of the capacity at either of its coal plants. This means TEP assumes in its modeling that the plants will have uninterrupted coal supplies and will be available at full capacity moving forward, despite current evidence to the contrary.

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[35] Attach. DG-2, TEP Response to Staff DR 5.04 (a) and (d), Attachment _STAFF 05 Set of DR's TEP RC FINAL 02 SUPP (5.04b) 12.08.22.pdf.

With renewables, on the other hand, there are zero fuel requirements and therefore no possibility that firm capacity will be disrupted by a fuel supply constraint. The output of solar PV also aligns well with TEP's peak summer demand needs. And with transmission reform underway across the US, it may become easier and less costly for TEP or other regional entities to build-out the transmission network needed for TEP to access New Mexico wind. While it is true that TEP will also need firm capacity, battery storage can provide firm capacity and many of the grid services currently provided by TEP's fossil resources. Additionally, TEP just brought online in 2019 and 2020 10 new peaking gas units (reciprocating internal combustion engine or "RICE" units), which provide 188 MW of firm capacity, for the purpose of assisting with the integration of renewables. TEP also purchased Gila River Unit 2, a 550 MW natural gas combined cycle plant that was built by Salt River Project in 2006.

Q What costs would TEP avoid by accelerating the retirement of its coal plants?

A TEP would avoid substantial sustaining capital expenditures, environmental capex, and O&M costs with early retirement of its coal plants. As shown in Table 12 below, TEP projected that its future capex at the Four Corners and Springerville plants will be much lower than its spending was historically. This is concerning because it indicates that TEP may be under-projecting the likely forward-going cost to maintain its coal plants. The decrease in spending relative to historical levels may be related to TEP's switch to seasonal operations at both plants, but it is unclear exactly how the Company plans to cut spending levels nearly in half at Four Corners and Springerville Unit 1 while maintaining reliable service. TEP's historical spending at Four Corners is much higher than industry averages, as measured by Sargent & Lundy, indicating that the plant is relatively expensive to maintain relative to other coal plants. All of this leads me to conclude that TEP's projected capex spending at these units is unrealistic, if the plants are to remain operating, even on a seasonal basis.

Table 12. Projected and historical sustaining capex for TEP's coal plants

	Capex ($2022 $/kW-year)		
	Sargent & Lundy sustaining capex estimates	TEP historical sustaining capex spending	TEP projected sustaining capex spending
Four Corners	$33.58	$72.91	$40.47
Springerville Unit 1	$30.68	$44.04	$19.96
Springerville Unit 2	$30.68	$14.19	$16.52

Source: Attach. DG-2, TEP Response to SC DR 1-14, Attachment SC 1.14-2 revised.xlsx; 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.

Table 13 below shows TEP's projected O&M spending at its coal plants. These projections are relatively in line with historical O&M spending at Four Corners and Springerville Unit 2, but much lower than historical spending at Springerville Unit 1. The Company's projected O&M spending at Four Corners and Springerville 2 is much higher than industry averages. It is unclear why TEP's costs to operate and maintain the plants are so much higher than the costs incurred by other utilities.

Table 13. Projected and historical O&M costs for TEPs coal plants

	Operations & Maintenance ($2022 $/kW-year)		
	Sargent & Lundy O&M estimates	TEP historical O&M spending	TEP projected O&M spending
Four Corners	$49.81	$79.07	$82.67
Springerville Unit 1	$61.56	$74.27	$56.50
Springerville Unit 2	$61.56	$82.05	$77.95

Source: See Table 12.

Q What is the total lifetime cost impact of the potential deviation between TEP's projected ongoing O&M and capex costs, historical spending, and industry average spending?

A Comparing TEP's projected capex spending to its historical spending level at its plants shows a lifetime difference of $66.9 million. This means that if TEP's spending at its coal plants is closer to historical levels than projected levels, TEP will be facing a net present value ("NPV") of $66.9 million in capex costs beyond what it currently projected.

For O&M, over the remaining life of each plant, TEP's projected O&M spending at each plant will cost its ratepayers $71.5 million more on an NPV basis than ratepayers at peer utilities are spending for coal plant O&M.

ii. TEP has provided no current analysis to justify the proposed test-year spending at Springerville Units 1 and 2 and Four Corners

Q What analysis has TEP conducted to demonstrate the reasonableness of continuing to operate Springerville and Four Corners relative to alternatives?

A I am not aware of TEP having conducted any recent analysis on the reasonableness of continuing to operate Four Corners through 2031. Although TEP did test a scenario for its 2020 IRP where all coal retired by 2027, it did not evaluate the economics of Four Corners alone. TEP's most recent analysis on Springerville, which determined the unit's retirement dates of 2027 and 2032, was conducted as part of its prior IRP process in 2020. The Company has begun its next IRP process, but in the meantime, it is requesting to place the costs associated with maintaining both plants into rates and rate base without providing any contemporaneous evidence that doing so is in the best interest of ratepayers. Meanwhile, TEP's analysis, as well as my own, shows that earlier retirement of the Company's coal fleet—and thus avoidance of these maintenance and sustaining capital costs—are in the best interest of TEP ratepayers. This leads me to conclude that continued operation of and spending on Springerville and Four Corners without robust updated analysis is imprudent.

Q How did TEP determine the proposed retirement dates for Springerville Units 1 and 2 and Four Corners?

A The 2031 retirement date for Four Corners was set by APS to align with the expiration of its coal contract in 2031. I am not aware of TEP conducting any analysis, either as part of its last IRP or any time subsequently, on whether it was cheaper to retire Four Corners earlier than 2031, pay off the coal contract, and build or procure alternative resource options. The Company did test one scenario where all coal retired by 2027 but this was not helpful in evaluating the economics of any plant or unit individually.

TEP determined the 2027 and 2032 retirement dates for Springerville Units 1 and 2 as part of its 2020 IRP. The Company did not have a planned retirement date for Springerville prior to the last IRP. The Company did not utilize optimized capacity expansion modeling software to create the IRP but instead tested a series of scenarios head-to-head to determine which was lower cost. This means that TEP did not allow a resource planning model to test optimized retirement dates or resource additions. Instead, the Company programmed in specific retirement dates and resource additions and the model produced the results for each scenario. TEP conducted no subsequent modeling to confirm that continued operation of the units for another five and ten years is the lowest-cost solution for ratepayers.

Q What did TEP find about the cost of continuing to operate Four Corners relative to alternatives?

A In its IRP analysis, TEP found that retiring the Company's share of Four Corners once the coal contract expires in 2031 and replacing it with less costly wind and solar would produce cost savings for customers while reducing emissions, thereby mitigating the risk of additional carbon control or carbon-related costs and supporting progress towards TEPs carbon reduction goals.[36] But, as discussed

[36] Gray Direct at 10:1-8.

above, TEP conducted very limited modeling to evaluate whether an even earlier retirement would produce additional savings. Given the savings and benefits TEP found in 2031, it is likely that even the Company's own modeling would have found additional savings from retiring TEP's share of the plant early and replacing it with alternatives.

Q What did TEP find about the cost of continuing to operate Springerville Units 1 and 2 relative to alternatives?

A In its last IRP, TEP found that retiring Springerville Units 1 and 2 in 2027 and 2032 respectively was necessary to achieve TEP's goals of (1) reducing CO_2 emissions 80 percent below 2005 levels by 2035; (2) generating 70 percent of power from renewables by 2035; and (3) reducing groundwater consumption for power generation by 70 percent. TEP also indicated in its application that these retirement dates would mitigate the risk associated with TEP's ability to secure an affordable coal supply and sufficient water for power generation.[37] TEP's preferred portfolio, which included the 2027 and 2032 retirement dates for Springerville, did not have the lowest revenue requirement of all the portfolios that TEP tested, but it did minimize emissions and manage risk. If this scenario were re-run today, with updated market conditions, coal and gas prices, and costs for existing and replacement resources, as discussed below, it would likely be one of the lowest cost scenarios, if not the lowest cost scenario.

Notably, TEP also stated in its rate case application that these retirement dates were driven by "a determination that coal is no longer the lowest-cost year-round energy-supply resource."[38] Given TEP's clear acknowledgement of the risks of continuing to rely on coal, it is concerning that it still opted to keep Springerville online for another ten years. The economic and risk factors that drove TEP to select 2027 and 2032 as Springerville retirement dates are not new issues that will

[37] *Id*. at 10:15-11:3.
[38] *Id*. at 10:24-25.

suddenly appear in five and ten years—they are ongoing issues that impact the cost and risk of continuing to rely on the Company's coal plants today.

Q Do you have any other concerns with TEP's IRP analysis?

A Yes, in addition to the concerns I outlined above, there have been substantial changes in the market since TEP published its 2020 IRP. These changes make TEP's IRP analysis essentially obsolete and the Company's continued reliance on its coal plants even more concerning. While it is normal for there to be some level of market and regulatory shift in the time between publication of successive resource plans, the level and scope of changes seen recently and many of the drivers (namely, a global pandemic, geopolitical conflict, and major domestic legislative efforts) are unprecedented. Specifically, these drivers include:

1. Congress's passage of the Inflation Reduction Act
2. High inflation and supply-chain challenges
3. High and volatile natural gas prices
4. High and volatile Palo Verde hub market prices
5. Coal supply availability challenges and high price risks
6. Water supply availability risks
7. Future environmental regulatory risks

I will explain each of these factors in detail below.

Q What tax credits were available for clean energy resources when TEP conducted its IRP modeling in 2020?

A When TEP conducted its last IRP modeling, solar PV projects could access the investment tax credit ("ITC"), but it was being phased out by 2024. Wind projects could access the production tax credit ("PTC") only through the end of 2021. Solar PV could not access the PTC and battery storage was not eligible for the ITC. The PTC was not available for projects beginning construction after December 31, 2021.

Q How does the IRA change the tax credits available to TEP for clean energy resources?

A The IRA provides additional tax credits for solar PV and wind, and new tax credits for battery storage that were not available before.[39] The IRA benefits wind by extending the existing ITC and PTC tax credits. But it is even more impactful and transformative for solar PV, which now qualifies for both the ITC and PTC, and for battery storage, which is now eligible for the ITC. As shown in Table 14, the ITC and PTC values have increased for projects placed into service in the next few years.

Table 14. Clean energy tax credits before and after the IRA

	Tax credit type	Quantity	Eligible resource types	Tax credit level for projects that began construction in:			
				2021	2022	2023	2024
Pre-IRA	PTC	2.5 cents/kWh, adjusted for inflation	Wind	60%	0%	0%	0%
	ITC	Percent of total investment	Wind	26%	26%	22%	10%
			Solar	26%	26%	22%	10%
Post-IRA	PTC	2.5 cents/kWh, adjusted for inflation	Solar, Wind, Storage		100%	100%	100%
	ITC	Percent of total investment	Solar, Wind, Storage		30%†	30%	30%

Notes: † The 30% tax credit level assumes that prevailing wage and apprenticeship requirements are met.

Sources: Attach. DG-6, Congressional Research Service, The Energy Credit or Energy Investment Tax Credit (2021), available at https://crsreports.congress.gov/product/pdf/IF/IF10479; Attach. DG-7, Congressional Research Service, Energy Tax Provisions: Overview and Budgetary Cost (2021), available at https://crsreports.congress.gov/product/pdf/R/R46865; Inflation Reduction Act of 2022 §§ 13101, 13102; 26 U.S.C. §§ 45, 48.

[39] Inflation Reduction Act of 2022, Pub. L. No. 117-169, §§ 13101, 13102, 13701, 13702, 136 Stat. 1818 [hereinafter "Inflation Reduction Act of 2022"], codified at 26 U.S.C. §§ 45, 45Y, 48, 48E.

Beyond what is depicted in Table 14, the IRA added new ITC and PTC tiers that entitle any solar, wind, or battery storage projects to an additional 10 percent tax credit adder if they meet domestic content criteria and another 10 percent adder if they are located in an energy community. Any census tract where a coal mine or coal-fired power plant has closed since 2009 is defined as an energy community (as well as the census tracts directly adjacent). Additionally, brownfield sites and areas where fossil fuels have (1) accounted for at least 0.17 percent of direct employment or (2) 25 percent of local tax revenues and where the unemployment rate is above the national average for the previous year qualify as energy communities.[40] The maximum ITC and PTC credits available across a broad swath of the country[41] are thus 50 percent, notably larger than when TEP created its 2020 IRP.

Q Explain how inflation and supply chain challenges have impacted TEP's resource planning efforts.

A Inflation and supply chain challenges originally stemming from the COVID-19 pandemic, then compounded by uncertainty from the U.S. Department of Commerce anti-dumping investigation pertaining to solar cells and modules,[42]

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[40] 26 U.S.C. § 45(b)(11)(B).

[41] Attach. DG-8, Tony Lenoir, *Mapping Communities Eligible for Additional Information Reduction Act Incentives*, S&P Global Market Intelligence (Oct. 11, 2022), *available at* https://www.spglobal.com/marketintelligence/en/news-insights/research/mapping-communities-eligible-for-additional-inflation-reduction-act-incentives (identifying "more than 2,800 [ ] U.S. census tracts across 42 states[,]" including Arizona, eligible for the 10 percent adder).

[42] Throughout 2022, the Department of Commerce investigated a complaint that certain solar companies have been evading requirements placed on solar cells and modules produced in the People's Republic of China. *See* Press Release, Dept. of Com., *Department of Commerce Issues Preliminary Determination of Circumvention Inquiries of Solar Cell and Modules Produced in China* (Dec. 27, 2022), *available at* https://www.commerce.gov/news/press-releases/2022/12/department-commerce-issues-preliminary-determination-circumvention. Uncertainty surrounding the outcome of this investigation has placed additional pressure on solar cell and module availability in the United States.

have persisted and have driven up the cost of both new conventional and renewable resources in the near term. This has led to project delays and a general level of uncertainty on whether projects will be able to come online at the scheduled date. But critically, many of these forces impact not just new resource costs but also the cost to operate and maintain existing resources. The costs of labor and parts to maintain existing resources have gone up, and even the availability of parts to repair existing resources has become constrained in some cases (as discussed below in Section V). This means that TEP needs to adopt a more proactive approach to resource planning that brings new clean energy resources online in a rolling process. This will leave a buffer if there is a project delay and provide a back-up if an existing resource fails and needs replacement.

Q Explain the changes in natural gas prices and volatility in recent years.

A The average price of wholesale natural gas from the San Juan Basin increased over 350 percent between April 2019 and April 2022.[43] This was due in large part to the global conflict in Ukraine, which increased the price of natural gas and created general instability around supply availability and long-term prices. This has made it much more expensive to operate natural gas plants and has driven up market prices.

Q Explain the change in Palo Verde market prices and volatility in recent years.

A Average around-the-clock wholesale power prices at Palo Verde in April 2022 were up over 175 percent compared to April 2019.[44] Market prices in the West have increased dramatically, due in part to the California Independent System Operator's ("CAISO") institution of new market rules, but also the high natural gas prices discussed above and general supply constraints. This means that if TEP

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[43] Direct Testimony of Molly Mitchell at 2:7-8.
[44] *Id*. at 2:6-7.

experiences an unplanned outage, or otherwise must rely on the market for energy, its ratepayers will likely have to pay very high costs. This does not mean TEP cannot rely on the market, but rather that as market prices become higher and more volatile, TEP should take steps to minimize the need for unplanned reliance on the market.

Q Explain the risk of coal supply availability that TEP faces at its coal plants.

A The risk of coal supply availability stems from challenges facing both coal suppliers themselves, and the railroads that transport the coal.

Many regional coal plants have retired or are planned to retire, including the Navajo Generating Station in Arizona which shut down in 2019, the San Juan Power Station in New Mexico which shut down in 2022, and the Cholla Power Plant which plans to shut down in 2025. This is driving down the demand for coal in the region.

Individual coal mines are facing challenges delivering the required quantities of coal. At San Juan, for example, the coal supplier was unable to supply the required quantity of coal due to mine conditions and issued a force majeure. TEP and the other co-owners had to de-rate their ownership shares to ensure the coal supply would last until the unit shut down in June 2022.[45]

Coal transportation companies have also caused reliability challenges by failing to deliver contracted quantities of coal. The Burlington Northern Santa Fe Railroad ("BNSF") that delivers coal to Springerville notified TEP in the spring of 2022 that it would not be able to meet its 2022 delivery obligations due to "lack of workforce availability." TEP's coal and lime inventories at the plant dropped to

[45] Attach. DG-2, TEP Response to Staff DR 5.11.

the lowest level seen in the plant's life.[46] To accommodate this shortage, TEP indicated that:

> Springerville Units 1 and 2 have been in a derated position almost daily since June 2022 and this is scheduled to continue until the inventory recovers and BNSF deliveries rebound. Additionally, the Company took a coal conservation outage on Unit 1 during October 2022 to build inventory going into the winter outage season. The failure of the BNSF to deliver the coal TEP forecasted to burn from June 2022 through October 2022 is 460k tons.[47]

TEP acknowledges the potential risk of coal supply availability at Springerville[48] in its application and lists it as a reason for the 2027 and 2032 retirement dates.[49] Moreover, in its 2020 IRP, TEP stated that "[t]he planned closure of other coal-fired power plants also has increased the risk of regional coal mine closure that could limit the availability of fuel for Units 1 and 2."[50] But the Company indicated in a discovery response that it has not evaluated the impact of regional coal plant closures on the cost to operate Springerville.[51] It is alarming that TEP has not factored into any resource planning or current analysis the risks and challenges it will likely face in maintaining a reliable coal supply going forward, especially after TEP had to de-rate the available capacity of both San Juan and Springerville coal plants in 2022 due to challenges in procuring the necessary quantity of coal.

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[46] Attach. DG-2, TEP Response to Staff DR 5.04(a), Attachment _STAFF 05 Set of DR's TEP RC FINAL 02 SUPP (5.04b) 12.08.22.pdf.

[47] Attach. DG-2, TEP Response to Staff DR 5.04(d), Attachment _STAFF 05 Set of DR's TEP RC FINAL 02 SUPP (5.04b) 12.08.22.pdf.

[48] Four Corners is served by coal from a specific regional mine under a long-term coal contract, so it is not likely to be impacted by regional shortages.

[49] Gray Direct at 10:20-23.

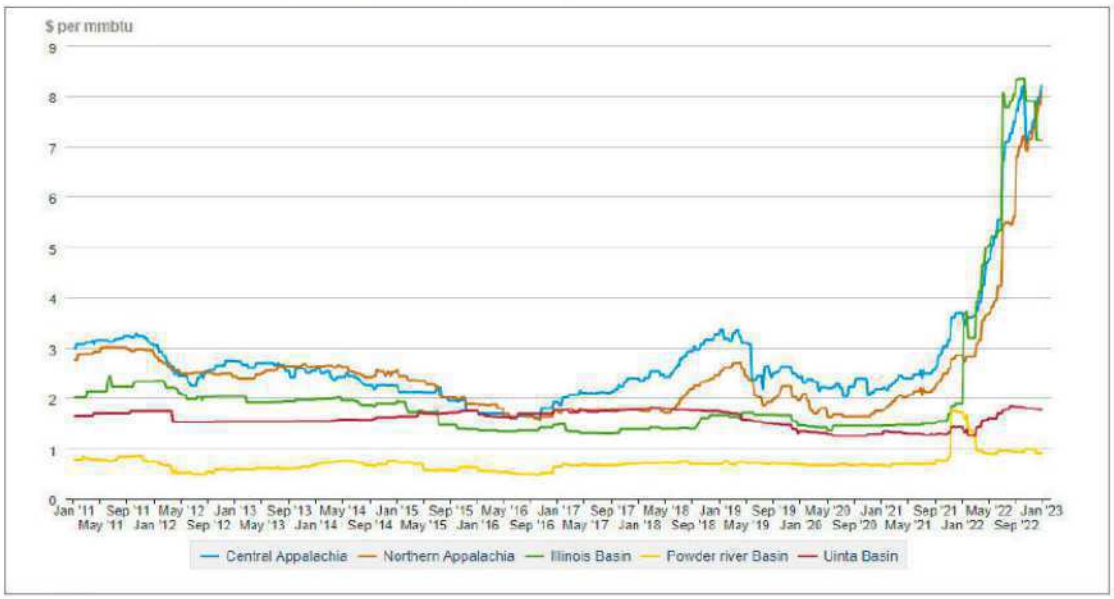
[50] TEP 2020 IRP at 15.

[51] Attach. DG-2, TEP Response to SC DR 1-21.

Q **Explain the risk of high coal prices and price volatility.**

A After staying relatively stable for the past decade, the price of coal has gone up significantly in some parts of the country over the last year, as shown in Figure 3 below. While this price spike specifically is something no one predicted, it is exactly the type of risk inherent in a system that relies on fossil fuel resources and that can be mitigated by a transition to clean energy resources.

Figure 3. Historical coal prices by region, 2011 to present



Source: U.S. EIA citing SNL Energy, Coal Markets Archive: Historical coal prices by region, 2011 – current data, available at https://www.eia.gov/coal/markets/includes/archive2.php.

Competitively Sensitive Confidential Figure 4 below shows TEP's Springerville coal prices forecast from its 2020 IRP. [redacted] TEP's IRP results significantly understate the likely future cost and risk of continuing to rely on its coal plants.

Competitively Sensitive Confidential Figure 4. TEP forecasted coal price for Springerville in 2020 IRP

[redacted]

Source: Attach. DG-4, TEP Response to SC DR 1.10, Attachment SC 1.10 FWRD PCE ASSMPT-Comp Sens Confidential.xlsx.

Q How much exposure does TEP have to coal price volatility?

A TEP's exposure to coal price volatility is based on the location of its coal supplies, the portion that it has secured under contract, and the transportation system used to deliver the coal (as discussed above).

In 2022 TEP sourced 41 percent of its coal from mines in New Mexico and 59 percent of its coal from mines in the Powder River Basin.[52] The Powder River Basin had more stable prices than mines in the Midwestern and the eastern United States in 2022 (as shown in Figure 3 above), but TEP is still relying on coal supplies outside Wyoming for a large portion of its coal supply.

In addition, while TEP gets the majority of its coal for Springerville from short- and long-term contracts, it still relies on spot contracts for a portion of its coal. Through the first nine months of 2022, TEP relied on the spot market for 10

[52] U.S. EIA Form 923, 2022 data.

percent of its purchases.[53] TEP indicated in discovery that during the test year, the three preceding years, or in any month after the test year it had not purchased coal on the spot market at a higher price than that contained in a long-term fuel supply contract.[54] But public data from the U.S. Energy Information Administration ("EIA") shows that during the first nine months of 2022, TEP paid an average of nearly $48.05/ton for coal it procured under contract, and $67.14/ton for coal it procured from the spot market. This works out to a 40 percent price premium for coal it purchased from the spot market relative to the coal it purchased under contract.[55]

Q Explain the risks of water scarcity and availability and how that will impact TEP's operation of its coal plants.

A Water scarcity in the West has driven up the cost and risk to operate steam-fired power plants that rely on water for cooling. TEP itself has at least partially acknowledged this risk and included in its last IRP a goal of decreasing groundwater consumption for power generation 70 percent by 2035. But given the increasing level of water scarcity in the West, this is not soon enough.

The risks posed by a water shortage are not just theoretical: Southwestern Public Service Company ("SPS") recently announced that it was moving up the retirement of the coal-fired Tolk Generating Station from 2032 to 2028 because it could no longer economically secure sufficient water to operate the plant through its planned retirement date in 2032.[56] This was after SPS proposed in its prior rate case to move Tolk's retirement date up from 2042 to 2032 and switch the unit to

[53] U.S. EIA Form 923, 2022 data.

[54] Attach. DG-2, TEP Response to Staff DR 4.104.

[55] U.S. EIA Form 923, 2022 data.

[56] Ethan Howland, *Xcel to retire Texas coal-fired power plant early, speeding up companywide exit from coal in 2030,* Utility Dive (Nov. 1, 2022), *available at* https://www.utilitydive.com/news/xcel-retire-texas-coal-fired-power-plant-tolk/635437/.

seasonal operation. This move was also driven by projected water shortages, specifically SPS's projection that it would run out of water in the mid-2020s if it continued to operate year-round. I served as an expert witness in that case and cautioned that SPS was ignoring the risks clearly outlined in its groundwater reports and data.[57] Specifically, SPS ignored the risks that it would have trouble meeting its groundwater demands, especially peak demands in the summer, and that depletion rates for the aquifer SPS relies on were likely underestimated based on uncertainty about groundwater pumping rates from area irrigators who also relied on the aquifer.[58] SPS ignored these cautions and now has a shorter window to plan for replacement resources.

Q Explain the risk posed by future environmental regulations and potential carbon pricing.

A There are a variety of environmental rules and regulations that Congress and regulators are considering, all of which would increase the cost to operate some or all fossil fuel power plans. These include, for instance, the federal Environmental Protection Agency's ("EPA") review of recently submitted state implementation plans under the Clean Air Act to implement Round II of the Regional Haze Rule, EPA's current rulemaking on the Cross State Air Pollution Rule (also known as the "Good Neighbor Rule"), EPA's proposed decision for the reconsideration of the national ambient air quality standards for particulate matter (PM) issues on January 6, 2023, EPA's plan to initiate rulemaking on greenhouse gas emission standards for new and existing power plants by April 2023, and the potential for future federal carbon pricing. Each of these has the potential to require significant pollution reductions at coal plants, which the plant operators could meet either through installation of expensive pollution control technologies or closure of the plant. While there may be uncertainty around exactly which rules and policies

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[57] Attach DG-9, Excerpt of Direct Testimony of Devi Glick, Case No. 19-00170-UT at 44-46 (NM Pub. Reg. Comm'n Nov. 22, 2019) [hereinafter "Attach DG-9, 2019 Glick Direct Excerpt"].

[58] Attach DG-9, 2019 Glick Direct Excerpt.

will be implemented, what form the final rules will take, and when the rules will be finalized, the direction of impact from increased environmental regulations is clear: coal plants will become more highly regulated and therefore more costly and riskier to operate.

Q What takeaways do you have about Springerville Units 1 and 2 after reviewing TEP's application and analysis?

A TEP should work to procure replacement resources for Springerville to reduce reliance on the units and ease the path to retirement. The risks that the cost of operation will increase are substantial, while the chance that coal will become a competitive or more desirable resource option is almost non-existent. Coal prices are high and coal availability is constrained, water scarcity risks are increasing, there is a high risk of increasing environmental regulations, and the costs of cleaner alternatives are falling.

Q What takeaways do you have about Four Corners after reviewing TEP's application and analysis?

A TEP has stated that, as a minority owner, it has limited control over the ongoing operations and retirement of Four Corners. But this does not justify the minimal oversight TEP has exercised over the units' operation and planning, especially given the high unit costs TEP expects to pass along to its customers. With the limited information we do have about the Four Corners plant's recent historical performance and projected future economics, I find it is in the best interest of ratepayers for TEP to evaluate a pre-2031 retirement date and retire the unit as soon as it can secure replacement resources. In the meantime, TEP should limit future spending at the unit. Four Corners has been costly to operate, it has a high unforced outage rate, and is likely to only become more costly in the future.

V. TEP SHOULD WORK TO PROCURE MORE CLEAN ENERGY RESOURCES ON A ROLLING BASIS TO MEET FIRM CAPACITY NEEDS, MANAGE PEAK, AND REDUCE CUSTOMER COSTS AND RISKS

i. Current resource procurement efforts

Q Provide an overview of TEP's recent procurement efforts.

A Prior to last rate case, TEP purchased Gila River Unit 2, a 550 MW combined cycle gas plant, and brought online 10 RICE units at the Sundt Generating Station, which provide 188 MW of peaking capacity.

More recently, in December 2020 TEP brought online the new 250 MW Oso Grande Wind project and is requesting it be added into base rates in this docket.[59]

As discussed in Section III above, TEP also issued an all-source RFP in April 2022 for 250 MW of renewables and energy efficiency resources. This could include new wind, solar PV, energy efficiency, and demand response.[60] The RFP also seeks 300 MW of a firm capacity resource that can be called on at any time. This includes 4-hour energy storage and demand response. TEP states that the firm capacity will not be from a fossil resource.[61] This is critical given TEP's commitment during the prior IRP that, as TEP retires its existing fossil resources, "all of the new replacement resources will be a combination of renewable resources, energy storage and energy efficiency."[62] TEP is currently evaluating results from the RFPs[63] and has indicated that it will provide an update as part of the 2023 IRP process.

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[59] Gray Direct at 2:16-19.

[60] Dukes Direct at 5:3-7.

[61] Attach. DG-2, TEP Response to SC DR 4.03(b).

[62] TEP 2020 IRP at 18.

[63] Attach. DG-2, TEP Response to SC DR 4.03(a).

Q What types of resources are other regional entities developing to meet their projected future needs?

A Arizona Southwest Public Power Agency ("SPPA") recently entered into a joint venture with BrightNight to have 300 MW of solar energy capacity and 600 MWh of battery energy storage delivered. SPPA expects the project will meet around a third of its peak capacity needs and roughly 20 percent of its energy needs. The power will come from Box Canyon solar project in Pinal County and is expected to be operational in 2025.[64] SPPA selected this project after issuing an RFP for up to 200 MW of gas-fired generation and 100 MW of solar PV. SPPA chose the clean energy project because the scope of technology surpassed its requirements as outlined in its RFP.[65]

In New Mexico, El Paso Electric ("EPE") is currently building or seeking approval for 390 MW of solar PV and 115 MW of battery storage across three different projects. Specifically, EPE is building a 120 MW solar PV and 50 MW storage project at Buena Vista, and a 140 MW solar PV project at Hecate. EPE is also requesting approval to build a 130 MW solar PV and 65 MW battery storage project at Carne.

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[64] Ryan Kennedy, *BrightNight to meet one third of Arizona utility's peak demand with solar and storage project*, PV Magazine (July 19, 2022), *available at* https://pv-magazine-usa.com/2022/07/19/brightnight-to-meet-one-third-of-arizona-utilitys-peak-demand-with-solar-and-storage-project/.

[65] Andy Colthorpe, *Arizona utility groups sign PPA for 300 MW/600 MWh solar-plus-storage power plant*, Energy Storage News (July 20, 2022), *available at* https://www.energy-storage.news/arizona-utility-groups-sign-ppa-for-300mw-600mwh-solar-plus-storage-power-plant/.

ii. ***<u>TEP needs supply- and demand-side resources to help manage peak demand</u>***

Q Why does TEP need more peak management resources?

A TEP's retail sales of kWh have declined over the last 10 years while its peak demand has risen. Specifically, TEP has seen a 5.7 percent increase in peak demand since the end of the last test year while sales have been relatively flat.[66] Lower sales equals fewer kWh to recover fixed costs. Eighty percent of TEP's fixed costs are recovered volumetrically on a per-kWh basis.[67]

Q What has driven this pattern of flat or declining load and increasing peak?

A TEP stated that the reduction in load it has observed on its system has been driven by the increased penetration of distributed generation and deployment of energy efficiency measures. According to TEP, distributed generation and energy efficiency measures "[p]rovide broad positive benefits for customers and the environment, but they also erode TEP's ability to recover fixed costs through volumetric energy charges. Those fixed costs are driven largely by consumption during peak usage period…"[68]

On the issue of increasing peak load, the Company does not appear to have sufficiently studied or evaluated key factors driving the increase in peak since the last test year in 2018. When asked to explain the key factors driving TEP's system peak load increase, the Company attached a chapter of its 2017 IRP.[69] But this document is outdated and precedes the near-term increase in demand TEP is most

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[66] Gray Direct at 3:8-12.
[67] TEP Application at 8.
[68] Gray Direct at 3:14-17.
[69] Attach. DG-2, TEP Response to WRA DR 1.07.

concerned about. TEP should have conducted updated analysis of the factors driving peak demand and measures it can take to manage peak load.

Additionally, TEP appears to have relied on the same 2018 energy efficiency implementation plan for every year between 2018-2021.[70] This means the Company relied on the same energy efficiency and demand management measures during that five-year period, despite experiencing increasing levels of peak demand. This plan had no residential load management programs. In 2021 TEP submitted an updated energy efficiency plan, which the Commission approved. Given TEP's concern with its increasing peak load, it's unclear why the Company waited until 2022 to implement a residential direct load control program.

Q What efforts has TEP taken to manage peak load?

A TEP appears to have implemented only minimal demand-side measures to manage peak load in recent years. Specifically, TEP indicated that it has a program called SmartDR which allows TEP to request that customers voluntarily curtail their load during specific hours. This program also allows TEP to call on the customers directly to curtail load during peak times. The Company also indicated it can make public requests for conservation during times of high demand.[71] But this program is a new pilot program, implemented in 2022 and is only reaching a handful of customers. In addition to this thermostat control, TEP also has some commercial and industrial ("C&I") direct load control, and pool pump control. These programs are far from sufficient to match the peak demand needs facing TEP.

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[70] Decision No. 78066, Docket No. E-01933A-20-0168 (Ariz. Corp. Comm'n June 24, 2021), *available at* https://docket.images.azcc.gov/0000203995.pdf?i=1673388913456.

[71] Attach. DG-2, TEP Response to SC DR 1.17; Attach. DG-2, TEP Response to WRA DR 1.04.

Q How have TEP's load-management programs been performing?

A TEP's energy efficiency programs broadly, and load management programs specifically, do not appear to be garnering high participation and delivering desired savings levels. In 2021, the Company underspent its $22.9 million energy efficiency budget by $6 million.[72] Out of that total, TEP spent only $215,128 on its C&I Direct Load Control program,[73] which is less than half of the $500,000 it had budgeted for the program.[74] TEP reported that its 2021 C&I program participation levels were lower than previous years due to "supply chain issues and rising materials costs related to the pandemic."[75] The Company reported 2.8 MW in savings from the C&I program in 2021, but indicated that the maximum capacity available for reduction events was actually 42.73 MW. Inclusive of the maximum C&I capacity, TEP reported that its total energy efficiency portfolio delivered 68.88 MW of capacity savings in 2021.[76]

In 2022, in the Company's Mid-year DSM Status Report, TEP had only spent 30 percent of its total energy efficiency budget (between January and June 2022). During this same time, TEP spent only $100 out of a budget of $1.5 million for a Residential Load Management Pilot, and $23,354 out of a total of $700,000 on C&I direct load control programs.[77] TEP expected its energy efficiency programs would deliver 72.18 MW of peak demand savings in 2022.

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[72] TEP, *2022 Demand Side Management Implementation Plan* at 2, Docket No. E-01933A-21-0182 (June 1, 2021) *available at* https://docket.images.azcc.gov/E000013816.pdf?i=1673384378859 [hereinafter "TEP 2022 DSM Implementation Plan"].

[73] Attach. DG-2, Excerpt of TEP Response to SC DR 1.16, Attachment SC 1.16_TEP_DSM_2021 Annual Report_FINAL.pdf at 9.

[74] TEP 2022 DSM Implementation Plan at 9.

[75] Attach. DG-2, TEP Response to SC DR 1.16, Attachment SC 1.16_TEP DSM 2021 Annual Report_Final.pdf.

[76] *Id*.

[77] Attach. DG-2, TEP Response to SC DR 1.16, Attachment SC 1.16_TEP DSM 2022 Mid-Year Report_Final.pdf.

Q What efforts should TEP be taking to manage peak load?

A TEP should be focusing on managing peak load with demand-side management measures, including time-of-use pricing, expanded residential and commercial direct load control, thermal storage, and hot water controls. TEP should also be deploying more battery storage resources, both paired with solar and stand alone.

Q Has the Company indicated any plans to expand its current load management program?

Yes, but only with pilot programs. TEP stated in its 2022 Plan[78] that it is working on implementing several load management pilot programs: (1) a feeder-level battery storage program to reduce system peak, feeder congestion, and support local power; (2) thermal storage; (3) demand response with connected smart thermostats. TEP also indicated that it is expanding its non-residential load management pilot and it is proposing to incorporate the TEP Customer-Sited Energy Storage Pilot into the Load Management Pilot. While these programs are all positive steps by TEP to manage peak, as pilot programs they are inherently limited in scope and impact.

Q Are TEP's coal plants good peak-management resources?

A No. Coal plants are large and relatively inflexible generation resources. They are costly and time-intensive to ramp up and down or turn on and off. Because of these characteristics, coal plants are generally bad at responding quickly to price signals or changes in load or generation levels on the grid throughout the day. Putting aside their environmental impacts, coal plants were adequate baseload resources for the grid of the past, when they largely operated all the time, but now coal plants are poor choices to support our present grid, which has an increasing

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[78] Decision No. 78780, Docket No. E-01933A-21-0182 (Ariz. Corp. Comm'n Nov. 21, 2022), *available at* https://docket.images.azcc.gov/0000208033.pdf?i=1673386342320.

penetration of renewables and requires flexible, responsive resources such as battery energy storage.

iii. ***TEP should shift its resource procurement efforts to focus on procuring clean energy on a rolling basis rather than just in response to capacity needs***

Q What are TEP's current and projected capacity and energy needs?

A In its most recent (2020) IRP, TEP projected it would need 3,144 MW of firm capacity to serve 2,995 MW of demand as of 2035.[79] TEP also indicated that it plans to retire 1,073 MW of coal-fired generation by 2035.[80] To serve projected the Company's projected demand and replace the retired coal capacity, TEP plans to add 2,460 MW of new generation resources and 1,400 MW of battery storage.[81]

Q What type of replacement resources should TEP be considering?

A TEP should be evaluating portfolios of resources that include solar PV, onshore wind, battery storage, demand-side management, transmission build-out, and market purchases.

As discussed above, with the recent passage of the IRA, tax credits available for renewables and battery storage are stabilizing prices in the near term and are expected to drive down prices in the near future. Arizona has excellent solar PV potential, which now qualifies for the PTC and ITC. Battery storage, which in the past did not qualify for a tax credit, now qualifies for the ITC. The preference to delay deployment while technology costs fall should be less of an issue now, with the ITC offsetting a substantial portion of the project cost.

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[79] TEP 2020 IRP.

[80] Bakken Direct at 3:13-14.

[81] *Id*. at 3:12-13.

Additionally, the IRA provided funding for transmission projects. TEP could use this funding to address load pockets, to access high quality wind resources from out of state, as well as to modernize and expand its transmission network to better integrate renewables.

Q How should TEP be thinking about resource procurement?

A Currently, TEP procures new resources when it identifies a capacity need during its IRP process. While utilizing existing resources is not inherently wrong, this model tends to favor the status quo. It keeps existing resources online and keeps the costs to operate and maintain these resources in rate-base, even if there are lower-cost, and feasible options. This model tends to understate the risk and cost of continuing to rely on existing resources, overstate the cost and risk of alternatives, and delay progress and action until something breaks or becomes so costly that it is impossible to ignore. Under this model, excess costs incurred when a plant breaks down or fuel prices spike are explained away as an anomaly, and something the utility never could have predicted.

But market and gas price spikes are becoming more frequent, and plant outages become more likely and frequent as a plant ages. The costs and risks associated with these factors can be mitigated with a rolling resource procurement model. For many of the reasons discussed in the section above, procuring new resources on a continuous basis can be lower cost and lower risk than relying on existing resources. Doing so also introduces flexibility into the resource planning process.

Q Won't a rolling procurement model just lead to over-procurement of capacity and produce an overbuilt system that is more costly for TEP ratepayers?

A No, not necessarily. My recommendation is not that TEP should dramatically overbuild, procuring thousands of MW more than it needs. But if an existing resource is facing forces that, while uncertain, are all likely to lead to higher costs and higher risks, and new low-cost, clean energy resources are available but require lead time to come online, there is little downside to planning actively and proactively.

Right now, TEP is relying on its costly and sometimes unreliable fossil resources that break down, are facing coal supply challenges, and require expensive replacement energy purchases. The Company is also relying on expensive tolling agreements to meet its capacity needs. Specifically, [redacted]. This is more than [redacted] the cost of new entry ("CONE") in several of the organized markets, which represents the current annualized capital cost of constructing a new power plant (based on the cost of an advanced combustion turbine).[82] This means that TEP could build replacement resources for less than a [redacted] of the cost per MW that it is currently paying SRP. In total, TEP paid more than [redacted] million in each of 2021, 2022, and 2023 for 300 MW of capacity (as shown in Competitively Sensitive Confidential Table 15 below).

Competitively Sensitive Confidential Table 15. TEP tolling agreement charges at Harquahala

	2023	2022	2021
Contract capacity (MW)	[redacted]	[redacted]	[redacted]
Delivery period	June 15 - October 15		
Capacity price ($/kW-month)	[redacted]	[redacted]	[redacted]
Capacity price $/MW-day	[redacted]	[redacted]	[redacted]
Total capacity charges	[redacted]	[redacted]	[redacted]

Source: Attach. DG-4, TEP Response to Staff DR 4.097, Attachment STF 4.097-Harquahala – SRP_TEP 2021 Tolling Confirmation (WSPP Agreement)_EXECUTED -Competitively-Sensitive-Confidential.pdf.

[82] MISO Cost of New Entry (CONE) Planning Year 2023/2024, Resource Adequacy Subcommittee (Oct. 12, 2022), *available at* https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf.

With renewables and battery storage, the costs of early deployment are minimal relative to the risks the resources help avoid and the value that they provide. Renewables and energy storage require no fuel and have limited and known variable operating costs, meaning that they are insulated from the risk of fuel price and market price volatility that can impact fossil resources. The only real costs are the revenue requirement impacts of building a resource a year or two in advance of when it is "needed" and at a cost that might be lower in a year or two. In the time it takes to bring the new resources online, it is likely that conditions will change such that the new resource either will be needed by the utility, will outcompete existing resources, or at the very least, will be valuable to other regional entities that are not as proactive.

Q Can you quantify the cost trade-off of waiting for renewables costs to drop relative to the cost of alternatives, such as market power?

A Yes. If we assume that TEP signs a solar PPA today for a 100 MW solar project with a commercial operation date of January 1, 2025, we estimate that that project would have a 20-year NPV of [redacted] million (as shown in Confidential Table 16 below). If TEP were to delay procurement by two years while waiting for project costs to fall, so that the project would not come online until January 1, 2027, TEP would have to procure resources in the intervening two years from another source. Assuming TEP relies on costly market energy in the interim, that would cost [redacted] for two years (2025 and 2026). The solar PPA prices would need to drop by 40 percent during the two-year delay for TEP to break even by waiting rather than procuring the project immediately. Otherwise, if solar PPA prices dropped by less than 35 percent, TEP would be paying as much as [redacted] in excess costs.

Confidential Table 16. NPV of 2025 vs 2027 PPA with replacement market energy

Commercial Operation Date	PPA price percent reduction	PPA cost *($/MW)*	Total energy *(GWh)*	Replacement market energy cost ($ million)	Solar cost ($ million)	Total cost combined cost ($ million)
1/1/2025	Original price	$29.96	5,299	$0	[redacted]	[redacted]
	0%	$29.96			[redacted]	[redacted]
	10%	$26.96			[redacted]	[redacted]
1/1/2027	25%	$22.47	5,347	[redacted]	[redacted]	[redacted]
	35%	$19.47			[redacted]	[redacted]
	40%	$17.98			[redacted]	[redacted]

Source: Synapse calculations based on TEP response to SC DR 3.02, Attachment SC 3.02.xlsx and SC DR 1-11, Attachment SC 1.11 Palo Verde Forward Price – Confidential.xlsx; EPE Amended Application in NM PRC Case No. 19-00099-UT.

Q Explain how you calculated the PPA and replacement energy costs.

A I relied on data that TEP provided in discovery as well as public data on a recent solar PPA contract in the region.[83] Using this data I was able to calculate the 20-year NPV for a hypothetical 100 MW solar PV project assuming a commercial operation date of January 1, 2025. I compared the NPV of this scenario to the NPV of a solar project delayed for two years (until 2027) and with market energy purchased in the intervening two years.

For the 2025 Solar PPA, I first calculated the expected on- and off-peak annual energy output from a solar resource in Arizona's service territory. I did this by averaging TEP's historical hourly PV resource profiles for a tracking solar array for the years 2017–2020.[84] Using the average generation level to represent year one output, I applied a 0.5 percent annual degradation rate[85] to calculate expected

[83] EPE Amended Application in NM PRC Case No. 19-00099-UT; EPE Amended Application in NM PRC Case No. 22-00093-UT.

[84] Attach. DG-2, TEP Response to SC DR 3-02, Attachment SC 3.02.xlsx.

[85] PV Lifetime Project – 2021 NREL Annual Report, National Renewable Energy Laboratory (September 2022), *available at* https://www.nrel.gov/docs/fy22osti/81172.pdf.

energy outputs over each year in the project's 20-year lifespan. I then applied a PPA cost of $29.96/MWh, based on regional PPA from EPE for a solar project also with a commercial online date of 2025,[86] to calculate the annual costs associated with this solar project. I relied on the company's WACC of 7.31 percent[87] to calculate the NPV of costs.

To calculate the NPV of costs in the delayed PPA scenarios, I first used TEP's most recent Palo Verde forecasts[88] to calculate the cost of purchasing replacement on- and off-peak market energy equivalent to the energy that would be generated by the hypothetical solar project in 2025 and 2026. I then assumed the 100 MW project would come online in 2027 with reduced PPA prices ranging from 0 percent to 40 percent of the original cost in 2025 ($17.98 to $29.96/MWh) and used the same approach described above to calculate the expected solar PV energy output through 2045. I applied the reduced PPA prices to these expected energy outputs to calculate the annual energy costs.

The total energy generated in the delayed scenarios is slightly greater than in the original scenario because I assumed equivalent market replacement energy was purchased in 2025 and 2026, and that the delayed projects were at full capacity in 2027 (whereas in the original scenario, the projects would have experienced two years' worth of degradation by 2027).

Q Doesn't this approach of procuring before the utility has a capacity need conflict with industry best practices for resource procurement?

A No. The rolling procurement represents a necessarily evolution in the planning process as the penetration of renewables on the grid increases, as fossil fuel prices

[86] EPE Amended Application in NM PRC Case No. 19-00099-UT; EPE Amended Application in NM PRC Case No. 22-00093-UT; *see also* Competitively Sensitive Confidential Table 9, *supra*.

[87] TEP Application at 8.

[88] Attach. DG-3, TEP Response to SC DR 1-11, Attachment SC 1.11 Palo Verde Forward Price – Confidential.xlsx.

become more volatile, and as project development is shifted from a few centralized utilities and a few centralized energy resources to many small parties and resources.

In fact, other utilities are starting to adopt this resource planning approach. For example, Ameren stated in a recent Certificate of Public Convenience and Necessity ("CCN") that "…a gradual, sustained transition to renewable energy is more cost effective and practical than waiting until there is an actual capacity need and ensures the Company can continue to deliver sufficient quantities of reliable, affordable energy to customers…"[89]

Q Why is this model better suited for the current clean energy transition?

A Transitioning to clean energy resources now rather than waiting until there is an immediate need provides more flexibility to retire aging units as needed and protects ratepayers from reliance on the market or volatile fossil resources, from coal supply disruptions, and from project delays or unit breakdowns.

The cost to maintain existing resources are high, and units can break down unexpectedly. As discussed above, both Springerville units experienced unplanned outages in recent years that required TEP to purchase a large amount of replacement market power. In 2021 alone, TEP estimated that the replacement power required during Springerville unplanned outages cost TEP ratepayers more than $[redacted] million dollars (as shown in Confidential Table 7 above).[90] Coal supplies can also be interrupted, as discussed above, causing plants to de-rate their capacity when their coal supplies were limited. When this happens, the full capacity of each resource is not available.

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[89] Direct Testimony of Ajay K. Akora, Docket No. EA-2022-0245 at 7 (Mo. Pub. Util. Comm'n July 14, 2022), *available at* https://efis.psc.mo.gov/mpsc/DocketSheet.html.

[90] Attach. DG-3, TEP Response to Staff DR 1-15, Attachment STF 1.15 – Forced Outages_2019-2022-Confidential.xlsx.

As another example, in Indiana, Center Point is facing unexpected high fuel and market energy and capacity costs because one of its coal plants, Culley Unit 3, broke down and the Company has no replacement resources available. The part that Center Point needs to repair Culley 3 is no longer made by General Electric, so Center Point had to purchase the part from a retired coal plant in Montana and transport it to Indiana. This process required Center Point to put Culley 3 into outage for a year and to purchase high-cost power in the interim.[91]

Additionally, all projects, especially renewable projects, may be delayed by a year or two with supply chain challenges. I have seen this around the country. PNM, for example, delayed the retirement of San Juan Generating Station by a year because the renewables PNM needed to replace the unit were delayed. As discussed above, EPE announced that the commercial operation dates for the Buena Vista and Hecate solar projects were delayed by one and two years respectively based on supply chain challenges and the Department of Commerce solar tariff.

Additionally, some renewable projects may require transmission build out or investment, which cannot happen overnight. But with transmission funding available through the IRA, and other transmission reforms underway around the country, the pace of transmission expansion should pick up. These reforms should remove barriers to transmission development and help socialize the costs across a larger group of ratepayers that will reap the lines benefits, rather than just requiring the next project to come online to bear the full transmission cost.

Planning a project around a specific deadline in the current environment is a risky strategy. That does not mean that TEP should not rely on renewables; rather, it means that shifting to a model where resources are deployed as they become

[91] Brady Williams, *Broken coal plant leads CenterPoint Energy to petition for rate increase*, 14 News (Nov. 22, 2022), *available at* https://www.14news.com/2022/11/22/broken-coal-plant-leads-centerpoint-energy-petition-rate-increase/.

available will make it more likely that resources will be online by the time TEP needs them.

Q Does this conclude your testimony?

A Yes.

Attachment DG-1

Resume of Devi Glick

Synapse Energy Economics, Inc.

Devi Glick, Senior Principal

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dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *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

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

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Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

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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.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

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Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

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Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

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Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Cost §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

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.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

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.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

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 Utilties 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.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

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

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

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

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

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

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

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. 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.

Resume updated January 2023

Attachment DG-2

Public Discovery Responses

Confidential and Competitively Sensitive
Confidential Information has been redacted.

Public TEP Responses to Data Requests:

1. TEP Response to SC DR 1-03(a), Attachment SC 1.03a.xlsx
2. TEP Response to SC DR 1-03(c), Attachment SC DR 1.03 and 1.05 Summary.xlsx
3. TEP Response to SC DR 1-13
4. TEP Response to SC DR 1.14, Attachment SC 1.14-1.xlsx
5. TEP Response to SC DR 1-14, Attachment SC 1.14-1-Revised.xlsx
6. TEP Response to SC DR 1-14, Attachment SC 1.14-2.xlsx
7. TEP Response to SC DR 1-14, Attachment SC 1-14.2 Revised.xlsx
8. TEP Response to Staff DR 4.003, Attachment STF 4.003 Oso Grande Plant-in-Service.xlsx
9. TEP Response to Staff DR 5.04, Attachment _STAFF 05 Set of DR's TEP RC FINAL 02 SUPP (5.04b) 12.08.22.pdf
10. TEP Response to Staff DR 5.11
11. TEP Response to SC DR 1-21
12. TEP Response to Staff DR 4.104
13. TEP Response to SC DR 4.03
14. TEP Response to WRA DR 1.07
15. TEP Response to SC DR 1.17
16. TEP Response to WRA DR 1.04
17. Excerpts from TEP Response to SC DR 1.16, Attachment SC 1.16_TEP_DSM_2021 Annual Report_FINAL.pdf
18. Excerpt from TEP Response to SC DR 1.16, Attachment SC 1.16_TEP DSM 2022 Mid-Year Report_Final.pdf
19. TEP Response to SC DR 3-02, Attachment SC 3.02.xlsx

SC 1.03a - Coal-Fired Capital Expenditures 2021

Row Labels	Sum of Total
Four Corners #4	**7,075,187.81**
E311 - Structures and Improvements	114,597.13
E312 - Boiler Plant Equipment	6,384,142.98
E314 - Turbogenerator Units	173,616.51
E315 - Accessory Electric Equipment	402,831.19
E316 - Misc Power Plant Equipment	0.00
Four Corners #5	**1,754,076.47**
E311 - Structures and Improvements	165,764.71
E312 - Boiler Plant Equipment	1,555,757.81
E314 - Turbogenerator Units	(1,308.49)
E315 - Accessory Electric Equipment	33,862.44
E316 - Misc Power Plant Equipment	0.00
Springerville Unit 1	**38,405,494.09**
E311 - Structures and Improvements	
E312 - Boiler Plant Equipment	27,857,353.02
E314 - Turbogenerator Units	10,506,333.32
E315 - Accessory Electric Equipment	41,807.75
E316 - Misc Power Plant Equipment	
Springervile Common & Coal Handling	**6,472,285.20**
E311 - Structures and Improvements	1,955,215.92
E312 - Boiler Plant Equipment	4,462,822.67
E314 - Turbogenerator Units	0.00
E315 - Accessory Electric Equipment	16,937.08
E316 - Misc Power Plant Equipment	37,309.53
Springerville Unit 2	**1,202,002.03**
E311 - Structures and Improvements	
E312 - Boiler Plant Equipment	1,080,502.43
E314 - Turbogenerator Units	121,499.60
E315 - Accessory Electric Equipment	
E316 - Misc Power Plant Equipment	
Grand Total	**54,909,045.60**

Tucson Electric Power Company
Sierra Club Data Request 1.03 and 1.05
Test Year Ending December 31, 2021

Total Company By Generating Station

FERC Account	Coal		Gas					
	Four Corners	Springerville	Demoss Petrie	Gila River	Sundt 3&4	Luna	North Loop	Rice
0408	$1,181,541	$2,539,671	$1,236	$305,336	$381,136	$11,815	$7,333	$59,766
0500	403,478	1,762,320	-	-	4,696,022	2,157	-	-
0502	1,916,133	17,388,458	-	-	171,782	-	-	-
0504	-	-	-	-	(209,641)	-	-	-
0505	97,005	1,625,600	-	-	51,852	-	-	-
0506	1,034,147	3,417,761	-	-	931,799	-	-	-
0507	101,340	-	-	-	-	-	-	-
0510	185,136	1,729,730	-	-	1,696,979	-	-	-
0511	958,202	1,948,360	-	-	1,034,658	-	-	-
0512	1,950,115	12,288,092	-	983,166	321,910	434,052	-	-
0513	573,018	5,888,798	-	-	4,814,077	-	-	-
0514	332,404	3,969,911	-	-	762,328	-	-	-
0546	-	-	29,200	1,160,994	-	5,076,804	-	-
0548	-	-	-	7,070,076	-	(57,994)	-	-
0549	-	-	334	66,366	-	(37,357)	-	-
0551	-	-	1,229	-	-	-	-	2,451,055
0552	-	-	10,722	1,309,645	28,803	-	6,438	-
0553	-	-	35,195	5,140,858	115,778	(135,009)	194,183	-
0554	-	-	15,165	2,189,985	40,145	-	164,429	-
0556	91,109	-	-	-	-	193,396	-	-
0560	1,056	-	-	-	-	159	-	-
0562	5,635	-	-	-	-	-	-	-
0568	1,581	-	-	-	-	-	-	-
0569	2,715	-	-	2,924	-	-	-	-
0570	18,141	1,202	-	175,621	-	-	-	-
0573	861	-	-	2,377	-	-	-	-
0920	-	1,841,670	-	26,362	-	-	-	-
0921	-	(418,851)	-	35,538	1,101,396	53,203	-	-
0923	19,421	690,191	-	221	-	-	-	-
0924	68,713	1,554,328	-	322,021	275,214	152,633	-	-
0925	62,855	113,681	303	1,422	43,949	77,259	889	8,869
0926	549,260	4,455,386	3,828	1,716,087	1,623,152	66,538	31,173	277,696
0935	-	-	-	-	-	-	-	-
4116	-	-	-	-	-	-	-	-
4118	-	-	-	-	-	-	-	-
5611	-	-	-	-	-	7,103	-	-
5612	-	-	-	-	-	30,981	-	-
5613	-	-	-	-	-	35,176	-	-
9301	-	1,180	-	-	-	-	-	-
9302	1,802,059	484,779	-	(2,526,346)	113,316	-	-	-
Grand Total	**$11,355,926**	**$61,282,265**	**$97,212**	**$17,982,652**	**$17,994,655**	**$5,910,913**	**$404,444**	**$2,797,386**

SC 1.13

For each of the Company's coal units, please provide the following historical annual data since 2017:

a. Installed Capacity
b. Capacity factor
c. Generation
d. Availability factor
e. Heat Rate
f. Forced outage rate
g. Fixed O&M costs
h. Non-Fuel Variable O&M costs
i. Fuel Costs
j. Environmental capital costs
k. Non-environmental capital costs
l. Energy revenues (i.e., avoided energy purchase costs)
m. Ancillary services revenues
n. Projected retirement date, if any

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a-f. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company is providing data that is readily available for the preceding two (2) years, see SC 1.13 a-f-Data from 2019-2021-Confidential.xlsx.

g. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company is providing data that is readily available for the preceding two (2) years. Please refer to page 402 in the FERC Form 1 links provided below for years 2019-2021.

2019

https://elibrary.ferc.gov/eLibrary/filedownload?fileid=02073863-66E2-5005-8110-C31FAFC91712

2020

https://elibrary.ferc.gov/eLibrary/filedownload?fileid=020C4562-66E2-5005-8110-C31FAFC91712

2021

https://elibrary.ferc.gov/eLibrary/filedownload?fileid=EB54FE93-F105-CC71-916A-7FB7B9700000

h. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company is providing data that is readily available for the preceding two (2) years. Please refer to page 402 in the FERC Form 1.

i. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company is providing data that is readily available for the preceding two (2) years. Please refer to page 402 in the FERC Form 1.

j. Please see annual data for years 2019-2021; other timeframes requested are not relevant to this rate case.

Coal Plant Enviornmental Capital Cost additions				
Coal Plant	2019	2020	2021	Grand Total
Four Corners Unit 4	585,514.62	836,250.16	2,604,489.25	4,026,254.03
Four Corners Unit 5	918,121.01	2,137,539.51	726,471.38	3,782,131.90
San Juan Unit 1	316,276.33	(7,764.87)	-	308,511.46
Springerville Unit 1	1,501,818.58	461,537.21	525,994.03	2,489,349.82
Springerville Unit 2	332,814.69	668,587.92	135,652.88	1,137,055.49
Springerville Common	222,563.86		1,003,477.99	1,226,041.85
Grand Total	3,654,545.23	4,096,149.93	3,992,607.54	11,743,302.70

k. Please see annual data for years 2019-2021; other timeframes requested are not relevant to this rate case.

Coal Plant Non-Enviornmental Capital Cost additions				
Coal Plant	2019	2020	2021	Grand Total
Four Corners Unit 4	1,015,512.78	1,277,684.16	4,470,698.56	6,763,895.50
Four Corners Unit 5	985,877.25	5,758,443.46	1,027,605.09	7,771,925.80
Four Corners Common	26,710.16	(1,778.17)	(14,508.19)	10,423.80
San Juan Unit 1	(862,287.41)	2,602.95	-	(859,684.46)
Springerville Unit 1	2,473,529.83	2,960,388.47	37,756,837.40	43,190,755.70
Springerville Unit 2	8,054,214.89	2,703,956.00	987,348.90	11,745,519.79
Springerville Common	113,219.62	630,766.10	1,549,725.84	2,293,711.56
Springerville Coal Handling	973,868.96	3,223,397.85	4,120,744.28	8,318,011.09
Grand Total	12,780,646.08	16,555,460.82	49,898,451.88	79,234,558.78

l. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company does not track the requested information.

m. The Company objects to this request as it is overly burdensome and includes timeframes not relevant to this rate case. However, without waiver of objection, the Company does not track the requested information.

n. Please see Staff 4.051.

The Excel file is not identified by Bates numbers.

RESPONDENT:

a-f. Reed Hancock

Generation by Station, GWh	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	641	613	623	622	596	596	596	596	596	426	-	-	-	-	-
Springerville	4,139	4,212	3,991	3,760	3,012	2,968	1,950	1,902	1,233	1,225	1,317	-	-	-	-

Unit Capacity, MW	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	110	110	110	110	110	110	110	110	110	110					
Springerville	793	793	793	793	793	793	406	406	406	406	406				

Heat Rate, Btu/kWh	
Four Corners 4	10,026
Four Corners 5	10,058
Springerville 1	10,468
Springerville 2	9,859

Forced Outage Rate, %	
Four Corners 4	11.75%
Four Corners 5	11.75%
Springerville 1	6.75%
Springerville 2	5.75%

Station Fuel Expense, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	$26,022	$24,738	$27,375	$28,056	$24,643	$24,942	$24,601	$25,602	$26,082	$37,042	$0	$0	$0	$0	$0
Springerville	$108,186	$110,844	$105,874	$101,653	$82,514	$83,112	$53,934	$54,179	$35,634	$35,976	$39,572	$0	$0	$0	$0

Variable O&M, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	$1,756	$1,716	$1,776	$1,810	$1,769	$1,805	$1,842	$1,878	$1,915	$1,399	$0	$0	$0	$0	$0
Springerville	$3,642	$3,833	$3,791	$3,722	$3,102	$3,176	$2,164	$2,187	$1,480	$1,531	$1,713	$0	$0	$0	$0

Planned Retirement Dates	
Four Corners 4	7/5/2031
Four Corners 5	7/5/2031
Springerville 1	12/31/2027
Springerville 2	12/31/2032

Generation by Station, GWh	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	641	613	673	677	596	596	596	596	595	426					
Springerville	4,133	4,212	3,991	3,760	3,012	2,968	1,950	1,932	1,233	1,225	1,317	-	-	-	-

Unit Capacity, MW	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	110	110	110	110	110	110	110	110	110	110					
Springerville	793	793	793	793	793	793	406	406	406	406	406				

Heat Rate, Btu/kWh	
Four Corners 4	10,076
Four Corners 5	10,058
Springerville 1	10,468
Springerville 2	9,659

Forced Outage Rate, %	
Four Corners 4	11.75%
Four Corners 5	11.75%
Springerville 1	5.75%
Springerville 2	5.75%

Station Fuel Expense, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	$26,022	$24,738	$27,575	$28,056	$24,643	$24,942	$24,601	$25,602	$26,082	$37,042	$0	$0	$0	$0	$0
Springerville	$108,126	$110,844	$105,874	$101,653	$82,514	$83,112	$53,984	$54,179	$35,634	$35,976	$39,572	$0	$0	$0	$0

This amount should not be seen as an additive cost to the annual O&M for each station. This amount is an estimate of variable O&M based on the generation output of the Aurora model.

Variable O&M, $000 [illegible]	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	$1,756	$1,716	$1,776	$1,810	$1,769	$1,805	$1,842	$1,878	$1,915	$1,395	$0	$0	$0	$0	$0
Springerville	$3,647	$3,833	$3,791	$3,722	$3,102	$3,176	$2,159	$2,187	$1,480	$1,531	$1,713	$0	$0	$0	$0

Variable O&M, $/MWh [illegible]	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Four Corners	$ 2.74	$ 2.80	$ 2.85	$ 2.91	$ 2.97	$ 3.03	$ 3.09	$ 3.15	$ 3.21	$ 3.28					
Springerville	$ 0.88	$ 0.91	$ 0.95	$ 0.99	$ 1.03	$ 1.07	$ 1.11	$ 1.15	$ 1.20	$ 1.25	$ 1.30				

Planned Retirement Dates	
Four Corners 4	7/5/2031
Four Corners 5	7/5/2031
Springerville 1	12/31/2027
Springerville 2	12/31/2032

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SC 1.14 (g)	Fixed O&M, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Four Corners	6,973	8,009	7,838	7,760	7,529	7,371	7,371	7,371	7,371	3,686				
	Springerville	42,768	43,459	44,071	44,687	45,319	45,967	45,498	47,040	47,593	48,156	48,731			
SC 1.14 (h)	Variable O&M, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Four Corners	520	530	2,028	2,068	563	574	1,168	1,174	609					
	Springerville	3,822	5,000	500	3,750	1,500	1,500	7,333	333	333	333				
SC 1.14 (k)	Non-Environmental Capital Costs, $000	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Four Corners	4,169	6,173	10,078	6,506	2,811	2,241	1,082	2,199	1,848	1,451				
	Springerville	33,882	11,152	13,471	24,632	9,487	5,774	9,260	7,465	5,452	3,600	3,380			

			2022		2023		2024
SC 1.14 (g)	Fixed O&M, $000		**2022**		**2023**		**2024**
	Four Corners	$	6,973	$	8,099	$	7,838
	Springerville	$	42,768	$	43,469	$	44,071

SC 1.14 (h)	Variable O&M, $000		**2022**		**2023**		**2024**
	Four Corners	$	520	$	530	$	2,028
	Springerville	$	3,822	$	5,000	$	500

SC 1.14 (j)	Environmental Capital Costs, $000		**2022**		**2023**		**2024**
	Four Corners	$	1,662	$	102	$	91
	Springerville	$	-	$	-	$	64

SC 1.14 (k)	Non-Environmental Capital Costs, $000		**2022**		**2023**		**2024**
	Four Corners	$	2,507	$	6,071	$	9,987
	Springerville	$	33,882	$	11,162	$	13,407

2025	2026	2027	2028	2029	2030
$ 7,760	$ 7,529	$ 7,371	$ 7,371	$ 7,371	$ 7,371
$ 44,687	$ 45,319	$ 45,967	$ 46,498	$ 47,040	$ 47,593

2025	2026	2027	2028	2029	2030
$ 2,068	$ 563	$ 574	$ 1,168	$ 1,174	$ 609
$ 3,750	$ 1,500	$ 1,500	$ 7,333	$ 333	$ 333

2025	2026	2027	2028	2029	2030
$ 4	$ 73	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -

2025	2026	2027	2028	2029	2030
$ 6,502	$ 2,739	$ 2,241	$ 1,982	$ 2,199	$ 1,848
$ 24,632	$ 9,487	$ 5,774	$ 9,260	$ 7,464	$ 5,462

	2031	2032	2033	2034	2035
	$ 3,686				
	$ 48,156	$ 48,731			

	2031	2032	2033	2034	2035
	$ 333				

	2031	2032	2033	2034	2035
	$ -	$ -			
	$ -	$ -			

	2031	2032	2033	2034	2035
	$ 1,451	$ -			
	$ 3,600	$ 3,380			

Tucson Electric Power Company
Oso Grande Plant in Service & Related Pro Forma Adjustments
4.003 Staff Data Request

	FERC ACCT	Total Cost 12/2021	Post Test Year Pro Forms	Delayed Utilization Pro Forma	Adjusted Total Cost 12/2021	2021 Accum Depr
Land and land rights	340	$54,823	$0	$0	$54,223	$2,720
Structures and improvements	341	10,661,584	427,603	-	11,059,187	376,053
Generators	344	281,369,265	(3,529)	-	281,355,436	5,469,297
Accessory electric equipment	345	56,415,222	(768)	-	56,414,454	1,456,042
Misc power plant equipment	346	59,143	-	-	59,143	311
Structures and improvements	390	4,815,547	-	-	4,815,547	5,658
Office furniture and equipment	391	1,039,368			1,039,368	110,063
Office furniture and equipment	391	44,178	-	-	44,178	77
Stores equipment	393	26,500	-	-	26,500	358
Tools, Shop, and garage equipment	394	-	-	2,418	2,418	
	Sub-Total	$354,485,630	$423,006	$2,418	$354,911,054	$7,420,609
Land and Land rights	350	2,554,000	-	-	2,554,000	22,507
Structures and improvements	352	10,088,176	-	-	10,088,176	105,935
Station equipment	353	30,004,905	-	-	30,004,905	348,327
Poles and fixtures	355	29,794,024			29,794,024	284,905
Overhead conductors and devices	356	11,724,232	-	-	11,724,232	117,242
Communications equipment	397	8,455,104	-	-	8,455,104	352,236
	Sub Total	$92,618,441	$0	$0	$92,618,441	$1,231,163
	Total	$447,104,071	$423,006	$2,418	$447,529,495	$8,651,772

$1,435

340 - 347: 2. Production Plant, D. Other Production
389 - 399: 6. General Plant
350-359: Transmission and Distribution Plant, 3. Transmission Plant

STAFF 5.04

Order 77856 at page 46-47 (quoting TEP) states that "Springerville Units 1 and 2 are a reliable solid fuel resource with an average of 45 days of on-site fuel inventory offering a measure of protection against weather events and natural gas infrastructure interruptions. These unique attributes enable Springerville to play a critical role in maintaining system reliability and grid reliability within the Company's resource portfolio."

a. During each month of 2021 and in 2022 to-date, has the Company been able to maintain at least a 45-day supply of on-site fuel inventory at the Springerville plant? If not, identify each month of 2021 and 2022 in which the level of fuel inventory at the Springerville plant fell below the minimum 45-day supply that was stated to be needed, and explain fully why the Springerville fuel supply fell below the 45-day level.

b. Show and explain in detail how Springerville performed in February 2021 during Winter Storm Uri.

c. Does the Company have any estimates of fuel savings associated with being able to operate the Springerville generating station in February 2021 including the periods affected by Winter Storm Uri? If so, please identify and provide those estimates.

d. Was the operation of Springerville constrained in any months of 2021 or 2022 due to having an inadequate on-site fuel supply? If so, identify, quantify, and explain each such instance.

RESPONSE: ORIGINAL RESPONSE DATE November 23, 2022

b. While the regional cold weather condition primarily impacted Texas, TEP also faced some challenges related to the cold weather. That said, SGS was able to provide the power necessary to meet our customer's needs during Winter Storm Uri.

Springerville, Unit 1	0007	2/1/2021 19:00	2/2/2021 00:54	D1	8521	209.00	Unit derated due to SDA slurry lines plugged up restricting flow.
Springerville, Unit 1	0008	2/9/2021 14:22	2/11/2021 11:57	U2	1000		Unit offline to repair boiler water wall tube leak
Springerville, Unit 1	0009	2/15/2021 14:57	2/15/2021 20:40	U1	8531		Unit tripped due to SDA Atomizer feeder breaker tripped
Springerville, Unit 1	0010	2/16/2021 04:00	2/16/2021 06:58	D1	0330	304.00	Unit derated due to coal mill coal leak and no spare avail.
Springerville, Unit 1	0011	2/17/2021 10:00	2/17/2021 18:30	D1	0110	319.00	Unit derated due to coal silos plugged from wet coal
Springerville, Unit 1	0012	2/22/2021 06:14	2/22/2021 12:28	D1	0310	309.00	Unit derated due to coal mill tripped due to grounded wiring. No spare avail.

Springerville, Unit 2	0002	2/19/2021 00:24	2/21/2021 08:46	U1	1000		Unit offline for boiler tube leak repairs.
Springerville, Unit 2	0003	2/25/2021 04:57	2/28/2021 23:59	D1	3411	209.00	Unit derated due to loss of BFP when motor went to ground.

RESPONDENT:

a., c-d Molly Mitchell

b. Erik Bakken

WITNESS:

Molly Mitchell

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TUCSON ELECTRIC POWER COMPANY'S 2nd SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
December 8, 2022

SUPPLEMENTAL RESPONSE: December 1, 2022

a. From January 2021 through May 2022, there were no months where the coal inventory for Springerville Units 1 and 2 fell below 45 days of inventory. Beginning in June 2022 and continuing today, the inventory for Units 1 and 2 have been below 45 days. As explained in response to Staff's 4.103 data request, in late May, the Burlington Northern Santa Fe ("BNSF") Railroad notified TEP that it would be unable to meet its 2022 delivery obligations due to the lack of workforce availability. This situation resulted in a significant reduction of both coal and lime to SGS. As a result, the coal and lime inventories onsite were reduced to the lowest levels seen during the life of the plant.

c. Based on the output from the Springerville Generating Station from February 14, 2021 through February 18, 2021, the Company estimates it would have incurred approximately $15 million in replacement power costs during this same time period if both SGS units were unavailable.

Estimated Replacement Power Costs during Winter Storm Uri 2/14/21-2/18/21			
Date	**SGS Unit 1&2 MWh**	**Palo Verde Market Prices $/MWh**	**Replacement Power Costs**
14-Feb	16,572	$68.80	$725,862
15-Feb	14,134	$229.05	$2,884,124
16-Feb	16,374	$237.40	$3,477,753
17-Feb	15,727	$342.29	$4,990,083
18-Feb	16,194	$237.56	$3,442,282
Total Replacement Power Costs			**$15,520,104**

d. Due to the ongoing issues with the BNSF, Springerville Units 1 and 2 have been in a derated position almost daily since late June 2022 and this is scheduled to continue until the inventory recovers and BNSF deliveries rebound. Additionally, the Company took a coal conservation outage on Unit 1 during October 2022 to build inventory going into winter outage season. The failure of the BNSF to deliver the coal TEP forecasted to burn from June 2022 through October 2022 is ~460k tons.

RESPONDENT:

a., c-d Molly Mitchell

b. Erik Bakken

WITNESS:

Molly Mitchell

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**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF's 5th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
November 23, 2022**

STAFF 5.11

During 2019, 2020, 2021, and to-date in 2022, did any of TEP's coal suppliers with whom TEP had coal supply contracts, declare force majeure events that excused having to make coal deliveries? If so, please identify and explain each such instance. Also describe how that affected TEP's access to coal supply and the delivery of coal to each of TEP's generating plants, and whether and how it impacted TEP's coal inventory and coal procurement decision

RESPONSE:

Several times during 2021 and prior to San Juan Generation Station Unit's 1 closure in 2022, Westmoreland Coal Company, which is the coal supplier, issued a force majeure due to non-normal conditions at the mine. There were numerous mitigation efforts made. TEP did agree to derating our ownership in Unit 1, in conjunction with the other owners of both remaining Units, in order to ensure coal supply through the end of June 2022, when Unit 1 was scheduled to close. The derate strategy was short term.

RESPONDENT:

Molly Mitchell

WITNESS:

Molly Mitchell

SC 1.21

Regarding TEP's coal contracts at Springerville and Four Corners:

a. Provide all coal contracts TEP has for coal at Springerville and Four Corners between now and 2035.
b. Provide the total annual projected coal demand at Springerville and Four Corners for every year between now and 2035.
c. Provide the total quantity of coal under contract for Springerville and Four Corners for every year between now and 2035.
d. State whether TEP has done any studies or research on the impact of regional coal plant closures on the cost and ability to get coal for Springerville plant:

    i. If yes, provide all such studies.
    ii. If no, explain why no such studies have been provided.

RESPONSE:

a. Please see SC 1.04 c

b. Please see SC 1.04 d

c. Please see SC 1.04 c

d. No, the Company has not done any studies or research on the impact of regional coal plant closures. The Company doesn't believe a study of this type would be useful in determining future coal options for Springerville.

RESPONDENT:

Molly Mitchell

WITNESS:

Molly Mitchell

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF's 4th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 October 18, 2022

STAFF 4.104

For any of its coal or natural gas fuel supply contracts, during the test year, the preceding three years, or in any month after the test year, did the Company buy spot coal or spot market natural gas at a higher price than that contained in the long-term fuel supply contract? If so, identify and explain each such instance.

RESPONSE:

No, during the test year, the preceding three years, or in any month after the test year the Company did not buy spot coal or spot market natural gas at a higher price than that contained in the long-term fuel supply contract.

RESPONDENT:

Blake Pederson / Molly Mitchell

WITNESS:

Molly Mitchell

SC 4.03

Refer to Company Witness Dukes, page 5 regarding the Company's request for up to 300 MW of a firm capacity resource that can be called on at any time.

a. Indicate whether TEP is considering only energy storage and demand response. If no, indicate what other resource types TEP is considering to meet its firm capacity needs.
b. Indicate whether TEP is considering a fossil resource, including natural gas or coal-fired resources, to meet this capacity need.

RESPONSE:

a. The Company is currently evaluating a variety of solar, wind and energy storage projects as part of its 2022 All-Source Request for Proposal (ASRFP). The evaluation of the ASRFP and selection of project bids is on-going. The Company is unable to provide any confidential or competitive sensitive information until the ASRFP evaluation process is complete. The Company plans to provide an update on the ASRFP and the selected projects as part of the 2023 Integrated Resource Plan filing that is due August 1, 2023.

b. No.

RESPONDENT:

Michael Sheehan

WITNESS:

Dallas Dukes

WRA 1.07

Referencing Garcia direct at page 14, lines 14-15, please provide the TEP peak load forecast.

Please provide all analysis, workpapers, studies, and supporting documentation used to complete the forecast. Please also provide a narrative explanation discussing the key factors driving the TEP system peak load increases.

RESPONSE:

Please see WRA 1.07.pdf, Bates numbers TEP\ 018389-018406. Chapter 2 of the attached document provides supporting documentation and narrative of key factors affecting the TEP peak load forecast.

RESPONDENT:

James Elliott

WITNESS:

Cynthia Garcia

SC 1.17

Explain what efforts TEP has undertaken to manage its peak demand over the past five years.

RESPONSE:

TEP has a program called SmartDR which allows TEP operations to request customers to voluntarily curtail their load during program hours. TEP operations has the option to call on these customers to curtail during peak load times.

Another option available to TEP is to make a public appeal for reduction, although its use is rare.

Please see also TEP's Commission Approved Energy Efficiency plan in the ACC docket.

RESPONDENT:

Lauren Briggs

WITNESS:

Dallas Dukes

WRA 1.04

Referencing the Application at page 5, lines 22-23, please describe all actions TEP is taking to reduce peak demand on its system. If TEP is not currently taking any actions to reduce peak demand, please describe why not.

RESPONSE:

TEP has a program called SmartDR which allows TEP operations to request customers to voluntarily curtail their load during program hours. TEP operations has the option to call on these customers to curtail during peak load times.

Another option available to TEP is to make a public request for conservation during times of high demand, although TEP rarely makes such requests.

Please see also TEP's Commission Approved Energy Efficiency plan in the ACC docket.

RESPONDENT:

Lauren Briggs

WITNESS:

Dallas Dukes

Tucson Electric Power Company
2021 ANNUAL DSM PROGRESS REPORT

DSM Annual Expenses

The annualized expenses for each program are reported in Table 3. Expenses are separated into the following categories: Rebates and Incentives, Training and Technical Assistance, Consumer Education, Program Implementation, Program Marketing Planning and Administration, Measurement, Evaluation, and Research

Table 3 - Expenses by Program

DSM Program	Rebates and Incentives	Training and Technical Assistance	Consumer Education	Program Implementation	Program Marketing	Planning and Admin	Measurement, Evaluation, and Research	Program Total Cost
Residential Programs								
Appliance Recycling	-	-	-	-	-	-	-	-
Efficient Products	$1,510,607	$9,731	-	$711,777	$11,642	-	$27,114	$2,270,870
Existing Homes	$2,518,230	-	-	$1,021,450	$1,345	-	$4,585	$3,545,610
Low-Income Weatherization	$481,032	-	-	$299,953	$10,694	-	$3,217	$794,897
Multi-Family	$187,233	-	-	$250,324	-	-	$1,027	$438,584
Residential New Construction	$859,200	-	-	$19,550	-	-	$878	$879,628
Shade Tree Program	$246,484	-	-	-	$500	-	$532	$247,516
Total for Residential Programs	$5,802,787	$9,731	-	$2,303,054	$24,181	-	$37,352	$8,177,105
Non-Residential Programs								
CHP Program (Pilot)	-	-	-	-	-	-	-	-
C&I Comprehensive Program	$1,366,988	-	-	$842,564	-	-	$11,893	$2,221,446
Commercial New Construction Program	$106,264	-	-	$28,949	-	-	$293	$135,506
Schools Energy Efficiency Program (Pilot)	$695,557	-	-	$146,607	-	-	$3,108	$845,271
Small Business Direct Install	$345,897	-	-	$272,315	-	-	$237	$618,449
Total for Non-Residential Programs	$2,514,706	-	-	$1,290,434	-	-	$15,530	$3,820,671
Behavioral Sector								
Behavioral Comprehensive	$1,069,519	$2,800	-	$633,050	$22,300	-	$1,830	$1,729,499
Home Energy Reports	$881	-	-	$214,461	-	-	$2,797	$218,138
Total Behavioral Sector	$1,070,400	$2,800	-	$847,511	$22,300	-	$4,626	$1,947,637
Support Sector								
Consumer Education & Outreach	-	-	-	$30,680	$362,502	$2,211	-	$395,394
Energy Codes and Standards	-	$15,750	-	-	-	-	-	$15,750
Total for Support Programs	-	$15,750	-	$30,680	$362,502	$2,211	-	$411,144
Utility Improvement Sector								
C&I Direct Load Control	$191,608	-	-	$18,288	-	$2,450	$2,783	$215,128
Conservation Volt Reduction	-	-	-	-	-	-	-	-
Generation Improvement & Facilities Upgrade	-	-	-	-	-	-	-	-
Total for Utility Improvement Sector								
Portfolio Totals	$191,608	-	-	$18,288	-	$2,450	$2,783	$215,128
	$9,579,501	**$28,281**	**-**	**$4,489,967**	**$408,983**	**$4,661**	**$60,292**	**$14,571,684**
							Program Costs	**$14,575,474**
					Program Development, Analysis, and Reporting			**$1,278,306**
							TOTAL	**$15,853,780**

- Provide incentives to facility operators for the installation of high-efficiency lighting equipment and controls, HVAC equipment and controls, HVAC system test and repair, premium efficiency motors and motor controls, plug load equipment, and energy-efficient refrigeration system retrofits;
- Overcome market barriers, such as:
  - Lack of awareness and knowledge about the benefits and cost of energy efficiency improvements;
  - Performance uncertainty associated with energy efficiency projects; and
  - High first costs for energy efficiency measures.
- Create a clear, easy to understand, and simple participation process; and
- Increase the awareness and knowledge of facility operators, managers, and decision makers on the benefits of high-efficiency equipment and systems.

Levels of Participation

In 2021, the program experienced lower participation than the previous year due to supply chain issues and rising material costs related to the pandemic.

Costs Incurred

Costs incurred for this program during the reporting period are listed below:

DSM Program	Rebates and Incentives	Training and Technical Assistance	Consumer Education	Program Implementation	Program Marketing	Planning and Admin	Measurement, Evaluation, and Research	Program Total Cost
C&I Comprehensive Program	$1,366,988	-	-	$842,564	-	-	$11,893	$2,221,446

Evaluation and Monitoring Activities and Results

Guidehouse performed quarterly reconciliations for the program to verify coincident demand and energy savings. The Guidehouse MER report is attached in **Appendix 2**.

kW, kWh, and Therm Savings

Measure Category	No. Measures Installed	kW savings	kWh savings
Custom	4,137	339	3,477,986
HVAC	408,818	830	1,711,134
Lighting	81,247	1,274	11,216,206
Motor	66	329	2,125,375
Refrigeration	157	35	251,545
Thermostats	6	-	58,110
Totals	**494,431**	**2,806**	**18,840,355**

Savings are adjusted for line losses of 9.94 percent for both demand and energy savings (excluding therms).

1.2 DSM Annual Expenses

Mid-year participation and program expenses as compared to the program budgets are reported in Table 3.

TABLE 3 - DSM EXPENSES AND PARTICIPATION BY PROGRAM

Program	Number of Participants	Number of Measures	Expenses YTD	Budget
Residential Sector				
Efficient Products	36,826	664,711	$1,406,699	$1,865,824
Existing Homes	2,595	2,595	$1,603,506	$3,162,972
Low Income Weatherization	71	72,046	$352,976	$1,004,252
Multi-Family	969	3,064	$230,528	$2,132,458
Residential New Construction	987	987	$480,647	$1,028,794
Residential Load Management Pilot	-	-	$100	$1,575,500
Shade Tree Program	2,443	6,135	$132,969	$251,652
Total for Residential Programs	**43,891**	**749,538**	**$4,207,424**	**$11,021,452**
Non-Residential Sector				
CHP Program	-	-	-	-
C&I Comprehensive Program	288	25,100	$882,342	$4,184,738
Commercial New Construction Program	3	3	-$11,140	$249,738
Schools Energy Efficiency Program (Pilot)	-	-	$64,940	$1,000,000
Small Business Direct Install	178	23,175	$368,741	$754,639
Total for Non-Residential Programs	**469**	**48,278**	**$1,304,884**	**$6,189,115**
Behavioral Sector				
Behavioral Comprehensive	239	7,668	$184,023	$595,866
Home Energy Reports	18	21,237	$126,740	$827,330
Total Behavioral Sector	**257**	**28,905**	**$310,763**	**$1,423,196**
Support Sector				
Consumer Education & Outreach Program	-	-	$278,707	$400,000
Energy Codes and Standards	-	-	$13,757	$25,000
Program Development, Analysis, and Reporting				
Total for Support Programs	**-**	**-**	**$818,884**	**$1,425,000**
Utility Improvement Sector				
C&I Direct Load Control Program	-	-	$23,354	$700,000
Conservation Volt Reduction	-	-	-	-
Generation Improvement and Facilities Upgrade	-	-	-	-
Total for Support Programs	**-**	**-**	**$23,354**	**$700,000**
EV Measures reverted back to Portfolio	**-**	**-**	**-**	**$2,158,000**
Portfolio Totals	**44,617**	**826,721**	**$6,665,309**	**$22,916,763**

TEP Response to SC DR 3-02, Attachment SC 3.02.xlsx provided on submitted USB drive and TEP Data Room

Attachment DG-3

Confidential Discovery Responses

Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-4

Competitively Sensitive Confidential Discovery Responses

Competitively Sensitive Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-5

Strategen Consulting, Arizona Coal Plant Valuation Study (Sept. 2019).

Arizona Coal Plant Valuation Study

STRATEGEN
CONSULTING

Economic assessment of coal-burning power plants in Arizona and potential replacement options

Prepared For:
Sierra Club
September 16, 2019

Arizona Coal Plant Valuation Study

Prepared for:
Sierra Club

Prepared by:
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Table of Contents

Executive Summary

Coal-burning generation serving Arizona customers is no longer economically competitive when compared to renewable energy resources such as wind and solar, or market purchases. Already, older coal-burning units powering the state have higher levelized costs of energy (LCOE) on a going forward basis than their replacement options. More specifically, retiring all 11 units at the six coal facilities examined in this study and replacing them with a solar PV plus storage or wind resource can save Arizona customers upwards of $3.5 billion.

Coal unit replacement with alternative resource options in the 2023 timeframe provides significant economic benefits to electricity consumers due to reduced operating and maintenance costs (including fuel) and avoided incremental capital costs, while at the same time dramatically reducing emissions. Among replacement options, solar generation plus storage is less expensive on a LCOE basis when compared to all the coal-burning units analyzed. Wind from New Mexico is also cheaper than the continuing operation of most of those units.

In addition to the operating and fuel savings that come from the replacement of coal-burning units with cleaner resources, there are also potential savings for ratepayers based on the regulatory treatment of the undepreciated value of the assets. An illustrative example of securitization in case of retirement of the first unit at Springerville shows significant additional savings on top of those achieved by the avoidance of its operating and fuel expenses.

The study also analyzed the Four Corners plant, one of the largest coal plants to service Arizona, and concluded that despite the coal supply agreement with the Navajo Transitional Energy Company through 2031, its continuing operation is more expensive than replacement options. The potential benefits from a Four Corners plant retirement, although significantly reduced by the plant's existing coal supply obligation, are still high enough to justify its replacement by other generation options in the near term.

1. Introduction

The U.S. coal-burning plant fleet is aging and facing increasing economic pressure due to the falling costs of renewable energy generation. Nationally, in 2018 and 2019, 100 units with a combined capacity 32,649 megawatts (MW) retired or are scheduled to retire. This trend has been particularly strong in the West and includes Arizona's Navajo Generating Station (NGS) -- the largest coal-fired power plant operating in the western U.S. -- which will close at the end of 2019. The transition away from coal increasingly makes economic sense due to reductions in the cost and the technology advancement of renewable energy and energy storage.

On behalf of the Sierra Club, Strategen conducted an economic analysis to better understand which of the coal units that serve Arizona's load may be most suitable for replacement with clean energy on an economic basis. The study concluded that all the coal units serving Arizona load are more expensive than currently available cleaner options. Arizona ratepayers stand to save money on their electricity bills by the retirement of coal-burning units and their replacement with renewable resources.

Recognizing the economic trend, Arizona Public Service (APS) has announced its plans to cease coal generation by 2038.[1] Similarly, Tri-state Generation and Transmission, a wholesale power supplier to western energy co-ops, has retired one coal-burning plant and plans to retire two more by the end of 2025, in addition to installing 100 MWs of solar and 104 MWs of wind in 2019[2]. Salt River Project (SRP) aims to reduce its coal fleet carbon emissions by 30% by 2035 and reduce its CO_2 emissions by 90% from 2005 levels by 2050[3]. Tucson Electric Power (TEP) plans to reduce reliance on coal to 38% of retail energy deliveries by 2030 and serve 30% of its retail load with renewable generation by 2030[4].

While there is a clear intention to move away from coal-burning generation, the pace is not fast enough to fully capture the economic benefits of this transition, and Arizona ratepayers might end up paying more than they should to keep expensive coal units operating for several more decades. Other western states are more ambitious in their plans to reduce coal-burning generation and increase renewables. For example, in spring 2019, Nevada passed a bill that would require the state to generate 50% of its electricity from renewable resources by 2030 and aim for 100% carbon-free resources by 2050. NV Energy supported the bill and has plans to add over 1.2 GW of solar and 590 MW of battery storage to its generation mix, pushing it past its target to double renewable energy capacity between 2018 and 2023.[5] Similarly, New Mexico has committed to 100% carbon-free electricity by 2045. The Public Service Company of New Mexico aims to

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[1] Arizona Public Service Integrated Resource Plan Stakeholder Meeting Presentation, April 4, 2019.
Accessed at https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[2] Tri-State Generation and Transmission, Responsible Energy Plan.
Accessed at: https://www.tristategt.org/responsibleenergyplan

[3] Salt River Project, 2035 Sustainability Goals.
Accessed at: https://www.srpnet.com/environment/sustainability/2035-goals.aspx

[4] Tuscon Electric Power, 2018 Action Plan Update.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[5] See: https://www.greentechmedia.com/articles/read/nv-energy-signs-a-whopping-1-2-gigawatts-of-solar-and-590-megawatts-of-stor#gs.16tp1m

eliminate carbon emissions from its power generation by 2040.[6] The Colorado Energy Plan is Xcel Energy's roadmap to develop a significantly cleaner energy mix and reduce carbon emissions in Colorado aiming for nearly 55% renewable energy by 2026, and a 60% reduction of carbon emissions from 2005 levels.[7] Within this context, Arizona utilities could speed up the retirement of coal units and invest in renewable energy, all while achieving net savings for their ratepayers, as shown in the study.

On the policy front, the Arizona Corporation Commission (ACC) adopted a Renewable Energy Standard (RES) in 2006 that calls for 15% of Arizona's power fleet that is regulated by the ACC to be powered by renewables by 2025, and for 30% of that renewable energy to come from distributed energy technologies. The Commission is now considering whether to expand this standard to account for the increasingly favorable economics and customer preference for renewable energy infrastructure. For example, the Commission Staff recently put forward a proposal that includes a voluntary renewable energy goal of 45% by 2035.[8] In response, 25 stakeholders developed a joint proposal that includes enforceable standards for 100% clean energy by 2045 and 50% renewable energy by 2030, aligning Arizona's goals with those of other western states.[9]

As mentioned above SRP has committed to a significant carbon emissions reduction goal in addition to deploying over 1000 MW of solar energy resources by 2025.

Strategen conducted a discounted cash flow analysis examining a "business-as-usual" case of energy production at 11 coal-burning generation units serving Arizona electricity customers. This analysis estimated the levelized cost of energy (LCOE) and the net present value (NPV) of costs for each coal unit's operating, maintenance, and incremental capital costs. Strategen then compared those results with the economics of three replacement portfolios: solar photovoltaics (PV) paired with battery storage, wind, and market-purchased energy. The analysis relied on data from publicly available sources as well as S&P Global Market Intelligence (formerly SNL) to estimate the levelized costs of renewable energy and coal-burning power.

Additionally, the study calculated the societal benefits of coal retirements based on the assumed future carbon price included in Arizona Public Service's Integrated Resource Plan. The study also included the effects that the existing must-take coal contract for the Four Corners plant would have on an early retirement decision, and finally the economic impact of installing pollution control equipment in the second unit of Coronado. Finally, the study includes an illustrative example of the additional savings for ratepayers that a refinancing mechanism could bring about. Arizona's utilities can both save families money on their electricity bills and clear pollution out of our communities and national parks by quickly replacing all coal power with new renewable infrastructure to take advantage of the state's abundant solar resources.

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[6] See: https://www.utilitydive.com/news/pnm-avista-commit-to-carbon-free-goals-on-heels-of-state-mandates/553240/

[7] Colorado Energy Plan. Accessed at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/CO-Energy-Plan-Fact-Sheet.pdf

[8] See: https://docket.images.azcc.gov/0000198875.pdf

[9] See: https://docket.images.azcc.gov/E000002141.pdf

2. Arizona's Coal Fleet

2.1. Coal Fleet

Arizona hosts five coal-burning generation stations. Two of those plants, Navajo and Cholla, are scheduled to be retired in 2019 and 2025 respectively and were not examined in this study. The three remaining plants, with seven generating units, are scheduled to operate until 2035 or later were analyzed in this study. Additionally, Arizona draws power from four coal-burning generation units at three plants outside the state -- Craig, Four Corners, and Hayden -- which were also examined. Together, the 11 coal-burning units that this study analyzed have a combined operating capacity of 4,792 MWs. Seven of those 11 units are 39 years or older, with Four Corners Unit 5 being the oldest. Springerville's four units are newer, with the most recently constructed Unit 4 beginning operations in 2009. Owners of the coal units examined in this study include utilities serving Arizona customers such as Arizona Public Service, Tucson Electric Power, Salt River Project, and Arizona Electric Power Cooperative. Additionally, some of the plants are co-owned by non-Arizona utilities including PacifiCorp, Xcel Energy, PNM Resources, Platte River Power Authority, and Tri-State Generation and Transmission Association. The Navajo Transitional Energy Company (NTEC) also owns a 7% stake in the Four Corners plant.

S&P Global
Market Intelligence

 July 30, 2019

Figure 1: Analyzed coal-burning generation units serving Arizona consumers

The Cholla (1,021 MW) and Navajo (2,250 MW) coal-burning plants also serve Arizona with a combined total capacity of 3,271 MWs. Cholla has four units, one of which retired in 2015, and one that is scheduled for retirement in 2020. The final two units are scheduled for retirement in 2025. Navajo has scheduled the retirement of all three of its units by the end of 2019. As such, we excluded these five operating Navajo and Cholla units from our analysis. The 11 units analyzed are all currently slated to operate through at least 2035.

Prior to 2035 however, co-owners of these plants face key decisions. For example, the coal supply agreements at Craig, Hayden, and Four Corners expire in 2020, 2027, and 2031, respectively. The agreements would either need to be renewed or a new fuel supply would need to be secured for the plants to continue operating. Additionally, Salt River Project has a transmission service agreement with the Western Area Power Administration to deliver power from Craig, Hayden, and Four Corners that could expire in 2024 unless it is renewed.

P ant – Unit	Operating Capacity (MW)	Owner	On ine Date	Current y P anned Retirement Date
Apache 3	325	Arizona E ectric Power Cooperative nc.	1979	2035
Coronado 1	380	Sa t River Project	1979	None Announced
Coronado 2	382	Sa t River Project	1980	None Announced
Craig 2	428	SRP (29%), TSG&T (24%), P atte River (18%), PacifiCorp (19.28%), Xce (9.72%)	1979	2039
Four Corners 4	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1969	2038 (APS), 2031 (TEP)
Four Corners 5	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1970	2038 (APS), 2031 (TEP)
Hayden 2	262	SRP (50%), Xce (37.4%), PacifiCorp (12.6%)	1976	2036
Springervi e 1	387	Tucson E ectric Power Company	1985	2040
Springervi e 2	406	Tucson E ectric Power Company	1990	2045
Springervi e 3	417	Tri-State Generation & Transmission Association, nc.	2006	None Announced
Springervi e 4	415	Sa t River Project	2009	None Announced
Tota	4,942			

Table 1: Operating Capacity, Ownership, and Retirement data for all studied units

Of the six plants included in this analysis, Springerville is the largest and is owned and operated by TEP. In December 2016, TEP purchased an undivided ownership in the common facilities at the plant and is party to a lease agreement with the other two plant owners (SRP and Tri-State) that expires in January 2021. If the common facilities leases are not renewed, the other parties may be obligated to buy a portion of these facilities or continue to make payments to TEP for their use of the plant. Thus, the terms of any lease extension or purchase could have implications for the retirement or future use of Springerville's facilities by parties other than TEP.

3. Comparative Cost Assessment of Arizona Coal Units

3.1. Overview

A cash flow analysis was used to calculate the cost of generating electricity from 11 coal-burning generation units at six power plants serving Arizona electricity customers. The methodology for this analysis is described in Appendix A, while key assumptions are described in Appendix B.

The analysis estimated the electricity generation costs of three resource comparison portfolios: (1) market purchases; (2) solar PV paired with battery storage (supplemented by market energy purchases); and (3) wind generation supplemented by capacity purchases (all replacement options are further characterized in Appendix A). The analysis compared generation costs in terms of both the LCOE (in $/MWh) as well as the NPV of total costs in 2019 dollars. We also conducted this analysis for a scenario including a hypothetical carbon price.

3.2. Levelized Cost Comparison

Based on our projections of costs through 2050 under a "business as usual" scenario, the LCOE for coal units serving Arizona ranges from the mid $40s per MWh for the Coronado units to the mid $60s per MWh for Four Corners. Among all coal-burning units in Arizona, the LCOE of generation is highest for the Four Corners units, both of which have already been in operation for about 50 years.

For a simple initial comparison, we compared the coal unit costs (in LCOE terms) to the costs of recent new wind projects in the eastern New Mexico region[10] and a recent new solar plus storage project in the central Arizona region.[11] An incremental transmission cost was added to the wind power purchase agreement (PPA) to reflect the cost of new transmission assets or wheeling charges that may be necessary to deliver renewable energy resources from New Mexico, which rendered the wind resource more expensive than the continued operation of one coal unit. Meanwhile, replacing coal-burning generation with market energy purchases or solar plus storage is significantly cheaper than all coal units.

[10] Based on SPS' recent procurement of the Sagamore and Hale wind projects with appropriate adjustments made for the phase out of the federal production tax credit. See Appendix A for more details.
[11] Based on the Central Arizona Project's recent procurement of a 20 MW solar plus 60 MWh storage facility. See Appendix A for more details.

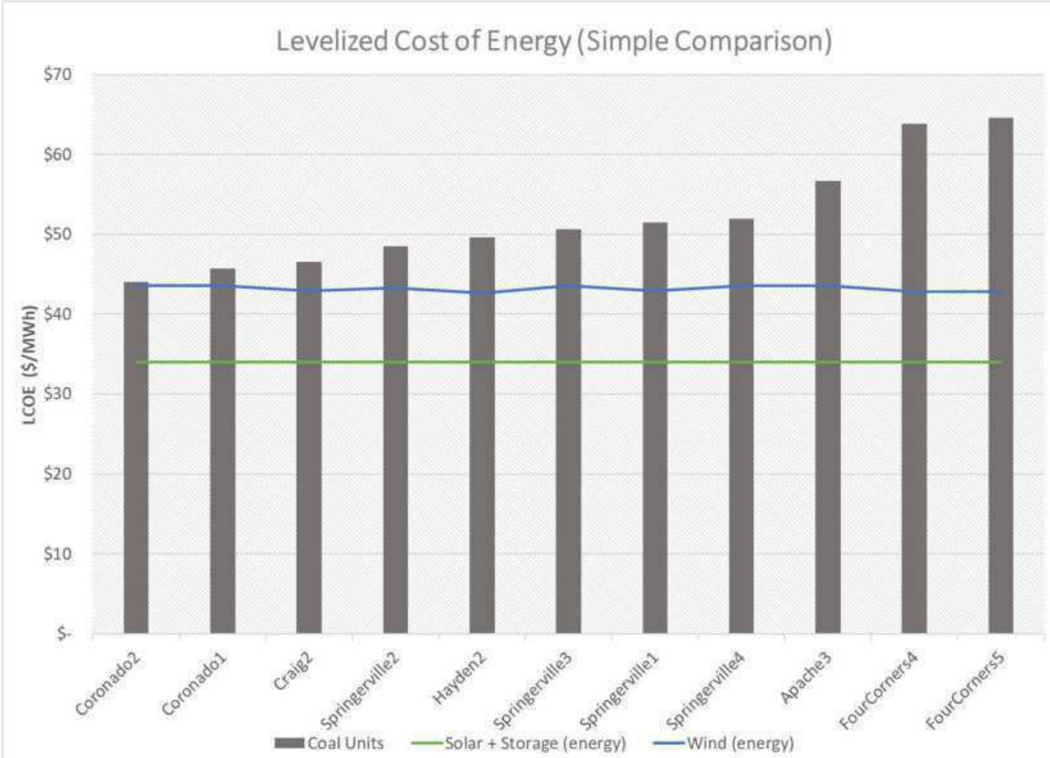

Figure 2: LCOE of coal units (2019 through 2050, or expected retirement date if sooner) compared to Sagamore Wind Energy PPA rate (with a transmission cost adder) and the solar plus storage PPA estimated by the Central Arizona Project (energy only)

While a simple LCOE comparison of wind and solar prices is useful, it does not fully capture the fact that individual wind and solar resources provide different capabilities than conventional fossil resources in terms of the availability of energy and capacity. Figure 3, below, compares the coal unit costs to three different "replacement resources" designed to provide an equivalent amount of energy and peak capacity as each of the coal units. Since wind resources are generally higher in energy value (i.e., higher capacity factor relative to solar), the wind replacement was sized to yield equivalent energy (MWh) as the coal unit and supplemented with market purchases to provide equivalent capacity (MW).[12] In contrast, since solar resources are generally higher in capacity value (i.e., higher effective load-carrying capability, or ELCC, value relative to wind), the solar replacement was sized to yield equivalent capacity (MW) as the coal unit and supplemented with market purchases to provide equivalent energy (MWh). Storage dispatch was optimized to minimize the cost of purchasing additional energy from the grid.

Furthermore, the second unit of the Coronado plant was assumed to install Selective Catalytic Reduction to control emissions that contribute to regional haze. Assuming a $110 million installation cost in 2029[13], and a 20-year lifetime, the installation increases the LCOE of the unit by approximately $2.80 per MWh.

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[12] For many years, a significant amount of excess generation capacity has existed near the Palo Verde and Mead trading hubs and may be available for purchase as a capacity resource. The amount of excess capacity has diminished in recent years through asset purchases and long-term contracts however a portion of uncontracted capacity still remains.

[13] See: https://www.azcentral.com/story/money/business/energy/2016/07/21/partial-shutdowns-proposed-srp-salt-river-project-coronado-generating-station-coal-plant-northern-arizona/87389718/

On August 20, 2019, the Environmental Protection Agency (EPA) issued new guidance to help states prepare for the second implementation period of the federal regional haze program. This new guidance puts emphasis on "discretion and flexibilities" for complying with long-standing mandates to protect visibility in federal areas. More specifically, EPA recommended that "visibility is the ultimate focus of the program and states ought to consider that against the costs and other impacts associated with the control measures." In the draft guidance, there was a recommendation that the older coal-burning power plants like Coronado, which were regulated under the first 10-year State Implementation Plan (SIP) period, could be forced to apply even more stringent pollution controls. This language is gone in the final guidance. Another recommendation reminds states they do not have to do everything during this 10-year period.[14] However, based on our analysis, a solar and storage resource remains more economic than the second unit of the Coronado plant, even in the absence of a regional haze control requirement.

Finally, the Four Corners plant has a coal supply agreement with the Navajo Transitional Energy Company through 2031. The agreement initially required a minimum tonnage of approximately 5.2 million tons per year but was amended in the summer of 2018 to reduce the coal tonnage to approximately 4.7 million tons each year. The minimum tonnage falls below that level in later years. If the plant retires before 2031, the operators will still have to pay for the minimum tonnage per year. Thus, although the LCOE in Four Corners is high, the levelized cost of an alternative would have to be significantly lower to compare favorably to the coal unit, due to the cost of the continuing coal supply obligation. Figure 3 presents the avoided LCOE in case of retirement (full height of the bar for Four Corners), as well as the reduction in this benefit by the unavoidable cost of the coal supply agreement (dotted bar is a negative benefit, subtracting from the total potential benefit of retirement). Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more renewable energy options.

[14] https://www.law360.com/articles/1190628/4-takeaways-from-epa-s-regional-haze-rule-guidance?copied=1

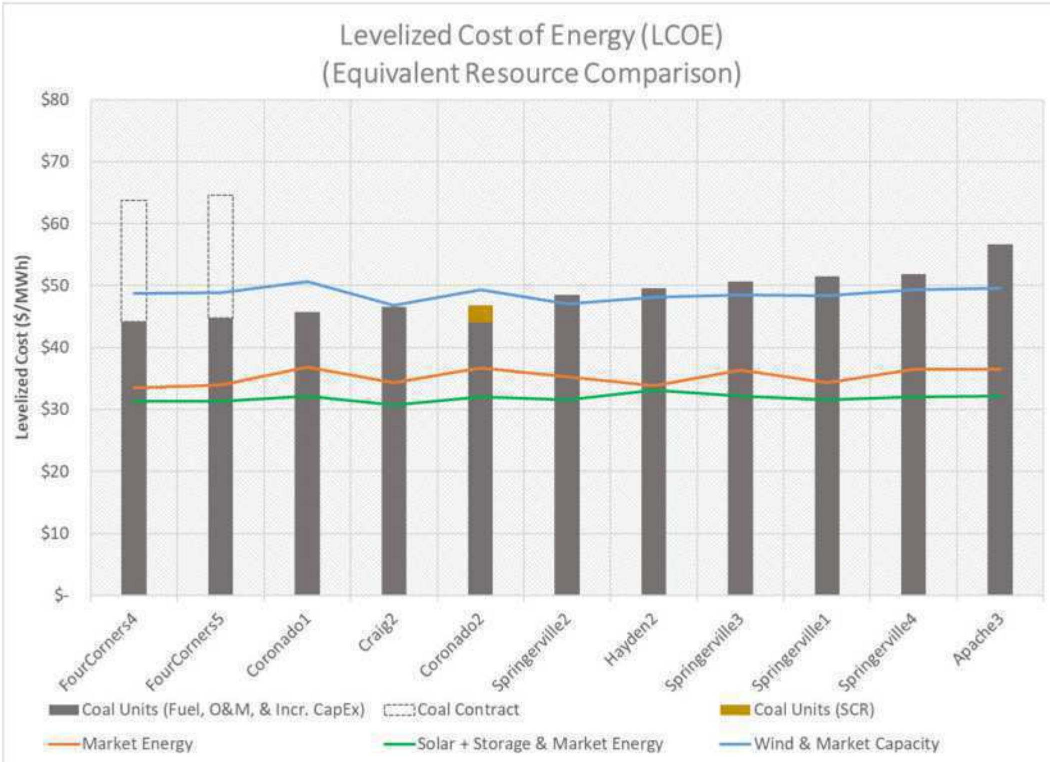

Figure 3: LCOE of coal units (2019 through 2050 or expected retirement date if sooner) versus replacement resource options. Replacements include: 1) forward market purchases (energy only), 2) solar PV plus storage supplemented with market energy purchases, 3) wind energy supplemented with market capacity purchases. A 2023 replacement start date was assumed.

Of the plants being considered, the analysis of Four Corners is worth further attention for several reasons:

1. After the retirement of Navajo Generating Station, Four Corners will be one of the largest coal-burning power plants serving Arizona customers.
2. The plant is located in a critical location for delivery of high-quality wind energy resources from central and eastern New Mexico to markets in Arizona and California. Continued operation of the plant creates a bottleneck on the transmission system that may prevent Arizona from accessing a more diverse portfolio of clean energy resources (especially wind) without construction of costly new transmission lines.
3. The plant is a significant limiting factor in the ability of Arizona utilities to invest in additional low-cost solar, due to concerns about overgeneration resulting from the minimum generation characteristics of baseload units.
4. APS currently intends to operate the plant through 2038, though other owners have indicated their plans to exit the plant on a more accelerated timeline.

Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more energy options, as well as alleviate concerns associated with overgeneration of solar.

The analysis concludes that operating any coal unit is more expensive than other alternatives examined.

3.3. Coal Replacement Analysis: Operations, Maintenance, and Incremental Capital Expenditures

In total, the retirement of the 11 units examined results in avoided costs of $10 billion (NPV) in fuel, operation and maintenance (O&M), and capital expenditures (prior to replacements). Some replacement options come in at a significantly lower cost and can thus provide net benefits to Arizona ratepayers.

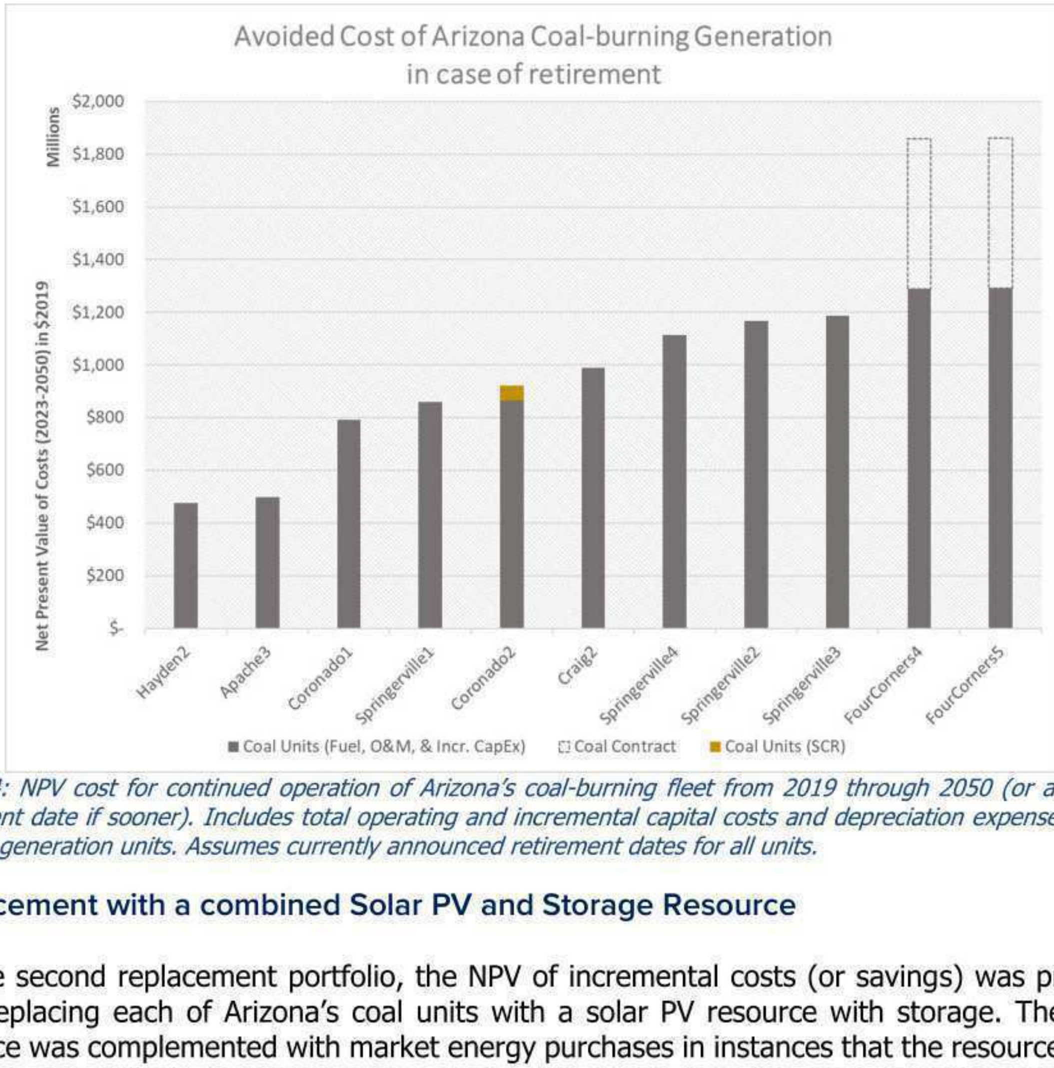

Figure 4: NPV cost for continued operation of Arizona's coal-burning fleet from 2019 through 2050 (or announced retirement date if sooner). Includes total operating and incremental capital costs and depreciation expenses of coal-burning generation units. Assumes currently announced retirement dates for all units.

Replacement with a combined Solar PV and Storage Resource

For the second replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a solar PV resource with storage. The paired resource was complemented with market energy purchases in instances that the resource cannot meet the coal output. Storage was assumed to only charge from the solar resource and dispatch optimally to minimize the cost of additional energy purchases. The resource matched both the peak capacity value and energy provided by the coal unit (see Figure 6). This solar and storage "replacement resource" is further characterized in Appendix A.

For example, replacing the 175 MW Apache 3 unit with an equivalent-capacity resource requires a 220 MW-ac solar PV resource paired with storage. This resource is estimated to replace about 62% of the coal unit's energy. The remaining energy is accounted for through market energy purchases so that the solar resource provides equivalent energy and capacity as the coal unit it is replacing. The majority of those purchases (83%) happen during off-peak hours.

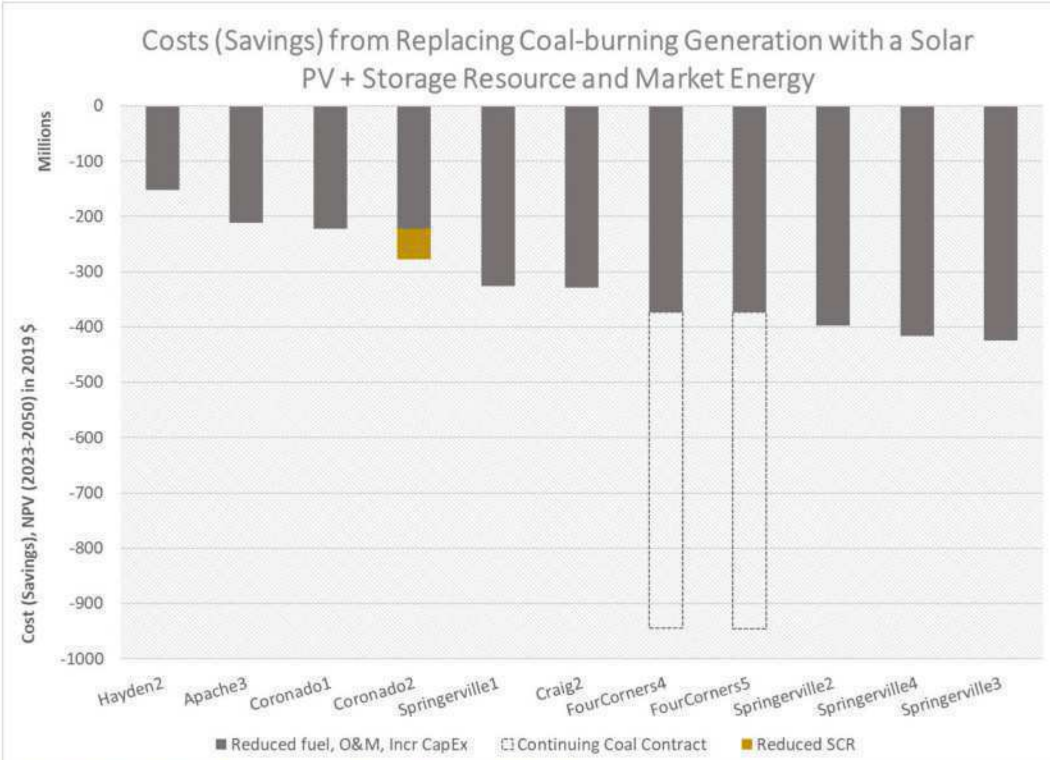

Figure 5: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a solar PV resource starting in 2023 that provides equivalent energy and capacity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

We estimate that replacing all 11 coal units with solar resources in this fashion could yield approximately $3.5 billion in total savings (NPV).

Replacement with Market Purchases

The NPV of incremental costs (or savings) was projected from replacing the generation of each coal unit on an hourly basis with forward market purchases based on the Palo Verde forward index (OTC Holdings). This market purchase "replacement resource" is characterized in Appendix A below.

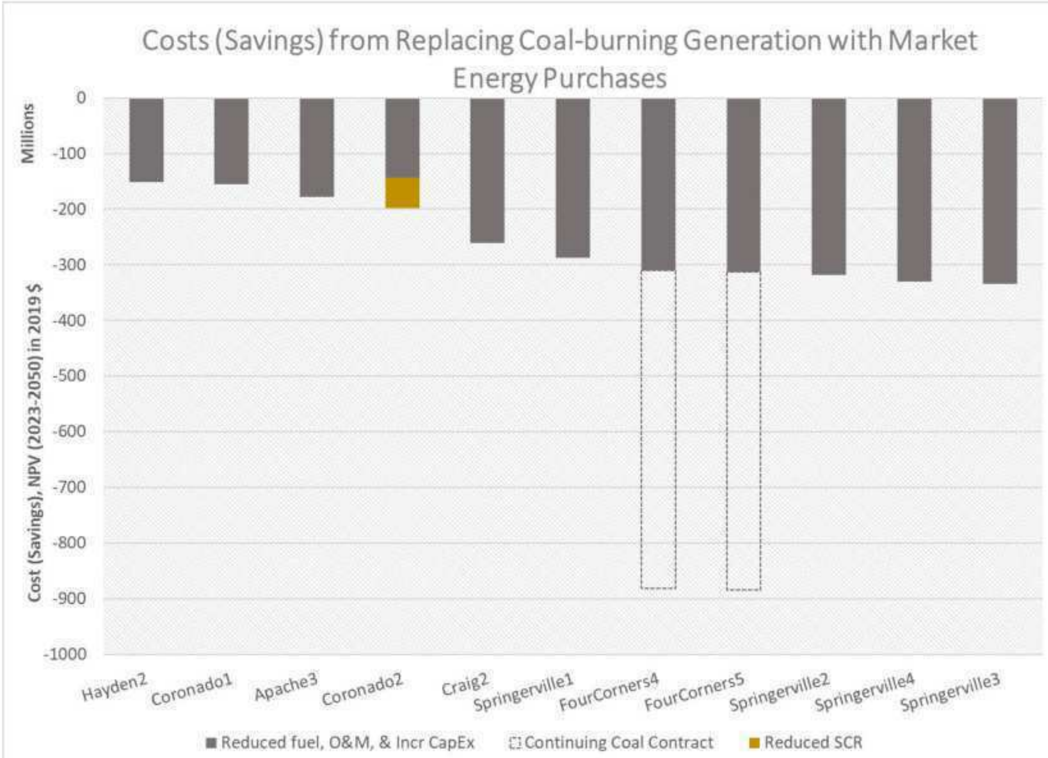

Figure 6: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with Forward Market Purchases starting in 2023. Negative values correspond to potential benefits for the plant owner's customers.

Cost savings were observed for replacing all of the units with market purchases starting in 2023. Total cost savings were calculated to amount to $2.8 billion.[15]

Replacement with Wind

For the third replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a wind resource, combined with additional market capacity purchases, to provide an equivalent resource starting in 2023 (see Figure 7). This wind "replacement resource" is further characterized in Appendix A.

For example, replacing the 891 GWh of annual production from the Apache Unit 3 with an equivalent-energy resource requires approximately a 231 MW-ac wind resource (assuming a 44% capacity factor). This resource is estimated to provide about 70 MW in terms of capacity value (based on a 30% wind capacity credit).[16] The remaining 216 MW were accounted for through capacity purchases to provide an equivalent resource in terms of both energy and capacity.

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[15] The market replacement option does not provide an equivalent resource, as it does not necessarily reflect firm capacity. Thus, expected savings might be lower.

[16] Based on the APS IRP Stakeholder Meeting presentation in April 2019, 30% approximates the capacity value of a wind resource in New Mexico.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

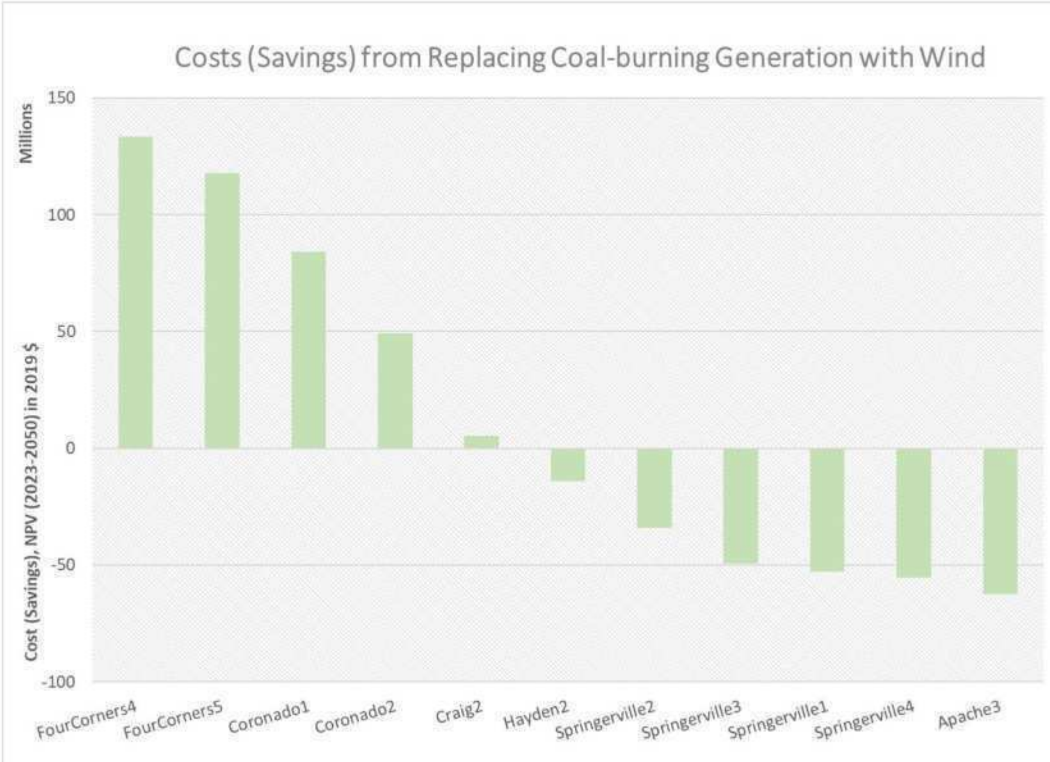

Figure 7. NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a wind resource starting in 2023 that provides equivalent energy and capacity. The green bars encompass the O&M and incremental Capital expenditure costs/savings for each unit, as well as the impact of the coal contracts in Four Corners and that of the SCR installation in Coronado. They are presented as a single number for the sake of clarity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Although a New Mexico wind PPA is estimated to be significantly lower than the LCOE of the coal units, the addition of the transmission cost, as well as the fact that the Production Tax Credit is phasing out, renders this replacement option more expensive than the other replacement options. However, it does still yield savings in comparison to continuing operation of some of the coal units. Replacing the four units of the Springerville plant, as well as unit 3 of the Apache plant, and unit 2 of Hayden with a wind resource results in total savings of $263 million.

The results are sensitive to the transmission cost assumption. Absent additional transmission cost, the replacement of all coal units with wind resources would result in savings for Arizona ratepayers. One option that was not fully investigated in this analysis would be the replacement of the units with Arizona wind. Although, the quality of the resource in Arizona might be lower than wind in New Mexico, newer technologies with higher hub height might enable increased generation, which would make Arizona wind a realistic alternative to ratepayers while eliminating considerations of additional transmission cost from New Mexico. Secondly, adding wind increases the diversity of resources, which increases its value, especially as wind and solar have different generation profiles and can be complementary to each other. Finally, the retirement of Four Corners could open up transmission capacity that could potentially be used to transfer wind from New Mexico to Arizona at a lower cost.

3.4. Carbon Pricing Risk Assessment

In addition to projecting operating costs and capital expenditures of coal-burning generation in Arizona, Strategen conducted an analysis of the societal costs associated with greenhouse gas emissions from the plants. As described in Appendix A, we assumed a carbon price of $15.99 per short ton in 2025, which is the price specified in the APS 2017 Integrated Resource Plan. In accordance with that plan, this analysis escalated the carbon price at an annual rate of 2.5%. A discount rate of 3% was applied to these carbon costs in the NPV analysis, which is reflective of a societal discount rate more typically used for carbon cost analysis.

Requiring coal plants to internalize the cost of carbon pollution through the application of a carbon price increases the total costs for Arizona's coal-burning generation units, adding to the benefits of the three replacement options. Figure 8 compares the cost of energy for each coal unit with alternatives on a levelized basis with the addition of the carbon cost (maroon bar). For market energy purchases (including those associated with the solar PV replacement resource), a carbon price that equates to the emissions associated with a natural gas combined cycle unit was applied.[17]

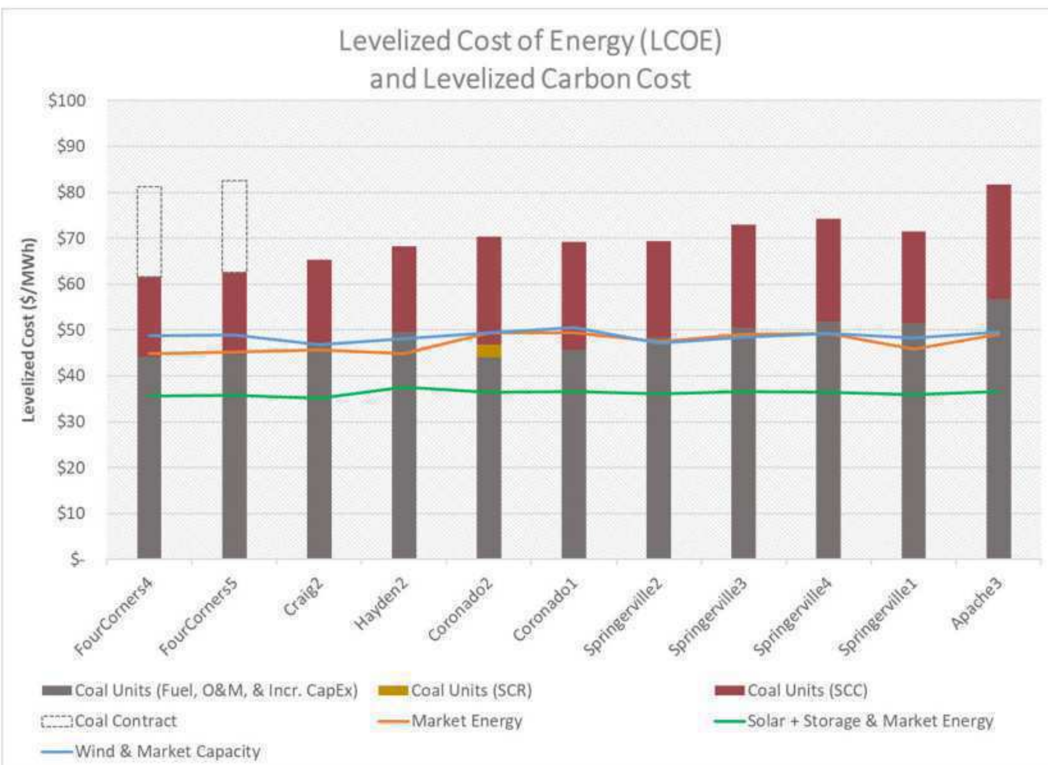

Figure 7: LCOE of coal units with added levelized carbon cost versus replacement resource options. The gray bars represent the operating costs (and incremental capital costs) of the plant, while the maroon bars represent the cost of carbon.

[17] As a simplifying assumption we assume that the marginal unit available for market purchases would most typically be a natural gas combined cycle unit. We also assume a heat rate of 7,649 BTU/kWh consistent with the following: https://www.eia.gov/electricity/annual/html/epa_08_02.html

The NPV analysis was conducted for the wind and solar replacement resources with the inclusion of a hypothetical carbon price. In all cases, adding the carbon cost substantially increases the NPV costs of coal units. It also adds to the market energy replacement option, as such energy is not necessarily clean.

Figure 8 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the solar PV plus storage replacement option in 2023 once the carbon price was factored in. The total net benefits of this scenario exclusively from avoided carbon costs are found to be $6.9 billion. The equivalent resource of solar plus storage is not completely carbon free due to the additional energy purchases. Even so, total benefits from replacing coal burning generation with solar plus storage, including both operating costs and carbon costs, can bring about $10.2 billion in benefits.

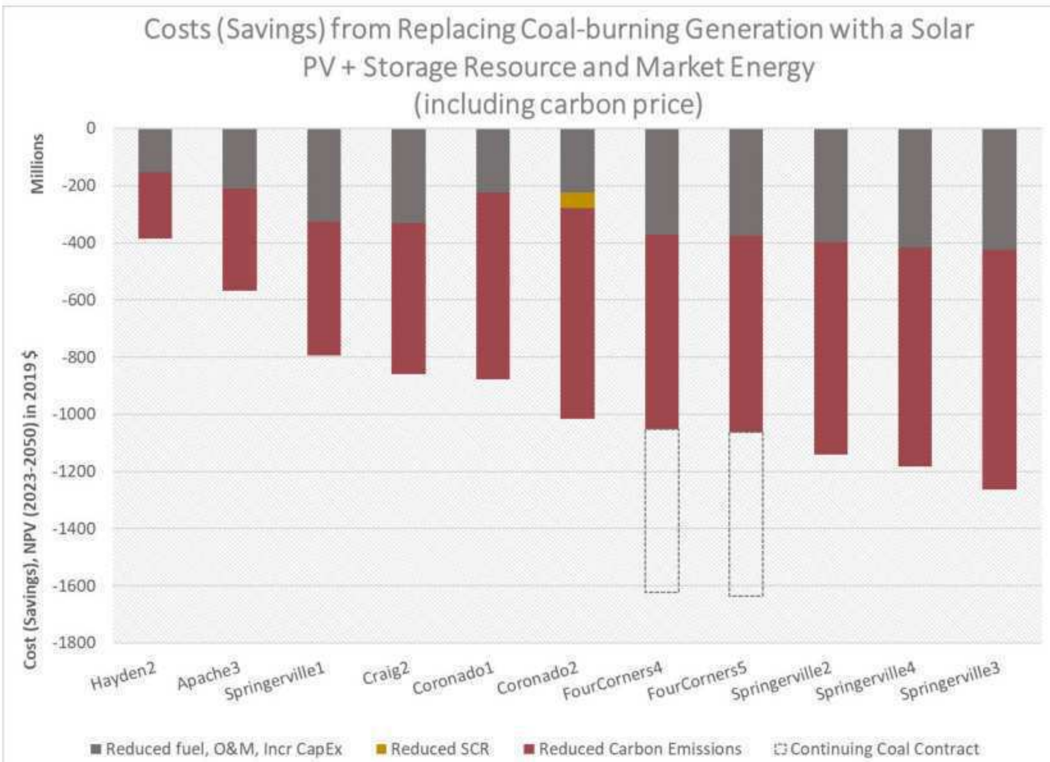

Figure 8: Savings in NPV from retiring coal units in 2023 compared to the solar PV plus storage replacement resource, when factoring in a carbon price.

Figure 9 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the wind replacement option in 2023 once the carbon price was factored in. Even though replacing coal-burning generation with a wind resource was not found to be economic for all units without factoring in the carbon emissions cost, once we accounted for a carbon price, the wind option became more economic than coal-burning generation for all units. The total net benefits of retiring all 11 units to this scenario are $7.3 billion.

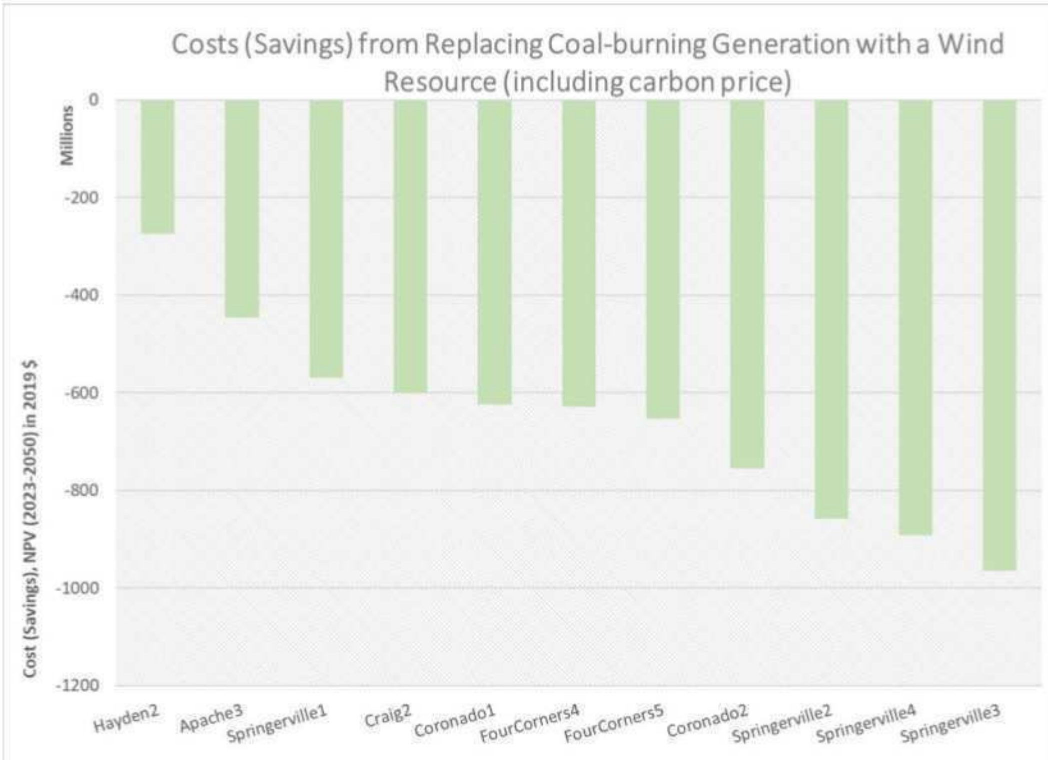

Figure 9: Savings in NPV from retiring Arizona coal generation units in 2023 compared to the wind replacement, when factoring in a carbon price.

3.5. Stranded Costs Analysis

Accelerated retirement of existing coal plants has the potential for significant ratepayer savings, simply by replacing the high operational costs of coal with cheaper, cleaner options as already analyzed in this study.

However, existing plants can have a substantial amount of capital invested in the plant that has not yet been fully depreciated. This capital invested in a plant is a cost that ratepayers have to pay if the plant continues to operate. However, in the case of a unit retirement, regulators have options to treat the remaining value of investment differently and potentially achieve even higher savings for ratepayers, beyond those previously quantified in the study.

Regulators may choose to let the utility continue to charge customers the full rate of return for capital invested in the plant and continue depreciating the plant as if it continued to operate, an option that would result in neither an increase nor a decrease in costs to ratepayers versus the status quo. However, other options available to regulators include the accelerated depreciation of the plant (potentially increasing rates in the near-term but getting the regulatory asset off the books quicker), the exclusion of some investments in the plant from earning a rate of return (if making such investments in an uneconomic plant was determined to be imprudent), or refinancing the unrecovered plant value at a lower interest rate, using a ratepayer-backed bond. All those options can result in significant ratepayer savings, in addition to the savings from O&M and fuel costs discussed earlier in the study.

To better understand the additional ratepayer savings that might result from one of those options, we looked at the refinancing option for the first unit of Springerville. Refinancing of a utility-owned asset like this can generally be done through the issuance of ratepayer-backed bonds which are used to repay the remaining undepreciated plant costs and decommissioning costs (net of salvage value). This mechanism is called securitization.

The benefits of securitization were estimated by determining differences in ratepayer capital costs under a "business as usual" (BAU) scenario, and a securitization scenario. Under the BAU scenario, these capital costs include annual depreciation expenses, and annual return on net plant (plus a gross up for taxes). For TEP, the current rate of return was assumed to be 7.04% based on TEP's current WACC[18]. For the securitization scenario, a 20-year bond was assumed with a starting value equal to the net plant balance in the year 2023, and an interest rate of 3.5%, which approximates the interest rate for a AAA-rated bond. Ratepayer costs were assumed to be equal to the principal and interest of the bond in each year of its tenor.

[18] Starting plant balance, depreciation reserve balance, and depreciation expenses for Springerville, unit 1, and TEP's current Weighted Average Cost of Capital (WACC) were based on TEP's recent rate application. Accessed at: https://docket.images.azcc.gov/0000197043.pdf

The NPV was calculated for both cases and the cost difference was estimated to be the overall benefit to TEP customers from securitization. Based on the depreciation study filed as part of TEP's 2019 rate application, the Springerville Unit 1's initial investment was $470 million, 70% of which has already been depreciated. The ratepayer benefits of refinancing through securitization were estimated to be $23 million.[19] This would be in addition to the net savings of approximately $326 million from replacing the unit with an equivalent solar plus storage option as described earlier.

[19] While the analysis presented here represents a reasonable first approximation of the benefits of securitization, we recognize there are other factors that were not explicitly analyzed and could influence the final outcome. These include the following:
- Additional capital expenditures associated with plant common costs (only unit costs were considered)
- Additional interim adjustments to depreciation schedules or plant balances
- Adjustments to net plant balance due to Accumulated Deferred Income Taxes (ADIT) were estimated for both the BAU and securitization case, however additional information is needed for a more precise estimate.

4. Key Findings & Conclusions

Arizona utilities can realize billions in savings for their customers through an orderly retirement of their coal fleets and replacement with clean energy alternatives. As this analysis shows, it is clear that coal is no longer an economic resource for utilities in the state when compared to clean energy replacement options.

Based on our analysis of operating and incremental capital costs, the highest-cost coal-burning units serving Arizona load (on an LCOE basis) are those at the Four Corners plant. However, the existing coal supply agreement reduces the potential savings that the plant retirement could bring about. Even with lower benefits, the retirement of the fourth and fifth units of Four Corners is an economically sound decision, as the savings from O&M and incremental capital costs are very high.

When replacement options were evaluated on an equivalent peak capacity basis, the results of this analysis did not change significantly when compared to an energy-only analysis. All the plants ended up being more expensive to operate than the solar plus storage replacement, while most of them are also more expensive than wind from New Mexico despite the additional transmission cost.

Accounting for a hypothetical carbon price reinforces the economics of replacing coal-burning generation, and also makes New Mexico wind more favorable for all units.

Solar PV generation plus storage in sun-rich Arizona has the greatest potential to produce energy at a lower cost than coal-burning power, even after including market purchases to provide an equivalent amount of energy output and peak capacity contribution.

STRATEGEN
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Appendix A: Methodology

A.1. Coal Fleet Cash Flow Analysis

Strategen conducted a discounted cash flow analysis for the Arizona coal units identified in Section 2. This analysis relied upon plant- and unit-specific cost data obtained from publicly available sources as well as the S&P Global Market Intelligence database and was supplemented by unit-specific data from other sources, including regulatory filings available via the Arizona Corporation Commission.

For each coal unit, the cost elements included fuel, operations and maintenance (O&M, both fixed and variable), incremental new capital expenditures, and dismantling costs. These cost elements were projected for each year through 2050 and discounted to present value using a discount rate equal to that used in TEP's current Action Plan.[20] While the analysis extended through year 2050, we assumed unit retirements would occur based on currently announced retirement dates. In the case of Springerville units 3 and 4, there are no publicly announced retirement dates, and it was thus assumed that the units will operate until 2050. However, for the purposes of our analysis no incremental operating costs beyond 2050 were included.[21] For future years, plant output (i.e., capacity factor) at each plant was assumed to be equal to the average of the three most recent years, 2016-2018. Exceptions to this assumption include the Coronado plant which according to SRP's 2018 Integrated Resource Plan (IRP) will curtail operations during non-peak months as a result of an agreement with the EPA in lieu of installing additional emissions reduction equipment to Unit 1.[22] For this reason, when projecting the generation of the first unit of Coronado in the future, a heavier weight was given to later years when lower generation was reported compared to earlier years. The calculation of the generation of Four Corners Units 4 and 5 was also adjusted as the units were down for prolonged periods in 2017 and 2018.

Non-fuel O&M costs were estimated based on plant-level data collected from S&P Global for years 2016-2018 and escalated at an assumed annual rate of inflation (1.8%).[23] These costs are based on data reported in EIA Form 923 and FERC Form 1. Similarly, fuel costs were based on inflation adjusted averages of the previous 3 years' reported fuel costs for each plant and escalated each year at the inflation rate.

Dismantling costs for Craig Unit 2 and Hayden Unit 2, were based on documents filed by Xcel with the Colorado Public Utilities Commission. A cost per MW average of these units was calculated and used to estimate the dismantling costs of other units.

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[20] Tuscon Electric Power, 2018 Action Plan Update.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[21] As such, the avoided fuel and O&M costs for Springerville 3 & 4 might be conservative.

[22] Salt River Project, Integrated Resource Plan Report 2017-2018.
Accessed at: https://www.srpnet.com/about/stations/pdfx/2018irp.pdf

[23] Some plants in Arizona have recently experienced extended outages due to operational issues (e.g. Four Corners). For these plants, years containing extended outages were excluded. Costs in the remaining years were benchmarked against prior years in the S&P Global database to ensure that more recent cost estimates were consistent with past performance.

Incremental capital expenditures were approximated based on the EIA NEMS modeling approach, which includes an annualized cost of $20/kW-yr for coal plants (in 2015 dollars), which increases by $7/kW-yr for plants over 30 years in age. Capital expenditures were assumed to decline during the years prior to retirement (whether retirement occurs early or not).

A.2. Replacement Analysis

As an initial screen, the LCOE of the coal units was compared to the LCOE of a market purchase resource, a solar PV plus storage resource, and a wind resource.

The cash flow for each coal unit was compared to several hypothetical "replacement resources" (or combinations of resources) that provided equivalent or nearly equivalent energy and capacity as the coal units. Three replacement portfolios were examined that represented different combinations of zero- or low-emissions resources – 1) forward market purchases, 2) solar PV plus storage plus market energy purchases, and 3) wind generation plus market capacity purchases. The portfolios were designed to capture a representative range of clean energy alternatives, while providing an equivalent amount of energy (MWh) as the coal unit being replaced. In addition, the wind and solar alternatives were constructed to provide equivalent capacity value (MW) as the coal unit being replaced. In each replacement case, the analysis assumed that the coal unit would operate until December 31, 2022, at which point the replacement resource would be placed into service. Replacement resource cost information was based on publicly available reports and data sources, as explained below.

Fuel supplies for at least three of the coal plants examined, Craig, Hayden, and Four Corners are currently subject to Coal Supply Agreements, ending in 2020, 2027, and 2031 respectively. While Strategen is not privy to the exact terms of these contracts, it is possible that they include "take or pay" provisions that are common to many Coal Supply Agreements. Strategen examined the impact of the Four Corners Coal Supply Agreement, as presented in the NPV Analysis. If "take or pay" provisions exist for the other two plants, we expect this would yield a modest reduction in the benefits of replacing the Hayden units prior to 2027 versus the BAU case, as the analysis has already showed for the Four Corners units.

Solar PV + Storage Replacement

A combined solar PV and storage replacement option was considered. The cost of a solar PV system was estimated assuming a fixed PPA rate of $33.99/MWh.[24] The PPA rate is based on a project that received full 30 percent investment tax credits (ITC). Absent the ITC, PPA rates could be higher. However, solar projects may qualify for the full ITC through 2019, as long as they are placed into service before 2024.[25]

The storage provides the ability to flatten the solar output across the on-peak hours, eliminating the need for a firming resource. No integration costs were assumed, while the duration of the storage was assumed to be 3.5 hours and the incremental capacity value of the combined resource was assumed to be 80% of the nameplate of the solar.[26]

The hourly MWh output of each solar PV system was estimated using NREL's System Advisor Model based on a 1-Axis tracking system being constructed near the location of each retired coal plant. The hourly generation profile of each coal unit was accessed through the S&P Market Intelligence Platform. The two were compared and in hours during which the solar output was not sufficient to cover the load otherwise served by the coal unit, additional energy purchases were assumed. Storage dispatch was optimized to minimize the cost of such additional purchases, while only being allowed to charge from the solar system. Hourly market prices were modeled as on/off peak[27] according to the forward curve at Palo Verde Index published by OTC Global Holdings (as of end of August 2019).

Below are three graphs of the average (over a year) hourly coal unit generation, solar generation, and storage charging profile. This example comes from the modeling of the third unit at Apache and includes a constraint that at least 75% of the energy used to charge the battery should come from solar.

[24] The rate is based on a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage. The bulk of the energy would be at the full contract rate of $33.99/MWh, but a portion of the energy over certain hourly thresholds will be charged at a discount rate of $19.00/MWh. Strategen used the full contract rate for all energy generated by the combined resource. Accounting for the discounted rate would result in additional savings of coal unit replacements. More information can be found at: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[25] Internal Revenue Service Notice 2018-59

[26] The Central Arizona Project PPA is based on a minimum dispatch capability of the battery of 17MW, and a total energy capacity of 60MWh, which implies a duration of 3.5 hours. Assuming a 20% incremental capacity value for utility solar, and a 100% value for solar plus 4 hours of storage, Strategen estimates a conservative 80% capacity value for solar of 20MW plus storage of 17MW, 60MWh.

[27] On peak hours: 6am-10pm

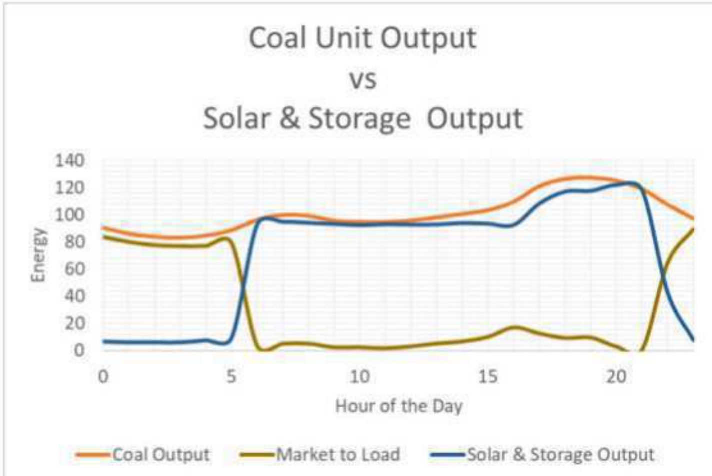

Figure 10: Coal unit output, Market Purchases to serve the load, and Solar & Storage Output

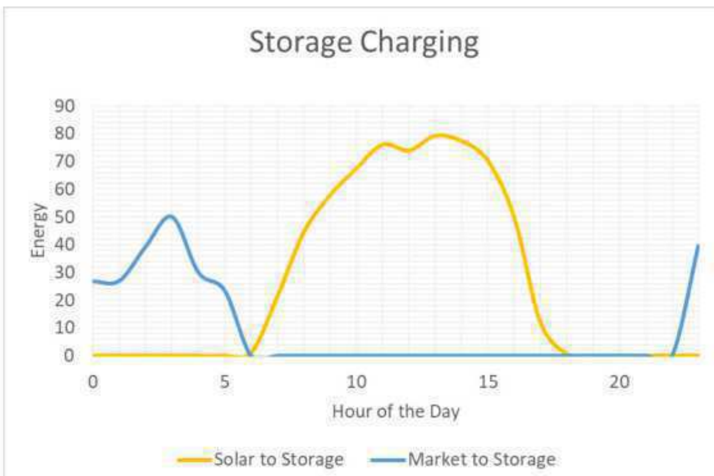

Figure 11: Storage charging profile

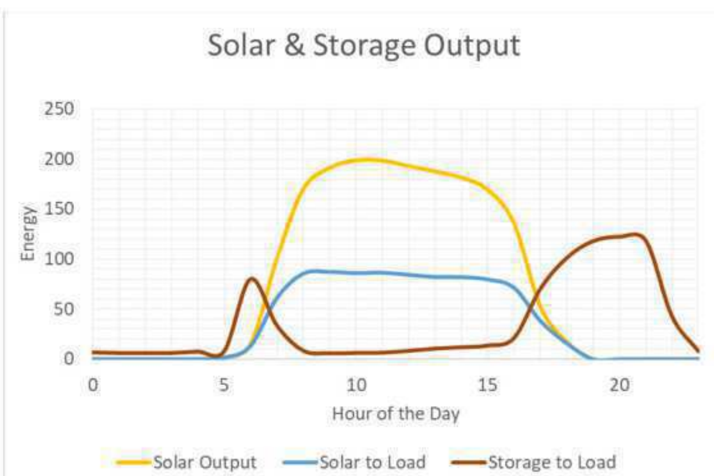

Figure 12: Solar & Storage Resource output

Forward Market Purchases

The cost of a market purchase replacement resource option was estimated based on the prices consistent with that in the Palo Verde Index published by OTC Global Holdings (as reported by S&P Global) as of end of August 2019. Annual on-peak and off-peak forward power prices were available through 2029. For the remaining periods (2029- 2050), power prices were assumed to escalate at the inflation rate. Market energy purchases were simulated to match hourly coal unit generation (as available through the S&P Global Market Intelligence database). The market replacement cost was calculated as the product of hourly prices (simulated as on/off peak Palo Verde forward prices) with the hourly coal unit generation.

Wind Replacement

A wind replacement option was also considered. The wind resource was assumed to have a capacity factor of 44%.[28] The cost of the wind generation was estimated assuming an average fixed PPA price of $18.97/MWh, escalating at 2% annually[29]. The Sagamore PPA price qualifies for a 100% Production Tax Credit (PTC). However, newer wind projects considered in this analysis would qualify for a lower PTC. Recent analysis has indicated that a substantial amount of wind projects in development for 2022 delivery have commenced construction in 2018 and would qualify for a 60% PTC.[30] Taking a conservative approach, we assumed that half of new wind resources entering service by December 2022 would qualify for a 60% PTC and half would qualify for a 40% PTC. The PPA price was thus adjusted upwards by $11.84/MWh.

Each wind system was sized to provide equivalent energy (MWh) to the coal unit being replaced. While sized to provide equivalent energy as the coal resource, a wind resource provides significantly less capacity value. As such, additional market capacity purchases were also included to ensure the MW of replacement capacity would be equal to the coal unit's capacity.

The capacity value for the wind resource was assumed to be equal to 30%, consistent with the value presented in the APS IRP Stakeholder meeting in April 2019. Additional capacity was purchased at an assumed cost of $39.48/kW-yr in 2019. This reflects an assumed blended average of $11.59/kW-yr in $2018 for short-term market purchases[31] and $69.60/kW-yr in $2021 cost for a new gas resource[32]. The capacity cost was assumed to escalate at the rate of inflation.

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[28] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[29] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[30] See: https://www.windpowerengineering.com/business-news-projects/more-than-61-gw-of-u-s-wind-turbine-equipment-has-qualified-for-the-ptc-since-2016/

[31] APS 2017 IRP, Table D-5.
Accessed at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf

[32] Average price of new gas resource according to APS 2019 Preliminary IRP
Accessed at: https://docket.images.azcc.gov/0000199276.pdf

The analysis assumed a $10/MWh transmission cost adder in 2019 reflecting the wheeling cost for transporting wind resources from New Mexico to Arizona. The adder was assumed to increase at the inflation rate.[33]

A.3. Carbon Pricing Risk Assessment

This analysis calculated the carbon cost of each coal plant's carbon-dioxide emissions using Arizona Public Service's guidelines for pricing, start date and escalation and discount rates. Based on APS parameters, the analysis set an initial carbon price at $15.99 starting in 2025, with an annual escalation rate of 2.5% and a discount rate of 3%.

[33] Consistent with the APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix B: Key Assumptions and Data Sources

Global Assumptions:

Assumption /Input	Value	Source & Description
Discount Rate	6.78%	Discount rate for Tuscon Electric Power consistent with its 2018 Action Plan 2016[34]
Inflation Rate	1.8%	Based on current inflation rate for the past 12 months (US inflation calculator)
Early Retirement Year	2023	Assuming last day of operations on 12/31/2022

Coal Plant Inputs & Assumptions:

Assumption/ Input	Value	Source & Description
Fuel Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Variable O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Fixed O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. 2019 values are based on average costs of 2016-2018 adjusted for inflation. Future costs were escalated at inflation rate. Fixed O&M costs for Four Corners were averaged over 5 years as late years might be considered higher than normal due to significant down time.
Incremental Capital Costs	$20-27/kW-yr	Based on EIA NEMS model:[35] $20/kW-yr (adjusted for inflation) assumed for plants <30 years and, $27/kW-yr (adjusted for inflation) assumed for plants >30 yrs.
Dismantling Costs	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E[36] for the Craig and Hayden plants. For other units, dismantling costs were assumed to be equal to the per-MW average costs of the Xcel units.
Capacity Factor	Varies by plant	Based on average of 2016-2018 as reported in S&P Global Market Intelligence database

[34] TEP Action Plan 2018.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[35] See:
https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/2016_EMM%20Coal%20Workshop%20Presentation%20(6-13-16).pdf

[36] See:
https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=

Retirement Date ("Business as Usual" Case)	Varies by plant	Based on utilities IRPs.[37]

Replacement Resource Inputs & Assumptions:

Assumption/Input	Value	Source & Description
Solar + Storage PPA	$33.99/MWh	Based on proposal to Central Arizona Project for a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage.[38]
Wind Cost	$18.97/MWh	Sagamore PPA escalating at 2%.[39]
Wind Transmission Cost (2019)	$10/MWh	Consistent with the analysis presented at APS IRP stakeholder Meeting in April, 2019
Market Energy Prices	Varies	Based on OTC Global Holdings Forward Power Index for Palo Verde as of 30/08/2019.
Capacity Price (2019)	$39.48/kW-yr	Blended cost between short- and long- term cost of a gas resource according to APS IPR 2017 & 2019 (preliminary).

Carbon Pricing Risk Assessment Inputs and Assumptions:

Assumption/Input	Value	Source & Description
Carbon price (2025)	$16/metric ton	Based on APS's IRP carbon assumption, which is based on California price, and begins in 2025.[40]
Escalation rate	2.5%	
Discount Rate	3%	Used only for computing the net present value of the cost of carbon portion of the analysis.

[37] Arizona Electric Power Cooperative. Accessed at: https://docket.images.azcc.gov/0000179477.pdf
Tri-State Generation and Transmission Association, Inc. Accessed at:
https://www.tristategt.org/sites/tristate/files/PDF/resourceplan/2015%20Electric%20resource%20plan.pdf
Arizona Public Service IRP. Accessed at:
https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf
Tuscon Electric Company. Accessed at:
https://www.tep.com/wp-content/uploads/2019/07/TEP-Preliminary-Integrated-Resource-Plan-070119-FINAL-Version-2.pdf

[38] See: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[39] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[40] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix C: Results

Plant	Coal Units				Solar plus Storage + Market Energy	Market Energy	Wind + Market Capacity
	Fuel, O&M, & Incr. CapEx	Coal Contract	SCR	Total Cost			
Apache3	$ 498,384,272	$ -	$ -	$ 498,384,272	$ 286,907,824	$ 320,754,721	$ 436,032,796
Coronado1	$ 792,125,301	$ -	$ -	$ 792,125,301	$ 569,634,144	$ 637,059,928	$ 876,160,519
Coronado2	$ 865,626,248	$ -	$ 54,951,732	$ 920,577,980	$ 642,959,355	$ 721,944,578	$ 969,637,675
Craig2	$ 989,755,707	$ -	$ -	$ 989,755,707	$ 660,437,245	$ 728,997,484	$ 994,918,447
FourCorners4	$1,858,982,946	$ (571,609,746)	$ -	$1,287,373,200	$ 914,760,152	$ 976,750,086	$1,420,784,366
FourCorners5	$1,862,499,108	$ (571,609,746)	$ -	$1,290,889,361	$ 917,060,335	$ 978,432,311	$1,408,607,970
Hayden2	$ 474,480,007	$ -	$ -	$ 474,480,007	$ 321,743,713	$ 323,440,325	$ 460,405,600
Springerville1	$ 860,548,900	$ -	$ -	$ 860,548,900	$ 534,247,461	$ 573,313,091	$ 807,809,590
Springerville2	$1,167,459,444	$ -	$ -	$1,167,459,444	$ 769,341,045	$ 849,578,346	$1,133,266,989
Springerville3	$1,187,885,222	$ -	$ -	$1,187,885,222	$ 763,685,587	$ 853,471,934	$1,138,434,270
Springerville4	$1,112,980,259	$ -	$ -	$1,112,980,259	$ 697,265,769	$ 783,214,978	$1,057,640,955

Table 2: Summary results: Avoided Cost (NPV) of coal units in case of retirement in 2023. and replacement options (by 2023). Each column represents a distinct set of and not a cumulative total. Results are in 2019$

Plant	Coal Units		Solar plus Storage + Market Energy		Market Energy		Wind + Market Capacity
	Avoided Cost in case of retirement	Avoided Carbon Cost	Resource Cost	Carbon Cost	Resource Cost	Carbon Cost	Resource Cost
Apache3	$ 498,384,272	$ 382,952,321	$ 286,907,824	$ 26,764,376	$ 320,754,721	$ 194,607,703	$ 436,032,796
Coronado1	$ 792,125,301	$ 707,538,708	$ 569,634,144	$ 53,311,340	$ 637,059,928	$ 383,166,900	$ 876,160,519
Coronado2	$ 920,577,980	$ 803,268,803	$ 642,959,355	$ 65,945,794	$ 721,944,578	$ 434,751,990	$ 969,637,675
Craig2	$ 989,755,707	$ 606,140,443	$ 660,437,245	$ 76,996,202	$ 728,997,484	$ 369,288,755	$ 994,918,447
FourCorners4	$1,287,373,200	$ 762,292,257	$ 914,760,152	$ 82,716,075	$ 976,750,086	$ 492,755,508	$1,420,784,366
FourCorners5	$1,290,889,361	$ 770,263,295	$ 917,060,335	$ 81,078,665	$ 978,432,311	$ 487,493,862	$1,408,607,970
Hayden2	$ 474,480,007	$ 259,828,776	$ 321,743,713	$ 27,776,451	$ 323,440,325	$ 152,449,979	$ 460,405,600
Springerville1	$ 860,548,900	$ 516,422,127	$ 534,247,461	$ 47,287,574	$ 573,313,091	$ 298,091,579	$ 807,809,590
Springerville2	$1,167,459,444	$ 823,666,864	$ 769,341,045	$ 81,494,684	$ 849,578,346	$ 481,808,026	$1,133,266,989
Springerville3	$1,187,885,222	$ 915,554,258	$ 763,685,587	$ 75,240,385	$ 853,471,934	$ 519,183,614	$1,138,434,270
Springerville4	$1,112,980,259	$ 836,926,208	$ 697,265,769	$ 71,165,310	$ 783,214,978	$ 474,673,440	$1,057,640,955

Table 3: Summary results: Cost (NPV) of replacing coal units with the three replacement options by 2023, including carbon cost. Each column represents a distinct set of benefits and not a cumulative total. Results are in 2019$

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Attachment DG-6

Congressional Research Service, *The Energy Credit of Energy Investment Tax Credit* (2021).

Updated April 23, 2021

The Energy Credit or Energy Investment Tax Credit (ITC)

Internal Revenue Code (IRC) Section 48 provides an investment tax credit (ITC) for certain energy-related property. This In Focus summarizes the current renewable energy ITC and reviews its legislative history.

Current Law

Certain investments in renewable energy property qualify for an ITC. The amount of the credit is determined as a percentage of the taxpayer's basis in eligible property (generally, the cost of acquiring or constructing eligible property). The tax credit rate and other credit parameters depend on the type of property or technology for which the credit is being claimed, as summarized in **Table 1**.

Table 1. Energy Credit: Summary of Current Law

Eligible Technology	Credit Rate	Expiration Date (End of Year)
Solar, Fiber Optic Solar, Fuel Cells, Small Wind, and Waste Energy Recovery Property[a]	30%	2019
	26%	2022
	22%	2023
Microturbines, Combined Heat and Power, Geothermal Heat Pump	10%	2023
Offshore Wind[b]	30%	2025
Solar, Geothermal Energy	10%	Permanent

Notes: Credit expiration dates are start-of-construction deadlines. For nonpermanent credits, property generally must be placed in service four years after the start of construction to qualify (five years if construction started in 2016 or 2017).

a. Waste energy recovery property is eligible starting in 2021.

b. Offshore wind facilities that began construction after 2016 are eligible. Facilities that began construction before 2017 may claim the ITC in lieu of the production tax credit (PTC).

Solar energy has a permanent 10% ITC. Temporarily, the credit rate for solar was increased to 30% through 2019, before being reduced to 26% through 2022 and 22% in 2023. Investments in small wind property (a wind turbine with 100 kilowatts of capacity or less) qualified for the 30% ITC through 2019, with the credit rate reduced to 26% through 2022 and 22% in 2023. Investments in fuel cell power plants and fiber optic solar may qualify for the ITC at these same rates. The credit for fuel cells is limited to $1,500 per 0.5 kilowatts in capacity. Waste energy recovery property that is not part of a combined heat and power (CHP) system and has a maximum capacity of 50 megawatts or less can qualify for the 26% credit if construction begins in 2021 or 2022, and a 22% credit if construction begins in 2023. Investments in microturbines, CHP systems, and geothermal heat pumps qualify for a 10% ITC. There is a 30% ITC for offshore wind property beginning construction by the end of 2025.

The expiration dates for the ITC are commence construction deadlines. For example, solar property that was under construction by the end of 2019 may qualify for the 30% tax credit, even if the property is not placed in service (or ready for use) until a later date.

Like the 10% ITC for solar, the 10% ITC for geothermal energy property is permanent. Geothermal energy property may also qualify for the renewable energy production tax credit (PTC) under IRC Section 45.

Legislative History

The Early Years

The energy tax credit was first enacted in the Energy Tax Act of 1978 (P.L. 95-618), which created a temporary 10% tax credit for business energy property and equipment using energy resources other than oil or natural gas. Tax credits for solar and wind energy property were refundable (credits could be received as a payment if the taxpayer did not have tax liability to offset), with nonrefundable credits available for a wide range of other qualifying technologies and property. The rationale behind the credits was to reduce U.S. consumption of oil and natural gas by encouraging the commercialization of a broader range of energy technologies and resources. Generally, the energy credits were scheduled to expire December 31, 1982.

The Windfall Profit Tax Act of 1980 (P.L. 96-223) expanded the energy credit to further the objective of developing an abundant range of energy resources and promoting investment in energy conservation. Tax credits for solar and wind energy property investments were extended for three years, through 1985. Additionally, the credit rate for solar and wind was increased to 15%, and the credit was made nonrefundable. The tax credit for geothermal was also increased from 10% to 15% and ocean thermal equipment was added as qualifying property. The 10% credit for biomass was also extended for three years, through 1985. The definition of biomass included materials such as municipal solid waste. The act also provided an 11% credit for small-scale hydroelectric generating property, through 1985. A 10% credit was provided for co-generation property (e.g., property that produces heat or other useful energy in addition to electricity) through 1982. The act made a number of other changes to the business energy ITC (the changes noted here are those most closely related to the current energy ITC).

When considering the Tax Reform Act of 1986 (TRA86; P.L. 99-514), Congress believed it desirable to maintain tax credits for renewable energy to continue stimulating technological development and the use of renewable energy sources. While there was not support for a broad extension of the energy credit (investment credits generally were repealed or allowed to expire in TRA86), investment tax credits for solar and geothermal energy property were extended, but phased down to 10% before being set to expire December 31, 1988. The credit for biomass was also extended, but reduced to 10% in 1987, when it was set to expire. The credit for ocean thermal property was extended at 15% through 1988. The credit for wind was not extended. The energy credit for many other types of property had expired at the end of 1982, as scheduled.

There were a number of short-term extensions to the energy credit in the late 1980s and early 1990s. The Miscellaneous Revenue Act of 1988 (P.L. 100-647) extended the solar, geothermal, and ocean thermal investment credits at their 1988 rates. The Omnibus Budget Reconciliation Act of 1989 (P.L. 101-239) again extended the credits for solar, geothermal, and ocean thermal equipment. The Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) extended the tax credits for solar and geothermal, as did the Tax Extension Act of 1991 (P.L. 102-227).

The Energy Policy Act of 1992 (P.L. 102-486) made the credits for solar and geothermal permanent. After P.L. 102-486, the only tax credits remaining from the Energy Tax Act of 1978 (P.L. 95-618) were the newly permanent 10% solar and geothermal credits.

Evolution of the Current Credit

The Energy Policy Act of 2005 (EPACT05; P.L. 109-58) increased the solar ITC from 10% to 30% for 2006 and 2007. The legislation also provided that fiber-optic distributed sunlight property was eligible for the tax credit, while solar property used to heat a swimming pool was not. EPACT05 also provided a 30% ITC for fuel cell power plants and a 10% ITC for stationary microturbine power plants that were placed in service during 2006 or 2007. The temporary components of the ITC and EPACT05 credit rates were extended through 2008 in the Tax Relief and Health Care Act of 2006 (P.L. 109-432).

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) substantially expanded and provided a long-term extension of the temporary components of the energy credit. The objective was to promote the continued development of alternative energy resources. In P.L. 110-343, the EPACT05 credits for solar, fuel cells, and microturbines were extended for eight years, through December 31, 2016. The legislation also provided a 10% credit for geothermal heat pump property, a 30% credit for small wind energy property, and a 10% credit for CHP property, each with a placed-in-service deadline of December 31, 2016. The purpose of the tax credit for CHP was to encourage more efficient use of fossil fuel power generation. The energy ITC was modified as part of the American Recovery and Reinvestment Act (ARRA; P.L. 111-5) in 2009, with certain limitations and restrictions relaxed. Changes in credit rates and expiration dates were not part of the ARRA modifications.

In 2015, the Consolidated Appropriations Act, 2016 (P.L. 114-113) further extended the credit. The 30% credit rate for solar electric or heating property (but not fiber-optic solar) was extended through 2019. The termination date was changed from a placed-in-service deadline to a construction start date. The higher rate was scheduled to phase out, with a 26% credit for property beginning construction in 2020, and 22% for property beginning construction in 2021.

The Bipartisan Budget Act of 2018 (P.L. 115-123) extended the ITC for five years for fiber-optic solar, fuels cell, small wind, microturbine, CHP, and geothermal heat pump property. For property eligible for a 30% credit through 2019, the credit rate is reduced following the reduction schedule for solar enacted in P.L. 114-113. All termination dates were changed to construction start deadlines.

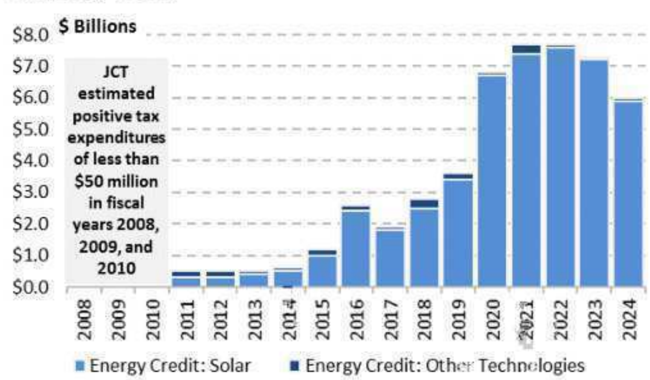
The energy credit deadlines were generally extended by two years in the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (Division EE of P.L. 116-260). This legislation expanded the credit to include waste energy recovery property and to allow an ITC for offshore wind. For offshore wind, the credit is allowed for property that begins construction by the end of 2025. The tax credit rate for offshore wind is 30% and does not phase out.

Cost of the Credit

For much of its history, there was little cost associated with the energy credit. From the credit's inception in 1978 through 2007, the Joint Committee on Taxation (JCT) estimated that tax expenditures—or forgone revenue—associated with the energy credit were generally *de minimis* (less than $50 million per year; fiscal years 1997, 1998, and 2007 were exceptions, when the tax expenditure estimate for the credit was $0.1 billion).

JCT provided energy credit tax expenditure estimates by type of qualifying technology starting in 2008 (**Figure 1**). Energy credit tax expenditure estimates have increased in recent years. The majority of the cost is for solar credits.

Figure 1. Tax Expenditures for the Energy Credit
FY2008-FY2024



Source: Joint Committee on Taxation.

For 2020, the JCT estimated energy credit tax expenditures to be $6.8 billion, with the majority of tax expenditures ($6.7 billion) attributable to solar. Between 2020 and 2024, the JCT has estimated energy credit tax expenditures to be $35.5 billion, with $34.9 billion for solar.

Molly F. Sherlock, Specialist in Public Finance

IF10479

Disclaimer

Attachment DG-7

Congressional Research Service, *Energy Tax Provisions: Overview and Budgetary Cost* (2021).

Congressional Research Service
Informing the legislative debate since 1914

Energy Tax Provisions: Overview and Budgetary Cost

August 3, 2021

Congressional Research Service
https://crsreports.congress.gov
R46865

CRS REPORT
Prepared for Members and Committees of Congress

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The 117th Congress is considering multiple proposals that would deploy energy tax provisions to pursue climate-related or infrastructure investment policy objectives. On May 26, 2021, the Senate Finance Committee passed the Clean Energy for America Act (S. 1298).[1] This legislation proposes tax credits for non-greenhouse gas (GHG)-emitting electricity generating technologies, with the provisions phasing out once emissions reductions targets are achieved. The legislation also proposes tax incentives for clean fuels (as defined in the bill) and transportation electrification, as well as for building energy efficiency, and would provide various other tax incentives for "clean energy." Qualifying projects would be required to meet certain workforce development requirements and pay prevailing wages. Tax incentives supporting fossil fuels would be repealed. The Joint Committee on Taxation (JCT) has estimated that this proposal would reduce federal revenues by $259.4 billion between FY2022 and FY2031.[2]

The Biden Administration's "American Jobs Plan" also proposes substantial modifications to energy tax policy. The Administration's proposal would expand and extend existing tax incentives supporting renewables, provide incentives for zero-emissions vehicles and electric vehicle infrastructure, expand tax incentives for building energy efficiency, and provide various other "clean energy" tax incentives. Tax incentives supporting fossil fuels would be repealed. The Treasury has estimated that the Administration's proposed energy tax policies would reduce federal revenues by $302.9 billion between FY2022 and FY2031.[3]

This report provides background information on current-law energy tax provisions. Specifically, the report includes a series of tables, each of which includes (1) the name of the provision and its Internal Revenue Code (IRC) citation; (2) a brief description of the provision; (3) the law first enacting the provision; (4) when the provision expires (if applicable) under current law; and (5) a cost estimate (if available).[4] For the purposes of this report, energy tax provisions have been categorized as follows:

- Renewable energy tax incentives (**Table 1**)
- Energy efficiency tax incentives (**Table 2**)
- Tax incentives for vehicles and vehicle infrastructure (**Table 3**)
- Renewable and alternative fuels tax incentives (**Table 4**)
- Fossil fuel tax incentives (**Table 5**)
- Carbon capture and sequestration (CCS), nuclear, and other tax incentives (**Table 6**)

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[1] Information and files related to Senate Finance Committee consideration of this legislation can be found at https://www finance.senate.gov/hearings/open-executive-session-to-consider-an-original-bill-entitled-the-clean-energy-for-america-act. On June 17, 2021, the Clean Energy for America Act (S. 2118) was introduced.

[2] Joint Committee on Taxation, *Estimated Revenue Effects of the Revenue Provisions Contained in the Chairman's Modification of the "Clean Energy for America Act," Scheduled for Markup by the Committee on Finance on May 26, 2021*, JCX-29-21, May 26, 2021, at https://www.jct.gov/publications/2021/jcx-29-21/.

[3] Department of the Treasury, *General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals*, May 2021, at https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf.

[4] The cost estimates are generally tax expenditure estimates, as provided in Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020. These estimates reflect tax laws enacted through September 30, 2020, and assume that temporary provisions expire as scheduled. If legislation enacted after September 30, 2020, extended the provision, the cost estimate associated with that extension is noted.

Table 1. Renewable Energy Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Residential energy-efficient property credit (IRC §25D)	A tax credit for the purchase of solar electric property, solar water heating property, fuel cells, geothermal heat pump property, or small wind energy property. Through 2019, the tax credit was 30% of the cost of qualifying property. Qualified biomass fuel property is eligible after 2020. The tax credit is reduced to 26% for property placed in service in 2020, 2021, and 2022 and 22% for property placed in service in 2023. The tax credit for fuel cells is limited to $500 for each 0.5 kilowatt of capacity.	Energy Policy Act of 2005 (EPACT05; P.L. 109-58)	Property placed in service by December 31, 2023.	FY2020: $1.8 FY2020-FY2024: $3.6 Extension in P.L. 116-260: $3.8 (FY2021-FY2030)
Renewable electricity production tax credit (PTC) (IRC §45)	A tax credit for electricity produced using qualifying renewable energy resources. The tax credit equals 2.5 cents per kWh for electricity produced from wind, closed-loop biomass, and geothermal energy in 2021. The tax credit equals 1.3 cents per kWh for electricity produced from open-loop biomass, landfill gas, trash combustion, qualified hydropower, and marine and hydrokinetic sources in 2021. Tax credit amounts are adjusted annually for inflation. The tax credit is available for 10 years after the date the facility is placed in service. Taxpayers may elect to receive a 30% investment tax credit (ITC) in lieu of the PTC. The tax credit for wind is reduced by 20% for facilities that began construction in 2017, 40% for facilities that began construction in 2018; 60% for facilities that began construction in 2019; and 40% for facilities that began construction in 2020 or 2021. For more, see CRS Report R43453, *The Renewable Electricity Production Tax Credit: In Brief*, by Molly F. Sherlock.	Energy Policy Act of 1992 (EPACT92; P.L. 102-486)	Construction must begin by December 31, 2021.	FY2020: $4.6 FY2020-FY2024: $17.0 Extension in P.L. 116-260: $1.7 (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Energy investment tax credit (ITC)(IRC §48)	A tax credit for investments in qualifying energy property. Investments in geothermal, microturbine, or combined heat and power (CHP) property qualify for a 10% credit. From 2006 through 2019 the credit rate was increased to 30% for solar, fuel cells, and small wind property. The tax credit rate for these technologies is 26% through 2022 and 22% in 2023. Waste energy recovery property is eligible for the ITC after 2020, at the increased credit amounts. Offshore wind facilities that begin construction after 2016 are eligible for a 30% credit. For more, see CRS In Focus IF10479, *The Energy Credit or Energy Investment Tax Credit (ITC)*, by Molly F. Sherlock.	The Energy Tax Act of 1978 (P.L. 95-618)	Construction must begin by December 31, 2023, except for geothermal and solar, where there is a permanent 10% credit. For offshore wind property, construction must begin by December 31, 2025.	FY2020: $6.8 FY2020-FY2024: $35.5 Extension in P.L. 116-260: $7.0 (FY2021-FY2030) Application of credit to waste energy recovery and offshore wind in P.L. 116-260: $0.6 (FY2021-FY2030)
Credit for investment in advanced energy property (IRC §48C)	A 30% tax credit for selected qualified investments in advanced energy property. A total of $2.3 billion was allocated for advanced energy property investment tax credits, which were competitively awarded by the Departments of Energy (DOE) and the Treasury.	American Recovery and Reinvestment Act (ARRA; P.L. 111-5)	Allocation limit; credits fully allocated.	FY2020: (i) FY2020-FY2024: $0.4
Credit for holders of clean renewable energy bonds (IRC §§54, 54C)	An income tax credit for holders of the bond. Clean Renewable Energy Bonds (CREBs) are subject to a volume cap of $1.2 billion with a credit rate set to allow the bond to be issued at par and without interest. New Clean Renewable Energy Bonds (New CREBs) are subject to a volume cap of $2.4 billion with a credit rate set at 70% of what would permit the bond to be issued at par and without interest. Tax credit bonds were repealed in the 2017 tax revision (commonly called the "Tax Cuts and Jobs Act" [TCJA]; P.L. 115-97).	EPACT05 (P.L. 109-58) Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Allocation limit; authority to issue repealed in P.L. 115-97.	FY2020: (i) FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Depreciation recovery periods for energy-specific items: five-year MACRS for certain energy property (IRC §168(e)(3)(B)(vi))	Accelerated depreciation allowances are provided under the modified accelerated cost recovery system (MACRS) for investments in certain energy property. Specifically, certain solar, wind, geothermal, fuel cell, microturbine, CHP, waste energy recovery, and biomass property have a five-year recovery period.	Tax Reform Act of 1986 (P.L. 99-514)	Construction must begin by December 31, 2023, for solar illumination, fuel cell, microturbine, CHP, small wind, geothermal heat pump, and waste energy recovery property. None otherwise.	FY2020: (i) FY2020-FY2024: $0.3

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. kWh = kilowatt-hour. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 2. Energy Efficiency Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credit for energy-efficient improvements to existing homes/nonbusiness energy property credit (IRC §25C)	A 10% tax credit for qualified energy-efficiency improvements and expenditures for residential energy property including qualifying improvements to the building's envelope, the HVAC system, furnaces, or boilers. The credit is subject to a $500 per taxpayer lifetime limit. Property must be installed in the taxpayer's primary residence.	EPACT05 (P.L. 109-58)	Property installed by December 31, 2021.	FY2020: $0.5 FY2020-FY2024: $0.8 Extension in P.L. 116-260: $0.4 (FY2021-FY2030)
Credit for energy-efficient new homes (IRC §45L)	A tax credit for eligible contractors for building and selling qualifying energy-efficient new homes. The credit is equal to $2,000, with certain manufactured homes qualifying for a $1,000 credit.	EPACT05 (P.L. 109-58)	Property acquired by December 31, 2021.	FY2020: $0.2 FY2020-FY2024: $0.6 Extension in P.L. 116-260: $0.3 (FY2021-FY2030)
Credit for holders of qualified energy conservation bonds (IRC §54D)	The federal government has authorized the issue of $3.2 billion in Qualified Energy Conservation Bonds (QECBs). QECBs provide a tax credit worth 70% of the tax credit bond rate stipulated by the Secretary of the Treasury. QECBs issued by state and local governments must fund an energy-savings project, such as the green renovation of a public building, R&D in alternative fuels, and public transportation projects. Tax credit bonds were repealed in the 2017 tax revision (TCJA; P.L. 115-97).	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Allocation limit (allocated to the states); authority to issue repealed in P.L. 115-97.	FY2020: (i) FY2020-FY2024: $0.1
Exclusion of energy conservation subsidies provided by public utilities (IRC §136)	Subsidies provided by public utilities to customers for the purchase or installation of energy conservation measures are excluded from taxable income. For the purposes of this provision, public utilities are entities selling electricity or natural gas.	EPACT92 (P.L. 102-486)	none	FY2020: (i) FY2020-FY2024: $0.1

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Exclusion of interest on state and local qualified private activity bonds for green buildings and sustainable design projects (IRC §142(a)(14))	Tax-exempt private activity bonds can be issued to finance (or refinance) qualified green building and sustainable design projects.	American Jobs Creation Act of 2004 (P.L. 108-357)	Does not apply to any bond issued after September 30, 2012.	*de minimis*
Energy-efficient commercial building deduction (IRC §179D)	A deduction of up to $1.80 per square foot is allowed for certain energy-saving property used in domestic commercial buildings. Qualifying energy-efficient commercial building property includes property installed as part of (1) the interior lighting system; (2) the heating, cooling, ventilation, or hot water system; or (3) the building envelope. To be deductible, property must reduce a building's annual energy and power costs by 50% or more as compared to a similar reference building meeting certain minimum energy standards. A reduced deduction may be available if a single system is upgraded (lighting, heating and cooling, or building envelope) and the 50% reduction threshold is not met. Government entities making energy-efficiency upgrades to public buildings, such as schools, can allocate the Section 179D deduction to designers of energy-efficient commercial building property.	EPACT05 (P.L. 109-58)	none	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.7 (FY2021-FY2030)

Source: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 3. Tax Incentives for Vehicles and Vehicle Infrastructure

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credits for fuel cell vehicles (IRC §30B)	A tax credit for fuel cell vehicles. Fuel cell vehicles receive a base credit of $4,000 for vehicles weighing less than 8,500 pounds. Heavier vehicles qualify for up to a $40,000 credit. An additional credit of up to $4,000 is available for cars and light trucks that exceed the 2002 base fuel economy.	EPACT05 (P.L. 109-58)	Property purchased by 12/31/2021.	*de minimis*
Credit for alternative fuel refueling property (IRC §30C)	A tax credit for the cost of any qualified alternative fuel vehicle refueling property installed by a business or at a taxpayer's principal residence. The credit is equal to 30% of these costs, limited to $30,000 for businesses at each separate location with qualifying property, and $1,000 for residences.	EPACT05 (P.L. 109-58)	Property placed in service by 12/31/2021.	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.2 (FY2021-FY2030)
Credit for plug-in electric vehicles (IRC §30D)	A tax credit for the purchase of qualifying plug-in electric vehicles. The credit ranges from $2,500 to $7,500 per vehicle, depending on the vehicle's battery capacity. The tax credit phases out once a vehicle manufacturer has sold 200,000 qualifying vehicles. If the vehicle is purchased by a tax-exempt organization, the seller of the vehicle may be able to claim the credit. For more, see CRS In Focus IF11017, *The Plug-In Electric Vehicle Tax Credit*, by Molly F. Sherlock.	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Credit phases out after reaching a 200,000 per-manufacturer limit.	FY2020: $0.7 FY2020-FY2024: $3.0
Credit for electric motorcycles (IRC §30D)	A 10% credit, up to $2,500, is available for the cost of two-wheeled plug-in electric vehicles. Eligible vehicles must have a weight rating of less than 14,000 pounds; be propelled by a battery-powered electric motor with a battery capacity of at least 2.5 kilowatt-hours; be manufactured for use on streets, roads, and highways; and be capable of achieving a speed of at least 45 miles per hour.	ARRA (P.L. 111-5)	Property purchased by 12/31/2021.	*de minimis*

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 4. Renewable and Alternative Fuels Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credit for second-generation biofuel production (IRC §40(a)(4))	A per-gallon tax credit for qualified second-generation biofuel production. The amount of the credit is generally $1.01 per gallon. Qualifying fuels include cellulosic biofuel, which is produced using lignocellulosic or hemicellulosic matter (cellulosic feedstock) available on a renewable or recurring basis, as well as second-generation biofuels, which include cultivated algae, cyanobacteria, or lemna.	The Food, Conservation, and Energy Act of 2008 (P.L. 110-246)	Fuel produced by 12/31/2021.	*de minimis* Extension in P.L. 116-260: (i) (FY2021-FY2030)
Credits for biodiesel and renewable diesel fuel (IRC §§40A, 6526, & 6427)	There are three tax credits for biodiesel: the biodiesel mixture credit, the biodiesel credit, and the small agri-biodiesel producer credit. Each gallon of biodiesel, including agri-biodiesel (biodiesel made from virgin oils), may be eligible for a $1.00 tax credit. Additionally, an eligible small agri-biodiesel producer credit of 10 cents is available for each gallon of "qualified agri-biodiesel production." The mixtures tax credit may be claimed as an instant excise tax credit against the blender's motor and aviation fuels excise taxes. Credits in excess of excise tax liability may be refunded. The biodiesel and small agri-biodiesel credits may be claimed as income tax credits.	American Jobs Creation Act of 2004 (P.L. 108-357)	Fuel sold, used, or removed by 12/31/2022.	FY2020: $8.1[b] FY2020-FY2024: $15.2[b]
50-percent expensing of cellulosic biofuel plant property (IRC §168(l))	Second-generation biofuel plant property was allowed an additional first-year depreciation deduction equal to 50% of the property's adjusted basis.	Tax Relief and Health Care Act of 2006 (P.L. 109-432)	Property placed in service by 12/31/2020.	*de minimis*

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Alternative Fuels and Alternative Fuels Mixture Credit (IRC §§6426 & 6427)	A tax credit for certain alternative fuels and alternative fuels mixtures. The credit is a 50-cents-per-gallon excise tax credit for certain alternative fuels used as fuel in a motor vehicle, motor boat, or airplane and a 50-cents-per-gallon credit for alternative fuels mixed with a traditional fuel (gasoline, diesel, or kerosene) for use as a fuel. Qualifying fuels include liquefied petroleum gas; P Series fuels (certain renewable, nonpetroleum, liquid fuels); compressed or liquefied natural gas (CNG or LNG); any liquefied fuel derived from coal or peat through the Fischer-Tropsch process that meets certain carbon-capture requirements; liquefied hydrocarbons derived from biomass; and liquefied hydrogen.	Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU; P.L. 109-59)	Fuel sold or used by 12/31/2021.	FY2020: $0.2[c] FY2020-FY2024: $0.3[c] Extension in P.L. 116-260: $0.2 (FY2021-FY2030)

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020; Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In The House Amendment To The Senate Amendment To H.R. 1865, the Further Consolidated Appropriations Act, 2020*, JCX-54R-19, December 17, 2019.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. The tax incentives for biodiesel and renewable diesel were extended for five years, through 2022, in the Further Consolidated Appropriations Act of 2020 (P.L. 116-94). This cost estimate reflects the extension, as estimated in Joint Committee on Taxation, *Estimated Budget Effects of the Revenue Provisions Contained in the House Amendment to the Senate Amendment to H.R. 1865, the Further Consolidated Appropriations Act 2020 (Rules Committee Print 116-44)*, JCX-54R-19, December 17, 2019. The income tax credit portion is *de minimis*.

c. The tax incentives for alternative fuels and alternative fuel mixtures were extended for one year, through 2021, in the Consolidated Appropriations Act, 2021 (P.L. 116-260). This cost estimate is the estimate associated with that extension.

Table 5. Fossil Fuels Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Enhanced Oil Recovery (EOR) Credit (IRC §43)	A tax credit for Enhanced Oil Recovery (EOR) costs available when oil prices are below a certain threshold. The credit amount is 15% of qualified domestic EOR costs. The EOR credit phases out over a $6 range once oil's reference price exceeds $28 per barrel (adjusted for inflation after 1991; $49.392 in 2019). The EOR credit was fully phased out every year from 2006 through 2016. Low oil prices led to the EOR credit becoming available in 2016 and 2017. A partial credit was available for 2018, but it was fully phased out in 2019 and 2020. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Insight IN11381, *Low Oil Prices May Trigger Certain Tax Benefits, but Not Others*, by Molly F. Sherlock and Phillip Brown.	Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508)	None	*de minimis*
Coal Production Credits: Refined Coal and Indian Coal (IRC §45)	A tax credit for Indian coal produced from reserves that were owned by an Indian tribe or held in trust by the United States for a tribe on June 14, 2005. The amount of the credit is $2.00 per ton (adjusted for inflation; $2.60 per ton in 2021). Tax credits may also be available for refined coal produced at refined coal production facilities placed in service after the date of the enactment of the American Jobs Creation Act of 2004 and before January 1, 2012.	EPACT05 (P.L. 109-58)	Coal produced by 12/31/2021	FY2020: (i) FY2020-FY2024: $0.2 Extension in P.L. 116-260: (i) (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Credit for producing oil and gas from marginal wells (IRC §45I)	A tax credit for producing oil and gas from marginal wells, available when oil and gas prices are below certain thresholds. The credit amount is $3 per barrel of qualified crude oil and 50 cents per 1,000 cubic feet (mcf) of qualified natural gas (adjusted for inflation after 2005; $3.90 for oil and 65¢ for gas in 2019; 66¢ for gas in 2020). The credit starts phasing out if the reference price for oil exceeds $15 per barrel or natural gas exceeds $1.67 per mcf for the preceding year (adjusted for inflation after 2005; $19.52 for oil and $2.17 for gas in 2019; $2.21 for gas in 2020). The credit is fully phased out if the reference price exceeds $18 per barrel or $2.00 per mcf (adjusted for inflation after 2005; $23.43 for oil and $2.60 for gas in 2019). The credit for crude oil has never been triggered. In 2016 and 2017, and again in 2019, a partial credit (in the phaseout range) was available for natural gas. For 2020 the credit for natural gas was not phased out; the full 66¢ per mcf credit was available. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Insight IN11381, *Low Oil Prices May Trigger Certain Tax Benefits, but Not Others*, by Molly F. Sherlock and Phillip Brown.	American Jobs Creation Act of 2004 (P.L. 108-357)	None	*de minimis*
Credits for Investments in Clean Coal Facilities (IRC §§48A and 48B)	A tax credit allocated for investment in certain advanced coal technologies. In EPACT05, the tax credit was 20% of investment for integrated gasification combined cycle (IGCC) systems and 15% for other advanced coal-based generation technologies. Additional allocations for a 30% advanced coal-based generation technologies credit were provided in the Energy Improvement and Extension Act of 2008 (P.L. 110-343). Credit allocations are available due to forfeitures of previously allocated credits. Round 3 Phase III credits being allocated in 2021 are 30% for IGCC or other advanced coal-based generation technologies. Credits were also allocated for gasification projects, with the credit amount equal to 30% (20% for credits allocated or reallocated before October 4, 2008). In 2016 the IRS announced no additional allocation rounds would be conducted under the qualifying gasification project program.	EPACT05 (P.L. 109-58)	Credits allocated. $2 billion of §48A credits are available for allocation in Round 3 of the Phase III Program, taking place in 2021.	FY2020: $0.2 FY2020-FY2024: $1.2

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Safe harbor from arbitrage rules for prepaid natural gas (IRC §148(b)(4))	This provision allows tax-exempt bonds to be used to finance prepaid natural gas contracts without applying otherwise applicable arbitrage rules.	EPACT05 (P.L. 109-58)	None	Not available.
Amortization of Geological and Geophysical Expenditures Associated with Oil and Gas Exploration (IRC §167(h))	Geological and geophysical (G&G) expenditures are costs associated with determining the location and potential size of a natural resource or mineral deposit. Generally, these costs are viewed as capital costs, and as such would be recovered over the same time frame as other capital costs. Most producers amortize G&G expenditures over two years. Major integrated oil companies amortize G&G expenditures over seven years. A major integrated oil company, as defined in statute, has (1) average daily worldwide production of crude oil of at least 500,000 barrels; (2) gross receipts in excess of $1 billion in its tax year ending during 2005; and (3) at least 15% ownership interest in a crude oil refinery. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	EPACT05 (P.L. 109-58)	None	FY2020: $0.1 FY2020-FY2024: $0.5
Seven-year MACRS Alaska natural gas pipeline (IRC §168(e)(3)(C)(iii))	A seven-year MACRS recovery period is provided for any natural gas pipeline system located in the State of Alaska that has a capacity of more than 500 billion Btu of natural gas per day.	American Jobs Creation Act of 2004 (P.L. 108-357)	None	*de minimis*
Seven-year MACRS for natural gas gathering lines (IRC §168(e)(3)(C)(iv))	Natural gas gathering lines are treated as 7-year property. A natural gas gathering line consists of the pipe, equipment, and appurtenances determined to be a gathering line by the Federal Energy Regulatory Commission (FERC) or a gathering line used to deliver natural gas to a gas processing plant, an interconnection with a transmission pipeline, or an interconnection with a local distribution company, a gas storage facility, or an industrial consumer.	EPACT05 (P.L. 109-58)	None	Not available.
15-year MACRS Depreciation Recovery Period for Natural Gas Distribution Lines (IRC §168(e)(3)(E)(vi))	A natural gas distribution line, the original use of which commences with the taxpayer after April 11, 2005, and which is placed in service before January 1, 2011, is treated as 15-year property.	EPACT05 (P.L. 109-58)	12/31/2010	FY2020: $0.1 FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Amortization of Air Pollution Control Facilities (§§169 and 291(a)(4))	Five-year (60-month) amortization applies to a "certified pollution control facility" used in connection with a plant or other property in operation before January 1, 1976, and to an "atmospheric pollution control facility" placed in service after April 11, 2005, and used in connection with an electric generation plant or other property that is primarily coal fired. Seven-year (84-month) amortization applies only to an "atmospheric pollution control facility" placed in service after April 11, 2005, and used in connection with an electric generation plant or other property that is primarily coal fired and that was placed in operation after December 31, 1975. If an election is made under §169 with respect to any certified pollution control facility, the amortizable basis of the facility is reduced by 20%.	EPACT05 (P.L. 109-58)	None	FY2020: $0.4 FY2020-FY2024: $2.1
Expensing of tertiary injectants (IRC §193)	Taxpayers can deduct tertiary injectant expenses, other than expenses for recoverable hydrocarbon injectants, in the year costs are incurred. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	The Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223)	None	*de minimis*
Expensing of Intangible Drilling Costs (IDCs) and Exploration and Development Costs (IRC §§263A(c)(3), 263(c), 291(b), 616, 617)	IDCs include expenses on items without salvage value (e.g., wages, fuel, and drilling site preparations). Integrated oil and gas producers (producers who also have substantial refining or retail activities) must capitalize 30% of IDCs and then recover those costs over a five-year period. The remaining 70% of IDCs can be fully expensed (costs deducted in the year they are incurred). Nonintegrated producers can fully expense IDCs. The election to deduct intangible drilling and development costs applies to oil and gas wells and to wells drilled for any geothermal deposit. For mineral properties, exploration and development expenditures are deductible as an expense in the year paid, as opposed to being capitalized. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	1916 Treasury regulation (T.D. 45, article 223); codified in 1954 (P.L. 83-591)	None	*Oil and Gas* FY2020: $0.5 FY2020-FY2024: $2.3 *Other Fuels* FY2020: (i) FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Passive loss rules for working interests in oil and gas property (IRC §469(c)(3))	Deductions from passive trade or business activities, to the extent they exceed income from all such passive activities, generally may not be deducted against other income (salary, interest, dividends, and active business income). These passive activity loss rules are not applicable to working interests in oil or gas property. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	Tax Reform Act of 1986 (P.L. 99-514)	None	FY2020: (i)[b] FY2021-FY2030: $0.2[b] (10-year estimate)
Percentage Depletion (IRC §§611, 613, and 613A)	Certain independent oil and gas producers (producers who are not retailers or refiners) may elect to claim percentage depletion as opposed to cost depletion. The percentage depletion allowance is 15% of gross income from the property, not to exceed (1) 100% of taxable income from the property, and (2) 65% of the taxpayer's taxable income. Oil and gas producers may claim percentage depletion on up to 1,000 barrels of average daily production (or an equivalent amount of domestic natural gas). Percentage depletion rates for other minerals range from 5% to 22%. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	Revenue Act of 1926 (P.L. 69-20)	None	*Oil and Gas* FY2020: $0.6 FY2020-FY2024: $2.9 *Other Fuels* FY2020: $0.1 FY2020-FY2024: $0.7
Fossil fuel capital gains treatment (IRC §631(c))	Certain sales of coal under royalty contracts qualify for taxation as capital gains rather than ordinary income. Income from these sales is taxed at the preferred 20% rate applied to capital gains, as opposed to being taxed as ordinary income.	Revenue Act of 1964 (P.L. 88-272)	None	FY2020: $0.1[b] FY2020-FY2029: $1.6[b] (10-year estimate)
Exceptions for Publicly Traded Partnerships with Qualified Income Derived from Certain Energy-Related Activities (IRC §7704)	Publicly traded partnerships are generally treated as corporations. The exception from this rule occurs if at least 90% of its gross income is derived from interest, dividends, real property rents, or certain other types of qualifying income. Qualifying income includes income derived from certain energy-related activities, such as fossil fuel or geothermal exploration, development, mining, production, refining, transportation, and marketing. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Report R41893, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry*, by Molly F. Sherlock and Mark P. Keightley.	Revenue Act of 1987 (P.L. 100-203)	None	FY2020: $0.3 FY2020-FY2024: $1.8

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. Exceptions to the passive activity loss rules are not classified as tax expenditures by JCT. These estimates are from the Treasury Department. Treasury Department tax expenditure estimates are available at https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

Table 6. Carbon Capture and Sequestration, Nuclear, and Other Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Credit for production of electricity from qualifying advanced nuclear power facilities (IRC §45J)	A tax credit for electricity produced from qualifying nuclear facilities. The advanced nuclear production tax credit (PTC) provides a 1.8 cent per kWh tax credit for electricity sold that was produced at qualifying facilities. Criteria for qualifying facilities include that they must use nuclear reactor designs approved by the Nuclear Regulatory Commission after 1993. Qualifying facilities can claim tax credits during the first eight years of production. The credit is restricted to 6,000 megawatts (MW) of total electric generating capacity for all qualifying facilities, with the 6,000 MW allocated by the Internal Revenue Service (IRS). Taxpayers can claim no more than $125 million in tax credits per 1,000 MW of the allocated capacity in any single year.	EPACT05 (P.L. 109-58)	Facilities placed in service by January 1, 2021. The IRS is to allocate unutilized national megawatt capacity after that date.	*de minimis*
Credit for Carbon Oxide Sequestration (IRC §45Q)	A credit for the capture and sequestration of carbon emissions (including carbon dioxide and carbon monoxide). The credit is the sum of four components: (1) $20 (adjusted to $23.82 for 2020) per metric ton of carbon oxide captured using carbon capture equipment placed in service before February 9, 2018, that is not used as a tertiary injectant; (2) $10 (adjusted to $11.91 for 2020) per metric ton of carbon oxide captured using carbon capture equipment placed in service before February 9, 2018, that is used as a tertiary injectant; (3) $31.77 in 2020 per metric ton of carbon oxide captured using carbon capture equipment placed in service on or after February 9,	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Construction must begin by December 31, 2025.	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.6 (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
	2018, that is not used as a tertiary injectant, during the first 12 years following the facility being placed in service; and (4) $20.22 in 2020 per metric ton of carbon oxide captured using carbon capture equipment placed in service on or after February 9, 2018, that is used as a tertiary injectant, during the first 12 years following the facility being placed in service. Carbon oxide that is not used as a tertiary injectant must be disposed of in a secure geological facility. For carbon dioxide captured at facilities placed in service before February 9, 2018, the credit applies until the IRS, in consultation with the Environmental Protection Agency, certifies that 75 million metric tons of carbon dioxide has been captured or used as a tertiary injectant. As of June 2020, 72 million metric tons of qualified carbon oxide had been taken into account.[b] For more, see CRS In Focus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.			
10-year MACRS for smart electric distribution property (IRC §§168(e)(3)(D)(iii) and 168(e)(3)(D)(iv))	10-year property includes any qualified smart electric meter and any qualified smart electric grid system. A smart electric meter is a time-based meter and related communication equipment. Smart electric grid systems include property that is used as part of a system for electric distribution grid communications, monitoring, and management.	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	None	FY2020: (i) FY2020-FY2024: $0.2
Transmission Property Treated as 15-year Property (IRC §168(e)(3)(E)(v))	15-year property includes original-use electricity transmission property that is used in the transmission of electricity for sale at 69 or more kilovolts.	EPACT05 (P.L. 109-58)	None	FY2020: (i) FY2020-FY2024: $0.2
Accelerated deductions for nuclear decommissioning costs (IRC §468A)	An eligible taxpayer may deduct cash payments made by the taxpayer to a nuclear decommissioning reserve fund, and to deduct the ratable portion of any special transfer to the fund, even if under the applicable method of accounting the taxpayer would typically claim the deduction in a later tax year.	Deficit Reduction Act of 1984 (P.L. 98-369)	None	Not available
Special tax rate for nuclear decommissioning	A special 20% tax rate for investments made by nuclear decommissioning reserve funds.	Deficit Reduction	None	FY2020: (i) FY2020-FY2024: $0.1

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
reserve funds (IRC §468A(e)(2))		Act of 1984 (P.L. 98-369)		

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. kWh = kilowatt-hour. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. Internal Revenue Service, *Inflation Adjustment Factor Issued for Sequestration Credit*, IRS Notice 2020-40, June 15, 2020.

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Disclaimer

Attachment DG-8

Tony Lenoir, *Mapping Communities Eligible for Additional Inflation Reduction Act Incentives,* S&P Global Market Intelligence (Oct. 11, 2022).

RESEARCH — 11 Oct, 2022

Mapping communities eligible for additional Inflation Reduction Act incentives

Author Tony Lenoir

Theme Energy, Energy Transition, Renewables

Introduction

Mapping out energy communities based on criteria specified in the Inflation Reduction Act of 2022 revealed that large swaths of the U.S. may currently qualify for 10% tax credit adders on new energy infrastructure. Further coal power plant retirements and coal mine closures could also contribute to expanding the pool of qualifying geographies, as might changes in the local unemployment rate, while the U.S. Federal Reserve further tightens monetary policy to bring down inflation.

The Take

With its "energy community" special rule, the Inflation Reduction Act incentivizes clean energy development in communities historically reliant on environmentally damaging fossil fuel industries, overlaying an economic revitalization strategy on top of energy transition objectives.

The law's energy community-qualifying employment criteria suggest that over 100 metropolitan and nonmetropolitan statistical areas, or MSAs and non-MSAs, will be eligible for the 10% tax credit step-up. Criteria on closed and retired coal assets, meanwhile, point to more than 2,800 identified U.S. census tracts across 42 states.

Further coal mine closures and coal power plant retirements will likely expand the qualifying census tract footprint, while an economic recession could lead to more eligible MSAs and non-MSAs.

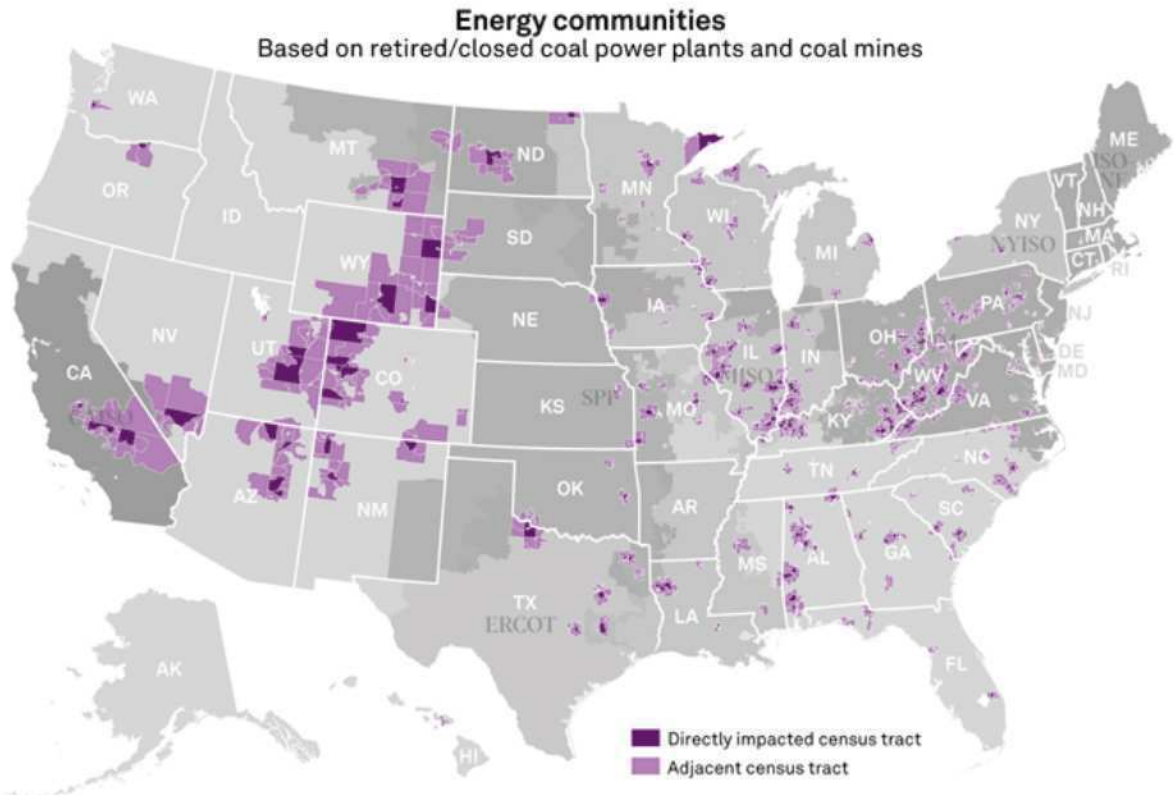
Qualifying energy communities

As per the act, the qualifying energy communities include the following:

* Census tracts — and all adjacent ones — in which any coal mine has closed after Dec. 31, 1999, or in which any coal power plant has been retired after Dec. 31, 2009.

* MSAs and non-MSAs where, after Dec. 31, 2009, industries tied to fossil fuels have accounted for at least 0.17% of direct employment or 25% of local tax revenues, and where the unemployment rate is above the national average for the previous year.

* Brownfield sites — broadly land where the presence or potential presence of pollutants, contaminants or hazardous substances impedes development. The U.S. Environmental Protection Agency estimates there to be more than 450,000 — and possibly as high as a million — brownfield sites in the country.



As of Sep. 14, 2022.
Census tracts — and all adjacent ones — in which any coal mine has closed after Dec. 31, 1999, or any coal power plant has been retired after Dec. 31, 2009.
Map credit: Ciaralou Agpalo Palicpic.
Source: S&P Global Market Intelligence.

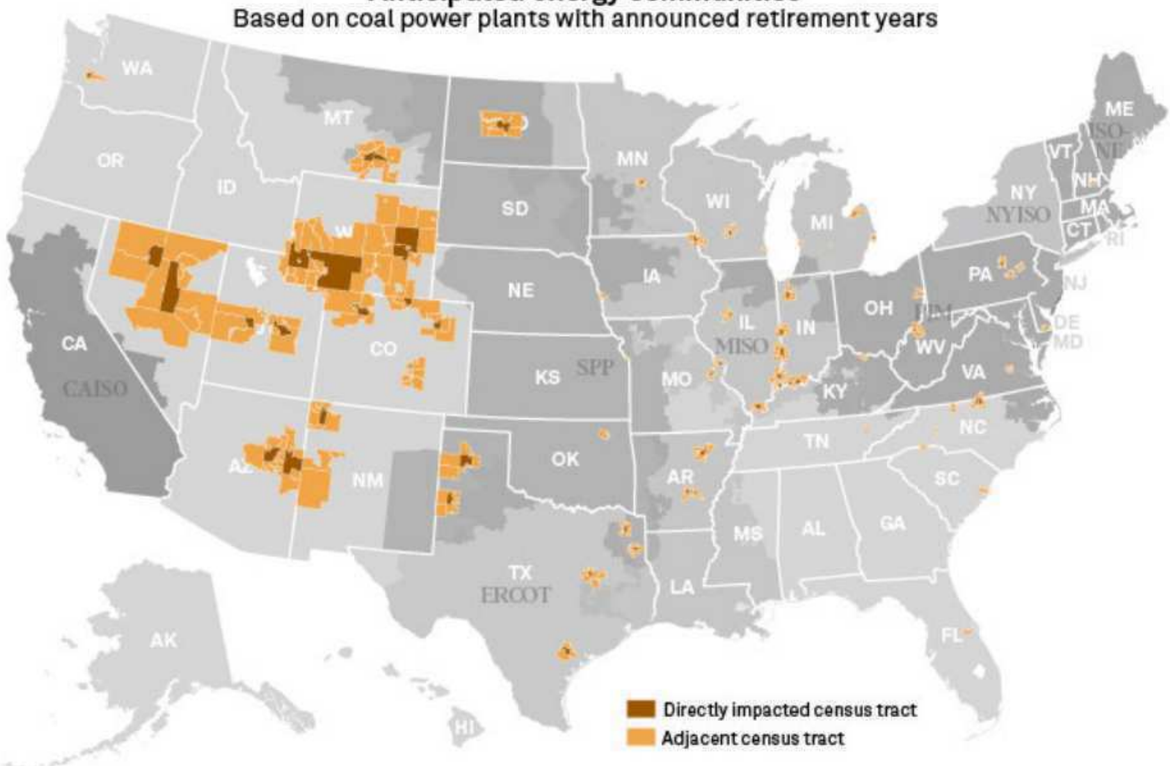
S&P Global Market Intelligence data shows 142 coal mines have closed in the U.S. since 2000. States across or bordering the Appalachian mountains were particularly impacted, with Alabama, Kentucky, Maryland, Ohio, Pennsylvania, Virginia and West Virginia accounting for nearly 79% of all U.S. coal mine closures in the last 22 years.

Plotting U.S. coal power plants retired since 2010 paints an economically and socially similar but geographically contrasting picture. The phasing out of fossil fuels as a major source of power generation in the U.S. has led, among other things, to the closing of 339 coal power plants from 2010 through 2022 year-to-date as of Sept. 14, according to S&P Global Market Intelligence data. Inventoried coal power plant retirements were more geographically diverse than identified coal mine closures, affecting not only coal-rich Appalachia but stretching all the way to the West Coast, particularly affecting the Rockies.

Overall, S&P Global Commodity Insights identified over 2,800 census tracts qualifying for the eligible 10% increase to the act's baseline production and investment tax credits based on the law's closed mine and retired coal power plant criteria. Numbering nearly 4.7 million households, these census tracts are scattered across 42 states. Rust Belt states of Pennsylvania, Illinois and Ohio, with their historical trends of industrial decline over the past half-century, top the energy community charts based on the act's closed or retired coal asset criteria, displaying the largest amount of qualifying census tracts, as well as the largest pool of impacted households. That said, our map of the identified areas displays larger census tracts west of the Mississippi — a feature giving developers more geographical options, particularly when pursuing outsized solar and wind projects.

An additional 77 U.S. coal power plants, including 21 in Rust Belt states, have announced plans to retire in future years. An incremental 309 census tracts across 27 states could become eligible for the 10% increase in the act's tax credits based on these announcements alone, with Texas ranking first in impacted census tracts and households. Colorado and Missouri are neck and neck for the number two spot. Michigan rounds out the top four. Ultimately, all U.S. coal power plants may face a retirement decision if the U.S stays the course on its clean energy goals and commitments. The U.S. currently operates 261 coal power plants, with an aggregate operating capacity of 200 GW, according to Market Intelligence data.

Anticipated energy communities
Based on coal power plants with announced retirement years



As of Sep. 14, 2022.
Census tracts — and all adjacent ones — in which operating coal power plants have announced retirements years.
Map credit: Ciaralou Agpalo Palicpic.
Source: S&P Global Market Intelligence.

Zooming in on the employment criteria for the act's energy community eligibility indicates at least 114 MSAs and non-MSAs qualifying, based on local and national unemployment rates from June 2021 to June 2022. It is important to note that the language used in the act suggests annual unemployment rates through regular calendar years as the benchmark for eligibility. However, this and other provisions of the law will likely need clarification from the U.S. Energy Department.

With employment and unemployment levels in constant flux, the act's employment criteria for extra energy community tax credits embody the proverbial "moving target." A potentially deteriorating employment environment on monetary tightening by the Fed, for example, could lead to an expansion of the pool of eligible MSAs and non-MSAs.

Commodity Insights identified an additional 120 MSAs and non-MSAs likely meeting the fossil fuel employment criteria — areas that would qualify for the act's 10% tax credit step-up if the local unemployment rate were to rise above the national average. Given the trend away from fossil fuels, our analysis assumes few changes to the identified fossil fuel employment footprint throughout the act's life.

While the act's clean energy production and investment tax credits have been making headlines, economic revitalization objectives underlie the law — hence its domestic manufacturing and sourcing quotas. By incentivizing developers and investors to focus on energy communities to build solar, wind and battery projects and clean-energy manufacturing facilities, the law seeks to accelerate the U.S. transition to clean energy while revitalizing communities historically reliant on fossil fuel industries.

Regulatory Research Associates is a group within S&P Global Commodity Insights.

Tanya Peevey and Ciaralou Palicpic contributed to this article.

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

Attachment DG-9

Excerpt of Direct Testimony of Devi Glick, Case No. 19-00170-UT at 44-46 (NM Pub. Reg. Comm'n Nov. 22, 2019)

BEFORE THE
NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 282; (2) AUTHORIZATION AND APPROVAL TO SHORTEN THE SERVICE LIFE AND ABANDON ITS TOLK GENERATING STATION UNITS AND (3) OTHER RELATED RELIEF	CASE NO. 19-00170-UT

PUBLIC (REDACTED) VERSION

Direct Testimony of Devi Glick

On Behalf of

Sierra Club

November 22, 2019

i. ***SPS's economic analysis does not properly evaluate the risk that the amount of economically recoverable water may fall faster than SPS currently contemplates***

Q Please summarize this section.

A First, I discuss my concerns with the way SPS incorporated, and relied upon, the WSP groundwater modeling into the Company's economic modeling and its plan to operate Tolk seasonally given the level of uncertainty in the WSP groundwater modeling. Second, I outline the implications of SPS's failure to incorporate the risks that agricultural and municipal pumping will deplete the aquifer faster than anticipated into its SPS's spreadsheet water model. Finally, I conclude that SPS has not presented adequate evidence to demonstrate that the aquifer can economically supply the water needed to support operations through 2031.

Q Do you have concerns with the Company's use of the WSP groundwater modeling to develop its plan to operate Tolk seasonally?

A Yes, SPS asserts that the WSP groundwater modeling "confirms that reduced operations can extend the useful lives of the Tolk units until 2030–2032 relative to typical operations."[62] However, the results presented by WSP actually do not fully support this statement. While the report finds that the difference between the available water supply and demand was likely to be significantly lower under an optimized demand scenario (relative to a tradition demand scenario), the report clearly states:

[62] Direct Testimony of M. Lytal at 75; Exhibit DG-6, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).

SPS will likely have challenges meeting the average annual groundwater demands throughout both scenarios, with these challenges accelerating in the year 2024. Meeting peak demands in the summer will also likely be a challenge for the wellfields starting in 2019.[63]

Moreover, WSP acknowledges that its model may have underestimated depletion rates, most notably because of the uncertainty about groundwater pumping rates from irrigators located close to the SPS Water Rights Area ("XWRA") boundary.[64]

Q What are the implications of WSP's findings that meeting peak water demands will be challenging starting in 2019, and accelerating starting in 2024?

A WSP's findings indicate that it will be difficult for SPS to ensure access to sufficient water at peak times through 2032, even assuming a baseline-level of additional wells. This means that water could be depleted more quickly than modeled in SPS's water model, and the Company would therefore need to spend more money than currently included in the Tolk Strategist analysis to maintain access to sufficient water. Any wells required beyond that baseline will make Tolk more uneconomic. Therefore SPS's Strategist economic analysis should have included robust evaluation of sensitives for deviations from (1) the water depletion windows calculated in SPS's water model, and thus (2) an increase in the number of wells required to supply peak water demands.

[63] Direct Testimony of M. Lytal, at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3; Exhibit DG-6, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).
[64] *Id.*

Instead, SPS's economic analysis relies on a best-case scenario input assumption around water availability, without also including any evaluation of the costs and impact on ratepayers if the water actually costs more to procure going forward. Just as prudent utilities evaluate a range of fuel and capital cost assumptions, energy prices, and load forecasts, SPS should have evaluated a high-band water depletion scenario that reflects the very real risk that SPS's baseline assumption is overly optimistic.

Q Please explain why pumping by irrigators located close to the SPS Water Rights Area ("XWRA") is relevant to SPS's analysis.

A The amount of water available to Tolk is critically influenced not just by how much water the Company uses at the plant, but also by how much water agricultural and municipal entities in the area are using.[65] SPS witness Lytal acknowledged this in stating that "one of the most significant variables in the WSP model relates to the amount of agricultural water used in the model domain outside of the SPS wellfield, which drives overall water usage in the area."[66] This means that SPS has no control over a main factor driving depletion of its water supply.[67]

Q How large of an impact could changes in agricultural and municipal pumping have on the aquifer depletion rates?

A SPS does not quantify how large of an impact changes in area water pumping could have on depletion rates; therefore, we have no information on how the

[65] Direct Testimony of M. Lytal at 66-67.
[66] *Id.*
[67] *Id.* at 76.