BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION (1) TO AMEND ITS CERTIFICATES OF PUBLIC CONVIENCE AND NECESSITY TO CONVERT HARRINGTON GENERATION STATION FROM COAL TO NATURAL GAS, (2) FOR AUTHORIZATION TO ACCRUE ALLOWANCE FOR FUNDS USED IN CONSTRUCTION, AND (3) FOR OTHER ASSOCIATE RELIEF	))))))))	**CASE NO. 21-00200-UT**

REDACTED VERSION

DIRECT TESTIMONY OF

DEVI GLICK

ON BEHALF OF SIERRA CLUB

January 14, 2022

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1. Introduction and Purpose of Testimony

Q Please state your name and occupation.

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

Q Please describe Synapse Energy Economics.

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

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

Q Please summarize your work experience and educational background.

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

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

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the New Mexico Public Regulation Commission ("Commission")?

A Yes. I submitted testimony in Case No. 19-00170-UT, Application of Southwestern Public Service Company ("SPS" or "The Company") for Authority to Revise Rates. I also reviewed the Tolk Analysis and submitted an expert report for Sierra Club as part of SPS's Integrated Resource Planning ("IRP") process in Case No. 21-00169-UT.

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

A In this proceeding, I review SPS's 2021 Harrington Analysis, presented in the testimony of Company witness Ben Elsey. I also evaluate the prudence of the Company's decision to convert Harrington to operate on gas, relative to retirement and replacement with alternatives based on the results of its own modeling. I present alternative analysis on the cost to replace the Harrington units using the same modeling platform as the Company (known as EnCompass) and based on revised assumptions and sensitivities.

Q How is your testimony structured?

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

In Section 3, I provide a summary SPS's coal fleet, and introduce SPS's proposal to convert the three units at the Harrington Generation Station to operate on gas.

In Section 4, I review the analyses that SPS conducted to justify converting Harrington to operate on gas to comply with sulfur dioxide ("SO_2") National Ambient Air Quality Standards ("NAAQS"). I discuss the main drivers of the company's results and outline the major shortcomings in its 2021 Harrington analysis.

In Section 5, I present the results of Synapse's updated alternatives modeling analysis. I discuss the correction, updates, and sensitivities that we tested, and I present the cost and emission results.

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 SPS witnesses. I also rely on other publicly available documents.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. SPS's 2021 Harrington Analysis that the Company uses to support its decision to convert the three Harrington units to operate on gas has a number of flaws and shortcomings. These include: (1) substantially understating the sustaining capital expenditures at the plant after it converts to gas; (2) assuming only minimal reductions in pipeline and capital costs with the retirement of incremental Harrington units; (3) modeling the wrong fixed operation and maintenance ("FOM") cost streams for the units after they convert to operate on gas; (4) overstating the cost of renewables and battery storage and assuming that the investment tax credit ("ITC") expires; (5) failing to model a CO_2 price; (6) failing to model alternative financial assumptions for the undepreciated plant balance at Harrington after the units retire.
2. SPS has not demonstrated that it needs the capacity provided by all three Harrington units. In fact, SPS's modeling shows that all three units are minimally used after conversion to operate on gas, and Unit 1 at Harrington is never actually operated after its conversion to gas operation.
3. SPS's own modeling results do not show meaningful savings from converting all three units to operate on gas relative to retirement, especially given the uncertainty in assumptions. In fact, SPS found it costs less to convert only two units and retire the other one in some of the scenarios, and in other scenarios SPS did not find an appreciable difference in the decision to retire two or all three of the units relative to conversion.

4. All of SPS's modeling assumes near-term accelerated depreciation of the retiring Harrington assets. Under alternative financing mechanisms, assuming some or all of the balance is disallowed, or assuming that a rate of return is disallowed post-retirement, any of the cost savings the Company claims from conversion versus retirement are reduced or disappear.
5. SPS omitted a carbon dioxide price sensitivity, and consideration from any future environmental regulations, from its Harrington Analysis. If the Commission is concerned about minimizing cost risk in the event that a carbon price or other environmental regulations having material compliance costs are implemented during the units' remaining lives, it would choose to retire between one and three Harrington units.
6. Synapse's modeling with updated assumptions for renewable and battery storage costs, as well as realistic ongoing sustaining capital expenditures at Harrington, finds that it costs less to retire all Harrington Units and fill any outstanding capacity gaps with Solar PV and battery storage than to convert the units to gas.
7. Synapse's modeling shows that retiring one unit is a no-regrets decision that has essentially the same net present value ("NPV") as converting all units to gas, and that retiring all units results in at least $25 million net present value revenue requirement ("NPVRR") savings relative to SPS's proposal to convert all three to operate on gas.

Q Please summarize your recommendations.

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

1. The Commission should deny SPS's request for an order amending its certificate of public convenience and necessity ("CCN") to convert the three Harrington units to operate on gas.
2. If the Commission does not deny SPS's request for a CCN, at the very least, the Commission should require the retirement of Unit 1, or affirm that it will not allow the Company to collect a rate of return on any plant balances which are not used and useful.
3. The Commission should find that SPS did not meet its obligation to demonstrate that converting all Harrington units to operate on gas is the least-cost option. This finding should be based SPS's use of unrealistic projections for ongoing capital costs, its failure to conduct a CO_2 price sensitivity, its flawed cost assumption for alterative resources, and its omission of any analysis on alternative financing mechanisms, such as a regulatory asset or securitization, which can spread out the costs over the economic life of the asset.
4. The Commission should require SPS to refresh its request for proposal ("RFP") and determine which resources are still available and their timeline for availability.

3. <u>SPS IS REQUESTING A CCN TO CONVERT ONE OF ITS TWO COAL-FIRED POWER PLANTS TO OPERATE ON GAS.</u>

Q Describe SPS's coal-fired fleet.

A The Company owns two coal-fired power plants. The Harrington Generating Station is a three-unit coal-fired power plant located near Amarillo, Texas. Unit 1 has a net capacity of 340 MW and is scheduled to retire in 2035. Units 2 and 3 have a net capacity of 355 MW each and are scheduled to retire in 2038 and

2040.[1] The plant burns sub-bituminous coal from the Power River Basin of Wyoming.[2]

The Company also owns the Tolk Generating Station, a 1,067 MW, two-unit coal-fired power plant located in Lamb County, Texas. SPS plans to operate both units seasonally through their scheduled retirement date in 2032. The Company switched to seasonal operation at Tolk in 2022 because it does not have access to enough economically recoverable water to operate the plant year-round through its scheduled retirement date.

Q What is SPS requesting in this case?

A SPS is requesting that the Commission amend its CCN at Harrington to allow the conversion of the three coal-power steam turbine units to natural gas ("Harrington Conversion"). The Company is requesting no change in the retirement dates of any of the units.

Q What analysis did SPS prepare to support its application for a CCN at Harrington?

A In 2019, SPS conducted an initial analysis using the Strategist model to support its request to accelerate the depreciation of the coal assets at Harrington.[3] The Company subsequently updated its analysis in 2021 ("Harrington 2021 Analysis") using the EnCompass model; I will discuss this updated analysis in depth in the next section. The Company presents this analysis to support its application for a CCN in this docket. SPS conducted the Harrington 2021 Analysis concurrently

[1] Direct Testimony of William A. Grant, page 9.
[2] Direct Testimony of Jeffrey L. West, page 4.
[3] Direct Testimony of Ben Elsey, page 12.

with the Tolk Analysis, which the Company used to support its decision to continue operating the Tolk units seasonally, rather than retiring and replacing them with alternatives.

Q What is the undepreciated balance remaining at the Harrington Plant?

A Harrington has an undepreciated balance of over $240 million as of June of 2021.[4]

Q Why is it concerning that the plant has such a large undepreciated balance?

A The large undepreciated balance at the Harrington plant has become, in the eyes of the utility, a barrier to the retirement of otherwise marginal or uneconomic generation units. Over the past several years, SPS has invested substantial costs in both the Tolk and Harrington generating stations despite numerous red flags. These include: the water shortage challenges at Tolk, SO_2 regulatory compliance concerns at Harrington, evidence that the plants are uneconomic, and stakeholders' repeated concerns that ratepayers would be forced to bear the costs of continued operation and investment at the plants. The utility then cited these largely self-inflicted undepreciated plant balances, and the near-term impact on ratepayers, as barriers to early retirement. We saw this first with the Tolk Analysis in Case No. 20-00169-UT, and now we see it with the Harrington Analysis. But this claim that ratepayers will be harmed by an early retirement is based on the assumptions that (1) the Company is entitled to full cost recovery of the remaining undepreciated plant balance plus a return on that investment, and (2) the cost recovery must happen entirely before each plant retires. Neither of these assumptions are justified.

[4] Ex. DG-2, SPS Response to SC 1-7, Exhibit SPS-SC 1-7(n).

As discussed above, SPS now seeks to invest substantial funds at Harrington to convert the plant to operate on gas and to build a gas pipeline to serve the plant—all while there is substantial evidence that retiring its coal generation assets and replacing them with clean energy resources is a lower cost option. Any costs approved to convert the plant to operate on gas and to build the necessary pipeline infrastructure will only end up further inflating the undepreciated plant balance and will make early retirement even more of a challenge.

Q Is SPS guaranteed recovery of the full undepreciated plant balance at Harrington if the plant retires early?

A No. The Company has not demonstrated that continued investment and operation of Harrington is prudent relative to alternatives. Therefore, it is not appropriate for SPS to assume full recovery of its undepreciated plant balance prior to retirement in all scenarios.

I am not an attorney, but it is my understanding that the Commission has the ability to weigh the relevant facts when an existing utility plant becomes no longer used and useful, and to specify alternatives other than full recovery and return on investment for the undepreciated plant balances if that is in the public interest. Even if the Commission deems that full recovery is appropriate, the Commission can require recovery to occur over a lengthier period representing the plant's original projected lifetime, rather than all at once.

SPS stated that it did not consider the development of a regulatory asset to allow the plant balance to be depreciated over the current project lifetime even after it retires.[5] When asked about depreciating the plant balance over the project's

[5] Ex. DG-2, SPS Response to SC 4-2(b).

current lifetime, SPS indicated that no such analysis was conducted, and that if such analysis was conducted it would require customers to continue to incur depreciation expenses for up to 16 years after they are used and useful.[6] But it is inappropriate for SPS to assume that the only option for cost recovery post-retirement is to include the full depreciation expense.

SPS's own modeling shows Unit 1 is never used after it is converted to operate on gas.[7] Therefore, is it unclear how the investments being made at Unit 1, and any associated incremental pipeline or common plant investments to convert Unit 1, meet the definition of used and useful as required for inclusion in rate base.

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

A Yes. In Southwest Electric Power Company's ("SWEPCO") most recent rate case PUC Docket No. 51415, the Public Utility Commission of Texas's proposed decision allowed SWEPCO to place the undepreciated plant balance for the Dolet Hills Power Plant into a regulatory asset after the plant retires; but it also recommended disallowing the Company's request to earn a rate of return on its investment once the plant retired.[8] SPS should also conduct analysis evaluating this option for early retirement.

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[6] Ex. DG-2, SPS Response to SC 4-1(b).

[7] Ex. DG-2, SPS Response to SC 1-3, SC 1-3(i) CONF – EnCompass Output Files for *EO_SPS_2021 CCN_PL_400TRX_2-21-06-21.xlsb*.

[8] Proposal for Decisions, SOAH Docket No. 473-21-0538, Pub. Util. Comm'n of Tex. Docket No. 51415, page 7, (Aug. 27, 2021).

Q Did SPS consider securitization of the undepreciated plant balance or any other alternatives?

A No. There is also no evidence that SPS has considered securitization, or any other approach that would result in recovery of the remaining plant balance but at a lower rate of return. When asked about this the Company stated "SPS is unaware of any legal authority permitting the securitization of the undepreciated balance at the Harrington units."[9]

The *New Mexico Energy Transition Act* ("ETA") was enacted to authorize securitization of undepreciated plant balances for abandoned coal plants located within New Mexico, and also for certain energy transition funding for local communities. Securitization results in very favorable interest rates for the bonds which finance these costs. However, the policy embedded in the ETA, that utilities shall only receive a *return of* undepreciated asset balances for abandoned plants, and not receive any *return on* such investment, or only the cost of debt, is implementable without securitization.

In Case No. 16-00276-UT, predating the ETA, the Commission ordered that Public Service Company of New Mexico ("PNM") would only be able to recover, at most, a return based on the cost of debt for certain Four Corners coal plant investments.[10] In another case predating the ETA, the Commission accepted a stipulation in connection with the early retirement of two of the four units at the San Juan Generating Station in which ratepayers were required to pay for only 50 percent of the undepreciated plant balances.

[9] Ex. DG-2, SPS Response to SC 1-11.

[10] Case No. 16-00276-UT, Revised Order Partially Adopting Certification of Stipulation at ¶ 67 (Jan. 10, 2018).

SPS should have provided an analysis evaluating retirement with recovery only at the cost of debt as an option, and also at varying percentages of recovery.

Q What evidence do you have that Harrington has been operating uneconomically?

A In Case No. 19-00170-UT, I presented analysis showing that Harrington incurred net losses of $191 million[11] over the four-year period between 2015–2018 on a total cost basis, and $35 million on just a variable cost basis.[12] I also found that Harrington was likely to lose ratepayers anywhere between $49 million and $510 million between 2020–2032 (with the likely value falling around $202 million).[13]

4. SPS'S HARRINGTON 2021 ANALYSIS DOES NOT SUPPORT THE COMPANY'S REQUEST TO CONVERT THE PLANT TO OPERATE ON GAS.

Q Is SPS required to convert Harrington to operate on gas or else shut the plant down?

A Yes. Air quality monitoring data demonstrates that Harrington is causing significant and routine violations of the health-based SO_2 NAAQS. To address those violations of the *Clean Air Act's* health-based standards, the Company was required to study the cost of retrofitting the plant to continue operation on coal, converting the plant (partially or entirely) to operate on gas, or retiring the plant and replacing it with alternatives. On October 27, 2020, the Texas Commission on Environmental Quality ("TCEQ") issued an administrative order requiring SPS to

[11] Ex. DG-3, Direct Testimony of Devi Glick, page 11. Case No. 19-00170-UT (filed Nov. 22, 2019).
[12] *Id.*, page 16.
[13] *Id.*, page 29.

cease burning coal at the Harrington units by January 1, 2025. Although the administrative order also directs SPS to make appropriate modifications to the units to burn gas, the order does not preclude SPS from retiring one or more Harrington units, so long as the Company ceases burning coal at all three units by January 1, 2025.[14]

Q Explain how the NAAQS regulations for SO_2 apply to the Harrington plant in this docket.

A Under the *Clean Air Act*, the U.S. Environmental Protection Agency ("EPA") is required to set NAAQS for pollutants considered harmful to public health and the environment. Compliance is monitored by the EPA and TCEQ. One of the pollutants regulated under the NAAQS is SO_2, which is a major pollutant emitted from coal plants.

In 2016, TCEQ installed monitors in the vicinity of Harrington and found that over the three-year period between 2017–2019, SO_2 levels exceeded the standard of 75 parts per billion ("ppb"). Because Harrington emits the majority of SO_2 emissions in Potter County, it was found to be a major contributor to the monitored violations of the SO_2 NAAQS.[15]

To address those air quality violations, TCEQ required SPS to develop a plan to comply with NAAQS standards. This plan was submitted to the TCEQ and agreed to in October 2020. The compliance date was set for January 1, 2025. The agreed

[14] *See* Direct Testimony of Jeffrey L. West, Attachment JLW-1 at 4.
[15] Direct Testimony of Jeffrey L. West, page 6.

order required SPS to convert Harrington to operate on gas and cease all coal burning by January 1, 2025.[16]

Q Are there any other environmental regulations directly relevant to the Harrington plant in this docket?

A Yes. There are likely to be future regulations on carbon emissions that are relevant to the Company's decision here. Additionally, even if Harrington were not violating the SO_2 NAAQS as discussed above, the *Clean Air Act's* Regional Haze program would likely require the Harrington units to reduce emissions to protect visibility in national parks and wilderness areas. Under the Regional Haze Rule, states (or EPA, where the state fails to act) must implement *Clean Air Act* plans that require many older and disproportionately large sources of pollution, like Harrington Units 1 and 2, to install and operate "best available retrofit technology" to reduce SO_2, nitrogen oxide, and particulate matter pollution that impair air quality in certain national parks and wilderness areas.[17] Separately, states and EPA are required this year, and again in 2028, to reevaluate all major sources of haze-causing pollution and to adopt pollution controls as necessary to ensure "reasonable progress" towards the national goal of eliminating haze pollution in all protected national parks and wilderness areas.[18]

Because Texas failed to submit a lawful haze plan addressing "best available retrofit technology" for sources like Harrington, EPA proposed a regulation on

[16] *Id.* page 8. As noted, although the TCEQ order directs SPS to convert the Harrington Units to burn gas, the order "does not . . . prohibit any modification of the facility . . . so long as such modification does not conflict with" the requirement to cease burning coal at all three units by January 1, 2025. *See id*., Attachment JWL-1 ¶¶ I.15 and II.1.
[17] *See generally* 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308(e).
[18] 40 C.F.R. § 51.308(d), (f).

January 4, 2017 that would have required Harrington Units 1 and 2 to install and operate flue gas desulfurization technology ("scrubbers") to reduce SO_2 emissions. EPA subsequently withdrew that proposal and finalized an emission trading rule in lieu of pollution controls. However, the federal agency's trading rule has been challenged in federal court and the new administration announced its intent to reconsider the imposition of source-specific controls to satisfy the *Clean Air Act's* best available retrofit requirements. Thus, setting aside compliance with the SO_2 NAAQS, the installation of scrubbers at Harrington Units 1 and 2 to comply with the Regional Haze Rule would cost approximately $400 million.[19]

Meanwhile, Texas and EPA are currently evaluating whether additional pollution controls to reduce SO_2 or nitrogen oxides from large electric generating units are necessary to fulfill the *Clean Air Act's* separate reasonable progress requirements. Even if the Harrington units are converted to burn gas, compliance with the Act's reasonable progress requirements could necessitate the installation of pollution controls to reduce nitrogen oxides. Under the Regional Haze Rule, EPA and other states have routinely required electric generating units without post-combustion nitrogen oxide controls, such as Harrington, to install and operate selective catalytic reduction ("SCR") or selective noncatalytic reduction ("SNCR") technology to reduce NOx emissions.[20]

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[19] Ex. DG-4, SPS, 2021 Integrated Resource Plan, Appendix K at 7, Case No. 21-00169-UT (July 16, 2021).

[20] In response to requests for information, SPS indicated that it anticipates Harrington's emission rates to be similar to Jones Unit 2, which the Company assumes will achieve a NOx emission rate of 0.1 lbs/mmbtu. SPS Response to SC 4-8 (referencing Resource Annual Emissions tab in the EnCompass Output Files provided in Exhibit SPS-SC 1-

SPS's 2021 IRP included a qualitative description of the potential impacts of the Regional Haze Rule at Harrington, but the current CCN application fails to mention the environmental compliance risks associated with Regional Haze and fails to model any scenario that includes the compliance *costs* that could be required to continue operating the Harrington units throughout their currently planned life-spans.

Q What analysis did SPS conduct to justify conversion of, and continued investment in, the Harrington plant?

A SPS modeled various scenarios and determined that compliance required either pollution controls, conversion to gas, or retirement. SPS's initial economic analysis was conducted in 2019 using the Strategist model. SPS then switched to the EnCompass model and updated its analysis in 2021 to support its application to convert the plant to operate on gas. The Harrington 2021 Analysis compared

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3(i)(CONF). SPS did not provide any analysis supporting this assumption. Modern NOx controls are capable of achieving an emission rate of 0.05 lbs/mmbtu NOx—about a 50 percent reduction from SPS's anticipated emissions—and EPA and other states have concluded that such controls are cost-effective under the Regional Haze program. *See, e.g.*, 76 Fed. Reg. 52,387 (Aug. 22, 2011) (requiring the San Juan Generating Station in New Mexico to install selective catalytic reduction technology and meet a NOx emission rate of 0.05 lbs/mmbtu). While we can't estimate the exact cost of SCR or SNCR technology for Harrington, the EPA's Integrated Planning Model (IPM) cost methodology provides a range for SCR and SNCR technologies (*see* Ex. DG-5, EPA IMP v6 – Emission Control Technology Attachment 5-3 SCR Cost Development Methodology (Jan. 2017) and Attachment 5-4 SNCR Cost Development Methodology (Jan. 2017)). The EPA estimates that installing SNCR at a 500 MW unit would cost approximately $11.7 million in 2021$ and installing SCR at a 600 MW unit would cost $368 million. Using this as a proxy for the three Harrington units implies a range of $25 million - $368 million to install NOx pollution control measures, a total which does not include annual O&M costs. Even if Harrington were not required to install additional controls, the continued operation of the units could require costs to optimize its current control equipment.

the revenue requirement of (1) complying with SO_2 NAAQS by adding environmental retrofits to the Harrington units; (2) retrofitting the three Harrington units to operate on gas and building out the necessary gas pipeline infrastructure; (3) retiring one of more of the units and replacing them with alternatives.

Q What did SPS find about the economics of continuing to operate the plant on coal?

A SPS found that it is more expensive to install environmental upgrades to comply with the SO_2 standards necessary to continue operating the plant on coal than to convert or retire the plant.

Q What is SPS proposing in its application?

A SPS is proposing to convert all three units at Harrington to operate on gas by the end of 2024. The conversion will not change the capacity of the plant.[21] To meet the plant's natural gas requirements, SPS is proposing to build a new 20-inch diameter natural gas supply line that will connect to two different gas supply transmission lines 20 miles northwest of the plant.[22]

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[21] Direct Testimony of Mark Lytal, page 10.
[22] *Id.*, page 9.

Q What assumptions did SPS make about the operational performance of the Harrington Plant if converted to gas operation?

A For heat rate, SPS assumed that the plant would operate in the range of [redacted][redacted] This is no more efficient than what SPS modeled for the plant when operating on coal between 2022–2024, where it had a heat rate range of [redacted].[24] SPS indicated that it relied upon the emission rates of its most similar gas-steam unit, Jones 2, for modeling the Harrington units after they convert to gas operation.[25]

As shown in Table 1, SPS projects that Harrington's emissions rate will fall by around 40 percent, its SO_2 rate will drop to zero, its NOx rate will decline by around one-quarter, and its particulate matter rate will drop by around 30-40 percent.

[23] Calculated based on outputs of SPS Response to SC 1-3, SC 1-3(i) CONF, Encompass Optimized Database 10.18.21.
[24] *Id*.
[25] Ex. DG-2, SPS Response to SC 4-8.

Table 1: CONF Average emissions rates of Harrington on coal and on gas

Unit Name	*lb/MWh* CO_2	*lb/MWh* SO_2	*lb/MWh* NO_x	*lb/MWh* PM	*lb/MWh* Hg
Harrington 1 – Coal	2,180	4.91	1.70	0.53	0.01
Harrington 1 – Gas	NA	NA	NA	NA	NA
Harrington 2 – Coal	2,135	4.77	1.41	0.12	0.01
Harrington 2 – Gas	1,259	0.1	1.14	0.08	0.00
Harrington 3 – Coal	2,280	4.98	1.49	0.15	0.01
Harrington 3 – Gas	1,258	0.01	1.14	0.08	0.00

Q How would the Harrington units, after conversion to gas, compare to other gas generating plants?

A The Harrington units would not be very attractive gas-fired generation assets. The units' projected heat rate will be more than [redacted] (i.e., less efficient) than the heat rates for current combined cycle gas plants, which average around 7,604 btu/kWh).[26] The Harrington units' heat rates will be [redacted] heat rates of many gas-fired combustion turbine peakers, but the units will have none of the performance benefits of a combustion turbine plant such as fast ramping.[27] Without even doing any modeling, I can say it is likely that these plants would only be called upon in an economic dispatch scenario when there are outages at more efficient plants or when there are other unusual system conditions.

[26] U.S. Energy Information Administration (EIA), Form EIA-860. Table 8.2 Averages Tested Heat Rates by Prime Mover and Energy Source, 2010-2020. Available at https://www.eia.gov/electricity/annual/html/epa_08_02.html.

[27] *Id.*

Q What did SPS's modeling show about the utilization of the Harrington plant after it is converted to gas operation?

A SPS's modeling results show that the Company assumed the plant would operate only minimally after conversion to gas operation (as shown in Table 2). Specifically, SPS modeled the Harrington units at a capacity factor of between 45.2 percent and 77.7 percent while operating on coal between 2022 and 2024. After the units are converted to operate on gas, SPS models the unit's operating at a maximum capacity factor of 3.9 percent, with Harrington 1 not operating at all after it is converted to operate on gas. This substantial change in capacity factor once the units convert to gas operation is mainly driven by the fuel delivery cost adder that SPS attaches to the Harrington units in EnCompass. This input increases the cost of delivered fuel at Harrington [redacted] with an average increase of [redacted] between 2025 and 2041, when compared to new gas combustion turbines.[28] Separate from the delivery cost adder, there is an additional cost of approximately [redacted] applied to Harrington fuel costs via a plant-specific commodity charge.[29] These delivery and commodity adders were included in SPS' EnCompass input files and remained unchanged in all modeled scenarios discussed in this testimony.

[28] SPS Response to SC 1-3(i) CONF, EnCompass Optimized Database Input Files, *SPS_ReferenceCase_1H21_2021-06-21.*
[29] *Id.*

Table 2: Average annual capacity factors at Harrington on coal and gas

Unit	Harrington (3 units) on Coal (2022-2024)		Harrington (3 units) on Gas (2025 – 2040)	
	Min	Max	Min	Max
Harrington 1	51.2%	64.5%	0%	0%
Harrington 2	45.2%	70.8%	0%	1.9%
Harrington 3	57.6%	77.7%	0%	3.9%

Source: Calculated based on SPS Response to SC 1-3(i) CONF, EnCompass Output Files, EO_SPS_2021_CCN_PL_400_TX_2021-06-21.

Q How does SPS explain investing tens of million dollars in a gas pipeline and plant upgrades for a resource that will operate on average less than 2 percent of the time?

A SPS does not explain this at all. But these results show that SPS is either (1) planning to maintain Harrington as strictly a capacity resource and rely on the plant only minimally as an energy resource; or (2) significantly understating how often the Harrington plant will actually operate and the associated costs that SPS will incur to operate it.

Both options are concerning. The first, because the Company is investing substantially in a plant that will almost never run. The second, because in the Harrington Analysis, the plant operated very minimally in the model based on plant economics. This means that SPS can meet its energy needs through a combination of its lower cost generation resources and market purchases. But there is no requirement that SPS actually operate the plant in alignment with its modeling. And unlike a new combustion turbine or other gas peaking resource, Harrington is not small and nimble, will not be able to provide fast-ramping generation capability, and will require potentially significant continued investment to stay operational. It is hard for a utility to justify continued investment in a plant that is only minimally utilized.

Another concern is whether SPS will be able to secure a firm gas contract that will give it access to enough gas to run each plant at full capacity during only peak times. SPS is proposing to build a pipeline and invest in upgrades for Unit 1, all while appearing to intend to never actually to use it.

Q Given SPS's projected reductions in air pollution with the gas conversion, isn't it reasonable to assume that there will be little, if any, environmental compliance costs associated with converting the Harrington units?

A No, not necessarily. While SPS projects that emissions will decrease by around 40 percent, that projection is based solely on the economic model's projected operation of the units. If the Harrington units are, in fact, operated only 2 percent of the time, as the model forecasts, emissions will decrease. Setting aside the prudence of spending approximately $75 million to convert a plant to operate a plant only 2 percent of the time, that low projected capacity factor will not necessarily avoid environmental compliance risk.

Under the *Clean Air Act's* Regional Haze program, for example, states must require large sources to install cost-effective pollution controls to protect air quality in national parks. To the extent that a state declines to impose additional pollution controls for any source based on that source's decline in utilization, the state must incorporate those operating parameters or assumptions as enforceable limitations in its regional haze regulation 40 C.F.R. §§ 51.308(i); (d)(3); (f)(2).[30] In other words, in evaluating the necessity of pollution controls, EPA generally evaluates the pollution benefits of controls based on a source's potential to emit, not the source's unenforceable intention to operate for only limited hours. Thus, without a federally enforceable limitation on the hours of operation at Harrington, the conversion of those units to gas carries continued risk that the units could be required to install additional pollution controls to further reduce NO_X and particulate matter.

Q Do you have any other specific concerns with SPS's Harrington 2021 Analysis?

A Yes. As an overarching point, it is implausible to assume that a coal plant that is marginal today will somehow become more economic as its equipment ages, renewables come onto the grid, and the grid itself faces carbon constraints—just because it is converted to operate on gas. It is still fundamentally an old, inefficient, steam plant. The Harrington units, when converted to natural gas, will be neither as efficient as a modern combined gas cycle plant, nor as flexible and responsive as a CT.

Preserving all three units at Harrington as a gas-fired plant best serves the Company's shareholders' interest by guaranteeing continued recovery of the undepreciated plant investments and providing a rate of return on the existing balance and any new capital investments. But it is not the best alternative for SPS

[30] *See also* EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 22, 34, 42-43 (Aug. 20, 2019). Available athttps://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

customers. Given this reality, SPS had to rely on overly conservative and unrealistic assumptions to produce the results it presented.

Aside from that general concern, I have the following specific concerns with SPS's Harrington 2021 Analysis:

1. **Interpretation of results:** The results do not definitively show that converting Harrington to operate on gas costs less than retiring one or more of the units. In fact, some of SPS's scenarios showed savings from retiring at least one unit under some scenarios. This is before factoring in the risk of CO_2 prices or other possible environmental regulation over the plant's remaining life.
2. **CO_2 price:** SPS did not model a CO_2 price.
3. **New gas pipeline costs:** SPS claimed no cost savings when scaling pipeline costs down from three units to two units.[31] But SPS could build a smaller pipeline to serve only one unit, saving approximately $17.5 million.[32]
4. **Undepreciated plant balance:** SPS relied on the assumption that if the plant, or an individual unit, retires early, the entire remaining balance for that unit (or plant) has to be paid off by the ratepayers on an accelerated basis prior to retirement. Under alternative financial scenarios, retirement is more beneficial to ratepayers.
5. **Capacity need:** SPS has not demonstrated the need for the capacity from all three units.

[31] Ex. DG-2, SPS Response to SC 1-4(e)(i), Attachments *Encompass Cost Inputs – Gas Conversion, and Encompass Cost Inputs – Partial Gas Conversion*.

[32] Direct Testimony of William A. Grant, page 5.

6. **Sustaining capital expenditures:** SPS's sustaining capital investment assumption for each unit when operating on gas are extremely low and unsupported. Specifically, without justification, the Company assumes that capex costs under gas operations will be only a fraction of the costs it has been incurring historically at its gas steam plants. Second, the Company assumed no additional environmental compliance costs over the next 20 years. Additionally, SPS assumed only minimal incremental capex cost savings when retiring one unit and two units relative to retiring all three.
7. **Fixed O&M:** SPS's fixed O&M cost adjustments when converting from coal to gas are incorrect.
8. **Solar PV capital costs:** SPS assumed that the federal ITC expired and was not extended for future solar PV projects.
9. **Battery storage capital cost:** SPS modeled battery storage capital and FOM cost together as a single FOM stream. This obscured the Company's individual assumption around capital cost and FOM costs.

Q Explain your concerns with the level of savings that SPS used to justify the decision to convert Harrington to operate on gas.

A SPS asserts that its results show that it is lower cost to retrofit Harrington to operate on gas than to retire the plant by the end of 2024. But the NPV of converting all three Harrington units to operate on gas is only marginally lower than the NPV of retiring and replacing all three units, even in SPS's own modeling. SPS's own results show that it is actually lower cost to retire one unit and only convert two (instead of all three). The deltas SPS found between the retirement scenario (full and partial) are very small relative to the Company's entire revenue requirement and could easily flip under slightly different and more realistic assumptions, as I show in this and the next section.

The projected savings is not immaterial, but when the input assumptions are flawed and highly uncertain over an extended planning period, this finding does not represent a significant result. In other words, the uncertainty or margin of error around each individual assumption is likely larger than the savings SPS reported.

Q Explain your concerns with SPS not evaluating a CO_2 price sensitivity as part of its Harrington 2021 Analysis.

A SPS failure to evaluate a carbon price sensitivity as part of the Harrington 2021 Analysis means that it did not incorporate carbon risk into its evaluation of whether to convert Harrington to gas or retire the plant. When asked about this, SPS stated that the Company did not "evaluate a speculative carbon pricing as part of the Harrington analysis as no such policy or regulation exists today or has ever been proposed in an actionable form."[33] This is concerning because SPS did evaluate carbon sensitivities as part of the IRP modeling in Case No. 21-00168-UT, and the carbon price has a large impact on the IRP results. While Harrington will emit less CO_2 operating on gas than it does currently operating on coal, it is still an aging, 30-plus-year-old fossil unit that emits a substantial quantity of CO_2.

As a steam-cycle plant, Harrington's converted units will have neither efficient heat rates or the flexibility to support wind and solar generation. A poor heat rate not only means higher fuel costs, it also means higher CO_2 emission per megawatt-hour of electricity produced. If a CO_2 price is imposed on Harrington's emissions at some point over the next 18 years (which is likely) that cost penalty would affect Harrington more than other gas plants in the Company's fleet (or in

[33] SPS Response to SC 4-4(b).

the SPP) and lead to even lower utilization than the 2 percent the Company projects.

The $60 million in new gas pipeline investment costs needs to be factored against that risk. Additionally, CO_2 price sensitivities serve as a proxy for other types of environmental regulation targeting CO_2 emissions and making fossil fuel plants more costly.

Q Explain your concerns with SPS's assumptions about the cost of the gas pipeline.

A SPS claimed there were no cost savings possible when scaling pipeline costs down from three units to two units and did not conduct any robust analysis on the potential cost savings if only one unit was converted. The Company did say it could likely build a smaller pipeline with only one unit but went on to admit that the Company "has not conducted detailed analysis to determined what cost savings, if any, might be achieved through the installation of a smaller pipeline. Indicative numbers for a smaller pipeline were developed and used in evaluating for a single unit conversion."[34] The indicative savings SPS modeled were approximately $17.5 million or 27 percent of the full pipeline cost with the conversion of just one unit.[35]

Additionally, SPS indicated that it has not yet obtained authorization from any federal agencies for the pipeline. In fact, SPS has not had any correspondence with the U.S. Army Corp, the Fish and Wildlife Service, the EPA, or TCEQ about

[34] Direct Testimony of Mark Lytal, page 12.
[35] Direct Testimony of William A. Grant, page 5.

the project.[36] It is my understanding that to move forward with the pipeline SPS would need certification from U.S. Army Corp of Engineers under *Nationwide Permit 12*, authorization from the EPA and TCEQ under the *Clean Water Act*, and authorization from the Fish and Wildlife Service and Texas Parks & Wildlife Department the *Endangered Species Act*. This lack of communication is concerning because it is likely that the permitting process will require more time and resources than SPS has anticipated.

Q Explain your concerns with SPS's assumption around Harrington's undepreciated plant balance.

A SPS relies on the assumption that if the plant, or an individual unit, retires early, the entire remaining balance for that unit (or plant) has to be paid off by the ratepayers on an accelerated basis prior to retirement. This front-loads the capital expenses for ratepayers, which results in a substantial increase in the NPVRR over the near term (2022–2024). But SPS is not guaranteed recovery of the full undepreciated balance at Harrington, with or without a return—especially if the assets are no longer used and useful. Additionally, there are alternative financing options, such as securitization and creation of a regulatory asset that can lower the cost of recovering the undepreciated plant balance, even after a plant retires. SPS should have explored all of these options and presented these scenarios. This is information the Commission needs to evaluate in order to grant the requested CCN.

[36] Ex. DG-2, SPS Response to SC 4-12; SPS Response to SPS 4-13; SPS Response to SC 4-14; SPS Response to SC 4-15.

Q Explain your assertion that SPS has not justified the need for all the Harrington capacity.

A SPS developed two different long-term load forecasts: first, a Financial Forecast that represents SPS's median expectation for future energy and peak demand, and second, a Planning Forecast that "accounts for the uncertainty in the pace of oil and gas expansion in the service territory."[37] The Planning Forecast represents the 85th percentile of the Financial Forecast and shows energy sales that are 31 percent higher and peak demand that is 20 percent higher than the Financial Forecast for 2041.[38]

SPS relied on the higher Planning Forecast as the basis of the Harrington 2021 Analysis, but it also modeled sensitivities using the Financial Forecast. SPS acknowledged that it has sufficient resources to meet its planning reserve margin in 2024, and that retiring one Harrington unit would not impact that.[39] But the Company claimed that if it retired one Harrington unit, it would need additional resources starting in 2025. As shown in Table 3, this need is only one year earlier than SPS's anticipated resource need even with all units converted to operate on gas (2026). When using the Financial Forecast, SPS's resource need is pushed back to years until 2027.[40] These two years could be valuable in allowing SPS time to build new resources and apply for interconnection approval for replacement resources.

[37] Direct Testimony of John M. Goodenough, pages 6-7.
[38] *Id.*, page 15.
[39] Ex. DG-2, SPS Response to SC 1-12.
[40] Ex. DG-2, SPS Response to SC 1-13, Exhibit SPS-SC 1-13.

Table 3: Resource position for Planning Forecast and Financial Forecast

Resource Position	2025	2026	2027	2028	2029	2030
Planning Forecast						
Assuming all Harrington Units are Converted	234	(70)	(199)	(502)	(699)	(774)
Assuming Harrington Unit 1 is Retired	(106)	(410)	(539)	(842)	(1,039)	(1,114)
Financial Forecast						
Assuming all Harrington Units are Converted	606	347	279	23	(134)	(168)
Assuming Harrington Unit 1 is Retired	266	7	(61)	(317)	(474)	(508)

Source: Exhibit SPC-SC 1-13.

Q Explain your concerns with SPS's sustaining capital expenditure assumption for the plant when operating on gas.

A SPS's sustaining capital expenditure assumption for each unit when operating on gas is implausibly low. SPS assumed annual capital expenditures of $3.75 million per year (escalated at 2 percent per year) after the units were converted to operate on natural gas. SPS's source for its $3.75 million estimate is "discussions with the Xcel Energy Projects team."[41] The lack of support for this low estimate is concerning for a number of reasons:

- The historical average capex spending at Harrington when operating on coal is five times higher—around $18.6 million per year.[42]
- Industry standard estimates produced by the firm Sargent & Lundy for the U.S. Energy Information Administration (U.S. EIA), were within 25 percent

[41] Ex. DG-2, SPS Response to SC Request 3-3 (a).

[42] Ex. DG-2, SPS Response to SC Request 1-7 (i, j)

of SPS's actual reported sustaining capital costs when the plant was operating on coal but are around four times higher than what SPS estimates with the plant operating on gas. Specifically, Sargent and Lundy estimated capex for a gas steam plant over 1,000 MW and over 30 years in age at $12.5 million a year.[43]

- SPS's reported capital spending at its gas steam plants in the prior rate case (test year April 1 2018 – March 31, 2019), worked out to an average of $8.6 million per year in capital investments when scaled to a plant the size of Harrington.[44]

Table 4 below summarizes the cost comparisons discussed above.

[43] Ex. DG-6, Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[44] Ex. DG-7, Attachment LJW-2 to Direct Testimony of Laurie Wold on Behalf of SPS, Case No, 19-00170-UT.

Table 4: Sustaining capital expenditure estimates vs actual spending for steam coal plans and steam gas plants

Item	Description	Annual Capex Spending ($2021) $Million
Coal Capex		
Harrington historical capex spending (coal)	Average of 2015 – 2020 actual spending	$18.59
U.S. EIA estimate of sustaining capex for steam coal plant	Sargent and Lundy report, plant 30-40 years old, no FGD	$24.12
Gas Capex		
Harrington projected capex spending (gas)	**Projection for 2024 – 2040, escalated at 2%/year**	**$3.75**
U.S EIA estimate of sustaining capex for steam gas plant	Sargent and Lundy report, plant >30 years old, >1000 MW	$12.47
SPS historical capex spending on steam gas plants	Rate case spending, April 1, 2018 – March 31, 2019 for company's steam gas units	$8.58

Source: Calculations based on SPS Response to SC Request 3-3 (a); Ex. DG-7, Exhibit Attachment LJW-2 to Direct Testimony of Laurie Wold on Behalf of SPS, Case No, 19-00170-UT; Ex. DG-6, Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019.

Q Do SPS's assumptions around sustaining capital expenditures have a large impact on its overall findings?

A Yes. As shown in Table 5, SPS estimated the NPV of sustaining capital expenditures for Harrington operating on gas at between $16.1 million (with one unit converted) and $33.9 million (with all units converted) over the remaining life of the plant.[45] These values are substantially lower than the $42.8 million (one unit converted) to $58.0 million (three units converted) range we estimate based

[45] Ex. DG-2, SPS Response to SC Request 3-3(a).

on SPS's historical spending on its gas steam plants,[46] and the $79.9 million (one unit converted) to $167.8 million (three units converted) we estimated based on the EIA's methodology.[47] While its reasonable that SPS would want to minimize investments at a plant with such a low projected capacity factor, there is a baseline level of investment and maintenance required to ensure the plant is actually reliable and functional when needed. In total, this means that SPS has very likely understated the ongoing costs required to maintain the Harrington plant by between $42.8 million and $133.9 million.

Table 5: Total capex spending at Harrington using original and updated assumptions

Total capex spending (NPV $2021 Million)	Convert 3 units to gas	Convert 2 units to gas	Convert 1 unit to gas
Total			
SPS projection for sustaining capex on gas in Harrington 2019 Analysis	$33.9	$25.7	$16.1
U.S. EIA estimate of sustaining capex for steam gas plant	$167.8	$127.6	$79.9
SPS historical capex spending on steam gas plants	$91.8	$77.5	$58.9
Delta between SPS projection and updated sustaining capex assumptions			
U.S. EIA estimate of sustaining capex for steam gas plant	$133.9	$101.8	$63.7
SPS historical capex spending on steam gas plants	$58.0	$51.7	$42.8

Source: Calculations based on SPS Response to SC Request 3-3 (a); Ex. DG-7, Exhibit Attachment LJW-2 to Direct Testimony of Laurie Wold on Behalf of SPS, Case No, 19-00170-UT; Ex. DG-6, Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019.

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[46] Calculated based on Ex. DG-7, Attachment LJW-2 to Direct Testimony of Laurie Wold on Behalf of SPS, Case No, 19-00170-UT.

[47] Ex. DG-6, Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

Looking at SPS's modeling results summarized in Table 6 below, the Company's likely underestimation of capex is significant; indeed, using SPS's own historical capex or EIA's estimates would flip the results in favor of retirement for some or all of the Harrington units.

Table 6: NPVRR Results from Table BRE-2

Scenario	Description	2022 – 2041 Delta ($M)
Scenario 2	Convert all Harrington Units to natural gas	$0
Scenario 1	Retire all Harrington Units	$124
Scenario 5	Convert 1 Unit to gas / Retire 2 Units	$62
Scenario 6	Convert 2 Units to gas / Retire 1 Unit	($5)

Source: Direct Testimony of Ben Elsey, page 29.

Q What is driving this large gap between SPS's assumptions around future sustaining capital expenditures and your updated assumptions?

A Part of this gap is due to SPS's failure to consider any future environmental compliance costs. Specifically, SPS indicated that it is unaware of any other impending regulations that will impact the Harrington units; therefore, it has modeled no additional environmental compliance costs beyond those relating to SO_2 controls.[48] The small margin that SPS used to justify the option to convert Harrington to operate on gas instead of retiring the plant shows how risky it is for SPS to plan as though Harrington is unlikely to incur other future environmental compliance costs over the next two decades.

[48] Ex. DG-2, SPS Response to SC 1-6.

Q Explain your concerns with SPS's FOM cost streams between 2022-2024 in the scenarios where the units are assumed to convert from coal to gas.

A SPS appeared to model the wrong FOM cost stream in EnCompass between 2022-2024 for units converted to operate on gas.[49] Specifically, the Company appears to have used the FOM cost stream intended for units that continue to operate on coal instead of using the intended ones with reduced FOM for units that convert to gas. Indeed, SPS admitted in a discovery response that the Company originally planned to model lower FOM costs for the years 2022-2024 for all scenarios where the units were converted to operate on gas.[50] These were provided in a separate discovery request.[51]

Q Explain your concerns with SPS's incremental reduction in sustaining capital expenditures when retiring one and two units.

A SPS assumed that there would be only small incremental reductions in sustaining capital expenditures with the retirement of additional units. Specifically, SPS modeled a reduction in sustaining capital expenditures of only 10 percent with the retirement of one unit, and 37 percent with the retirement of two units (relative to total projected spending for the entire plant) between the years 2024-2024.[52] While it's understandable that some economies of scale will be lost with reducing

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[49] Ex. DG-2, SPS Response to SC 1-3(i) CONF, Encompass Optimized Database 10.18.21.

[50] Ex. DG-2, SPS Response to SC 4-7(c).

[51] Ex. DG-2, SPS Response to SC 1-4(i) Attachments *Encompass Cost Inputs – Gas Conversion, EnCompass Cost Inputs – Partial Gas Conversion, EnCompass Cost Inputs – Early Retirement.*

[52] Calculations based on SPS Response to SC 1-4(e)(i), Attachments *Encompass Cost Inputs – Gas Conversion, and EnCompass Cost Inputs – Partial Gas Conversion;* SPS Response to SC 1-3(i) CONF, *Encompass Optimized Database 10.18.21.*

the plant size, it is unclear why SPS can only reduce capital investments by 10 percent while reducing the plant capacity by a full third, and 37 percent when reducing plant capacity by a full two-thirds. These assumptions are unsupported and substantially understate the likely savings that SPS could experience if it shut down one or two units.

Q Explain your concerns with SPS's assumptions for the capital costs of new solar PV and battery storage resources?

A SPS models new generic solar PV project additions assuming that the ITC expires. This results in a large jump in solar PV costs after 2027. This decision makes solar look more expensive than it likely will be, and disadvantages solar PV as a choice relative to new gas resources.

SPS also models new generic battery storage resources with a single fixed cost stream that includes all capital costs, fixed costs, financing costs and returns into one single value. This makes it very challenging to evaluate the reasonableness of SPS's individual cost stream and assumptions regarding new battery storage costs.

Q What is your conclusion with regard to the evidence on which SPS relied and the prudence of the Company's decision to convert Harrington to operate on gas?

A SPS has not demonstrated that conversion of all three units at Harrington to operate on gas is the least-cost option for ratepayers based on the Harrington 2021 Analysis. SPS relied on many concerning assumptions to produce the results that it published, omitted a sensitivity around CO_2 prices, and even had errors in its modeling. But even with all these assumptions that skewed the analysis in favor of converting all three units at Harrington to operate on gas, SPS's analysis shows that the savings from converting all three units are very marginal, and likely not significant.

5. <u>SYNAPSE'S MODELING FINDS THAT IT IS THE LOWEST COST SCENARIO TO RETIRE ALL HARRINGTON UNITS, AND IT IS A NO-REGRETS DECISION TO RETIRE UNIT 1 AT HARRINGTON.</u>

Q Explain the alternative modeling that Synapse conducted.

A We began with SPS's Encompass files used by the Company to conduct its Harrington 2021 Analysis.[53,54] We reviewed the inputs and methodology as discussed in the prior section. We developed updates and corrections to address the items outline above.

We used four of SPS's scenario from the Harrington 2020 Analysis as the basis for our modeling and we used SPS's results as reference costs.

1. Scenario 1 – Retire all Harrington units
2. Scenario 2 – Harrington Units 1-3 are converted to operate on gas[55]
3. Scenario 5 – Retire Units 1 & 2 and convert Unit 3 to operate on gas
4. Scenario 6 – Retire Unit 1 and convert Units 2 and 3 to operate on gas.

For each model run, we used the following assumptions as shown in Table 7:

[53] SPS Response to SC 1-3(i) CONF *Encompass Optimized Databased 10.18.21* files.
[54] The modeling files provided by SPS did not contain the databases for Scenario 2. We therefore relied on the EnCompass files that were provided as part of the Tolk Analysis during the IRP Docket, Case No. 21-00169-UT as the basis of our evaluation of Scenario 2.
[55] *Id.*

Table 7: Scenarios modeled

Base Scenario	Tolk Retirement	Harrington Retirement / Conversion	Tx Cost[56]
Scenario 2	2032	All units converted at end of 2024	$400/kW
Scenario 1	2032	Full Retirement at end of 2024	$400/kW
Scenario 6	2032	Unit 3 converted at end of 2024	$400/kW
Scenario 5	2032	Units 2 and 3 units converted at and of 2024	$400/kW

Q Explain each of the changes you made to the model.

A We first updated several assumptions in SPS's base runs.

First, for all generic solar, wind, and battery storage resource additions we relied on the National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB") capital cost assumption for generic solar PV and wind resources. SPS assumed that the federal investment tax credit expires in 2025, while NREL assumed that it is extended beyond 2025 for solar PV.[57]

Second, we updated the FOM assumptions for the Harrington units between 2022 – 2024 to correct the error we discussed above. We used the cost stream that was $1.5 million lower for all units that SPS planned to retire in 2024, and the higher cost stream for all units that SPS planned to convert to operate on gas.

Third, we did not allow the model to build any new gas projects prior to 2030 in any scenarios. Although we did allow new gas after 2030, we assume that any new gas projects that the model selects after 2030 are not actually gas resources,

[56] SPS modeled transmission costs of $200/kW, $400/kW, and $600/kW. We used SPS' central value of $400/kW in all scenarios.

[57] National Renewable Energy Laboratory, Annual Technology Baseline.

but instead are simply place-holders for firm and dispatchable capacity resources that SPS may need in the future.

Fourth, we modeled sustaining capital expenditures for Harrington on the basis of SPS's historical spending. As discussed above in Table 4 and Table 5, the historical Harrington sustaining capital values we use in our modeling are higher than those used in the SPS scenarios but remain below EIA's projections.

Finally, we capped annual storage additions at 300 MW over the modeling horizon. This annual limit was used to ensure that the model would not overbuild battery storage in any single year. There was no cumulative constraint, however, on any resource type over the period of analysis.

Q Explain which sensitivities you tested.

A We tested a number of sensitivities based on likely future outcomes that SPS should consider in deciding whether to retire or convert Harrington to operate on gas.

1. **CO_2 price:** To assess the impact that future carbon regulations would have on the cost to continue to operate Harrington, we tested a carbon price sensitivity. We used the middle carbon price that SPS relied on for its most recent IRP, which was $20/metric ton base year of 2011, escalated at 2.5 percent per year.[58]
2. **Financial Load:** Like SPS, we tested our sensitivities using both the higher Planning Load and the lower Financial Load.

[58] Ex. DG-4, SPS 2021 IRP, page 85.

3. **Depreciation schedule:** Given the uncertainty around SPS's recovery of the remining plant balance at Harrington, we tested several alternative assumptions for recovery of the undepreciated plant balance at Harrington:
    a. Depreciate remaining balance over each unit's remaining life instead of three years for any unit that retired early *without* a return on investment post-retirement.
    b. Disallow the entire undepreciated plant balance after a unit retired.
    c. Disallow half the undepreciated plant balance after a unit retires and disallow a rate of return on the remaining balance.
4. **Gas sustaining capital expenditure costs:** SPS's assumptions around the sustaining capex costs required after the units are converted to gas operation are extremely low and unsupported. Therefore, we tested a sensitivity using SPS historical data based on its existing steam gas plants for sustaining capex costs. We did not model the risk of compliance costs from future environmental regulations. Technologies to limit NOx emissions could cost between $24.9 million and $368 million for SNCR and SCR technologies respectively.[59] The inclusion of these costs, and the associated annual O&M, would make gas conversion more expensive in our modeling compared to a partial retirement or full retirement scenario.

Q What did you find when you made the changes and tested the sensitivities outlined above?

A I find that retiring all units results in a lower NPVRR than converting Harrington to operate on gas, as shown in Table 8 below. Specifically, our results show that

[59] This range was calculated using the updated methodology developed by Sargent and Lundy in January 2017 for the EPA IMP Model v6. The Emission Control Technology Attachment 5-3 SCR Cost Development Methodology and Attachment 5-4 SNCR Cost Development Methodology are attached in Ex. DG-5.

SPS would save roughly $25 million if it chose to retire all three Harrington units instead of converting them. While SPS would incur higher capital costs and non-fuel variable costs, it would also see significant savings from fuel and FOM costs, as shown in Table 9 below. Our modeling also indicates that SPS would gain additional revenue in the Early Retirement scenario by selling excess solar and wind generation to the market. Results are similar with both the planning load and the financial load.

Table 8: NPVRR results from Synapse modeling runs

	2022-2024		2022-2041	
Cost ($Million)	**Delta**	**NPV**	**Delta**	**NPV**
SPS Modeling Results				
Convert all Harrington (IRP Scenario 2)	$0	**$2,450**	$0	**$11,949**
Retain 1 Gas Harrington / Retire 2	$92	**$2,542**	$62	**$12,011**
Retain 2 Gas Harrington / Retire 1	$39	**$2,490**	($5)	**$11,944**
Early Retire All Harrington	$168	**$2,618**	$123	**$12,072**
Planning Load				
Convert all Harrington	$0	**$2,257**	$0	**$10,522**
Retain 1 Gas Harrington / Retire 2	$95	**$2,352**	$3	**$10,525**
Retain 2 Gas Harrington / Retire 1	$40	**$2,297**	($48)	**$10,474**
Early Retire All Harrington	$188	**$2,445**	($25)	**$10,497**
Financial Load				
Convert all Harrington	$0	**$2,098**	$0	**$9,228**
Retain 1 Gas Harrington / Retire 2	$101	**$2,199**	($1)	**$9,227**
Retain 2 Gas Harrington / Retire 1	$40	**$2,138**	($26)	**$9,202**
Early Retire All Harrington	$194	**$2,292**	($12)	**$9,215**
CO_2 Price				
Convert all Harrington	$0	**$2,579**	$0	**$11,072**
Retain 1 Gas Harrington / Retire 2	$98	**$2,677**	($51)	**$11,021**
Retain 2 Gas Harrington / Retire 1	$38	**$2,616**	($31)	**$11,041**
Early Retire All Harrington	$185	**$2,764**	($27)	**$11,045**

Source: Synapse results from modeling completed based on SPS Response to SC 1-3(i) CONF, Encompass Optimize Databased 10.18.21.

Table 9: NPVRR breakdown for Synapse Early Retire All scenario

Cost Category Description	2022 – 2041 Delta from Convert All Baseline ($Million)
Capital Costs	$93
Fuel Costs	($61)
Commitment Costs	($5)
Non-Fuel VOM	$79
FOM	($54)
Purchase Costs	($79)
Other Costs	$2
Total	**($25)**

Source: Synapse results from modeling completed based on SPS Response to SC 1-3(i) CONF, Encompass Optimize Databased 10.18.21

As shown in Table 10, I also find that retiring Unit 1 is a no-regrets decision that results in nearly identical or lower NPVRR than converting all three units under every scenario and sensitivity I tested. Additionally, I find that SPS's modeling substantially understated the likely savings from retiring the Harrington units relative to converting it. Despite recommending conversion of all three units to gas, SPS's own results did show that over the planning period (2022-2041), there would be NPVRR savings of $5 million from retiring Unit 1 relative to converting all three units. Our results show that the likely savings are much larger, ranging between $26 million at the low end and $123 million at the high end.

Table 10: NPVRR of retire one unit scenario

Description	2022 – 2041 Delta from Convert All Baseline ($Million)
SPS Scenario 5	
SPS Base (Planning Load)	($5)
Financial Load	($29)
Synapse Scenario 5	
Synapse Base with baseline changes discussed above	($48)
Financial Load	($26)
CO_2 Price	($31)
Undepreciated balance disallowed post-retirement	($123)
Undepreciated balance allowed but no return allowed	($34)
Financial Load, undepreciated balance disallowed post-retirement	($101)

Source: SPS results from Tables BRE-2 and BRE-3. Synapse results from modeling completed based on SPS Response to SC 1-3(i) CONF, Encompass Optimize Databased 10.18.21.

Q What resources are required to replace the units when they retire?

A SPS already has several new renewable projects for which it received RFP bids which are selected by the model, regardless of scenario, for 2024. Therefore, the retirement of one unit doesn't necessitate any incremental resource over what the model already selects in the "Convert All" scenario until 2029. At that time, our modeling results show an addition of 10 MW of incremental solar PV. This minimal difference over the next decade, and in fact over the entire planning period, between the scenarios with and without Unit 1 shows exactly how little remaining value and use Unit 1 has for SPS and its ratepayers. This finding is supported by the Company's own modeling results which, as discussed above, shows that Unit 1 is never used even after it is converted to gas operation.

To replace all three Harrington units after they are retired at the end of 2024, our modeling shows the capacity and energy is replaced by 30 MW of incremental solar and 640 MW of incremental storage by 2029.

Q What did you find in terms of CO_2 prices, pollutants, and emissions?

A Synapse modeled a CO_2 price sensitivity set to $20/metric tonnes in base year 2011, escalating at 2.5 percent per year. The CO_2 price scenarios were identical to the Synapse base EnCompass runs, with the exception of the CO_2 price. In these scenarios, we found that converting all Harrington units to gas was the most expensive option and that converting two Harrington units, converting one Harrington unit, or retiring all Harrington units would all be cheaper for SPS customers between 2022 and 2041 if a CO_2 price is implemented. As shown in Table 11, savings ranged from $27 million in the Retire All Harrington Units scenario to $51 million in the Convert One Harrington Unit scenario.

Table 11: CO_2 price sensitivity results

Scenario	NPVRR ($Million) 2022-2041	Delta ($Million) Compared to Convert All Scenario
Convert All Harrington Units	$11,072	$0
Convert Two Harrington Units	$11,041	($31)
Convert One Harrington Unit	$11,021	($51)
Retire All Harrington Units	$11,045	($27)

Source: Synapse results from modeling completed based on SPS Response to SC 1-3(i) CONF, Encompass Optimize Databased 10.18.21.

Given these results, our recommendation is that SPS model a CO_2 price sensitivity so that the utility's modeling can capture the risk that the conversion of all Harrington units to gas would pose to SPS customers should federal carbon legislation be enacted.

Q What did you find under alternative financing options and plant balance assumptions?

A I find that when all or part of the undepreciated balance is disallowed after retirement, or if the rate of return is disallowed post retirement, the savings from retiring Harrington relative to conversion increase substantially, as shown in Table 12. It intuitively makes sense that if the balance is disallowed, savings will increase. But these results show the cost that SPS assumes its ratepayers will be required to pay for the remaining plant balance at Harrington. Specifically, if the plant is retired and the full plant balance is disallowed post-retirement, SPS ratepayers will save $222 million relative to the cost of converting the unit to operate on gas and paying off the balance prior to retirement. Even if only 50 percent of the balance is disallowed, savings will be around $76 million. And if the full balance is allowed post-retirement but a rate of return is not permitted, we estimate savings of around $92 million.

Table 12: NPVRR of Synapse runs under alternative financing and plant balance recovery assumptions

	2022-2024		2022-2014	
Cost ($Million)	**Delta**	**NPV**	**Delta**	**NPV**
100% Undepreciated balance disallowed post-retirement				
Convert all Harrington	$0	**$2,257**	$0	**$10,522**
Retain 1 Gas Harrington / Retire 2	($12)	**$2,245**	($104)	**$10,418**
Retain 2 Gas Harrington / Retire 1	($7)	**$2,250**	($95)	**$10,427**
Early Retire All Harrington	($8)	**$2,249**	($222)	**$10,300**
50% Undepreciated balance disallowed post-retirement				
Convert all Harrington	$0	**$2,257**	$0	**$10,522**
Retain 1 Gas Harrington / Retire 2	($12)	**$2,245**	($22)	**$10,500**
Retain 2 Gas Harrington / Retire 1	($7)	**$2,250**	($59)	**$10,463**
Early Retire All Harrington	($8)	**$2,249**	($76)	**$10,445**
Undepreciated balance allowed, no return post-retirement				
Convert all Harrington	$0	**$2,257**	$0	**$10,522**
Retain 1 Gas Harrington / Retire 2	($12)	**$2,245**	($30)	**$10,491**
Retain 2 Gas Harrington / Retire 1	($7)	**$2,250**	($63)	**$10,459**
Early Retire All Harrington	($8)	**$2,249**	($92)	**$10,430**
Financial Load / 100% undepreciated balance disallowed post-retirement				
Convert all Harrington	$0	**$2,098**	$0	**$9,228**
Retain 1 Gas Harrington / Retire 2	$26	**$2,124**	($77)	**$9,151**
Retain 2 Gas Harrington / Retire 1	$11	**$2,109**	($73)	**$9,155**
Early Retire All Harrington	$47	**$2,145**	($168)	**$9,059**

Source: Synapse results from modeling completed based on SPS Response to SC 1-3(i) CONF, Encompass Optimize Databased 10.18.21

Q What do you conclude about the reasonableness and cost of SPS's proposal to convert all three Harrington units to operate on gas?

A I find that SPS has not demonstrated that converting Harrington to operate on gas is in the best interest of its ratepayers. As discussed above, SPS's modeling is flawed and based on inaccurate assumptions and its results do not show a meaningful cost difference between many scenarios. Our modeling results, produced based on SPS's modeling files with our own modifications, show that retiring all three units is a substantially lower cost option than converting all three units to operate on gas.

Q Does this conclude your testimony?

A Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION (1) TO AMEND ITS CERTIFICATES OF PUBLIC CONVIENCE AND NECESSITY TO CONVERT HARRINGTON GENERATION STATION FROM COAL TO NATURAL GAS, (2) FOR AUTHORIZATION TO ACCRUE ALLOWANCE FOR FUNDS USED IN CONSTRUCTION, AND (3) FOR OTHER ASSOCIATE RELIEF	))))))))	**CASE NO. 21-00200-UT**

VERIFICATION

I, Devi Glick, state and affirm under penalty of perjury under the laws of the State of New Mexico, that the preceding Direct Testimony of Devi Glick, was prepared by me or under my direction, and that its contents are true and accurate to the best of my knowledge.

Devi Glick

Devi Glick

Date: 1/14/2022

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION (1) TO AMEND ITS CERTIFICATES OF PUBLIC CONVIENCE AND NECESSITY TO CONVERT HARRINGTON GENERATION STATION FROM COAL TO NATURAL GAS, (2) FOR AUTHORIZATION TO ACCRUE ALLOWANCE FOR FUNDS USED IN CONSTRUCTION, AND (3) FOR OTHER ASSOCIATE RELIEF	))))))))))))	**CASE NO. 21-00200-UT**

CERTIFICATE OF SERVICE

I certify that a true and correct copy of *Direct Testimony of Devi Glick on Behalf of Sierra Club* was electronically served only to each of the following on this 14th day of January 2022.

VIA EMAIL:

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PROFESSIONAL EXPERIENCE

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

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

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

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

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

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

Associate

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

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

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

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

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

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

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

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

EDUCATION

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

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

PUBLICATIONS

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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Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

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Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

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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.

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TESTIMONY

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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-7, Sub 1250): 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.

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.

Texas Public Utility Commission (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.

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. December 31, 2019.

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): 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. April 12, 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.

Resume updated December 2021

Exhibit DG-2

SPS Responses to

Sierra Club's Interrogatories and

Requests for Production of Documents

	Data Request
1.	SPS Response to SC 1-3
2.	SPS Response to SC 1-4
3.	SPS Response to SC 1-6
4.	SPS Response to SC 1-7
5.	Exhibit SPS-SC 1-7(i,j)
6.	Exhibit SPS-SC 1-7(n)
7.	SPS Response to SC 1-11
8.	SPS Response to SC 1-12
9.	SPS Response to SC 1-13
10.	Exhibit SPS-SC 1-13
11.	SPS Response to SC 3-3
12.	SPS Response to SC 4-1
13.	SPS Response to SC 4-2
14.	SPS Response to SC 4-4
15.	SPS Response to SC 4-7
16.	SPS Response to SC 4-8
17.	SPS Response to SC 4-12
18.	SPS Response to SC 4-13
19.	SPS Response to SC 4-14
20.	SPS Response to SC 4-15

QUESTION NO. SC 1-3:

Please refer to the Direct Testimony of Ben R. Elsey at page 13. Please provide all Encompass and all Strategist modeling input and output files supporting SPS/Xcel's application and supporting testimony (in electronic, machine-readable format with formulae intact).

RESPONSE:

Please refer to Exhibit SPS-SC 1-3(i)(CONF) for the EnCompass input and output files.

Please refer to Exhibit SPS-SC 1-3(ii) for the Strategist output files. The structure of the Strategist input files are proprietary to the vendor and can only be provided to active licensees of the Strategist software.

Preparers: Mark Christner, Ben R. Elsey
Sponsor: Ben R. Elsey

QUESTION NO. SC 1-4:

Please refer to the Direct Testimony of Ben R. Elsey at page 13-14. For the Harrington analyses, please provide all documents, analyses, or forecasts that the Company relied upon to calculate or develop costs included in the Company's modeling, including, without limitation, all:

a. Fuel costs for all electric power supply resources (owned and purchased, including all fuel contracts) and market energy costs (which are forecasted based on gas prices);

b. Purchased energy costs for all electric power supply resources;

c. Capacity costs of purchased power;

d. Variable operational and maintenance ("VOM") costs of purchased power;

e. Capital cost forecasts for new and existing electric generation facilities, including, but not limited to, the assumed costs for converting each of the three Harrington units and assumed pipeline costs;

f. Energy costs for new and existing wind and solar generation facilities;

g. Electric transmission interconnection and network upgrade costs for new generation;

h. Fixed operation and maintenance costs for existing and new generation facilities;

i. VOM costs for existing and new generation facilities, including all maintenance schedules or maintenance plans;

j. Remaining book value of SPS-owned generating units; and

RESPONSE:

a. Please refer to Exhibit SPS-SC 1-4(a)(CONF) for the fuel costs and market energy costs used for the Harrington Analysis.

b. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the purchased energy costs for all existing purchased power agreements.

c. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the capacity costs for all existing purchased power agreements.

d. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the Variable operational and maintenance ("VOM") costs for existing purchased power agreements.

e. Please refer to Exhibit SPS-SC 1-4(e)(i) for the scenario specific capital cost forecasts for each of the Harrington units and assumed pipeline costs used for the Harrington analysis. Please refer to Exhibit SPS-SC 1-4(e)(ii)(CONF) for additional information supporting the cost of installing environmental controls at Harrington. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the capital cost forecasts for SPS's other generating facilities. Please refer to Exhibit SPS-SC 1-4(e)(ii)(CONF) for all capital cost forecasts for new generation proposals received from SPS's Request for Information which were used in the Harrington Analysis. Please refer to the EnCompass inputs provided in Exhibit SPS-SC 1-3(i)(CONF) for the generic costs assumptions used for other new generating resources.

f. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the energy cost of all existing wind and solar generating facilities. Please refer to Exhibit SPS-SC 1-4(e)(ii)(CONF) for all energy cost assumptions for new generation proposals received from SPS's Request for Information and subsequently which were used in the Harrington Analysis. Please refer to the EnCompass inputs provided in response to Question No. SPS-SC 1-3 for the generic costs assumptions used for other new generating resources.

g. Please refer to Exhibit SPS-SC 1-4(g)(CONF) for the electric transmission interconnection and network upgrade costs for new generation.

h. Please refer to Exhibit SPS-SC 1-4(e)(i) for the scenario specific fixed operational and maintenance ("FOM") forecasts for each of the Harrington units used for the Harrington Analysis. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the FOM forecasts for SPS's other generating facilities. Please refer to Exhibit SPS-SC 1-4(e)(ii)(CONF) for all FOM forecasts for new generation proposals received from SPS's Request for Information and subsequently which were used in the Harrington Analysis. Please refer to the EnCompass inputs provided in Exhibit SPS-SC 1-3(i)(CONF) for the generic costs assumptions used for other new generating resources.

i. Please refer to Exhibit SPS-SC 1-4(e)(i) for the scenario specific VOM forecasts for each of the Harrington units used for the Harrington Analysis. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF) for the VOM forecasts for SPS's other generating facilities. Please refer to Exhibit SPS-SC 1-

4(e)(ii)(CONF) for all VOM forecasts for new generation proposals received from SPS's Request for Information and subsequently used in the Harrington Analysis. Please refer to the EnCompass inputs provided in Exhibit SPS-SC 1-3(i)(CONF) for the generic costs assumptions used for other new generating resources.

j. Please refer to the EnCompass input files provided in Exhibit SPS-SC 1-3(i)(CONF).

Preparers: Ashley Gibbons, Ben R. Elsey
Sponsor: Ben R. Elsey

QUESTION NO. SC 1-6:

Has SPS/Xcel evaluated whether any of the Harrington units will require additional investments to comply with final, proposed, or possible future environmental regulations including, but not limited to: existing consent decrees, new source review provisions, coal combustion residuals, effluent limitation guidelines, national ambient air quality standards, cooling water intake standards, the cross-state air pollution rule, the mercury and air toxics standards, regional haze, and carbon dioxide emissions?

a. If not, please explain why not.

b. If so, please provide a summary, organized by electric generating unit, briefly describing the additional investments, including the purpose, and capital and annual O&M costs of such investments.

c. Please also include all supporting analyses, calculations, data, documents, modeling input and output files, and work papers associated with each investment.

RESPONSE:

Currently there are no other impending regulations that would be applicable to all three Harrington units other than the current SO2 National Ambient Air Quality Standards (NAAQS) requirements for which this gas conversion is being implemented. As stated in testimony by Mr. West, the current options to comply with the SO2 NAAQS standard involve the installation of SO2 controls, fuel conversion, retirement or some combination of these alternatives. The installation of SO2 controls would most likely require all three Harrington units to further comply with requirement in the Coal Combustion Residuals (CCR) rules. SPS beneficially uses 100% of its coal ash and is currently not subject to these requirements. The installation of SO2 controls would most likely render the majority if not all of the ash unusable for beneficial use and subject to these regulations.

The US Environmental Protection Agency (EPA) has also vacated the Affordable Clen Energy (ACE) rule for greenhouse gas regulations and will not be reinstating the former Clean Power Plan (CPP). It is SPS's understanding that the EPA intends to draft a new rule to replace the CPP. The contents of this rule are not known until published and cannot be evaluated until then.

There are no other known rules in any proposed or final state applicable to all three Harrington units that are not already incorporated into the operating permits for the facility. All three units are demonstrating compliance with these required operating permits.

Preparer: Jeffrey L. West
Sponsor: Jeffrey L. West

QUESTION NO. SC 1-7:

For the Harrington units, please provide the following historical annual data going back to 2015 – 2021, broken down by unit:

a. Installed Capacity

b. Capacity factor

c. Availability factor

d. Heat Rate

e. Forced outage rate

f. Fixed O&M costs

g. Non-Fuel Variable costs

h. Fuel Costs

i. Environmental capital costs

j. Non-environmental capital costs

k. Energy revenues (i.e., avoided energy purchase costs)

l. Ancillary services revenues

m. Any other revenues

n. Depreciation

o. Undepreciated net book value

p. Property taxes

q. Property insurance

r. Projected retirement date, if any.

RESPONSE:

a. Please refer to Exhibit SPS-SC 1-7(a-e). Please note that 2021 data for Harrington will not be available until after the year end.

b. Please refer to Exhibit SPS-SC 1-7(a-e). Please note that 2021 data for Harrington will not be available until after the year end.

c. Please refer to Exhibit SPS-SC 1-7(a-e). Please note that 2021 data for Harrington will not be available until after the year end.

d. Please refer to Exhibit SPS-SC 1-7(a-e). Please note that 2021 data for Harrington will not be available until after the year end.

e. Please refer to Exhibit SPS-SC 1-7(a-e). Please note that 2021 data for Harrington will not be available until after the year end.

f. Please refer to Exhibit SPS-SC 1-7(f-h). Please note that 2021 data for Harrington will not be available until after the year end.

g. Please refer to Exhibit SPS-SC 1-7(f-h). Please note that 2021 data for Harrington will not be available until after the year end.

h. Please refer to Exhibit SPS SC 1-7(f-h). Please note that 2021 data for Harrington will not be available until after the year end.

i. Please refer to Exhibit SPS SC 1-7(i, j). Please note that 2021 data for Harrington will not be available until after the year end.

j. Please refer to Exhibit SPS SC 1-7(i, j). Please note that 2021 data for Harrington will not be available until after the year end.

k. Please refer to Exhibit SPS-SC 1-7(k). Please note that 2021 data for Harrington will not be available until after the year end.

l. Please refer to Exhibit SPS-SC 1-7(l). Please note that 2021 data for Harrington will not be available until after the year end.

m. Please refer to Exhibit SPS-SC 1-7(m). Exhibit represents annual coal ash revenue for Harrington. Please note, this information is not invoiced on a per unit basis.

n. Please refer to Exhibit SPS-SC 1-7(n).

o. Please refer to SPS's response to subpart (n).

p. Please refer to Exhibit SPS-SC 1-7(p). Please note that 2021 data for Harrington will not be available until after the year end.

q. Xcel Energy does not allocate insurance costs to individual assets. The amount allocated to SPS is based on the replacement value of insurable SPS assets as it bears to the replacement value of insurable assets for the entire company. Amounts allocated to SPS are below:

	2016	2017	2018	2019	2020
SPS	$2,918,882	$2,774,425	$2,931,713	$3,514,302	$3,947,113

Please note that 2021 data for Harrington will not be available until after the year end.

r. SPS is not requesting a modification to the Commission approved retirement dates in this case. For Harrington Generating Station Units 1, 2, and 3, those dates are 2036, 2038, and 2040, respectively.

Preparers: Allison Johnson, Ryan Crotty, Sean Young, Jeff Comer
Sponsors: William A. Grant, Ben R. Elsey, Mark Lytal

Exhibit DG-2

Southwestern Public Service Company

Category	Unit	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	Sum of 2020	Total by Unit / Category
Environmental	0	$ 227,257	$ 2,319	$ -	$ -	$ 208,301	$ -	$ 437,877
	1	262,847	2,387,532	469,327	149,949	327,957	121,036	3,718,647
	2	240,333	188,539	82,427	223,905	12,969	(24)	748,149
	3	1,027,360	5,161	14	666,208	-	7,579	1,706,322
Environmental Total		**$ 1,757,797**	**$ 2,583,551**	**$ 551,767**	**$ 1,040,062**	**$ 549,227**	**$ 128,591**	**$ 6,610,995**
Non-Environmental	0	$ 3,088,562	$ 2,568,492	$ 1,987,030	$ 464,086	$ 1,554,819	$ 2,804,956	$ 12,467,945
	1	3,398,946	2,711,367	2,958,808	1,683,589	3,477,608	4,534,648	18,764,966
	2	9,363,520	6,778,674	853,748	6,308,090	703,429	2,795,541	26,803,001
	3	10,904,775	8,201,917	10,164,517	3,682,263	5,423,188	1,632,788	40,009,448
Non-Environmental Total		**$ 26,755,803**	**$ 20,260,451**	**$ 15,964,104**	**$ 12,138,027**	**$ 11,159,044**	**$ 11,767,933**	**$ 98,045,361**
Grand Total		**$ 28,513,600**	**$ 22,844,003**	**$ 16,515,871**	**$ 13,178,089**	**$ 11,708,271**	**$ 11,896,524**	**$ 104,656,356**

Southwestern Public Service Company

Depreciation

Unit	As of : 12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	6/30/2021
Harrington Common	$ 1,037,111	$ 1,070,952	$ 1,093,549	$ 1,103,644	$ 1,130,016	$ 1,732,058	$ 903,665
Harrington Unit 1	3,214,701	3,339,024	3,527,941	3,513,054	3,583,446	4,545,936	2,270,139
Harrington Unit 2	3,283,984	3,389,395	3,563,851	3,621,987	3,618,198	4,730,527	2,454,133
Harrington Unit 3	3,274,992	3,424,056	3,414,092	3,429,929	3,616,604	4,401,310	2,219,106
Harrington Common - Coal	-	-	-	-	-	-	177,460
Harrington Unit 1 - Coal	-	-	-	-	-	-	349,314
Harrington Unit 2 - Coal	-	-	-	-	-	-	313,180
Harrington Unit 3 - Coal	-	-	-	-	-	-	286,411
Total	**$ 10,810,787**	**$ 11,223,426**	**$ 11,599,433**	**$ 11,668,614**	**$ 11,948,264**	**$ 15,409,831**	**$ 8,973,407**

Undepreciated Net Book Value (a)

Unit	As of : 12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	6/30/2021
Harrington Common	$ 24,259,646	$ 24,770,137	$ 24,734,514	$ 23,929,376	$ 27,280,194	$ 10,423,757	$ 9,661,972
Harrington Unit 1	64,073,446	75,113,651	76,262,615	72,088,884	68,452,041	60,639,832	58,732,717
Harrington Unit 2	72,839,066	75,798,513	84,399,420	80,928,565	74,995,763	73,998,083	72,470,578
Harrington Unit 3	71,354,373	68,689,605	66,462,954	70,930,529	72,292,897	73,240,001	71,166,452
Harrington Common - Coal	-	-	-	-	-	3,365,490	3,135,708
Harrington Unit 1 - Coal	-	-	-	-	-	8,813,183	8,496,149
Harrington Unit 2 - Coal	-	-	-	-	-	9,016,256	8,396,578
Harrington Unit 3 - Coal	-	-	-	-	-	8,556,063	8,243,614
Total	**$ 232,526,532**	**$ 244,371,906**	**$ 251,859,502**	**$ 247,877,354**	**$ 243,020,894**	**$ 248,052,665**	**$ 240,303,767**

(a) Undepreciated Net Book Value excludes Land Owned (non-depreciable)

QUESTION NO. SC 1-11:

Please refer to the Direct Testimony of Ben R. Elsey at 6. Indicate whether SPS has considered securitization of other financing options as a way to minimize rate impacts from early retirement of the Harrington units.

RESPONSE:

SPS is unaware of any legal authority permitting the securitization of the undepreciated balance of the Harrington units.

Preparer: Counsel
Sponsor: William A. Grant

QUESTION NO. SC 1-12:

Please refer to the Direct Testimony of Ben R. Elsey at 7. If SPS retired one Harrington unit at the end of 2024, and converted the other two, would the Company need additional replacement resources in 2024? Please explain.

RESPONSE:

No. SPS has sufficient generating resources to meet its planning reserve margin requirements in 2024. Retiring one Harrington Unit at the end of 2024 would have no impact on SPS's capability to meet its planning reserve margin requirements in 2024. However, retiring one Harrington unit at the end of 2024 would necessitate the need for additional replacement resources in subsequent years. Please refer to SPS's financial and planning forecast tables in Exhibit SPS-SC 1-13 for SPS's capacity need, with and without, one Harrington Unit.

Preparer: Ben R. Elsey
Sponsor: Ben R. Elsey

QUESTION NO. SC 1-13:

Please refer to the Direct Testimony of Ben Elsey at 6 and 17, discussing the need for replacement capacity if Harrington is retired, rather than repowered. Please state by year, through 2040, how much replacement capacity would be needed if SPS retired Harrington Unit One in 2024, while repowering units Two and Three. Please state whether your responses to this interrogatory are consistent with the Loads and Resources Table presented in SPS's most recent IRP, and if not, what is changed.

RESPONSE:

Please refer to Exhibit SPS-SC 1-13 for SPS's capacity need from 2025 to 2040, using SPS's most recent financial and planning load forecasts. Exhibit SPS-SC 1-13 assumes Harrington Unit 1 is retired at the end of 2024 and the remaining units are converted to operate on natural gas. Therefore it is not consistent with the Loads and Resource Tables presented in the most recent IRP, in which all three Harrington Units were converted to operate on natural gas.

In addition, SPS updates its Loads and Resources Tables frequently and has incorporated the following changes since filing its most recent IRP and conducting its most recent Harrington Analysis:

(1) SPS began using Southwest Power Pool's effective load carrying capability ("ELCC") methodology for assigning accredited capacity for renewable generation resources. In addition, SPS began assigning accredited capacity to four of its wind qualifying facilities. Ultimately, updating the Loads and Resources Tables to incorporate Southwest Power Pool's ELCC methodology lowered the accredited capacity provided from renewable generation by up to 254MW.

(2) SPS lowered the summer capacity from the Lea Power Partners, LLC combined cycle facility by 16MW.

(3) SPS's current Loads and Resources Tables includes the company's updated load forecast.

Preparers: Ashley Gibbons, Ben R. Elsey
Sponsor: Ben R. Elsey

Southwestern Public Service Company

Financial Forecast

	2025	2026	2027	2028	2029	2030	2031	2032
SPS Resource Position (NM IRP L&R MW)	770	595	532	266	124	101	(174)	(478)
Updated to ELCC / Lea Power PPA (MW)	(169)	(251)	(260)	(246)	(252)	(257)	(263)	(261)
Updated Load Forecast (MW)	(5)	(3)	(6)	(3)	5	10	15	16
Updated PRM (MW)	(1)	(0)	(1)	(0)	1	1	2	2
SPS Resource Position - Assuming all Harrington Units are Converted (MW)	**606**	**347**	**279**	**23**	**(134)**	**(168)**	**(453)**	**(756)**
Less Harrington 1 (MW)	(340)	(340)	(340)	(340)	(340)	(340)	(340)	(340)
SPS Resource Position - Assuming Harrington Unit 1 is retired (MW)	**266**	**7**	**(61)**	**(317)**	**(474)**	**(508)**	**(793)**	**(1,096)**

Planning Forecast

	2025	2026	2027	2028	2029	2030	2031	2032
SPS Resource Position (NM IRP L&R MW)	398	178	53	(259)	(440)	(504)	(799)	(1,171)
Updated to ELCC / Lea Power PPA (MW)	(169)	(251)	(260)	(246)	(252)	(257)	(263)	(261)
Updated Load Forecast (MW)	(5)	(3)	(7)	(3)	6	11	17	19
Updated PRM (MW)	(1)	(0)	(1)	(0)	1	1	2	2
SPS Resource Position - Assuming all Harrington Units are Converted (MW)	**234**	**(70)**	**(199)**	**(502)**	**(699)**	**(774)**	**(1,081)**	**(1,452)**
Less Harrington 1 (MW)	(340)	(340)	(340)	(340)	(340)	(340)	(340)	(340)
SPS Resource Position - Assuming Harrington Unit 1 is retired (MW)	**(106)**	**(410)**	**(539)**	**(842)**	**(1,039)**	**(1,114)**	**(1,421)**	**(1,792)**

Southwestern Public Service Company

Financial Forecast

	2033	2034	2035	2036	2037	2038	2039	2040
SPS Resource Position (NM IRP L&R MW)	(1,578)	(2,179)	(2,694)	(2,770)	(3,144)	(3,171)	(3,563)	(3,602)
Updated to ELCC / Lea Power PPA (MW)	(265)	(254)	(104)	(98)	(100)	(102)	(104)	(106)
Updated Load Forecast (MW)	22	29	36	46	55	62	71	80
Updated PRM (MW)	3	3	4	6	7	7	9	10
SPS Resource Position - Assuming all Harrington Units are Converted (MW)	**(1,868)**	**(2,465)**	**(2,839)**	**(2,920)**	**(3,305)**	**(3,342)**	**(3,747)**	**(3,797)**
Less Harrington 1 (MW)	(340)	(340)	(340)	(340)	0	0	0	0
SPS Resource Position - Assuming Harrington Unit 1 is retired (MW)	**(2,208)**	**(2,805)**	**(3,179)**	**(3,260)**	**(3,305)**	**(3,342)**	**(3,747)**	**(3,797)**

Planning Forecast

	2033	2034	2035	2036	2037	2038	2039	2040
SPS Resource Position (NM IRP L&R MW)	(2,300)	(2,942)	(3,453)	(3,595)	(4,005)	(4,044)	(4,488)	(4,553)
Updated to ELCC / Lea Power PPA (MW)	(265)	(254)	(104)	(98)	(100)	(102)	(104)	(106)
Updated Load Forecast (MW)	26	34	43	54	65	74	85	96
Updated PRM (MW)	3	4	5	7	8	9	10	12
SPS Resource Position - Assuming all Harrington Units are Converted (MW)	**(2,594)**	**(3,234)**	**(3,604)**	**(3,754)**	**(4,178)**	**(4,229)**	**(4,687)**	**(4,766)**
Less Harrington 1 (MW)	(340)	(340)	(340)	(340)	0	0	0	0
SPS Resource Position - Assuming Harrington Unit 1 is retired (MW)	**(2,934)**	**(3,574)**	**(3,944)**	**(4,094)**	**(4,178)**	**(4,229)**	**(4,687)**	**(4,766)**

QUESTION NO. SC 3-3:

Refer to SPS response to Sierra Club 1-4(e) and (h) regarding FOM and capital cost forecasts.

a. Explain the basis of the Company's assumptions and adjustments for FOM and capital costs across all scenarios. Provide all documentation and analysis that shows the basis of each cost forecast, and how each was developed.

b. Explain how both the FOM and capital expenditure costs were adjusted down in the scenarios where one or two units were retired. Provide all analysis that shows how SPS calculated the adjustments to the values it used in EnCompass.

c. State whether the Company assumed that capital costs and FOM costs ramped down in advance of a unit's retirement.

    i. If yes, explain the assumptions and provide all workbooks that show the Company's assumptions.

    ii. If no, explain what the values were not ramped down in advance of retirement.

RESPONSE:

a.

On-going Capital Expenditure Forecasts

For scenarios in which coal operations are maintained beyond 2024 (i.e. the SDA and DSI environmental control scenarios), SPS relied upon its final five-year capital expenditure budget (2020 – 2024) to assume continued coal operations. The five year average capital expenditure was then used all for future years and escalated at 2% per year. SPS then incorporated additional capital expenditure for the SDA and DSI environmental controls systems based on the Burns and McDonnell study.

For scenarios in which coal operation are ceased at the end of 2024 (i.e the gas conversion and early retirement scenarios), SPS relied upon its 2021 – 2025 capital budget for the years 2021 – 2024. Based on discussions with the Xcel Energy Projects team, SPS then assumed an annual capital expenditure forecast of \$3.75M per year (escalated at 2% per year) after the units were converted to operate on natural gas.

In all scenarios, SPS assumed no capital expenditure in the final year of each Harrington unit's operation, a 50% reduction in the year prior to the unit's retirement and 25% reduction two years prior to the units retirement.

Supporting documentation is contained on the worksheets entitled "GasCapX" or "CoalCapX" in each of the spreadsheets provided in response to Exhibit SPS-SC 1-4(e)(i).

Fixed O&M

For each scenario, SPS relied upon fixed O&M budgets created by Xcel Energy's Strategic Asset Management group which are contained on the tabs titled "FOM" in each of the spreadsheets provided in response to Exhibit SPS-SC 1-4(e)(i). The total plant level fixed O&M is then divided equally among each unit.

b. In the event one or two units are retired at the end of 2024, SPS removed the capital expenditure and fixed O&M costs for each of the retiring units after the unit was retired (i.e. 2025 and beyond). In addition, As described in subpart (a), SPS assumed no capital expenditure in the final year of each Harrington unit's operation, a 50% reduction in the year prior to the unit's retirement and 25% reduction two years prior to the units retirement. No further adjustments were made to FOM in the years preceeding a unit's retirement.

c. Yes. Please refer SPS's response to subpart (b).

Preparer: Ben R. Elsey
Sponsor: Ben R. Elsey

RESPONSES

QUESTION NO. SC 4-1:

State whether SPS evaluated the early retirement of Harrington, assuming that any remaining plant balance was depreciated over each unit's current lifetime.

a. If yes, provide all such analysis.

b. If no, explain why no such analysis has been completed.

RESPONSE:

a. Not applicable.

b. No, no such analysis was completed. First, such an analysis would not resolve the challenges SPS face if the Harrington Units are retired by the end of 2024. Second, such an analysis would require SPS customers to continue to incur depreciation expense for the Harrington Units up to 16 years after they are used and useful. Please refer to pages 6-8 of the Direct Testimony of Ben R. Elsey for additional information.

Preparer: Ben R. Elsey
Sponsors: Ben R. Elsey, William A. Grant

QUESTION NO. SC 4-2:

State whether SPS has evaluated the possibility of converting the undepreciated plant balance at Harrington into a regulatory asset and depreciating the balance over the current plant life if any of the units, or the entire plant, retires early.

a. If yes, provide all analysis and reports evaluating this option.

b. If no, explain why not.

RESPONSE:

a. Not applicable.

b. Please refer to SPS's response to Question No. SC 4-1.

Preparer: Ben R. Elsey
Sponsors: Ben R. Elsey, William A. Grant

QUESTION NO. SC 4-4:

State whether SPS tested a CO_2 price as part of the Harrington analysis.

a. If yes, provide all analysis.

b. If no, explain why not.

RESPONSE:

a. Not applicable.

b. SPS did not evaluate a speculative carbon pricing as part of the Harrington analysis as no such policy or regulation exists today or has even been proposed in an actionable forum.

Preparers: Ben R. Elsey, Jeffrey L. West
Sponsors: Ben R. Elsey, Jeffrey L. West

QUESTION NO. SC 4-7:

Refer to the EnCompass files provided for the Harrington 2021 analysis.

a. Explain what costs are represented in the Annual Capital Expenditures ($000) timeseries.

b. Explain what costs are represented in the Capital Expenditures ($000) field.

c. Explain why Scenario 5 (where units 1 and 2 retire early) uses the same FOM cost stream for Units 1 and 2 as Scenario 2 (where both units convert to gas), instead of the same cost stream as Scenario 1 (where all units retire early).

d. Explain why Scenario 6 (where unit 1 retires early) uses the same FOM cost stream for unit 1 as Scenario 2 (where unit 1 converts to gas) instead of the same cost stream as Scenario 1 (where the unit retires early).

RESPONSE:

a. SPS confirmed with Sierra Club this question is regarding the 'TimeSeriesDatedChanges' tab in the file 'SPS_ReferenceCase_1H21_2021-06-21.xlsx'.

The annual capital expenditures ($,000) timeseries represents on-going capital expenditure forecasts for each unit. For example, the 'Early Retire 2024 Annual CapEx' time series includes on-going capital expenditure projections for Harrington units 0 – 3 assuming all three Harrington units retire end of year 2024. The 'Gas 20***xx*** Annual CapX' times series includes on-going capital expenditure projections for Harrington units 0 – 3 assuming all three units are converted to operate on natural gas and retire at the end of their currently scheduled service lives'.

*Note: In the second example above, the naming structure for the times series is specific to the unit's retirement date. For example, the time series for Unit 1 is called "Gas 2036 Annual CapEx", the time series for Unit 2 is called "Gas 2038 Annual CapEx" etc.

b. SPS confirmed with Sierra Club this question is regarding the 'Project' tab in the file 'SPS_ReferenceCase_1H21_2021-06-21.xlsx'.

The column 'CapEx' generally represents the existing net book value plus decommissioning costs for each unit. In the case of the Harrington Units there are multiple entries depending on the fuel source and retirement date of the Harrington

Units and additional entries for the SDA and DSI environmental control options. For example, the entry 'Harrington 1 - Coal 2036 CapEx' represents continued coal operation and depreciating the net book value through 2036. The entries 'Harrington 1 - Coal 2024 CapEx' and 'Harrington 1 - Gas 2036 CapEx' represent (1) converting the units to operate on natural gas, (2) depreciating the coal assets through 2024, and (3) depreciating the remaining assets through 2036.

c. As demonstrated in Exhibit SPS-SC 1-4(e)(i), for the years 2022 – 2024, SPS had originally intended to utilize a slightly lower fixed O&M forecast when comparing the cessation of coal scenarios against the continued coal operation scenarios. In other words, (1) retirement of all three units, (2) conversion of all three units, or any (3) combination of retirement and gas conversion would use a slightly lower O&M forecast in 2022 – 2024 when compared to either of the environmental control scenarios. However, upon discovering such a minor change was immaterial, SPS opted against adding another layer of complextity to the analysis and kept the fixed O&M forecast in 2022 – 2024 consistent across all scenarios, with the exception of retiring all three units. In doing so, the analysis understates the advantages of converting Harrington to gas compared against alternatives such as continued operation of coal and early retirement of the units.

d. Please refer to subpart (c).

Preparer: Ben R. Elsey
Sponsor: Ben R. Elsey

QUESTION NO. SC 4-8:

Please refer to SPS's modeling files provided in response to SC 1-3(i). Please provide SPS's projected emission rates for the following pollutants at the Harrington units if converted to operate on gas:

a. CO_2,

b. NOx,

c. particulate matter.

d. Explain in detail and provide all documentation supporting SPS's assumptions around the projected emissions rates for CO2, NOx, and particulate matter, if the Harrington units are converted to gas.

RESPONSE:

a. Please refer to the Resource Annual Emissions tab in the EnCompass Output Files provided in Exhibit SPS-SC 1-3(i)(CONF).

b. Please refer to subpart (a).

c. Please refer to subpart (a).

d. For the purposes of modeling the Harrington units following the gas conversion, SPS relied upon the emission rates of its most similar gas-steam unit, Jones 2. These will be refined as performance specifications for the modified equipment once they are obtained and verified.

Preparers: Ben R. Elsey, Jeffrey L. West
Sponsors: Ben R. Elsey, Jeffrey L. West

QUESTION NO. SC 4-12:

Please refer to SPS Exhibit SPS-SC 1-27.1 at 4 of 90.

a. Did SPS obtain any authorization from the U.S. Army Corps of Engineers for the proposed pipeline, including, but not limited to, any certification under Nationwide Permit 12 or any other authorization under the Clean Water Act or the Endangered Species Act? If so, please provide all such authorizations or documents reflecting any communications with the U.S. Army Corps of Engineers related to any such authorization. If not, why not?

b. Please provide all communications with the U.S. Army Corps of Engineers related to the need for any authorization for the pipeline.

RESPONSE:

To date, there has been no correspondence with the U.S. Army Corp or Engineers regarding the proposed pipeline. This agency will be contacted in the future as required.

Preparer: Jeffrey L. West
Sponsor: Jeffrey L. West

QUESTION NO. SC 4-13:

Please refer to SPS Exhibit SPS-SC 1-27.1 at 17 of 90.

a. Did SPS obtain any authorization from the Fish and Wildlife Service under the Endangered Species Act for the proposed pipeline? If so, please provide all such authorizations or documents reflecting any communications related to any such authorization. If not, why not?

b. Please provide all communications with the Texas Parks & Wildlife Department related to the pipeline or its impacts to endangered species, including, but not limited to all assessments referenced in paragraph 12.3.

c. Please provide all communications with the Fish and Wildlife Service related to the pipeline or its impacts to endangered species, including, but not limited to all assessments, all additional species-specific surveys, or seasonal restrictions referenced in paragraph 12.3.

RESPONSE:

a. There has been no correspondence with Fish and Wildlife Service to date. This agency will be contacted in the future as required.

b. In Texas, the Texas Parks & Wildlife Department requested that SPS provide a copy of the Environmental Assessment filed in the Texas case (Docket No. 52485). Please refer to Exhibit SPS-SC 4-13 for a copy of the communication. In New Mexico, there has been no correspondence with Texas Parks & Wildlife to date. This agency will be contacted in the future as required.

c. See "a" above.

Preparer: Jeffrey L. West
Sponsor: Jeffrey L. West

QUESTION NO. SC 4-14:

Please refer to SPS Exhibit SPS-SC 1-27.1 at 18 of 90. Did SPS obtain any authorization from the U.S. Environmental Protection Agency or the Texas Commission on Environmental Quality for the proposed pipeline, including, but not limited to any authorization under the Clean Water Act or the Clean Air Act? If so, please provide all such authorizations or documents reflecting any communications related to any such authorization. If not, why not?

RESPONSE:

To date, there has been no communication with the US Environmental Protection Agency or the Texas Commission on Environmental Quality regarding the proposed pipeline.

This agency will be contacted in the future as required.

Preparer: Jeffrey L. West
Sponsor: Jeffrey L. West

QUESTION NO. SC 4-15:

Please provide all communications with the U.S. Environmental Protection Agency or the Texas Commission on Environmental Quality related to the pipeline, including, but not limited to all assessments referenced in paragraph 12.5.

RESPONSE:

There has been no communication with the US Environmental Protection Agency or the Texas Commission on Environmental Quality to date regarding the proposed pipeline. These agencies will be contacted in the future as required.

Preparer: Jeffrey L. West
Sponsor: Jeffrey L. West

Exhibit DG-3

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** NO [illegible] 019

PUBLIC (REDACTED) VERSION

Direct Testimony of Devi Glick

On Behalf of

Sierra Club

November 22, 2019

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DG-4: Fisher, Jeremy, *et al., Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets,* Sierra Club (October, 2019).

DG-5: Southwest Power Pool - Market Monitoring Unit, *State of the Market Report, Summer 2019* at 2 (Oct. 25, 2019).

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DG-7: EIA, "U.S. coal consumption in 2018 expected to be the lowest in 39 years." (Dec. 28, 2018).

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DG-9: Nelson, William and Sophia Lu, Half of U.S. Coal Fleet on Shaky Economic Footing. Bloomberg New Energy Finance (Mar. 26, 2018).

DG-10: Gheorghiu, Iulia. Cleco, "SWPECO shift coal plant use, target 2.8 GW renewables in latest resource plans." Utility Dive (Sept. 6, 2019).

DG-11: Daniel, Joseph. "Seasonal Shutdowns: How Coal Plants that Operate Less Can Save Customers Money." Union of Concerned Scientists (Dec. 20, 2018).

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 2, 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, non-exhaustively, power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on plant economics, utility resource needs, and solar valuation in the states of Connecticut, Virginia, North Carolina, South Carolina, and Florida. I authored a report on replacement analysis for the San Juan Generating Station in northwestern New Mexico. In the course of my work, I develop in-house models and perform analysis using industry-standard models.

Prior to 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 seven years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the New Mexico Public Regulation Commission?

A No, I have not.

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

A My testimony evaluates Southwestern Service Company's ("SPS" or the "Company") Application as it relates to the Company's request for cost recovery in base rates for its operations and investment at its Tolk Generating Station ("Tolk") and its Harrington Generating Station ("Harrington"), both multi-unit coal-fired power plants.

First, in Section 3 below, I evaluate Tolk and Harrington's actual historical economic performance over the past few years. My analysis looks first at the plants' overall economics relative to the market, and then more narrowly on an operational basis, by calculating each plant's annual costs and revenues from 2015 through 2018. In doing so, I evaluate the reasonableness of SPS's request to recover ongoing operations and maintenance ("O&M") and capital expenditures—including certain avoidable costs that stem from the Company's general practice of choosing to "self-commit" the units, *i.e.*, dispatching the units into the market regardless of whether it loses money by doing so.

Next, in Sections 4–6, I evaluate the likely future economic performance of the Tolk and Harrington plants. For the Tolk plant specifically, I focus on the reasonableness of SPS's request for approval to operate both of Tolk's two units seasonally, and in synchronous condenser mode, in an attempt to address the plant's serious water constraints.

Finally, in Section 7, I discuss the problems with SPS's prior Strategist unit retirement analysis. I also describe my recommendations that SPS should perform updated, more comprehensive (and hence more accurate) retirement analysis for both Tolk and Harrington.

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 SPS witnesses associated with this proceeding. Additionally, I rely to a limited extent on certain external, publicly available documents such as the Southwest Power Pool's ("SPP") 2018 State of the Market Report and U.S. Energy Information Administration (EIA) data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings include the following:

1. Tolk has historically been operated and dispatched uneconomically. When it converts to seasonal operation, it will likely continue to operate uneconomically, at an unnecessary cost to ratepayers.
2. Harrington, too, has historically been operating uneconomically and will likely continue to do so.
3. SPS's general practice of deciding to "self-commit" these units in the SPP market—so that they are dispatched even when wholesale prices are lower than what's needed for the units to break even—has resulted in net uneconomic operations at both Tolk and Harrington at ratepayers' expense.
4. SPS cannot economically procure enough water to operate through the Tolk units' current respective retirement dates of 2042 and 2045.
5. Even if SPS can procure enough water to operate Tolk seasonally, or at a reduced capacity through 2031, the Company has not demonstrated that doing so would be the least-cost option to provide its customers with reliable service.
6. SPS's future operating plan and economic analysis for Tolk does not consider: (1) the risk that the water shortage faced by the plant is more extreme than currently projected, (2) the potential opportunity to sell the water for valuable alternative uses, (3) the impact of water limitations on peak availability, and (4) the possibility of retiring the generating assets at Tolk while operating the synchronous condenser year-round to get the necessary voltage support services.
7. SPS's 2014–2015 unit replacement analysis for Tolk and Harrington relies on outdated demand forecasts and resource cost assumptions. In addition, SPS's analysis fails to consider future capital expenditures that may be necessary to

address both current and reasonably possible future environmental regulations.

Q Please summarize your recommendations.

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

1. The Commission should disallow recovery of the increment of test year (April 1, 2018–March 31, 2019) O&M expenses at Tolk and Harrington incurred during the months of the year that the Company's self-dispatch practices for each plant resulted in net uneconomic operations. During those months, the Commission could disallow specifically the increment of cost incurred to operate and dispatch the units that is over and above the cost at which SPS could have procured energy from the SPP market to serve its customers. To the extent SPS has not provided data at a sufficiently granular level to enable calculation, the Commission should order SPS to provide it.
2. The Commission should investigate (as some other regulators have) whether costs (including fuel costs) have been improperly passed on to customers due to uneconomic self-commitment and dispatch of Tolk and Harrington.
3. The Commission should deny recovery of the costs of any significant future capital projects that may be intended to prolong the lives of Tolk and Harrington as generating assets, given the plants' uneconomic performance and the impending water shortages at Tolk.
4. The Commission should require SPS to perform a full retirement analysis for Tolk, assuming a retirement date earlier than 2025 as part of its next Integrated Resource Plan ("IRP"). This analysis should include sensitivities on the timing of water depletion and incorporate (1) the risk of significant future capital and O&M expenditures on environmental compliance, (2) potential revenue from sale of the

water, and (3) unit de-rating to reflect the risk to peak operations as the aquifer becomes depleted.

5. The Commission should require SPS to perform and submit an updated unit replacement study for Harrington as part of its next IRP. This analysis should include the risk of substantial future expenditures (capital as well as any increased O&M) stemming from environmental compliance, as well as the possibility of seasonal operations.

3. SPS HAS BEEN OPERATING ITS COAL PLANTS UNECONOMICALLY SINCE AT LEAST 2015

Q Please summarize this section.

A I start by providing a brief overview of the Tolk and Harrington plants. I then summarize SPS's rate requests regarding historical capital and O&M costs. In Section (i), I evaluate the economics of Tolk and Harrington, and I find that total costs exceeded the cost to procure energy from the market in each year from 2015 through 2018 for both plants. In Section (ii), I evaluate the annual operational performance of Tolk and Harrington from 2015 through 2018. I find that variable operational costs alone often exceeded the cost at which SPS could have procured energy from the SPP market, which could have provided retail customers with less costly (while adequate and reliable) service. In Section (iii), I review SPS's coal plant dispatch practices more broadly, discuss the implications for ratepayers, and recommend that the Commission disallow an increment of test year (April 1, 2018–March 31, 2019) O&M expenses at Tolk and Harrington on the basis of uneconomic operations stemming from self-commitment in the SPP market.

Q Please provide a brief overview of the Tolk Generating Station.

A Tolk consists of two 1980s-era coal-fired units located in Sudan, Texas. Unit 1 is rated at 540 MW and Unit 2 is rated at 542 MW. Although the units were originally estimated to operate for only 35 years—*i.e.*, until 2017 (Unit 1) and 2020 (Unit 2)—the Commission approved extensions of their retirement dates to 2042 and 2045, respectively.[1] Tolk relies exclusively on groundwater from the Ogallala Aquifer for generation cooling. However, as SPS's own testimony in this case emphasizes, the aquifer is currently in serious and irreversible decline.[2] At the current rate of consumption, SPS will not have sufficient water to operate the plant beyond the mid-2020s at the latest.[3]

Q Please provide a brief overview of the Harrington Generating Station.

A Harrington consists of three coal-fired units located northeast of Amarillo, Texas. The plant's units came online between 1976 and 1989. Units 1 and 2 are rated at 339 MW, and Unit 3 is rated at 340 MW. The units currently have Commission-approved retirement dates of 2036, 2038, and 2040, respectively.

Q What are SPS's requests in this rate case for Tolk and Harrington?

A SPS is requesting the following:

1. Inclusion in base rates of O&M costs for the test year period April 1, 2018–March 31, 2019 for the operation of Tolk and Harrington;

[1] Direct Testimony of M. Lytal on Behalf of SPS, at 51–52.

[2] *Id.* at 53.

[3] *Id.* at 56.

2. Inclusion in rate base of capital expenditures of $4.3 million for Tolk and $3.9 million for Harrington for the test year period of April 1, 2018–March 31, 2019,[4] as well as $1.87 million for Tolk and $3.0 million for Harrington for the period April 1, 2019–August 31, 2019[5] (associated depreciation expenses and a return on investment requested for inclusion as well);
3. A change to Tolk's retirement dates from 2042 for Unit 1 and 2045 for Unit 2, to 2032 for both units, along with a corresponding adjustment of depreciation rates; and
4. A switch to the seasonal operation of both units starting in 2020.[6]

i. ***Tolk and Harrington each lost money overall relative to the market from 2015 through 2018***

Q What did you find regarding the overall economic performance of the Tolk units?

A Using data provided by SPS, I calculated that the Tolk units incurred net losses relative to the SPP energy market in the years 2015 through 2018. This is based on a comparison of the annual costs of energy production and the annual market revenue for each of the two Tolk units. Table 1 shows that the Tolk units collectively lost at least $34 million relative to the market in each year from 2015 through 2018. This includes annual losses relative to the market as high as $33

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[4] *Id.* at Exhibit ML-2, New Mexico Retail portion of Additions to Plant-in-service.

[5] *Id.*

[6] *E.g.*, Direct Testimony of W. Grant on Behalf of SPS at 8.

million for Tolk Unit 1 alone in 2015. Over the four-year timeframe, the Tolk units combined lost $158 million relative to the market.

Table 1. Net annual revenues of Tolk 1 and 2, 2015-2018 (2018 $Million)

Unit	2015	2016	2017	2018	Total
Tolk 1					
Tolk 2					
Total					

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(i).

Q What did you find regarding the overall economic performance of the Harrington units?

A Again, using data provided by SPS, I calculated that the Harrington units also incurred net losses relative to the market in the years 2015 through 2018. Table 2 shows that the three Harrington units lost at least $16 million relative to the market in each year from 2015 through 2018, with combined losses relative to the market as high as $75 million in 2016 alone. Total losses relative to the market over the four-year period were $230 million dollars combined for Harrington's three units.

Table 2. Net annual revenues of Harrington 1-3, 2015-2018 ($Million)

Unit	2015	2016	2017	2018	Total
Harrington 1					
Harrington 2					
Harrington 3					
Total					

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(i).

Q Describe how you arrived at the values in Table 1 and Table 2.

A The net revenue values in Table 1 and Table 2 are based on data provided by SPS. This includes data on Tolk and Harrington's respective energy revenues, ancillary services revenues, fixed O&M costs, variable costs, fuel costs, environmental capital costs, non-environmental capital costs, and property taxes. I calculated annual net revenues by subtracting fixed O&M costs, variable costs, fuel costs, environmental capital costs, non-environmental capital costs, and property taxes from energy revenues and ancillary services revenues.

SPS provided some of the data at the unit level. This includes energy revenues, ancillary services revenues, and property taxes.[7] Fixed O&M costs, variable costs, fuel costs, environmental capital costs, and non-environmental capital costs were provided at the plant-level.[8] I converted plant-level fuel costs and variable costs using a simple ratio of each unit's annual generation relative to the plant's total

[7] Exhibit SPS-SC 1-9(k); SPS Response to SPS-SC 1-9(p) (*see* Exhibit DG-2).

[8] Exhibit SPS-SC 1-9(f); Exhibit SPS-SC 1-9(i) (*see* Exhibit DG-2).

annual generation in gigawatt-hours (GWh).[9] Similarly, I converted plant-level fixed O&M costs, environmental capital costs, and non-environmental capital costs using a ratio of each unit's share of the plant's total capacity in megawatts (MW).[10]

Q Would the results change if you included a capacity value in the calculations?

A We did not include a capacity value in the preceding analyses because SPP does not have a capacity market. If we were to try to include SPS's savings from not acquiring capacity from other sources, net losses would be slightly smaller. Nonetheless, both plants would still have net losses relative to the market in each historical year I evaluated.[11] I valued capacity at the price SPS earns for firm capacity sales (according to the Strategist model output)[12] and found that the value of the capacity from Tolk and Harrington (in $2018) would be $10.3 million and $9.8 million, respectively, annually in each year from 2015 through 2018. Thus, that capacity value is still significantly below the net losses that each plant incurred in each year from 2015 through 2018. When I add a capacity value into the equation, Tolk's total losses relative to the market over the four-year period are $117 million and Harrington's total losses are $191.

[9] I relied on annual generation data from the Strategist outputs included as workpapers with witness B. Weeks' Direct Testimony on Behalf of SPS. Specifically, I relied on data from "SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx".

[10] Source of unit-level capacity data: https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/harrington; https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/tolk.

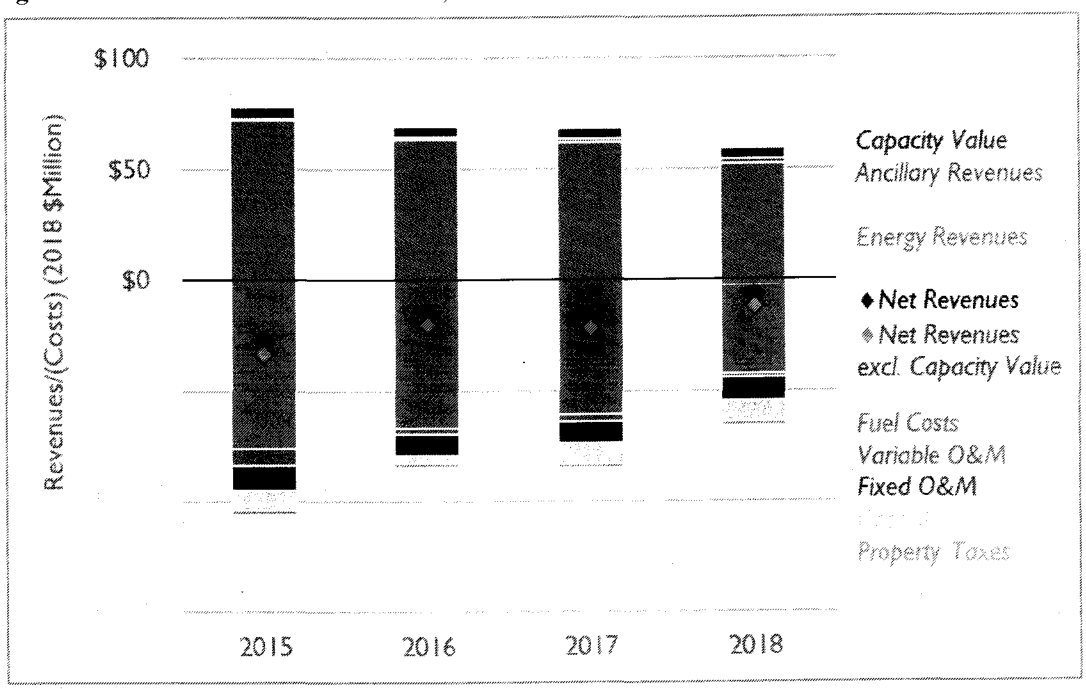
[11] On a unit level, all units with the exception of Harrington 2 in 2018, would have net losses.

[12] Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx.

Q Is it possible to present the results from Tables 1 and 2 above to show each cost and revenue component of your analysis including the capacity value?

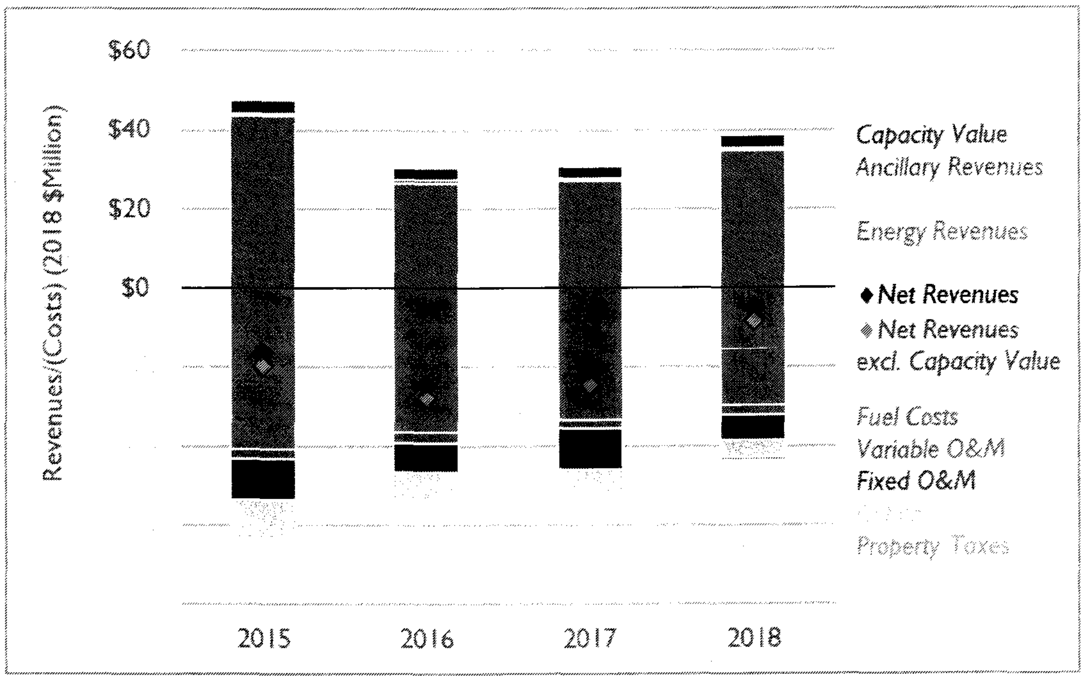
A Yes. Figure 1 and Figure 2 present the results of the historical analysis for Tolk 1 and Harrington 1 with each cost and revenue component shown separately, including the capacity value discussed above. The results for Tolk 2, Harrington 2, and Harrington 3 show a similar pattern. Because they are so similar, I do not produce them here due to space considerations. Figure 1 and Figure 2 illustrate that, in many years, the units' annual fuel costs alone approach or exceed the units' annual revenues.

Figure 1. Annual net revenues of Tolk 1, 2015-2018



Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(l) (see Exhibit DG-2).

Figure 2. Annual net revenues of Harrington 1, 2015-2018



Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(i) (see Exhibit DG-2).

Q Would SPS be justified in keeping a unit online that was operating at an average annual loss relative to the market over multiple years?

A No. As I will discuss in the next section, SPS could be justified in operating Tolk or Harrington at a loss relative to the market on an hourly, daily, or potentially monthly basis in order to meet peak demand, or conceivably for reliability reasons. However, it is not reasonable to operate a plant for years at a time if the operator cannot earn enough revenue from the market to cover the costs to operate and maintain the plant. To justify operation, generation resources should, on average, be able to earn enough per kilowatt-hour from the market to cover the variable operations costs, plus a small amount each towards the fixed and capital costs needed to maintain the plant. Otherwise, the Company could more economically procure energy for its customers from the market.

Q Do your findings regarding the recent net losses incurred by SPS's coal units indicate that the Company should retire all five of those units immediately?

A No. There are likely sound logistical and reliability-related reasons to not retire SPS's entire coal fleet at once. In addition, retiring one or more coal units may improve the economics of the remaining coal units. Also, past losses relative to the market are not a guarantee of future losses relative to alternative resource options. Given the recent net losses of SPS's coal units relative to the market, however, the Company should conduct rigorous economic assessments of near-term retirement dates for each of those units.

ii. <u>Tolk and Harrington often did not earn enough revenue even to cover variable operational costs from 2015 through 2018</u>

Q Please explain the purposes of this section, including the difference between its analysis and the analysis above in Section (i).

A In Section (i), I reviewed the total cost to operate and maintain Tolk and Harrington relative to procuring energy from the market. That analysis evaluated the combination of variable operational costs, fixed costs, and capital costs, and then compares the total cost to keep the plant online to the cost of procuring energy from the market. That type of analysis is relevant for determining whether a plant should be kept online or retired and replaced with an alternative.

In this section, by contrast, I review the variable operations costs (including fuel) and evaluate whether the plant is covering even the incremental cost to operate the unit each hour. This type of analysis is relevant for evaluating a plant's dispatch practices, and it sets up evaluation of the reasonableness of SPS choosing to self-commit the units into the wholesale energy market. I discuss this further in Section (iii), below.

Q Please summarize your findings regarding the operational economic performance of the Tolk units in the years from 2015 through 2018.

A Using data provided by SPS, I calculated that each of the Tolk coal units incurred net operational losses relative to the market in multiple years from 2015 through 2018 (Table 3). Net operational losses result when the sum of the hourly fuel and variable O&M costs over a given year are greater than the sum of the hourly nodal locational marginal prices ("LMPs") during all hours the unit is generating energy. Combined, these two units experienced annual net operational losses over half of the time, with the highest annual net operational loss of $10 million occurring in 2015 at Tolk 1.

Table 3. Annual net operational revenues of Tolk 1 and 2, 2015-2018 (2018 $Million)

Unit	2015	2016	2017	2018	Total
Tolk 1			($0)	$10	
Tolk 2	$17	$2			$12
Total	$6			$6	$6

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(i) (see Exhibit DG-2).

Q Please summarize your findings regarding the operational economic performance of the Harrington units in the years from 2015 through 2018.

A Using the same data provided by SPS discussed above, I calculated that each of the Harrington coal units incurred annual net operational losses in multiple years from 2015 through 2018. Table 4 shows that each of the Harrington units incurred aggregate operational losses of more than $7 million from 2015 through 2018.

Together, the units incurred net operational losses of $35 million from 2015 through 2018. This means that customers would have saved money over this time period if SPP had purchased energy from the market rather than operating its coal units.

Table 4. Annual net operational revenues of Harrington 1, 2, and 3, 2015-2018 (2018 $Million)

Unit	2015	2016	2017	2018	Total
Harrington 1	$1			$3	
Harrington 2				$11	
Harrington 3				$4	
Total				$18	

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-SC 1-9(k) and Response to SPS-SC 1-9(p), Exhibit SPS-SC 1-9(f) and Exhibit SPS-SC 1-9(i) (see Exhibit DG-2).

Q Describe how you arrived at the values in Table 3 and Table 4.

A I arrived at the net operational revenue values in Table 3 and Table 4 by subtracting each of the Tolk and Harrington units' 2015–2018 variable O&M costs and fuel costs from its energy revenues and ancillary services revenues. Each of these costs and revenues were directly provided by SPS, as described in Section 3i.

iii. ***<u>SPS's decision to self-commit its units to dispatch in the market has resulted in the uneconomic operation of Tolk and Harrington, at avoidable expense to ratepayers</u>***

Q Please provide a summary of this section.

A In this section, I discuss some of the decisions and dynamics underlying the annual net operational losses identified in Section 3ii. Specifically, I show how

SPS's operational decision-making is biased in favor of running its coal plants to generate energy rather than serving its load with energy available at lower cost in the market. Running SPS coal plants to serve load has resulted in higher costs to ratepayers.

Q How does SPS typically operate the Tolk and Harrington units?

A SPS operates its coal units in the SPP energy market with the units' commitment statuses set to "Self-Commit" most often, and "Economic" or "Outage" each less often. When a unit is set to "Self-Commit" status, a utility decides in advance that it will operate the unit at its minimum operational level or higher regardless of market prices. Conversely, when a unit is set to "Economic" status, the utility is indicating that it will only operate the plant if it is selected based on the day-ahead market results. This means that the utility bids in the price to operate the unit, based on its variable and fuel costs in each hour, and the unit is selected if the bid price is lower than the bid price of the marginal unit (the last unit needed to meet demand in that hour).

Table 5 shows that each of Tolk's two units was set to Self-Commit for at least [redacted] of the hours in each year from 2016 through 2018, and in some years considerably more. For Harrington, Table 6 shows that, on average from 2016 through 2018, each of the three units was set to Self-Commit for [redacted] of the hours (in the case of Harrington 2, substantially more).

Table 5. Tolk commitment practices, 2016-2018 CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 2-6(b)(CONF)(CD) (see Exhibit DG-2).

Table 6. Harrington commitment practices, 2016-2018 CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 2-6(b)(CONF)(CD) (see Exhibit DG-2).

Q Describe how you arrived at the values in Table 5 and Table 6.

A I relied on unit-level hourly commitment status data provided by SPS to arrive at the values shown in Table 5 and Table 6. For each unit, I calculated the total number of hours of data provided for each year, and the number of hours each unit's commitment status was set to Economic, Outage, Reliability, and Self-Commit. Finally, I divided the hours for each commitment status by total hours of data to arrive at the percentage of hours that each unit was set to a given commitment status.

Q How does SPS describe its unit-commitment practices?

A SPS asserts that "under most market operating conditions, SPS offers the Tolk and Harrington units into the SPP Integrated Market ("IM") in "market status" which allows the SPP IM to economically commit and dispatch the units according to market needs." SPS further indicates that it will "'self-schedule' Tolk and Harrington units under certain conditions…"[13] As a matter of fact, however, most of the time SPS does *not* offer the Tolk or Harrington units in 'Market' (by which the Company presumably means to suggest 'Economic' status) as illustrated above. The Company offers no clear explanation for the discrepancy between how it describes its dispatch practices and how it actually dispatches its plants.

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[13] SPS Response to SC 2-8 (*see* Exhibit DG-2). "SPS will 'self-schedule' Tolk and Harrington units under certain conditions such as required environmental emissions testing, unit performance testing, coal bunker management for safety purpose, and to ensure adequate reserve margins for system reliability under high demand and adverse weather conditions that jeopardize the renewable energy production; such as extreme hot or cold weather, icing, wind over speed, cold and hot temperatures cut outs of the wind turbines and potential impacts to natural gas supplies for the SPS generating fleet."

Q Do you have concerns with SPS's commitment practices?

A Yes. SPS's claim that it offers Tolk and Harrington in Market status under most operating conditions is not supported by the Company's own dispatch record, in which the Company has clearly designated the units with a Self-Commit status [redacted] (see Table 5 and Table 6).[14] In the past, when natural gas prices were higher and renewable prices were still coming down, the coal plants may have actually been earning enough revenue to cover their operational costs during a majority of hours. (Note this does not mean that the units were covering their fixed and capital costs, and were therefore overall economic to operate.) In this context, applying a Self-Commit status would not have had as large an impact on market conditions as it would today. However, the modern market environment is driven by persistently low gas prices and greater levels of zero-marginal-cost renewables such as wind and solar. In this context, the coal units are actually uneconomic to operate during a large portion of the year, and SPS's continued bias in favor of committing and dispatching them is costing ratepayers millions of dollars a year.

Q Have other entities raised concerns about self-commitment in the SPP region?

A Yes. The SPP Market Monitor raised this concern in its 2018 *State of the Market* report, in which it states: "Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and

[14] Exhibit SPS-SC 2-6(b)(CONF)(CD) (*see* Exhibit DG-2).

low prices."[15] The SPP Market Monitor's report further states that it continues to "view reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals."[16]

Moreover, public utilities commissions in both Minnesota and Missouri have opened formal dockets to investigate utility self-dispatch practices.[17] Additionally, the Sierra Club recently published a report outlining the problems that self-commitment and uneconomic dispatch pose in wholesale energy markets (known as "ISOs" or "RTOs").[18]

Q Have you conducted any additional analyses that explore the frequency with which SPS operates its units at a loss, beyond the economic analysis presented above in Section 3(ii)?

A Yes. I used data provided by SPS to determine the number and percentage of hours in which each unit operated when the hourly unit-level LMP was less than the unit's variable O&M costs and fuel costs.[19] This analysis is similar to what I

[15] Exhibit DG-3, Southwest Power Pool - Market Monitoring Unit, *State of the Market 2018* at 5 (May 15, 2019), *available at*: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.

[16] *Id.*

[17] *See* Missouri Public Service Commission, Docket No. EW-2019-0370; Minnesota Public Utilities Commission, Dockets Nos. E999/AA-17-492 and E999/AA-18-373.

[18] Exhibit DG-4, Fisher, Jeremy, *et al.*, *Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets,* Sierra Club (October, 2019), *available at:* https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

[19] I relied on: hourly unit-level generation data provided in Exhibit SPS-SC 1-10(a)(CD); hourly unit-level day-ahead LMP data provided in Exhibit SPS-SC 2-6(i)(CD); unit-level variable O&M costs data provided in Exhibit SPS-SC 2-6(g)(CONF)(CD), provided at irregular intervals but with at least one unit-level datum per year; and monthly plant-level fuel costs data provided in Exhibit SPS-SC 1-10(b) (*see* Exhibit DG-2).

presented in Section 3(ii), except here I focus on the frequency of hourly results rather than net annual results. Specifically, I calculated the percentage of annual operational hours in which each unit's fuel costs alone are greater than the unit's LMP. Then I added in each unit's variable O&M costs and calculated the percentage of hours where the combined variable and fuel costs exceed the unit's LMP.

Q What did you find about the frequency with which SPS operates the Tolk and Harrington units at a loss?

A I found that in 2016 and 2017, for more than [redacted] of the operational hours at Harrington and Tolk, the units' estimated[20] fuel costs were greater than the units' LMP (Figure 3). When I added in the estimated variable O&M costs to the fuel costs, that percentage increased to [redacted] of the time (Figure 4). Plant performance for both Tolk and Harrington appears to improve in 2018, but this is due in large part to the LMP spike in 2018. There is no reason to believe that LMPs will remain at this level; in fact, the average day-ahead energy prices were 10 percent lower this summer (2019) than they were in the summer of 2018.[21] It is important to note that for Tolk, this slight improvement in 2018 was also concurrent with SPS introducing an Opportunity Cost Calculator (OCC) at Tolk to alter the offer price to reduce dispatch and conserve water.[22] It is concerning that the combination of the OCC and the high LMPs only slightly

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[20] Estimated because fuel costs data was provided on a monthly basis only.

[21] Exhibit DG-5, Southwest Power Pool - Market Monitoring Unit, *State of the Market Report, Summer 2019* at 2 (Oct. 25, 2019), *available at*: https://www.spp.org/documents/60882/spp_mmu_qsom_summer_2019.pdf.

[22] OCC was introduced in April 2018. SPS Response to SC 2-5 (*see* Exhibit DG-2).

improved unit performance. This indicates that even when the plant switches to seasonal operations, its fuel and variable costs could still likely exceed its LMPs.

Figure 3. Percent of operational hours where estimated fuel costs were greater than LMP, 2016-2018 CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 1-10(a)(CD); Exhibit SPS-SC 2-6(i)(CD); Exhibit SPS-SC 2-6(g)(CONF)(CD); Exhibit SPS-SC 1-10(b) (see Exhibit DG-2).

Figure 4. Percent of operational hours where estimated fuel costs plus variable O&M costs were greater than LMP CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 1-10(a)(CD); Exhibit SPS-SC 2-6(i)(CD); Exhibit SPS-SC 2-6(g)(CONF)(CD); Exhibit SPS-SC 1-10(b) (see Exhibit DG-2).

Q Is there a monthly or seasonal trend in uneconomic dispatch by SPS?

A Yes, as shown in Table 7 and Table 8, all units operated uneconomically during a larger portion of the off-peak season hours—namely, October through May—compared to the on-peak season hours—June through September. Below, Table 7 shows the estimated percentage of peak and off-peak season hours when just the units' fuel costs were larger than the units' LMP. Table 8 shows the percentage of peak and off-peak season hours when the units' total variable operational costs, which includes fuel and variable O&M costs, were larger than the units' LMP.

Table 7. Operating hours with fuel costs > LMP (%) by peak season and off-peak season CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 1-10(a)(CD); Exhibit SPS-SC 2-6(i)(CD); Exhibit SPS-SC 2-6(g)(CONF)(CD); Exhibit SPS-SC 1-10(b) (see Exhibit DG-2).

Note: Peak season is defined as June–September; Off-peak is defined as October–May.

Table 8. Operating hours with total operational costs > LMP (%) by peak season and off-peak season CONFIDENTIAL

[redacted]

Source: Exhibit SPS-SC 1-10(a)(CD); Exhibit SPS-SC 2-6(i)(CD); Exhibit SPS-SC 2-6(g)(CONF)(CD); Exhibit SPS-SC 1-10(b) (see Exhibit DG-2).

Q Do you know how the magnitude of total operational losses or revenues break down by peak and off-peak season?

A No. We know total annual net operational losses (or revenues), which I presented in Section 3(ii). However, we do not know how those losses break down by season because SPS has not provided data on hourly costs (which Sierra Club requested).[23] Without these more granular, hourly data, we are unable to calculate operational losses by season. To be clear, the data in Table 7 and Table 8 tell us about the estimated *frequency* of uneconomic operation, but not the *magnitude*. This means we do not know if, on the whole, the Tolk and Harrington units are actually covering operational costs during the peak season (but not off-peak season), or if they are uneconomic during both seasons. The Commission should require SPS to produce this information to evaluate the reasonableness of the seasonal operation plan for Tolk, and to help determine whether seasonal operation at Harrington would benefit ratepayers relative to continued full-year operations.

Q What are the implications of this section's findings of uneconomic plant operations and unit commitment decision-making by SPS?

A These results indicate that, in many hours over the past three years (the historical years for which SPS provided data), SPS is often committing and dispatching its units in ways that result in net operational losses. This means the plants are not even covering their operational costs, let alone earning enough to cover the fixed and capital costs required to make the plant economic and reasonable to keep online. Moreover, these losses could have been avoided or mitigated by choosing not to offer the units into the SPP market in self-commit status—at the least during the off-peak season. The years with net operational losses represent extreme cases of uneconomic operations (relative to years when the plants covers operational costs, but do not fully cover fixed and capital costs). These findings

[23] Fuel costs were provided as monthly averages, and variable O&M costs were provided for only a few hours per unit for the years 2016 through 2018. Exhibit SPS-SC 2-6(g)(CONF)(CD); Exhibit SPS-SC 1-10(b) (*see* Exhibit DG-2).

indicate that SPS is imprudently making its unit commitment and operations decisions. In doing so, the Company is incurring net operational losses that it passes on to its retail ratepayers.

Q What are your recommendations to the Commission with regard to SPS's request for O&M for Tolk and Harrington?

A I recommend that the Commission disallow recovery of a portion of the requested test year O&M costs from April 1, 2018–March 31, 2019 for Tolk and Harrington on the basis that the plants have been, on average, failing to cover even their operational expenses. Specifically, the Commission should disallow recovery of O&M associated with the units' uneconomic self-commitment dispatch practices. To calculate the exact amount to disallow, I recommend that the Commission require SPS to first calculate total operational revenues or losses on a monthly basis. For the months with net uneconomic operations, the Commission should disallow the increment of cost incurred to operate and dispatch the unit that is over and above the cost at which SPS could have purchased energy from the market.[24]

I further recommend that the Commission investigate whether costs have been improperly passed on to customers due to uneconomic self-commitment and dispatch of Tolk and Harrington through a docket dedicated to the issue. At a minimum, the Commission should make clear that it will continue to evaluate the issue in future proceedings, including in SPS's fuel and purchased power cost adjustment clause ("FPPCAC"), rate, and planning dockets.

[24] Alternatively, the Commission would disallow just the portion of O&M incurred to operate the units during the hours they are operating uneconomically in self-commit mode.

4. TOLK AND HARRINGTON ARE LIKELY TO CONTINUE TO BE UNECONOMIC INTO THE FUTURE, AT UNNECESSARY COST TO RATEPAYERS

Q Please provide a summary of this section.

A In this section I evaluate the likely future economic performance of both Tolk and Harrington using the forward-going cost projections and power prices provided by SPS.[25] First, I calculate projected future net revenues or losses for each unit and find that continued operation of both Tolk and Harrington is likely to result in substantial losses to ratepayers from 2020-2032. Then, to back up these findings, I compare just the Company's projected costs to the revenues that would be required to avoid operating at an economic loss, *i.e.*, "break-even revenues." I compare the results to the historical revenues, and I find that both Tolk and Harrington would need to earn significantly more revenue than each unit has historically to avoid continuing operating at a loss.

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[25] After the close of business on November 21, 2019, the evening before the filing deadline for this testimony, SPS provided a supplemental discovery response to SC 3-1, in which the Company admitted that it erroneously designated May as a "summer peak" month in its Tolk Strategist analysis. Given the late disclosure and the fact that SPS has not provided the updated Strategist output results for our review, or an update to the monthly data requested in SC 3-1, I was unable to incorporate the new information into this testimony.

I will note, however, that SPS's error appears to have biased the Company's analysis in favor of continuing to operate Tolk, for at least two reasons. First, since the plant will be operating only four months, rather than five, that means SPS will receive approximately 20% less annual revenue (even though variable O&M and fuel costs drop by the same percent, SPS relies on projected power market prices that are higher than projected fuel and variable costs) . Second, since the additional year of operation will be when the water shortage is most extreme, the extended operation may require additional wells and associated costs. In light of SPS's corrected discovery response, I reserve the right to supplement or amend my testimony and conclusions, as may be appropriate.

Q **Using the data provided by SPS, what can you say about the likely future economic performance of both plants?**

A I find that both Tolk and Harrington are very likely to lose ratepayers a substantial amount of money between 2020 and 2032. Specifically, I find that Tolk could lose anywhere between $8 million and $234 million and Harrington could lose between $49 and $510 million between 2020 and 2032, depending on how often each plant is dispatching during on-peak and off-peak times.[26] Based on the likely scenario that each plant dispatches two-thirds of its monthly generation during on-peak hours, and one-third during off-peak hours (Table 9), I find that Tolk is likely to lose $88 million and Harrington is likely to lose $202 million between 2020 and 2032.

[26] The upper and lower bounds associated with dispatching 100% of generation during on-peak hours or 100% during off-peak hours are not feasible because start-up and shut-down costs would prevent the units from operating in this manner. In reality, a portion of each unit's generation will be dispatched during on-peak hours, and a portion off-peak.

Table 9. Projected net revenues (losses) assuming 2/3 of generation is dispatched during on-peak hours and 1/3 during off-peak hours

[redacted]	[redacted]	[redacted]
Tolk 1	$14	
Tolk 2		
Harrington 1		
Harrington 2		
Harrington 3		

Source: SPS response to SC 1-23; SPS response to SC 3-1; Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx"; SPS response to SC 1-26 (see Exhibit DG-2).

Q Describe how you calculated the values in Table 9.

A I calculated the forward-going costs the Tolk and Harrington units are projected to incur based on adding together the fuel costs, variable O&M costs, fixed O&M costs, and ongoing capital costs—including the costs to drill additional wells at Tolk (allocated evenly between Units 1 and 2)—provided by Company witness B.F. Weeks in the Strategist output files.[27] I then calculated energy revenue using monthly generation data from the Tolk Strategist model[28] and the monthly on and off-peak power prices provided by SPS for SPP South.[29] I assumed that two-thirds of monthly generation was dispatched during on-peak hours, and one-third was dispatched during off-peak hours.

[27] Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx."

[28] SPS Response to SC 3-1 (*see* Exhibit DG-2).

[29] SPS Response to SC 1-26 (*see* Exhibit DG-2). SPS provided projected power prices for several locations; however, given the location of Tolk and Harrington in SPP south, I selected the prices for this location.

Q SPS's data seems to indicate that Tolk will become more economic after 2025. Do you think this is accurate and does this support continued operation of the plant?

A No. First, the plant is projected to lose significant money relative to the market between now and 2025. Those losses far outweigh the projected net revenues. Second, projected revenues are based on power market price projects that are increasingly uncertain as you get further out. Finally, the Company appears to be understating the costs to maintain access to sufficient water at Tolk based on the Company's recent historical spending on water supply and water availability projects at Tolk. While it is reasonable for SPS to project lower O&M costs when the plant switches to seasonal operation, and to avoid spending on large capital projects as the plant nears retirement, [30] SPS's projection of future capital investments needs to reflect the full likely costs to maintain access to sufficient water. Between 2014 and 2017, SPS spent $11.2 million on water supply and water availability-related capital investments, and the Company has spent an additional $4.9 million since the beginning of 2019. [31] Going forward, SPS projects spending an average of only $1 million annually on water projects at Tolk.[32]

[30] With a switch to seasonal operation, SPS will have to recover the fixed and capital costs over a smaller portion of hours. However, SPS asserts that with a switch to seasonal operation, O&M will be lower and "the interval between [capital] projects can be extended." Further, SPS states that "all capital projects in the later years will be evaluated for the need during managed decline phase of the units." SPS Response to SC 1-23 (*see* Exhibit DG-2).

[31] SPS Response to SC 1-24 (*see* Exhibit DG-2).

[32] Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx".

Q **Given the uncertainty about future conditions, have you performed any other analysis to support your findings above?**

A Yes. I have also performed break-even analysis to focus on just SPS's projected costs, and the revenue required to cover those costs. The analysis I presented above, comparing projected future costs and revenues for each unit, relies on uncertain power price projections years into the future. This analysis also required me to make a key assumption about when each unit was dispatching. The analysis answers the question, "Based on the power prices and costs provide by the Company, and your assumptions around unit dispatch, what is the likely economic performance of each unit." The break-even analysis, on the other hand, is based almost entirely on the Company's information and involves minimal additional operational assumptions. It answers the question, "What assumptions about future power prices are needed for the analysis to show positive net revenues, given the Company's assumptions around future costs, in order for the plants to earn net revenues."

Q **What is a break-even analysis?**

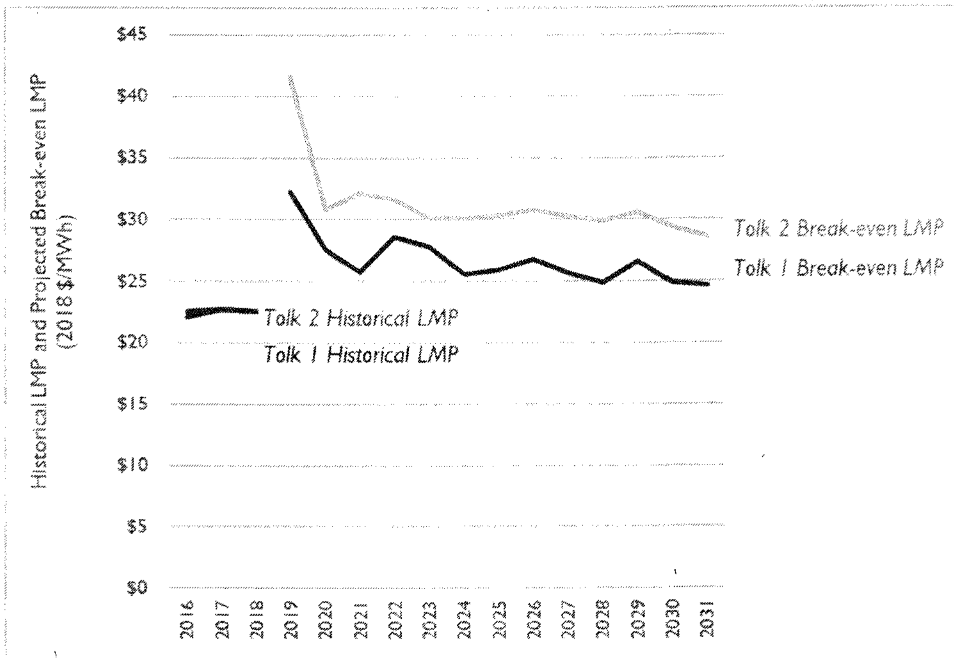
A A break-even analysis in this context calculates the LMP or the revenue that is required for the plant's revenues to exactly equal its operational costs (fuel and variable O&M). The break-even LMPs can be thought of as the minimum average LMP a unit must receive for generation in order to not lose money during a given year. If the actual, average LMPs during a year are less than the break-even LMP, the unit would operate at 1-256a loss. Break-even total revenue can be thought of as the minimum total revenue that a plant must earn in a year, based on the calculated LMPs and the likely projected future generation levels.

Q Please summarize your findings regarding the future economic performance of the Tolk units.

A Using future cost and generation projections provided by SPS,[33] and historical LMPs from SPP,[34] I find that the Tolk units will need to receive an average LMP that significantly exceeds average peak-season LMPs from the recent past (2015–2018) to avoid operating at an economic loss (Figure 5). I present the forward-going costs as the hourly LMP that the Tolk units would need to earn. I compared these projected LMPs to historical annual average hourly LMP for each unit from the months of June through September based on hourly unit-level LMPs from the SPP from 2015 through 2018. SPS has presented no evidence or projections that indicate that the Company believes future LMPs will increase to the level required to make sustained operation of Tolk economic.

[33] Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx."
[34] *Available at*: https://marketplace.spp.org/pages/rtbm-lmp-by-location.

Figure 5. Tolk Units 1 & 2 historical and future break-even LMPs, 2015–2032



Source: Source: Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx."

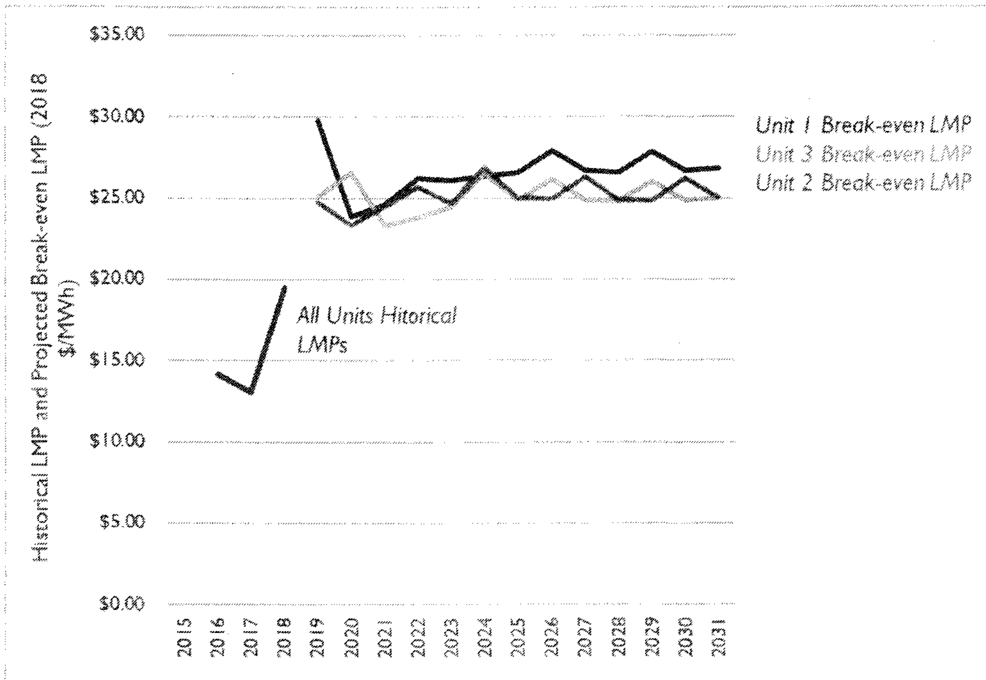
Note: Historical LMPs represent the average of the hourly LMPs for only the four on-peak months that SPS plans to operate Tolk beginning 2020 (June through September).

Q Please summarize your findings regarding the future economic performance of the Harrington units.

A Using the same data provided by SPS, I calculated the forward-going costs that the Harrington units are projected to incur through 2032, and therefore the revenues and LMPs that the Harrington units would need to receive to operate economically. Figure 6 shows that for the Harrington units to avoid operating at a loss they would need to receive annual average LMPs in most years that exceed the annual historical average LMPs they received from 2015 through 2018. Despite the 2018 spike in SPP energy prices, there is no evidence to support an assumption that future revenues and LMPs will continue to increase to a level required to sustain economic operations. Using past LMPs as a proxy for future

LMPs, all three Harrington units would be operating at an economic loss in the majority of years through 2032.

Figure 6. Harrington Units 1–3 historical and future break-even LMPs, 2015–2032



Source: Workpaper of B. Weeks, "SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx."

Q Describe how you arrived at the values in Figure 5 and Figure 6.

A I calculated the forward-going costs the Tolk and Harrington units are projected to incur using the same data and methodology outlined in the first part of this section.[35] I used the projected annual costs for each unit net of the capacity value to estimate the level of annual revenues SPS would have to receive from the ancillary and energy markets in order to break even. That is, if the annual revenues for a unit were exactly equal to the annual costs, the unit would achieve

[35] Workpaper of B. Weeks, "SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx."

break-even economic status. However, if the annual revenues are less than the annual costs, the unit would be operating at a loss.

Because SPS plans to reduce operations at Tolk and operate the plant only from June through September (peak season) between 2020 and 2032,[36] it is not useful to directly compare forward-going break-even revenues with historical revenues.[37] Instead, I divided the calculated annual break-even revenues by projected generation by unit—provided in SPS's Strategist output files[38]—to arrive at break-even LMPs. For consistency of analysis, I present the results from Harrington as a break-even LMP as well based on year-round operation.

Q Is there other analysis that supports your overall economic assessment of SPS's Tolk and Harrington Stations' forward-going economics?

A Yes. Analysis from SPP's Market Monitoring Unit (MMU) supports this assessment. SPP's 2018 *State of the Market* report describes coal plant economics within the SPP region and indicates that "…MMU analysis shows that market revenues do not support going forward costs for coal resources."[39]

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[36] Direct Testimony of B. Weeks at 22.

[37] Due to the reduced operations in the forward-going analysis, forward-going production costs will be lower than historical production costs, and consequently the break-even revenues will be less than historical revenues.

[38] Workpaper of B. Weeks, "SO -_SPS_SCENARIO2_REDUXOPS_2031.xlsx."

[39] Exhibit DG-3, Southwest Power Pool - Market Monitoring Unit, *State of the Market 2018* at 2 (May 15, 2019), *available at*: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.

Q What are the implications of these uneconomic results for ratepayers?

A Based on SPS's own input assumptions, we find during two separate types of analysis, that Tolk and Harrington are very likely to continue operating at a loss going forward. This means that ratepayers will continue to pay for SPS to uneconomically operate the Company's coal fleet.

Q What are your recommendations to the Commission with regard to any request for recovery of future capital investments at Tolk and Harrington?

A Given that Tolk and Harrington will likely remain uneconomic, I recommend that the Commission preemptively deny recovery of the costs of any substantial future capital projects that may be intended to prolong the lives of Tolk and Harrington as generating assets. It is unreasonable for ratepayers to spend any more money to keep economically non-competitive plants online, particularly in light of the impending water shortages at Tolk.

5. TOLK CANNOT ECONOMICALLY PROCURE WATER TO OPERATE THROUGH ITS UNITS' CURRENT RESPECTIVE RETIREMENT DATES OF 2042 AND 2045

Q Please summarize this section.

A In this section I review SPS's request to adjust the depreciation dates of the two Tolk units based on a retirement date of 2032, accelerated from the current dates of 2042 for Unit 1 and 2045 for Unit 2. Specifically, I examine the Company's groundwater modeling and economic analysis and find that the modeling and analysis supports the Company's assertion that it cannot economically procure groundwater to maintain operations at Tolk through 2042 and 2045.

Q What is SPS's request regarding future operations of Tolk in this rate case?

A SPS requests the following relief:

- A change to the Tolk Station retirement dates from 2042 for Unit 1 and 2045 for Unit 2 to 2032 for both units, and a switch to seasonal operation starting in 2021.[40]
- A change in the depreciation lives of the Tolk Units to 2032 for generating purposes.[41]
- A depreciable life for the assets associated with Tolk's operation in synchronous condenser mode ending in 2055.[42]

Q Has SPS previously requested a change in the remaining useful life for Tolk?

A Yes, in SPS's last rate case, the Company requested to shorten the retirement dates for Tolk for depreciation purposes. However, SPS did not officially request a 2032 retirement date until this case.[43]

Q Why is SPS requesting a change in the remaining useful life date for Tolk?

A SPS is requesting a change to the retirement date, and plans to switch to seasonal operations at Tolk, due to the "continuing and irreversible decline of the Ogallala Aquifer."[44] SPS asserts that if Tolk continues to operate at current levels, economic depletion of the aquifer will occur between 2024 and 2026. Once

[40] Direct Testimony of W. Grant on Behalf of SPS at 8.
[41] Direct Testimony of M. Lytal on Behalf of SPS at 5-6.
[42] *Id.*
[43] Direct Testimony of W. Grant at 79.
[44] Direct Testimony of M. Lytal at 4.

economic depletion occurs, the cost to secure water through continued drilling of new wells or alternative procurement measures will make it uneconomic to ratepayers for SPS to continue operating the plant.[45]

Q What alternative solutions has SPS explored to procure the water needed to keep Tolk operating through its original retirement dates of 2042 and 2045?

A SPS explored alternative solutions in the prior rate case; specifically a water pipeline project with the City of Lubbock and the construction of hybrid cooling towers.[46] However, the City of Lubbock notified SPS that it is not able to provide Tolk the required quantity of water, and the construction of two hybrid cooling towers would be cost prohibitive at around $236 million.[47] Based on this and other assessments, SPS has asserted that "there is no feasible operational scenario that would allow SPS to economically maintain the Tolk generating units until the end of their currently approved service lives in 2042 and 2045."[48]

Q Has SPS already been facing water supply challenges at Tolk?

A Yes. As the Ogallala Aquifer is depleted and the level of saturated thickness drops,[49] SPS has had to drill an increasing number of wells to supply the water needed for peak operations. Tolk's well count has increased 207 percent since 1992, yet total wellfield production has declined by 25 percent during the same

[45] *Id.* at 38.

[46] Direct Testimony of W. Grant at 82.

[47] Company Witness Grant stated "SPS has determined that the installation of hybrid cooling towers at Tolk to be economically imprudent given the age of Tolk, the uncertainty and cost of the technology, and the potential for increased environmental costs that may occur at some point in the future." *Id.* at 83.

[48] Direct Testimony of M. Lytal at 81.

[49] The saturated thickness of the aquifer is defined as the distance from the water table to the base of the aquifer.

timeframe.[50] SPS hired an external firm, WSP USA, to perform its groundwater modeling. WSP's 2018 groundwater modeling concluded that SPS would have trouble extracting enough water from the wellfield to meet peak demand in the summer starting in 2019.[51]

Q Has Tolk undertaken any projects recently related to water supply access?

A Yes. Tolk added eight new wells between 2018 and 2019 to offset predicted production deficits from the current wells.[52] SPS acknowledged that the Company will need to continue regularly drilling new wells to sustain operation through 2031.[53]

Q Has SPS presented sufficient evidence to support its assertion that Tolk cannot feasibly maintain operations at current levels through the units currently approved service lives of 2042 and 2045?

A Yes. Based on groundwater data collected for the Company between 2007 and 2018,[54] and the Company's evaluation of alternatives, SPS has presented ample evidence to demonstrate that the costs of obtaining the water required to sustain operation through 2042 and 2045 far exceeds economic levels. In light of the rapidly deteriorating water supply, it is clear that the Tolk units should be retired

[50] At the time Tolk was built, the wellfield average flow was approximately 700 gallons per minute (gpm) per well; now the flow rate is approximately 200 gpm and projected to drop to between 50-80 gpm as the aquifer is further depleted. Direct Testimony of M. Lytal at 65.

[51] *Id. at* 64.

[52] *Id.* at 64.

[53] *Id.* at 76-77.

[54] Sources included 3-D modeling and other public data from the High Plains Water District ("HPWD"), modeling and data from the United States Geological Survey, semi-annual wellfield productivity test, and groundwater modeling from the firm WSP.

by 2032 *at the latest*. Indeed, our analysis of the Company's own data makes clear that customers would save money by retiring the plant even sooner. Based on this, I recommend that the Commission approve a retirement (and depreciation) date for Tolk no later than 2032, or ideally earlier.

6. SPS HAS NOT DEMONSTRATED THAT SEASONAL OPERATION OF TOLK THROUGH 2031 IS THE LOWEST-COST OPTION FOR SERVING CUSTOMERS' NEEDS

Q Please summarize this section.

A In this section I first explain SPS's proposal to conserve water by operating Tolk seasonally as a generator from 2020 through 2031, and by operating the unit as a synchronous condenser in the off-peak season. I summarize the groundwater modeling and Strategist analysis upon which SPS relied and outline my concerns with the groundwater modeling and economic analysis. Then, in Section (i), I review how the risk of water shortage is incorporated into SPS's water model. In Section (ii), I discuss an alternative use for the water currently used at Tolk. In Section (iii), I outline how water shortages can impact modeling of peak capacity. In Section (iv), I review the Company's Tolk Strategist analysis. Finally, in Section (v), I outline how to incorporate each of the water-related risks and opportunities into the Company's economic analysis.

Q Please explain SPS's proposed seasonal operation plan at Tolk between now and the proposed retirement date of 2032?

A To conserve the economically recoverable water to which Tolk has access, and to extend the life of the plant to maintain the capacity value of the plant, SPS is proposing to reduce operations seasonally.[55] Between 2019 and 2020, SPS proposes to operate Tolk as a coal-fired generator at full "economic dispatch" between June through September, and to operate the unit only at minimum load in the remaining off-peak months.[56] Then, starting in 2021, SPS proposes to continue full "economic dispatch" operations during the peak months (June–September) and operation in synchronous condensing mode during the off-peak months (October–May).[57]

Q Why does SPS propose to operate Tolk in synchronous condenser mode when it is not operating as a generator?

A Tolk currently provides voltage stabilization to the transmission system when it generates electricity.[58] SPS claims that the regional transmission system will face voltage constraints when Tolk is not generating electricity. Installation of a synchronous condenser and operation in synchronous condenser mode will allow the plant to provide the voltage stabilization SPS asserts is needed without operating the plant in generation mode and consuming fuel.

Q What analysis did SPS rely on to develop its strategy to operate Tolk seasonally?

A As noted, SPS relied on 2018 groundwater modeling from the firm WSP to evaluate whether the groundwater supply could roughly meet the required demand

[55] Direct Testimony of M. Lytal at 50, 72.

[56] Direct Testimony of B. Weeks at 22. SPS indicates that because of the time required to install the synchronous condenser, it is not feasible to take Tolk offline during the off-peak months beginning in 2019.

[57] *Id* at 17.

[58] Direct Testimony of M. Lytal at 72.

for continued operation under both current operations (typical demand) and seasonal operations (optimized demand).[59] Based on the results of this modeling, SPS then developed a spreadsheet-model ("SPS's water model") to more closely evaluate Tolk's long-term water supply under five operating scenarios[60] and identify a water depletion window in which the Company could no longer economically meet its generation cooling needs.[61] SPS then input the parameters from the water model into the Strategist model ("Tolk Strategist analysis") to calculate present value revenue requirement of each scenario.

Q Do you have any concerns with the way SPS incorporated its water depletion assumptions into the economic analysis?

A Yes. SPS asserts that seasonal operation of the plant offers the lowest-cost option for ratepayers. However, SPS's Tolk Strategist analysis contains several flaws and shortcomings—specifically that it: (1) does not properly account for the risk that the amount of economically recoverable water may fall faster than currently contemplated; (2) does not consider the revenue that could be gained by selling the remaining water in place of using it to support plant operations; (3) does not directly consider the impact that accelerated water shortages could have on the plants' peak availability; and (4) is limited to five scenarios that each assume continued operation and do not contemplate retirement earlier than 2025 alongside replacement with alternatives.

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[59] Direct Testimony of M. Lytal at 72.

[60] Direct testimony of M. Lytal at 72; SPS Response to SC 1-25(CD) attachment Tolk_x water supply model_scenario_2 (*see* Exhibit DG-2); Direct Testimony of M. Lytal at Attachment ML-6(CD).

[61] Direct Testimony of M. Lytal at 73.

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

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:

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[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.

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[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.

magnitude of uncertainty from external pumping compares to the magnitude of impacts from changing plant operations.[68] Without this information, the Commission cannot know on whether internal operational efforts by SPS to manage aquifer depletion rates could be easily negated and overwhelmed by changes in external pumping practices.

Q How does SPS's water model take into account the uncertainty of pumping by agricultural and municipal parties in the area?

A SPS's water model uses a small range (three years) of potential depletion dates to capture some uncertainty.[69] However, the model does not directly quantify or evaluate uncertainty from agricultural and municipal pumping. SPS's water modeling focuses only on how changes in operation of its own plants impact the water depletion timeline.[70]

Q Do you have any other concerns with SPS's modeling of future water availability?

A Yes. None of the groundwater modeling on which SPS relies considers the risk of future regional droughts leading to less economically recoverable water.[71] Drought can directly impact the water available to Tolk. For example, by decreasing the surface water available to municipal and agricultural parties in the

[68] SPS Response to SC 1-19 (*see* Exhibit DG-2). SPS states that it has not performed any analysis to evaluate or quantify the risk of less than projected economically recovery water resources preventing seasonal operation of the Tolk plant through 2032.

[69] *Id.*

[70] SPS Response to SC 1-25(CD) attachment Tolk_x water supply model_scenario_2 (*see* Exhibit DG-2).

[71] SPS Response to SC 1-18 (*see* Exhibit DG-2).

area, drought can cause an increase in the rate at which they draw from the aquifer beyond the levels anticipated.

Q Has SPS adequately demonstrated that optimized seasonal operations will ensure there is sufficient water to sustain operations through 2031?

A No. While SPS has definitely demonstrated that there is not sufficient water to sustain operations through the currently approved 2042 and 2045 retirement dates, the Company's analysis does not demonstrate that there will be sufficient water to sustain operations through 2031. As discussed above, SPS will face increasing challenges meeting groundwater need as soon as 2019 and accelerating beyond 2024.[72] Despite this, SPS is still proposing to run Tolk in seasonal operations mode for an additional 13 years beyond the 2019 date of increasing challenges, and eight years beyond the 2024 date of the onset of accelerating problems.

Q If the evidence does not definitively support the feasibility or economic soundness of operation through 2031, why is SPS proposing this date?

A It is unclear why SPS is requesting approval for a 2032 retirement date for ratemaking reasons while simultaneously admitting its analysis shows that an earlier retirement date is likely.[73] Specifically, Witness Weeks includes the following in testimony:

[72] Direct Testimony of M. Lytal at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3.

[73] Direct Testimony of B. Weeks at 22-23.

> Q: "If SPS's analysis shows that the retirement date for Tolk could be earlier than 2032, why does SPS propose a 2032 retirement date for ratemaking purposes?"
>
> A: SPS is proposing this date to be conservative for ratemaking purpose. SPS first requested a 2032 retirement date in Case No. 17-00255-UT but the request was denied…[74]"

The lack of clarity provided by the Company here on why the 2032 date was selected indicates that it is was likely arbitrarily selected rather than supported by analysis or actual evidence.

ii. SPS's economic analysis does not consider alternative uses for the water other than plant operations at Tolk

Q Has SPS considered selling its water rights instead of using the water to operate Tolk?

A No. SPS claims it has not explored any opportunities to sell the water the Company would otherwise use to operate Tolk.[75]

Q Is there evidence that there would be demand for Tolk's water supply or Xcel's water rights?

A Yes. SPS discussed the possibility of buying water from the City of Lubbock. This plan was not pursued because the City realized it did not have sufficient

[74] Direct Testimony of B. Weeks at 22-23.
[75] SPS Response to SC 1-20 (*see* Exhibit DG-2).

water to supply Tolk.[76] SPS has also discussed the declining levels of water available for area agricultural and municipal parties. All of these parties facing water shortages themselves present potential buyers for the water that SPS is currently using to run Tolk.

Q What is the implication of omitting this potential revenue stream from economic or retirement analysis of Tolk?

A The value of selling the water or water rights represents a real value stream that SPS could realize under alternative resource scenarios. Omitting potential revenue streams from the sale of Tolk's water results in an undervaluing of alternative resource options relative to continued operations of Tolk.

iii. <u>SPS's economic analysis does not properly reflect how the water shortage will impact peak capacity availability</u>

Q How does uncertainty about future water availability discussed above impact the economics of operations at Tolk?

A SPS cited the value of Tolk's capacity as a reason to maintain the unit as a seasonal resource.[77] However, WSP's findings clearly indicate that SPS will have trouble maintaining access to water sufficient to support peak summer operations beyond 2019.[78] Based on this uncertainty, SPS cannot rely on Tolk's full capacity as a firm resource during summer peaks. Therefore, modeling Tolk at its full

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[76] Direct Testimony of W. Grant at 82.
[77] Direct Testimony of M. Lytal at 72.
[78] Direct Testimony of M. Lytal at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3.

capacity results in an overstatement of the summer capacity value that Tolk actually provides to the system and overstates the value of keeping Tolk operating as a generator.

iv. ***SPS's economic analysis is limited in scope and fails to consider retirement in advance of 2025***

Q Please summarize this section.

A In this section I review the limitations of the Strategist modeling that SPS performed using the water depletion findings from the Company's water model. I discuss how SPS constrained its analysis to only five scenarios and did not consider retirement in advance of 2025 in any of its scenarios. Then, I discuss why the Tolk Strategist analysis does not actually provide adequate information on whether continued operation of Tolk in seasonal mode through 2031 is the least-cost option for ratepayers.

Q Please describe SPS's Strategist analysis and how it connects with the WSP groundwater modeling, and SPS's water model.

A SPS used the Company's water model to develop an estimate of when aquifer depletion would occur based on five different scenarios of plant operation. SPS then modeled these five scenarios (Table 10) of plant operation in the Strategist model,[79] along with the costs required for each, to determine the total cost of each

[79] "Strategist is a resource planning model specifically designed to determine the least-cost resource mix for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions." Direct Testimony of B. Weeks at 7.

scenario.[80] SPS presented the net present value of revenue requirements ("NPVRR") of each scenario, and the cost difference for each scenario relative to the baseline of sustaining current operations through 2025.

Table 10. Strategist scenarios modeled by SPS

Scenario 1	Full economic dispatch until the water runs out
Scenarios 2-4	Variations of economic dispatch in peak season and operation of one or both units in either Synchronous Condenser mode or at minimum load in off-peak seasons
Scenario 5	Full economic dispatch of one unit with retirement of the other unit and installation of synchronous condenser

Source: Direct Testimony of B. Weeks at 17-18.

Q Do the scenarios modeled capture an adequate range of operational scenarios?

A No. All of SPS's scenarios assume that both units stay online as generators through at least 2025. This means there is no analysis of partial or full retirement of the generation assets in advance of 2025 and replacement with alternatives. In other words, SPS's strategist analysis does not answer the question, "What is the least-cost option for ratepayers going forward to provide the energy, capacity and voltage support services that the system needs, and would otherwise get from Tolk?" Instead, SPS's strategist analysis answers the question, "Assuming the Tolk units stay online as generators through at least 2025, which combination of seasonal operation, generator retirement, and operation in synchronous condenser mode, from among the five options we have outlined, is the lowest cost?" This is

[80] SPS modeled the following costs for each scenario: (1) ongoing capital expenditures; (2) ongoing capital expenditures associated with additional water wells; (3) the cost associated with synchronous condensers; (4) fixed O&M; (5) and costs associated with TUCO fuel handing. Direct Testimony of M. Lytal at 76-77.

not a replacement or a retirement analysis; rather, this is a comparison of the costs of five specific scenarios that all assume full operation through 2025.

Q Is it reasonable for SPS to narrow down a unit replacement or economic analysis to that set of potential scenarios?

A While it can be reasonable for a utility to conduct economic analysis based on comparing only specific scenarios, those scenarios need to be inclusive of the full range of reasonable results, spanning near-term retirement, through long-term continued operation. In this case, the given scenarios were all biased towards continue operations of Tolk, and therefore the scenarios did not encompass a full range of outcomes. Therefore, the results are unsuitable for determining whether seasonal operation through 2031 is the least-cost plan for ratepayers.

Q What are the implications for ratepayers of SPS relying on outdated retirement analysis and incomplete Strategist modeling of seasonal operations?

A Ratepayers are being asked to pay for a resource plan that SPS has not demonstrated is the lowest-cost option to provide the energy, capacity, and voltage support services. Instead, SPS has calculated the net present value of revenue requirements for a few specific scenarios based on a set of incomplete model inputs. This means that SPS is saddling ratepayers with the cost of operating Tolk without adequately evaluating whether retiring the plant prior to 2025, and replacing it with lower cost resources, would be less costly to ratepayers.

v. ***SPS should incorporate the risks and opportunities relating to water and water shortage, among other modifications, into an updated retirement analysis***

Q Please summarize how SPS should incorporate all of the factors outlined above into an updated economic analysis of Tolk.

A SPS should evaluate, and incorporate into an updated unit replacement and retirement modeling of Tolk, the following items (in addition to other modifications described in other sections of my testimony, including additional environmental risks and costs): (1) the value of selling the water (or even water rights) that Tolk would otherwise rely on for cooling; (2) capacity de-ratings for Tolk based on the real and likely risk that water availability may not be able to support future peak operations; and (3) operation of Tolk in synchronous condenser mode year-round starting when the conversion is complete.

Q How should SPS be incorporating the opportunity cost to sell water?

A SPS should add the revenue that the Company would earn from selling Tolk's water, or alternatively the value to the Company of using the water at Plant X as a value stream in its economic modeling. SPS actually does currently include an opportunity-cost adder to alter Tolk's offer price to reduce plant dispatch and reduce water consumption when making dispatch decisions.[81] However, this has not been incorporated into its planning analysis.

[81] SPS Response to SC 2-5b (*see* Exhibit DG-2).

Q How should the uncertainty around future water availability to support peak operations be integrated into SPS's modeling?

A Tolk's firm capacity should be de-rated over the years to reflect the constraints water availability will place on Tolk's ability to meet peak summer demand. In the Strategist model, SPS models Tolk at full capacity (540 MW for Unit 1 and 543 MW for Unit 2) through 2031.[82] This allows SPS to credit the full capacity of Tolk towards meeting its reserve margin, and therefore avoiding new capacity. In reality, Tolk's capacity should be de-rated after 2019 to reflect the risk that the Company will not be able to economically procure sufficient water to support peak operations.

Q What alternatives should SPS be considering for supplying the year-round voltage support services currently provided by Tolk?

A SPS currently plans to get voltage support services from Tolk both when the plant is operating in generation mode and as a synchronous condenser. However, SPS does not need to operate the plant as a generator between June and September (peak season), as currently planned, to obtain voltage support. Instead, as an alternative, SPS should evaluate retiring the generation portions of Tolk as soon as it installs the synchronous condenser, and operating the plant year-round in only synchronous condenser mode. Converting the coal plant exclusively to a synchronous condenser would allow SPS to meet its voltage support needs, while extending the depreciation schedule for the Tolk assets required for synchronous condenser operation.

[82] SPS Response to SC 2-2 (*see* Exhibit DG-2).

7. SPS SHOULD PERFORM UPDATED RETIREMENT ANALYSIS FOR TOLK AND HARRINGTON THAT COMPREHENSIVELY EVALUATES ALTERNATIVES AS WELL AS ENVIRONMENTAL REGULATIONS, WITH ACCURATE UPDATED ASSUMPTIONS

Q Please summarize this section.

A In this section I first review the prior retirement analysis conducted for Tolk and Harrington and find that the most recent analysis from 2014–2015 needs to be updated based on changes in the prices of gas and renewables, which have dramatically shifted the electricity market. I will note that SPS was or should have been aware of these changes ahead of the filing of this rate case. Second, I summarize environmental regulations that could impact plant operations in the future, yet that SPS failed to include in its modeling. I then discuss the likely impact that each would have on plant economics. Finally, I outline my recommendations for an updated retirement analysis for both Tolk and Harrington that fully considers alternative resources and properly evaluates what the system actually needs.

i. SPS's most recent retirement analysis reflects outdated assumptions and market trends

Q When did SPS last conduct retirement analysis for its coal units?

A SPS's last retirement analysis of Tolk and Harrington was completed in the 2014–2015 timeframe (this analysis was conducted using the Strategist model).[83] SPS actually concluded from this analysis that shutting down Tolk would not be

[83] SPS Response to SC 1-6 (*see* Exhibit DG-2).

expensive due to the presence of the production tax credits and investment tax credits for renewables, and due to lower gas and oil prices. Additionally, the analysis concluded that SPS should acquire additional wind resources and seek additional solar resources in late 2016.[84] It is unclear why the Company did not act on this finding. For this current rate case, SPS conducted Strategist analysis as well. However as discussed above, the analysis was constrained to five operational scenarios for the Tolk Plant and did not consider retirement for Tolk prior to 2025.

Q Why should SPS do a full updated unit replacement analysis for Tolk and Harrington?

A There have been large shifts in electricity markets since 2014–2015. These changes include the persistence of low natural gas prices, declining costs of renewables and storage, and minimal growth in electricity demand. The status of environmental regulations that could require large capital expenditures to comply has also changed. Additionally, the new operational constraints at Tolk significantly change the economics of operating the plant. Finally, neither Tolk nor Harrington is locked into a long-term coal contract that would pose a challenge to early retirement; [85] therefore there are no significant cost barriers to retirement.

[84] SPS Response to SC 1-6(a), Exhibit SPS-SC 1-6(a) at 33 (*see* Exhibit DG-2).
[85] Direct Testimony of H.C.Romer on Behalf of SPS at 20.

Q What impacts have electricity market trends had on the operations of coal-fired plants nationwide?

A In recent years, the trends around lower-cost gas and renewables, combined with the higher cost of environmental compliance for higher-polluting coal units, have driven the retirement of many coal units. The EIA recently reported that more than 65,000 MW of U.S. coal capacity retired between 2007 and 2018.[86] Furthermore, 2018 saw nearly 13,000 MW of U.S. coal capacity retired.[87] As an alternative to shutting down, some coal-fired plants, such as the Dolet Hill plant in Louisiana, have switched to seasonal operation, shutting down in off-peak seasons when demand is low and turning back on for just the peak seasons.[88] This decreases the environmental impact of running the plants while allowing the utility to retain the peak capacity.

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[86] Exhibit DG-7, EIA, "U.S. coal consumption in 2018 expected to be the lowest in 39 years." (Dec. 28, 2018), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=37817.

[87] Exhibit DG-8, EIA, "More than 60% of electric generating capacity installed in 2018 was fueled by natural gas." (Mar. 11, 2019), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=38632; Exhibit DG-9, Nelson, William and Sophia Lu, Half of U.S. Coal Fleet on Shaky Economic Footing. Bloomberg New Energy Finance (Mar. 26, 2018).

[88] Exhibit DG-10, Gheorghiu, Iulia. Cleco, "SWPECO shift coal plant use, target 2.8 GW renewables in latest resource plans." Utility Dive (Sept. 6, 2019), *available at*: https://www.utilitydive.com/news/cleco-swepco-shift-coal-plant-use-target-28-gw-renewables-in-latest-reso/562213/.

ii. __SPS needs to include the costs and risks of all likely environmental regulations in its updated retirement analysis__

Q How should SPS include the future costs and risks of environmental regulations?

A SPS should be modeling the projected impact of future environmental regulations that are likely to impact either plant. Specifically, SPS should include sensitivities in an updated unit replacement and retirement analysis on the risks of incurring new expenses for environmental compliance. The cost to comply with several of the regulations is considerable, meaning the economics would likely not support installation of the environmental controls and continued operation of the units. As such, SPS should evaluate resource portfolio options that can economically replace each plant over the range of possible years, reflected the uncertainty in the timing of when the regulations discussed below could be implemented.

Table 11 lists proposed environmental rules and their likely associated cost that SPS should add, at a minimum, to its existing modeling.

Table 11. Proposed and final environmental rules that could impact Tolk and Harrington

[illegible]	[illegible]	[illegible]
Regional Haze	Tolk identified as a "reasonable progress" source contributing to regional haze, and required to install dry scrubbers by Feb 2021; Xcel challenged that rule, and the Fifth Circuit remanded to EPA for review in 2017; there has been no action since, but the plant would be subject to review in 2021 plan.	Tolk: $400–$600 million,[89] plus $24 million annual O&M
Best Available Retrofit Technology (BART)	Harrington identified as "best available control technology" source; no final action taken yet.	Harrington: $400–500 million, plus $21 million annual O&M
Affordable Clean Energy Rule	Emissions guidelines, finalized July 2019.	TBD

Source: SPS response to SC 1-8 (see Exhibit DG-2).

Q Do any SPS company witnesses acknowledge the potential impact of future environmental compliance costs on plant economics?

A Yes, on Tolk specifically. SPS witness Hudson acknowledged the potential impact on Tolk from environmental compliance costs, stating: "It should be noted that future environmental regulations may even further reduce the life span of the plant (Tolk)."[90] Company witness Grant also acknowledged that future environmental regulation could reduce the life span of Tolk as a generating resource, stating in a footnote (in reference to the request for a 2032 retirement date): "It should be noted that future environmental regulations may even further reduce the life span of the plant…"[91] Additionally, the risk of future additional

[89] Includes additional costs for water acquisition that would need to be made to operate the dry scrubbers appropriately. SPS Response to SC 1-8 (*see* Exhibit DG-2).

[90] Direct Testimony of D. Hudson on Behalf of SPS at 34.

[91] Direct Testimony of W. Grant at 79.

environmental regulations was also cited as one of the reasons SPS decided not to pursue the hybrid cooling towers at Tolk.[92]

Q Why has SPS not included the cost of those proposed or other likely future environmental regulations in its most recent Tolk Strategist modeling?

A Despite several SPS Company witnesses openly acknowledging the likelihood of future additional environmental compliance costs, the Company defends its position not to include these potential costs by stating that "SPS does not evaluate the effect of 'possible environmental regulations' (i.e. neither the subject or a proposed or final rulemaking) because they are speculative and may never be adopted, or they may be adopted in some different form than the proposal."[93]

Q What regulations should SPS include in its retirement analysis for Tolk?

A At Tolk, SPS should be modeling the cost to ratepayers of keeping Tolk if EPA moves forward on the "reasonable progress" requirements of the Regional Haze Rule, which could require the installation of ion dry scrubbers at a cost of $400–$600 million with annual O&M of $24 million.[94] It is worth noting that, regardless of the status of EPA's current regional haze rulemaking, Tolk would be subject to review and further control analyses in 2021, during the second planning period under the Regional Haze Rule.[95]

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[92] *Id.* at 83.
[93] SPS Response to SC 1-8 (*see* Exhibit DG-2).
[94] *Id.*
[95] *See* 40 C.F.R. §§ 51.308(d), (f).

Q What regulations should SPS include in its retirement analysis for Harrington?

A At Harrington, SPS should be modeling the costs of installing additional sulfur dioxide (SO_2) controls, which SPS indicated may be required to comply with the National Ambient Air Quality Standards ("NAAQS").[96] EPA's ruling on a final designation is expected by December of 2020 (once monitoring is finalized).[97] In 2017, EPA also proposed to require the installation of scrubbers at two of the Harrington units under the "best available retrofit technology" provisions of the regional haze rule.[98] Harrington's environmental compliance risk under the regional haze rule is still unresolved. As with Tolk, Harrington would also be subject to review and further control analyses in 2021, during the second planning period under the Regional Haze Rule.[99] The Company admitted that it has not evaluated the impacts that these potential investments will have on the economic operation of the Harrington units.[100]

Q How does SPS's omission of potential environmental regulations impact the Strategist modeling results?

A Omission of these costs understate the ongoing costs to operate the coal plant, and therefore makes the coal plants appear more economic than they are likely to be in reality. This also prevents SPS from adequately evaluating and planning for alternatives to provide the energy, capacity, and other services that the Company

[96] SPS Response to SC 1-8 (*see* Exhibit DG-2).
[97] *Id.*
[98] 82 Fed. Reg. 912, 949 (Jan. 4, 2017).
[99] *See* 40 C.F.R. §§ 51.308(d), (f).
[100] SPS Response to SC 1-8 (*see* Exhibit DG-2).

would need to replace either unit. If the EPA moves on the Regional Haze Rule or NAAQS SO_2 compliance, and Tolk or Harrington are required to install new environmental controls, the costs of compliance could easily exceed the economic value to ratepayers of continuing to operate the plants. These risks are real and should be factored into the utility's forward-looking decision-making.

iii. SPS should perform this updated retirement analysis as part of its next IRP

Q How should SPS be evaluating the energy, capacity, and other services that it actually needs in a retirement analysis?

A In its future retirement analysis, SPS should focus on evaluating what the system actually needs in terms of energy, capacity, and other grid services, once one or both of the plants (or certain of their units) are retired. This is different than how utilities, including SPS, have traditionally approached retirement and replacement analysis by focusing on a replacement resource, or combination of resources, that provides the services that the retiring resource provides. This is critically inefficient because it presumes that the retiring unit was supplying exactly what the system needed, and this is almost never true. While the system needs may be aligned with or similar to the characteristics of the retiring unit, this approach biases resource planning in favor of resources that look like the resource that was retired, and that means fossil generators instead of alternative portfolios that include renewables, battery storage, and demand-side management.

Q What do we know about SPS's current capacity need?

A SPS's demand forecasts dropped each year between 2014 and 2018, before increasing again in 2019 (Figure 7 and Table 12). This means that when SPS completed its retirement analysis back in 2015, the Company assumed a significantly higher level of demand than we know has actually materialized. In a high demand future, Tolk and Harrington would be assigned a high capacity value, and therefore the model would be less likely to retire the resources. With the Company's most recent Tolk Strategist analysis, it relied on its 2019 demand forecast, which projected a much higher level of demand than just a year prior in the 2018 IRP. This projected upturn in demand is driven by the Eddy County and Lea County Permian Basin oil and natural gas customer segments,[101] an industry where short-term growth often does not translate into sustained long-term demand. Once again, to fill perceived need of this new industry, the Strategist model would be likely to keep Tolk online as a generator, based on the avoided cost of building new capacity.

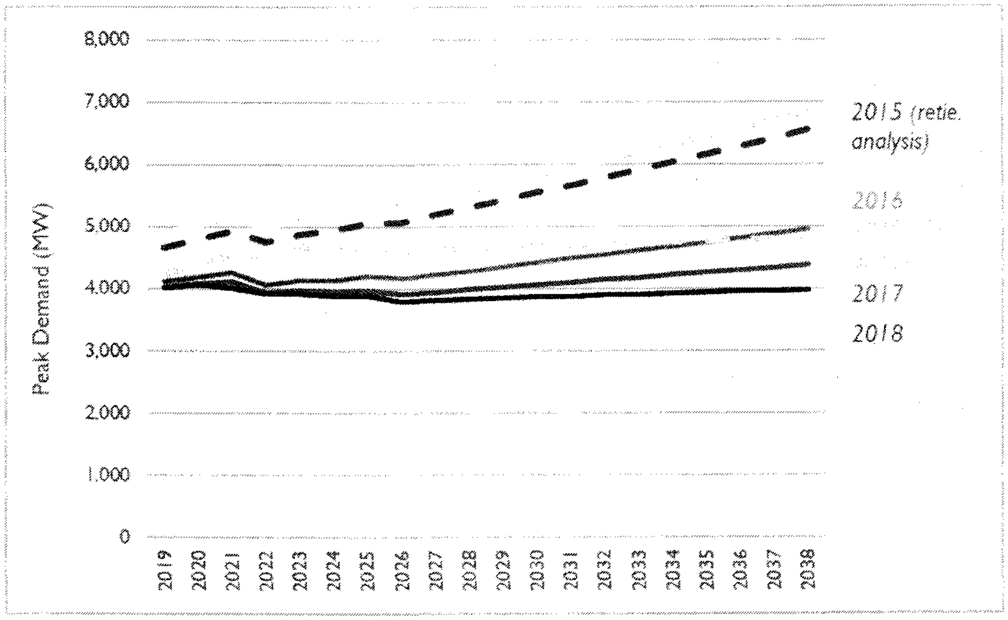
Table 12. Peak demand growth rates from SPS's load forecasts (2019–2038)

[illegible]	Compound Average Growth Rate (CAGR)
2019 Tolk Strategist analysis	0.76%
2018 IRP	0.0%
2014/2015 Strategist retirement analysis	1.75%

Source: SPS Response to SC 1-12; Workpaper SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx"; SPS Response to SC 1-6, Attachment SO – 05_RET EOY 21 23 (see Exhibit DG-2).

[101] Direct Testimony of D. Hudson at 19.

Figure 7. SPS's peak demand forecasts (2019–2038)



Source: SPS Response to SC 1-12; Workpaper SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx"; SPS Response to SC 1-6, Attachment SO – 05_RET EOY 21 23 (see Exhibit DG-2).

Q What do we know about what SPS likely needs for energy, capacity, and voltage support services if Tolk retires?

A If Tolk retires and SPS has a capacity shortfall, the need should roughly align with the summer peak capacity that Tolk was going to provide operating in seasonal mode. This makes solar particularly well suited as a replacement option due to the alignment between the timing of system peak and solar generation in the region during summer months. If Tolk's retirement creates an energy need that cannot be met by solar, existing resources on the grid that could likely ramp up to provide the energy. SPS should not need any additional voltage support services when Tolk retires the plant's generation assets, assuming the proposed synchronous condenser is installed.

Q What alternatives should SPS be considering in its retirement analysis for Harrington?

A SPS should evaluate alternative resource options, including wind, solar, and battery storage, in addition to market purchases to replace Harrington. Additionally, the Company should be considering alternative operational options, such as seasonal operation for some or all the units. Seasonal operations would allow the Company to retain the capacity from the units but decrease the plants operational costs by generating electricity only during summer peak months when LMPs are highest. This would also decrease the environmental impact of the units by decreasing the amount of coal burned, which could have implications for compliance with the environmental regulations discussed above. This approach to switch to seasonal operation has been adopted by several plants, including Dolet Hills.[102]

Q What do we know about the cost competitiveness of the renewables mentioned above in the region?

A Other utilities in the region are actively procuring renewables. Public Service Company of New Mexico ("PNM") recently issued an all-source request for proposals ("RFP") in which the Company will seek to assess and integrate all bids, including packaged renewable energy, storage, demand-side resources, and distributed energy solutions.

[102] Exhibit DG-11, Daniel, Joseph. "Seasonal Shutdowns: How Coal Plants that Operate Less Can Save Customers Money." Union of Concerned Scientists (Dec. 20, 2018), *available at*: https://blog.ucsusa.org/joseph-daniel/seasonal-shutdowns-how-coal-plants-that-operate-less-can-save-customers-money.

Similarly, SPS's sister company, Xcel Energy Colorado, recently conducted an all-source RFP and received over 400 bids, most of which were for renewable resources, with the median bid for stand-alone wind energy resources at \$18.10/MWh. Adding battery storage to wind energy resulted in median bids of \$21/MWh. Moreover, Xcel Energy Colorado received 152 bids for solar projects comprising more than 13 GW of capacity, with the median bid at \$29.50/MWh. Coupling solar with battery storage resulted in bids for \$36/MWh. SPS should conduct a similar RFP process, and incorporate those cost assumptions into a revised retirement and replacement analysis.[103]

Q Please summarize your recommendations to the Commission with regards to updated retirement analysis for both Tolk and Harrington.

A The Commission should require that SPS conduct an updated and more comprehensive retirement analysis for both Tolk and Harrington as part of the next IRP. This analysis should include updated peak demand and load forecasts, alternative resource costs based on an RFP process similar to the ones outlined above, and alternative operational options, specifically seasonal operation for Harrington. Further, it should incorporate sensitivities around the cost of all likely future additional environmental regulations, as discussed above. Additionally, the retirement analysis for Tolk should include scenarios that incorporate capacity de-rating based on future water availability constraints, and the potential revenue from selling the water to other parties.

[103] Xcel Energy, *2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version)*, California Public Utility Commission, Proceeding No. 16A-0396E (Dec. 28, 2017).

Q **Does this conclude your testimony?**

A Yes.

Exhibit DG-3

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL ELECTRIC 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**

AFFIDAVIT

STATE OF Massachusetts)
) ss.
COUNTY OF Middlesex)

Devi Glick, first being sworn on her oath, states:

I am the witness identified in the preceding direct testimony. I have read the direct testimony and am familiar with the contents. Based upon my personal knowledge, the facts stated in the direct testimony are true. In addition, my judgment is based upon my professional experience, and the opinions and conclusions stated in the direct testimony are true, valid, and accurate.

Devi Glick
Devi Glick

SUBSCRIBED TO AND SWORN TO before me this ___ day of November, 2019, by Devi Glick.

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

Notary Public

My commission expires: 4/29/2022

Exhibit DG-3

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 OF AND ABANDON ITS TOLK GENERATING STATION UNITS; AND (3) OTHER RELATED RELIEF,

SOUTHWESTERN PUBLIC SERVICE COMPANY,

APPLICANT.

Case No. 19-00170-UT

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that this day, a true and correct copy of the Direct Testimony of Devi Glick on Behalf of Sierra Club was sent to the following:

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Exhibit DG-3

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DATED this 22 day of November 2019.

Jason Marks
Jason Marks Law LLC
1011 Third St NW
Albuquerque, NM 87102

Exhibit DG-4

July 16, 2021

Ms. Melanie Sandoval, Records Bureau Chief
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269

Re: Case No. 21-00169-UT *In the Matter of Southwestern Public Service Company's 2021 Integrated Resource Plan*

Dear Ms. Sandoval:

Pursuant to Section 9(A) of NMAC 17.7.3, Southwestern Public Service Company ("SPS") hereby files with the New Mexico Public Regulation Commission ("Commission"), its 2021 New Mexico Integrated Resource Plan ("IRP") for the period 2022 through 2041.

A copy of this filing is being provided electronically to the Commission's Utility Division Staff, interveners in SPS's most recent general rate case, and participants in SPS's most recent renewable energy, energy efficiency, and IRP proceedings.

SPS is also providing a copy of the filing on the Xcel Energy IRP website, https://www.xcelenergy.com/company/rates_and_regulations/resource_plans.

If you have any questions, please contact me at (806) 378-2115 or Linda Hudgins, Case Specialist II at (806) 378-2709.

Yours very truly,

/s/ Mario Contreras
Mario Contreras,
Manager Rate Cases

Enclosures

2021
Integrated Resource Plan
Filed in Compliance with 17.7.3 NMAC

Southwestern Public Service Company

July 16, 2021

Xcel Energy[SM]
SOUTHWESTERN PUBLIC SERVICE

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties, and other factors, most of which are beyond Southwestern Public Service Company's, a New Mexico corporation ("SPS"), control and many of which could have a significant impact on SPS's operations, results of operations, and financial condition, and could cause actual results to differ materially from those anticipated. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.xcelenergy.com.

The information in this document is based on the best available information at the time of preparation. SPS undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in the Integrated Resource Plan ("IRP") that are required to be reported to the New Mexico Public Regulation Commission ("Commission") pursuant to 17.7.3.10 NMAC.

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Glossary of Acronyms and Defined Terms

Acronym/Defined Term	**Meaning**
2021 IRP	Integrated Resource Plan, filed July 16, 2021
Action Plan	IRP Implementation During the First Four Years of the IRP
Action Plan Period	2021 IRP implementation from 2022-2025
ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
CC	Combined Cycle
CO_2	carbon dioxide
Commission	New Mexico Public Regulation Commission
CTG	Combustion Turbine Generator
DSM	Demand-Side Management
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EOY	End of Year
EUEA	Efficiency Use of Energy Act
FOM	Fixed Operations and Maintenance
GCP	Combined Real Gross County Product
GWh	gigawatt-hour
HRSG	Heat Recovery Steam Generator
ICO	Interruptible Credit Option
IRP	Integrated Resource Plan

Acronym/Defined Term	Meaning
IRP Rule	17.7.3 NMAC
ISO	independent system operator
ITC	Investment Tax Credit
kW	kilowatt
kWh	kilowatt-hour
L&R	Loads and Resources
LED	Light Emitting Diode
LM	Load Management
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
MMBtu	Million British Thermal Unit
MW	megawatt
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
Planning Period	2022-2041 Planning Period

Exhibit DG-4

Acronym/Defined Term	Meaning
Planning Reserve	available capacity above the projected peak demand
PPA	Purchased Power Agreement
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	photovoltaic
QF	Qualifying Facility
RFI	Request for Information
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPS	Southwestern Public Service Company, a New Mexico corporation
Staff	Utility Division Staff of the Commission
STG	Steam Turbine Generator
TCEQ	Texas Commission on Environmental Quality
Tolk Analysis	analysis evaluating the economically optimal retirement date of the Tolk Units
TOU	Time of Use
VOM	Variable Operations and Maintenance
Xcel Energy	Xcel Energy Inc.

Executive Summary

SPS presents its 2021 Integrated Resource Plan ("2021 IRP") identifying the most cost-effective portfolio of resources over the 20-year Planning Period (2022 – 2041). For more than a decade, SPS has strived to serve its customers with a cleaner mix of generating resources and with an energy grid that is more reliable and secure - all while keeping customer energy bills low. SPS continues to deliver on this goal, successfully adding an additional 1,230 megawatts ("MW") of low-cost wind generation since the filing of the 2018 IRP. In addition, SPS is well positioned to comply with New Mexico's Renewable Portfolio Standards ("RPS") and the State's carbon emission reduction goals. In SPS's most recent RPS filing (New Mexico Case No. 21-00172-UT), SPS proposed early compliance with the RPS's 2025 goal to supply no less than 40% of SPS's New Mexico retail energy sales by renewable energy, and last year, SPS's carbon emissions were reduced 55% when compared with 2005 levels.

The highlighted changes below demonstrate that SPS's 2021 IRP continues to support the company's commitment to provide clean, reliable and affordable energy.

Future Operation of SPS's Coal Generating Units

SPS's existing coal generating units have, or are planned to, undergo substantial operational changes since SPS's filed its last IRP in 2018. Beginning 2021, the Tolk Generating Units located in Texas are economically dispatched during the high load summer months, and to conserve limited groundwater are shut down in the eight off-peak months (unless called upon in urgent need conditions). SPS's Tolk Analysis, which was filed in advance of this IRP, continues to support seasonal operation of the Tolk Units until a 2032 retirement date. Additionally, per an agreed order with the Texas Commission on Environmental Quality ("TCEQ"), SPS's other coal-fired plant, the

Harrington Generating Station located in Texas, is planned to be converted to operate exclusively on natural gas by the end of 2024. Both the Tolk and Harrington Generating Stations are scheduled to retire within the 20-year IRP planning period.

Aging Gas Steam Resources

Several of SPS-owned gas steam generating units are at the end of their useful life. During the 4-year Action Plan[1], over 650 MW of gas steam generation is scheduled to retire and within the Planning Period, SPS's entire 1.6 GW portfolio of gas steam generating units are scheduled to retire.

Economic Renewable Energy Resources

SPS's most cost-effective portfolio of resources and alternative portfolios support a continued transition to a more renewable-heavy portfolio of generating resources, especially as SPS's existing coal and aging gas steam resources are scheduled to retire. Despite scheduled retirements, during the Action Period, SPS has sufficient resources to meet its reliability and regulatory requirements, therefore is well positioned to acquire new economic energy resources only when they are most likely to economically benefit SPS's customers.

Emerging Technologies

The continued transition to a more renewable heavy portfolio of resources will also necessitate a need for firm peaking and load-following resources to provide reliability and energy while intermittent resources, such as wind and solar, are not available. Currently, natural gas combustion turbine generators ("CTG") are the most economical technology to provide critical system reliability needs. However, to meet New Mexico's 2045 carbon-free goal, natural gas CTGs may be required to use carbon-free hydrogen as a fuel source, or CTGs may ultimately be replaced by emerging

[1] IRP Implementation During the First Four Years of the IRP

technologies, such as battery energy storage systems ("BESS"). By preserving the capacity and energy benefits of the Tolk and Harrington Generating Stations under current planning, SPS's most cost-effective portfolio of resources does not include any new carbon-emitting resources until 2031, therefore, providing SPS time to re-evaluate emerging technologies in future IRPs.

Section 1. INTRODUCTION

SPS, a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), presents its 2021 integrated resource plan ("2021 IRP") in accordance with the Efficient Use of Energy Act (NMSA 1978, § 62-17-1, *et seq.*, "EUEA") and 17.7.3 NMAC (the "IRP Rule"). SPS's 2021 IRP: (i) identifies the most reasonable, cost-effective resource portfolio to meet all applicable regulatory requirements and to supply the energy needs of New Mexico customers during the 2022-2041 Planning Period ("Planning Period"); and (ii) provides an Action Plan discussing 2021 IRP implementation from 2022-2025 ("Action Plan Period").

Per the uncontested comprehensive stipulation in SPS's New Mexico Base Rate Case No. 19-00170-UT, SPS's 2021 IRP includes an updated "Tolk Analysis" evaluating the economically optimal retirement date of the Tolk Units. The Tolk Analysis is included in its entirety in Appendix H and was filed with the Commission in advance of the IRP on June 30, 2021.

SPS's 2021 IRP was developed by considering studies, forecasts, regulatory predictions, and information exchanged through a series of technical conferences and a public advisory process, combined with historical data, existing and potential resource capabilities, and costs associated with alternative generation resource expansion plans. SPS's analysis considered applicable regulatory, and operational obligations and both short- and long-term least-cost impacts to customers, while balancing the ability to deliver the expected level of service to customers while meeting applicable regulatory and operational obligations. The goal of SPS's 2021 IRP was to develop a reliable, robust, cost-effective, and environmentally-focused generation expansion plan.

Many factors may impact this IRP and could potentially require updates to the Action Plan and will be the subject of future IRPs. These factors include: (i) changes to the operation of SPS's existing coal-fired generating units; (ii) changes to, or the extension of, renewable tax credits; (iii) uncertainty in the cost and schedule of interconnecting new generation within SPS's footprint; and (iv) potential technological and economic advances in emerging technologies. Each of these factors are discussed in more detail in Section 7.

Most importantly, the resource plan is presented based on the best information available at this time and with recognition that SPS will have to be flexible in resource plan execution over the Action Plan and Planning Period as new information becomes available and in response to the inherent uncertainty of long-term forecasting and resource planning. SPS will continue to actively monitor developments in these areas. However, as presented, SPS's 2021 IRP provides a well-rounded resource portfolio that addresses customer cost impacts, environmental impacts, critical reliability needs in localized areas of SPS, operational issues, and complies with applicable regulatory requirements.

The remainder of the IRP is organized as follows: (i) Section 2 provides a background; (ii) Section 3 discusses existing supply- and demand-side resources, and reserve margin/reliability requirements, (iii) Section 4 provides SPS's current load forecast; (iv) Section 5 presents SPS's Loads and Resources ("L&R") table for the Planning Period; (v) Section 6 identifies the resource options; (vi) Section 7 presents a determination of the most cost-effective resource portfolio and alternative portfolios; (vii) Section 8 discusses the public advisory process; and (viii) Section 9 presents SPS's Action Plan.

Section 2. BACKGROUND

The objective of the IRP is to identify the most cost-effective portfolio of resources to supply the energy needs of customers while giving preference to resources that minimize environmental impacts and whose costs and service quality are equivalent (17.7.3.6 NMAC).

Specifically, the IRP Rule requires that affected utilities provide the following details (17.7.3.9(B) NMAC):

(1) description of existing electric supply-side and demand-side resources;
(2) current load forecasts;
(3) load and resources tables;
(4) identification of resource options;
(5) description of the resource and fuel diversity;
(6) identification of critical facilities susceptible to supply-source or other failures;
(7) determination of the most cost-effective resource portfolio and alternative portfolios;
(8) description of the public advisory process;
(9) Action Plan; and
(10) other information that the utility finds may aid the Commission in reviewing the utility's planning process.

Please refer to Appendix N for a table indicating where each of the rule requirements is met in this filing.

In addition, the uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT required SPS's 2021 IRP to include a robust analysis of Tolk abandonment and economical potential means of replacement by June 2021 (the "Tolk Analysis"). The Tolk Analysis is included in its entirety in Appendix H and was filed with the Commission in advance of the IRP on June 30, 2021.

SPS filed its initial New Mexico IRP on July 16, 2009 (Case No. 09-00285-UT), its second IRP on July 16, 2012 (Case No. 12-00298-UT), its third IRP on July 16, 2015 (Case No. 15-00217-UT), and its fourth IRP on July 16, 2018 (Case No. 18-00215-UT); all of SPS's IRPs were accepted by the Commission. SPS's 2021 IRP includes all required components of the IRP Rule.

Section 3. EXISTING SUPPLY-SIDE & DEMAND-SIDE RESOURCES

3.01 - SPS-Owned Resources

SPS owns supply-side thermal generation resources, located in both New Mexico and Texas, which serve its entire system. SPS's supply-side thermal resources had a 2020 summer generation capacity of 4,335 MW and were comprised of a mix of coal-fired, gas steam, and simple-cycle CTG units. As shown in Table 3-1 (next page), the Tolk and Harrington coal-fired generating units provided nearly half of the 2020 summer peak capacity; gas steam units totaled approximately 1.6 GW; and simple-cycle CTG units totaled over 600 MW.

SPS also owns and operates two wind generating facilities. The 478 MW Hale Wind generating facility (Hale County, Texas) was placed in-service in June 2019, and the 522 MW Sagamore Wind generating facility (Roosevelt County, New Mexico) was placed in-service in December 2020.

The names, fuel types, locations, rated capacities (MW), expected retirement dates, capital costs (gross plant balance), fixed and variable operation and maintenance costs ("FOM" and "VOM"), fuel costs, heat rates (Btu/kWh), and annual capacity factors for calendar year 2020 are provided in Table 3-1 (next page).

Exhibit DG-4

Table 3-1: Location, Rated Capacity, Retirement Date, Cost Data, Heat Rate, and Capacity Factor for all Generating Units - Calendar Year 2020

Southwestern Public Service Company
Location, Rated Capacity, Retirement Date, Cost Data, Heat Rate, & Capacity Factor for all Owned Generating Units
Calendar Year 2020

Unit Name	Location	Rated Capacity (MW)	Expected Retirement Date	Capital $ (Gross plant)	O&M $	Fuel $	Net Unit Heat Rate (Btu/kWh)	Annual Capacity Factor
Steam Production - Gas/Oil								
Jones Unit 1	Lubbock Co., TX	243	2031	$ 54,714,121	9,504,622	$ 31,153,663	10,860	51%
Jones Unit 2	Lubbock Co., TX	243	2034	$ 48,095,614			10,889	44%
Plant X Unit 1	Lamb Co., TX	39	2022	$ 13,451,522	8,652,844	$ 14,622,353	13,577	18%
Plant X Unit 2	Lamb Co., TX	90	2022	$ 24,644,736			11,831	25%
Plant X Unit 3	Lamb Co., TX	0	2024	$ 18,947,804			0	0%
Plant X Unit 4	Lamb Co., TX	193	2027	$ 41,695,050			10,902	40%
Steam Production - Gas								
Cunningham Unit 1	Lea Co., NM	68	2022	$ 17,960,216	5,683,791	$ 11,537,882	11,640	43%
Cunningham Unit 2	Lea Co., NM	171	2025	$ 41,996,765			10,539	31%
Maddox Unit 1	Lea Co., NM	112	2028	$ 48,678,630	3,561,308	$ 7,318,514	11,201	51%
Nichols Unit 1	Potter Co., TX	108	2022	$ 26,144,622	9,888,210	$ 22,649,935	11,709	27%
Nichols Unit 2	Potter Co., TX	111	2023	$ 27,212,118			11,434	38%
Nichols Unit 3	Potter Co., TX	246	2030	$ 48,467,985			11,208	30%
Steam Production - Coal								
Harrington Unit 1	Potter Co., TX	340	2036	$ 168,499,280	23,260,669	$ 56,125,073	11,442	35%
Harrington Unit 2	Potter Co., TX	340	2038	$ 185,120,344			11,063	36%
Harrington Unit 3	Potter Co., TX	341	2040	$ 191,081,811			10,746	42%
Tolk Unit 1	Bailey Co., TX	531	2032	$ 326,426,504	17,733,283	$ 36,010,273	11,399	20%
Tolk Unit 2	Bailey Co., TX	538	2032	$ 361,728,360			11,094	20%
Turbine - Gas								
Cunningham Unit 3	Lea Co., NM	106	2040	$ 47,076,368	556,537	$ 10,299,704	11,816	34%
Cunningham Unit 4	Lea Co., NM	104	2040	$ 43,994,537			12,354	30%
Maddox Unit 2	Lea Co., NM	61	2025	$ 19,619,416	359,224	$ 3,773,271	13,647	34%
Jones Unit 3	Lubbock Co., TX	166	2056	$ 95,173,578	662,642	$ 11,117,912	10,606	22%
Jones Unit 4	Lubbock Co., TX	167	2058	$ 83,646,977			10,500	22%
Turbine - Fuel Oil								
Quay	Hutchinson Co, TX	17/23	2034	$ 26,418,131	191,823	$ 76,600	17,184	0.13%
Other Production - Wind								
Hale	Hale Co, TX	478	2044	$ 680,220,686	11,999,743	$ -	N/A	50%
Sagamore	Roosevelt Co, NM	522	2050	$ 800,917,397	201,016	$ -	N/A	N/A

Note (1) The O&M $ are reported by plant
Note (2) Fuel $ is measured at the plant level
Note (3) SPS plans on converting the Harrington Units to operate on natural gas end of year 2024

3.02 - SPS-Purchased Power

In addition to SPS's owned generation, SPS currently has long-term purchased power agreements ("PPA") totaling 2,444 MW of nameplate capacity and associated energy. SPS purchases the energy output from renewable intermittent generation consisting of 1,450 MW of wind and 192 MW_{AC} of solar. These resources serve SPS's entire system. Table 3-2 lists the nameplate capacity and expiration dates for each long-term PPA under which SPS currently purchases capacity and/or energy.

Table 3-2: PPA Capacity and Expiration Dates

Purchased Power Agreement	Nameplate Capacity (MW)	Commercial Operation Date	Expiration Date
Sid Richardson Carbon Ltd. Gas Facility	5	2001	2021[2]
Blackhawk Station Simple Cycle Combustion Turbines	223	1999	2024[3]
Lea Power Partners Combined Cycle	574	2008	2033
Subtotal	**802**		
Caprock Wind	80	2004	2024
San Juan (Padoma) Wind	120	2005	2025
Wildorado Wind	161	2007	2027
Spinning Spur Wind	161	2012	2027
Mammoth Wind	199	2014	2034
Palo Duro Wind	249	2014	2034
Roosevelt Wind	250	2015	2035
Lorenzo Wind (Bonita I)	80	2018	2048
Wildcat Wind (Bonita II)	150	2018	2048
Subtotal	**1,450**		
Sun Edison Solar	50	2011	2031
Chaves Solar	70	2016	2041
Roswell Solar	70	2016	2041
SoCore Clovis 1 LLC[4]	1.98	2021	2041
Subtotal	**192**		
Total Firm (PPAs)	**2,444**		

Figure 3F.1 below provides a regional map of the SPS generation fleet (owned and PPAs). A regional map of SPS's transmission system is also provided in Appendix O.

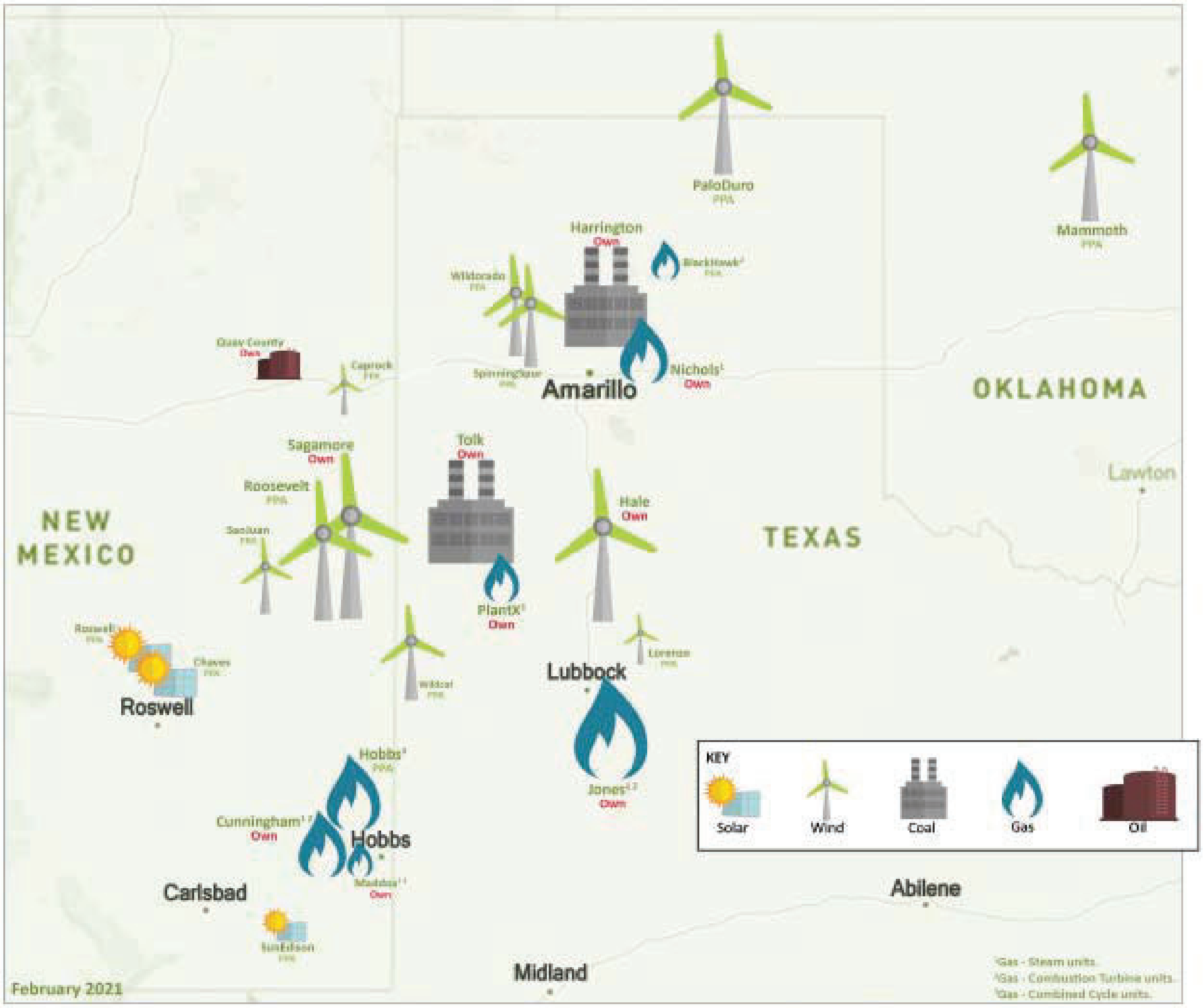
[2] The PPA between SPS and Tokai Carbon CB Ltd. (Sid Richardson) is scheduled to terminate August 1, 2021, which is prior to the end of the Southwest Power Pool Summer Season (June 1 – September 31).

[3] The PPA between SPS and Borger Energy Associates (Blackhawk Station) is scheduled to terminate on June 12, 2024, which is prior to the expected summer peak .

[4] The SoCore Facility is utilized for SPS's Voluntary Renewable Energy Program in New Mexico, referred to as Solar*Connect.

Exhibit DG-4

Figure 3F.1: SPS Existing Generation Fleet (Owned and PPAs)



3.03 – SPS Qualifying Facilities

In addition to SPS's owned and long-term PPAs, SPS also purchases energy from eight Qualifying Facilities ("QF"), with a total nameplate capacity of 111 MW, that are put to SPS under the Public Utility Regulatory Policy Act of 1978. Per SPS's New Mexico Rate No. 4 or the Texas Electric Tariff Sheet No. IV-117 (Rev. No. 4) a QF that chooses to sell energy to SPS under these Rates/Tariffs, must execute the standard Purchase Agreement. See Table 3-3 below for a list of SPS QF Wind facilities.

Table 3-3: QF Wind

QF Wind	Nameplate Capacity (MW)	Commercial Operation Date
Ralls Wind	10	07/20/2011
Cirrus Wind	61.2	12/12/2012
Pantex Wind	11.5	06/20/2014
Pleasant Hills Wind	19.8	06/04/2014
Aeolus Wind	3	04/05/2004
National Windmill	0.66	12/07/2005
West Texas A&M	3.51	11/11/2013
Mesalands Community College	1.5	07/08/2015

In addition, SPS historic cost (calendar year 2020) information regarding each of the long-term PPAs and QFs is provided in Appendix A.

3.04 - Existing & Approved Energy Storage Resources

Currently, SPS has no existing or approved energy storage resources.

3.05 - Additional SPS Owned Generation Approved but not In-Service

Currently, SPS has no new generating resources under construction or scheduled for the Planning Period.

3.06 - Wheeling Agreements

SPS does not purchase any capacity or energy under wheeling agreements with other utilities.

3.07 - Demand-Side Resources

The IRP Rule specifically requests that the utilities detail their existing demand-side management ("DSM") resources in their IRP filing and defines those resources as "energy efficiency and load management." Energy efficiency ("EE") is defined in the IRP Rule as "measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services."[5] Load management ("LM") is defined as "measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods."[6] SPS offers DSM resources in both New Mexico and Texas in accordance with state-specific rules and laws.[7]

New Mexico DSM

SPS must annually report its achieved levels for the previous calendar year and receive approval of its forward looking plans every three years to continue towards its statutory goals. SPS's 2019 EE Triennial Plan approving Plan Years 2020-2022 was approved in Case No. 19-00140-UT on February 19, 2020.[8] SPS will continue its approved Triennial Plan through Plan Year 2021. In

[5] Rule 17.7.3.7.D NMAC.
[6] Rule `7.7.3.7.I NMAC.
[7] DSM costs are directly assigned by jurisdiction.
[8] *In the Matter of Southwestern Public Service Company's Triennial Energy Efficiency Plan Application Requesting Approval of: (1) SPS's 2020-2022 Energy Efficiency Plan and Associated Programs; (2) A Financial Incentive for Plan Year 2020; (3) Recovery of the Costs Associated with a potential Energy Efficiency Study over a Two-Year Time Period; and (4) Continuation of SPS's Energy Efficiency Tariff Rider to Recover Its Annual Program Costs and Incentives,* Case No. 19-00140-UT, Final Order Approving Certification of Stipulation (Feb 19, 2020).

accordance with the Final Order in Case No. 19-00140-UT, SPS refiled its Plan Year 2022 portfolio and proposed goals on July 15, 2021. Previous plans were approved for calendar years 2011 – 2019 in Case Nos. 11-00400-UT, 13-00286-UT, 15-00119-UT, 16-00110-UT, 17-00159-UT, 18-00139-UT, and 19-00140-UT, respectively. Table 3-4 below describes SPS's EE achievements under the EUEA.

Table 3-4: New Mexico EE Achievements for Plan Years 2013-2020

Year	Customer kW[9] Saved	Customer kWh Saved
2013	8,056	37.674.221
2014	8,873	30,492,802
2015	10,716	35,225,196
2016	8,486	34,384,659
2017	8,476	33,191,039
2018	7,539	42,841,455
2019	9,415	39,420,766
2020	7,404	46,980,168

At the time of this IRP filing, SPS is offering the following approved DSM programs to its New Mexico customers (designated by "EE" for energy efficiency and "LM" for load management).

<u>Residential Segment</u>:

- Residential Energy Feedback (EE) – This program is designed to quantify the effects of informational feedback on energy consumption in approximately 15,000 residential households, consistent with the Commission's Final Order in Case No. 09-00352-UT.[10] This program provides educational materials and communication strategies to create a change in energy usage behavior. The purpose of the program is to measure when, how, and why customers change their behavior when provided with feedback on their energy using habits.

- Residential Cooling (EE) – This program offers rebates for the purchase of high efficiency evaporative cooling, air conditioning, and heat pump units. Rebates for evaporative coolers are paid for purchase of new units with an efficiency greater than 85%, installed in new or existing construction, regardless of whether or not the customer is replacing an existing unit.

[9] kilowatt

[10] Case No. 09-00352-UT, *In the Matter of Southwestern Public Service Company's Application for Approval of its 2010/2011 Energy Efficiency and Load Management Plan and Associated Programs, Requested Variances, and Cost Recovery Tariff Rider,* Final Order Adopting Certification of Stipulation (Mar. 15, 2011).

Air conditioning and heat pump rebates are paid to registered contractors who perform a quality installation in new and existing homes.

- Home Energy Services (EE) – Under this program, SPS provides incentives for the installation of a wide range of energy savings measures that reduce customer energy costs. The incentives are paid to energy efficiency service providers on the basis of deemed (*i.e.,* pre-determined) energy savings. The program, which also includes a Low-Income offering, includes attic insulation, air infiltration reduction, refrigerators (for low-income participants) and duct leakage repairs. The program is delivered via third-party providers interacting directly with customers to perform the home improvements. Additionally, Income-qualified customers, will receive an offer through mail informing them of their eligibility to receive a free Energy Savings Kit. A customer is qualified by being identified as receiving energy assistance through federal Low-Income Home Energy Assistance Program. If the customer chooses to receive a kit, they will send their response to the third-party implementer. Customers will receive a kit within six to eight weeks.

- Home Lighting (EE) – This program provides incentives for customers to purchase energy efficient LEDs[11] through participating retailers. Participating retailers may include home improvement, mass merchandisers, and hardware store locations. Customers will be able to recycle used compact fluorescent lights at select retail partner locations.

- Heat Pump Water Heaters (EE) – This program provides rebates for the purchase of high-efficiency electric heat pump water heaters. Customers can purchase these units through local home improvement stores or heating, ventilating, and air conditioning contractors.

- School Education Kits (EE) – The School Education Kits Program provides free kits to fifth grade classrooms in SPS's New Mexico service area. These kits include energy efficiency educational materials and products, including four LEDs, one low-flow showerhead, a kitchen and bathroom aerator, and an LED nightlight, which are distributed along with curriculum. This program provides value beyond the direct installation of measures included in the kits by creating awareness of energy efficiency with students, teachers, and parents.

- Smart Thermostats (EE) – In SPS's 2019 Triennial, the Saver's Stat program was transitioned into an exclusively energy efficiency program utilizing the new ENERGY STAR connected Thermostat specification in Plan Year 2020. Eligible customers will be able to receive the $50 rebate for an ENERGY STAR connected thermostat through the Xcel Energy storefront, paper applications and online applications that are available to both end use customers and trade allies.

[11] Light Emitting Diode

<u>Business Segment</u>:

- Business Comprehensive Program, which is made up of the following components:
    - Cooling Efficiency (EE) – provides rebates for purchasing air conditioning equipment that exceeds standard efficiency equipment. This product also includes rebates for specific commercial refrigeration equipment;
    - Custom Efficiency (EE) – offers rebates to reduce incremental project costs for customers who install energy efficient measures. Since energy applications and building systems can vary greatly by customer type, this program provides rebates for business projects or process changes that are not covered by SPS's prescriptive programs;
    - Large Customer Self-Direct (EE) – provides the opportunity for qualifying large customers to either self-direct their own EE projects or opt-out of the EE tariff rider if they can prove they have completed all cost-effective conservation. Self-direct participants of this program are also eligible for the other Business Segment programs;
    - Lighting Efficiency (EE) – offers rebates for customers to install more efficient lighting, or de-lamp, as needed;
    - Motor & Drive Efficiency (EE) – offers rebates to customers who install motors exceeding the National Electrical Manufacturers Association Premium Efficiency® motors standards and variable frequency drives in existing and new construction facilities; and
    - Building Tune-up (EE) – is a study/implementation option designed to assist smaller business customers to improve the efficiency of existing building operations by identifying existing functional systems that can be "tuned up" to run as efficiently as possible through low- or no-cost improvements.

EE Goals from 2009-2020

Under the 2008 amendment of the EUEA, SPS was required to acquire cost-effective and achievable DSM to achieve no less than an 8% reduction in 2005 sales by 2020. SPS's 2005 New Mexico retail sales were 3,750,469 megawatt-hour ("MWh") therefore SPS needed to achieve savings of 300,037,520 kilowatt-hour ("kWh") or greater by 2020. SPS met this obligation in Plan Year 2018 by achieving savings of 302,366 kWh (8.06%).

Table 3-5 below shows SPS's savings achievements during the 2008 EUEA requirement, using the Portfolio Effective Useful Lifetime method (energy savings provided in gigawatt-hours ("GWh")).[12]

Table 3-5: New Mexico Actual Savings Provided by the 2008-2020 EE Programs

Year	Annual Net Customer Achievement (GWh) [13]	Cumulative Net Customer Achievement (GWh)	Cumulative % of 2005 Retail Sales
2008	3.355	3.355	0.09%
2009	14.136	17.491	0.47%
2010	23.231	40.722	1.09%
2011	35.642	76.363	2.04%
2012	31.534	107.897	2.88%
2013	34.452	142.349	3.80%
2014	30.493	172.841	4.61%
2015	32.805	202.962	5.41%
2016	31.966	234.257	6.25%
2017	29.429	263.686	7.03%
2018	38.680	302.366	8.06%
2019	36.081	320.169	8.54%
2020	46.980	348.061	9.28%

EE Goals through 2041

Under the 2019 amendment of the EUEA, SPS is required to achieve no less than savings of 5% of 2020 total retail kWh sales to as a result of EE and LM programs implemented in years 2021 through 2025. The following goals were developed in accordance with the 2008 EUEA, which SPS was following at the time of SPS's most recent Triennial Plan Filing. Note that the EUEA neither

[12] This calculation method is consistent with the methodology proposed by the Commission's Utility Division Staff in Case No. 09-00352-UT (*see Staff Compliance Affidavit Regarding Decretal Paragraph "L" of the Certification of Stipulation Adopted by the Commission in its March 11, 2010 Final Order in this Proceeding,* Oct. 19, 2010).

[13] Annual Net Customer Achievement (GWh) does not include the Energy Feedback Program's yearly savings achievement as the product only has a 1-year life.

requires nor establishes annual goals. Thus, the goals in Table 3-6 below are preliminary and subject to change in SPS's upcoming re-filing of PY 2022, Triennial Filing covering PY 2023-2025, and future Triennial Filings covering years 2025-2041.

Table 3-6: Filed and Forecasted New Mexico DSM Goals at the Customer Level for the Planning Period

Year	Demand Savings (MW)	Energy Savings (GWh)
2021	5.42	40.134
2022	8.81	56.492
2023-2041	8.81	56.492

In SPS's recent EE Potential Plan filing, filed one day before this IRP filing, SPS proposed a revised EUEA goal for 2025 based on an adjustment to SPS's 2020 total kWh retail sales used to determine the goal. The adjustment excludes kWh sales to certain customers for which there is no corresponding recovery of costs to fund EE programs due to the application of the EUEA's $75,000 per customer EE program cost-recovery cap. Based on the adjusted 2020 kWh retail sales, SPS proposed a revised EUEA energy savings goal for 2025 of 269,769 MWh to be achieved over the period of 2021 through 2025. SPS's proposed revised goal has not yet been approved by the Commission.

Texas DSM Requirements

SPS offers DSM programs in its Texas service territory pursuant to the Public Utility Regulatory Act and 16 Tex. Admin. Code § 25.181. These programs include standard offer and market-transformation programs for commercial and industrial, LM, residential, and low-income customers limited to customers receiving service at 69 kilovolts or less and all government customers. Table 3-7 below shows SPS's historic demand savings (in MW) and energy savings (in GWh) in its Texas service territory.

Table 3-7: SPS's EE and LM Achievements - 2011 to 2020 in Texas

Year	Customer Demand Savings (MW)	Customer Energy Savings (GWh)
2011	3.88	13.821
2012	5.30	9.077
2013	5.10	7.950
2014	5.02	11.900
2015	8.17	14.537
2016	8.19	14.451
2017	7.80	16.871
2018	9.57	18.908
2019	9.57	23.328
2020	11.672	25.663

In addition, SPS offers residential Saver's Switch and Interruptible Credit Option ("ICO") LM programs (the savings are not included in the table above).

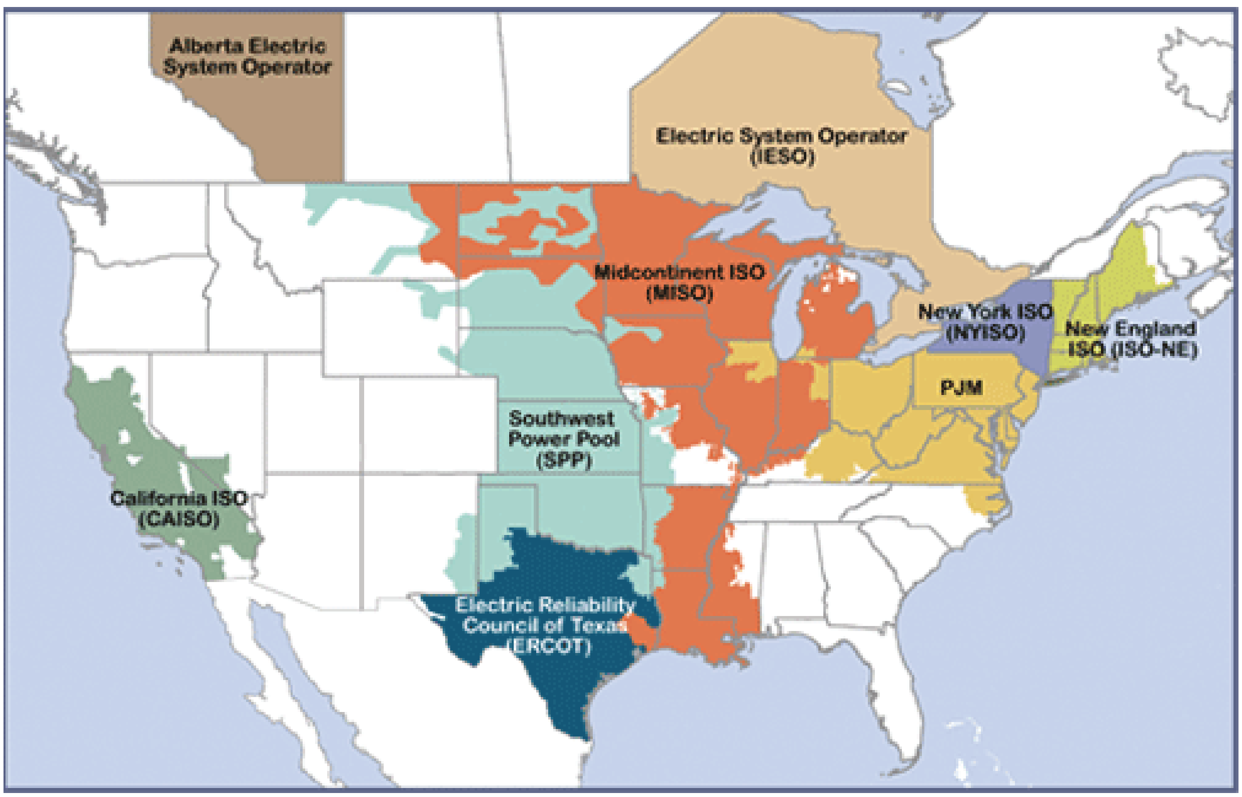
3.08 - Reserve Margin and Reserve Reliability Requirements

Southwest Power Pool Integrated Market

SPS is a member of the Southwest Power Pool. Southwest Power Pool is one of nine independent system operators ("ISO") and Regional Transmission Organizations ("RTO") in North America. Southwest Power Pool's Integrated Marketplace is the mechanism through which it facilitates the sale and purchase of electricity to ensure cost-effective electric reliability throughout a 14-state region in the Eastern Interconnect. As a Balancing Authority, Southwest Power Pool balances electric supply and demand, ensuring there is adequate generation to meet the demand.

Southwest Power Pool is responsible for generation unit commitment and dispatch across the Southwest Power Pool footprint. Additionally, Southwest Power Pool administers the day-ahead and real-time balancing market, including incorporation of a price-based operating reserve market (i.e., regulation up/down and spin/supplemental reserves). Instead of each load serving entity (e.g., SPS) committing and dispatching its own generation resources to meet its own load requirements, reliability unit commitment and economic dispatch are performed by the Southwest Power Pool. Current expectations and future requirements regarding market operations, locational generation dispatch, congestion, and losses will impact future transmission and generation planning/siting activities.

Figure 3F.2: ISO / RTO Map



Planning and Operating Reserves

Each system must preserve an adequate supply of firm electric generation that will meet the maximum demand of its customers (i.e., the "peak" demand) and provide for unforeseen events (e.g., transmission line outages, generating unit outages, and potential increased in actual load, etc.). To accomplish these objectives, electric utilities acquire (through direct ownership or PPAs) and operate more generation capacity than is needed to meet peak demand. The available capacity above the projected peak demand is typically referred to as the "reserve margin" (i.e., "Planning Reserves"). Generally, there are two basic types of reserves: (i) Planning Reserves, which are the amount of installed capacity required above annual firm peak demand, and (ii) Operating Reserves, which are the amount of generation capacity required in real-time, either with units carrying regulation and/or spinning reserves; or units offline but in warm standby and capable of providing additional electric supply in order to meet real-time changes in load/demand and any unforeseen contingencies (e.g., transmission outage, generator forced outage, gas supply disruptions, etc.).

Southwest Power Pool Capacity Reserve Requirements

The Planning Reserve Margin ("PRM") for capacity is set in Section 4 of the Southwest Power Pool Planning Criteria.[14] Southwest Power Pool currently requires each Load Responsible Entity ("LRE") to have a reserve margin of at least 12% of its peak demand forecast (the planning reserve requirement is a minimum requirement, not a maximum or a target). Determination of the PRM is described in Attachment AA[15] of the Southwest Power Pool Open Access Transmission Tariff ("OATT") and is supported by a probabilistic Loss of Load Expectation ("LOLE") Study, which analyzes the ability of the Transmission Provider to reliably serve the Southwest Power Pool

[14] https://spp.org/Documents/58638/spp%20planning%20criteria%20v2.4.pdf
[15] https://spp.org/Documents/58597/Attachment%20AA%20Tariff.pdf

Balancing Authority Area's forecasted peak demand. The LOLE Study is performed biennially, and Southwest Power Pool studies the PRM such that the LOLE for the applicable planning year does not exceed one day in ten years, or 0.1 day per year.

3.09 - Existing Transmission Capabilities

SPS, as a member of Southwest Power Pool, participates in several technical groups and committees. SPS is also a member of the North American Transmission Forum, a group that promotes sharing of technical solutions among members.

An analysis of the SPS transmission system is contained in the Southwest Power Pool 2020 Integrated Transmission Planning Assessment Report, which is provided as Appendix B. This report discusses the performance of the SPS network and recommends new projects to improve the network performance.

A list of current transmission projects SPS is constructing based on notifications to construct is provided as Appendix C. This list also includes service for one generator interconnection project.

Transmission Import Rights

Southwest Power Pool has a total of 1,885 MW of transmission flow capability minus the single largest contingency and other factors (i.e., imports from Palo Duro and Mammoth Wind) to deliver resources to the SPS zone from the rest of the Southwest Power Pool transmission system. SPS's reservation of this capability on a firm basis is more fully described below.

249 MW Palo Duro Wind

SPS has firm transmission service for this wind farm beginning January 1, 2018 and continuing for the term of the PPA through December 31, 2034.

199 MW Mammoth Plains Wind

SPS has firm transmission service for this wind farm beginning November 16, 2018 and continuing for the term of the PPA through December 31, 2034.

96 MW Import from Elk City 2 Wind

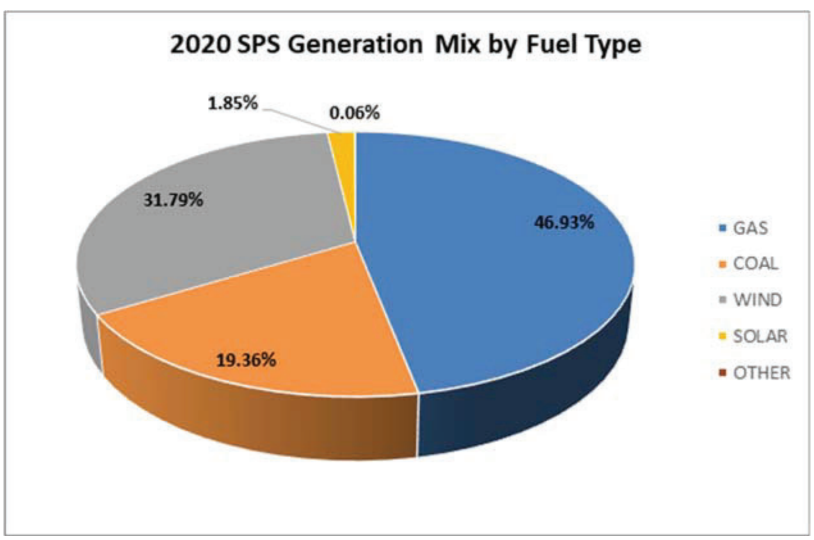
As agent for the City of Lubbock, Texas, SPS holds the firm network transmission rights to import up to 96 MW from the Elk City 2 Wind Farm, located in Oklahoma. This resource represents part of the replacement power required to serve the City of Lubbock upon termination of its full requirements contracts with SPS. The term of this service began June 1, 2019 and continues for 13 years. Any capacity associated with this reservation is held by the City of Lubbock.

3.10 - Environmental Impacts of Existing Supply-Side Resources

Percentage of MWh Generated

The percentages of MWh generated by each fuel type used by SPS for Calendar Year 2020 are provided in Figure 3F.3 below.

Figure 3F.3: Percentage of MWh Generated in 2020 by Fuel Type



SPS Emissions Information

The emission rates for SPS-owned generation resources are shown in Table 3-8 below. All emission rates are expressed in pounds per kWh.

Water Consumption Rates

Average water consumption rates, by plant, and expressed in gallons per kWh (H_2O Consumption) are also shown in Table 3-8 below.

Exhibit DG-4

Table 3-8: Emission and Water Consumption Rates

2020 SPS Emission Rates of Criteria Pollutants plus Mercury and Carbon Dioxide Expressed in Pounds per Kilowatt-Hour (lb/KWh) and Water Consumption Expressed in Gallons per KWh

Plant	Unit	SO2	NOx	PM	CO2	Hg	CO	Pb	VOC	H2O Consumption (Plant Average)
Cunningham	1	7.212E-06	1.879E-03	8.625E-05	1.3736E+00	3.115E-09	8.092E-06	5.841E-09	6.242E-05	0.433
Cunningham	2	6.356E-06	1.729E-03	7.935E-05	1.2582E+00	2.621E-09	1.059E-04	5.242E-09	5.743E-05	
Cunningham	3	6.438E-06	6.591E-04	5.348E-05	1.2980E+00	2.894E-09	5.460E-05	0.000E+00	2.293E-05	
Cunningham	4	6.987E-06	6.553E-04	5.577E-05	1.3906E+00	3.011E-09	9.360E-05	0.000E+00	2.457E-05	
Harrington	1	4.912E-03	1.699E-03	5.283E-04	2.1800E+00	1.081E-08	1.126E-03	6.160E-08	3.913E-05	0.698
Harrington	2	4.768E-03	1.412E-03	1.244E-04	2.1354E+00	8.097E-09	1.156E-03	2.089E-08	3.770E-05	
Harrington	3	4.984E-03	1.489E-03	1.453E-04	2.2797E+00	7.923E-09	1.124E-03	2.181E-08	3.663E-05	
Jones	1	6.408E-06	1.490E-03	8.071E-05	1.2696E+00	2.782E-09	2.549E-04	5.286E-09	5.841E-05	0.326
Jones	2	6.538E-06	1.138E-03	8.219E-05	1.2932E+00	2.869E-09	2.595E-04	5.314E-09	5.947E-05	
Jones	3	6.263E-06	3.059E-04	2.714E-05	1.2409E+00	2.681E-09	1.012E-04	0.000E+00	2.089E-06	
Jones	4	6.203E-06	3.052E-04	3.721E-05	1.2285E+00	2.656E-09	1.143E-04	0.000E+00	3.101E-06	
Maddox	1	6.538E-06	1.975E-03	8.118E-05	1.2928E+00	2.799E-09	7.613E-06	4.398E-09	5.875E-05	0.656
Maddox	2	1.052E-05	3.767E-03	9.007E-05	1.5964E+00	3.620E-09	2.047E-05	6.723E-09	2.866E-05	
Maddox	3	1.791E-05	7.648E-03	1.567E-04	2.7871E+00	0.000E+00	5.448E-04	0.000E+00	5.075E-05	
Nichols	1	6.783E-06	1.109E-03	8.171E-05	1.3047E+00	2.833E-09	2.580E-04	5.261E-09	5.913E-05	0.701
Nichols	2	1.123E-05	1.360E-03	8.595E-05	1.3718E+00	2.708E-09	2.714E-04	5.417E-09	6.220E-05	
Nichols	3	1.146E-05	1.887E-03	8.538E-05	1.3632E+00	2.989E-09	2.696E-04	5.663E-09	6.179E-05	
Plant X	1	8.394E-06	7.923E-03	1.039E-04	1.6505E+00	3.412E-09	1.148E-03	6.824E-09	7.520E-05	0.738
Plant X	2	7.058E-06	8.819E-04	8.747E-05	1.3941E+00	3.087E-09	2.761E-04	5.659E-09	6.326E-05	
Plant X	3	0.000E+00	0.000E+00	0.000E+00	0.0000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	
Plant X	4	6.597E-06	1.638E-03	8.225E-05	1.3095E+00	2.851E-09	2.597E-04	5.402E-09	5.951E-05	
Quay County	1	3.202E-05	1.608E-02	2.516E-04	2.7712E+00	0.000E+00	2.382E-04	4.058E-07	8.389E-04	0.000
Tolk	1	4.884E-03	1.737E-03	7.675E-05	2.2389E+00	8.898E-09	2.514E-03	1.297E-08	3.933E-05	0.650
Tolk	2	5.158E-03	2.165E-03	1.203E-04	2.5482E+00	8.112E-09	2.440E-03	1.882E-08	3.833E-05	

3.11 - Identification of Critical Facilities Susceptible to Supply-Source or Other Failures and Summary of Back-up Fuel Capabilities and Options

SPS takes system reliability very seriously and devotes significant resources to protecting the electric grid from multiple types of risks. The SPS transmission system is planned and designed for single contingency or N-1 standards, and therefore has the ability to sustain overall grid reliability in the face of various types of generator and transmission contingencies. In addition, SPS is compliant with the applicable NERC[16] reliability standards which require that assets critical to operation of the bulk electric system be identified and special protections for those facilities implemented. For safety and reliability, any lists or descriptions of these critical assets are considered highly confidential and not available to the public domain. Furthermore, SPS's owned generation units have redundant fuel supplies, mitigating the risk of supply-source failures. Additionally, purchases from the Southwest Power Pool market would typically address any deficiencies in SPS resources.

[16] North American Electric Reliability Corporation

Section 4. CURRENT LOAD FORECAST

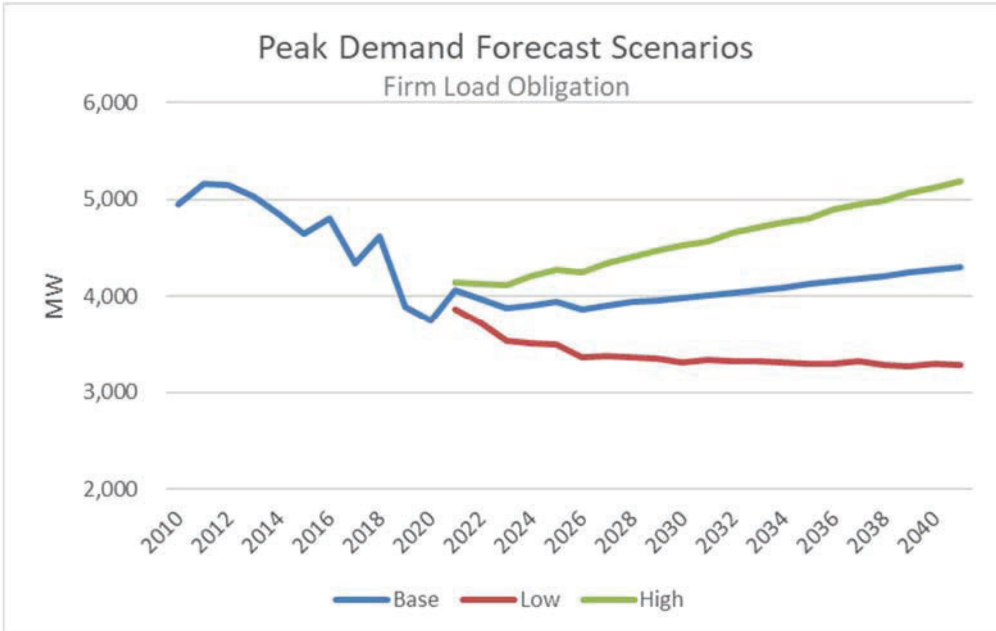
4.01 - Forecast Overview

Projections of future energy sales and coincident peak demand are fundamental inputs into SPS's resource need assessment. As required by the IRP Rule, SPS has prepared base, high, and low case scenario forecasts (17.7.3.9(D)(2) NMAC).

SPS projects its base or median electric firm obligation load (firm retail and firm wholesale requirements customers) to increase at a compounded annual growth rate of 0.4% or an average of 12 MW per year through the Planning Period (2022-2041). Growth in retail demand is expected to more than offset the impact of losing wholesale customers through the forecast period. SPS's base or median energy sales are forecasted to increase at a compounded annual growth rate of 0.6% or an average growth rate of 154 GWh during the same period. The load growth over the Planning Period contrasts to the historical annual average load decline of -2.7% over the last 10 years (ending 2020). The historical annual average energy decline over the ten years ending 2020 is -1.9%. Load and energy decreases were driven primarily by the decline of wholesale load due to expiration of the New Mexico Cooperatives' wholesale contracts and contractual changes within existing wholesale contracts. In addition, the decline in oil prices that started in the third quarter of 2015 paused the oil and gas expansion in southeastern New Mexico and the SPS region has seen a decline in potash mining in the last decade. Finally, 2020 sales and demands were negatively impacted by the business shutdowns and economic slowdown as a result of the COVID-19 pandemic.

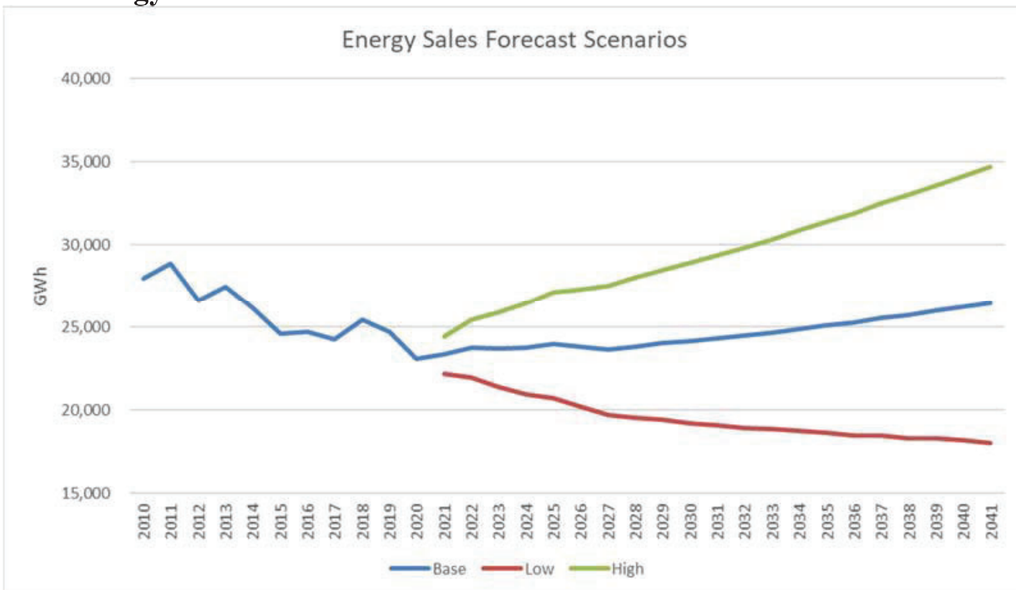
The SPS low forecast scenario of coincident peak demand decreases at a compounded annual growth rate of -0.6% through the Planning Period, and the high forecast scenario of coincident peak demand increases at a compounded annual growth rate of 1.2% per year. Figure 4F.1 below contains a graphical representation of the low and high forecast scenarios of coincident peak demand.

Figure 4F.1: Coincident Peak Demand Forecasts



SPS's annual energy sales low forecast scenario decreases at a compounded annual growth rate of -1.0% through 2041, and the annual energy sales high forecast scenario increases at a compounded annual growth rate of 1.6% per year. Figure 4F.2 below contains a graphical representation of the low and high scenario forecasts of annual energy sales.

Figure 4F.2: Energy Sales Forecasts



Figures 4F.1 and 4F.2 (above) show the base, high, and low forecasts for firm coincident peak demand and annual energy sales graphically. Appendix D (Tables D-10 and D-11) provides the data supporting the charts. Appendix D (Table D-11) also shows the SPS forecast for its total annual energy sales with eleven years of history starting in 2010, and it shows annual growth and compounded growth to/from 2020. The bold line across the table delineates historical from projected information.

The base peak demand forecast assumes economic growth based on projections from IHS Markit[17] and normal summer peak weather conditions. SPS estimates a 70% probability that the actual peak demands and energy sales will fall between the high and the low forecast scenarios.

4.02 - Peak Demand Discussion

Firm peak demand in the SPS service territory has declined over the last 10 years (through 2020). SPS's firm peak demand decreased by -1,203 MW or -24.3%, from 2010 to 2020. Load

[17] As discussed below, IHS Markit is a trusted data source for forecasting professionals that SPS uses for economic and demographic data and forecasts.

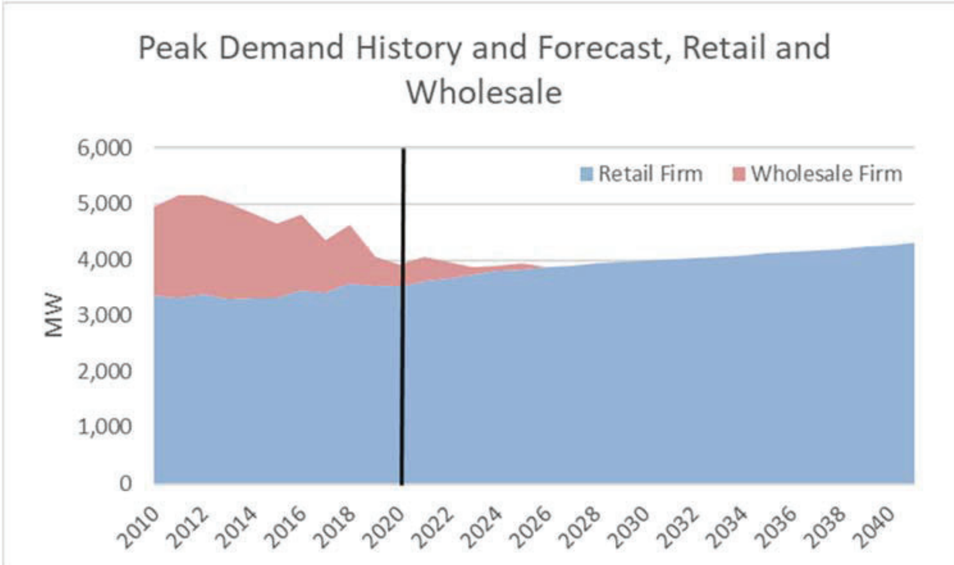
growth was dampened as a result of decreased demand from wholesale customers due to changes in contracted load. In the 10-year period ending 2020, the population in the SPS service territory grew by an annual average rate of 0.1% per year. Combined Real Gross County Product ("GCP") for the counties in the SPS service territory averaged gains of 2.0% from 2010 through 2020. During this same period, SPS gained about 17,900 residential customers, for total growth of 6.0%.

The peak demand forecast compounded annual growth rate for the Planning Period through 2041 is 0.4%. This is stronger growth than seen over the past ten years, which averaged annual declines of 2.7%. Retail peak demand for the Planning Period increases at a compounded annual growth rate of 0.8%, compared to the ten-year period ending 2020 compounded annual growth rate of 0.4%. Retail peak demand growth is driven by population and economic growth in the service territory, continued expansion of the oil and gas industry in southeastern New Mexico, and adoption of electric vehicles. Wholesale peak demand for the Planning Period gradually decreases as contracts expire and is zero starting in 2026. SPS assumes that expiring wholesale contracts will not be renewed after their known expiration dates.

SPS service territory GCP is expected to average 2.3% through 2041. Population growth is similar to the recent past, with annual gains averaging 0.3% through the Planning Period. SPS projects residential customer growth will average annual increases of 0.5% per year through 2041.

Table D-4 in Appendix D (Electric Energy and Demand Forecast) shows the SPS coincident peak demand by retail and wholesale customer categories. Figure 4F.3 shows the SPS coincident peak demand by retail and wholesale customers graphically.

Figure 4F.3: Peak Demand History and Forecast, Retail and Wholesale

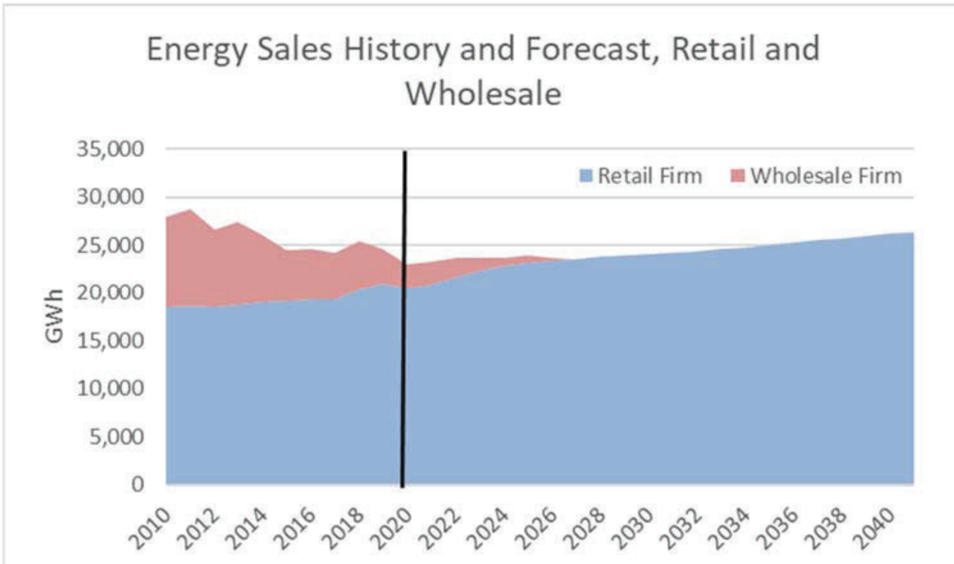


4.03 - Annual Energy Discussion

SPS is anticipating energy sales in the base case forecast to average 0.6% growth annually over the Planning Period. The declines in wholesale energy sales corresponding to the termination or reduction of sales to specific wholesale customers will offset growth in the retail sector.

During the past ten years SPS has experienced declines in energy sales, much of that also impacted by the declining wholesale sales. Energy sales decreased by 4,853 GWh, or -17.3%, from 2010 to 2020. The energy sales forecast's compounded annual growth rate for the Planning Period through 2041 is 0.6%. The growth in retail energy sales is expected to more than offset the declines in wholesale. Retail energy sales for the Planning Period increase at a compounded annual growth rate of 1.0%, similar to the 10-year period ending 2020 compounded annual growth rate of 1.0%. Retail energy sales will benefit from strong growth in the New Mexico commercial and industrial sector, which is heavily dependent on the oil and natural gas industries, and the adoption of electric vehicles. Base case wholesale energy sales are forecasted to decline steadily before reaching zero in 2027. Figure 4F.4 shows SPS's energy sales by retail and wholesale customer class graphically.

Figure 4F.4: Energy Sales History and Forecast, Retail and Wholesale



<u>4.04 - Electric Vehicles</u>

SPS has developed a projection of electric vehicle adoption in its service territory. SPS expects to have 307,700 electric vehicles in its service territory by 2041. These vehicles are expected to contribute 1,972 GWh to annual energy sales and 241 MW to coincident summer peak demand.

<u>4.05 - High and Low Case Forecasts</u>

Development and use of different energy sales and demand forecasts for planning future resources is an important aspect of the planning process. Alternative high and low forecast scenarios to the base case were developed for the 2021 IRP. The high and low forecast scenarios are based on a Monte Carlo simulation for energy sales and peak demand forecasts with probabilistic inputs for the economic, energy, and weather drivers of the forecast models and for model error. The high forecast scenario is the forecast level from the Monte Carlo simulation that represents a plus one standard deviation confidence band from the base case forecast. The low forecast scenario is the forecast level from the Monte Carlo simulation that represents a minus one standard deviation confidence band from the base case forecast. There is a 70% probability that actual energy sales and coincident peak demand will fall within the high and low forecast scenarios.

Appendix D (Table D-10 and Table D-11) provides a summary of the base, high, and low peak demand and energy sales forecasts.

Typical Historic Day Load Patterns

Please refer to Appendix E for the typical day load patterns on a system-wide basis for each customer class provided for: peak day, average day, and representative off-peak days for each calendar month.

4.06 - Forecasting Methodologies

The following discussion describes the methods used to forecast energy sales and coincident peak demand for each of its various customer classes in SPS.

SPS forecasts retail energy sales and customers by class for each jurisdiction. Retail coincident peak demand is forecasted in aggregate at the total SPS level. The wholesale energy sales and coincident peak demand forecasts are developed at the individual customer level of detail. SPS models its forecasts at a monthly frequency and uses monthly historical data to develop the customers, energy sales, and coincident peak demand forecasts. Annual energy sales are an aggregation of the monthly energy sales estimates. Energy sales are forecasted at the delivery point and peak demand is forecasted at the generating source. The annual coincident peak demand occurs in July throughout the Planning Period 2022-2041.

IHS Markit, a trusted data source for forecasting professionals, provides economic and demographic data and forecasts. SPS assumes normal weather for the forecast period. Normal weather is based on a 30-year rolling average of historical weather data for the energy sales and retail coincident peak forecasts.

4.07 - Energy Sales Forecasts

SPS's retail customer counts, retail energy sales, and full requirement wholesale energy sales forecasts are developed using econometric models and trend models. An econometric model is a widely accepted modeling approach involving linear regression analysis. Linear regression analysis is a statistical technique that attempts to understand the movement of the dependent variable, for example, energy sales, as a function of movements in a set of independent variables, such as economic and demographic concepts, customers, price, trend, and weather, through the quantification of a single equation. Other variables used in the econometric models may include autoregressive correction terms and binary variables. Binary variables are used in models to account for non-weather-related seasonal factors and unusual billing activity. The autoregressive correction term is used to aid in eliminating bias found in time-series models. After developing and testing the econometric models to identify the relationship between the dependent and independent variables, forecasts of the independent variables are used to predict future energy sales and customer counts.

SPS's econometric models are evaluated through examining the model statistics output and tests results. Each variable coefficient in the models is checked for the correct theoretical signs and statistical significance. The coefficient of determination (R-squared) test statistic is a measure to verify the quality of the model's fit to the historical data. The models are also tested for correlation of errors from one period to the next. The absence of correlation between the residual errors is an important indicator that the model is performing adequately. Graphical inspection of a model's error term helps identify if a model suffers from auto-correlation (i.e., error terms are not random and are correlated between periods) or heteroscedasticity (i.e., inconstant variance of errors over the sample period). A model with auto-correlation may indicate model misspecification.

The output from the econometric models for the retail energy sales is adjusted to reflect the expected incremental impact of DSM programs. The model output is also adjusted for electric vehicle impacts. SPS developed a base, low, and high scenario of estimated sales due to electric vehicles. The forecast assumes the base sales scenario. The model output may also be adjusted with information from SPS's Managed Account Sales group regarding SPS's largest commercial and industrial customers. The Managed Account Sales group provides information about known events that can impact energy sales that would not be captured in the historical data. Such events might include a scheduled increase or decrease in load for a specific customer due to a plant expansion, or a reduction in load stemming from a plant shutdown. The final adjusted output from the econometric models becomes part of the base case energy sales forecast.

Energy sales forecasts for SPS's partial requirement wholesale customers are developed based on historical consumption patterns or econometric models as described above, subject to contractual agreement with the customer.

4.08 - Peak Demand Forecasts

SPS develops an econometric model, as described above, to forecast the monthly retail coincident peak demand. Total retail coincident peak demand is forecasted in aggregate at the source for the total SPS company level. The exogenous variables in the retail coincident peak demand model include weather, binary and trend variables, and retail energy sales. Retail energy sales are not adjusted for DSM savings, electric vehicle increases, or load increases or decreases as identified by the Managed Account Sales group prior to being used in the model. Instead, such adjustments are made to the output from the retail peak demand model.

The full requirements wholesale coincident peak demand is developed on an individual customer basis. SPS uses a load factor methodology to calculate the coincident peak demand associated with the energy sales for each full requirement wholesale customer. For each customer, SPS calculates a monthly load factor based on historical energy sales and coincident peak demand data as recorded at the delivery point. Monthly load factors are calculated as:

Load Factor = Energy Sales/(Peak Demand * Hours Per Month)

The monthly load factors are then applied to each full requirement wholesale customer's respective energy sales forecast to derive the monthly peak demand forecasts.

Peak Demand = Energy Sales/(Load Factor * Hours Per Month)

The peak demand forecasts are then adjusted for line losses to derive the peak demand forecast at the source.

The partial requirement wholesale customer coincident peak demand forecasts are determined by individual customer contractual agreement.

4.09 - Modeling for Uncertainty

SPS has developed high and low forecast scenarios to the base case forecast. These alternative forecasts are derived from Monte Carlo simulations of energy sales and coincident peak demand.

Monte Carlo simulation is a modeling technique that ascribes probabilistic characteristics to selected inputs and the output of a model. The Monte Carlo simulations are based on econometric models used to forecast energy sales and coincident peak demand. In particular, energy sales and coincident peak demand are modeled at the combined retail and full requirement wholesale sales level of aggregation.

In these models, probability distributions are defined for exogenous variables with inherent uncertainty associated with their forecast values. Probability distributions are a realistic way of describing uncertainty in variables. An example of a variable with inherent uncertainty is the maximum peak day temperature in the coincident peak demand model. While SPS assumes the value will be 99.6 degrees Fahrenheit for each July during the forecast period, it is unlikely that each year the actual peak day maximum temperature will be 99.6 degrees Fahrenheit. The probability distributions contain the possible values for variables with inherent uncertainty over the forecast period, based on characteristics of the data set for each variable. The weather, economic and energy variables, and the model error are assumed to have inherent uncertainty in the models used to develop the high and low energy sales and coincident peak demand forecast scenarios.

For each simulation run of these forecasting models, the values for the exogenous variables with inherent uncertainty are randomly selected from respective probability distribution. By using probability distributions, variables can have different probabilities of different outcomes occurring. Monte Carlo simulation calculates the model results over and over, each time using a different set of random values from the probability functions. The output from the Monte Carlo simulation models is then calibrated so that the 50% probability forecast is equal to the respective energy sales and coincident peak demand base case forecast.

4.10 - Weather Adjustments

SPS incorporates several different weather variables in its forecasting models. For the energy sales models, SPS may include monthly heating degree days, cooling degree days, and precipitation.

The heating degree days and the cooling degree days are calculated on a base of 65 degrees Fahrenheit for each day and then totaled by month.

Heating Degree Days = Max (65 - Average Daily Temperature, 0)

Cooling Degree Days = Max (Average Daily Temperature - 65, 0)

The coincident peak demand models include a maximum peak day temperature variable and a rolling two-week summation of the days prior to the monthly peak day with a maximum daily temperature of 95 degrees Fahrenheit or greater variable.

Weather during the forecast period is assumed to be normal. Normal weather is defined as a rolling 30-year average for heating degree days, cooling degree days, precipitation, maximum temperature, minimum temperature, average temperature, and days with maximum temperature 95 degrees Fahrenheit or greater. The energy sales and coincident peak demand forecasts do not have any other weather normalization adjustments.

For historical periods, SPS weather normalizes historical energy sales and coincident peak demand data for variance analysis purposes. This weather normalization process involves subtracting weather-impacted energy sales or peak demand from actual sales or peak demand. Weather-impacted sales or peak demand is calculated by multiplying the forecast model weather variable coefficients by the variance of actual weather from normal weather.

Weather-Impacted Energy Sales =

Weather Coefficient * (Actual Weather-Normal Weather)

Weather Impacted Peak Demand =

Weather Coefficient * (Actual Weather-Normal Weather)

4.11 - Demand-Side Management

SPS promotes DSM programs that help its customers reduce energy sales and peak demand through energy efficiency and education. Xcel Energy's DSM Regulatory Strategy and Planning group develops the projections of future and embedded DSM program savings.

SPS adjusts its retail energy sales and coincident peak demand forecasts with projected incremental DSM program savings. The incremental DSM program savings are calculated by subtracting embedded DSM savings from future DSM savings.

Incremental DSM Savings = Future DSM Savings – Embedded DSM Savings

SPS does not directly adjust its forecast models or model output for naturally occurring DSM savings that could be attributed to actions other than those of SPS. However, theoretically, the historical energy sales and coincident peak demand data used in SPS's forecast modeling process does have embedded in it any naturally occurring DSM savings. Therefore, the forecast models and model output do account indirectly, through the historical data, for naturally occurring DSM savings. Naturally occurring DSM energy and peak demand savings do not impact SPS's sponsored DSM resources.

4.12 - Demand Response, Energy Efficiency, and Behind-the-Meter Generation

The historical energy sales data used in SPS's forecast modeling process is net of behind-the-meter generation and demand response energy sales. Therefore, the forecast models and model output indirectly account, through the historical data, for behind-the-meter and demand response energy sales. The historical peak demand data used in the forecasting process has not been adjusted to account for behind-the-meter generation and demand response.

4.13 - Forecast Accuracy

SPS reviews its demand and energy forecasts for accuracy annually. Appendix D (Table D-12 through Table D-17) provides a comparison of the actual energy sales and firm load obligation demand forecasts to the forecasted sales and firm load obligation demands, as required by the IRP Rule. Firm load obligation equals actual load less available interruptible load. See Figures 4F.5 and 4F.6 (next page).

Figure 4F.5: Forecast Comparison with Actual Energy Sales

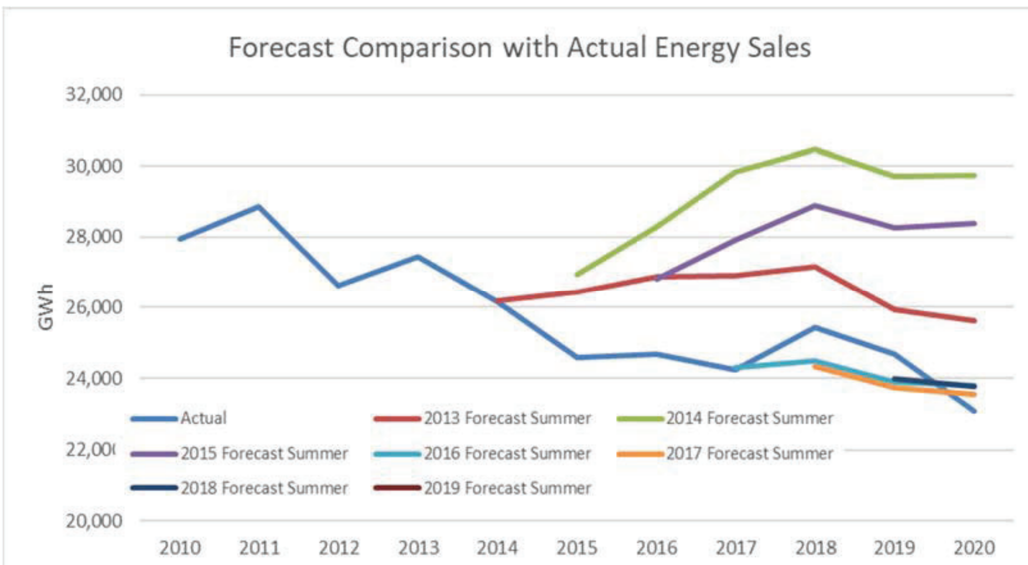
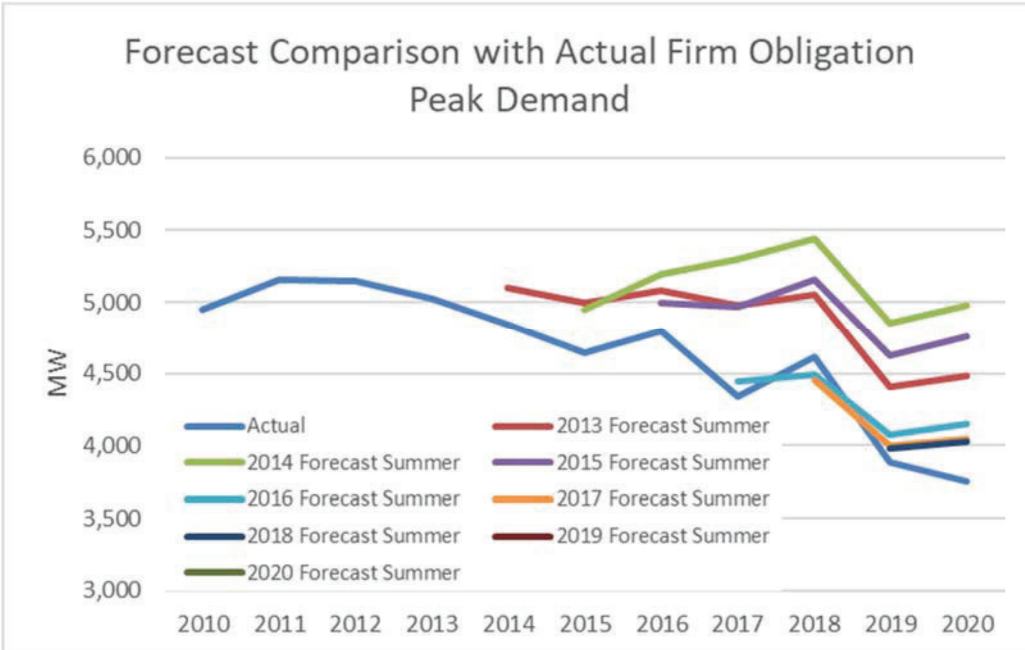


Figure 4F.6: Forecast Comparison with Actual Firm Load Obligation Peak



4.14 - Econometric Model Parameters

Please refer to Appendix F, which provides the parameters associated with SPS's econometric forecasting model.

Section 5. L&R TABLE

The IRP Rule requires that utilities provide an L&R table of existing loads and resources at the time of its IRP filing, specifically including: (1) utility-owned generation; (2) energy storage resources; (3) existing and future contracted-for purchased power including, where applicable, QF purchases, (4) purchases through net metering programs, as appropriate, (5) demand-side resources, as appropriate, and (6) any other resources relied upon by the utility.

Resource planners use a range of approaches to help identify the amounts, timing, and types of generation resources that should be added to meet increasing customer demand for electric power. One basic and straightforward tool is the L&R table. The function of an L&R table is to provide a comparison between the amount of electric generating supply and the peak load of a system. In years when load plus the planning reserve margin exceeds generation supply, additional generation is needed. Table 5-1 provides a summarized L&R table for the SPS electric system assuming the base load forecast described in Section 4.

Table 5-1: Summarized L&R Table

		2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)
(a)	Owned Generation Capacity	4,333	4,270	4,159	4,159
(b)	Purchased Power Capacity	1,208	1,254	1,030	1,020
(c)	Total Generation Capacity	5,541	5,524	5,189	5,179
(d)	Firm Load Obligation	3,969	3,874	3,899	3,937
(e)	Capacity Margin (12%)	476	465	468	472
(f)	Total Firm Load + Reserves	4,445	4,339	4,367	4,409
(g)	Resources Position Long / (Short)	1096	1184	823	770

The Summarized L&R table above provides foresight into the amounts and timing of future generation resource needs. As shown in the summarized L&R table, SPS has sufficient supply-side resources to meet its planning reserve margin requirements during the Action Plan and, therefore, does not require any new generating resources. However, as described in Section 7, SPS may consider procuring additional resources if they are expected to provide other benefits, such as economical energy savings.

Exhibit DG-4

Table 5-2: Summary of SPS Base Case L&R

SPS Loads & Resource Balance Summer 2022 - 2031 - Base Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	5,541	5,524	5,189	5,179	4,926	4,906	4,672	4,560	4,560	4,314
LOAD										
Retail	3,696	3,778	3,827	3,865	3,895	3,933	3,962	3,988	4,009	4,034
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	3,969	3,874	3,899	3,937	3,867	3,905	3,934	3,961	3,982	4,007
RESERVES										
Planning Reserve Margin @ 12%	476	465	468	472	464	469	472	475	478	481
TOTAL PLANNING RESERVE MARGIN	476	465	468	472	464	469	472	475	478	481
CAPACITY REQUIREMENT	4,445	4,339	4,366	4,409	4,331	4,374	4,407	4,436	4,460	4,488
RESOURCE POSITION (MW): LONG/(SHORT)	1,096	1,184	823	770	595	532	266	124	101	(174)

SPS Loads & Resource Balance Summer 2032 - 2041 - Base Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	4,039	2,970	2,396	1,922	1,881	1,541	1,541	1,186	1,186	624
LOAD										
Retail	4,060	4,088	4,111	4,149	4,181	4,211	4,235	4,269	4,305	4,331
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	4,033	4,061	4,085	4,122	4,153	4,183	4,207	4,241	4,275	4,302
RESERVES										
Planning Reserve Margin @ 12%	484	487	490	495	498	502	505	509	513	516
TOTAL PLANNING RESERVE MARGIN	484	487	490	495	498	502	505	509	513	516
CAPACITY REQUIREMENT	4,517	4,549	4,575	4,616	4,651	4,685	4,712	4,749	4,788	4,819
RESOURCE POSITION (MW): LONG/(SHORT)	(478)	(1,578)	(2,179)	(2,694)	(2,770)	(3,144)	(3,171)	(3,563)	(3,602)	(4,194)

Table 5-3: Summary of SPS High Load Case L&R

SPS Loads & Resource Balance Summer 2022 - 2031 - High Load Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	**5,541**	**5,524**	**5,189**	**5,179**	**4,926**	**4,906**	**4,672**	**4,560**	**4,560**	**4,314**
LOAD										
Retail	3,860	4,018	4,135	4,197	4,268	4,361	4,431	4,492	4,549	4,593
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	**4,133**	**4,115**	**4,207**	**4,269**	**4,240**	**4,333**	**4,403**	**4,464**	**4,522**	**4,565**
RESERVES										
Planning Reserve Margin @ 12%	496	494	505	512	509	520	528	536	543	548
TOTAL PLANNING RESERVE MARGIN	496	494	505	512	509	520	528	536	543	548
CAPACITY REQUIREMENT	4,629	4,608	4,712	4,781	4,748	4,853	4,932	5,000	5,064	5,113
RESOURCE POSITION (MW): LONG/(SHORT)	**912**	**915**	**477**	**398**	**178**	**53**	**(259)**	**(440)**	**(504)**	**(799)**

SPS Loads & Resource Balance Summer 2032 - 2041 - High Load Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	**4,039**	**2,970**	**2,396**	**1,922**	**1,881**	**1,541**	**1,541**	**1,186**	**1,186**	**624**
LOAD										
Retail	4,679	4,732	4,793	4,826	4,918	4,980	5,015	5,095	5,154	5,211
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	**4,652**	**4,706**	**4,767**	**4,799**	**4,890**	**4,952**	**4,987**	**5,066**	**5,125**	**5,182**
RESERVES										
Planning Reserve Margin @ 12%	558	565	572	576	587	594	598	608	615	622
TOTAL PLANNING RESERVE MARGIN	558	565	572	576	587	594	598	608	615	622
CAPACITY REQUIREMENT	5,210	5,270	5,339	5,375	5,477	5,547	5,585	5,674	5,740	5,804
RESOURCE POSITION (MW): LONG/(SHORT)	**(1,171)**	**(2,300)**	**(2,942)**	**(3,453)**	**(3,595)**	**(4,005)**	**(4,044)**	**(4,488)**	**(4,553)**	**(5,180)**

Exhibit DG-4

Table 5-4: Summary of SPS Low Load Case L&R

SPS Loads & Resource Balance Summer 2022 - 2031 - Low Load Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EXISTING RESOURCES										
Owned - Thermal Resources	4,333	4,070	3,959	3,959	3,714	3,714	3,523	3,411	3,411	3,165
Owned - Renewable Resources	0	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	797	797	574	574	574	574	574	574	574	574
Purchased Power - Renewable Resources	410	456	456	446	438	418	375	375	375	375
TOTAL ACCREDITED CAPACITY (MW)	**5,541**	**5,524**	**5,189**	**5,179**	**4,926**	**4,906**	**4,672**	**4,560**	**4,560**	**4,314**
LOAD										
Retail	3,437	3,431	3,436	3,413	3,391	3,404	3,391	3,371	3,335	3,359
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	301	125	100	100	0	0	0	0	0	0
DSM / Interruptibles	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(27)	(27)
FIRM LOAD OBLIGATION	**3,709**	**3,528**	**3,507**	**3,484**	**3,363**	**3,376**	**3,363**	**3,343**	**3,308**	**3,332**
RESERVES										
Planning Reserve Margin @ 12%	445	423	421	418	404	405	404	401	397	400
TOTAL PLANNING RESERVE MARGIN	445	423	421	418	404	405	404	401	397	400
CAPACITY REQUIREMENT	4,154	3,951	3,928	3,902	3,767	3,781	3,767	3,745	3,705	3,732
RESOURCE POSITION (MW): LONG/(SHORT)	**1,386**	**1,572**	**1,261**	**1,277**	**1,159**	**1,125**	**906**	**816**	**855**	**582**

SPS Loads & Resource Balance Summer 2032 - 2041 - Low Load Case Forecast
Based on March 2021 Load Forecast

SPS Load and Resources	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EXISTING RESOURCES										
Owned - Thermal Resources	2,922	1,853	1,853	1,593	1,593	1,253	1,253	898	898	336
Owned - Renewable Resources	200	200	200	200	200	200	200	200	200	200
Purchased Power - Thermal Resources	574	574	0	0	0	0	0	0	0	0
Purchased Power - Renewable Resources	343	343	343	129	88	88	88	88	88	88
TOTAL ACCREDITED CAPACITY (MW)	**4,039**	**2,970**	**2,396**	**1,922**	**1,881**	**1,541**	**1,541**	**1,186**	**1,186**	**624**
LOAD										
Retail	3,339	3,349	3,333	3,322	3,326	3,352	3,306	3,299	3,314	3,311
Firm Wholesale	0	0	0	0	0	0	0	0	0	0
Firm PR Load	0	0	0	0	0	0	0	0	0	0
DSM / Interruptibles	(27)	(27)	(26)	(27)	(28)	(28)	(28)	(29)	(29)	(29)
FIRM LOAD OBLIGATION	**3,312**	**3,322**	**3,307**	**3,295**	**3,298**	**3,324**	**3,278**	**3,270**	**3,285**	**3,283**
RESERVES										
Planning Reserve Margin @ 12%	397	399	397	395	396	399	393	392	394	394
TOTAL PLANNING RESERVE MARGIN	397	399	397	395	396	399	393	392	394	394
CAPACITY REQUIREMENT	3,710	3,721	3,704	3,690	3,694	3,722	3,672	3,663	3,680	3,677
RESOURCE POSITION (MW): LONG/(SHORT)	**330**	**(751)**	**(1,307)**	**(1,767)**	**(1,812)**	**(2,181)**	**(2,130)**	**(2,476)**	**(2,493)**	**(3,052)**

Section 6. IDENTIFICATION OF RESOURCE OPTIONS

The basic types of resources that are available for matching electricity supply and demand are discussed below. These resources play different roles in meeting an electric utility's demand and energy requirements. Supply-side resources provide generation capacity to serve load, whereas demand-side resources act to reduce the level of customer demand for electric power so fewer supply side-resources are required. Supply-side resources generally fall into three categories: traditional (or thermal), renewable, and energy storage. Traditional supply-side resources are typically fossil fuel-based generation resources with physical fuel supplies that can be dispatched as the demand (or need) for power changes (increases or decreases) throughout the day. Renewable resources, on the other hand, are intermittent supply-side "as available" generation resources, effectively the energy produced is a function of the timing and force created by the wind blowing or the solar radiation intensity and conversion of photons of light to electrical voltage (e.g., photovoltaic "PV"). Renewable resources are typically must-take resources, which at times can create operational issues related to their integration into the electrical power grid. Energy storage is typically achieved through BESS, which are electrochemical devices that store energy for use when needed. Battery chemistries vary in technical characteristics; however, lithium-ion chemistries are currently the most widely utilized in the U.S. The most common thermal, renewable, and BESS technologies are described in more detail below

Examples of Thermal Supply-Side Resources

- CTG (Combustion Turbine Generator) – Combustion Turbine Generators are typically referred to as simple-cycles because they operate on a single thermodynamic cycle known as the Brayton Cycle. CTGs can operate on several fuel sources but are typically fired with natural gas which turns a turbine coupled with an electric generator to generate electricity. Recent CTG technological advancements have enabled operation, for both new and retrofitted CTGs, to utilize carbon-free hydrogen as an alternative fuel source. CTGs are available in a wide range of sizes (4 MW to over 400 MW) and are typically inexpensive to build but are relatively inefficient sources of generation. As such, they are often considered "peaking" units, which are utilized during times of high electric demand. CTGs also provide extremely fast start capabilities and ramp rates, providing the capability to follow demand and intermittent renewable generation, such as wind and solar.

- CC (Combined Cycle) – Combined Cycle ("CC") facilities utilize single or multiple CTGs in conjunction with Heat Recovery Steam Generators ("HRSG") and a Steam Turbine Generator ("STG") to generate electricity. These facilities are known as CCs because they combine the Brayton Cycle, mentioned above in the CTG section, with the Rankine Cycle, the HRSG, and STG's thermodynamic cycle. The waste heat from the CTG's exhaust gas is ducted through a HRSG which generates steam to turn a steam turbine coupled with an electric generator which produces additional electric power along with the CTGs. CCs can operate in multiple configurations, i.e., 1-on-1, 2-on-1, or 3-on-1, with the first number being the number of CTGs and HRSGs and the second number being the steam turbine, which is appropriately sized to efficiently utilize the total CTG waste heat. For example, a 2-on-1 CC consists of two CTGs and HRSGs and one STG. CCs can also operate on various fuel sources, including hydrogen, since the base motive drivers are the CTGs mention in the CTG section above. CC units come in a variety of sizes near 100 MW to over 1,600 MW depending on the specific configuration of the facility. CC units have higher installed costs than CTG units, but better efficiency and operating costs, thus CCs offer more expensive capacity but lower cost energy when compared to simple cycle CTGs.

Examples of Renewable Supply-Side Resources

- Solar – Solar generation resources convert the sun's energy (photons of light) into electricity. Solar generation has several forms, such as PV, concentrating PV, or concentrating solar power. Solar generation is intermittent, like other renewable energy resources. In SPS's service territory, solar generation capacity factors typically range from 30% - 35%. Solar generation is only available during the daytime and its output is coincident with the time of the day (i.e., as the sun rises and falls, so does the solar generation output). Maximum solar output occurs prior to the time when electric demand reaches its highest level. Therefore, less than the full nameplate generating capability of solar generation is counted toward meeting electric system peak demands.
- Wind – Wind generation typically consists of large, three-bladed turbines mounted atop towers over 250 feet tall arranged over several thousand acres of land. Wind generation consist of a multiple Wind Turbine Generators with aggregated capacities up to hundreds of MW. Because the wind drives the turbines, the generation from a wind turbine is considered intermittent and can be difficult to predict. Wind generation units in New Mexico and Texas typically have an annual capacity factor in the 45-55% range, depending on the specific location within these regions. As maximum wind generation output is variable and often noncoincidental to peak system loads, wind generation has a low capacity value when compared to other generating resource (including solar generation).

Examples of Energy Storage Supply-Side Resources

- Energy Storage – Lithium ion battery storage has become increasingly popular due to declining costs. These battery storage devices typically range in size from 10 to over 250 MW and vary in duration from 2 – 8 hours. For short duration requirements, battery storage can bring about frequency control and stability, and, for longer duration requirements, they can bring about energy management or reserves.

DSM Resources

- DSM resources act to reduce the demand for electric power and include a variety of measures such as EE, energy conservation, LM, and demand response. There are two basic types of demand-side resources: peak shavers and energy savers. Peak shavers are used to reduce a customer's demand and energy requirements during periods of high demand. Examples of peak shaver DSM options include ICO and the Saver's Switch programs. Energy savers are used to reduce energy over all periods of the year. An example of an energy saver would be replacement of incandescent light bulbs with more energy efficient LED bulbs to reduce energy consumption throughout the year.

Transmission Upgrades

- Investments in transmission can be used as an alternative for investments in new generating facilities or demand-side resources, where transmission upgrades are used to access existing generation within other transmission-constrained areas.

Supply-Side Resource Comparison

Each of the different supply-side generation technologies described above have distinctly different technical characteristics as well as capital and operating cost characteristics. These characteristics dictate how various technologies are dispatched or used to serve load requirements of the system. A high-level comparison of the supply-side generating resources is shown below in Table 6.1.

Table 6-1: Supply-Side Generating Resources Comparison

Costs	Gas CT	Gas CC	Wind	Solar	BESS
Installed Cost	Low	Mid	High	Mid/High	High
Operating Costs	High	Mid	Low	Low	Low
Expected Capacity Factor %	0-25%	25-80%	45-55%	30%	N/A
CO_2[18] per MWh	Medium	Low	None	None	N/A

6.01 - Resource Options Considered

SPS's 2021 IRP considers each of the five resource options described above; i.e., CTG, CC, Solar, Wind, and BESS. Depending on the year the resource option was available for selection in the EnCompass production cost model, SPS used one of two different approaches when determining the cost and technical characteristics of new generating resources. First, as shown in Table 6-2, for the thermal resources available for selection in 2026 and beyond, SPS used general generic characteristics such as asset life, capital costs, fixed and variable operating and maintenance costs, fuel type (when applicable), heat rates (when applicable), and CO_2 emissions. These general generic characteristics are carried through each year of the planning period and costs are escalated where stated. Annual

[18] Carbon Dioxide

capacity factors are not an input for thermal generic resources, rather they are calculated by the EnCompass production cost model. The EnCompass output files will be provided under Protective Order. Availability factor can vary year-on-year and are also available in the EnCompass output files. Second, for resources available for selection between the years 2023 and 2025, inclusive, SPS used information contained in proposals received from the Tolk Analysis Request for Information ("RFI").

6.02 - Generic Resources

Generic characteristics are developed "in-house" utilizing SPS's experience with these technologies and leveraging market relationships to validate any characteristic assumptions. When determining the future cost of renewable resources, SPS also leveraged data from National Renewable Energy Laboratory's ("NREL") 2020 Annual Technology Baseline ("ATB"). These resource characteristics were then included in the EnCompass production cost model to represent how these various technologies would integrate with the existing SPS electric system to serve future customer load projections. The cost of SPS's generic thermal resources, which are summarized below in Table 6-2, were estimated in current dollars and then escalated at 2% per year thereafter. SPS used NREL ATB cost data as a baseline for estimating annual costs for wind, solar and BESS resources. Annual cost estimates for wind, solar and BESS incorporated applicable renewable tax credits for the year the project was expected to be in-serviced and, where applicable, continued declining costs in real dollars. The annual cost estimates for wind, solar, and a 4-hour BESS resource are shown below in Table 6-3. Additional cost and performance information related to the generic thermal resource types is presented in Appendix G.

Table 6-2: Thermal Generic Resource Summary Cost and Performance - 2021[19]

Technology	Asset Life (yrs)	Capacity (MW)	Capacity Cost $/kw	Fixed O&M[20] $000/yr	On-Going Capital $000/yr	VOM $/MWh	Heat Rate MMBTu/MWh	CO_2 Emissions Lbs/MMBTu
2x1 CC	40	771	$773	$5,400	$5,150	$1.22	6,608	117
CTG	40	201	$495	$1,120	$1,313	$0.00	10,009	117

Table 6-3: Generic Renewable and BESS Resource Cost by Year

Levelized Costs by In-Service Year (LCOE)			
EOY[21]	**Wind ($/MWh)**	**Solar ($/MWh)**	**Battery ($/kW-mo)**
2026	$ 39.20	$ 30.68	$ 12.80
2027	$ 38.96	$ 29.14	$ 12.57
2028	$ 38.70	$ 27.56	$ 12.33
2029	$ 38.41	$ 25.94	$ 12.09
2030	$ 38.78	$ 26.08	$ 12.17
2031	$ 39.16	$ 26.21	$ 12.26
2032	$ 39.53	$ 26.35	$ 12.34
2033	$ 39.91	$ 26.48	$ 12.42
2034	$ 40.28	$ 26.61	$ 12.50
2035	$ 40.65	$ 26.74	$ 12.58
2036	$ 41.03	$ 26.87	$ 12.58
2037	$ 41.40	$ 27.00	$ 12.57
2038	$ 41.76	$ 27.12	$ 12.55
2039	$ 42.13	$ 27.24	$ 12.51
2040	$ 42.49	$ 27.36	$ 12.47
2041	$ 42.86	$ 27.47	$ 12.41

6.03 - Proposals Received from the Tolk Analysis RFI

As part of the Tolk Analysis, SPS was required to issue an RFI. The proposals received from the RFI generally included indicative commercial operation dates through the end of year 2025.

[19] Table 6-2 reflects 2021 costs escalating at 2% per year.
[20] Operations and Maintenance
[21] End of Year

Therefore, rather than use generic characteristics through 2025, SPS utilized the proposals received from the RFI for resources that were available for selection in the EnCompass production cost model between 2023 – 2025. For the purposes of determining the most cost-effective portfolio of resources, SPS utilized the commercial operational dates provided from perspective bidders. However, as described in more detail in Section 7.07, it is doubtful that many of the proposals can still meet the commercial operation dates they submitted in the RFI.

As a result of the RFI, SPS received information from 18 different bidders, with most bidders submitting multiple proposals and/or pricing structures. The majority of proposals submitted were for new wind generation, solar generation, or solar generation plus battery energy storage.

Wind Generation

SPS received wind proposals ranging from a little over 100 MW up to 1,000 MW. The median pricing of wind proposals received from the RFI was $23.05/MWh, assuming 60% production tax credits ("PTC") eligibility. However, as discussed in detail in the Tolk Analysis, most proposals did not include the full cost of the necessary transmission network upgrades required to interconnect the new generation.

Solar Generation

SPS received solar proposals ranging from less than 50 MW to just over 1,000 MW. The median pricing of solar proposals received from the RFI was $27.52/MWh. SPS received solar proposals that included 30%, 26%, and 10% investment tax credits ("ITC"). Again, most proposals did not include the full cost of the necessary transmission network upgrades to interconnect the new generation.

Battery Energy Storage Systems

SPS did not receive any standalone BESS resources. Instead, SPS received several proposals for solar generation coupled with BESS as this allowed the BESS to qualify for the same ITC as the solar generation. To qualify for the solar ITC, SPS assumed the BESS must be charged by the coupled solar generation for the first 5 years of operation. The incremental cost of a 4-hour BESS was approximately $6/kW-month to $8/kW-month inclusive of qualifying ITCs.

6.04 - Other Supply-side Resource Technologies

SPS received other supply-side resource technology proposals from the RFI. These technologies included gravitational energy storage, compressed air storage, and a 1-on-1 CC with hydrogen production and storage. Gravitational and compressed air storage provide the potential for longer duration energy storage than current lithium-ion BESS. In the absence of carbon-free fuels, longer duration energy storage is critical to achieving New Mexico's carbon free energy aspirations. However, neither gravitational or compressed air storage is currently well-established, and the proposals received are in the early developmental stage; as such, it is highly doubtful that either proposal could achieve commercial operation within the Action Plan and therefore were not considered for SPS's most cost-effective portfolio of resources. Currently, the cost of hydrogen production and storage is cost prohibitive when compared to other energy resources, such as wind, solar or even traditional gas-fired CCs. However, as demonstrated in Section 7, as SPS transitions to a more renewable-heavy portfolio of generating resources, SPS will need firm and dispatchable resources. Hydrogen-capable resources are one possibility to fulfill this critical need in the future.

Accredited Capacity - Planning Reserve Margin

Each of the supply-side resource technologies described above has the ability to contribute capacity to SPS's planning reserve margin requirements. Thermal resources, such as CTGs and CCs, can be dispatched when needed and provide 100% of their rated capacity towards SPS's planning reserve margin. Intermittent resources, such as wind generation and solar generation contribute less than their full nameplate generating capacity toward meeting SPS's planning reserve margin requirement due to their variability. The current accredited capacity SPS assumed for each resource type is shown below in Table 6-6. The Southwest Power Pool determines the methodology that is used to determine the amount of renewable capacity that can be applied to SPS's planning reserve requirement. Beginning summer of 2023, Southwest Power Pool will replace the current renewable accreditation methodology with the Effective Load Carrying Capability ("ELCC") methodology. The Southwest Power Pool will also apply the ELCC methodology to energy storage resources in the future. The ELCC methodology will result in decreasing accreditation of renewable resources and energy storage resources as the penetration of those resources increase across the Southwest Power Pool Balancing Authority Area. As SPS is unable to determine the future penetration of renewable resources and energy resources across the Southwest Power Pool Balancing Authority Area, when determining the most cost-effective portfolio of resources, SPS did not incorporate diminishing accredited capacity for generic solar, wind, and BESS resources.

Table 6-4: Accredited Capacity for New Resources

Summer Accredited Capacity for Generic Resources	
Generic Solar	58.00%
Generic Wind	19.90%
Generic CTG	100.00%
Generic CC	100.00%
Generic BESS	100.00%

Lead Time for New Resources

Development and subsequent construction of new generation facilities can take several years to complete, depending on the public and regulatory environment for which the resource is planned. SPS's recent experience has shown the regulatory approval process for new resources can exceed 12 months – excluding a competitive procurement process that can add a further six to nine months. Development of resources can take anywhere from 1 year to multiple years depending on the resource, such as renewable energy, where thousands of acres of land are required to be secured for development. Finally, engineering, procurement, construction, startup, and commissioning of new facilities can take anywhere from two to three years. Although most of the processes are scheduled to occur strategically in parallel, that is, concurrently, especially development and other "at-risk" engineering and planning, the best case execution of these tasks from start to finish would result in a resource coming online within approximately two to four years from start to finish. These public and regulatory details must be strategically accounted for when planning and executing the installation of new resources, including the lead times for critical equipment manufacturing and delivery to sites. Other factors such as current lead times for interconnection agreements detailed in Section 7.07 also add an additional level of schedule uncertainty and risk that must be considered in the overall schedule.

6.05 - Existing Rates and Tariffs

SPS's current mix of seasonal rate design, service curtailment programs, and EE programs provide a fair balance between the interest in meeting, delaying, or avoiding the need for new capacity, balanced with cost containment and minimizing adverse rate impacts resulting from significant changes in rate structures.[22]

General Service Rates

All general service rates have some form of seasonality in the kWh consumption charge or the kW demand charge. Summer rates are higher than winter (non-summer) rates, which requires the customer to pay more for electricity used in higher demand, peak periods in the summer compared to the same levels of usage in winter billing months. A higher bill can serve to discourage excessive usage in summer months and, where possible for the customer, serve as an incentive to shift usage to lower demand winter billing periods; thus, mitigating the need for new resources over time.

TOU Rates

Time of Use ("TOU") rates are available as an option for all general service customers, except Large General Service – Transmission. TOU rates provide a lower rate compared to general service rates for off-peak demand or energy consumption, with a higher charge based upon avoided capacity cost during peak hours. Peak hours are 12 noon through 6 p.m., Mondays through Fridays, during the summer billing months of June through September. Lower rates during off-peak hours, and all

[22] SPS's current rates were set in Case No. 19-00170-UT. The rates are subject to revision in Case No. 20-00238-UT.

hours for eight off-peak months, can encourage customers to take electric service during periods in which capacity is not strained. Higher rates during peak hours can encourage customers to minimize or avoid taking electric service when capacity can potentially be strained, minimizing the requirement to expand capacity and related costs, as a result of requirements during peak hours.

Section 7. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS

7.01 - Resource Planning Fundamentals

In its simplest form, electric resource planning is the process of taking forecasts of customer electric demand and energy use and determining the appropriate diversification of generation sources, including but not limited to, thermal generation, renewable resources, energy storage, DSM and LM, that should be developed to meet customer requirements in a cost-effective and reliable fashion. Engineering, permitting, and constructing electric generating facilities takes a significant amount of time and therefore the resource planning process must be completed with adequate lead-time to allow the development of new resources that are needed to meet customer energy requirements.

Computer Models

After developing forecasts of customer demand, L&R tables, and load duration curves of the system, computer modeling of the electric system is often the next step in the planning process. Computer models allow the resource planner to examine how different resource technologies will integrate with the existing fleet to meet the system needs under a range of assumptions from key inputs such as fuel costs. A utility expansion-planning model is specifically designed to construct combinations or portfolios of resources that would meet the capacity and energy needs of the system. The model simulates operation of each of these combinations of resources together with existing generation resources, while keeping track of all associated fixed and variable costs of the entire system. The resources available for selection in the model are described in more detail in Section 6.

The computer model is needed because it can keep track of the thousands of calculations on costs, emissions, operational data, and various other metrics for each of the possible resource portfolios.

While this model is a powerful tool that can be used to generate and evaluate thousands of possible resource portfolios, the sheer complexity of resource evaluations of this magnitude would quickly overwhelm the model's data storage and computational capabilities unless steps are taken to limit the size of the optimization problem presented to the model at any one time. The number of resource combinations that can be generated each year grows exponentially depending on the number of resources made available to the model.

7.02 - EnCompass Production Cost Model

SPS recently transitioned to the EnCompass production cost model in its resource planning process. EnCompass is a production costing model that uses an algorithm to determine the most cost-effective resource portfolio for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions. The EnCompass model includes: 1) a modern "solve anything" algorithm; 2) hourly operation detail that can accurately capture ramp rates, start-up, etc.; and 3) enhanced storage logic and ancillary services. EnCompass is also able to perform utility capital accounting (revenue requirements).

In addition to the usual input variables needed for a production costing model, EnCompass incorporates a wide variety of resources expansion planning parameters to develop a coordinated, integrated plan that best suits the utility system being analyzed. For example, EnCompass incorporates resource expansion planning parameters such as: alternative generation technologies available to meet future needs; renewable energy resources; unit capacity sizes; heat rates; LM; conservation programs; reliability limits; and environmental compliance options.

Costs Included in EnCompass

The EnCompass model includes the critical generation costs SPS incurs to provide electric service to its customers. The following lists summarize the costs that are typically included in the EnCompass model.

1. Fuel costs for all electric power supply resources (owned and purchased) and market energy costs (which are forecasted based on gas prices;
2. Purchased energy costs for all electric power supply resources;
3. Capacity costs of purchased power;
4. VOM costs of purchased power;
5. Capital costs for new electric generation facilities added to meet future load;
6. Energy costs for new wind and solar generation facilities added to meet future energy need;
7. Electric transmission interconnection and network upgrade cost for new generation;
8. FOM costs for existing and new generation facilities;
9. VOM costs for existing and new generation facilities; and
10. Remaining book value of SPS-owned generating units.

7.03 - Development of Resources Portfolios

The following factors were considered in, or affected, the development of the most cost-effective portfolio of resources and alternative portfolios.

System reliability and planning reserve margin requirements

Maintaining system reliability and planning reserve margin requirements is a critical modeling constraint when developing resource portfolios. The EnCompass model was constrained to maintain at a minimum Southwest Power Pool’s 12% planning reserve margin on a monthly basis. Failure to meet the planning reserve margin resulted in the EnCompass model adding new capacity resources. The EnCompass model evaluated the ability of the resource portfolio to meet electric demand on an hourly basis. However, rather than program a hard constraint, SPS assigned an extremely high emergency energy cost ($/MWh) in hours where SPS's resources and market energy purchases could not meet hourly demand. This high cost ensured EnCompass would add additional resources if SPS could not regularly meet hourly demand, but also prevented the model from adding new resources whenever the emergency energy need was extremely small.

Renewable Energy Portfolio Requirements

As demonstrated in New Mexico Case No. 21-00172-UT, SPS is projecting continued compliance with the RPS throughout the Action Plan. During the Planning Period, New Mexico's RPS requirement is scheduled to increase to 80% of NM retail sales. Modeling long-term compliance with the RPS is challenging for multi-jurisdiction utilities, such as SPS, that must plan resources on a total system basis, not a jurisdictional basis. New Mexico retail sales represent approximately 35% - 40% of SPS's total system sales. Therefore, without knowing exactly how RPS compliant resources will be allocated between jurisdictions, it is challenging to determine exactly the quantity of renewable resources required to meet 80% New Mexico retail sales. Therefore, SPS did not constrain the resource portfolios to meet the NM RPS; however, SPS did retrospectively evaluate the resource portfolios to ensure compliance through the planning period is achievable. SPS's most cost-effective portfolio of resources includes renewable resources generating approximately 82% of the total system wide sales in 2040.

Load Management and Energy Efficiency Programs

SPS's base, low and high energy and demand forecasts are net of projected load management and energy efficiency programs. Therefore, load management and energy efficiency programs were directly incorporated into the load forecasts SPS used when developing the resource portfolios.

Existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions.

In developing the most cost-effective portfolio of resources and alternative portfolios, SPS evaluated compliance with all existing environmental law and regulations. SPS did not evaluate the effect of anticipated or possible future environmental regulations (that is neither the subject of a proposed or final rulemaking) because they are speculative and may never be adopted, or they may be adopted in some different form than the proposal. The one exception being the standardized cost of carbon emissions that is included in the analyses, which is described in more detail in Section 7.13.

A summary of the current status and remaining unknowns about each environmental regulation, along with the potential impacts on SPS's generation resources is included in Appendix K.

Fuel Diversity

It is difficult to directly quantify the value of fuel diversity when determining resource portfolios; therefore, SPS did not directly assign a quantitative fuel diversity benefit as a direct input or factor. However, SPS recognizes the importance of the reliability and economic benefits of fuel diversity. Outside of the EnCompass analysis, SPS considers the benefits of fuel diversity in its resource planning decisions. For example, fuel diversity is an additional benefit of maintaining the Tolk Units through 2032.

Susceptibility to fuel interdependencies

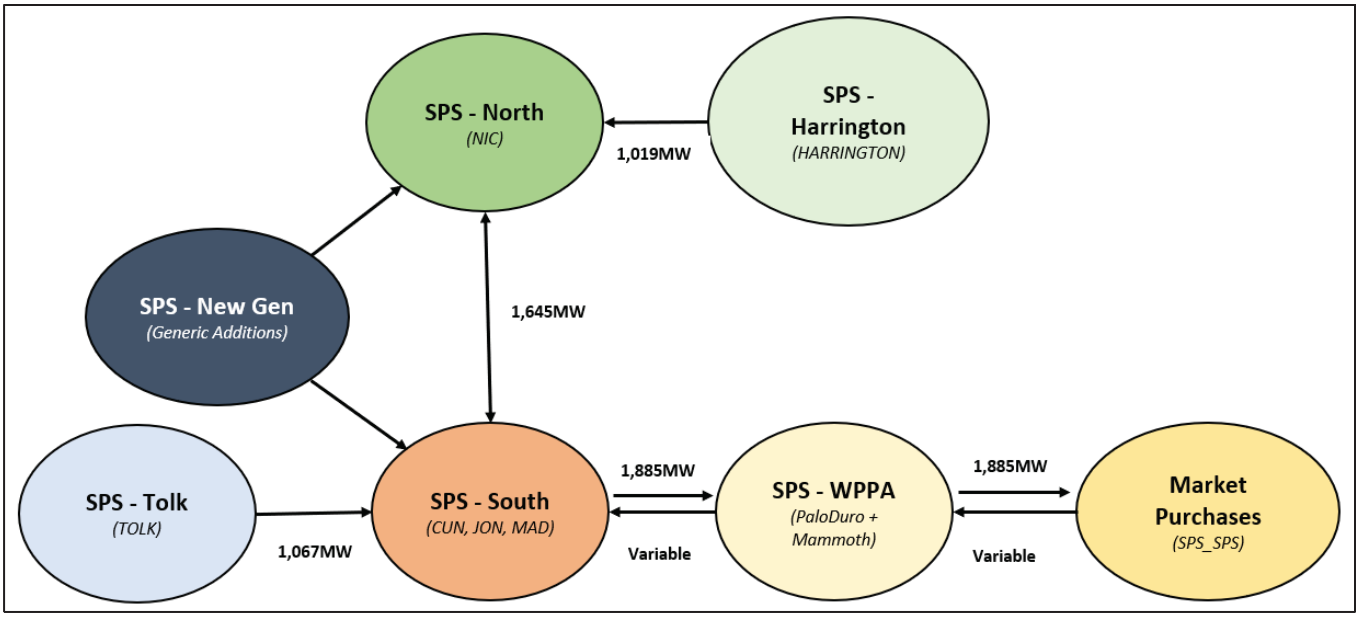
EnCompass provides hourly operation detail that can accurately capture ramp rates, start-up times, minimum up and minimum down times, and other factors. Therefore, EnCompass determines how different technologies (and fuel types) interact with one another when calculating the most cost-effective portfolio of resources and alternative portfolios.

Transmission Constraints

SPS included two major transmission constraints in the EnCompass model. First, as described in Section 3.09, Southwest Power Pool has a total of 1,885 MW of transmission flow capability minus the single largest contingency and other factors (i.e., imports from Palo Duro and Mammoth Wind) to deliver resources to the SPS zone from the rest of the Southwest Power Pool transmission system. Second, SPS's analysis included a 1,645 MW North to South constraint. New Generation was not subjected to the North to South constraint.

In addition to the transmission constraints, SPS included generator point of injection constraints between Harrington and Tolk and the SPS system. In the event resources are selected at Tolk and/or Harrington and SPS exercised its rights to use replacement or surplus interconnection capacity, these constraints ensured neither facility could exceed its current maximum capability. For example, in the event a new wind generator was co-located at Tolk, the total output of the existing Tolk Generators and the new wind facility could still not exceed 1,067 MW.

Figure 7F.0: EnCompass Transmission Constraints



7.04 - Establishing a Base Case Analysis in EnCompass

When establishing the most cost-effective portfolio of resources in EnCompass, SPS first determined the critical inputs and assumptions to be used for its base case analysis. The base case analysis incorporates the following critical inputs and assumptions:

- Base natural gas and market energy forecast (see section 7.10)
- Base load forecast (see Section 7.11)
- Mid-point transmission network upgrade costs (see section 7.12)
- $0 social cost of carbon (see section 7.13)

SPS's base case analysis assumed specific dates for the retirement of SPS generation consistent with Table 3-1 (see Section 3, above). SPS also considered alternative retirement dates for the Tolk Units and the Harrington Units, which are presented in the alternative portfolios section below.

7.05 - Based Case - Resource Need

Action Plan Period

As shown in Table 5-2, SPS has enough supply-side resources to meet its planning reserve margin requirement until the Summer of 2031. Also, as demonstrated in SPS's New Mexico 2021 RPS filing, Case No. 21-00172-UT, SPS anticipates continued RPS compliance beyond the Action Plan Period. Therefore, SPS does not need any additional resources to reliably serve its customers or meet regulatory requirements during the Action Plan. However, even without a defined resource need, SPS may still pursue additional resources if such resources are reasonably expected to provide other benefits, such as economic energy savings. When deciding whether to acquire economic energy resources, SPS must consider the likelihood that the economic resources will provide the energy savings anticipated.

Planning Period

Over the next 10-years, several of SPS's older gas steam units are scheduled to retire, creating a 174 MW capacity need by the Summer of 2031. SPS's capacity need then increases significantly over the remainder of the 20-year Planning Period as existing generating units retire and PPAs expire. For example, during the planning period, SPS's two largest plants, Tolk and Harrington, are scheduled to retire as is the remainder of the gas steam generating units and the Lea Power combined cycle PPA is also scheduled to expire. By the end of the Planning Period, SPS's capacity need is expected to grow to 4,194 MW.

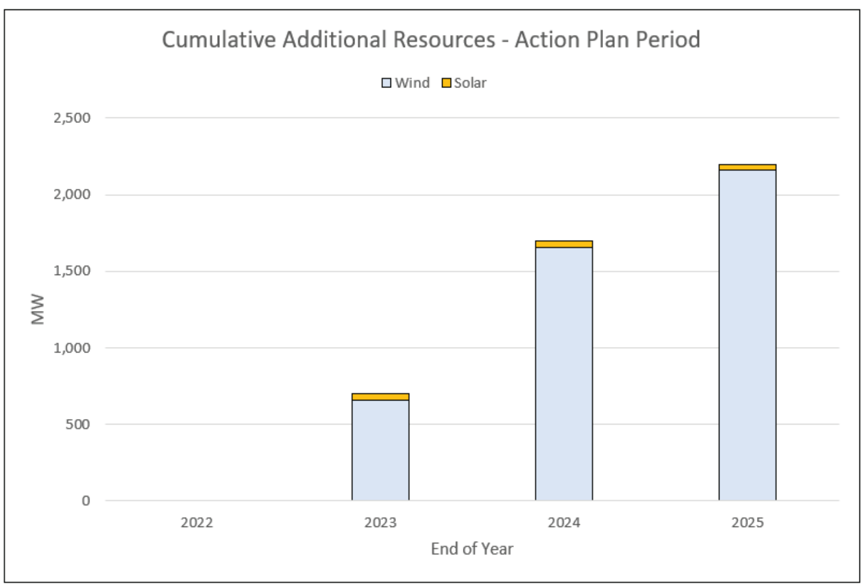
7.06 - Most Cost-Effective Resource Portfolio – Base Case

Action Plan Period

As described above, over the course of the 4-year Action Plan Period, SPS does not require any new resources for reliability needs or regulatory requirements. However, SPS may pursue additional economic energy resources. As shown below in figure 7F.1, SPS's most cost-effective resource portfolio includes an additional 2,158 MW of economic wind generation and 40 MW of economic solar generation added during the Action Plan Period.

Although the most cost-effective resource portfolio includes additional economic energy resources, SPS must consider risks and uncertainties when procuring economic energy resources. Risks and uncertainties are discussed in detail in the Tolk Analysis and summarized below in Section 7.07.

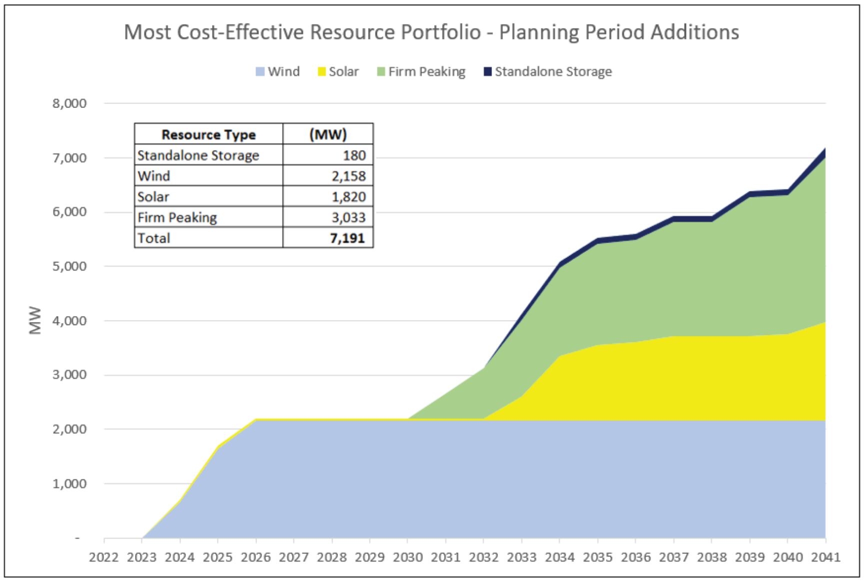
Figure 7F.1: Most Cost-Effective Resource Portfolio – Additional Resources During the Action Plan



Planning Period

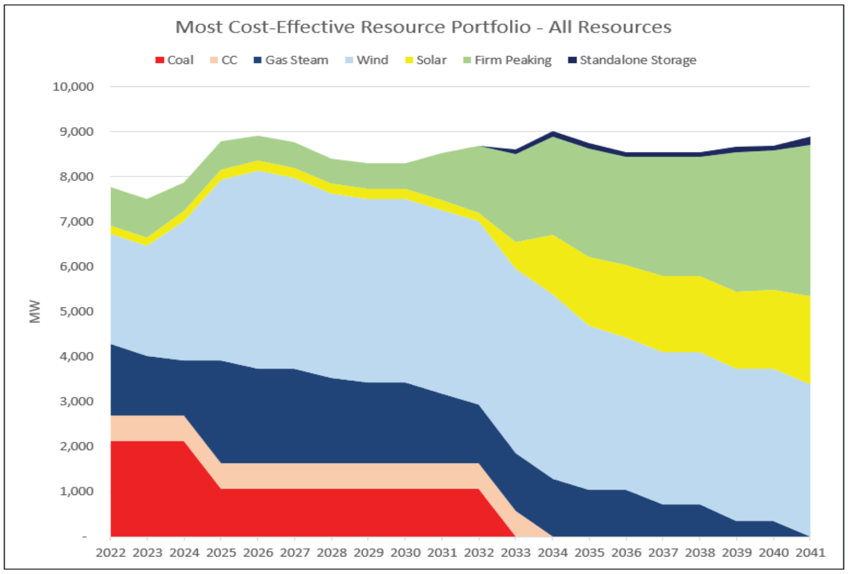
As discussed above in Section 7.05, SPS's capacity need is expected to grow from 174 MW in 2031 to 4,194 MW in 2041. While renewable generation, particularly solar, can meet some of this capacity need, SPS will also need firm and dispatchable resources to serve load when intermittent renewable resources are unavailable. Based on SPS's growing capacity need, as shown in Figure 7F.2, it is not surprising that SPS's most cost-effective resource portfolio includes 1,780 MW of new solar generation, 180 MW of BESS, and approximately 3,000 MW of new CTGs over the Planning Period – in addition to the resources added during the Action Plan. Environmental mandates, such as New Mexico's RPS, or technological and/or economic improvements of emerging technologies may drive the need for the CTGs to switch to carbon-free hydrogen as a fuel source, or ultimately replace the combustion turbines with other technologies, such as long-duration energy storage or other technologies that are not currently commercially viable. SPS's most cost-effective portfolio of resources does not require any new CTGs until 2031, providing SPS time to re-evaluate alternative carbon-free fuel sources, or technological alternatives to CTGs, as the next generation of carbon-free technologies mature. SPS believes the development of carbon-free fuel sources and/or the advancement of technologies not currently commercially viable will be essential in achieving the 2045 carbon free goal specified in the Energy Transition Act.

Figure 7F.2: Most Cost-Effective Resource Portfolio –Additional Resources During the Planning Period



SPS's most cost-effective resource portfolio will experience an unprecedented transition over the next two decades. As shown below in Figure 7F.3, SPS's entire coal-fired generation will either be retired or converted to operate on natural gas before the end of 2032 and all units that burn coal today will be retired before the end of the Planning Period. SPS's entire gas-steam generating fleet is also scheduled to retire before the end of the Planning Period, as is the Lea Power combined cycle. In its place, SPS's 2041 most-cost effective resource portfolio is projected to include 3.4 GW of wind generation, nearly 2 GW of solar generation, 180 MW of BESS and 3.4 GW of firm peaking generation. Again, while current modeling inputs and assumptions show CTGs providing firm peaking and load-following generation, this will likely change as the cost of emerging technologies continue to trend down.

Figure 7F.3: Most Cost-Effective Resource Portfolio – Planning Period All Resources



7.07 - Uncertainty in Modeling the Cost of New Resources

While there is inherent uncertainty in modeling the cost of generating resources up to 20-years in advance, SPS's 2021 IRP has been prepared during a period of heightened uncertainty that impacts the cost of resources in the near and long term. Uncertainties, such as the possible extension of renewable tax credits and the high cost of transmission network upgrades can, and most likely will fundamentally change SPS's most cost-effective resource portfolios over the 4-year Action Plan and 20-year Planning Period. These uncertainties are discussed in detail in the Tolk Analysis and summarized below.

Extension of Federal Tax Credits

For the purposes of determining the most cost-effective portfolio of resources, SPS assumed wind production tax credits and solar investment tax credits would expire or step-down based on the currently approved schedule. However, at the federal level, several bills that could extend or revise renewable tax credits are currently being considered. If passed, the extension of renewable tax credits would likely fundamentally change SPS's most cost-effective resource portfolio. For example, as demonstrated above in figure 7F.2, the currently scheduled EOY 2025 expiration of wind production tax credits have a significant impact on the timing of future wind acquisitions. SPS's most cost-effective portfolio of resources includes 2,158 MW of new PTC qualifying wind generation before the end EOY 2025 and then no additional wind generation after the PTCs expire. An extension of PTCs will (1) potentially defer the acquisition of wind generation during the Action Period and (2) likely add additional wind resources not currently seen in the Planning Period. Additional wind generation during the Planning Period may mitigate the need for some, but not all, firm peaking generation in the future.

Transmission Network Upgrade Costs and Schedule Uncertainty

The acquisition of new generating resources within SPS's service territory is subject to Southwest Power Pool's severely backlogged transmission interconnection study process – with new requests taking several years to be completed. Furthermore, when the results of the transmission network upgrade studies are identified, they often result in proposed generators being assigned cost-prohibitive transmission network upgrades, for example the DISIS 2017-01 2nd Phase Study assigned $934/kW to new generators in SPS's service territory. In comparison, the cost to construct a new solar facility excluding transmission network upgrades is estimated to be approximately $1,000/kW - $1,200/kW. Currently, it is challenging to anticipate and evaluate the cost of network upgrades in the near- and long-term future. Furthermore, it is uncertain whether projects will actually proceed once transmission network upgrade costs are known. For example, the DISIS 2017-01 study initially contained nearly 3,800 MW of new renewable generation in SPS's service territory. After Southwest Power Pool required each proposed project to submit a 20% deposit only a single 200 MW wind generating facility remained. As discussed in more detail in Section 6 and in the Tolk Analysis, in the base case analysis, SPS assumed generators requiring a new generator interconnection agreement would be assigned $400/kW for transmission network upgrades (less than half of the amount assigned in the 2017-01 DISIS). As described later in this section, SPS also conducted sensitivity analyses for the cost of transmission network upgrades. SPS did not assign additional transmission network upgrade costs to RFI proposals that either (1) already possessed an executed generator interconnect agreement, or (2) build-transfer proposals that interconnected at the site of existing SPS generators. SPS assumed the latter would provide the opportunity for SPS to exercise its rights for replacement or surplus interconnection rules to avoid the need for a new generator interconnection agreement. SPS assigned the same additional transmission network upgrade costs to all future generic CC, wind, and solar resources. SPS did not assign additional transmission network upgrade costs for generic CTGs or BESS resources, on the assumption the resources would be located at the site of existing generation.

In addition, as described in Section 6, SPS modeled the commercial operation dates of the proposals submitted in the RFI. These proposals included projects that have subsequently withdrawn from the 2017-01 DISIS and proposals that have not yet entered Southwest Power Pool's study process.

Emerging and Future Technologies

Technological and economic improvements of 'emerging technologies', such as solar and battery energy storage, will continue to redefine SPS's resource portfolio over the 20-year Planning Period. In addition, the next generation of technologies such as hydrogen capable generation or long-duration energy storage will become increasing important as SPS and New Mexico work together towards decarbonizing the power sector. For the purposes of determining the most-effective portfolio of resources, SPS used the pricing for the resource options described in Section 6 in developing the base case analysis.

7.08 - Alternative Portfolios / Mitigating Ratepayer Risk

To mitigate ratepayer risk, SPS evaluated alternative portfolios (sensitivities) assuming changes to critical modeling inputs, such as: the future operation and retirement dates of SPS's existing coal generation, natural gas price forecast, market energy price forecast, and load forecast. In addition, due to the uncertainty in transmission network upgrade cost described above, SPS also conducted sensitivity analyses for transmission network upgrade costs. Each of the sensitivity analyses are described in more detail in the Tolk Analysis. Finally, as described in Section 7.13, SPS also evaluated three different carbon price sensitivity analyses. In addition to the sensitivity analyses described throughout the remainder of this section, SPS also evaluated multi-factor sensitivity analyses, such as low load and low natural gas price forecasts. The results of these analyses are provided in Appendix J.

7.09 - Future Operation of SPS's existing coal generation

SPS's two largest plants, Tolk Station and Harrington Station, both face unique operational challenges. The coal-fired Tolk Units, rely upon water from the Ogallala Aquifer for generation and cooling, and the aquifer is in irreversible decline. The limited availability of economic water necessitates either: (1) the conservation of water through reduced / seasonal operations or (2) the early retirement of both units. SPS's other coal plant, Harrington Station, is subject to an agreed order with the TCEQ to cease burning coal at the end of 2024, at which point all three units will be converted to operate on natural gas.

Tolk Operation and Retirement Analysis

Per the uncontested comprehensive stipulation in New Mexico Case No. 19-00170-UT, SPS's 2021 IRP includes an updated "Tolk Analysis" evaluating the optimal retirement date of the Tolk Units. The Tolk Analysis continues to support seasonal / summer operations of the Tolk Units and a 2032 retirement date for both units. The Tolk Analysis is included in its entirety in Appendix H and was previously filed with the NMPRC in June 2021.

Harrington Operation and Retirement Analysis

In New Mexico base rate Case No. 20-00238-UT, SPS presented its analysis supporting the October 2020 agreed order with the TCEQ to cease burning coal at the end of 2024. SPS intends to file a Certificate of Public Convenience and Necessity in New Mexico soon after the filing of this IRP supporting the decision to the convert the units to operate on natural gas. A summary of this analysis is presented in Appendix I.

7.10 - Natural Gas & Market Energy Price Forecast

The price of natural gas is an important variable. SPS uses a combination of market prices and fundamental price forecasts, based on multiple highly respected, industry leading sources, to calculate monthly delivered gas prices. As the foundation of the gas price forecast, Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally based forecasts from Wood Mackenzie, IHS Energy, and S&P Global. The forecast is fully market-based for the current year plus two additional years and then transitions into blending the four sources to develop a composite forecast. The Henry Hub forecast is adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

SPS conducted low and high natural gas price forecast sensitivity analyses. For the low and high price cases, the base gas forecast for Henry Hub was adjusted down by 50% of the growth (escalation) in the base gas case to represent the low gas case, and adjusted up by 150% of the growth in the base gas to represent the high gas case. SPS's market price forecast is dependent on the gas price forecast used. As such, the market price forecast was adjusted with the low and high gas sensitivity analyses.

SPS's base, low and high natural gas and market energy forecast for the years 2022 – 2041 are shown in Appendix G (oil and coal price forecasts are also included in Appendix G).

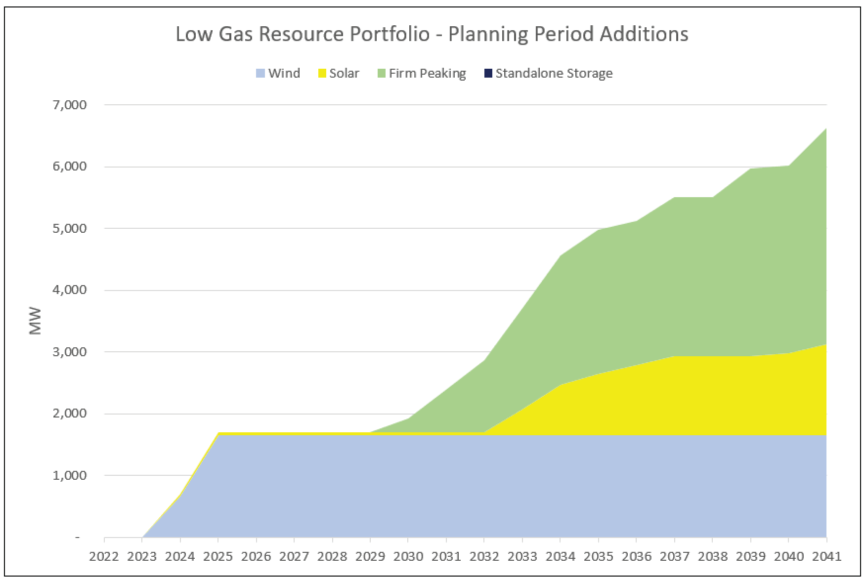
Low Forecast

The low natural gas and market energy price sensitivity analysis resulted in the acquisition of similar resources during the Planning Period – notably, wind, solar and CTGs. However, as shown in Table 7.1 and Figure 7F.4 below, when compared to the base case analysis, the low natural gas and market energy price sensitivity acquired two additional CTGs at the expense of 500 MW less wind and 350 MW less solar generation. The low natural gas and market energy price sensitivity did not add any standalone BESS projects during the Planning Period.

Table 7.1: Low Natural Gas & Market Energy Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	-	(180)
Solar + Storage	-	-	-
Wind	2,158	1,658	(500)
Solar	1,820	1,470	(350)
Firm Peaking	3,033	3,500	467
CC	-	-	-
Total	**7,191**	**6,628**	**(563)**

Figure 7F.4: Low Natural Gas and Market Energy Forecast – Additional Resources During the Planning Period



High Forecast

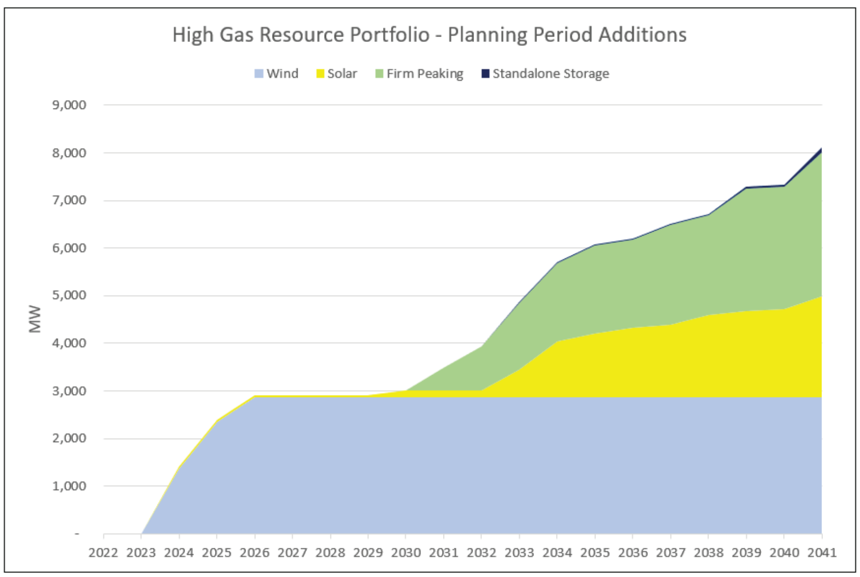
Again, the high natural gas and market energy price sensitivity analysis resulted in the acquisition of similar resources during the Planning Period – notably, wind, solar, and CTGs. However, as shown in Table 7.2 and Figure 7F.5 below, when compared to the base case analysis, the high natural gas and market energy price sensitivity acquired an additional 700 MW of wind and

310 MW of additional solar. The high natural gas and market energy price sensitivity acquired 100 MW of BESS – 80 MW less than the base case analysis.

Table 7.2: Low Natural Gas & Market Energy Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	100	(80)
Solar + Storage	-	-	-
Wind	2,158	2,858	700
Solar	1,820	2,130	310
Firm Peaking	3,033	3,033	-
CC	-	-	-
Total	**7,191**	**8,121**	**930**

Figure 7F.5: High Natural Gas and Market Energy Forecast – Additional Resources During the Planning Period



7.11 - Load Forecast

Demand and energy forecasts are another important variable. As such, SPS conducted low and high load forecast sensitivity analyses using the methodology described in section 4. However, it is worth noting, the methodology described in Section 4 for calculating the 'base' load case forecast is largely used for financial planning purposes. Despite continued growth in oil and gas developments in the New Mexico portion of the Permian basin and due to the volatility of the industry, the financial load forecast incorporates only a modest amount of projected oil and gas load growth. The 'high' load case forecast represents a more accurate projection of SPS's capacity position if oil and gas load continue to increase. For the purposes of resource planning, the high load forecast is predominately used to ensure SPS has enough resources to reliably serve customers.

SPS's base, low, and high load forecast for the years 2022 – 2041 are shown in Appendix G.

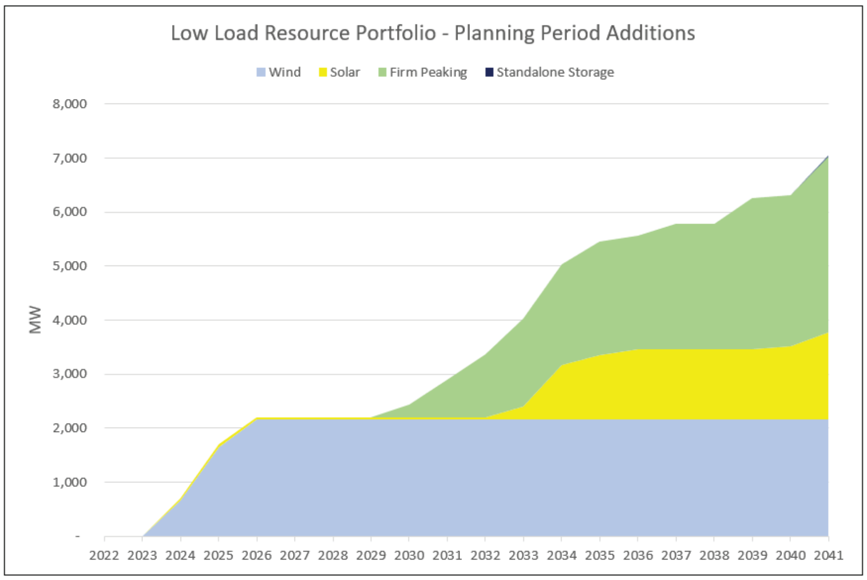
Low Load Forecast

As shown below in Table 7.3 and Figure 7F.6, during the Planning Period, the low load forecast resource portfolio added the new wind generating resources as the base case. The low load forecast resource portfolio added an additional CTG during the planning period at the expense of 170 MW less BESS and 210 MW less solar generation.

Table 7.3: Low Load Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	10	(170)
Solar + Storage	-	-	-
Wind	2,158	2,158	-
Solar	1,820	1,610	(210)
Firm Peaking	3,033	3,266	233
CC	-	-	-
Total	**7,191**	**7,044**	**(147)**

Figure 7F.6: Low Load Forecast – Additional Resources During the Planning Period



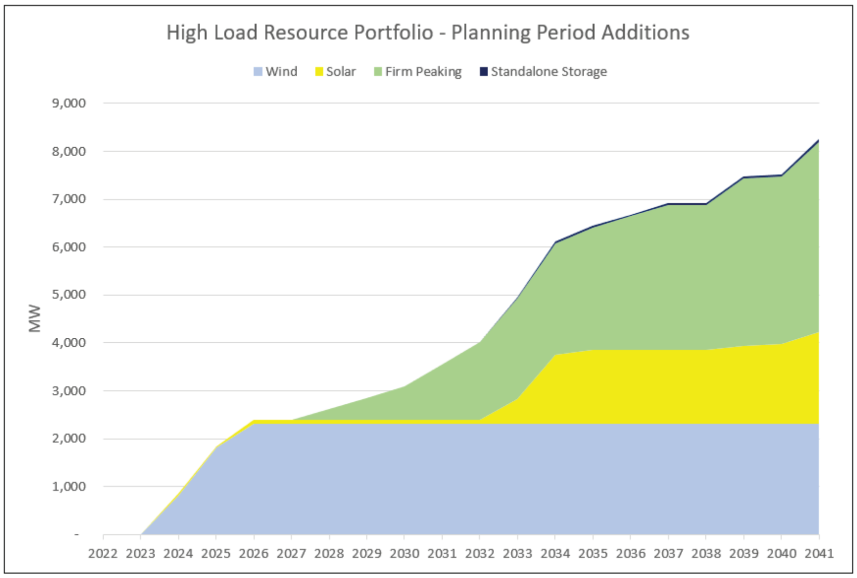
High Load Forecast

As shown below in Table 7.4 and Figure 7F.7, during the Planning Period, the high load forecast resource portfolio added an additional 150 MW of wind, 100 MW of solar and 4 additional CTGs. The high load forecast resource portfolio added 170 MW less BESS than the base case.

Table 7.4: High Load Forecast – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	60	(120)
Solar + Storage	-	-	-
Wind	2,158	2,308	150
Solar	1,820	1,920	100
Firm Peaking	3,033	3,966	933
CC	-	-	-
Total	**7,191**	**8,254**	**1,063**

Figure 7F.7: High Load Forecast – Additional Resources During the Planning Period



7.12 - Transmission Network Upgrades

As described in Section 7.07, due to the current high uncertainty in transmission network upgrade costs, SPS evaluated alternative portfolios using two alternative transmission network upgrade costs: $200/kW and $400/kW.

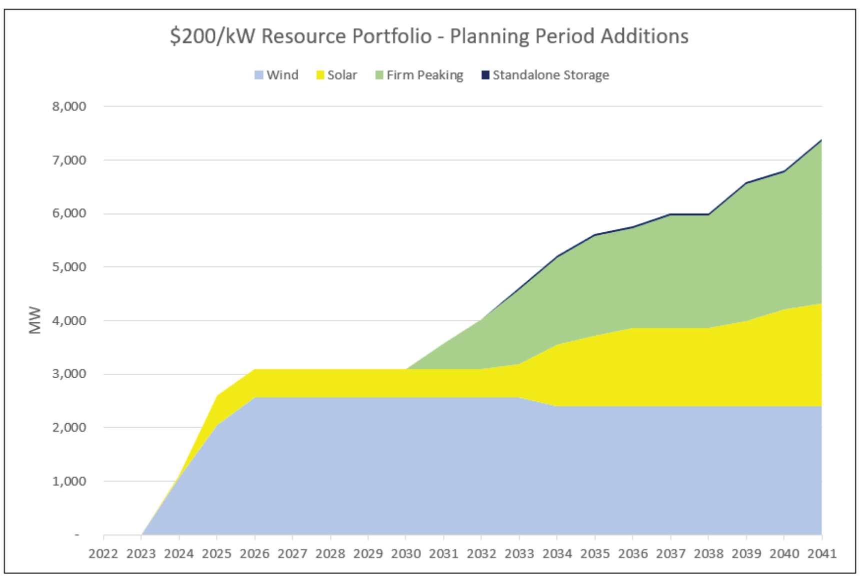
$200/kW Transmission Network Upgrades Costs

As shown below in Table 7.5 and Figure 7F.8, during the Planning Period, the $200/kW resource portfolio added an additional 251 MW of wind and 90 MW of additional solar. The $200/kW resource portfolio added the same amount of CTGs as the base case and 130 MW less BESS than the base case.

Table 7.5: $200/kW Transmission Network Upgrade Costs – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	50	(130)
Solar + Storage	-	-	-
Wind	2,158	2,409	251
Solar	1,820	1,910	90
Firm Peaking	3,033	3,033	-
CC	-	-	-
Total	**7,191**	**7,402**	**211**

Figure 7F.8: $200/kW Transmission Network Upgrades – Additional Resources During the Planning Period



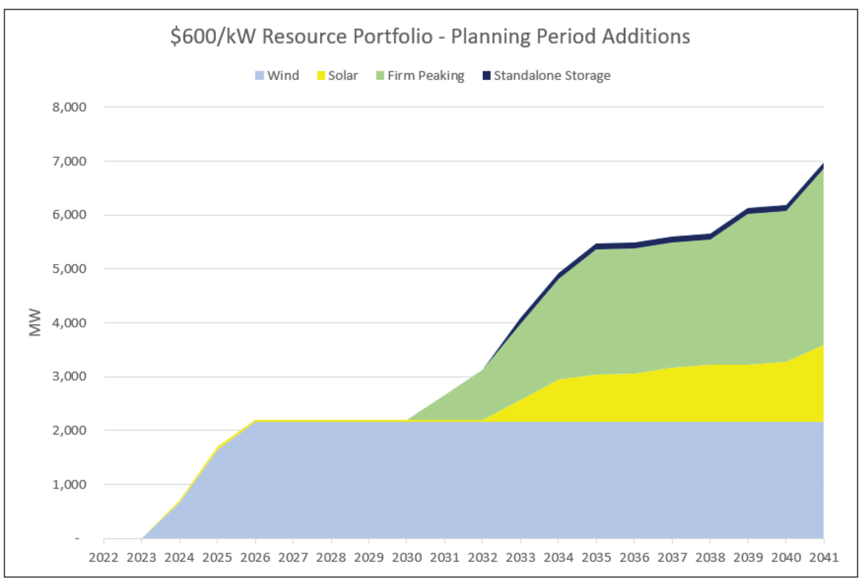
$600/kW Transmission Network Upgrade Costs

As shown below in Table 7.6 and Figure 7F.9, during the Planning Period, the $600/kW resource portfolio added an additional CTG. The $600/kW resource portfolio added the same amount of wind generation as the base case and 380 MW less solar 70 MW less BESS than the base case.

Table 7.6: $600/kW Transmission Network Upgrade Costs – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	110	(70)
Solar + Storage	-	-	-
Wind	2,158	2,158	-
Solar	1,820	1,440	(380)
Firm Peaking	3,033	3,266	233
CC	-	-	-
Total	**7,191**	**6,974**	**(217)**

Figure 7F.9: $600/kW Transmission Network Upgrades – Additional Resources During the Planning Period



7.13 - Carbon Price Sensitivity

In addition to the alternative portfolios described in the Tolk Analysis, SPS also conducted a carbon price sensitivity analysis. Emissions of CO_2 were modeled at $8, $20, and $40 per metric ton base year of 2011, escalated at 2.5%/year consistent with the final order in NMPRC Case No. 06-00448-UT (*Order Approving Recommended Decision and Adopting Standardized Carbon Emission Costs for Integrated Resource Plans*).

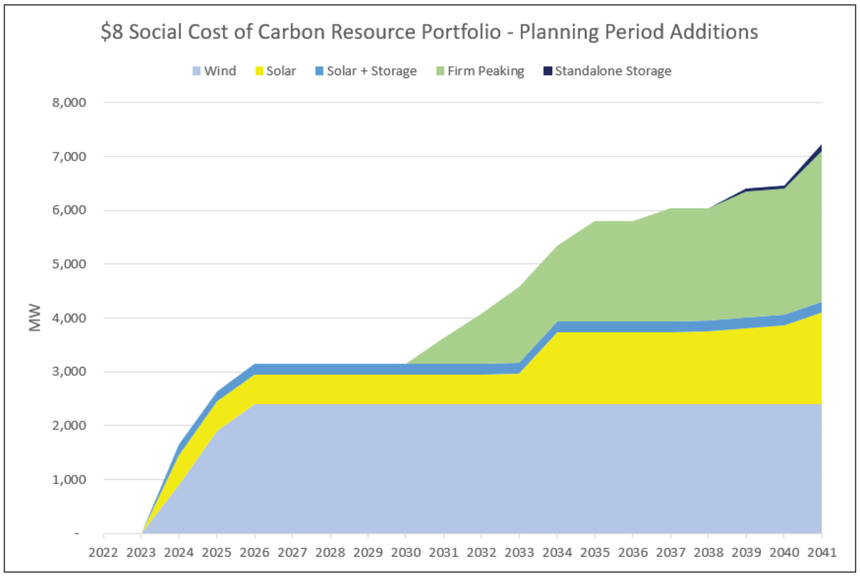
$8 per metric ton

As shown below in Table 7.7 and Figure 7F.10, during the Planning Period, the $8 per metric ton social cost of carbon resource portfolio added an additional 250 MW of wind and 200 MW of additional solar + BESS. The $8 per metric ton social cost of carbon resource portfolio added one less CTG, 60 MW less standalone BESS, and 120 MW less solar as the base case.

Table 7.7: $8 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	120	(60)
Solar + Storage	-	200	200
Wind	2,158	2,408	250
Solar	1,820	1,700	(120)
Firm Peaking	3,033	2,800	(233)
CC	-	-	-
Total	**7,191**	**7,228**	**37**

Figure 7F.10: $8 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



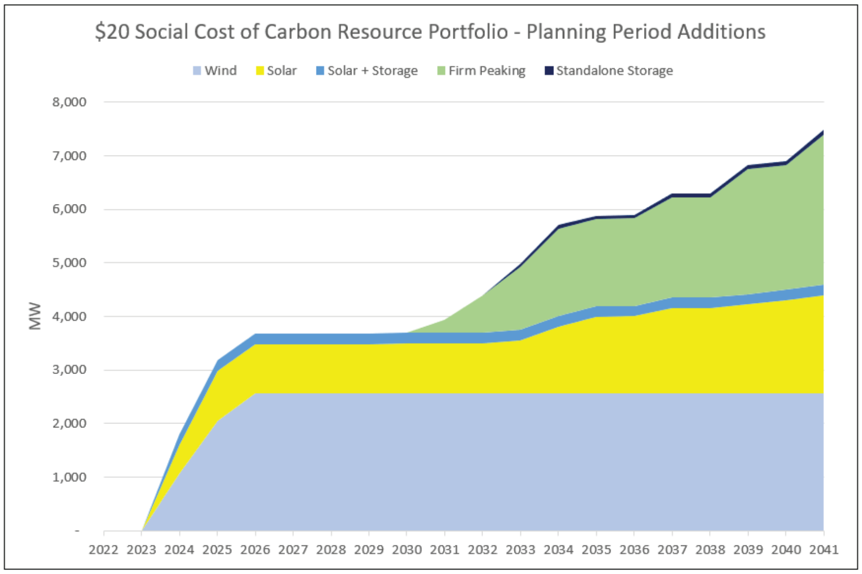
$20 per metric ton

As shown below in Table 7.8 and Figure 7F.11, during the Planning Period, the $20 per metric ton social cost of carbon resource portfolio added an additional 400 MW of wind, 15 MW of additional solar, and 200 MW of additional solar + BESS. The $8 per metric ton social cost of carbon resource portfolio added one less CTG and 90 MW less standalone BESS.

Table 7.8: $20 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	90	(90)
Solar + Storage	-	200	200
Wind	2,158	2,558	400
Solar	1,820	1,835	15
Firm Peaking	3,033	2,800	(233)
CC	-	-	-
Total	**7,191**	**7,483**	**292**

Figure 7F.11: $20 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



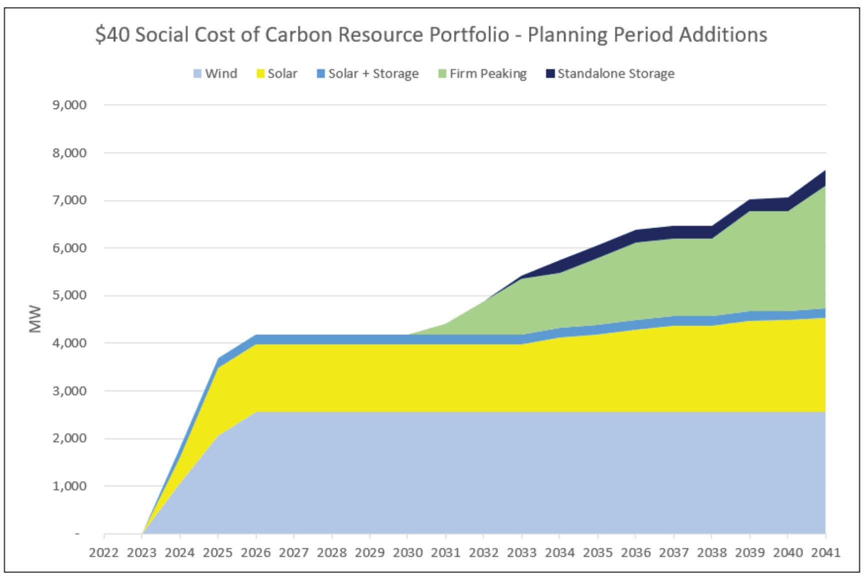
$40 per metric ton

As shown below in Table 7.8 and Figure 7F.11, during the Planning Period, the $20 per metric ton social cost of carbon resource portfolio added an additional 400 MW of wind, 165 MW of additional solar, 150 MW of additional BES, and 200 MW of additional solar + BESS. The $40 per metric ton social cost of carbon resource portfolio added two less CTGs.

Table 7.9: $40 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period

	Base Case	Alternative Portfolio	Change
Standalone Storage	180	330	150
Solar + Storage	-	200	200
Wind	2,158	2,558	400
Solar	1,820	1,985	165
Firm Peaking	3,033	2,566	(467)
CC	-	-	-
Total	**7,191**	**7,639**	**448**

Figure 7F.12: $40 Metric Ton Social Cost of Carbon – Additional Resources During the Planning Period



7.14 - Conclusion

The most cost-effective portfolio of resources and each of the alternative portfolios evaluated include a similar portfolio of resources at the end of the Planning Period. First, each portfolio adds a significant amount of new wind generation during the action plan period to take advantage of the currently scheduled-to-expire PTCs. After the PTCs are scheduled to expire, little-to-no additional wind is added in each of the portfolios. The possible extension of PTCs will fundamentally change the timing and extent of future wind acquisitions.

Looking further ahead, each portfolio comprises of additional solar generation, CTG's and to a lesser extent, BESS, to meet SPS's growing capacity need. As SPS transitions to a more renewable heavy portfolio mix and existing thermal resources retire, SPS's need for firm and dispatchable energy will increase. Currently, this need is fulfilled with CTGs, however, as emerging technologies continue to mature, these CTGs may be replaced with long duration battery energy storage or other technologies that are not currently commercially viable.

Section 8. PUBLIC ADVISORY PROCESS AND TECHNICAL CONFERENCES

Pursuant to the IRP Rule (17.7.3.9.H NMAC), SPS was required to begin planning for the 2021 IRP filing a minimum of one year prior to the filing date; therefore, consistent with the IRP Rule, invitations and notices for the initial meeting, held on May 21, 2020, were sent and published a minimum of 30 days prior to the first meeting. To ensure broad public input, SPS invited the Utility Division Staff of the Commission ("Staff"), as well as the interveners in its most recent general rate case, renewable energy, EE, and IRP proceedings. The invited parties cover multiple interest areas (e.g., residential, environmental, industrial, and consumer advocacy) to ensure varied opinions and perspectives.

On April 8, 2020, SPS published notice of the first Public Advisory meeting in the Carlsbad Current-Argus, Eastern New Mexico News, Hobbs News-Sun, Quay County Sun, and Roswell Daily Record newspapers. These newspapers cover the general circulation of every county in New Mexico that SPS serves. SPS also provided notice with a one-time bill insert to all New Mexico retail customers during the mid-March through mid-April 2020 billing period. Copies of the invitation, public notice, and bill insert are included in Appendix L.

Pursuant to the uncontested comprehensive stipulation in Case No. 19-00170-UT (SPS's 2019 New Mexico Rate Case), SPS was required to host a series of Technical Conferences. SPS actively sought feedback from interested parties throughout the Tolk Analysis by hosting a series of 'Technical Conferences' specific to the Tolk Analysis in addition to and in parallel with SPS's 2021 IRP Public Advisory Process.

Before each Public Advisory meeting and technical conference, SPS provided adequate notice and an agenda of topics to be discussed. SPS experienced medium to high public participation at

Public Advisory meetings and technical conferences. Commonly, attendance included members from Staff, numerous renewable energy developers, several environmental agency representatives, and other energy industry representatives (i.e., oil and gas producers, electric cooperatives, consulting companies, renewable energy service providers). SPS either responded to or followed-up on multiple questions from participants throughout the Public Advisory Process and technical conferences.

Public Advisory meetings and Technical Conferences were held over an approximate12-month time frame. Due to the COVID 19 pandemic, all Public Advisory meetings and Technical Conferences were conducted via video and telephone conferences. A complete list of each Technical Conference and all contents presented at each of the Technical Conferences can be found in Appendix H. In addition, a complete timeline of the Public Advisory meetings and summary of subject matters that were discussed at each of these meetings is presented in Table 8-1. A complete record showing the content presented at each of these meetings is included in Appendix M.

Table 8-1: Public Advisory Process Timeline and Subject Areas

Meeting Date	Topics Discussed
May 21, 2020	Xcel Energy and SPS System Overview Resource Planning Overview Factors Impacting Resource Planning Since 2018 NM IRP Factors That Will Likely Influence Resource Planning Over the Action Plan Period SPS's New Renewable Wind Facilities
August 20, 2020	Emerging Environmental Impacts for SPS Harrington NAAQS[23] Compliance
January 12, 2021	Introduction to the New Mexico Integrated Resource Plan NM Energy Efficiency and Load Management Programs

[23] National Ambient Air Quality Standards

Exhibit DG-4

	Sales and Load Forecasting
March 23, 2021	Coal Supply Tolk Station Water Supply Gas & Power Market Price Forecasting
May 13, 2021	Energy Storage Generator Interconnection Agreement Issues

Section 9. ACTION PLAN

9.01 - SPS Action Plan for 2022-2025

SPS has adequate generating capacity to meet its planning reserve margin over the Action Plan 2022-2025. Furthermore, as demonstrated in SPS's most recent RPS filing (Case No. 21-00172-UT), SPS anticipates continued RPS compliance throughout the Action Plan. Therefore, SPS does not need to procure additional resources to reliably serve its customers or meet regulatory requirements under 17.9.572 NMAC during the Action Plan. However, even without a defined resource need, SPS may still pursue additional resources if they are expected to provide additional benefits, such as economic energy savings. Results from SPS's recent RFI indicate the acquisition of additional wind resources within the Action Plan may provide economic energy savings; however, these savings are highly dependent on the expiration of PTCs and uncertain transmission network upgrade costs. Furthermore, SPS has subsequently learned that several proposals received in the RFI are no longer viable projects. As such, SPS is not proposing any new resources in the Action Plan, instead SPS is proposing to continue to evaluate and monitor the feasibility of new economic energy resources.

After evaluating the proposals submitted in the RFI, it is clear the transmission network upgrade costs currently being assigned to new generation are cost prohibitive. And, SPS has several gas steam generators retiring during the Action Plan. Thus, SPS is currently evaluating the use of generator replacement or surplus interconnection rules as a way of avoiding high transmission network upgrade costs.

Finally, during the Action Plan, SPS intends to cease coal operations at Harrington and convert the units to operate on natural gas at the end of 2024.

9.02 - Status Report

SPS's 2018 IRP was indicative that SPS had adequate generating capacity over the Action Plan period 2019-2022, and, therefore SPS did not need to procure additional resources to reliably serve its customers or meet regulatory requirements. However, in keeping with SPS's 2018 IRP Action Plan, SPS received approval from the Commission of the 522 MW Sagamore Wind Facility, the 478 MW Hale Wind Facility, and the 230 MW Bonita Wind PPA Facilities which were all in-serviced within the 2019 IRP's Action Plan and were acquired because they provided low-cost renewable energy benefits to customers.

Historically low natural gas prices delayed the retirement of Plant X Unit 1, Plant X Unit 2 and Cunningham Unit 1. Each of these units is now scheduled to retire the end of 2022.

Exhibit DG-4

Existing and Anticipated Environmental Laws and Regulations

This appendix summarizes the current status and remaining unknowns about each environmental regulation, along with the potential impacts on SPS's generation resources.

A. Greenhouse Gas ("GHG") Emissions from New and Existing Power Plants

The landscape for Federal carbon dioxide ("CO_2") regulation is highly uncertain at this time. The major greenhouse gas regulations that were put into place under the Obama administration, including the Clean Power Plan and the emission standards for new power plants, were repealed and replaced under the Trump administration with the Affordable Clean Energy ("ACE") rule. Subsequently, the ACE rule was vacated by the U.S. Court of Appeals for the D.C. Circuit in a January 19, 2021 decision. This decision, as modified by a subsequent clarification by the court, would have the effect of invalidating the ACE rule and allowing the Environmental Protection Agency ("EPA") to proceed with a new approach to regulating Green House Gas ("GHG") emissions from the power sector. At this point, the timing or nature of any such rules is unclear. The significant uncertainty in Federal climate policy makes decades long resource planning a challenge. SPS will continue to monitor these developments, maintain its leadership on clean energy, and keep bills low for its customers.

B. Particulate Matter, Nitrogen Oxides, Sulfur Dioxide, and Mercury Emissions

Particulate matter ("PM") (including "fine" PM under 2.5 micrometers in diameter), nitrogen dioxide ("NO_2"), and sulfur dioxide ("SO_2") are three of the primary pollutants regulated by the EPA under the Clean Air Act ("CAA"). These pollutants are regulated under three main programs: National Ambient Air Quality Standards ("NAAQS"), CAA programs that address interstate transport of air pollution, and the Regional Haze program, which addresses visibility impairment in national parks and wilderness areas. Mercury emissions from coal-fired power plants are regulated under the Mercury and Air Toxics Rule ("MATS"). Each of these requirements is addressed in this section.

National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both: (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children, and the elderly; and (2) secondary standards to protect public welfare, including protection against damages to animals, crops, and buildings. The EPA has established NAAQS for six criteria pollutants: PM, NO_2, SO_2, ozone, carbon monoxide, and lead. The NAAQS program has been in place since the early 1970s.

Once the EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data, and submit to the EPA their classification of the state into Attainment Areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment Areas (areas having monitored ambient air quality concentrations above the NAAQS), and unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later.

When the EPA designates an area as Nonattainment, the state is generally given three years to develop a new State Implementation Plan ("SIP") which identifies actions to be taken to bring the area back into Attainment. A nonattainment SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval.

Exhibit DG-4

The NAAQS are periodically reviewed and, if appropriate, individually revised for each pollutant. The following table shows Texas' and New Mexico's status under the current NAAQS in areas where SPS operates power plants:

NAAQS for New Mexico and Texas

NAAQS	Precursor Emissions Regulated*	Last Revised or Reviewed	New Mexico Status at SPS Plant Locations	Texas Status at SPS Plant Locations
Particles	NOx, SO_2, PM	2012	Attainment	Attainment
Ozone	NOx	2008	Attainment	Attainment
Ozone	NOx	2015	Attainment	Attainment
Sulfur Dioxide		2010	Attainment	Attainment, except Potter County is Unclassifiable
Nitrogen Dioxide		2010	Attainment	Attainment
Carbon Monoxide		2011	Attainment	Attainment
Lead		2016	Attainment	Attainment

* Precursor emissions contribute to formation of the NAAQS-regulated pollutants ozone and particles after being released to the atmosphere from a source.

In June 2016, the EPA issued final SO_2 designations which found the area near the Harrington Plant in Potter County, Texas was "unclassifiable." The area near the Harrington Plant was then monitored to gather additional data to support a further attainment/nonattainment decision. If the area near the Harrington Plant had been designated nonattainment, the Texas Commission on Environmental Quality ("TCEQ") would have developed a SIP, which would have been due by 2022, designed to achieve the SO_2 NAAQS by early 2026. The TCEQ could have required additional SO_2 controls at Harrington as part of such a plan.

The monitoring completed in 2020 showed an exceedance of the SO_2 NAAQS in the area of the Harrington Plant. Rather than proceed with a nonattainment designation, SPS negotiated an order with the TCEQ providing for the end of coal combustion and the conversion of the Harrington plant to a natural gas fueled facility by Jan. 1, 2025. This will allow the area to meet the SO_2 NAAQS. The area will remain designated as unclassifiable in the interim.

If an area attains a NAAQS, no further emission reduction plan is required. Every five years, the EPA reviews the scientific data on health effects and decides whether any revision to the NAAQS is needed. If areas were to be designated as nonattainment at some point in the future under a revised NAAQS, this could require emission reductions from SPS's thermal generation units. It is not known what adjustments to the NAAQS, if any, the EPA may make in future reviews.

Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[1] The EPA has developed programs for the Eastern United States that would reduce interstate transport of pollutants that are precursors to ozone and fine particles. Nitrous Oxide ("NO_X") is a precursor to ozone and fine particle formation, and SO_2 is a precursor to fine particle formation. For the utility industry, the current program is the Cross-State Air Pollution Rule ("CSAPR"). CSAPR was adopted to address upwind states' emissions that impact downwind states' attainment of the ozone and particulate NAAQS. As the EPA revises NAAQS in the future, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program.

[1] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

Exhibit DG-4

CSAPR was designed as a "cap-and-trade" program that reduces overall emissions from electric generating units ("EGUs"). This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount but, provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both. Depending on the EPA's analysis of an upwind state's contribution to nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NOx emissions (to address ozone), and/or (2) annual NOx and SO_2 emissions (to address fine particles).

In September 2017, the EPA adopted a final rule that withdrew Texas from the CSAPR particle program and determined that further emission reductions in Texas are not needed to address interstate particle transport. Texas is no longer subject to the annual SO_2 and NOx emission budgets (for particles) under CSAPR. Texas remains subject to the summertime NOx emission budgets under the CSAPR ozone program.

There has been considerable judicial and regulatory activity since that time, but it appears that for the existing ozone standards, Texas (and therefore SPS) is unlikely to face additional NOx restrictions. Thus, SPS currently forecasts compliance with the CSAPR emission limits, without installation of additional controls, through the purchase of NOx allowances as needed.

Visibility Impairment in National Parks and Wilderness Areas (Regional Haze)

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed, and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness areas throughout the United States, including New Mexico and Texas.

In 1999, the EPA adopted the current Regional Haze Rule ("RHR") to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. The Best Available Retrofit Technology ("BART") requirements of the EPA's RHR require emission controls to be determined in the first planning period for industrial facilities put into operation between 1962 and 1977 that emit air pollutants that cause or contribute to visibility impairment in national parks and wilderness areas. Under BART, regional haze plans identify facilities that will have to reduce SO_2, NO_X, and PM emissions and set emission limits for those facilities. BART requirements can also be met through participation in interstate emission trading programs such as the Clean Air Interstate Rule ("CAIR") and its successor, CSAPR. SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064.

The New Mexico Regional Haze SIP for the first planning period did not affect any SPS New Mexico facilities. That plan covers reductions for the 2008-2018 planning period.

The Texas Regional Haze SIP for the first planning period was subject to a lengthy EPA review. Texas developed a SIP in 2009 that found the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would have been required. In 2014, the EPA proposed to approve the BART portion of the SIP, with substitution of CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that deferred its approval of CSAPR compliance as BART until the EPA considered further adjustments to CSAPR emission budgets under the D.C. Circuit Court's remand of the Texas SO_2 emission budgets.

Exhibit DG-4

The EPA then published a proposed rule in January 2017 that, if adopted as proposed, would have required the installation of dry scrubbers to reduce SO_2 emissions at Harrington Units 1 and 2. Investment costs associated with dry scrubbers for Harrington Units 1 and 2 are approximately $400 million. In October 2017, the EPA issued a final rule adopting a Texas only SO_2 trading program as a BART alternative. The program allocated SO_2 allowances to EGUs in Texas, including all three Harrington units and both Tolk units, consistent with their allocation under CSAPR, resulting in an emissions budget for Texas that is consistent with the EPA's 2012 rule that found CSAPR emission reductions approvable under the RHR as "Better than BART." SPS expects the allowance allocations to be sufficient for SO_2 emissions from Harrington and Tolk units in 2019 and future years. Similarly, EPA found that the CSAPR ozone program that regulates summertime NO_X emissions satisfies BART for NO_X for EGUs.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's October 2017 final BART rule to the Fifth Circuit and, filed a petition for administrative reconsideration of the final rule with the EPA. In January 2018, the court granted SPS's motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The litigation was being held in abeyance pending EPA's decision whether to administratively reconsider the rule.[2] EPA has now completed its reconsideration and, in September 2020 issued a final rule approving a Texas SO_2 trading program consistent with the 2017 rule (with minor modifications). SPS expects to be able to meet the allowance allocations of the rule.

[2] Several parties also challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree lodged with the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The litigation is being held in abeyance pending EPA's decision whether to administratively reconsider the rule.

Exhibit DG-4

In addition to making BART determinations, the RHR requires states to consider whether further emission reductions need to be imposed to achieve reasonable progress toward the long-term national visibility goal. The Texas SIP evaluated this issue and did not impose additional emission reduction requirements for reasonable progress in the first planning period. In January 2016, the EPA disapproved the Texas SIP on this issue and adopted a final rule establishing a federal implementation plan for the state of Texas, which imposed SO_2 emission limitations that require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately $600 million. SPS appealed the EPA's decision and requested a stay of the final rule, which the Fifth Circuit granted.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, while leaving the stay in effect. The Fifth Circuit is now holding the case in abeyance until the EPA completes its reconsideration of the rule. In the final BART rule that affects Tolk and Harrington described above, the EPA noted that it will address the remanded rule in a future action. Such a rule will address whether further SO_2 emission reductions are needed at Tolk to address the reasonable progress requirements of the RHR. The EPA has not announced a schedule for acting on the remanded rule, but the issue has not formally been resolved. As indicated below, neither Tolk nor Harrington are proposed by Texas for additional controls in the next round of regional haze planning, but those plans also will be subject to review by EPA. This issue may get rolled into the next review. The next planning cycle for the regional haze program requires the states to evaluate progress in their Class I areas and design emission reduction programs to continue reasonable progress toward the national visibility goal. The SIPs, including those for New Mexico and Texas, are due in 2021 and will then be subject to EPA review. At this point, although it could still change with EPA review (as noted above), the states of Texas and New Mexico are not currently proposing any additional regulation of SPS sources in this next planning cycle. Assuming a SIP is adopted in 2021 by a state and reviewed by EPA by 2023, any control equipment that may be required in the RHR's second planning period would need to be installed by approximately 2028.

Mercury and Air Toxics Rule

EPA adopted the MATS in 2012 to reduce emissions of mercury, acid gases, and other non-mercury metals from coal-fired power plants. SPS has installed the activated carbon injection control systems needed to meet the mercury limits and complies with the acid gas and non-mercury metals emission limits imposed by the MATS using existing controls installed at Harrington and Tolk.

C. Regulation of Coal Combustion Residuals (Ash)

Coal Combustion Residuals ("CCR"), often referred to as coal ash, are regulated as non-hazardous wastes under the federal Resource Conservation and Recovery Act ("RCRA") and are also regulated under state regulatory programs. Coal ash is residue from the combustion of coal in power plants. Generally, CCRs are captured by pollution control equipment and either recycled for beneficial reuse or disposed of appropriately. Environmental issues involving coal ash derive primarily from concerns regarding structural failure of large surface impoundments (e.g., the 2008 Tennessee Valley Authority Kingston ash pond failure, and more recent incidents at Duke Energy power plants in the southeast U.S.), and the potential for releases from unlined ash impoundments and landfills to impact groundwater.

Currently, the CCRs that result from the combustion of coal at SPS units are 100% beneficially used in dry form and marketed by an onsite marketing facility for use. There are no wet operations for ash management in SPS.

SPS's operations are subject to federal and state laws that impose requirements for handling, storage, treatment, and disposal of wastes. On December 19, 2014, the EPA signed a final rule establishing national standards for the management and disposal of CCRs ("CCR Rule").[3] The rule, as subsequently modified by litigation and rule amendment, regulates this material as a non-hazardous waste under Subtitle D of the RCRA. The rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to SPS's current requirements under State enforceable, site-specific permits, and operating plans. SPS has evaluated the rule, and, determined the rule will have minimal direct impact on SPS's current operations or costs. As long as ash remains viable to the industry and control technologies that may be required under other air regulations do not chemically or physically change the ash, 100% beneficial use of ash will be maintained. In the event the installation of controls through other regulations renders the ash unusable for market purposes, SPS will be required to follow the CCR Rule for disposal, potentially requiring the installation, maintenance, and monitoring of ash landfills.

D. *Water Quality Regulation*

Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act ("CWA") requires the EPA to develop regulations governing the design, maintenance, and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to

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[3] *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*. Final Rule, December 19, 2014. See http://www2.epa.gov/coalash/coal-ash-rule.

aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

SPS's New Mexico and Texas facilities are not affected by this rule because no SPS facilities withdraw surface water for cooling purposes. In addition, SPS does not operate any cooling ponds.

Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. SPS facilities are not subject to this rule because they do not discharge any heated cooling water from power plants to surface waters.

Effluent Limitation Guidelines

As part of the National Pollutant Discharge Elimination System ("NPDES") process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines ("ELG"). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil, or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In October 2020, EPA revised the ELG rule for certain waste streams and postponed compliance requirements for units retiring by 2028. SPS facilities are not subject to the ELG rule because they do not discharge to surface waters.

Exhibit DG-5

IPM Model – Updates to Cost and Performance for APC Technologies

SCR Cost Development Methodology

Final

January 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

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SCR Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume, temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

The 2004 to 2006 industry cost estimates for SCR units from the "Analysis of MOG and Ladco's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the SCR cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010, and 2013. The published data were significantly augmented by the S&L in-house database of recent SCR projects. The current industry trend is to retrofit high-dust hot-side SCRs. The cold-side tail-end SCRs encompass a small minority of units and as such were not considered in this evaluation.

The data was converted to 2016 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2012 to 2016 were included to confirm the index validity. Finally, the cost estimation tool was benchmarked against recent SCR projects to confirm the applicability to the current market conditions.

The available data was analyzed in detail regarding project specifics such as coal type, NO_x reduction efficiency, and air pre-heater requirements. The data was refined by fitting each data set with a least-squares curve to obtain an average $/kW project cost as a function of unit size. The data set was then collectively used to generate an average least-squares curve fit. Based on the recently acquired data, it appears the overall capital cost has increased by approximately 15% over the costs published in 2013. Analysis of the data indicates that these units had a high degree of retrofit difficulty, high elevation, or low quality fuel.

The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units. In light of the recent retirement of smaller than 200-MW size units, the evaluation of SCR technology may not be necessary. The older units, which comprise a large proportion of the plants in this range, generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor, and therefore new fans may be required.

A combined SCR for small units is not a feasible option. The flue gas from the boiler is treated after the economizer in the SCR before entering the air heater. Thus, SCR is an integral part of the heat recovery cycle of an individual boiler. Each boiler has to be retrofitted with its own SCR reactor. Minor savings can be achieved by utilizing a common reagent storage and preparation system.

The least-squares curve fit was based upon an average of the SCR retrofit projects in recent years. Retrofit difficulties associated with an SCR may result in significant capital cost increases. A typical SCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = < 3.0 lb/MMBtu;
- Type of Coal = Bituminous; and
- Project Execution = Multiple lump-sum contracts.

Methodology

Inputs

To predict SCR retrofit costs several input variables are required. The unit size in MW is the major variable for the capital cost estimation followed by the type of fuel (Bituminous, PRB, or Lignite), which will influence the flue gas quantities as a result of the different typical heating values. The fuel type also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem. The unit heat rate factors into the amount of flue gas generated and ultimately the size of the SCR reactor and reagent preparation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The NO_x rate and removal efficiency will impact the amount of catalyst required and size of the reagent handling equipment.

SCR Cost Development Methodology

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SCR and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SCR and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SCR and balance of plant costs

The NO_x removal efficiency specifically affects the SCR catalyst, reagent and steam costs. The lower level of NO_x removal is recommended as:

- 0.07 NO_x lb/MMBtu – Bituminous;
- 0.05 NO_x lb/MMBtu – PRB; and
- 0.05 NO_x lb/MMBtu – Lignite.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The base modules are:

BMR =	Base SCR cost
BMF =	Base reagent preparation cost
BMA =	Base air pre-heater cost
BMB =	Base balance of plant costs including: ID or booster fans, ductwork reinforcement, piping, etc…
BM =	BMR + BMF + BMA + BMB

SCR Cost Development Methodology

The total base module installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 6% of the CECC and owner's costs. The AFUDC is based on a two-year engineering and construction cycle.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SCR installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, half of an operator’s time is required to monitor a retrofit SCR. The FOMO is based on that half-time requirement for the operations staff.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 0.5% of the BM for units less than 300 MW and 0.3% of the BM for units greater than or equal to 300 MW.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

SCR Cost Development Methodology

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Catalyst replacement and disposal costs;
- Additional power required and unit power cost; and
- Steam required and unit steam cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per-megawatt-hour (MWh) basis.
- The reagent consumption rate is a function of unit size, NO_x feed rate, and removal efficiency.
- The catalyst replacement and disposal costs are based on the NO_x removal and total volume of catalyst required.
- The additional power required includes increased fan power to account for the added pressure drop and the power required for the reagent supply system. These requirements are a function of gross unit size and actual gas flow rate.
- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The steam usage is based upon reagent consumption rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost in $/ton. Due to escalation, urea cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Catalyst costs that include removal and disposal of existing catalyst and installation of new catalyst in $/cubic meter. No escalation has been observed for catalyst removal and disposal cost since 2013.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Steam cost in $/1000 lb.
- Operating labor rate (including all benefits) in $/hr.

SCR Cost Development Methodology

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for urea reagent

VOMW = Variable O&M costs for catalyst replacement & disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for steam

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet.

SCR Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SCR System

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.				
BMR ($) =	310000*(B)*(L)^0.2*(A*G*H)^0.92	$	88,780,000	SCR (ductwork modifications and strengthening, reactor, bypass) island cost
BMF ($) =	564000*(M)^0.25	$	3,225,000	Base reagent preparation cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$	8,446,000	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	529000*(B)*(A*G*H)^0.42	$	7,042,000	ID or booster fans & auxiliary power modification costs
BM ($) =	BMR + BMF + BMA + BMB	$	107,493,000	Total bare module cost including retrofit factor
BM ($/KW) =			215	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,749,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,749,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	10,749,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**139,740,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =			**279**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	6,987,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$	146,727,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**293**	Total project cost per kW without AFUDC
B2 = 6% of (CECC + B1)		$	8,804,000	AFUDC (Based on a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$**	**155,531,000**	Total project cost
TPC ($/kW) =			**311**	Total project cost per kW

SCR Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1/2 operator time assumed)*2080*V/(A*1000)	$	0.13	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = (IF A < 300 then 0.005*BM ELSE 0.003*BM)/(B*A*1000)	$	0.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.78**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = N*R/(A*1000)	$	0.52	Variable O&M costs for Urea
VOMW ($/MWh) = (0.4*(G^2.9)*(L^0.71)*S)/(8760)	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMP ($/MWh) =P*T*10	$	0.33	Variable O&M costs for additional auxiliary power required including additional fan power
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.20**	

Exhibit DG-5

IPM Model – Updates to Cost and Performance for APC Technologies

SNCR Cost Development Methodology

Final

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Project 13527-001

Eastern Research Group, Inc.

Prepared by

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SNCR Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume or temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as a project contingency.

Establishment of the Cost Basis

The formulation of the SNCR cost estimating model is based upon a proprietary Sargent & Lundy LLC (S&L) in-house data base of recent (2009 to 2016) quotes for both lump-sum contracts and Engineering, Procurement and Construction (EPC) contracts. The S&L data were analyzed in detail regarding project specifics such as coal type, boiler type, and NO_x reduction efficiency. The S&L in-house data includes projects that involved cyclone boilers and T-fired and wall-fired systems with multiple levels of injection. The cyclone boiler costs include rich reagent injection (RRI). The data was the basis for the cost estimate algorithms developed.

The S&L data were fitted with a least-squares curve to establish the trend in $/kW as a function of gross MW. The SNCR cost model parameters were adjusted to account for market changes and escalation, and then the model output was compared to the S&L data. The model output followed a $/kW correlation very similar to the S&L in-house data, once the adjustments were made to the model.

The rapid rise in project costs at the lower end of the MW range is due primarily to economies of scale. Additionally, older power plants in the 50-MW range tend to have plant sites that are more compact, and therefore it is difficult to accommodate the reagent

SNCR Cost Development Methodology

storage areas and piping, injection mixing/dilution equipment, and construction activities. The smaller power plants also tend to have older control systems that may require upgrades to accommodate the new SNCR control system. S&L is not aware of any SNCR installations in recent years for smaller than 100-MW utility units. In light of recent retirement of smaller than 200-W size units, the evaluation of SNCR technology may not be necessary. There are not many utilities that we are aware of operating smaller than 25-MW units. Most of these units are operated by universities, hospitals, or industries that need heat and power. Industrial MACT has basically covered most of these units, and they are required to add pollution controls. In particular, a number of cement kilns have added SNCR systems for NO_x control. The algorithm prepared in the study should not be used to estimate the SNCR system costs of smaller than 50-MW electric generating units or boilers.

A combined SNCR for small units is not a feasible option. The urea solution injection takes place in the boiler. Each boiler has to be retrofitted with multiple levels of injectors to achieve maximum NO_X removal. Minor amount of saving can be achieved by utilizing a common reagent storage and preparation system.

The SNCR efficiency is significantly lower for large boilers compared to small boilers primarily due to the large penetration required for urea droplets to cover the flue gas. For units greater than 500 MW that achieve 0.15 lb/MBtu NO_X, only 15 to 20% NO_X reduction may be achievable.

The SNCRs for Fluidized-Bed Combustors (FBC) are more effective than PC boilers primarily due to long residence time in the boiler in a desired temperature zone. The SNCRs on FBC boilers have shown to achieve up to 50% efficiency with target floor emission as low as 0.08 lb/MBtu.

The S&L data includes SNCR projects with various types of boilers, coals, sulfur levels, and retrofit complexities. The typical SNCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = < 3 lb/MMBtu;
- Type of Coal = PRB; and
- Project Execution = Multiple lump-sum contracts.

SNCR Cost Development Methodology

Methodology

Inputs

To predict future retrofit costs several input variables are required. The unit size in MW and NO_x levels are the major variables for the capital cost estimation followed by the type of fuel. The fuel type affects the air pre-heater costs if sulfuric acid or ammonium bisulfate deposition poses a problem. In general, if the level of SO_2 is above 3 lb/MMBtu, it is assumed that air heater modifications will be required. The unit heat rate factors into the amount of NO_x generated and ultimately the size of the SNCR reagent preparation system. A retrofit factor that equates to the difficulty of constructing the system must be defined. The NO_x rate and removal efficiency will impact the amount of urea required and the size of the reagent handling equipment. Finally, the boiler type will influence the capital costs of the SNCR system and the balance of plant considerations.

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SNCR costs are directly impacted by the site elevation. This base cost module should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SNCR cost should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SNCR cost

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical;
- Water treatment for the dilution water; and
- Retrofit difficulty.

SNCR Cost Development Methodology

The base modules are:

BMS =	Base SNCR system
BMA =	Base air heater modifications, as required
BMB =	Base balance of plant costs including: piping, site upgrades, water treatment for the dilution water, etc...
BM =	BMS + BMA + BMB

The total base module installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 0% of the CECC and owner's costs as these projects are expected to be completed in less than a year after the equipment is released for the fabrication.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Based on in-house projects since 2012, no changes in the capital cost have been observed. The capital cost algorithm developed for 2012 is, therefore, still valid for 2016.

SNCR Cost Development Methodology

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SNCR installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW yr) basis.
- In general, no additional operators are required for a new SNCR system.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 1.2% of the BM.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Dilution water required and unit water cost;
- Additional power required and unit power cost; and
- Boiler efficiency reduction due to the added water in the boiler and unit replacement coal cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per-megawatt-hour (MWh) basis.
- The reagent usage is a function of the amount of NO_x removed, NO_x inlet rate, and boiler type. A utilization factor (UF) of 15% is used for units with an inlet NO_x of 0.3 lb/MMBtu or lower and 25% for units with an inlet NO_x greater than 0.3 lb/MMBtu. For CFB boilers a utilization factor of 25% is used.
- The dilution water usage is based on creating a 5% dilute reagent stream for injection into the boiler.
- The additional power required includes compressed air or blower requirements for the urea injection system and the reagent supply system.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.

SNCR Cost Development Methodology

- Impacts on the unit heat rate due to injection of liquid water into the boiler are accounted for by additional coal costs to provide added boiler heat input and can be included in the total variable costs.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost for a 50% by weight solution in \$/ton; due to escalation, this cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of the solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Auxiliary power cost in \$/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Dilution water cost in \$/1000 gallon.
- Operating labor rate (including all benefits) in \$/hr.
- Replacement coal cost in \$/MMBtu.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for urea reagent

VOMM = Variable O&M costs for dilution water

VOMP = Variable O&M costs for additional auxiliary power

VOMB = Variable O&M costs for additional coal

The total VOM is the sum of VOMR, VOMM, VOMP, and VOMB. Table 1 shows a complete capital and O&M cost estimate worksheet for an SNCR on a T-fired boiler. Table 2 shows a complete capital and O&M cost estimate worksheet for an SNCR on a CFB boiler.

SNCR Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SNCR System Installed on a T-fired boiler

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Tangential	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	1172	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	22263	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.53	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.67	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMS ($) =	BT*B*G*220000*(A*H)^0.42; (IF CFB then BT=0.75, ELSE BT=1)	$ 2,967,000	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ -	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT=0.75, ELSE BT=1)	$ 4,869,000	Balance of plant cost (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$ 7,836,000	Total bare module cost including retrofit factor
BM ($/KW) =		16	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 784,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 784,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 784,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$ 10,188,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**20**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 509,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$ 10,697,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**21**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1		**$ 10,697,000**	Total project cost
TPC ($/kW) =		**21**	Total project cost per kW

SNCR Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Tangential	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	1172	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	22263	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.53	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.67	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.012/(B*A*1000)	$	0.19	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.19**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*Q/A/1000	$	0.82	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.01	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.10	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMM + VOMP + VOMB	**$**	**0.96**	

SNCR Cost Development Methodology

Table 2. Example of a Complete Cost Estimate for an SNCR System Installed on a CFB boiler

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		CFB	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	703	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	13358	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power Include in VOM? ☑	**O**	**(%)**	0.05	0.05 default value
Dilution Water Rate	P	(1000 gph)	1.60	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	BT*B*G*220000*(A*H)^0.42; (IF CFB then BT=0.75, ELSE BT=1)	$	2,225,000	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$	-	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT=0.75, ELSE BT=1)	$	3,652,000	Balance of plant cost (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$	5,877,000	Total bare module cost including retrofit factor
BM ($/KW) =		12		Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	588,000	Engineering and Construction Management costs
A2 = 10% of BM		$	588,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	588,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**7,641,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**15**		Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	382,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$	8,023,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**16**		Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1		**$**	**8,023,000**	Total project cost
TPC ($/kW) =		**16**		Total project cost per kW

SNCR Cost Development Methodology

Table 2 Continued

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		CFB	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	703	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	13358	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	1.60	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.012/(B*A*1000)	$	0.14	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.14**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*Q/A/1000	$	0.49	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.00	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.06	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMM + VOMP + VOMB	**$**	**0.59**	

Exhibit DG-6

Independent Statistics & Analysis
U.S. Energy Information Administration

Generating Unit Annual Capital and Life Extension Costs Analysis

December 2019

Exhibit DG-6

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA’s data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Generating Unit Annual Capital and Life Extension Costs Analysis

In a period of accelerating retirements of electric power generators, EIA sought to revisit its assumptions of age-related generation costs. EIA commissioned Sargent & Lundy (S&L) to evaluate capital expenditures (CAPEX) and operations and maintenance (O&M) costs for non-nuclear generating units, with a particular emphasis on how costs of coal and other fossil-fueled plants change over time. The following report represents S&L's findings. A separate EIA report, *Updates to Cost Assumptions in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)*,[1] details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number DE-EI0003250. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained herein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

[1] https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/addendum.pdf

Exhibit DG-6

Prepared by

Sargent & Lundy Consulting

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FINAL

Generating Unit Annual Capital and Life Extension Costs Analysis

Final Report on Modeling Aging-Related Capital and O&M Costs

Prepared for

U.S. Energy Information Administration

SL-014201
May 2018

Project 13651-001

LEGAL NOTICE

Exhibit DG-6

Sargent & Lundy is a full-service architect-engineering firm that has been dedicated exclusively to the electric power industry for over 125 years. Sargent & Lundy has provided comprehensive planning, development, permitting, technical and financial consulting, engineering, design, construction management, and commissioning services for electric power generation and power delivery projects—1,557 clients in 88 countries worldwide—since its founding in 1891. Having designed 958 power plants, totaling 140,667 MW of electric generation capacity, Sargent & Lundy is regarded as one of the oldest, largest, and most experienced power generation engineering companies in the U.S.

Sargent & Lundy's roles on electric power generation projects include full-design architect-engineer, owner's engineer, lender's independent engineer/technical advisor, and consultant. Our services include specialized technical advisory and consulting services to complete engineering and program management, encompassing procurement, construction management, technology transfer, and assistance with construction. Sargent & Lundy provides professional consulting, engineering, and design services throughout the lifecycle of power generation projects, from project concept and development, through detailed design and procurement, to construction and operation.

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
2017$	2017 dollars
A&G	Administrative and general
AEO	*Annual Energy Outlook*
ARIMA	Autoregressive integrated moving average
ATB	Annual Technology Baseline
CAPEX	Capital expenditures
CC	Combined cycle
CF	Capacity factor
COD	Commercial operation date
CT	Combustion turbine
DOE	Department of Energy
EIA	Energy Information Administration
EMM	Electricity Market Module
ESP	Electrostatic precipitator
FERC	Federal Energy Regulatory Commission
FERC Form 1	FERC Form No. 1
FGD	Flue gas desulfurization
Hg	Mercury
HP	High pressure
ID	Identifier or induced draft
IP	Intermediate pressure
IPP	Independent power producer
IRENA	International Renewable Energy Agency

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
kW	Kilowatts
kW-yr	Kilowatt-years
LCOE	Levelized cost of electricity
LP	Low pressure
MMRA	Major maintenance reserve account
MW	Megawatts
MWh	Megawatt-hours
NO_X	Nitrogen oxide
NREL	National Renewable Energy Laboratory
OEA	Office of Energy Analysis
O&M	Operations and maintenance
PM	Particulate matter
PV	Photovoltaic
R^2	R-squared
Sargent & Lundy	Sargent & Lundy LLC
SO_2	Sulfur dioxide
TCP	Total Cost of Plant

EXECUTIVE SUMMARY

IDENTIFYING IMPACTS OF AGING ON GENERATION COST AND OPERATION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

For most types of generators evaluated, we did not find a statistically significant relationship between plant age and costs (both CAPEX and O&M). CAPEX spending over the life of each plant represents a series of capital projects—rather than a single life extension project—that includes both discretionary spending and vendor-specified spending. For discretionary spending, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Vendor-specified spending is primarily for major maintenance, typically based on cumulative hours of operation and/or cumulative starts, and more commonly applied to gas/oil CC and CT plants. We did, however, find a statistically significant relationship between age and CAPEX spending for fossil steam coal generators with flue gas desulfurization (FGD) equipment, and between age and O&M spending for conventional hydroelectric plants and wind turbines. We also found age and CAPEX spending to be significantly correlated for CC and CT plants, although measured in terms of operating hours or starts, rather than years. Table ES-1 summarizes the variables found to have a significant effect on annual changes in real spending per kilowatt (kW) for each generator type. We recommend the EIA incorporate these variables in the EMM representation of CAPEX and O&M.

Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW

Generating Capacity	CAPEX Spending	O&M Spending
Coal Steam Plants	Age and FGD (see Table ES-3)	-
Gas/Oil Steam Plants	Capacity (see Table ES-5)	-
Gas/Oil Combined-Cycle Plants	Operating Hours (see Table ES-7)	-
Gas/Oil Combustion Turbines	Starts (see Table ES-7)	-
Conventional Hydropower	-	Age (Regression Equation)
Pumped Storage – Hydraulic Turbine Reversible	-	-
Solar Thermal – Central Tower	-	-
Solar Photovoltaic – Single-Axis Tracking	-	-
Geothermal	-	-
Wind	Capacity (see Table ES-11)	Age (Regression Equation)

While we did not find a consistent relationship between aging and CAPEX and O&M costs, changes in performance-related factors and external market conditions are also related to changes in these costs over time. Examples of these factors and conditions include the following:

- Plant efficiency (heat rate)
- Capacity degradation
- Outage rates
- Market prices (electricity, fuel)

These factors and conditions were not part of the scope of our study. We recommend the EIA consider studying these in the future.

MODELING IMPACTS OF AGING IN EIA PROJECTIONS

Existing Treatment of Aging in EIA's Electricity Market Module

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX that is intended to extend the life or preserve the performance of an existing generator. In the EMM, costs for plant O&M do not vary with plant age.

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[1] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

Need for Update to EIA's Treatment of Aging

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[2] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

[1] Internal communication with EIA, February 2018.
[2] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.
2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in Section 2.

ANALYSIS OF AGING IMPACTS IN PUBLICLY-REPORTED COST INFORMATION

Cost Breakdowns in Reported Data

Our analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

The reporting formats of our in-house data and the FERC Form 1 data have a clear delineation between CAPEX and O&M. However, while the in-house data often contains an explicit breakdown between fixed and variable O&M, the FERC Form 1 accounts for O&M are not categorized as such. Rather, the reported O&M costs in a given account are the combined fixed and variable costs at the reported generating output. Thus, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data.

O&M costs for the following technologies are essentially all fixed: solar thermal (central tower), solar PV (single-axis tracking), geothermal, and wind. By definition, fixed O&M costs are independent of plant generation, so they are expressed in $/kW-year.

O&M costs for the following technologies include a significant variable component: coal steam, gas/oil steam, gas/oil CC, gas/oil CTs, conventional hydropower, and pumped storage (hydraulic turbine reversible). By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh.

As mentioned, the variable O&M components cannot be clearly delineated from the total reported O&M costs. For this assessment, the variable components were combined with the fixed components and expressed in $/kW-year. The combined total O&M was found to correspond to the combined total O&M representation in the EMM, which includes a $/MWh variable O&M breakout, as presented in the subsections below.

CAPEX spending values, expressed in $/kW-year, were derived from the new dataset as an additive to the EMM O&M costs and as replacements for the existing EMM CAPEX representation for all technologies, except for gas/oil CC and gas/oil CTs. CAPEX spending for gas/oil CC and gas/oil CTs was found to be primarily for major maintenance events, which are already represented as a $/MWh variable O&M cost in the EMM.

Data Compilation

The data compilation for this analysis consisted of the following annual plant data (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant megawatts (MW) (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

All available and validated cost data over the plant operating life, historical or forecasted, was normalized as follows for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from commercial operation date [COD])
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

In all cases, the yearly values are expressed in constant 2017 price levels and would increase annually with the inflation rate.

IDENTIFYING CHANGES IN SPENDING PATTERNS OVER PLANT LIFE

Differences in Spending Approach by Plant Type

CAPEX spending over the life of each plant represents a series of capital projects throughout the plant life, rather than a single life extension project. This consists of both discretionary spending and vendor-specified spending, examples of which are as follows:

- Discretionary spending is notable for most coal steam and gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Typical industry-standard frequencies for repairs and replacements of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.
- Vendor-specified major maintenance spending, such as commonly applied to gas/oil CC and gas/oil CTs, is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:
    - Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
    - Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

Potential Benefits of CAPEX and O&M Spending on Future Spending

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

Potential Impacts of Plant Age on Future Spending

The spending characteristics described in the previous subsections are evident in the datasets, which reveal significant variability in plant spending as a function of age. Sargent & Lundy's evaluation therefore examined additional variables that might explain some of the variability in age-related spending: plant capacity (MW), capacity factor, external market conditions, regulatory environment, fuel characteristics, and FGD. These additional variables and their effects are described in the following subsections.

Effect of Plant Capacity (MW)

The effect of plant MW capacity on age-related spending, expressed in $/kW-year, was examined by breaking the dataset into separate plant size categories, summarized as follows:

- Coal Steam
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - 1,000 MW – 2,000 MW
  - > 2,000 MW
- Gas/Oil Steam
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CC
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CT
  - All MW
  - < 100 MW
  - 100 MW – 300 MW
- Conventional Hydroelectric
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Pumped Hydroelectric Storage
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Solar Photovoltaic
  - < 5 MW
  - > 5 MW
- Wind Turbine
  - All MW
  - < 100 MW
  - 100 MW – 200 MW
  - > 200 MW

For some of the MW breakdowns above, the age coefficient in the regression analysis of CAPEX or O&M was found to be statistically significant. For the other MW breakdowns, an average value by age group was found to be more appropriate (see Table ES-1).

Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure ES-1. A similar decline also occurred with the gas/oil steam plants, as shown in Figure ES-2.

Figure ES-1 — Capacity Factor vs. Age for All Coal Plants

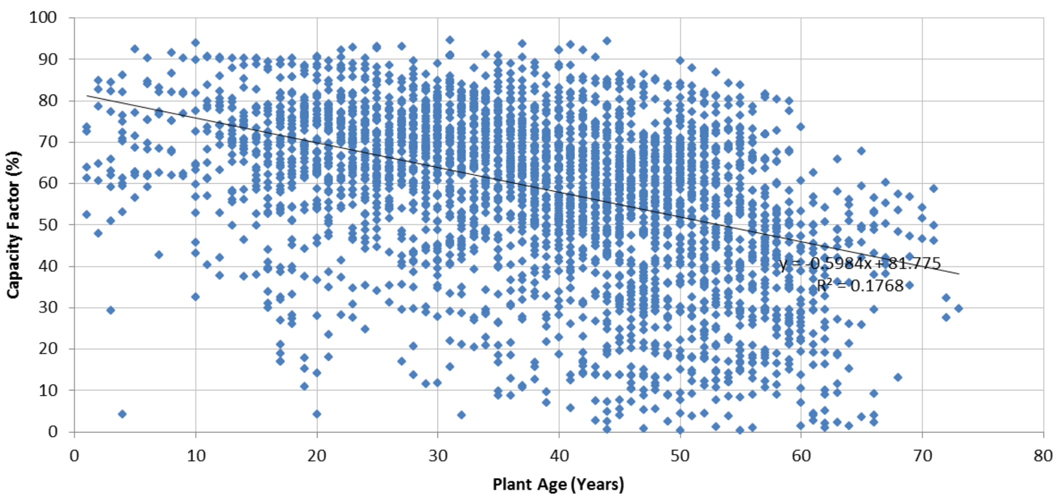
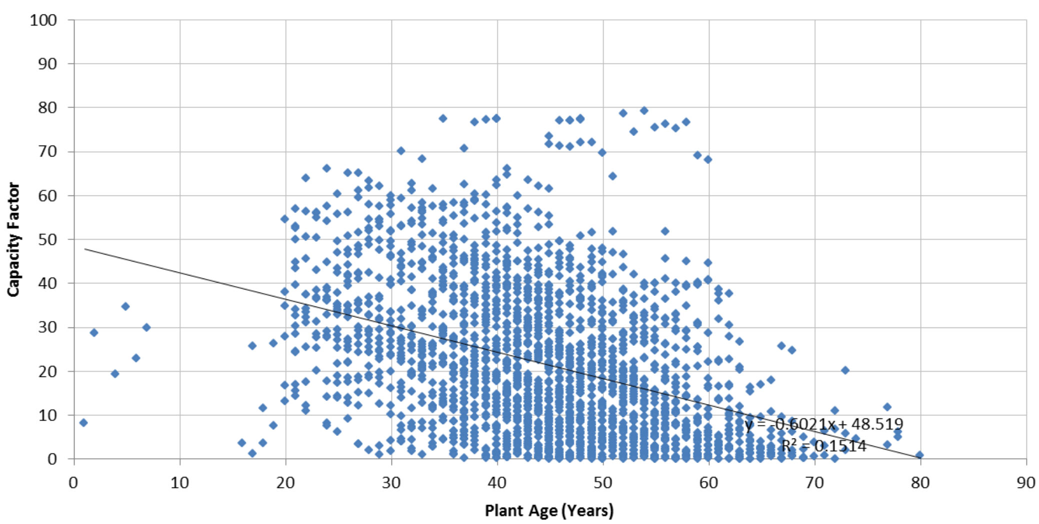


Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



Effect of External Market Conditions

The declining capacity factors with age, shown above, may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam and gas/oil steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam and gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[3]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam and gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their plant lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table ES-2 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

[3] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 $/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 $/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 $/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 $/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 $/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 $/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states. Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types. The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Effect of Flue Gas Desulfurization

The regression analysis indicated a significant difference in CAPEX spending for coal plants with FGD. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

PROPOSED UPDATES TO EMM METHODOLOGY

The EMM captures changes in age-related spending patterns through multiple cost categories: CAPEX, O&M, fuel, energy sales, and capacity sales. The updates below relate only to the CAPEX and O&M. The focus of the work scope was to more accurately represent power plant aging impacts on CAPEX and O&M. Detailed derivations of fixed and variable O&M costs for the EMM were not part of the work scope.

Sargent & Lundy's recommended updates to the fixed and variable O&M costs and CAPEX in the EMM for each generating technology are summarized in the tables below. Values are in constant 2017 price levels and are incurred in every year of plant operation, starting from commercial operation through plant retirement. In all cases, the yearly values would increase annually with the inflation rate.

Coal Steam

Sargent & Lundy's analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and FGD. Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-3 compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 $/kW-year)	$/kW-yr (Years 1-10)	$/kW-yr (Years 10-20)	$/kW-yr (Years 20-30)	$/kW-yr (Years 30-40)	$/kW-yr (Years 40-50)	$/kW-yr (Years 50-60)	$/kW-yr (Years 60-70)	$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated to the midpoint of the given age band.

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-4).

Table ES-4 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

Gas/Oil Steam

The analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-5 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-5 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 $/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-6). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC and gas/oil CT plants represents a series of capital projects throughout the plant life, which include projects for "life extension." Most CAPEX spending for gas/oil CC and gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs described in the previous subsection, major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table ES-7 compares the new CAPEX and O&M values derived from the gas/oil CC and CT datasets with the values currently used in the EMM. As indicated above, the combined CAPEX and O&M values in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC and CT plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

- The EMM fixed and variable O&M costs for CT plants are high for all plant sizes. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)**
CC Dataset Results (All Plants)	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)
CT Dataset Results (All Plants)	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value***	12.60	14.63	5.13	17.73	1.52	19.25

*Fixed and variable split is estimated, assuming all CAPEX costs are represented as variable O&M, either hours-based ($/MWh) or starts-based ($/start).
**Calculated at the dataset average capacity factor of 46% for CC and 4% for CT.
***Source: Internal communication with EIA, February 2018.

Conventional Hydroelectric

Overall, the conventional hydroelectric dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. The average CAPEX value over all operating years is $22.56/kW-year. The dataset does support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table ES-8) and outside the range of values published in the AEO[4] and by the International Renewable Energy Agency (IRENA).[5] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

Pumped Storage

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table ES-9). The existing values used in the EMM are not available.

Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

Solar Photovoltaic

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Sargent & Lundy notes that the average change in the "Total Cost of Plant" (TCP) reported in the FERC data for the limited usable dataset (15 sites not filtered out) is approximately $26/kW-year. However, due to the limited dataset, lack of clarity on what qualifies as a change to the TCP, and general lack of

[4] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.

[5] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

consistency in the FERC capital cost data provided, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based upon closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old.

When considering the average O&M costs per plant as a single data point and then averaging those values, Sargent & Lundy calculated an average O&M cost of $75/kW-year from the FERC data for sites under 5 MW. Using the same method, an average O&M cost of $15/kW-year was calculated from the FERC data for sites over 5 MW.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero. Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

Geothermal

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table ES-10 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value**	91.66	0.00	0.00	91.66

**Source: Internal communication with EIA, February 2018.

Wind

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table ES-11. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)
Wind Dataset Results – All Plants	31.66 + (1.22 × age)	0.00	18.29
< 100 MW	39.08 + (1.12 × age)	0.00	20.48
100 MW – 200 MW	23.80 + (1.17 × age)	0.00	16.93
> 200 MW	26.78 + (0.92 × age)	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.

RECOMMENDED AREAS FOR FURTHER STUDY

Based on our analyses performed for the update to the EMM treatment of age-related spending, Sargent & Lundy identified several areas that warrant further study, including:

- Impact of regional labor cost differences versus the effects of a regulated/deregulated environment;
- Compatibility of EMM plant technology and size breakdowns and fixed/variable O&M cost breakdowns with proposed EMM updates;
- Identification of the factors supporting consistently high capacity factors over the plant lives at particular coal units; and
- Impact of aging on plant performance (heat rates, capacity derates, etc.). If capacity factors decline, regardless of the causes, this includes examining the impact of the lower capacity factors on plant costs and performance.

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Date

1. INTRODUCTION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

This final report is the fourth milestone task of the EMM update project, which is organized as follows:

- Task 1 – Analysis of publicly available information for use in estimating capital costs related to ongoing operations for specified plant types.

- Task 2 – Analysis of publicly available information for use in estimating changes in O&M expenditures due to aging for specified plant types.
- Task 3 – Interim report on assembled aging-related capital and O&M costs.
- Task 4 – Final report on modeling aging-related capital and O&M costs.

2. ASSESSMENT METHODOLOGY

2.1 BACKGROUND

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX. These added expenditures are intended to extend the life or preserve the performance of an existing generator, including repowering, major repairs or retrofits, and/or covering increases in maintenance required to mitigate the adverse effects of aging, including any decreases in plant performance. The portion of the annual CAPEX associated with the step increase is referred as "life extension costs."

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[6] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[7] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.

[6] Internal communication with EIA, February 2018.

[7] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in the following subsections.

2.2 SOURCES OF COST INFORMATION

2.2.1 FERC Form 1 Data

Sargent & Lundy reviewed the FERC Form 1 data through 2016, financial information available from other publicly available sources, and detailed in-house project information with which we are familiar. We assembled a sufficient volume of source material for each technology in order to characterize the distribution of capital and O&M expenditures over the life of a plant.

We obtained the FERC Form 1 data via ABB’s Velocity Suite EV Power database. Using the available FERC Form 1 data, we assessed and summarized the “Cost of Plant” components of the data by major plant type category. The “Cost of Plant” components include the following categories of “Electric Plant in Service” accounts in FERC Form 1 data, which have been reported annually since the database’s inception:

- Steam Power Generation – Cost of Plant
  - 310 Land and land rights.
  - 311 Structures and improvements.

    - 312 Boiler plant equipment.
    - 313 Engines and engine-driven generators.
    - 314 Turbo generator units.
    - 315 Accessory electric equipment.
    - 316 Miscellaneous power plant equipment
    - 317 Asset retirement costs for steam production plant.
- Hydraulic Power Generation – Cost of Plant
    - 330 Land and land rights.
    - 331 Structures and improvements.
    - 332 Reservoirs, dams, and waterways.
    - 333 Water wheels, turbines, and generators.
    - 334 Accessory electric equipment.
    - 335 Miscellaneous power plant equipment.
    - 336 Roads, railroads, and bridges.
    - 337 Asset retirement costs for hydraulic production plant.
- Other Power Generation – Cost of Plant
    - 340 Land and land rights.
    - 341 Structures and improvements.
    - 342 Fuel holders, producers, and accessories.
    - 343 Prime movers.
    - 344 Generators.
    - 345 Accessory electric equipment.
    - 346 Miscellaneous power plant equipment.
    - 347 Asset retirement costs for other production plant.

The sum of these components includes the original construction cost and all ongoing CAPEX. Therefore, each annual FERC Form 1 submittal includes the cumulative additions to the "Total Cost of Plant" (TCP). Annual changes in the TCP between each submittal year give an indication of the amount of CAPEX for the given year. Sargent & Lundy assessed and summarized these annual changes to derive age-related CAPEX, as discussed in the following subsections.

Sargent & Lundy also assessed and summarized the annual O&M expenditures for each technology as reported under the "Electric Operation and Maintenance Expenses" accounts in FERC Form 1:

- Steam Power Generation – O&M
  - 500 Operation supervision and engineering.
  - 502 Steam expenses.
  - 505 Electric expenses.
  - 506 Miscellaneous steam power expenses.
  - 507 Rents.
  - 509 Allowances.
  - 510 Maintenance supervision and engineering.
  - 511 Maintenance of structures.
  - 512 Maintenance of boiler plant.
  - 513 Maintenance of electric plant.
  - 514 Maintenance of miscellaneous steam plant.
- Hydraulic Power Generation – O&M
  - 535 Operation supervision and engineering.
  - 536 Water for power.
  - 537 Hydraulic expenses.
  - 538 Electric expenses.
  - 539 Miscellaneous hydraulic power generation expenses.
  - 540 Rents.
  - 541 Maintenance supervision and engineering.
  - 542 Maintenance of structures.
  - 543 Maintenance of reservoirs, dams, and waterways.
  - 544 Maintenance of electric plant.
  - 545 Maintenance of miscellaneous hydraulic plant.
- Other Power Generation – O&M
  - 546 Operation supervision and engineering.
  - 548 Generation expenses.
  - 549 Miscellaneous other power generation expenses.
  - 550 Rents.
  - 551 Maintenance supervision and engineering.
  - 552 Maintenance of structures.
  - 553 Maintenance of generating and electric plant.
  - 554 Maintenance of miscellaneous other power generation plant.

The above O&M expenditures are reported for individual power plants. Administrative and general (A&G) expenses in FERC accounts 920 through 935 are reported for the entire utility company. A&G expenses in these accounts were not included in this evaluation because of the significant differences in company sizes, mix of resources, and methods of allocating costs to individual power plants. In a similar manner, corporate-level A&G costs were also excluded from Sargent & Lundy's internal data.

The above FERC accounts 500 to 554 correspond to the following fixed and variable O&M components:

- Fixed O&M
    - Labor
    - Maintenance materials
    - Supplies and miscellaneous expenses
- Variable O&M
    - Consumables (chemicals, water, waste disposal, etc.)
    - Other costs proportional to generating output

The FERC accounts do not explicitly break out labor costs, as most of the accounts include both labor and non-labor expenditures. Likewise, the FERC accounts are not categorized according to fixed and variable cost components. The O&M costs in a given account are combined fixed and variable costs at the reported generating output.

2.2.2 Sargent & Lundy Internal Data

In addition, Sargent & Lundy compared publicly available, non-fuel-related financial and cost data with a characterization of proprietary information with which we are familiar, to the extent permissible by applicable confidentiality agreements (information about plant location, equipment type, or plant configuration was never disclosed from the proprietary data). We utilized our knowledge of actual projects to assemble a characterization of life extension/repowering costs from our in-house data.

A large portion of the in-house data used in this report was developed from business plan forecasts that capture actual budgeted costs for scheduled projects as well as longer-term projections. Historical spending data for standalone projects was not usable for this analysis, unless Sargent & Lundy had access to the complete O&M or CAPEX spending totals at a given plant for a given year. For consistent comparisons with other plants over time, each O&M or CAPEX data point needed to represent a comprehensive total of all spending projects.

2.2.3 Other Data Sources

Other publicly available data sources were searched, including regulated utility filings with public utility commissions, routine financial reports for publicly traded companies, utility integrated resource plans, data reported by various municipalities and electric cooperatives, and requests for proposals (RFPs) for plant improvements at public power entities. Cost data from each of these sources was found to be unsuitable for this study for one or more of the following reasons:

- Cost data was for initial capital investment costs only, with no O&M or ongoing CAPEX spending reported;
- Annual O&M or annual CAPEX amounts were for limited purposes and not representative of a complete year; and/or
- Annual O&M and annual CAPEX amounts were aggregated across business units and not assigned to specific plants.

Several publications or studies of power plant aging and life extension costs were used, which are cited herein.

2.3 DATA VALIDATION

Sargent & Lundy's approach to validating the FERC Form 1 data involved the following steps (note that capitalized words are proper FERC Form 1 terms):

1. For each Plant/Prime Mover combination (e.g., steam turbine, CC, simple-cycle CT), determine the difference between the prior and current year TCP reported in the FERC data. Note that a plant can have multiple prime movers on site (e.g., CT units and steam turbine units). Fortunately, that data is reported separately.
2. Flag and invalidate any years where the difference is negative (i.e., a decreasing value of the TCP).
3. Identify if the TCP difference is significantly due to asset retirement costs. If so, flag this plant reporting year consider it invalid, as capital would have been spent on non-aging items.
4. Identify if there has been any year-to-year change in nameplate capacity. If so, flag this plant reporting year and consider it invalid, because the TCP would be assumed to be spent on an expansion or addition.
5. Identify if any sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter (PM), or mercury (Hg) control equipment was installed for the plant reporting year. If so, flag that plant reporting year and consider it invalid, because capital would have been spent on non-aging items. The year

prior to or after the actual emissions control installation date is sometimes flagged as well, because of when the spending occurred (this is usually a judgement call).

6. Identify if any unit at the plant has been retired in a plant reporting year. If so, flag that plant reporting year and consider invalid, because capital would have been spent on non-aging items. Also, if the plant's TCP dropped significantly the last few years before retirement, flag those plant reporting years and consider them invalid.
7. Cross-check if any additional units at the plant site (using the same technology) show too great of time duration between installed dates of the units. If the first unit and the last unit installed is greater than 10 years apart, then flag the data and consider it invalid, because the TCP difference would not reflect the actual age of the plant (considered to be the age of the first unit). This was flagged as "Removed due to non-equal units at site."
8. If any TCP is reported to be zero for most of all of the reporting years of the plant, consider the data invalid.
9. If the TCP difference is highly volatile, flag and invalidate at discretion. For example, if one year TCP drops from $2,000/kW-year to $1,000/kW-year and then back to $2,000/kW-year in the year after, this would be considered highly volatile for those two reporting years.
10. If a reporting plant has only one or two years of reported TCP data, flag the plant and do not use its data.
11. If any plant reports negative Total O&M Costs, flag that year and do not use it.
12. Use only data that is valid for both CAPEX spending and O&M spending in the analysis of combined CAPEX and O&M spending. Otherwise, analyze CAPEX spending and O&M spending separately. Sargent & Lundy found that a large portion of the data points determined to be valid for CAPEX spending were also valid for O&M spending.

The resulting data points from this validation process are summarized in Table 2-1.

For each year of plant data, we also compiled the associated nameplate capacity (MW) and annual generation (MWh). EIA Form 860 was used to confirm the plant technology, environmental equipment, year in service, and other attributes.

Table 2-1 — Summary of Valid Data Points

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Coal (10)	All MW	All	3,713	3,098	3,109	655	615
	< 500 MW	All	1,592	1,274	1,284	318	318
	500 MW – 1,000 MW	All	986	689	689	337	297
	1000 MW – 2,000 MW	All	813	813	814	0	0
	> 2,000 MW	All	322	322	322	0	0
	All MW	< 50%	965	889	896	76	76
	All MW	> 50%	2,748	2,209	2,213	579	539
Gas/Oil Steam (20)	All MW	All	2,220	2,204	2,226	20	16
	< 500 MW	All	1,377	1,361	1,366	20	16
	500 MW – 1,000 MW	All	488	488	489	0	0
	> 1,000 MW	All	355	355	355	0	0
Gas/Oil Combined Cycle (30)	All MW	All	1,367	980	981	408	387
	< 500 MW	All	764	462	463	304	302
	500 MW – 1,000 MW	All	547	462	463	104	85
	> 1,000 MW	All	177	177	177	0	0
	All MW	< 50%	843	661	662	203	182
	All MW	> 50%	524	319	319	205	205
Gas/Oil Combustion Turbine (40)	All MW	All	5,041	4,905	4,949	437	136
	< 100 MW	All	2,873	2,873	2,911	189	0
	100 MW – 300 MW	All	1,341	1,239	1,248	177	102
	> 300 MW	All	901	867	875	71	34
Conventional Hydroelectric (50)	All MW	All	2,179	2,179	2,180	0	0
	< 100 MW	All	1,272	1,272	1,272	0	0
	100 MW – 500 MW	All	924	924	925	0	0
	> 500 MW	All	41	41	41	0	0

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Pumped Storage Hydroelectric (55)	All MW	All	226	226	227	0	0
	< 100 MW	All	12	12	12	0	0
	100 MW – 500 MW	All	88	88	88	0	0
	> 500 MW	All	126	126	126	0	0
Solar Thermal (60)			0				
Solar Photovoltaic (65)	All MW	All	57	410	57	0	0
Geothermal (70)							
Wind Turbine (80)	All MW	All	310	310	310	270	0
	< 100 MW	All	174	174	174	165	0
	100 MW – 200 MW	All	91	91	91	56	0
	> 200 MW	All	51	51	51	73	0

Note: A data point is one reported value for one year by one plant, i.e., a plant that reports values for 25 years will have 25 data points.

2.4 DATA NORMALIZATION

Sargent & Lundy developed a Microsoft Excel model template for compiling and normalizing all of the CAPEX and O&M data, subsequent to the initial review and validation steps outlined in the previous sections. The data normalization consisted of the following steps:

Step 1: Assign data “identifiers” for each plant:

Technology ID:

- 10 = Coal Steam Plants
- 20 = Gas/Oil Steam Plants
- 30 = Gas/Oil CC Plants
- 40 = Gas/Oil CTs
- 50 = Conventional Hydropower; Pumped Storage – Hydraulic Turbine Reversible
- 60 = Solar Thermal – Central Tower;
- 65 = Solar PV – Single-Axis Tracking
- 70 = Geothermal
- 80 = Wind

Data source:

- 1 = FERC Form 1
- 2 = Sargent & Lundy Internal Data
- 3 = Other Public Source

Step 2: Enter basic information for each plant:

- Year of commercial operation date (COD)
- End year of project life or forecast period
- Nameplate capacity (MW)
- Summer net capacity (MW)

Step 3: Adjust pricing basis for raw data:

- If provided in current dollars, adjust to 2017 dollars
- If provided in 2017 dollars, do not adjust
- If provided in constant dollars of another reference year, adjust to 2017 dollars

Step 4: Enter annual data for each plant (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant MW (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

Using the inputs from Steps 1-4 above, the "Normalizer" worksheet derives the following for each plant:

- Annual O&M in 2017 \$/kW-year versus age (years from COD)
- Annual CAPEX in 2017 \$/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 \$/kW-year versus age (years from COD)

The output worksheets ("O&M," "CAPEX," and "O&M + CAPEX") each have the following user-selected filters:

- Technology ID (10, 20, 30, etc.)

- Data source (1,2, or 3)
- MW range (low, high)
- Outlier maximum $/kW
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

Each output worksheet ("O&M," "CAPEX," and "O&M + CAPEX") calculates the following for a given user-defined set of filters:

- $/kW-year (2017 dollars) versus age
- Statistical tests of linear curve fit: annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + [constant × age (years from COD)]
- Average $/kW-year (2017 dollars) for age bands (10-year bands, 30-year bands, and all-years band)

In all cases, the yearly values are expressed in constant 2017 price levels and increase annually with the inflation rate.

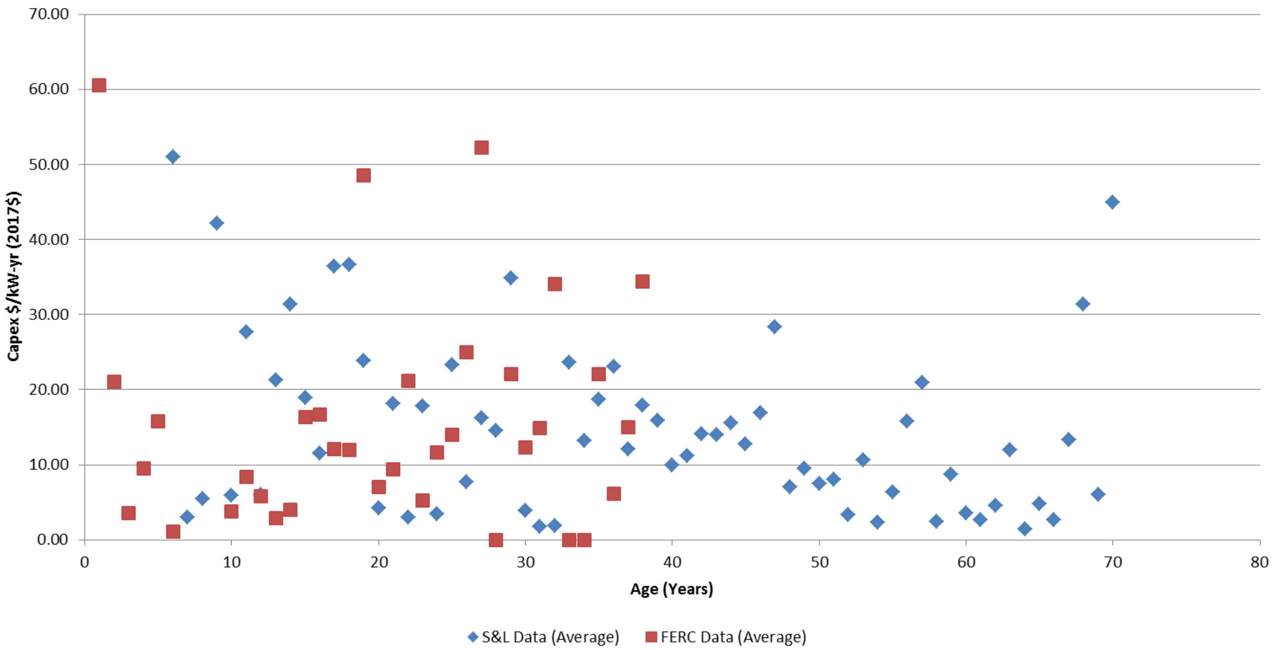
2.5 STATISTICAL TESTS

2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data

FERC Form 1 data only covers historical data for utilities that are required to file and does not include the owners' projected expenditures or any data for merchant plants and independent power plants. Most of Sargent & Lundy's proprietary data, on the other hand, covers the owners' projected expenditures for utility plants and includes both historical and projected expenditures for merchant plants and independent power plants. The data points from both data sources were judged to be complementary and combined as a single dataset.

The compatibility of the FERC data and Sargent & Lundy internal data is illustrated by the CAPEX spending for a sample of 500-MW coal plants (Figure 2-1). This example is based on a sample of 11 plants from the Sargent & Lundy data and 12 plants from the FERC data, each sample having an average plant capacity of approximately 500 MW and an average age of approximately 30 years. Each data point in the figure is the average value for all the plants that have a valid data point at the given plant age. There are a total of 175 valid data points for the FERC plants and 200 valid data points for the Sargent & Lundy plants. In this particular sample, all of the FERC data is historical and all of the Sargent & Lundy data is owners' projected expenditures.

Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data



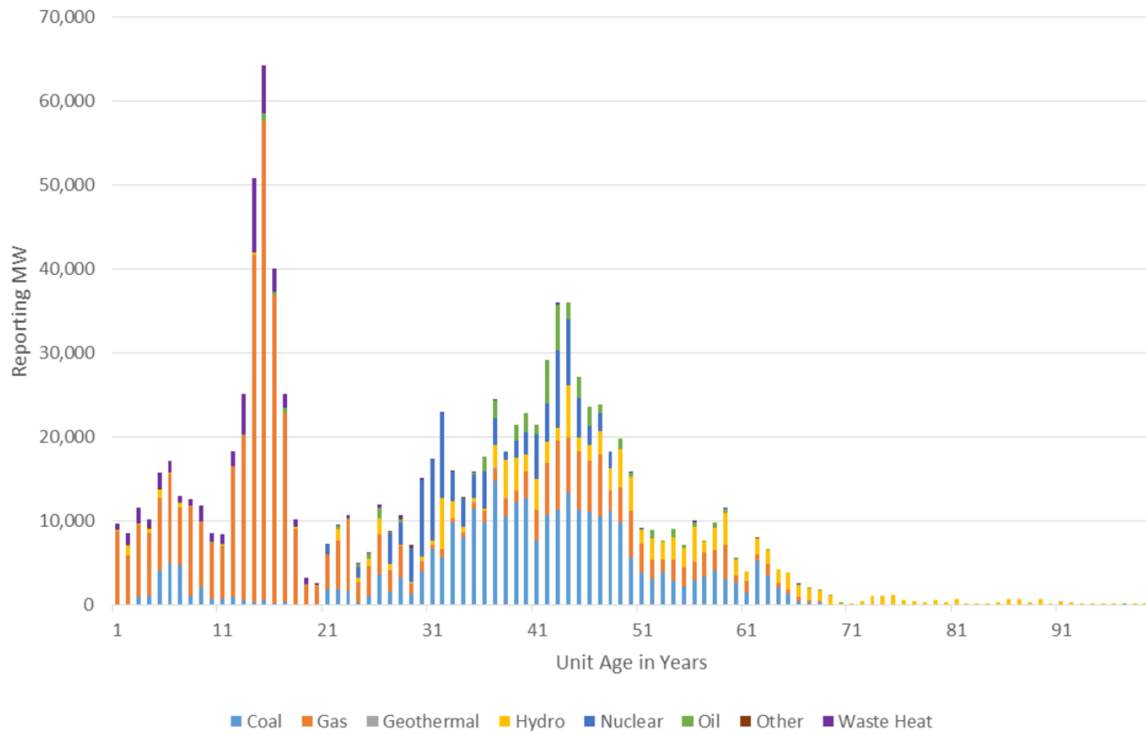
As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

For some utility plants, data was available from both FERC Form 1 and proprietary data. The historical O&M and CAPEX spending for these plants were examined in each year to verify their consistency.

The distribution of valid data points for each technology versus age (years from COD in which the spending occurs) was examined to verify consistency with typical plant ages nationwide. Figure 2-2 shows a recent distribution of the U.S. power plant fleet by unit age and fuel type as reported by FERC[8]. This distribution indicates a large portion of coal-fired capacity with ages of 30-50 years, and a large portion of gas-fired capacity (mostly CT or CC) with ages under 20 years. The valid data points assembled in this report were found to be representative of these major age and technology cohorts.

[8] North American Electric Reliability Corporation, *State of Reliability 2017*, June 2017 (p.116)

Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type



A recent study found that the average age of the U.S. generator fleet has increased significantly over time, due in part to regulatory uncertainty in a deregulated market environment. At the same time, the average expected physical life of the fleet has been decreasing as a result of new investments in smaller, shorter-lived capacity. This has been a means of mitigating the regulatory risk of more limited stranded cost recovery mechanisms.[9] In another recent study, this one on the causes of power plant retirements, the strongest predictors of retirements were found to be SO_2 emission rates, planning reserve margins, variations in load growth or contraction, the age of older thermal plants, the ratio of coal to gas prices, and delivered natural gas prices. The impacts of annual CAPEX and O&M spending on retirement decisions were not specifically identified.[10]

2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures

For each technology group, Sargent & Lundy performed a regression analysis on the O&M spending, CAPEX spending, and combined O&M plus CAPEX spending using the following linear equation:

- Annual spending in 2017 \$/kW-year = \$/kW-year (y-intercept) + (constant × age)

[9] Rode, D., Fischbeck, P., and Paez, A., "Power Plant Lives and their Policy Implications," *Energy Policy*, 106 (2017) 222-232, April 1, 2017.
[10] Mills, A., Wiser, R., and Seel, J, "Power Plant Retirements: Trends and Possible Drivers," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, November 2017.

The purpose of the regression analysis was to determine whether plant age is a statistically significant predictor of annual spending. The regression coefficient for age measures the change (+ or -) in annual spending as a function of plant age, measured as the number of years from the COD. Its statistical significance is measured by the p-value, which tests the null hypothesis that the coefficient is equal to zero (i.e., has no effect on spending).

The R-squared (R^2) statistic ("coefficient of determination") is an indication of the goodness of fit of the regression equation to the real data points. A low R^2 indicates that the regression equation explains a relatively small amount of the variability of the data around its mean. A low p-value (< 0.05) indicates that the age coefficient is statistically significant, regardless of the R^2 statistic. A low p-value corresponds approximately to a t-value that is greater than 2 or less than -2. For higher p-values, the simple average $/kW-year per year may be a more appropriate estimation for a given age band (e.g., 20-year bands and all-years band). Depending on the characteristics of the dataset, especially the number of data points, Sargent & Lundy applied engineering judgement (as further described in each section that follows) in our recommendations.

2.5.3 Autocorrelation of Time Series Data

In addition to the correlation between annual spending and plant age, an autocorrelation may also exist between spending in a given year and spending in previous years. Autocorrelation commonly occurs with time series data. If statistical tests verify the presence of autocorrelation, a lagged (autoregressive) variable may be added to improve the goodness of fit (R^2) of the regression model. Models with this functional form are referred to as "autoregressive integrated moving average" (ARIMA) models.

ARIMA models are typically constructed for the purpose of predicting the future from a given point in time, based on correlations with historical values and other exogenous variables. The functional form of an ARIMA model may better capture curvilinear or cyclical data trends and therefore improve the goodness of fit. For the purposes of this study, an ARIMA model was not necessary or appropriate. The datasets in this analysis already capture plant O&M and CAPEX spending patterns throughout a typical plant lifespan. The purpose of this study was to represent costs for generators as they age, and not to predict future spending from a given point in time.

3. COAL STEAM

3.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for coal steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M expenditures:
  - 456 plants in FERC data and 32 plants from Sargent & Lundy internal data
  - 3,098 valid data points in FERC data, 655 valid data points in Sargent & Lundy internal data
- CAPEX:
  - 457 plants in FERC data and 29 plants from Sargent & Lundy internal data
  - 3,109 valid data points in FERC data, 615 valid data points in Sargent & Lundy internal data

The coal steam data was broken down by plant MW capacity and average capacity factor—as summarized in Table 3-1—for the regression analysis shown in Appendix A.

Table 3-1 — Coal Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	3,713	3,098	3,109	655	615
< 500 MW	All	1,592	1,274	1,284	318	318
500 MW – 1,000 MW	All	986	689	689	337	297
1,000 MW – 2,000 MW	All	813	813	814	0	0
> 2,000 MW	All	322	322	322	0	0
All MW	< 50%	965	889	896	76	76
All MW	> 50%	2,748	2,209	2,213	579	539

Table 3-2 below identifies the relative effects in the data validation process of the top three data filters on the number of valid data points. These filters are described as follows:

- Change in Capacity: A change in nameplate capacity of 20% or more during the reported time of the unit. Data points prior to the change in capacity are no longer comparable to the data points after the change in capacity, so the entire unit was filtered out.
- Negative Change in Total Cost: Any year with a decrease in the cumulative historical capital cost reported in the FERC data was not included.
- Environmental Retrofit: Data points in years where SO_2, NO_X, PM, or Hg removal equipment was installed were filtered out.

Table 3-2 — Effect of Data Validation Filters on Coal Data Points

Coal Steam – FERC Dataset	Data Points
Total Data Points, Unfiltered	6,699
Total Data Points, Filtered Out	3,774
Top Three Filters	
Change in Capacity	1,659
Negative Change in Total Cost	889
Environmental Retrofit	599
Total Data Points, Valid (FERC Only)	**2,925**

3.2 SUMMARY OF RESULTS

3.2.1 Recommended CAPEX Values

The analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and flue gas desulfurization (FGD). Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 3-3 below compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 $/kW-year)	$/kW-yr (Years 1-10)	$/kW-yr (Years 10-20)	$/kW-yr (Years 20-30)	$/kW-yr (Years 30-40)	$/kW-yr (Years 40-50)	$/kW-yr (Years 50-60)	$/kW-yr (Years 60-70)	$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated from the following regression equation to the midpoint of the given age band:

Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)
Where FGD = 1 if a plant has FGD; zero otherwise

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently compared with plants without FGD.

Table 3-4 below provides indicative typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant.

Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals

Project Description	Typical Frequency of Repairs/Replacement from COD (Years)
Boiler	
Coal mills and exhausters, burner tips and ignitors	5
Lower nose tube, burner panels, economizer banks, air heater tubes, and baskets	15
Lower and upper waterwalls, superheater and reheater horizontal sections and pendants, economizer header, coal feeders, mill motors	20
Superheater and reheater header, feedwater supply piping	25
Mud and steam drums	30
Turbine and Generator	
Control valves, nozzle block	12
Electro-hydraulic control system (EHC), governor, turbine controls, generator rotor, turbine lubrication pumps	15
Stop valves, low-pressure (LP) turbine and blades, LP casing/diaphragms,	20
Steam chest, high-pressure/intermediate-pressure (HP/IP) turbine with blades, HP/IP casing/diaphragm, generator stator, exciter	25
HP/IP rotor, LP rotor, isophase	30
Balance of Plant	
Condensate pumps, cooling tower fill, cooling tower fan drives and blades, conveyor belts, conveyer idlers/pulleys/motors, coal crushing equipment	10
Slag conveyors and tanks	12
Induced draft (ID) fans, electrostatic precipitator (ESP) casing, ESP plates/wires, deaerator, circulating water pumps, boiler feed pumps, distributed control system (DCS)/unit controls, boiler master/combustion controls, coal handling dust control system	15
Forced draft (FD) fans, primary air (PA) fans, fan motors, windbox and ductwork, ESP transformer/rectifier (TR) sets and rappers, condenser valves and cleaner system, LP feedwater heaters, HP feedwater heaters, gland coolers, conveyor structures, coal unloading equipment, fuel oil heaters, and delivery pumps	20
Condenser retube, deaerator storage tank, vacuum pumps/steam air ejectors, pump motors	25
Main power transformer, auxiliary transformer	30

3.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (Table 3-5).

Table 3-5 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

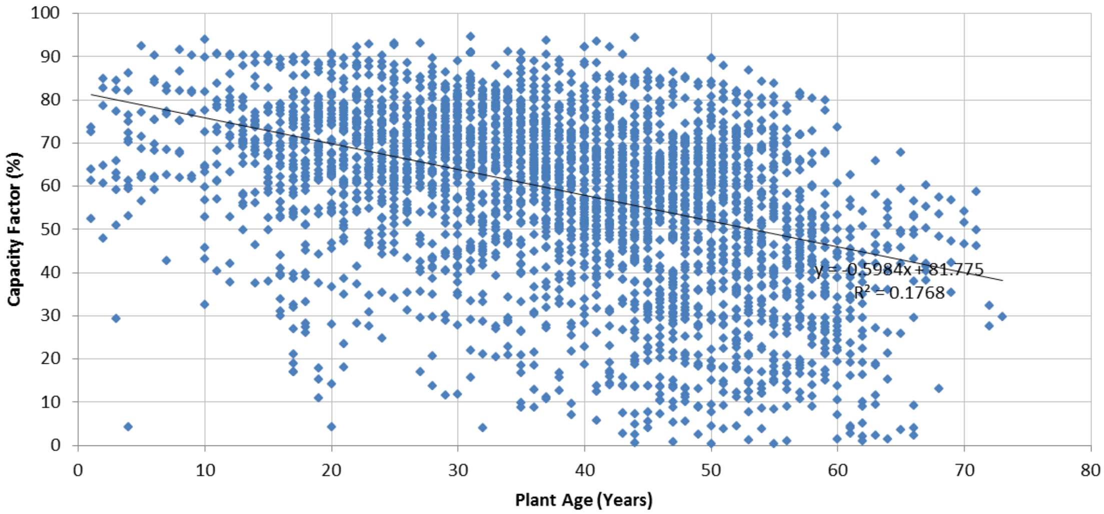
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

3.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 3-1.

Figure 3-1 — Capacity Factor vs. Age for All Coal Plants



3.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[11]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam plants would likely retire under the following circumstances:

[11] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table 3-6 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 $/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 $/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 $/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 $/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 $/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 $/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

3.2.5 Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states (see Appendix A). Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

3.2.6 Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types (Appendix A). The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

4. GAS/OIL STEAM

4.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,204 valid data points in FERC data, 20 valid data points in Sargent & Lundy internal data
- CAPEX
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,226 valid data points in FERC data, 16 valid data points in Sargent & Lundy internal data

The gas/oil steam data was broken down by plant MW capacity, as summarized below in Table 4-1, for the regression analysis shown in Appendix B.

Table 4-1 — Gas/Oil Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,220	2,204	2,226	20	16
< 500 MW	All	1,377	1,361	1,366	20	16
500 MW – 1,000 MW	All	488	488	489	0	0
> 1,000 MW	All	355	355	355	0	0

4.2 SUMMARY OF RESULTS

4.2.1 Recommended CAPEX Values

Sargent & Lundy's analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 4-2 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 4-2 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 $/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair. Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

4.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table 4-3). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

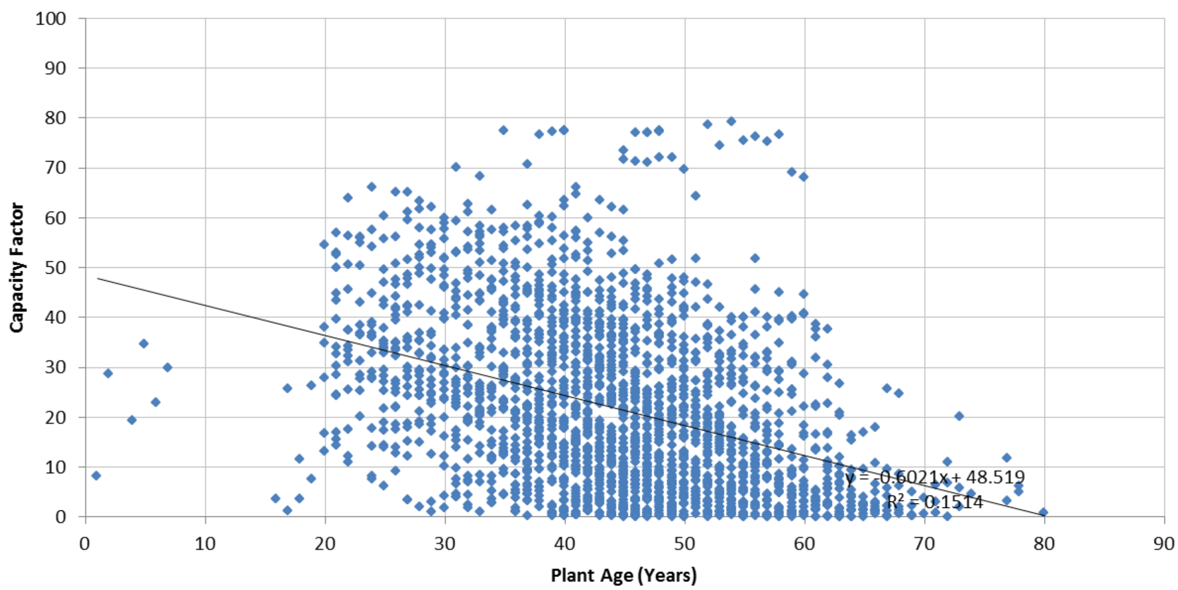
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

4.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the gas/oil steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 4-1.

Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



4.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for gas/oil steam plants include:

- Competition with more efficient gas turbines

- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

5. GAS/OIL COMBINED CYCLE

5.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CC plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 144 plants in FERC data and 20 plants from Sargent & Lundy internal data
  - 980 valid data points in FERC data, 408 valid data points in Sargent & Lundy internal data
- CAPEX
  - 142 plants in FERC data and 17 Sargent & Lundy proprietary plants with valid data
  - 981 valid data points in FERC data, 387 valid data points in Sargent & Lundy internal data

The gas/oil CC data was broken down by plant MW capacity and average capacity factor, as summarized below in Table 5-1, for the regression analysis shown in Appendix C.

Table 5-1 — Gas/Oil CC Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	1,367	980	981	408	387
< 500 MW	All	764	462	463	304	302
500 MW – 1,000 MW	All	547	462	463	104	85
> 1,000 MW	All	177	177	177	0	0
All MW	< 50%	843	661	662	203	182
All MW	> 50%	524	319	319	205	205

5.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CC plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 5-2 compares the new CAPEX and O&M values derived from the gas/oil CC dataset with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the dataset would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)*
CC Dataset Results – All Plants	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)

*Calculated at the gas/oil CC dataset average capacity factor of 46%. Fixed and variable O&M split is estimated.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

6. GAS/OIL COMBUSTION TURBINE

6.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CT plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 625 plants from FERC data and 27 plants from Sargent & Lundy internal data
  - 4,905 valid data points in FERC data, 437 valid data points in Sargent & Lundy internal data
- CAPEX
  - 579 plants from FERC data and five plants from Sargent & Lundy internal data
  - 4,949 valid data points in FERC data, 136 valid data points in Sargent & Lundy internal data

The CT data was broken down by plant MW capacity, as summarized below in Table 6-1, for the regression analysis shown in Appendix D.

Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	5,041	4,905	4,949	437	136
< 100 MW	All	2,873	2,873	2,911	189	0
100 MW – 300 MW	All	1,341	1,239	1,248	177	102
> 300 MW	All	901	867	875	71	34

6.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CT plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CTs is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 6-2 compares the new CAPEX and O&M values derived from the gas/oil CT datasets with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, EMM fixed and variable O&M costs across all plant sizes are higher than values Sargent & Lundy has observed in actual CT plants. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)*
CT Dataset Results – All Plants	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value**	12.60	14.63	5.13	17.73	1.52	19.25

*Calculated at the gas/oil CC dataset average capacity factor of 4%.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

7. CONVENTIONAL HYDROELECTRIC

7.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for conventional hydroelectric plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 348 plants in FERC data
  - 2,179 valid data points in FERC data
- CAPEX
  - 348 plants in FERC data
  - 2,180 valid data points in FERC data

The conventional hydroelectric data was broken down by plant MW capacity, as summarized below in Table 7-1, for the regression analysis shown in Appendix E.

Table 7-1 — Conventional Hydroelectric Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,179	2,179	2,180	0	0
< 100 MW	All	1,272	1,272	1,272	0	0
100 MW – 500 MW	All	924	924	925	0	0
> 500 MW	All	41	41	41	0	0

7.2 SUMMARY OF RESULTS

Sargent & Lundy's linear regression analysis of the dataset for conventional hydroelectric plants (Appendix E) supports age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 \$/kW-year = 7.269 + (0.296 × age)

The dataset also supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table 7-2) and outside the range of values published in the AEO[12] and by the International Renewable Energy Agency (IRENA).[13] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

[12] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
[13] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

8. PUMPED HYDROELECTRIC STORAGE

8.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for pumped storage plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 37 plants in FERC data
  - 226 valid data points in FERC data
- CAPEX
  - 37 plants in FERC data
  - 227 valid data points in FERC data

The pumped storage data was broken down by plant MW capacity, as summarized below in Table 8-1, for the regression analysis shown in Appendix F.

Table 8-1 — Pumped Storage Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	226	226	227	0	0
< 100 MW	All	12	12	12	0	0
100 MW – 500 MW	All	88	88	88	0	0
> 500 MW	All	126	126	126	0	0

8.2 SUMMARY OF RESULTS

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table 8-2). The existing values used in the EMM are not available.

Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

9. SOLAR PHOTOVOLTAIC

9.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for solar PV storage plants were compiled using the assessment methodology described in Section 2. The FERC data includes 105 solar PV installations ranging in capacity from 10 kW to 36 MW.

The solar PV data, summarized below in Table 9-1, was used for the regression analysis shown in Appendix G.

Table 9-1 — Solar Photovoltaic Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	57	410	57	0	0

9.2 SUMMARY OF RESULTS

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size (see Appendix G). Sargent & Lundy determined that a significant portion of the data needed to be filtered out, resulting in a limited dataset of 15 sites. The average annual CAPEX (i.e., change in TCP) for these sites was approximately $26/kW-year. However, due to the limitations of the solar PV dataset, described in Appendix G, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based on a closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old and the fact that nearly all data points for plants over 10 years old are reported as having zero O&M expenses. Additionally, many of these plants also reported zero O&M expenses for all years of operation.

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

An average O&M cost of $75/kW-year was calculated from the FERC data for sites under 5 MW, and $15/kW-year for sites over 5 MW. Sargent & Lundy notes that, compared to other industry metrics shown in Appendix G, the FERC data averages are similar for the sites over 5 MW but much higher for the sites under 5 MW.

If the results of the regression analysis are used, the average O&M costs are reduced to $41/kW-year for sites under 5 MW and $10/kW-year for sites over 5 MW. The regression analysis uses each year of plant data as a unique data point, which captures the years in which zero O&M costs were reported.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero.[14] Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

[14] Internal communication with EIA, February 2018.

10. SOLAR THERMAL

10.1 DATA DESCRIPTION

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

10.2 SUMMARY OF RESULTS

The U.S. National Renewable Energy Laboratory (NREL) published an Annual Technology Baseline (ATB) in 2017 that estimates the capital and O&M cost of a 100-MWnet solar power tower plant with 10 hours of thermal storage, based on cost models benchmarked with industry data.[15] The estimate includes future projections based on possible reductions in costs (high, mid, or low). The 2017 ATB includes a 2015 baseline. An update is expected to be made available in 2018.

[15] NREL 2017 Annual Technology Baseline (https://atb.nrel.gov/electricity/2017/index.html?t=sc)

11. GEOTHERMAL

11.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for geothermal plants were compiled using the assessment methodology described in Section 2. The FERC data includes five geothermal installations ranging in capacity from 23 MW to 1,224 MW.

The geothermal data summarized in Table 11-1 was used for the regression analysis shown in Appendix I.

Table 11-1 — Geothermal Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	36	38	36	0	0

11.2 SUMMARY OF RESULTS

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table 11-2 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value*	91.66	0.00	0.00	91.66

*Source: Internal communication with EIA, February 2018.

12. WIND

12.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for wind plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 73 plants in FERC and 24 from Sargent & Lundy proprietary plants with valid data
  - 310 valid data points in FERC, 270 valid data points in Sargent & Lundy proprietary plants
- CAPEX
  - 97 plants in FERC with valid data
  - 310 valid data points in FERC

Sargent & Lundy's dataset includes both actual historical cost reporting from operating wind projects as well as forecasted budgetary cost projections prepared by project developers and operators with large project portfolios.

Operating costs are assumed to include all expenses related to the maintenance of the wind project, such as planned and unplanned maintenance of the wind turbines and electrical balance of plant (including labor, parts, materials, and consumables) as well as operating expenses (such as facility monitoring and management fees, utilities, land lease and royalty payments, professional service fees, taxes, and insurance).

The wind data was broken down by plant MW capacity, as summarized below in Table 12-1, for the regression analysis shown in Appendix J.

Table 12-1 — Wind Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	310	310	310	270	0
< 100 MW	All	174	174	174	165	0
100 MW – 200 MW	All	91	91	91	56	0
> 200 MW	All	51	51	51	73	0

12.2 SUMMARY OF RESULTS

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table 12-2. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)
Wind Dataset Results – All Plants	31.66 + (1.22 × age)	0.00	18.29
< 100 MW	39.08 + (1.12 × age)	0.00	20.48
100 MW – 200 MW	23.80 + (1.17 × age)	0.00	16.93
> 200 MW	26.78 + (0.92 × age)	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.

Sargent & Lundy Consulting

Appendix A. Regression Analysis – Coal Steam

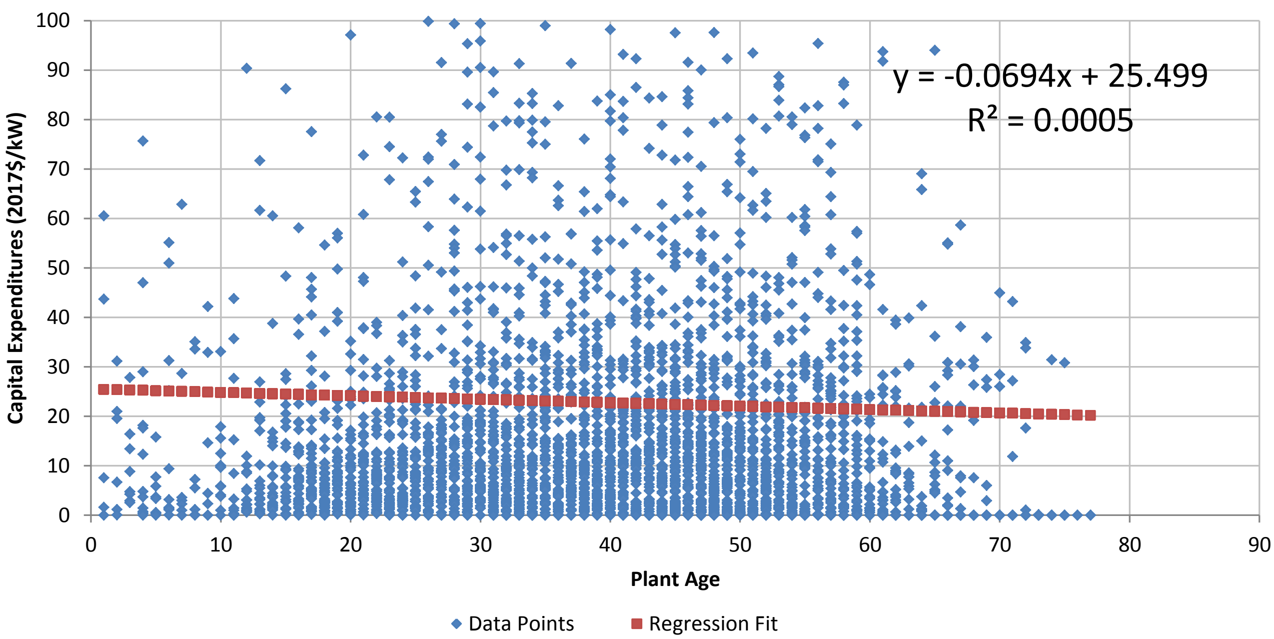
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.19, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, age and FGD are significant variables when an FGD variable is added to the regression equation (see below).

Table A-1 — Regression Statistics – Coal CAPEX for All MW

		t statistic	*p-value*
Observations	3,724		
Simple Average ($/kW)	22.782		
Intercept	25.499	11.4859	4.95E-30
Slope	-0.069	-1.3054	1.92E-01
R^2	0.00046		

Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

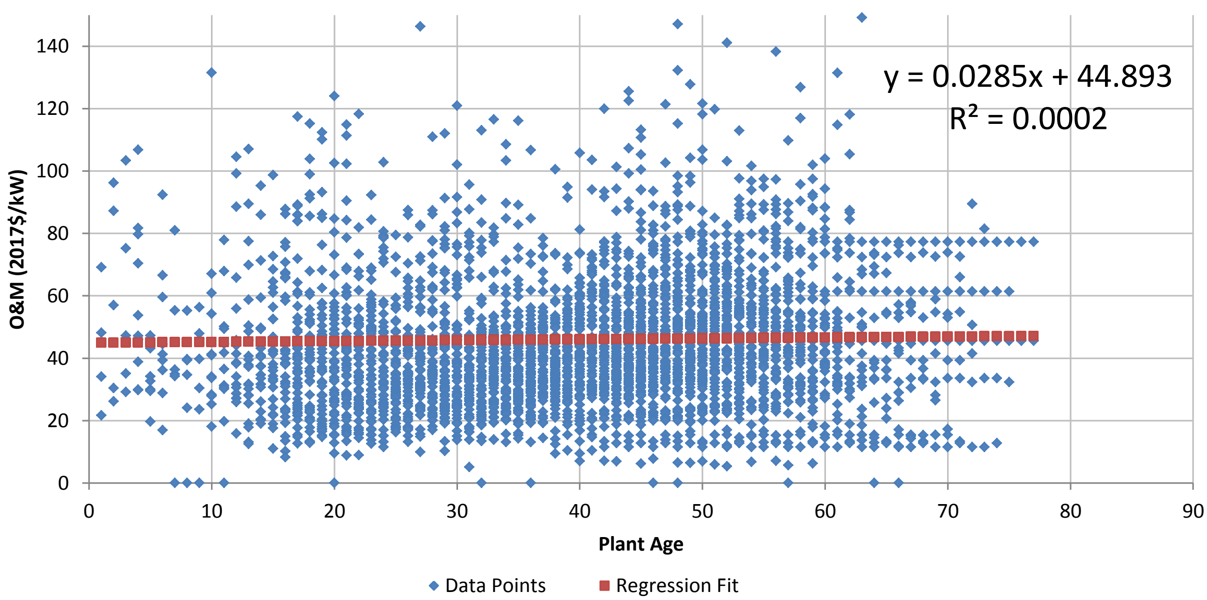
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.38, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-2 — Regression Statistics – Coal O&M for All MW

		t statistic	*p-value*
Observations	3,753		
Simple Average ($/kW)	46.013		
Intercept	44.893	33.2097	3.08E-212
Slope	0.028	0.8843	3.77E-01
R^2	0.00021		

Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	53.90	40.06	48.77	**46.01**	440	1,448	1,865	**3,753**
Net Total Capex - 2017 $/kW	17.92	26.20	21.25	**22.78**	441	1,450	1,833	**3,724**
Net Total O&M and Capex - 2017 $/kW	71.86	66.25	69.82	**68.67**	440	1,448	1,825	**3,713**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

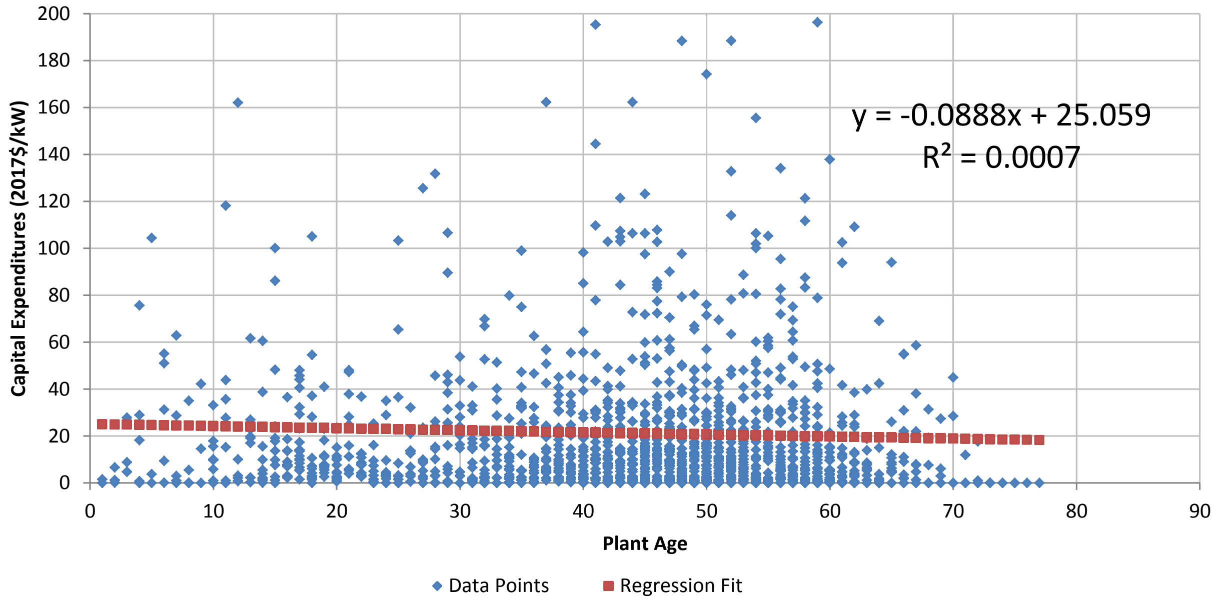
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.28, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-3 — Regression Statistics – Coal CAPEX < 500 MW

		t statistic	*p-value*
Observations	1,602		
Simple Average ($/kW)	21.187		
Intercept	25.059	6.5593	7.28E-11
Slope	-0.089	-1.0685	2.85E-01
R^2	0.00071		

Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

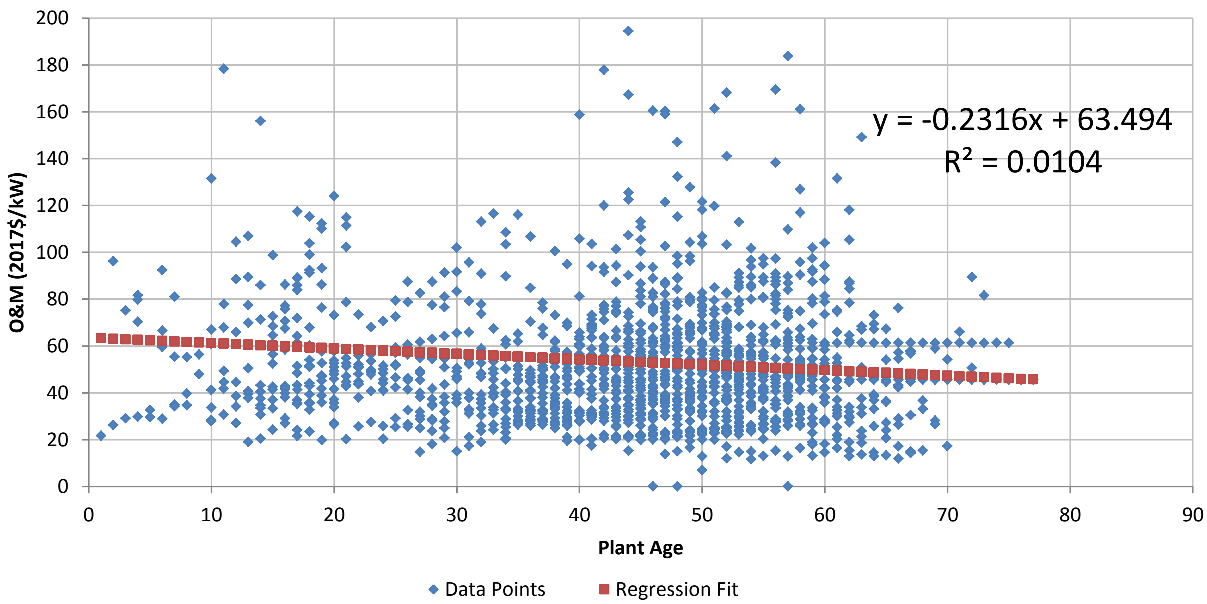
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the following regression equation:

Annual spending in 2017 $/kW-year = 63.494 + (-0.232 × age)

Table A-4 — Regression Statistics – Coal O&M < 500 MW

		t statistic	*p-value*
Observations	1,592		
Simple Average ($/kW)	53.406		
Intercept	63.494	24.4603	2.03E-112
Slope	-0.232	-4.0977	4.38E-05
R^2	0.01045		

Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	68.13	47.13	53.16	**53.41**	169	355	1,068	**1,592**
Net Total Capex - 2017 $/kW	21.01	22.83	20.67	**21.19**	169	357	1,076	**1,602**
Net Total O&M and Capex - 2017 $/kW	89.14	69.91	73.93	**74.65**	169	355	1,068	**1,592**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

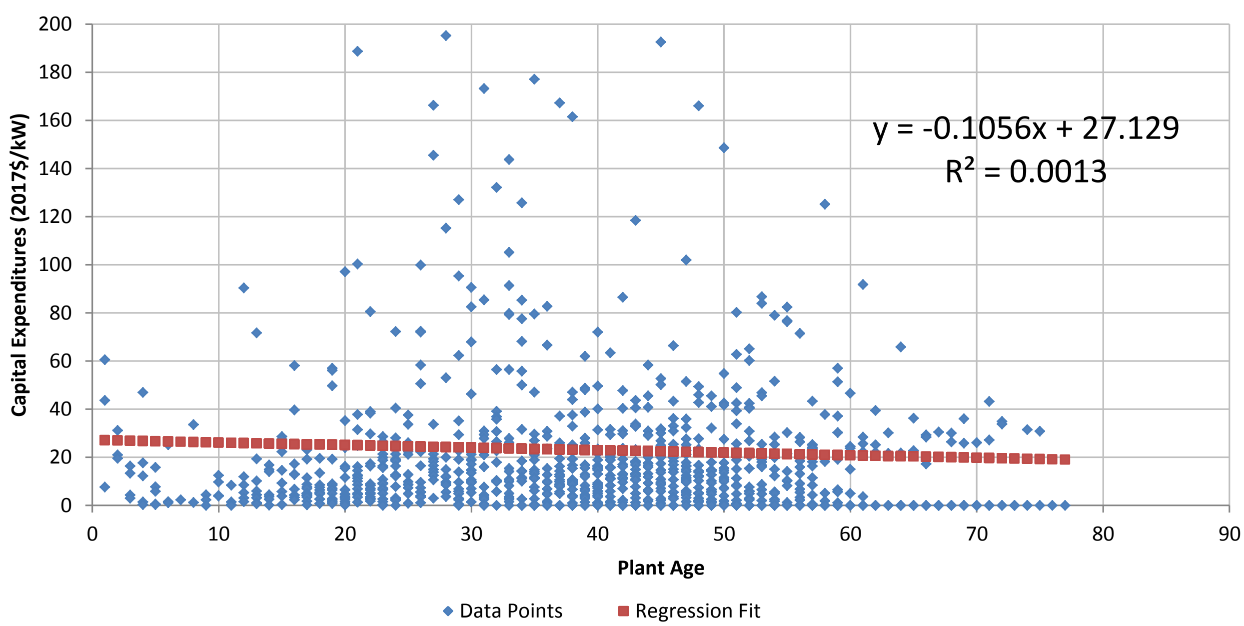
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	986		
Simple Average ($/kW)	23.021		
Intercept	27.129	6.8576	1.24E-11
Slope	-0.106	-1.1195	2.63E-01
R^2	0.00127		

Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

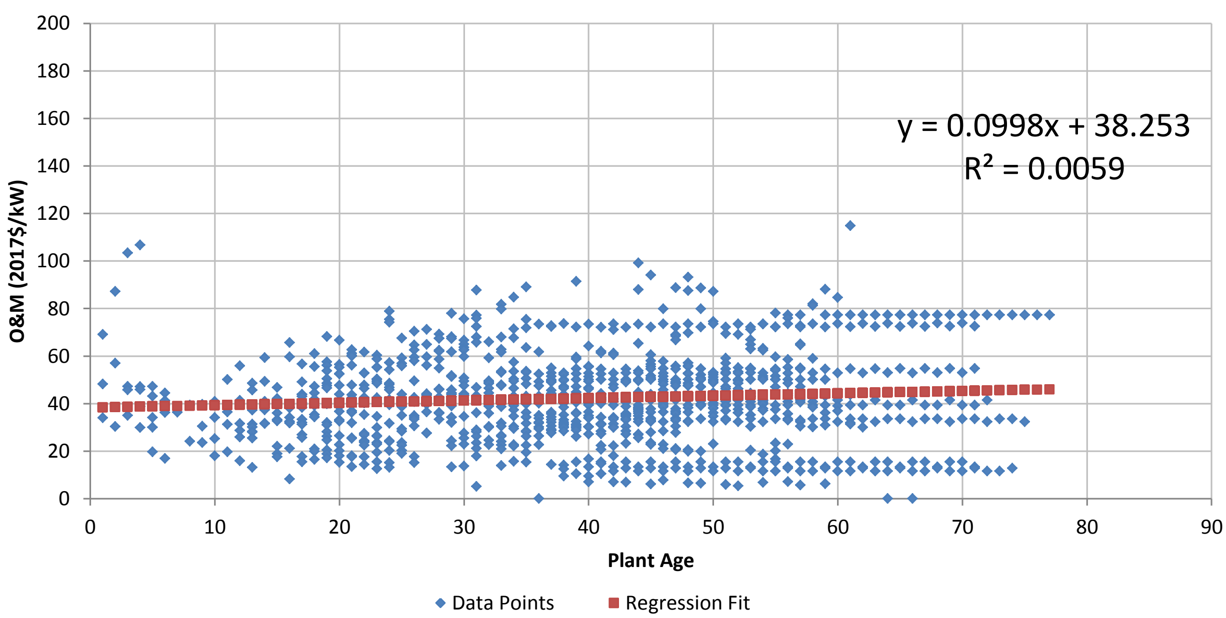
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 $/kW-year = 38.253 + (0.100 × age)

Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	1,026		
Simple Average ($/kW)	42.223		
Intercept	38.253	22.0915	9.54E-89
Slope	0.100	2.4710	1.36E-02
R^2	0.00593		

Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	38.15	42.09	43.40	**42.22**	138	369	519	**1,026**
Net Total Capex - 2017 $/kW	12.27	32.63	18.71	**23.02**	138	369	479	**986**
Net Total O&M and Capex - 2017 $/kW	50.41	74.72	60.65	**64.49**	138	369	479	**986**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

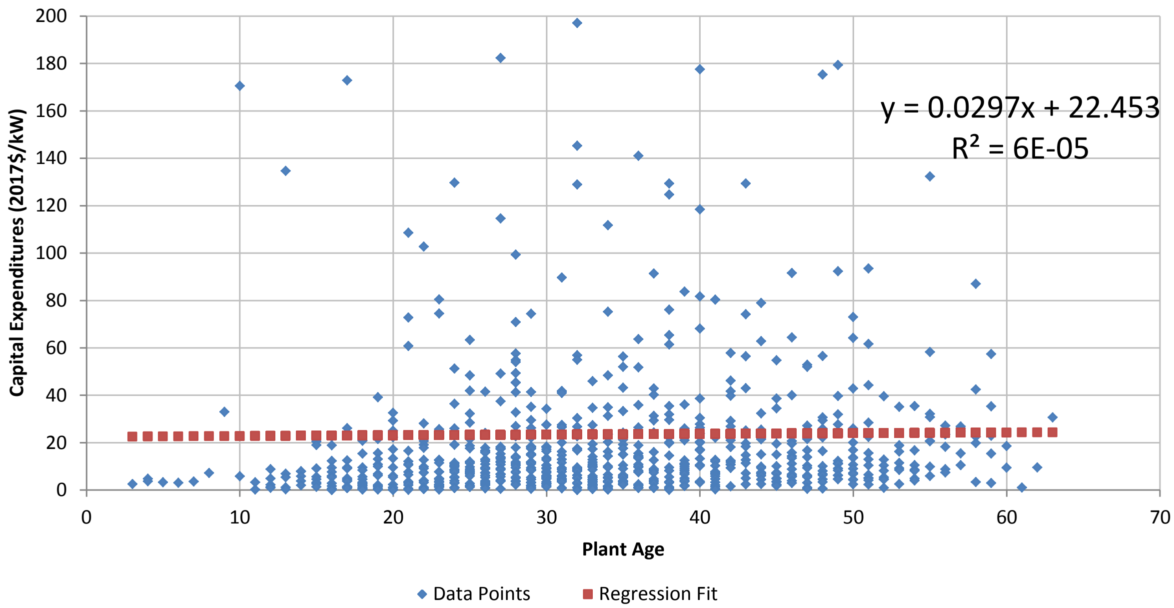
CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.83, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW

		t statistic	*p-value*
Observations	814		
Simple Average ($/kW)	23.448		
Intercept	22.453	4.6325	4.21E-06
Slope	0.030	0.2174	8.28E-01
R^2	0.00006		

Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

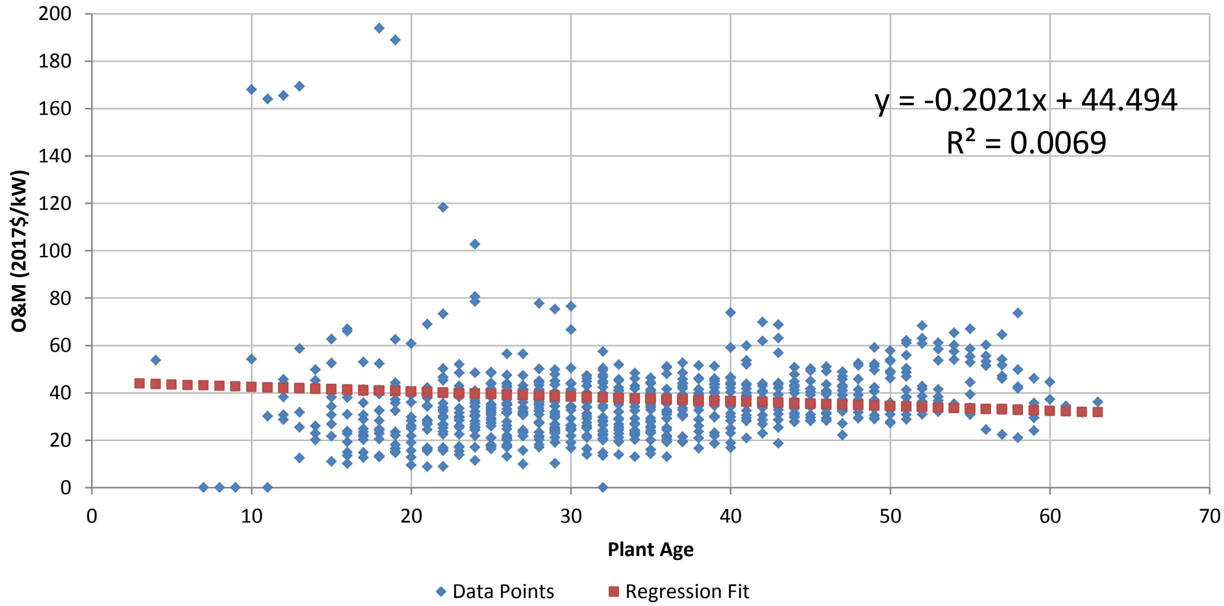
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 $/kW-year = 44.494 + (-0.202 × age)

Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW

		t statistic	*p-value*
Observations	813		
Simple Average ($/kW)	37.722		
Intercept	44.494	14.7620	7.42E-44
Slope	-0.202	-2.3785	1.76E-02
R^2	0.00693		

Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
1000 MW - 2000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	53.51	32.80	40.62	**37.72**	107	478	228	**813**
Net Total Capex - 2017 $/kW	22.56	23.31	24.16	**23.45**	108	478	228	**814**
Net Total O&M and Capex - 2017 $/kW	76.28	56.11	64.78	**61.20**	107	478	228	**813**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

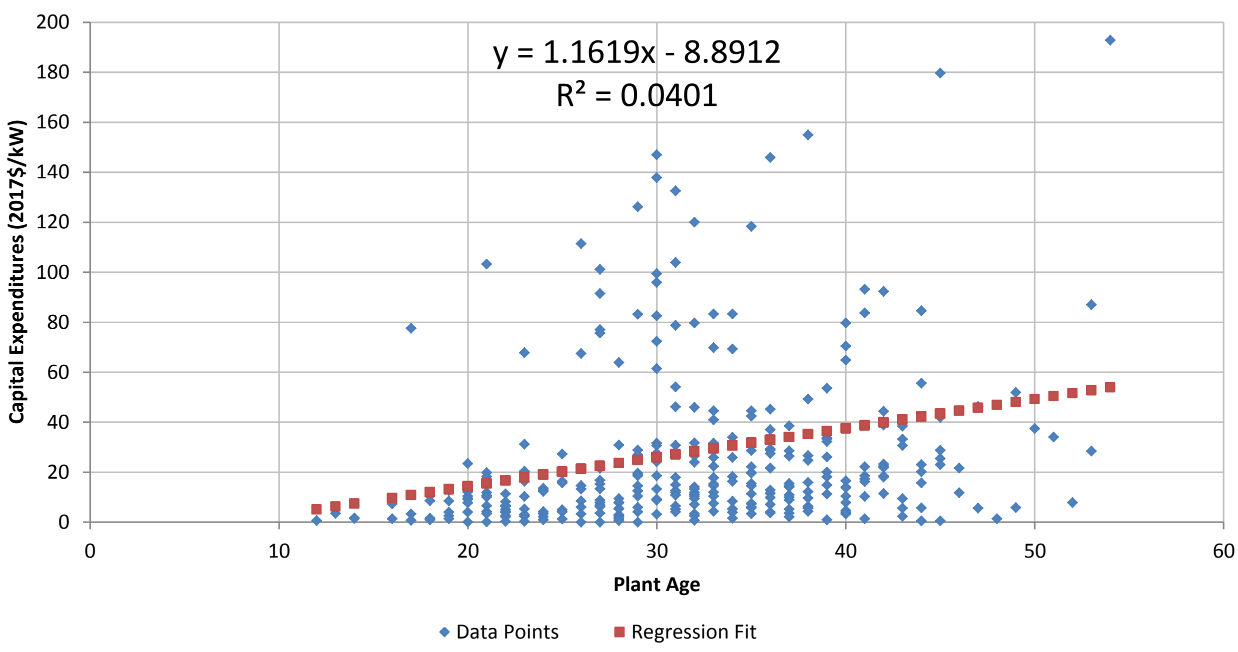
CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the linear regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW

		t statistic	*p-value*
Observations	322		
Simple Average ($/kW)	28.303		
Intercept	-8.891	-0.8468	3.98E-01
Slope	1.162	3.6556	3.00E-04
R^2	0.04009		

Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size



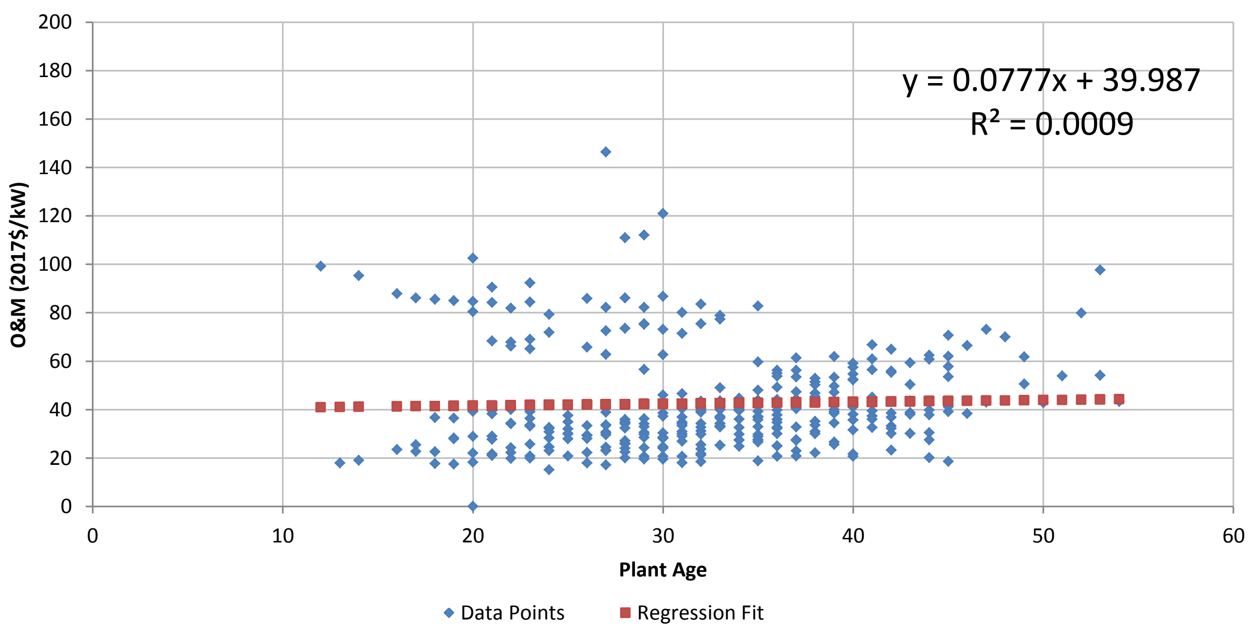
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of O&M spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.59, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-10 — Regression Statistics – Coal O&M > 2,000 MW

		t statistic	*p-value*
Observations	322		
Simple Average ($/kW)	42.474		
Intercept	39.987	8.3303	2.39E-15
Slope	0.078	0.5348	5.93E-01
R^2	0.00089		

Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 2000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	46.55	40.91	48.04	**42.47**	26	246	50	**322**
Net Total Capex - 2017 $/kW	8.65	27.06	44.64	**28.30**	26	246	50	**322**
Net Total O&M and Capex - 2017 $/kW	55.20	67.97	92.67	**70.78**	26	246	50	**322**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

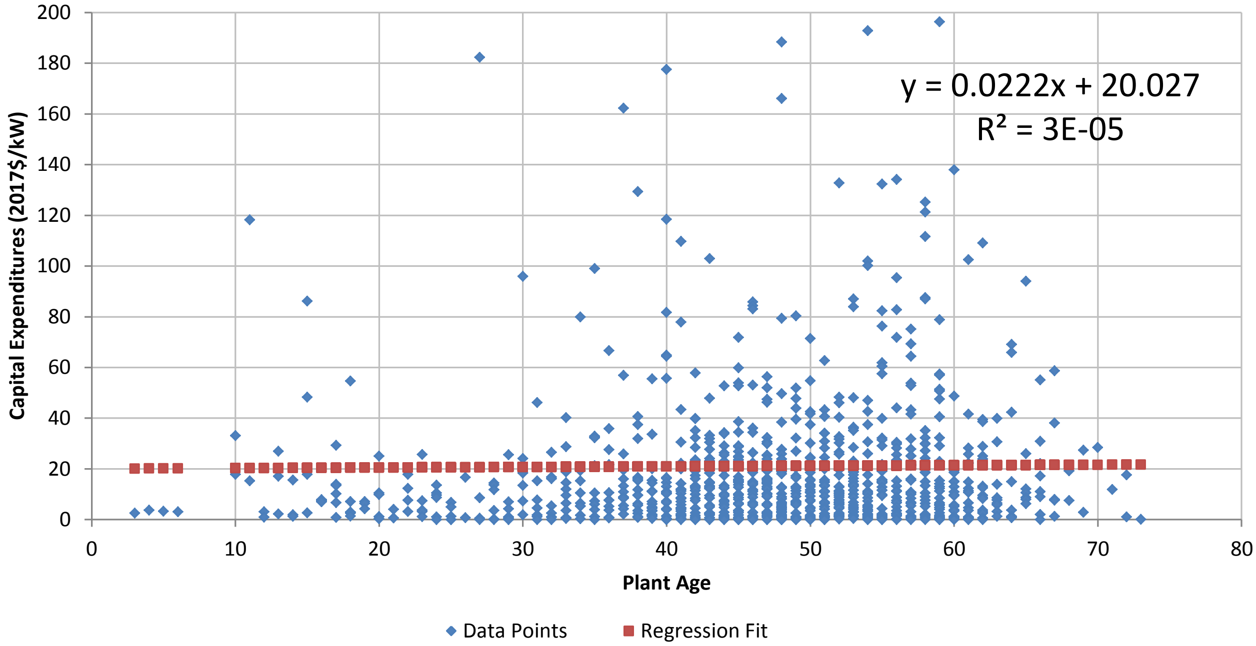
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.87, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50%

		t statistic	*p-value*
Observations	972		
Simple Average ($/kW)	21.063		
Intercept	20.027	3.1188	1.87E-03
Slope	0.022	0.1663	8.68E-01
R^2	0.00003		

Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

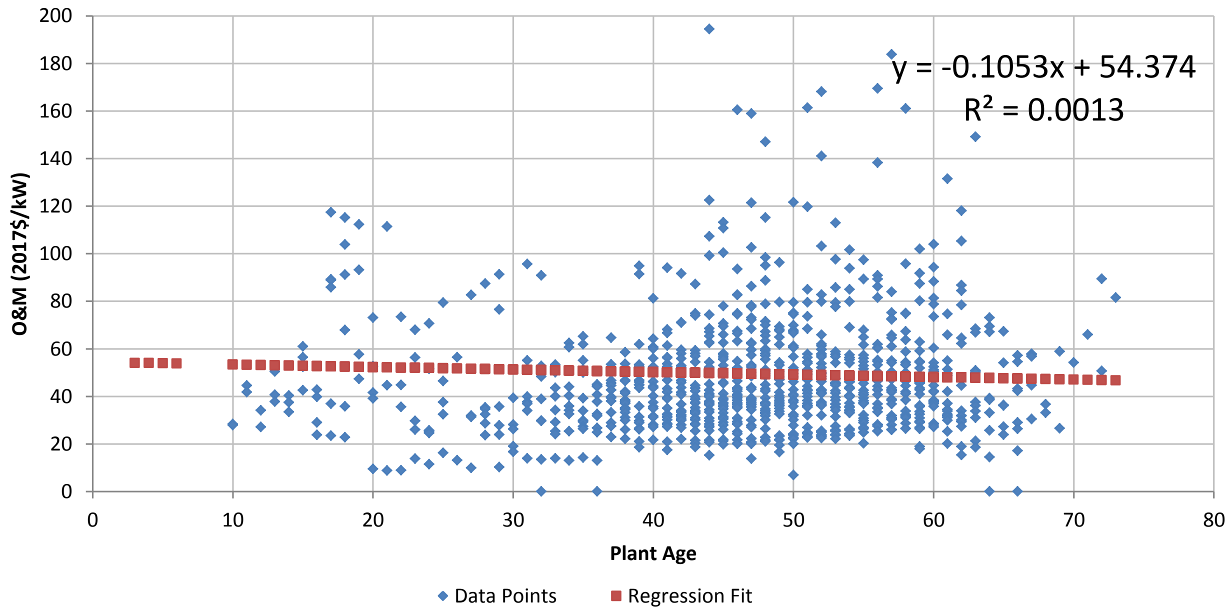
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50%

		t statistic	*p-value*
Observations	965		
Simple Average ($/kW)	49.454		
Intercept	54.374	12.0380	3.43E-31
Slope	-0.105	-1.1234	2.62E-01
R^2	0.00131		

Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 0 - 50%								
Net Total O&M- 2017 $/kW	76.43	40.01	50.07	**49.45**	45	177	743	**965**
Net Total Capex - 2017 $/kW	19.62	23.74	20.51	**21.06**	45	179	748	**972**
Net Total O&M and Capex - 2017 $/kW	96.04	63.66	70.63	**70.54**	45	177	743	**965**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

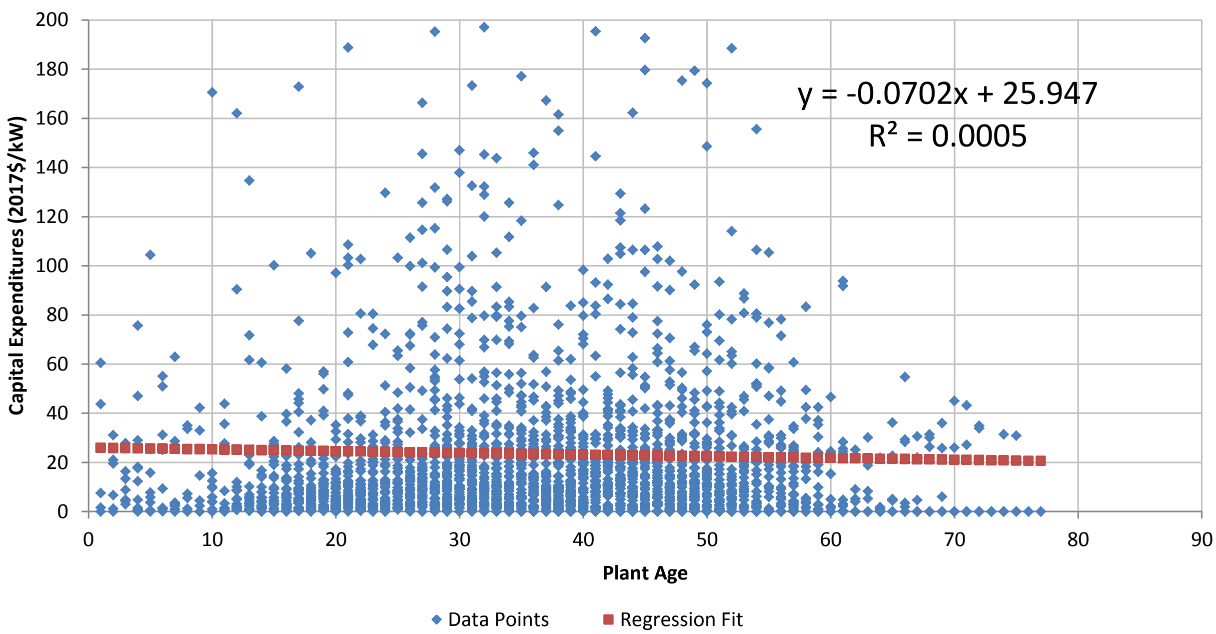
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.25, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50%

		t statistic	*p-value*
Observations	2752		
Simple Average ($/kW)	23.389		
Intercept	25.947	10.7905	1.29E-26
Slope	-0.070	-1.1446	2.52E-01
R^2	0.00048		

Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50%



Note: Age coefficient in above regression equation is not statistically significant.

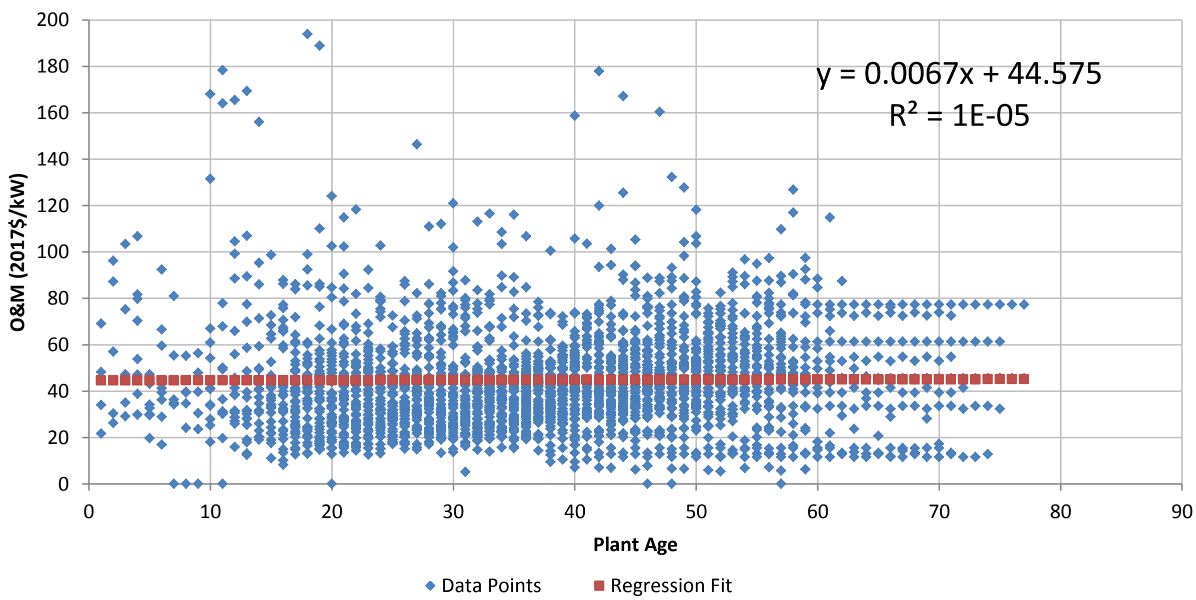
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.85, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50%

		t statistic	*p-value*
Observations	2788		
Simple Average ($/kW)	44.822		
Intercept	44.575	32.6995	8.78E-199
Slope	0.007	0.1954	8.45E-01
R^2	0.00001		

Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 50% - 100%								
Net Total O&M- 2017 $/kW	51.33	40.07	47.92	**44.82**	395	1,271	1,122	**2,788**
Net Total Capex - 2017 $/kW	17.73	26.55	21.75	**23.39**	396	1,271	1,085	**2,752**
Net Total O&M and Capex - 2017 $/kW	69.11	66.62	69.25	**68.01**	395	1,271	1,082	**2,748**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

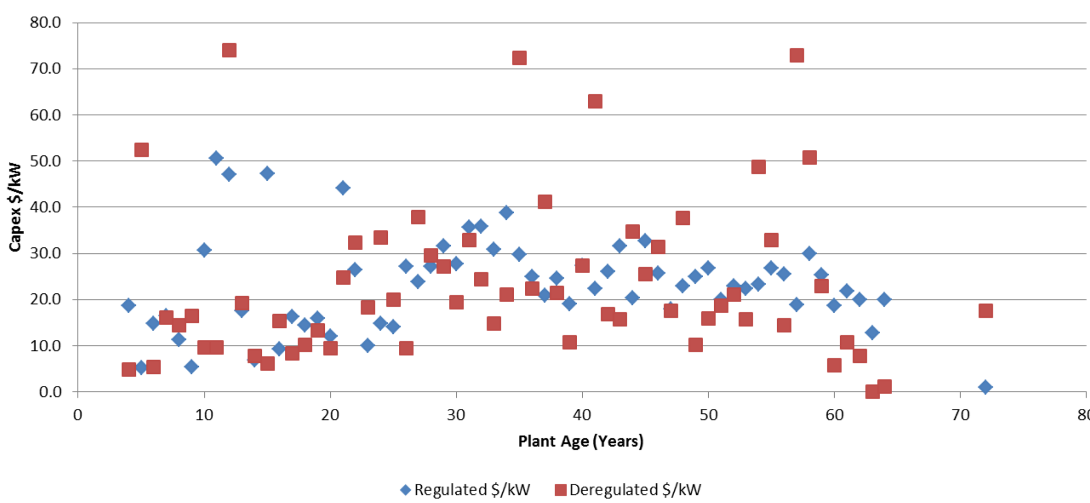
CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in regulated versus deregulated locations are summarized in the table below. Since the p-value for the age ("slope") and regulation/deregulation coefficients are much greater than 0.05, age and regulatory status are not statistically significant predictors of CAPEX spending.

Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated

	Coefficients	Standard Error	t Stat	P-Value
Intercept	23.22826383	2.9645403	7.835367875	6.36821E-15
Age	0.097334249	0.064355791	1.512439626	0.130523796
Reg./Dereg. (1/0)	-2.479225741	2.148990587	-1.153669893	0.248724297

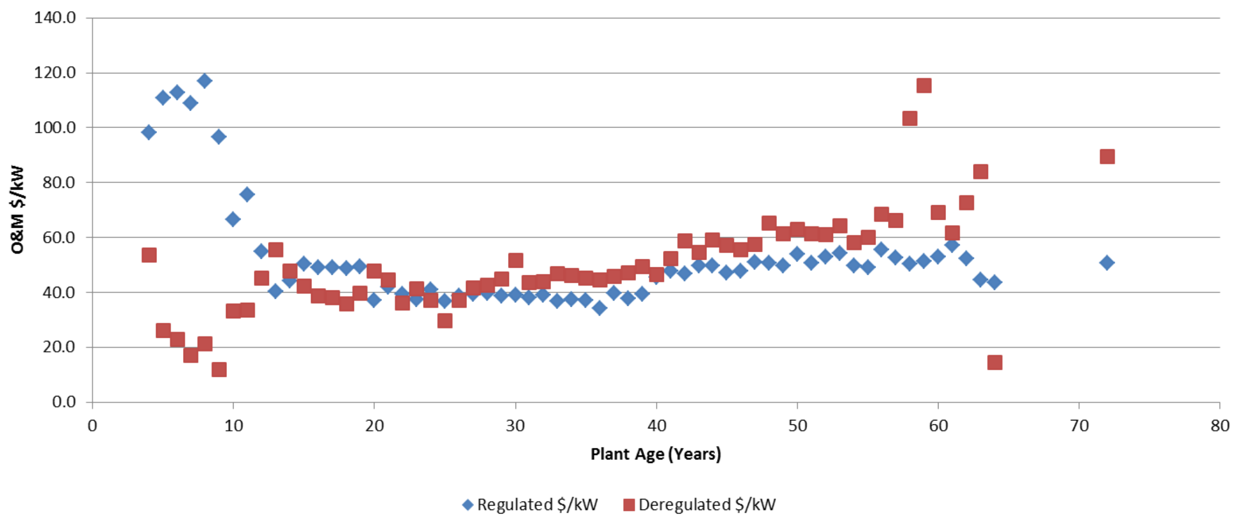
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated



OPERATIONS & MAINTENANCE EXPENDITURES – REGULATED VS. DEREGULATED

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and regulated/deregulated coefficients are much less than 0.05 (i.e., statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. After year 20, a visual inspection of the data points indicates higher O&M spending in deregulated states compared with regulated states (Figure A-16). This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending is not apparent at this level of detail.

Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated



CAPITAL EXPENDITURES – FGD VS. NO FGD

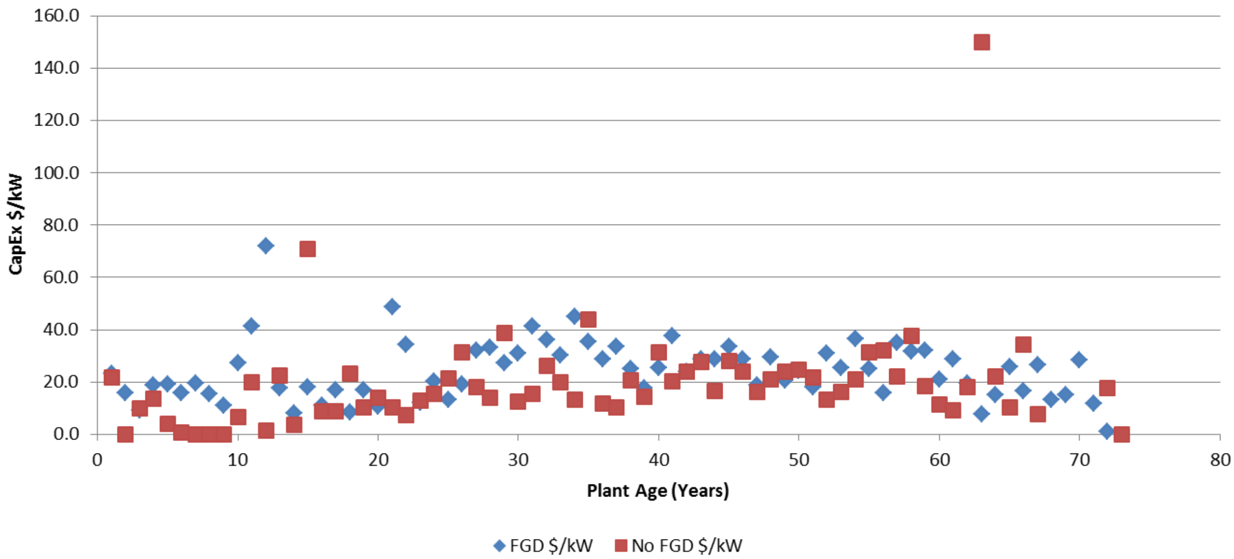
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age ("slope") coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the FGD/no-FGD coefficient is much less than 0.05 (statistically significant). A visual inspection of the difference between the FGD and no-FGD data points in Figure A-17 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending may be represented by the following regression equation:

Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)
Where FGD = 1 if plant has FGD; zero otherwise

Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD

	Coefficients	Standard Error	t Stat	P-Value
Intercept	16.52586075	3.06139723	5.39814323	7.2399E-08
Age	0.126266024	0.065143952	1.93826166	0.05268181
FGD/No FGD (1/0)	5.6788887	1.913609818	2.96763146	0.00302395

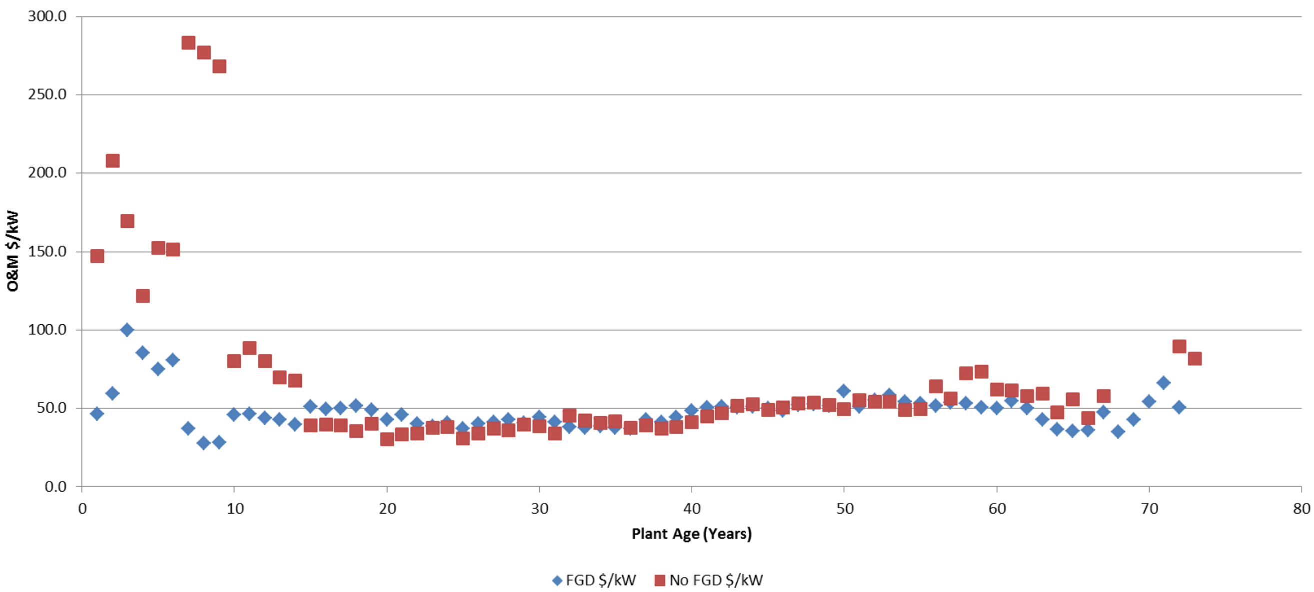
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD



OPERATIONS & MAINTENANCE EXPENDITURES – FGD VS. NO FGD

The regression analysis of O&M expenditures indicates that the p-value for the age (“slope”) and FGD/no-FGD coefficients are much less than 0.05 (i.e., statistically significant). However, outliers before year 15 may tend to distort the regression analysis. A visual inspection of the difference between the FGD and no-FGD data points in Figure A-18 shows a similarity in O&M spending amounts across all ages after year 15. The differences in annual coal plant spending due to having FGD is more significant in the CAPEX accounts, as shown in the previous subsection, rather than the O&M accounts.

Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD



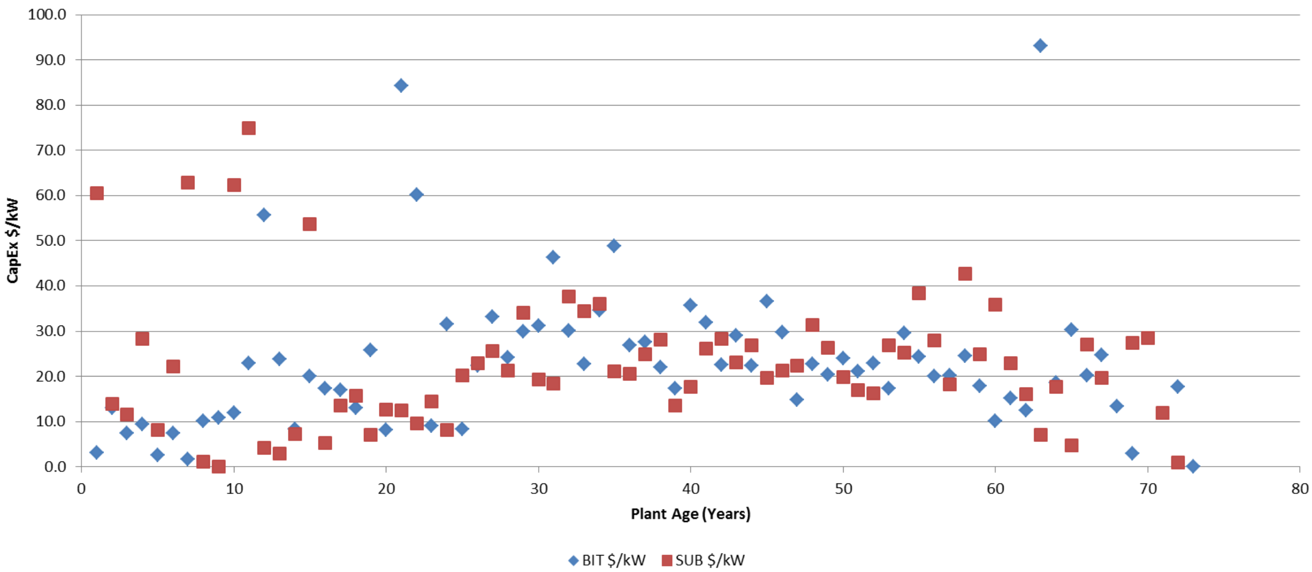
CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in bituminous versus subbituminous coal types are summarized in the table below. The p-value for the age (“slope”) coefficient is much greater than 0.05 (not statistically significant), while the p-value for the bituminous/subbituminous coefficient is much less than 0.05 (statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-19 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous

	Coefficients	Standard Error	t Stat	P-Value
Intercept	15.39252046	2.257695952	6.817800442	1.08205E-11
Age	-0.00350504	0.054578287	-0.064220408	0.948798346
Bit./Sub. (1/0)	10.93481186	1.525466511	7.168175624	9.20398E-13

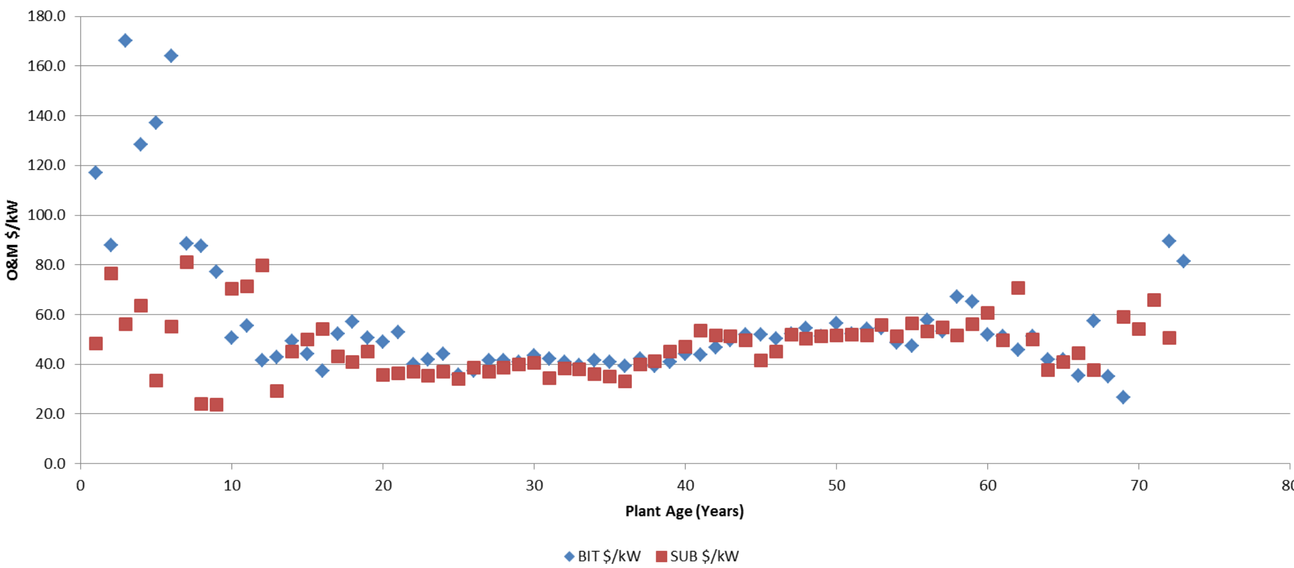
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous



OPERATIONS & MAINTENANCE EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and bituminous/subbituminous coefficients are much less than 0.05 (statistically significant). However, as with CAPEX spending, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-20 shows a similarity in O&M spending amounts across all ages. Therefore, average O&M spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous



EFFECT OF PLANT CAPACITY FACTOR

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time. Figure A-21 and Figure A-22 indicate real annual increases in CAPEX and O&M spending for the coal steam plants in constant 2017 $/MWh versus plant age, with linear regression results as follows:

- Annual CAPEX in 2017 $/MWh = 3.27 + (0.0426 × age)
- Annual O&M in 2017 $/MWh = 5.44 + (0.133 × age)

Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh)

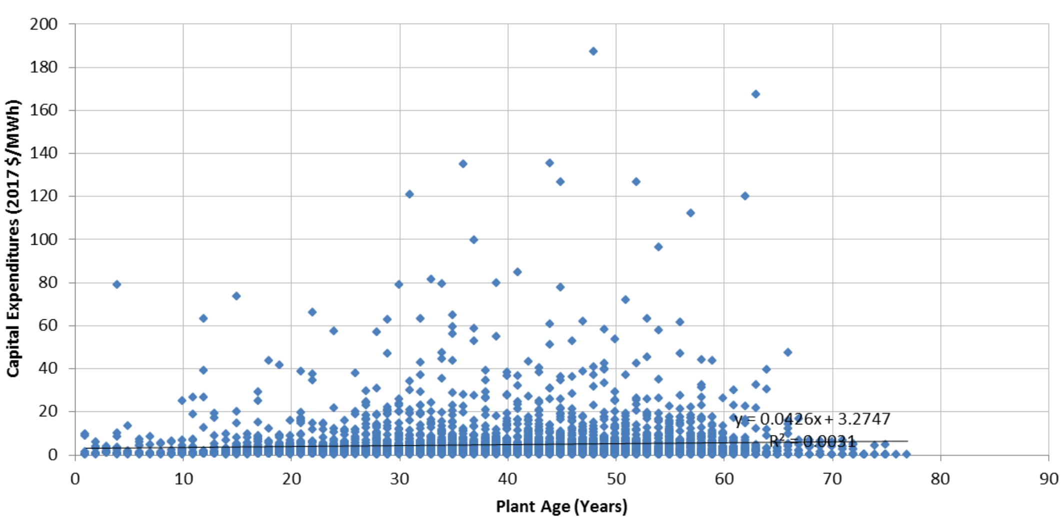
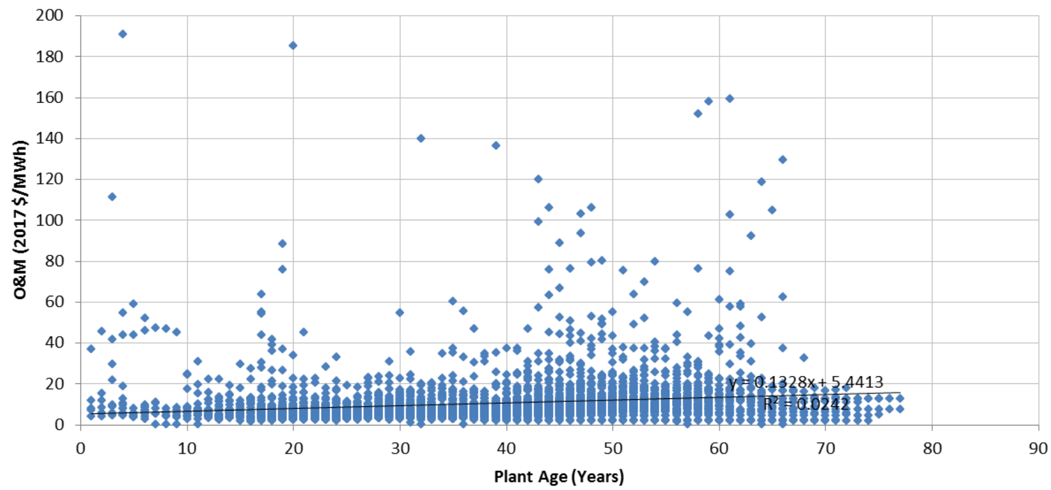


Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh)



In both of the above regression results, the age coefficient was found to be statistically significant. This was determined to be a result of the average decline in capacity factors for the coal steam plants, as shown in Figure A-23. A similar decline also occurred with the gas/oil steam plants, as shown in Figure A-24.

Figure A-23 — Capacity Factor vs. Age for All Coal Plants

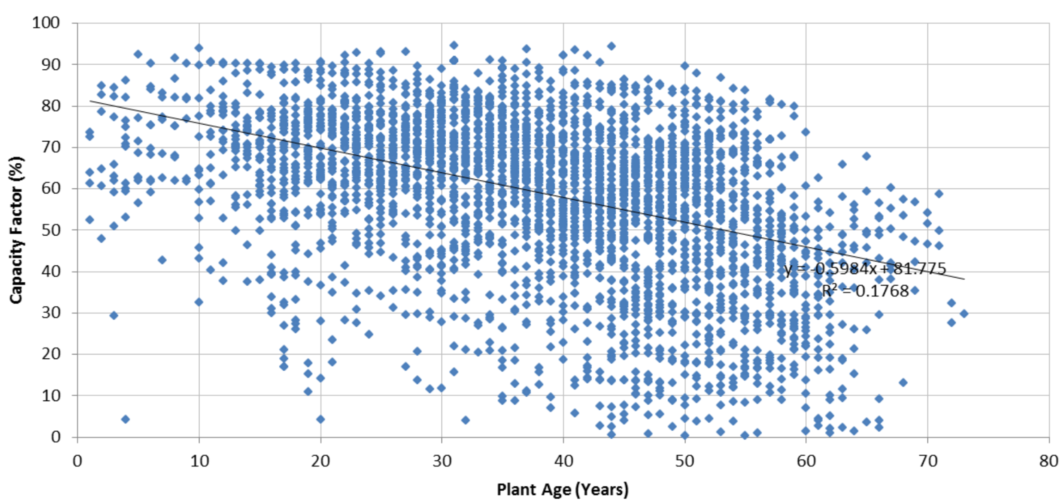
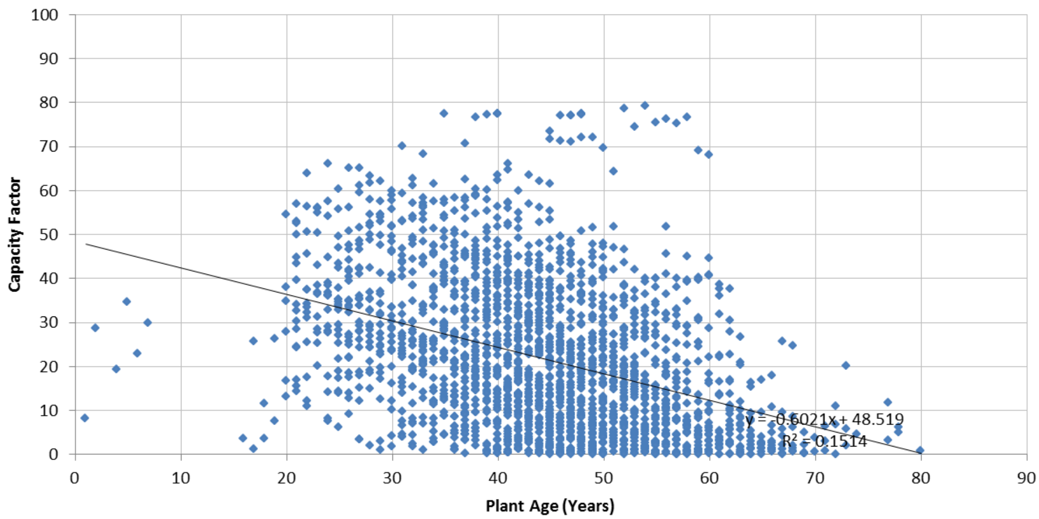


Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



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Appendix B. Regression Analysis – Gas/Oil Steam

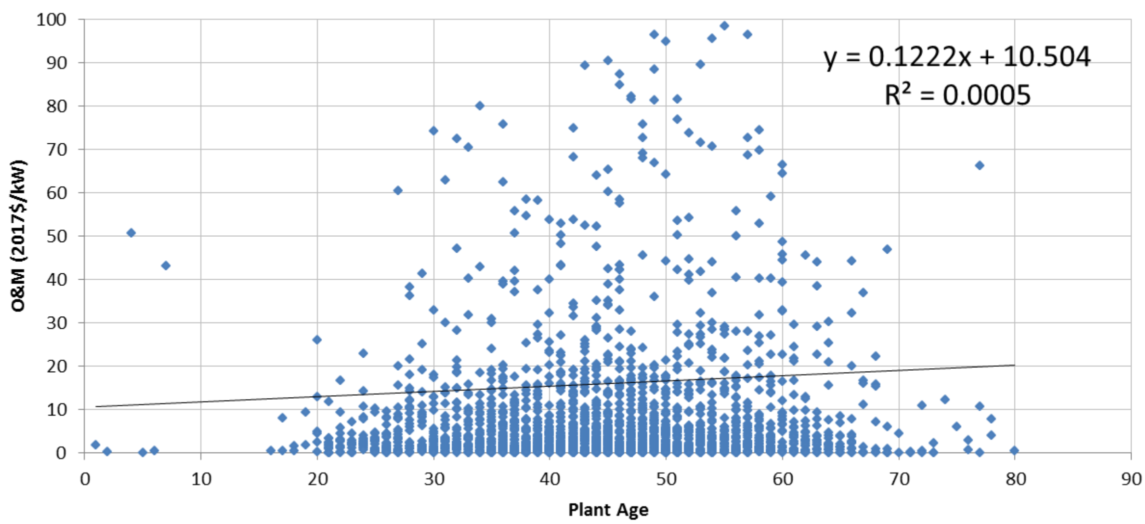
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.29, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW

		t statistic	*p-value*
Observations	2,226		
Simple Average ($/kW)	15.955		
Intercept	10.504	1.9741	4.85E-02
Slope	0.122	1.0551	2.91E-01
R^2	0.00050		

Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

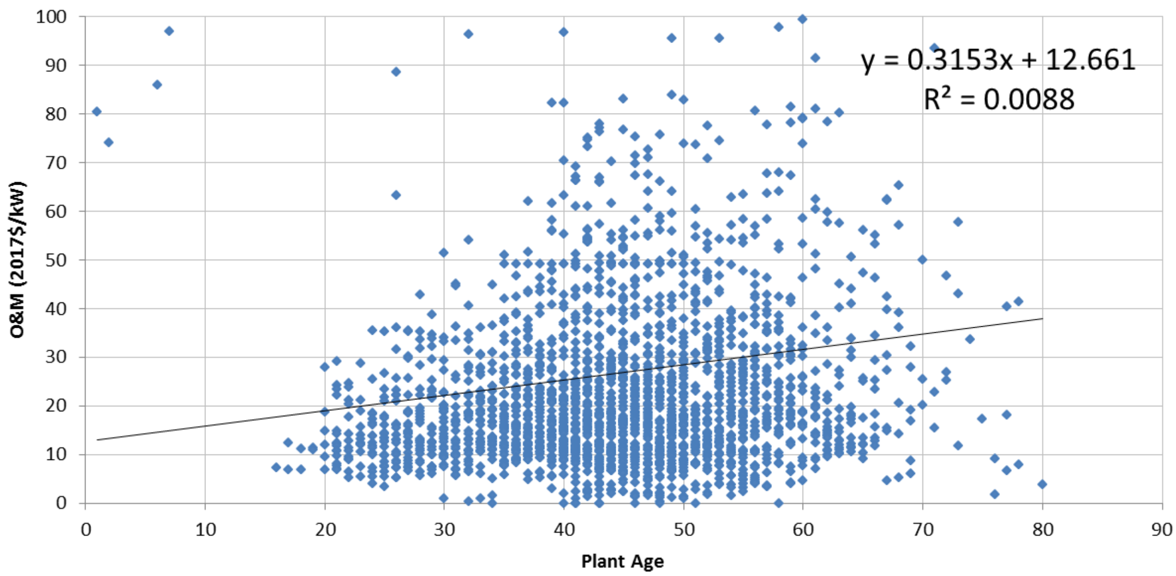
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW

		t statistic	*p-value*
Observations	2,224		
Simple Average ($/kW)	26.723		
Intercept	12.661	3.8863	1.05E-04
Slope	0.315	4.4455	9.20E-06
R^2	0.00882		

Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	39.39	23.48	28.18	**26.72**	19	733	1,472	**2,224**
Net Total Capex - 2017 $/kW	8.91	14.18	16.93	**15.96**	19	733	1,474	**2,226**
Net Total O&M and Capex - 2017 $/kW	48.30	37.53	45.10	**42.63**	19	731	1,470	**2,220**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

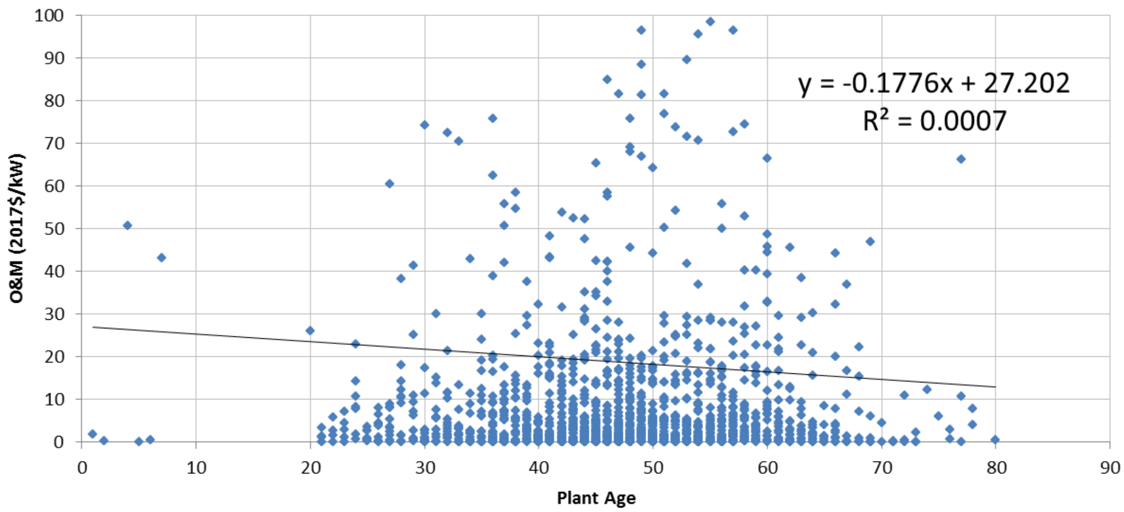
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.32, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW

		t statistic	*p-value*
Observations	1382		
Simple Average ($/kW)	18.392		
Intercept	27.202	3.1265	1.81E-03
Slope	-0.178	-0.9867	3.24E-01
R^2	0.00071		

Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

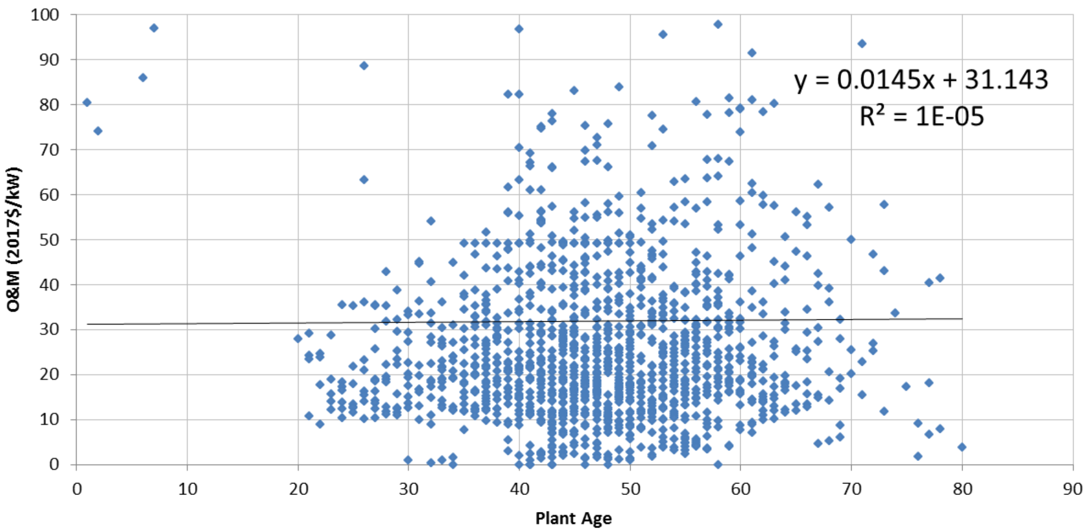
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of O&M spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.90, which is greater than 0.05, age is not a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW

		t statistic	*p-value*
Observations	1,381		
Simple Average ($/kW)	31.827		
Intercept	31.143	5.7925	8.58E-09
Slope	0.015	0.1305	8.96E-01
R^2	0.00001		

Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	88.54	33.36	30.98	**31.83**	7	324	1,050	**1,381**
Net Total Capex - 2017 $/kW	17.44	22.13	17.82	**18.83**	7	324	1,051	**1,382**
Net Total O&M and Capex - 2017 $/kW	105.98	55.32	48.78	**50.60**	7	322	1,048	**1,377**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

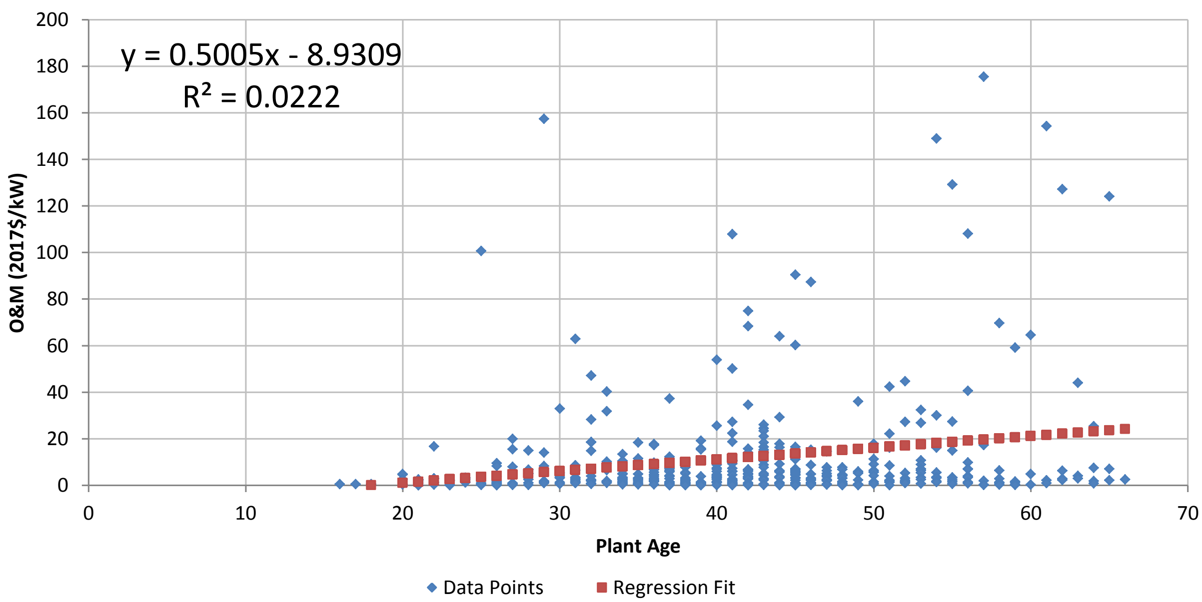
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	489		
Simple Average ($/kW)	11.570		
Intercept	-8.988	-1.4118	1.59E-01
Slope	0.501	3.3322	9.27E-04
R^2	0.02229		

Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



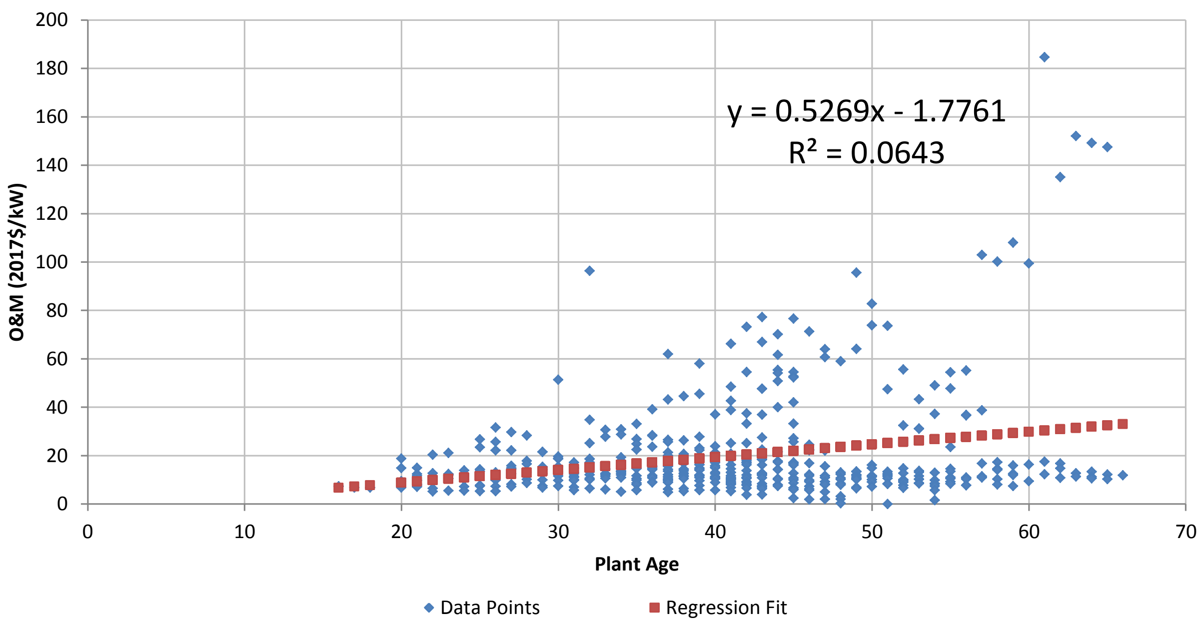
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending. However, the regression analysis shows the intercept value (i.e., the O&M cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited data causes the regression analysis to be distorted.

Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	488		
Simple Average ($/kW)	19.823		
Intercept	-1.776	-0.4606	6.45E-01
Slope	0.527	5.7810	1.33E-08
R^2	0.06434		

Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	10.10	15.82	23.61	**19.82**	7	225	256	**488**
Net Total Capex - 2017 $/kW	1.94	6.32	16.43	**11.57**	7	225	257	**489**
Net Total O&M and Capex - 2017 $/kW	12.04	22.14	40.07	**31.40**	7	225	256	**488**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

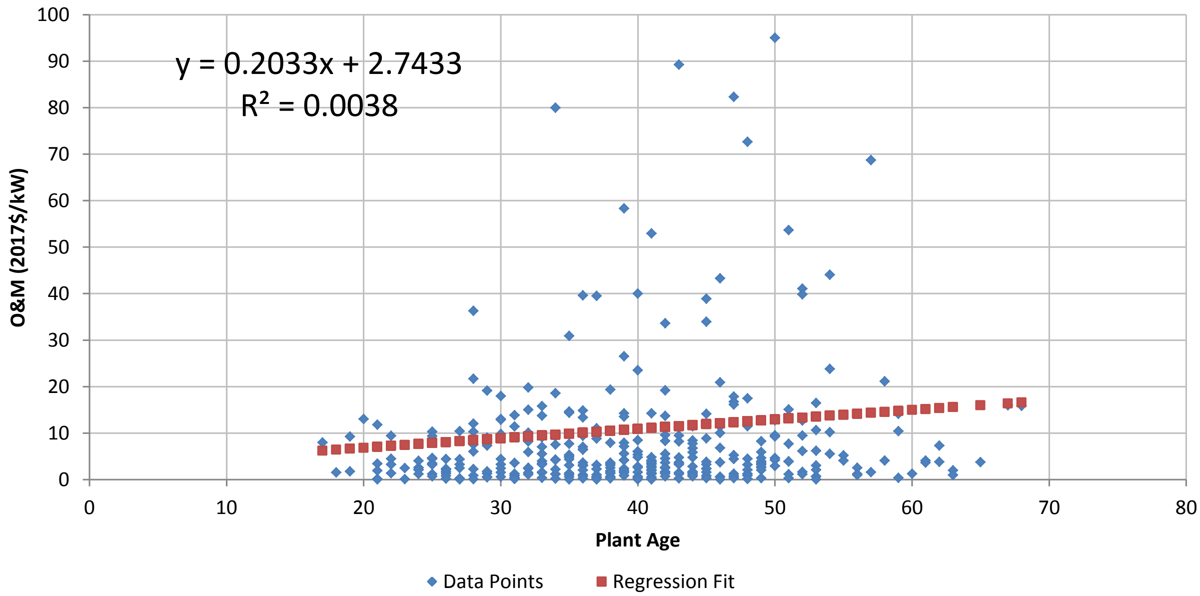
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.24, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW

		t statistic	*p-value*
Observations	355		
Simple Average ($/kW)	10.815		
Intercept	2.743	0.3846	7.01E-01
Slope	0.203	1.1660	2.44E-01
R^2	0.00384		

Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

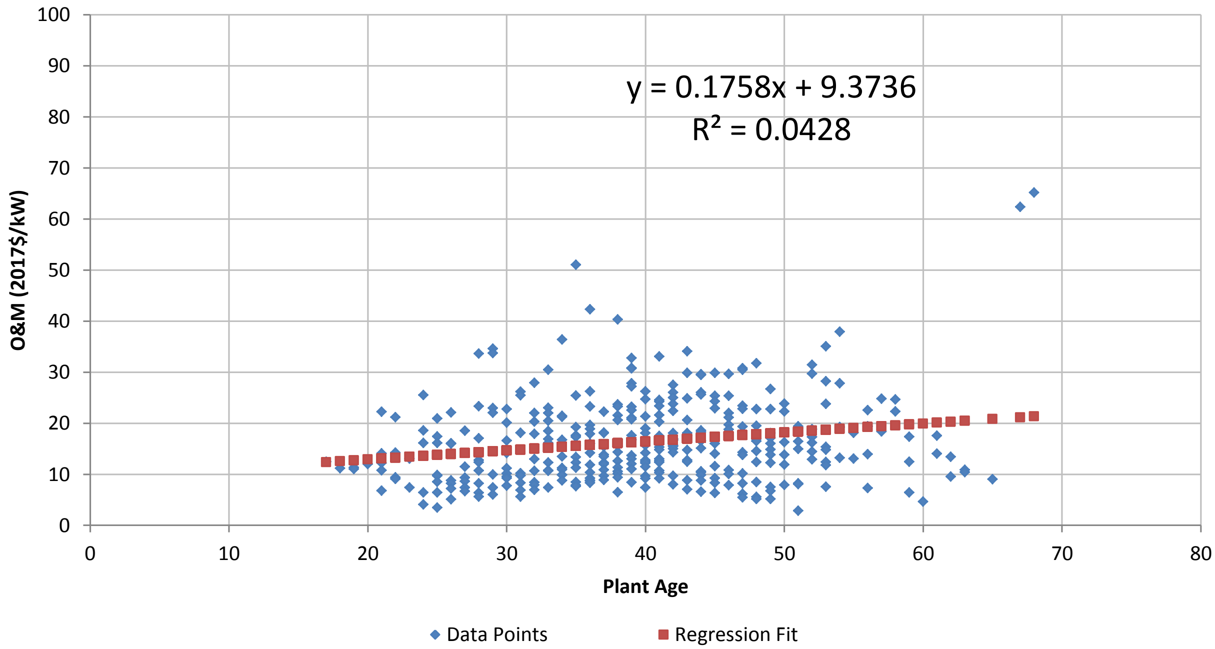
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW

		t statistic	*p-value*
Observations	355		
Simple Average ($/kW)	16.353		
Intercept	9.374	5.1812	3.71E-07
Slope	0.176	3.9752	8.53E-05
R^2	0.04285		

Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	11.59	15.44	17.50	**16.35**	5	184	166	**355**
Net Total Capex - 2017 $/kW	6.70	9.78	12.09	**10.82**	5	184	166	**355**
Net Total O&M and Capex - 2017 $/kW	18.29	25.22	29.60	**27.17**	5	184	166	**355**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

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Appendix C. Regression Analysis – Gas/Oil Combined Cycle

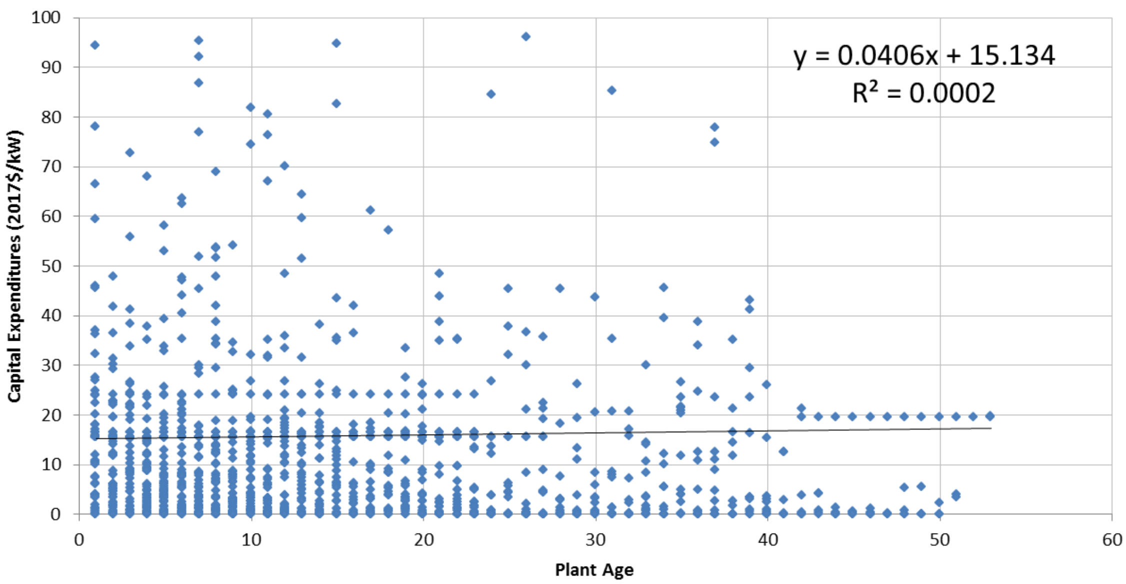
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.63, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-1 — Regression Statistics – CC CAPEX for All MW

		t statistic	*p-value*
Observations	1,368		
Simple Average ($/kW)	15.765		
Intercept	15.134	9.2176	1.11E-19
Slope	0.041	0.4853	6.28E-01
R^2	0.00017		

Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

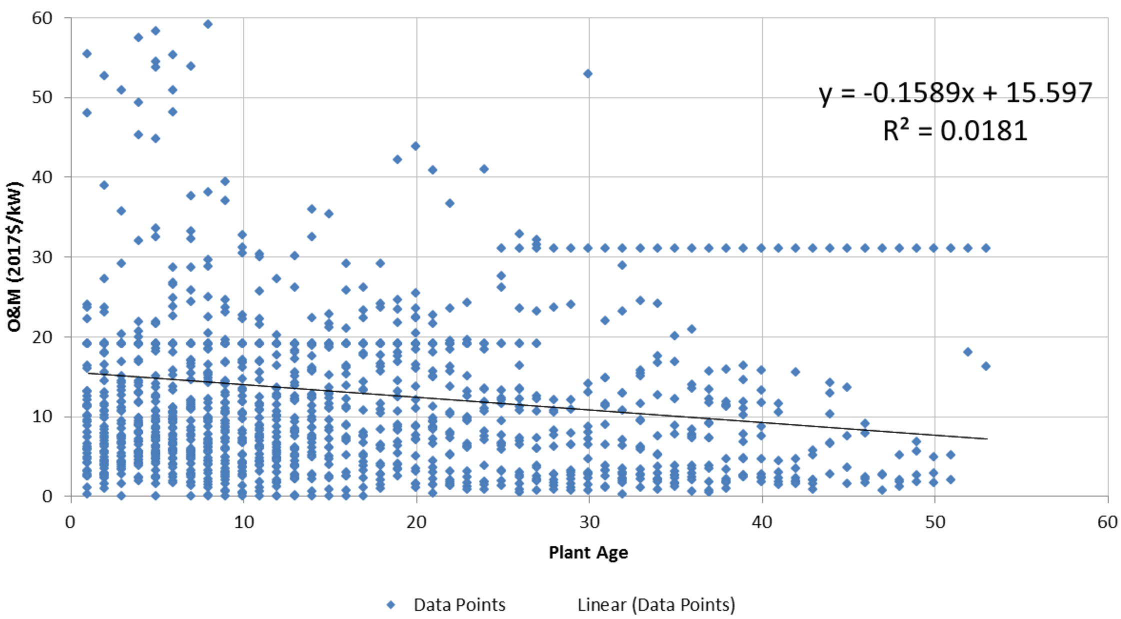
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is much lower than 0.05, the dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table C-2 — Regression Statistics – CC O&M for All MW

		t statistic	*p-value*
Observations	1,388		
Simple Average ($/kW)	13.080		
Intercept	15.597	24.8961	2.19E-113
Slope	-0.159	-5.0573	4.82E-07
R^2	0.01812		

Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	14.16	10.56	10.26	**13.08**	978	344	66	**1,388**
Net Total Capex - 2017 $/kW	15.45	16.37	17.56	**15.76**	979	326	63	**1,368**
Net Total O&M and Capex - 2017 $/kW	29.64	27.24	28.19	**29.00**	976	326	63	**1,365**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

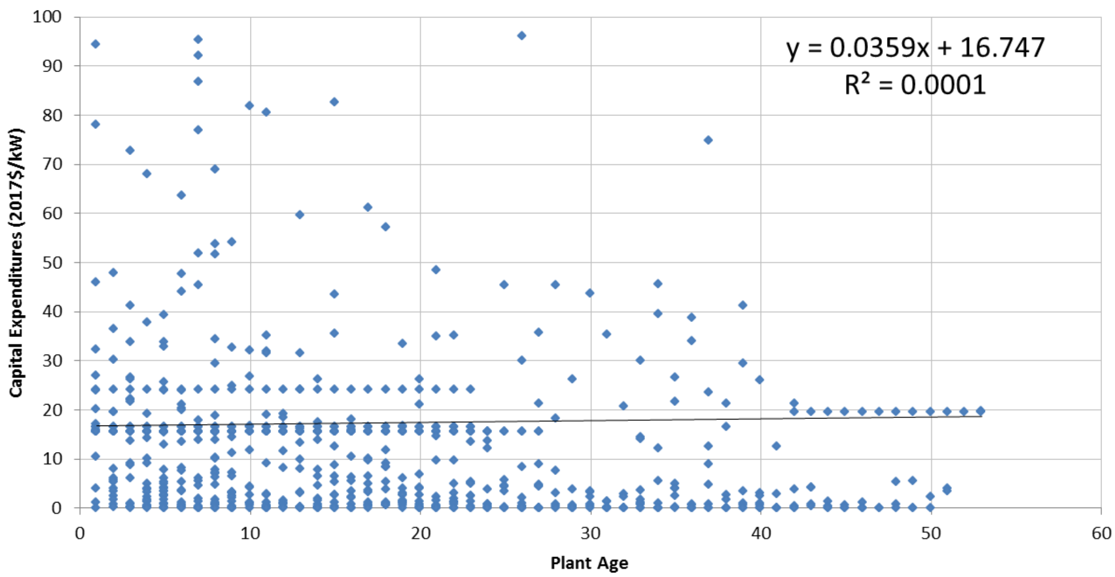
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants under 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.76, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-3 — Regression Statistics – CC CAPEX < 500 MW

		t statistic	*p-value*
Observations	765		
Simple Average ($/kW)	17.378		
Intercept	16.747	6.4870	1.57E-10
Slope	0.036	0.3007	7.64E-01
R^2	0.00012		

Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

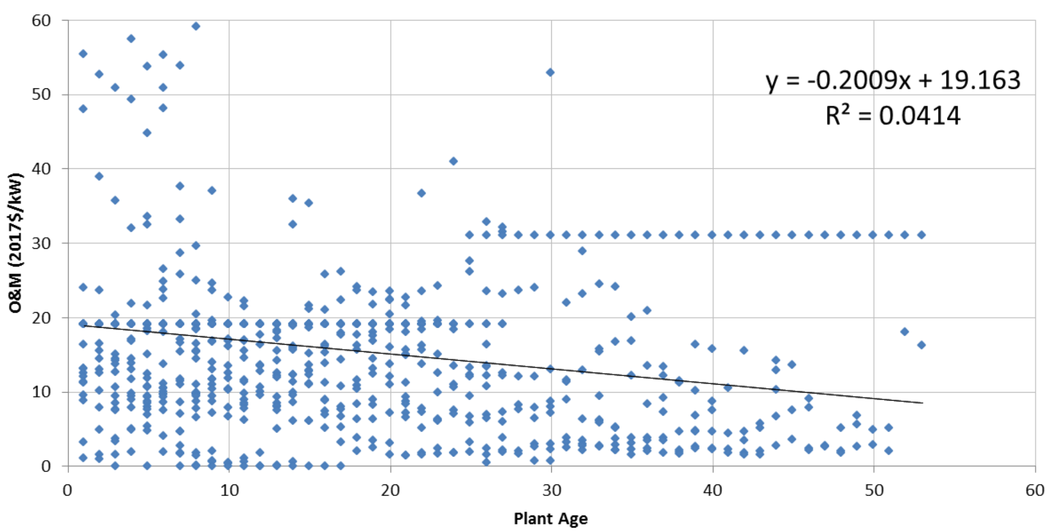
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of O&M spending for gas/oil CC plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-4 — Regression Statistics – CC O&M < 500 MW

		t statistic	*p-value*
Observations	766		
Simple Average ($/kW)	15.619		
Intercept	19.163	25.2973	4.82E-103
Slope	-0.201	-5.7467	1.31E-08
R^2	0.04143		

Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	17.10	13.01	12.27	**15.62**	498	216	52	**766**
Net Total Capex - 2017 $/kW	16.83	17.78	21.01	**17.38**	499	214	52	**765**
Net Total O&M and Capex - 2017 $/kW	34.00	30.72	33.28	**33.03**	497	214	52	**763**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

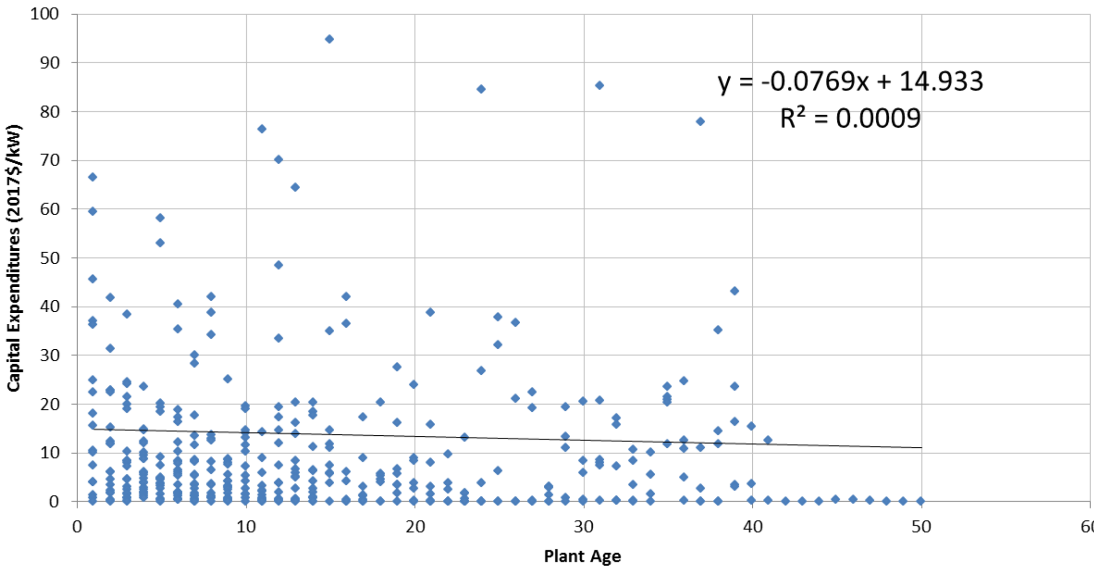
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.52, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	426		
Simple Average ($/kW)	13.780		
Intercept	14.933	6.3972	4.19E-10
Slope	-0.077	-0.6252	5.32E-01
R^2	0.00092		

Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

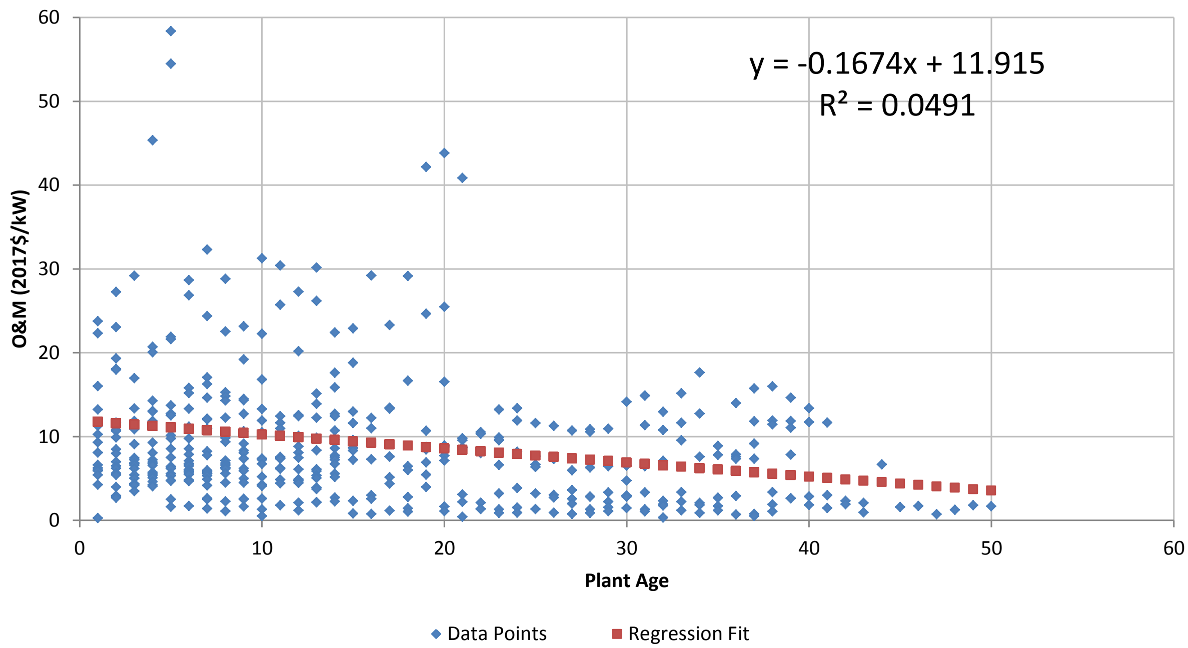
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	445		
Simple Average ($/kW)	9.269		
Intercept	11.915	17.1008	1.04E-50
Slope	-0.167	-4.7810	2.38E-06
R^2	0.04907		

Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	10.68	6.50	2.78	**9.27**	307	124	14	**445**
Net Total Capex - 2017 $/kW	14.38	13.36	1.28	**13.78**	307	108	11	**426**
Net Total O&M and Capex - 2017 $/kW	25.06	20.38	4.15	**23.33**	306	108	11	**425**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

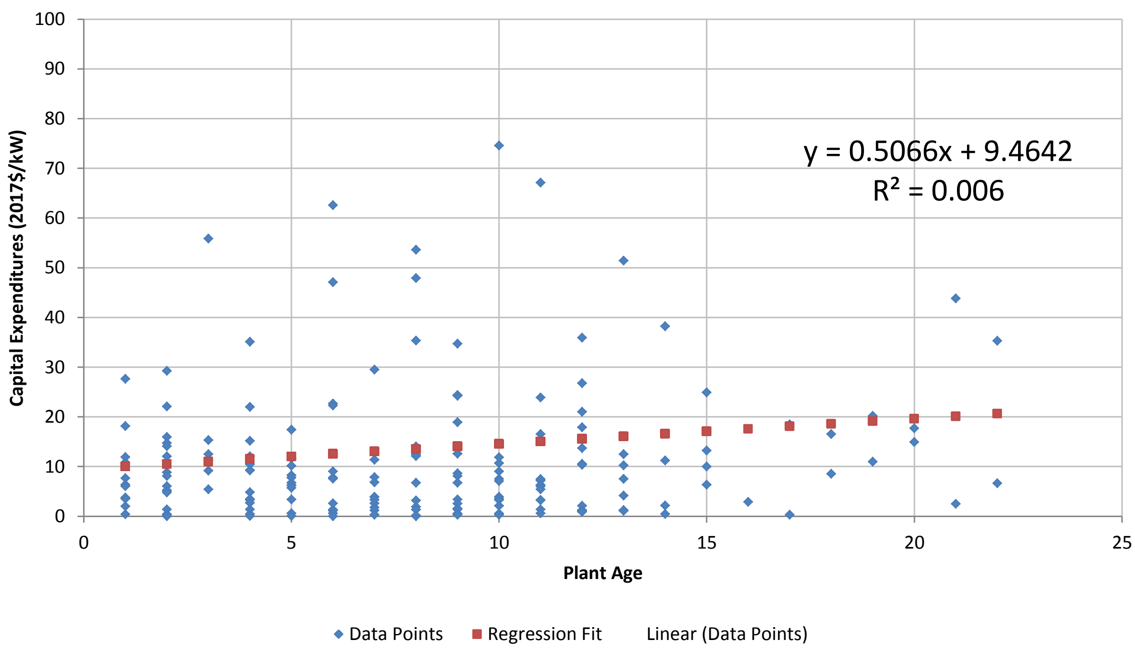
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.30, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW

		t statistic	*p-value*
Observations	177		
Simple Average ($/kW)	13.566		
Intercept	9.464	2.0308	4.38E-02
Slope	0.507	1.0309	3.04E-01
R^2	0.00604		

Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

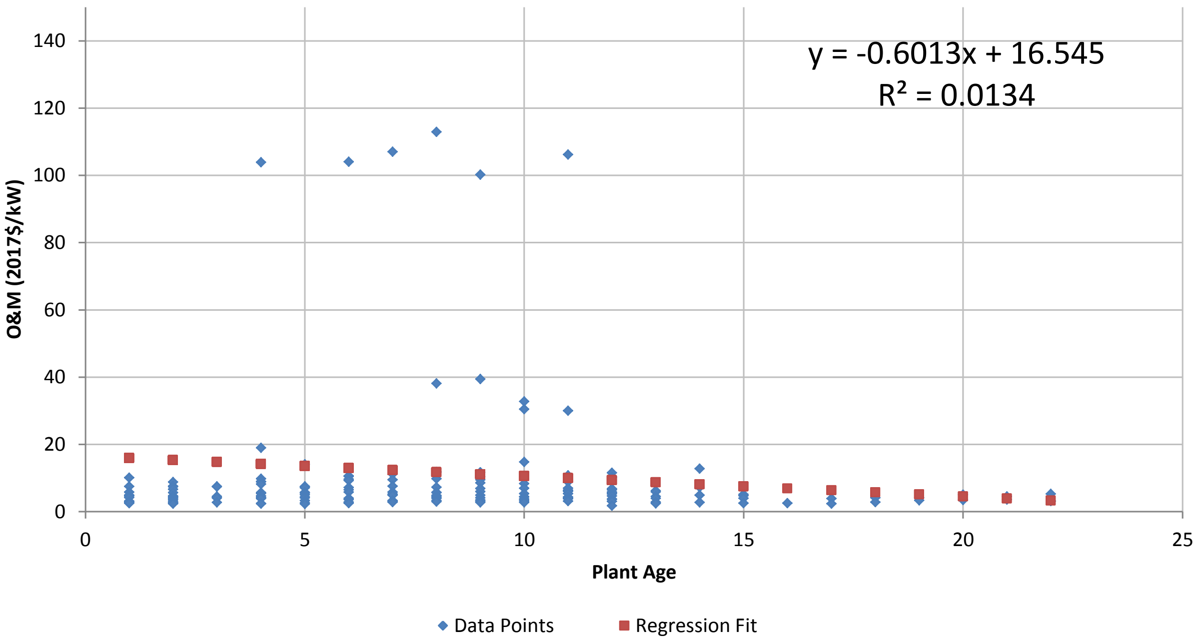
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.13, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table C-8 — Regression Statistics – CC O&M > 1,000 MW

		t statistic	*p-value*
Observations	177		
Simple Average ($/kW)	11.676		
Intercept	16.545	4.4651	1.43E-05
Slope	-0.601	-1.5389	1.26E-01
R^2	0.01335		

Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	11.85	4.14	-	**11.68**	173	4	0	**177**
Net Total Capex - 2017 $/kW	13.37	22.06	-	**13.57**	173	4	0	**177**
Net Total O&M and Capex - 2017 $/kW	25.22	26.20	-	**25.24**	173	4	0	**177**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

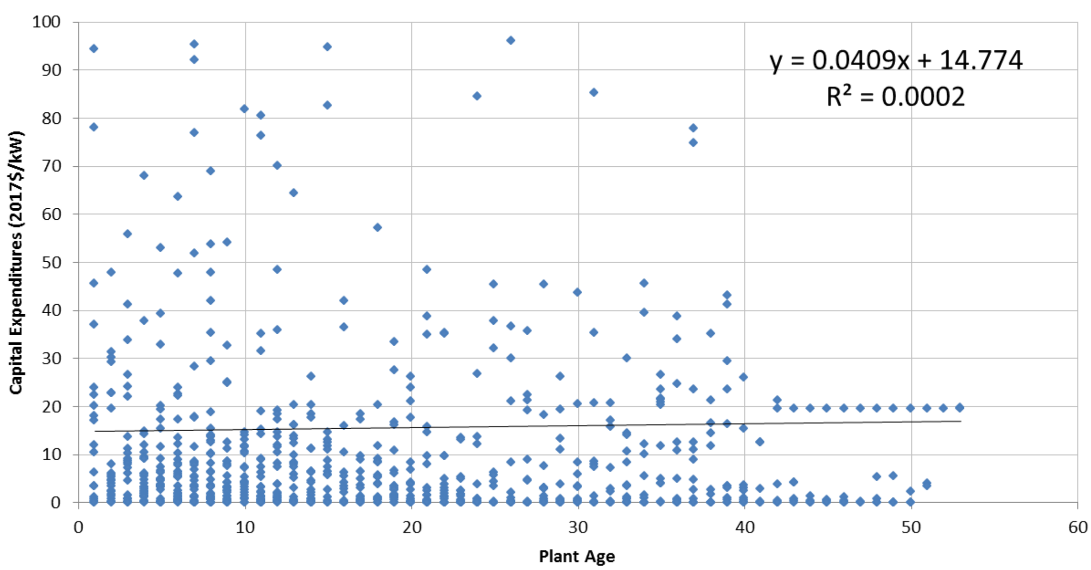
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.71, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50%

		t statistic	*p-value*
Observations	844		
Simple Average ($/kW)	15.554		
Intercept	14.774	5.7075	1.59E-08
Slope	0.041	0.3659	7.15E-01
R^2	0.00016		

Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50%

		t statistic	*p-value*
Observations	864		
Simple Average ($/kW)	10.791		
Intercept	12.292	13.9850	3.33E-40
Slope	-0.077	-2.0625	3.95E-02
R^2	0.00491		

Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50%

Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 0 - 50%								
Net Total O&M- 2017 $/kW	11.54	9.65	10.26	**10.79**	500	298	66	**864**
Net Total Capex - 2017 $/kW	15.35	15.46	17.56	**15.55**	501	280	63	**844**
Net Total O&M and Capex - 2017 $/kW	26.95	25.41	28.19	**26.53**	499	280	63	**842**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

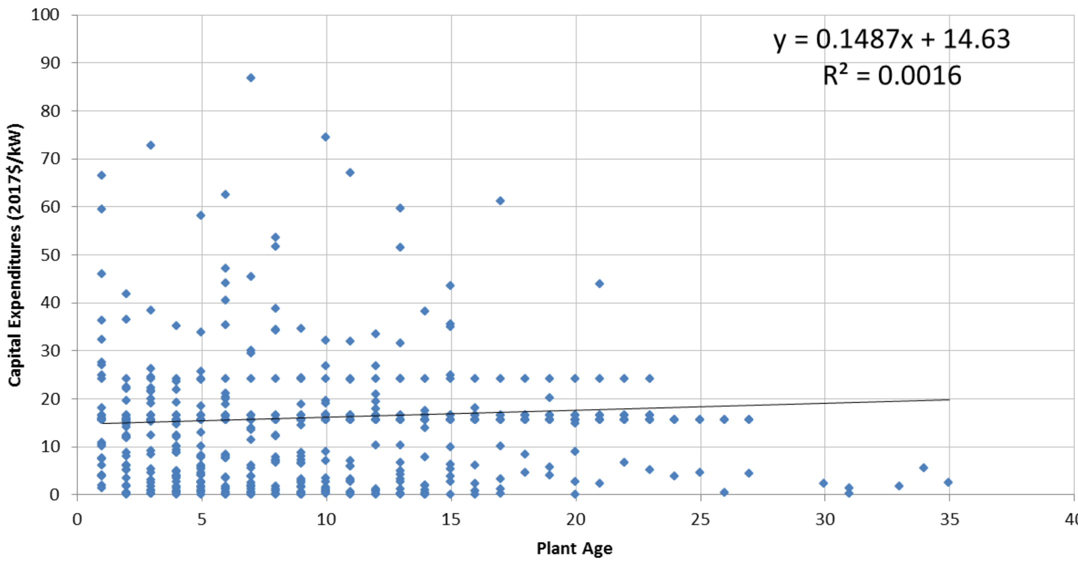
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.37, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50%

		t statistic	*p-value*
Observations	524		
Simple Average ($/kW)	16.104		
Intercept	14.630	7.3893	5.90E-13
Slope	0.149	0.9054	3.66E-01
R^2	0.00157		

Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

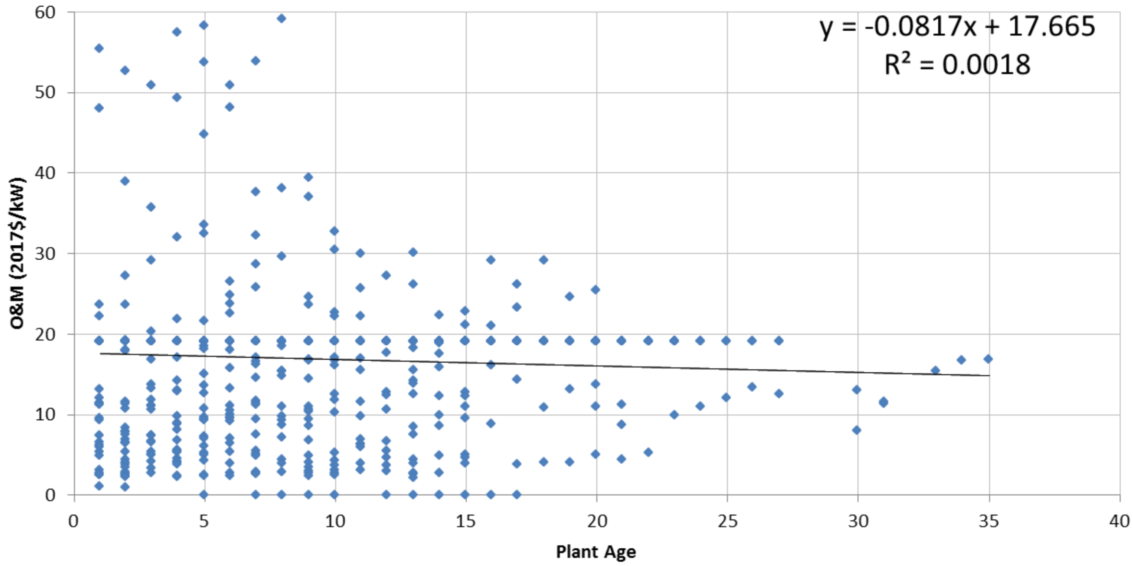
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below. Since the p-value for the age coefficient ("slope") is 0.33, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50%

		t statistic	*p-value*
Observations	524		
Simple Average ($/kW)	16.855		
Intercept	17.665	17.5298	1.93E-54
Slope	-0.082	-0.9777	3.29E-01
R^2	0.00183		

Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 50% - 100%								
Net Total O&M- 2017 $/kW	16.90	16.44	-	**16.85**	478	46	0	**524**
Net Total Capex - 2017 $/kW	15.55	21.89	-	**16.10**	478	46	0	**524**
Net Total O&M and Capex - 2017 $/kW	32.46	38.32	-	**32.98**	477	46	0	**523**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

Appendix D. Regression Analysis – Gas/Oil Combustion Turbine

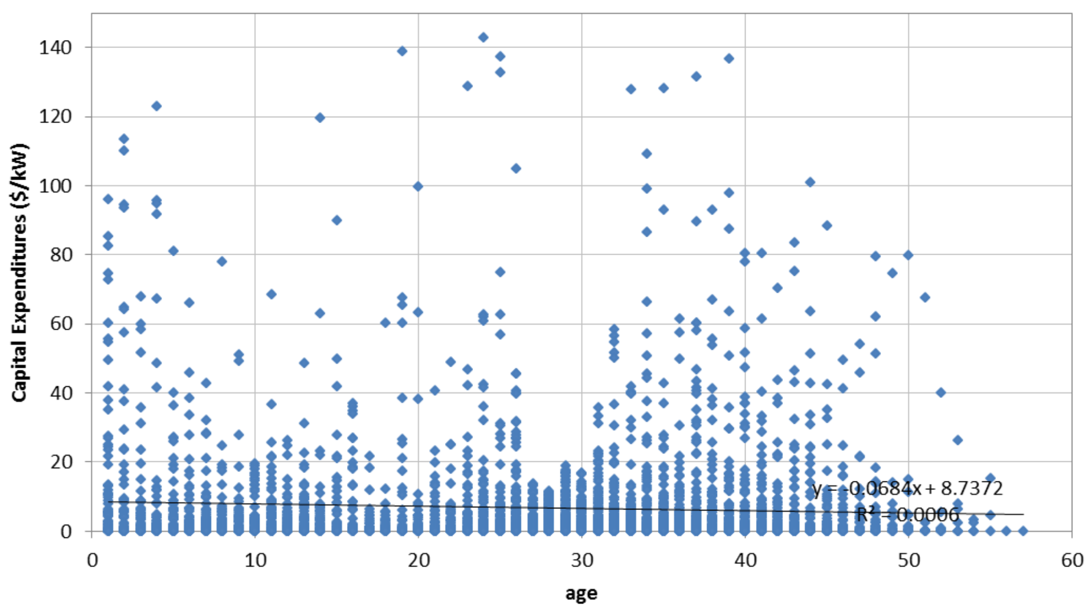
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.09, which is greater than 0.05, dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table D-1 — Regression Statistics – CT CAPEX for All MW

		t statistic	*p-value*
Observations	5065		
Simple Average ($/kW)	6.897		
Intercept	8.737	7.3087	3.12E-13
Slope	-0.068	-1.6948	9.02E-02
R^2	0.00057		

Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

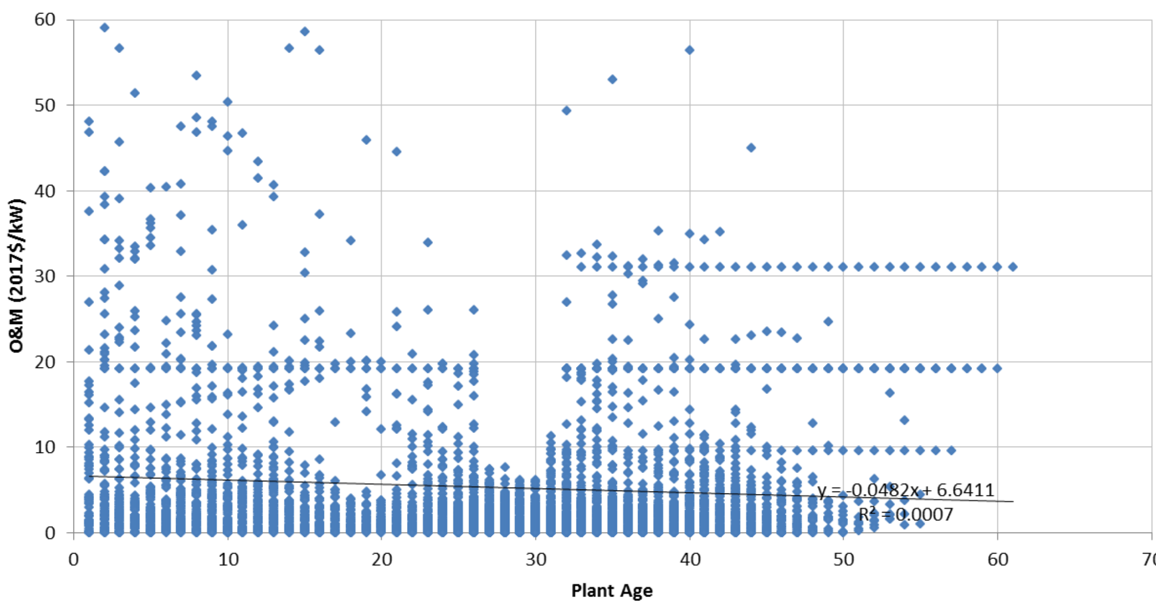
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of O&M spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.062, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-2 — Regression Statistics – CT O&M for All MW

		t statistic	*p-value*
Observations	5283		
Simple Average ($/kW)	5.331		
Intercept	6.641	8.5764	1.27E-17
Slope	-0.048	-1.8683	6.18E-02
R^2	0.00066		

Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	7.86	3.99	6.11	**5.33**	1,418	3,118	747	**5,283**
Net Total Capex - 2017 $/kW	9.17	5.78	7.40	**6.90**	1,360	3,054	651	**5,065**
Net Total O&M and Capex - 2017 $/kW	16.43	9.43	10.92	**11.49**	1,341	3,040	640	**5,021**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – LESS THAN 100 MW

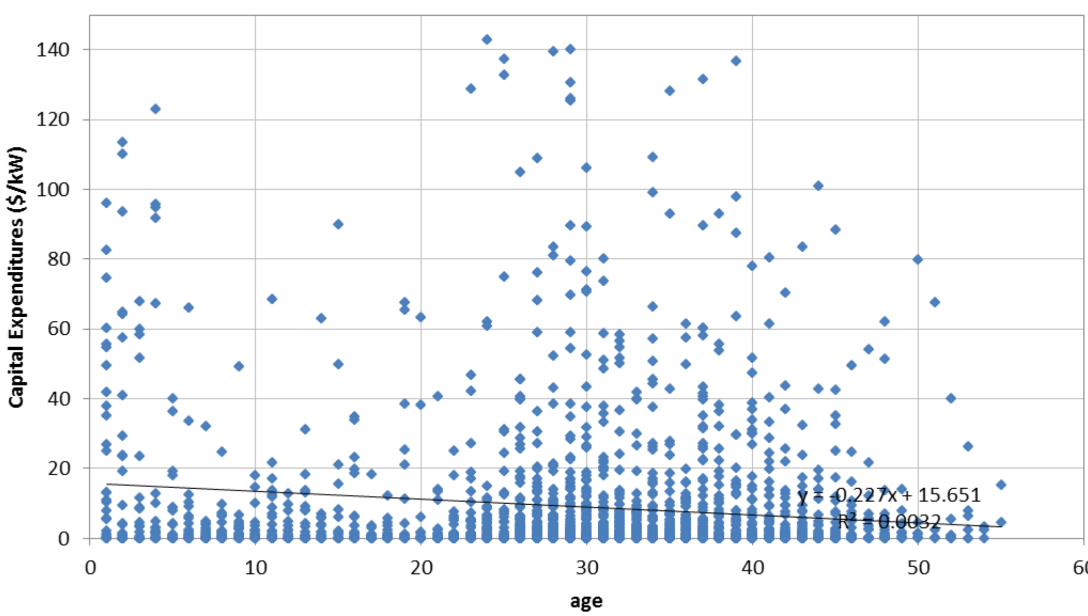
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 15.651 + (-0.227 × age)

Table D-3 — Regression Statistics – CT CAPEX < 100 MW

		t statistic	*p-value*
Observations	2,911		
Simple Average ($/kW)	9.003		
Intercept	15.651	6.6753	2.94E-11
Slope	-0.227	-3.0345	2.43E-03
R^2	0.00316		

Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size



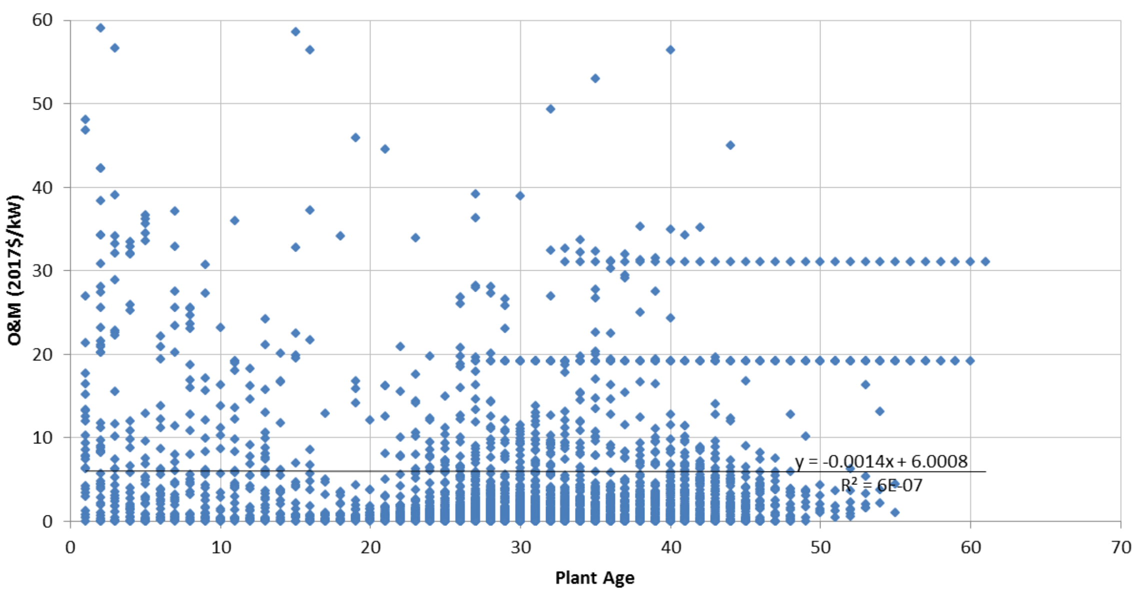
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

The results of the regression analysis of O&M spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.966, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-4 — Regression Statistics – CT O&M < 100 MW

		t statistic	*p-value*
Observations	3,062		
Simple Average ($/kW)	5.958		
Intercept	6.001	5.5008	4.09E-08
Slope	-0.001	-0.0423	9.66E-01
R^2	0.00000		

Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 100 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	8.76	4.93	7.40	**5.96**	489	2,060	513	**3,062**
Net Total Capex - 2017 $/kW	15.08	7.98	6.64	**9.00**	497	1,999	415	**2,911**
Net Total O&M and Capex - 2017 $/kW	24.04	12.31	10.26	**14.02**	489	1,978	406	**2,873**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

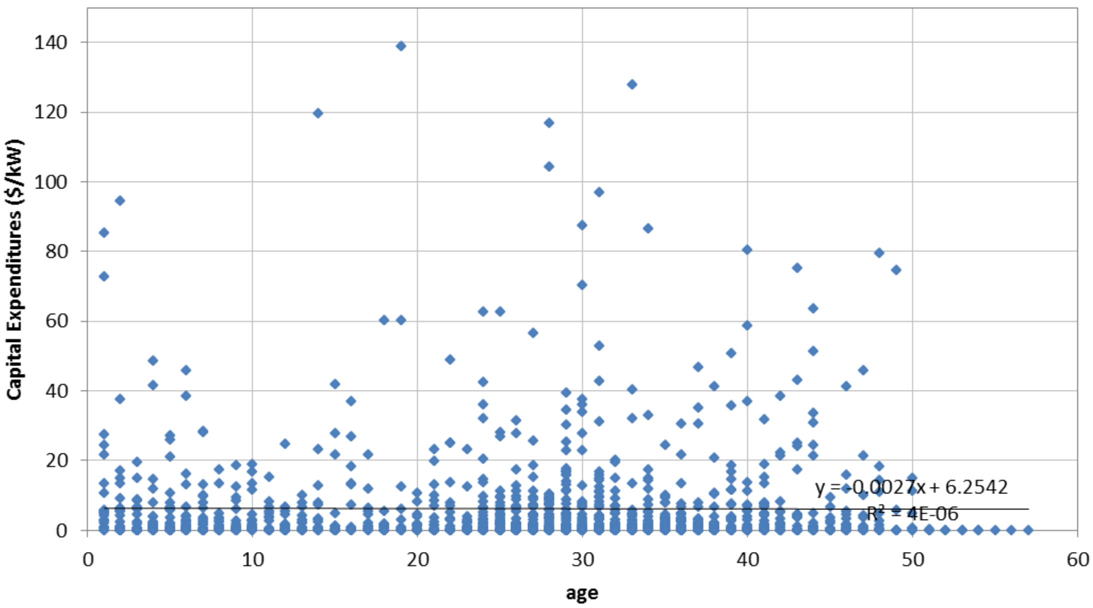
CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

The results of the regression analysis of CAPEX spending for CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.939, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW

		t statistic	*p-value*
Observations	1,350		
Simple Average ($/kW)	6.183		
Intercept	6.254	6.0376	2.02E-09
Slope	-0.003	-0.0768	9.39E-01
R^2	0.00000		

Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 100 MW AND 300 MW

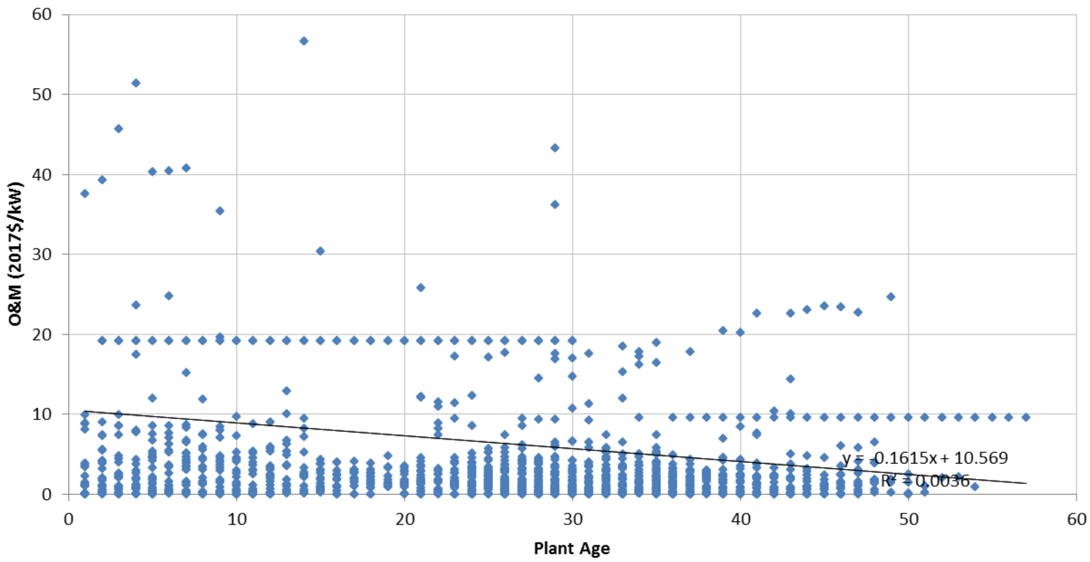
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.023, which is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 10.569 + (-0.162 × age)

Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW

		t statistic	*p-value*
Observations	1,416		
Simple Average ($/kW)	6.430		
Intercept	10.569	5.1759	2.59E-07
Slope	-0.162	-2.2723	2.32E-02
R^2	0.00364		

Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
100 MW - 300 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	9.97	5.18	3.24	**6.43**	442	794	180	**1,416**
Net Total Capex - 2017 $/kW	6.32	6.07	6.38	**6.18**	407	762	181	**1,350**
Net Total O&M and Capex - 2017 $/kW	15.14	9.09	9.66	**10.98**	402	759	180	**1,341**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – GREATER THAN 300 MW

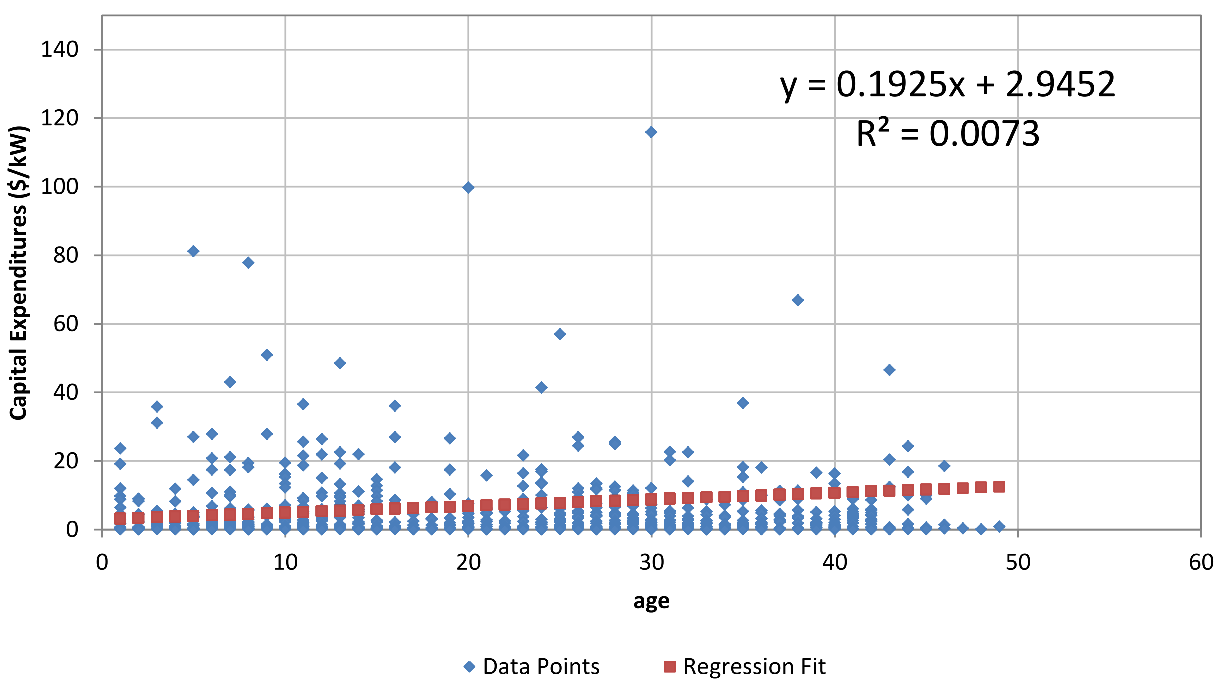
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.010, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 2.945 + (0.193 × age)

Table D-7 — Regression Statistics – CT CAPEX > 300 MW

		t statistic	*p-value*
Observations	909		
Simple Average ($/kW)	6.952		
Intercept	2.945	1.6382	1.017E-01
Slope	0.193	2.5842	0.010
R^2	0.00731		

Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size



OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 300 MW

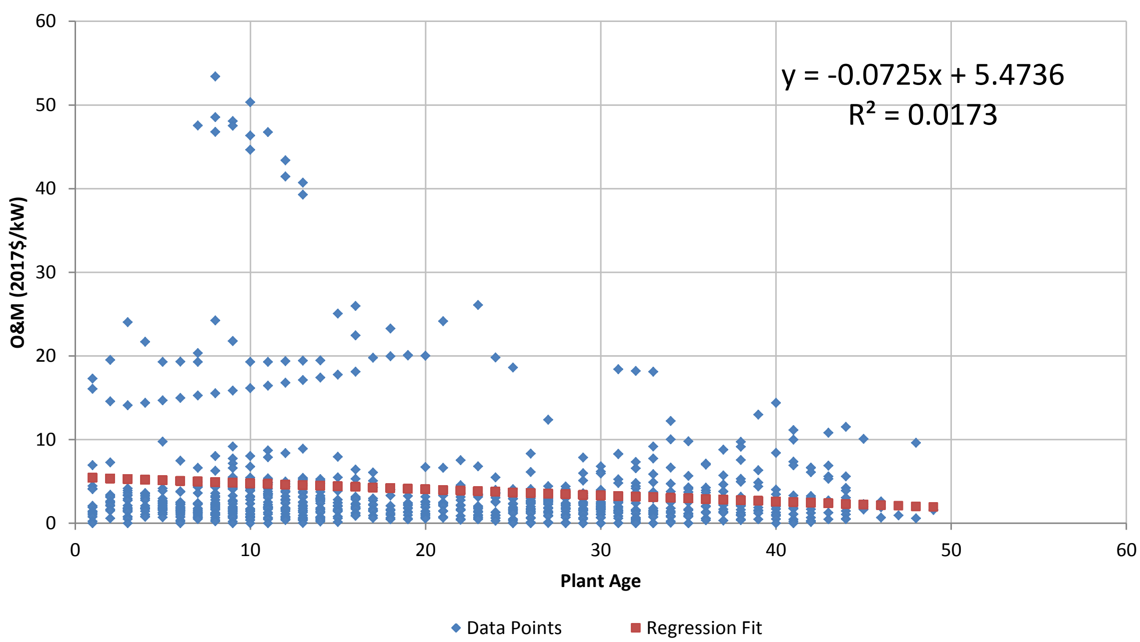
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 5.474 + (-0.072 × age)

Table D-8 — Regression Statistics – CT O&M > 300 MW

		t Statistic	*p-value*
Observations	938		
Simple Average ($/kW)	3.994		
Intercept	5.474	12.8980	3.75E-35
Slope	-0.072	-4.0612	5.29E-05
R^2	0.01732		

Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 300 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	5.03	2.78	3.46	**3.99**	488	396	54	**938**
Net Total Capex - 2017 $/kW	5.26	7.58	16.50	**6.95**	457	397	55	**909**
Net Total O&M and Capex - 2017 $/kW	9.30	10.38	20.11	**10.42**	451	396	54	**901**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

Appendix E. Regression Analysis – Conventional Hydroelectric

CAPITAL EXPENDITURES – ALL PLANT SIZES

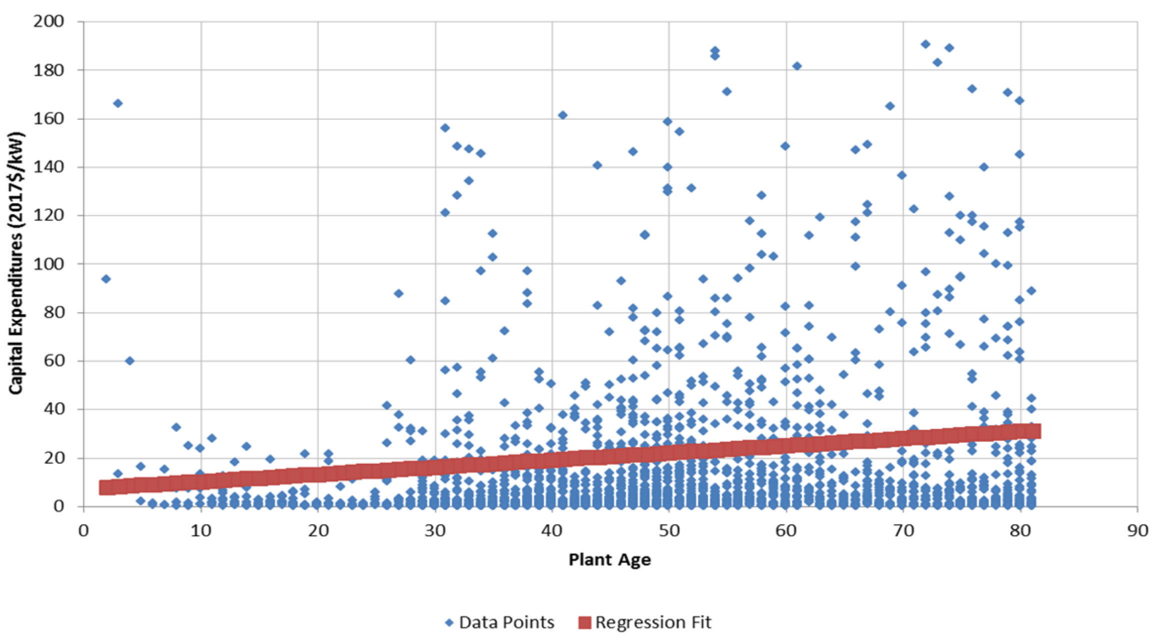
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)

Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW

		t statistic	*p-value*
Observations	2180		
Simple Average ($/kW)	21.999		
Intercept	7.269	1.4681	1.42E-01
Slope	0.296	3.1441	1.69E-03
R^2	0.00452		

Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes



OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

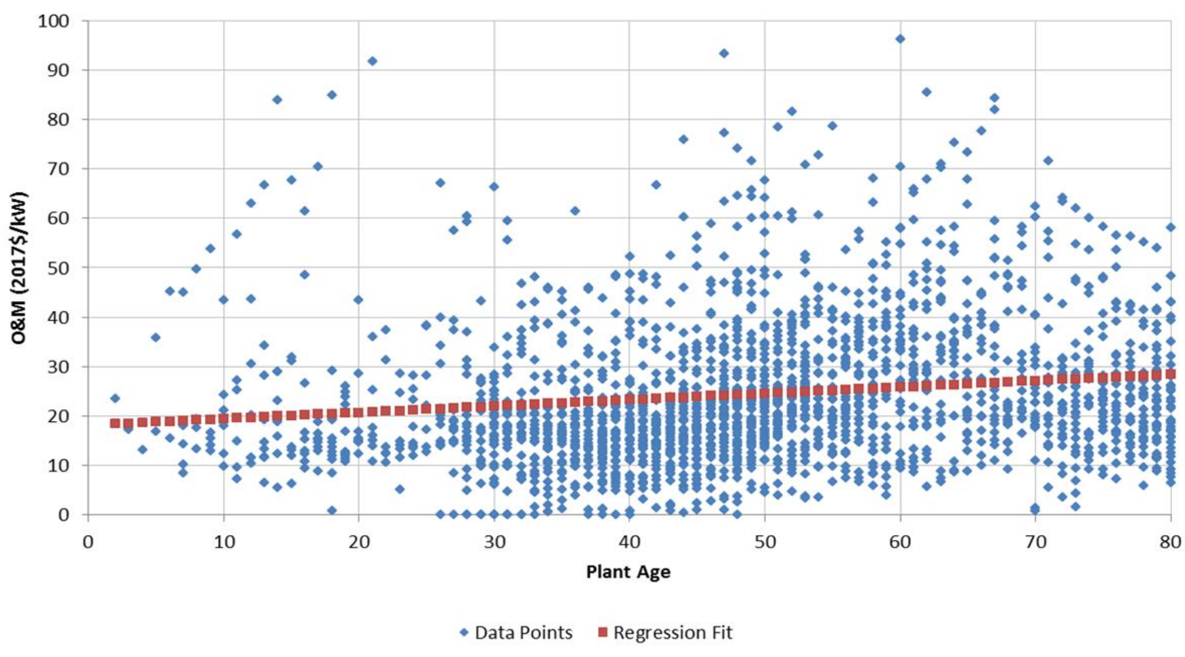
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)

Table E-2 — Regression Statistics – Hydroelectric O&M for All MW

		t statistic	*p-value*
Observations	1,272		
Simple Average ($/kW)	24.473		
Intercept	22.360	13.7360	3.92E-40
Slope	0.073	2.5053	1.24E-02
R^2	0.00492		

Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes



Appendix F. Regression Analysis – Pumped Hydroelectric Storage

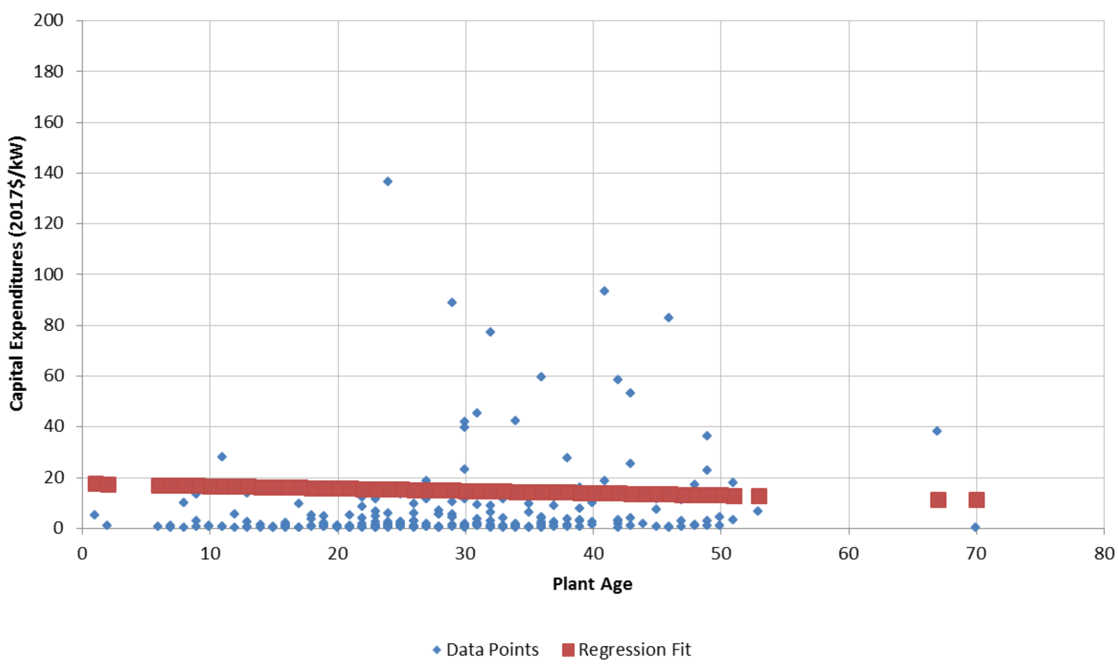
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW

		t statistic	*p-value*
Observations	227		
Simple Average ($/kW)	11.398		
Intercept	-6.907	-0.4501	6.53E-01
Slope	0.743	1.2723	2.06E-01
R^2	0.01278		

Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

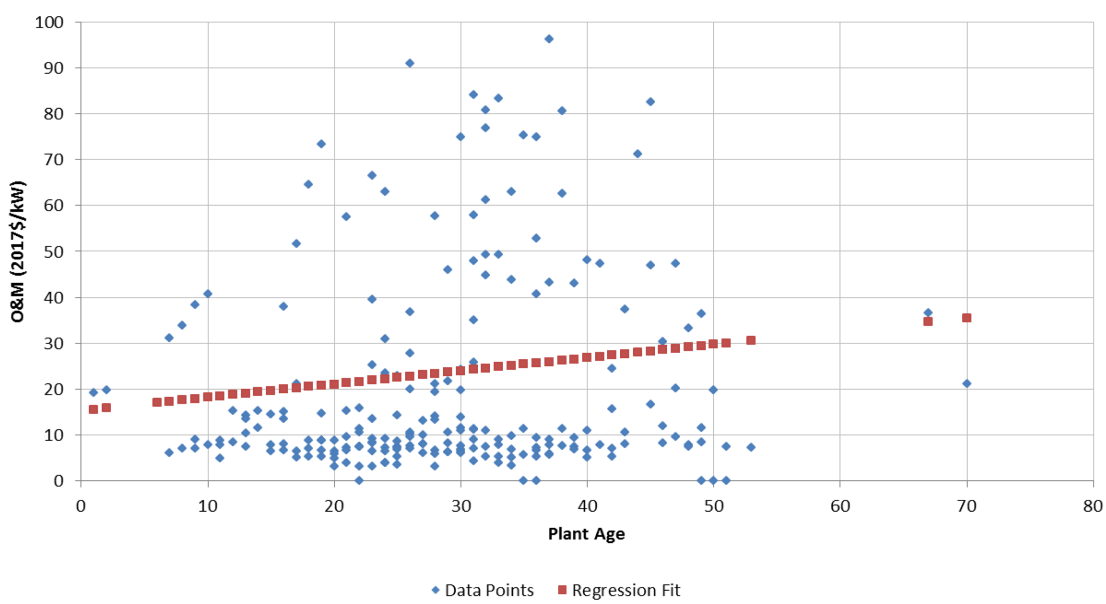
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW

		t statistic	*p-value*
Observations	226		
Simple Average ($/kW)	23.634		
Intercept	15.296	2.9021	4.08E-03
Slope	0.288	1.7010	9.03E-02
R^2	0.01275		

Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	18.97	23.41	31.00	**23.63**	50	140	36	**226**
Net Total Capex - 2017 $/kW	22.94	11.93	14.92	**14.83**	50	141	36	**227**
Net Total O&M and Capex - 2017 $/kW	41.91	35.34	45.92	**38.46**	--	--	--	--

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing pumped hydroelectric storage plants are described in Section 8.

Appendix G. Regression Analysis – Solar Photovoltaic

CAPITAL EXPENDITURES

Annual CAPEX, labeled in FERC Form 1 as TCP, are broken down into subcategories, including:

- Land & Land Rights
- Structures & Improvements
- Reservoirs, Dams & Waterways
- Water Wheels
- Turbines & Generators
- Accessory Electric Equipment
- Equipment
- Asset Retirement Costs
- Roads, and Railroads & Bridges

These subcategories are based on traditional power generation technologies and have minimal applicability to solar PV. Expected CAPEX for solar PV, such as inverter replacement and repair or module replacement, are clearly not applicable to any of the categories listed in FERC Form 1.

In the FERC Form 1 data, only 10 of the solar PV sites had a breakdown of TCP into the above subcategories, with even fewer providing such a breakdown for more than one year. As discussed in Section 9, the year-over-year change in TCP is the sole source of annual CAPEX information in FERC Form 1. Of this data, Sargent & Lundy determined that a significant portion of it needed to be filtered out due to the following reasons:

- A negative change in the TCP between two consecutive years
- A change in the capacity of the plant greater than 20%
- A significant increase in TCP without a capacity increase
- Large unexplained fluctuations (e.g., negative to positive) in TCP from year to year
- Large gaps in annual data

After filtering out clearly suspect data, about one-third of the remaining data was for plants having only three years of data or less. In addition, many of the plants reported no changes in TCP, suggesting that most annual expenditures at those sites were being reported as O&M rather than being capitalized.

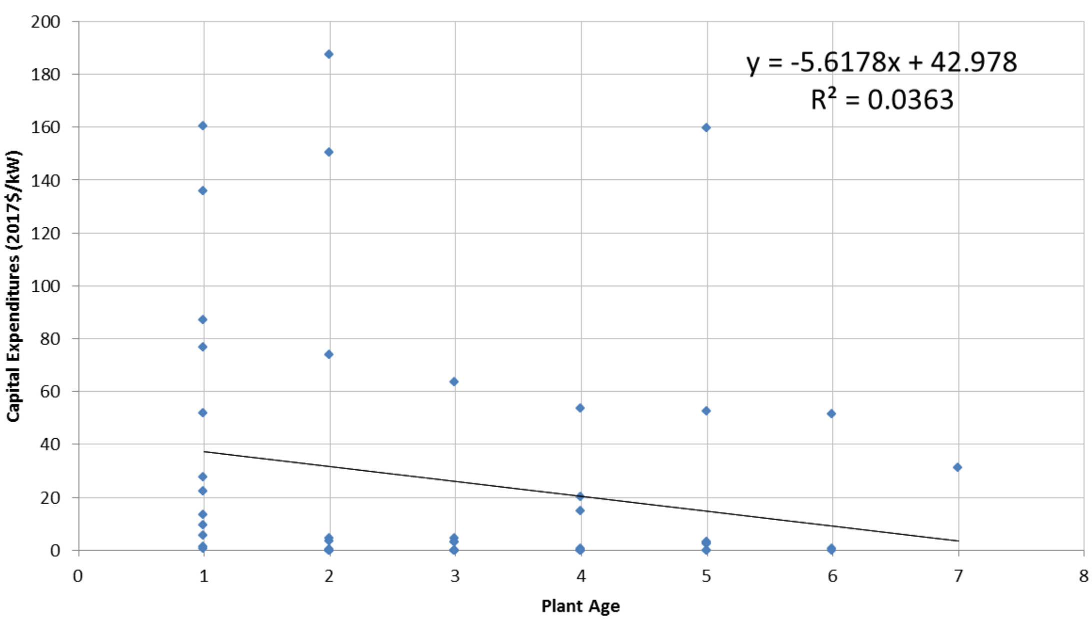
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately $26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, such as inverter or module replacement, or other factors.

The results of the linear regression analysis of CAPEX spending for solar PV plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.16, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). In addition, as indicated in the table below, there are a relatively small number of data points for CAPEX (less than 60 points). The average CAPEX across all years is approximately $26/kW-year (2017 dollars).

Table G-1 — Regression Statistics – Solar PV CAPEX for All MW

		t statistic	*p-value*
Observations	57		
Simple Average ($/kW)	26.026		
Intercept	42.978	3.2248	2.12E-03
Slope	-5.618	-1.4387	1.56E-01
R^2	0.03627		

Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

The total production cost, which is the sum of the total operating expense and total maintenance expense, was reported for slightly over half of the sites. Of the sites reporting, several sites only reported this data in certain years, leaving gaps in the data. Subcategories for operating costs and maintenance cost were provided in the FERC Form 1 data, but rarely was the reported data broken into subcategories.

Sargent & Lundy organized the FERC Form 1 data into two presentation formats. In the first format, the annual O&M cost was averaged across all years of the reported data to obtain the average annual O&M cost per plant. This resulted in approximately 60 data points. In the second format, the annual O&M cost was averaged across each year of operation. This resulted in approximately 200 data points. The average O&M cost results are not equal between the two presentation formats. Table G-2 provides a simple example of these differing results, using FERC Form 1 O&M data from three plants.

Table G-2 — Example of Calculation Method Differences

	O&M Cost ($/kW-year)															
Age (Years)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**Plant Average**
Example Plant 1	127.8	0.0	0.1	0.0	-	-	-	-	-	-	-	-	-	-	-	32.0
Example Plant 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Example Plant 3	32.2	15.3	24.8	-	-	-	-	-	-	-	-	-	-	-	-	24.1

Example Average (All Data Points)	9.1
Example Average (of Plant Averages)	18.7

In the example above, a single plant with more data points is able to sway the average O&M cost across the three plants. The values calculated below are based on averaged data points (i.e., a data point is the average annual O&M cost across the reported data for a given plant).

Figure G-2 and Figure G-3 show the average site O&M cost, expressed in $/MWh, for sites with a capacity less than 5 MW and greater than 5 MW, respectively. In general, these figures show a high level of variability across sites, with smaller sites having a higher O&M cost per MWh produced. Several data points were for sites having very low capacity factors (less than 5%), which also results in higher O&M costs per MWh. For the sites greater than 5 MW, the average O&M cost was $8.5/MWh. When expressed on the basis of cost per kW of capacity (see Figure G-4 and Figure G-5), the average O&M for sites greater than 5 MW was $15/kW-year.

Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW)

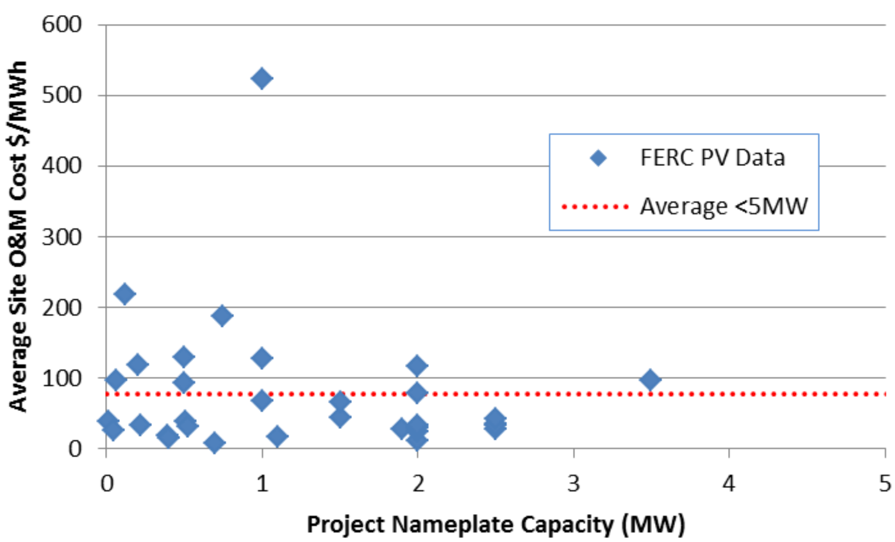


Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)

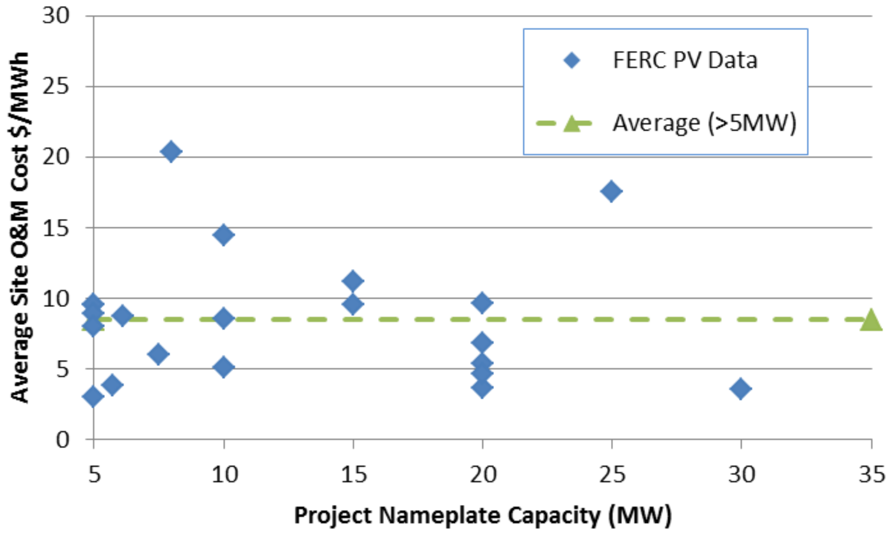


Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)

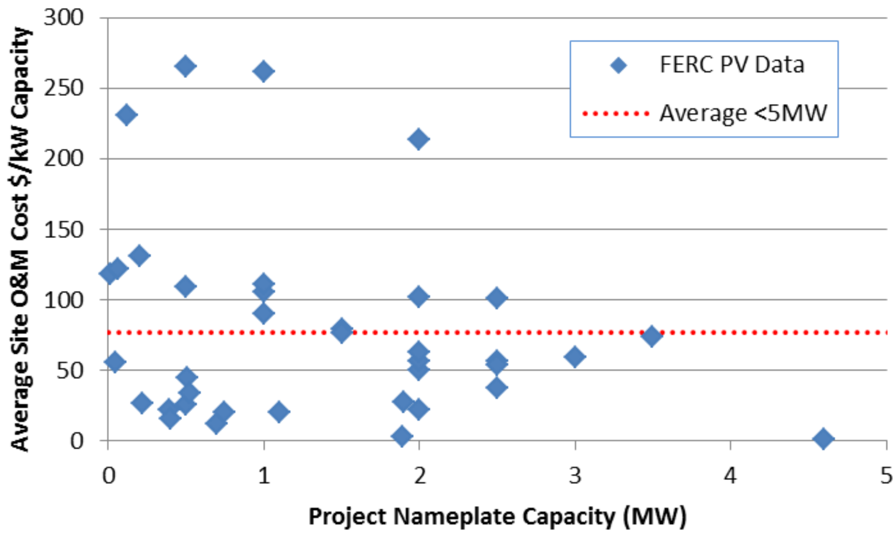
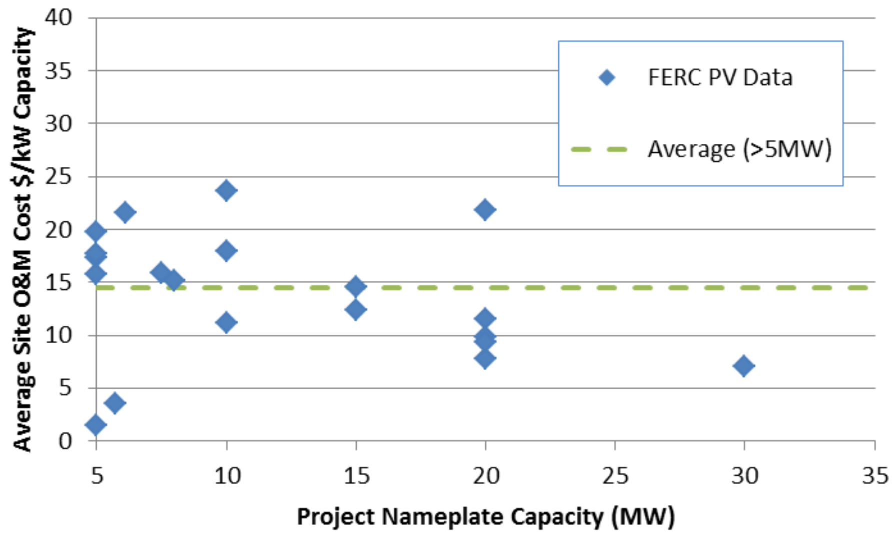


Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)



The figures below show the annual site O&M cost (in $/MWh and $/kW-year) versus the age of the project. In general, little correlation can be seen between age and O&M cost.

Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project

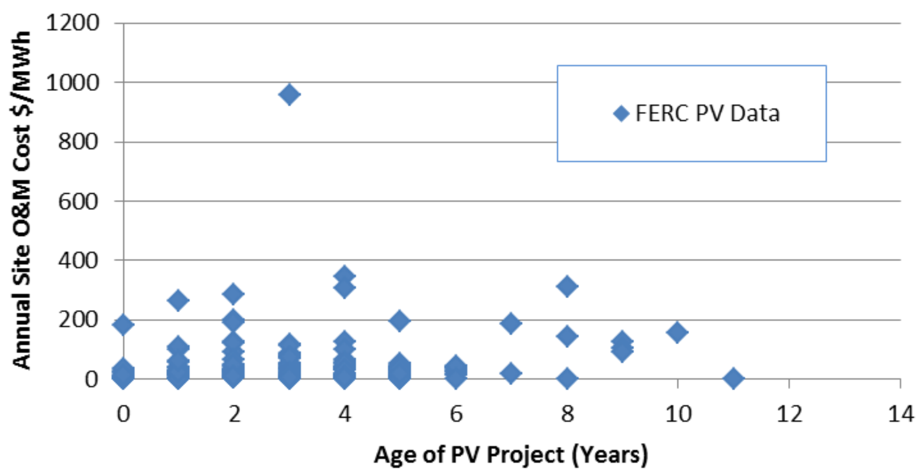
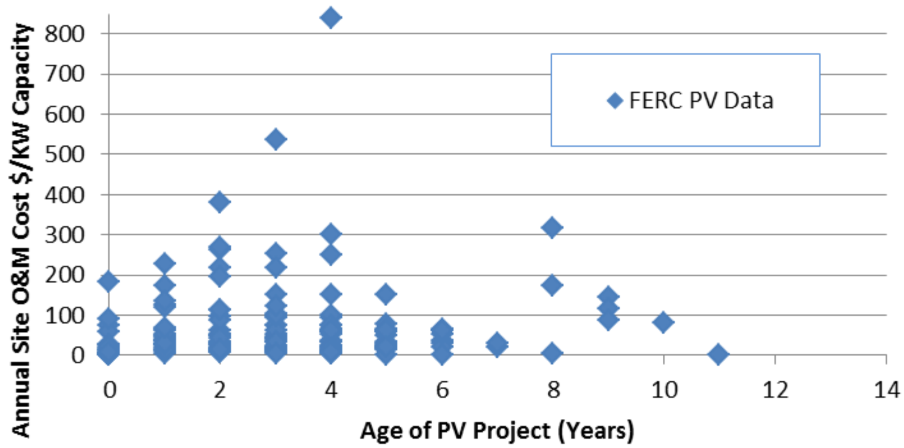


Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project



Sargent & Lundy compiled O&M data from other sources in Table G-3 below for comparison against the FERC data. In general, the O&M costs in $/kW-year capacity are in the same range as the FERC data for sites over 5-MW capacity.

Table G-3 — Summary of Industry O&M Cost Data for Solar PV

O&M Cost Sources	O&M Cost $/kW-yr	Notes	Report Source Data Year
NREL & Sunshot	15	Fixed	2015
NREL & Sunshot	18	Single-Axis Tracking	2015
Sunshot + NREL	20.5	Good O&M	2016
Sunshot + NREL	25.0	Optimal O&M	2016
IRENA Power to Change	10	Minimum	2015
IRENA Power to Change	18	Maximum	2015
Utility Scale Solar	17	Overall	2014
Utility Scale Solar 2016	7	Minimum	2016
Utility Scale Solar 2016	27	Maximum	2016
Utility Scale Solar 2016	18	Mean	2016
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017	15.4	Fixed LCOE Assumption	2017
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018	18.5	SAT LCOE Assumption	2017

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing solar PV plants are described in Section 9.

Appendix H. Regression Analysis – Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

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Appendix I. Regression Analysis – Geothermal

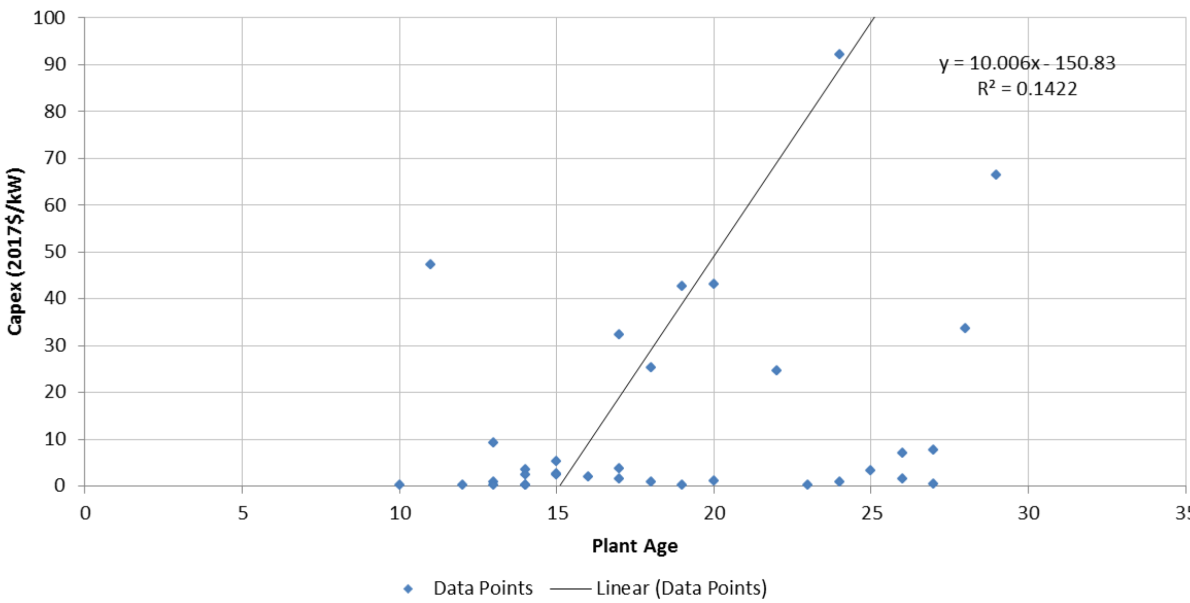
CAPITAL EXPENDITURES

The results of the linear regression analysis of CAPEX spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Although the p-value is less than 0.05, the dataset is inconclusive because the intercept is negative due to no plants reporting data between ages and 0 and 10.

Table I-1 — Regression Statistics – Geothermal CAPEX for All MW

		t statistic	*p-value*
Observations	36		
Simple Average ($/kW)	40.948		
Intercept	-150.830	-1.7907	8.23E-02
Slope	10.006	2.3736	2.34E-02
R^2	0.14215		

Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes



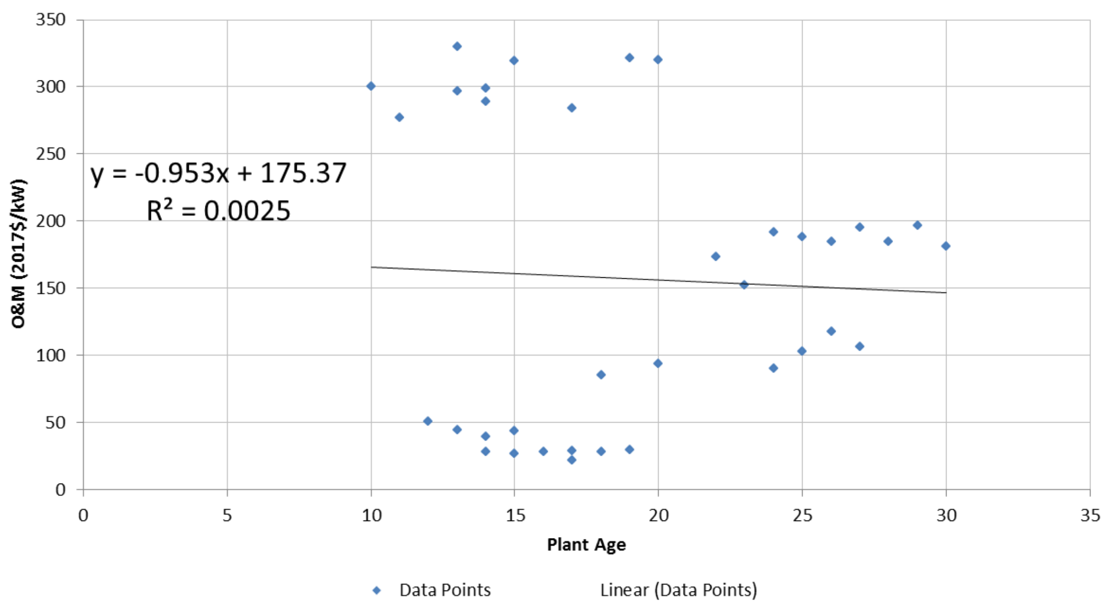
OPERATIONS & MAINTENANCE EXPENDITURES

The results of the linear regression analysis of O&M spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.071, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table I-2 — Regression Statistics – Geothermal O&M for All MW

		t Statistic	*p-value*
Observations	36		
Simple Average ($/kW)	157.103		
Intercept	175.369	2.6984	1.08E-02
Slope	-0.953	-0.2930	7.71E-01
R^2	0.00252		

Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table I-3 — Geothermal All MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (Years 21-25)	Average $/kW-yr (Years 26-30)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (Years 21-25)	Data Points (Years 26-30)	Data Points (All Years)
All MW, All Capacity Factors														
Net Total O&M – 2017 $/kW-yr	--	300.62	170.44	124.24	149.97	166.77	**157.10**	--	1	12	10	6	7	**36**
Net Total CAPEX – 2017 $/kW-yr	--	--	72.05	30.16	27.64	114.45	**40.94**	--	1	12	10	6	7	**36**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing geothermal plants are described in Section 11.

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Appendix J. Regression Analysis – Wind

CAPITAL EXPENDITURES

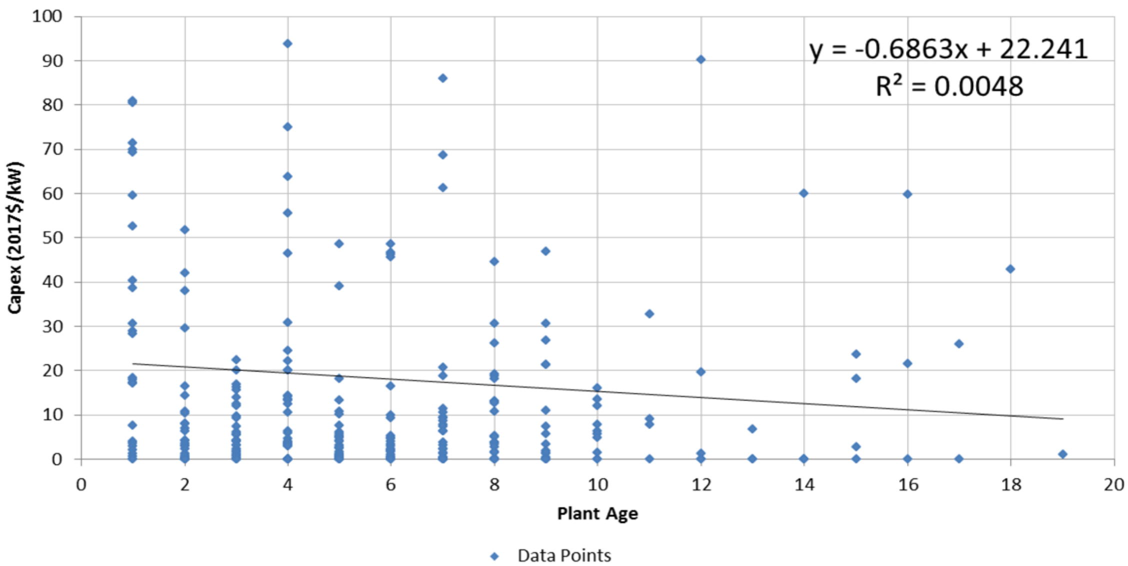
Full Dataset

The results of the linear regression analysis of CAPEX spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-1 — Regression Statistics – Wind CAPEX for All MW

		t Statistic	*p-value*
Observations	310		
Simple Average ($/kW)	18.285		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R^2	0.00480		

Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-2 — Wind All MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
All MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	21.06	10.97	32.62	21.60	**18.29**	168	112	23	7	**310**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

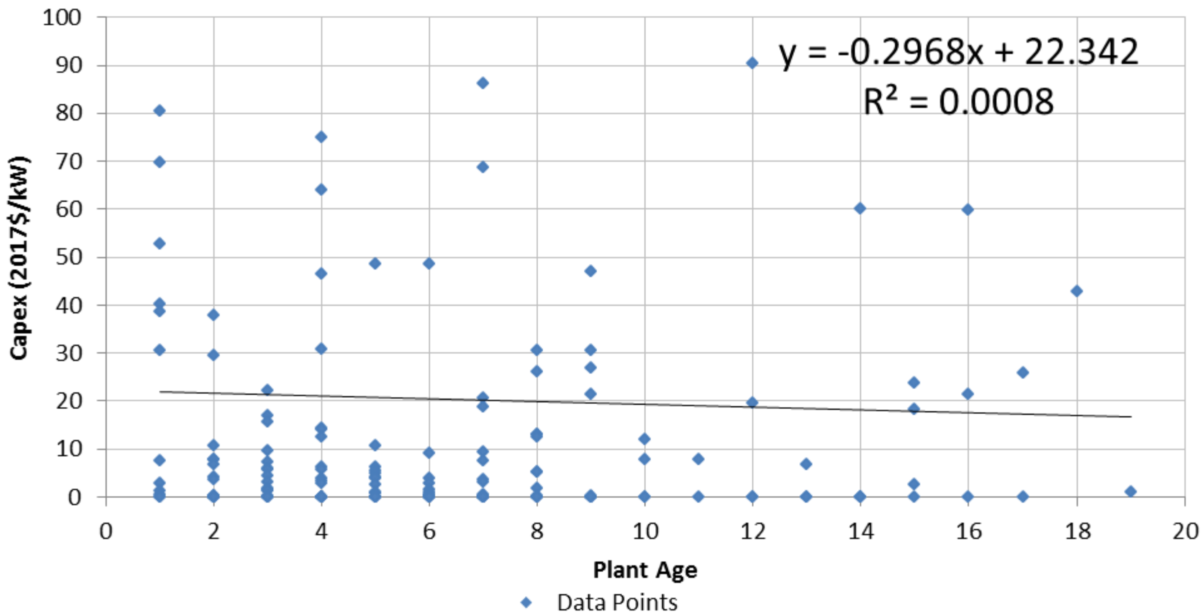
0-100 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.706, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, a more appropriate predictor of CAPEX spending for this dataset is a simple average by plant age band, as discussed in Section 12.

Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW

		t Statistic	*p-value*
Observations	174		
Simple Average ($/kW)	20.483		
Intercept	22.342	3.7750	2.20E-04
Slope	-0.297	-0.3779	7.06E-01
R^2	0.00083		

Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-4 — Wind < 100-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
< 100 MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	22.83	11.62	35.35	21.60	**20.48**	89	58	20	7	**174**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

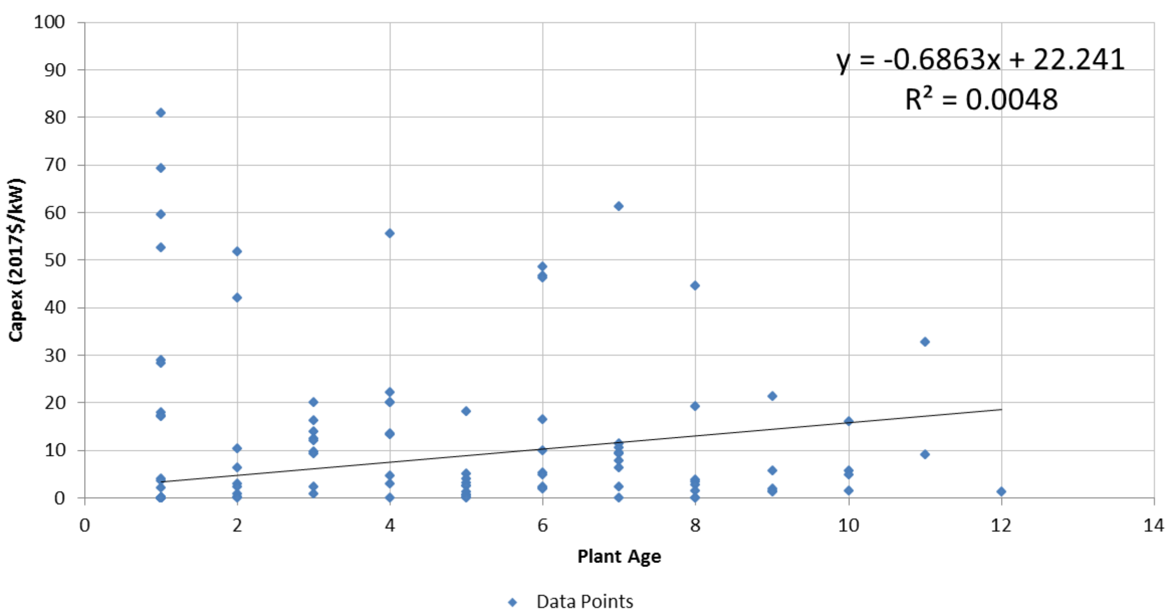
100-200 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 100 MW and 200 MW are summarized in the table below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW

		t Statistic	*p-value*
Observations	310		
Simple Average ($/kW)	16.935		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R^2	0.00480		

Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-6 — Wind 100-200-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
100 - 200 MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	20.36	12.20	14.41	--	**16.93**	52	36	3	--	**91**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

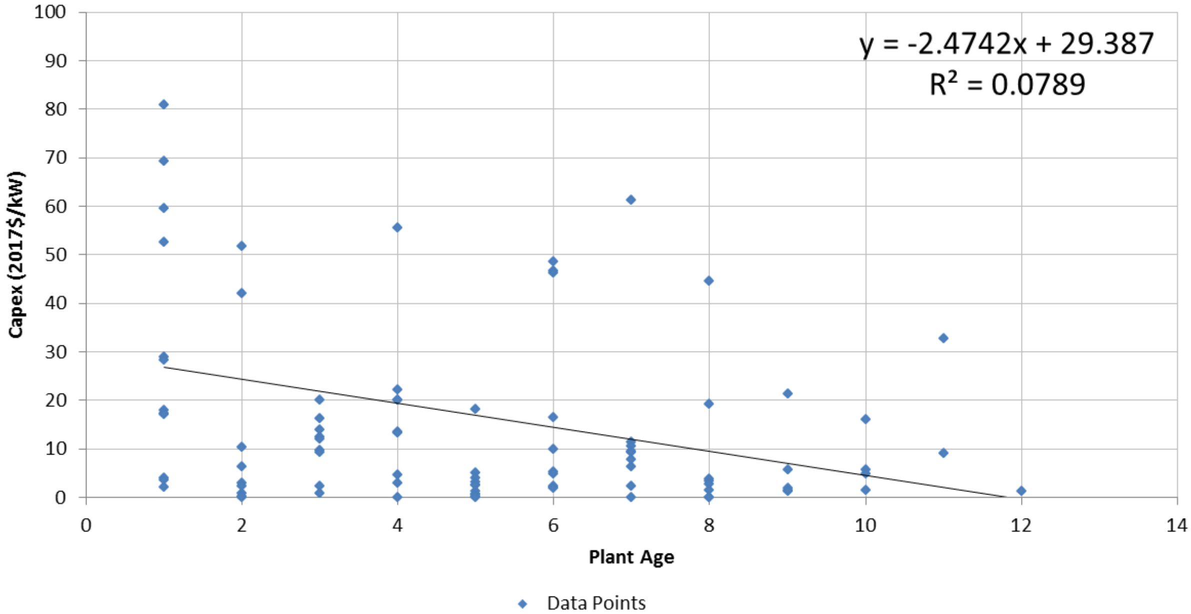
Greater than 200 MW

The results of the linear regression analysis of CAPEX spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.006, which is less than 0.05, the dataset does support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, a visual inspection of the data in the graph below shows that there are a limited number of data points over 10 years, which may be skewing the regression.

Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW

		t Statistic	*p-value*
Observations	91		
Simple Average ($/kW)	16.935		
Intercept	29.387	5.6538	1.87E-07
Slope	-2.474	-2.7612	6.99E-03
R^2	0.07891		

Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes



The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-8 — Wind Greater than 200-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (All Years)
> 200 MW, All Capacity Factors						
Net Total CAPEX – 2017 $/kW-yr	**16.61**	**8.65**	**13.48**	31	20	**51**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

OPERATIONS & MAINTENANCE EXPENDITURES

Full Dataset

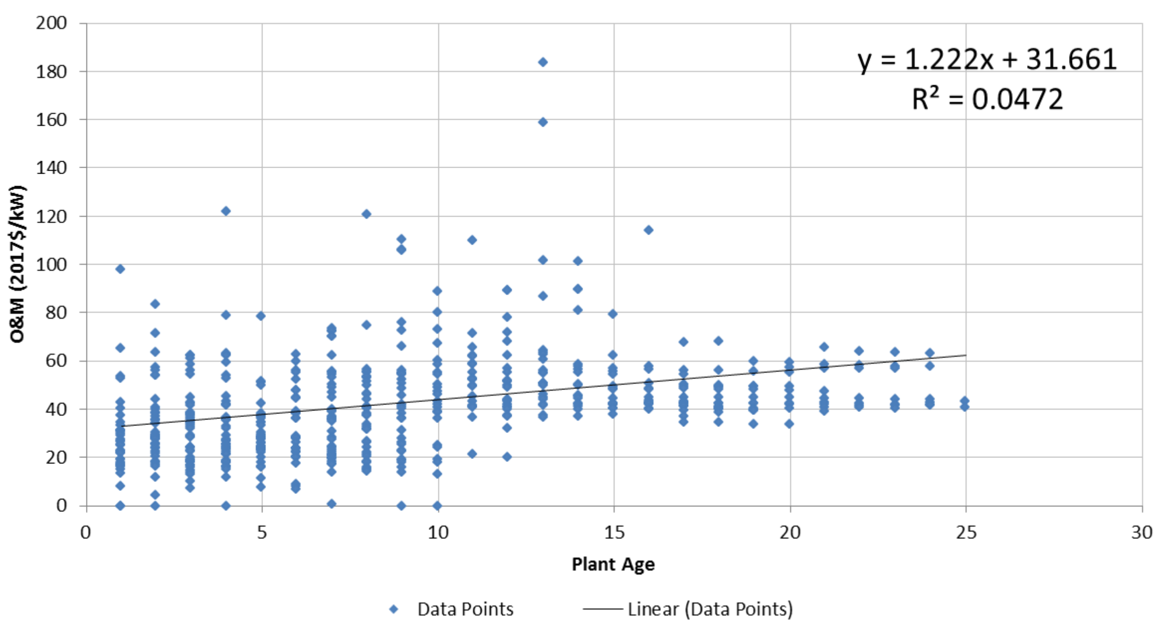
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 31.661 + (1.222 × age)

Table J-9 — Regression Statistics – Wind O&M for All MW

		t statistic	*p-value*
Observations	580		
Simple Average ($/kW)	42.680		
Intercept	31.661	12.7763	4.24E-33
Slope	1.222	5.3515	1.26E-07
R^2	0.04721		

Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes



0-100 MW

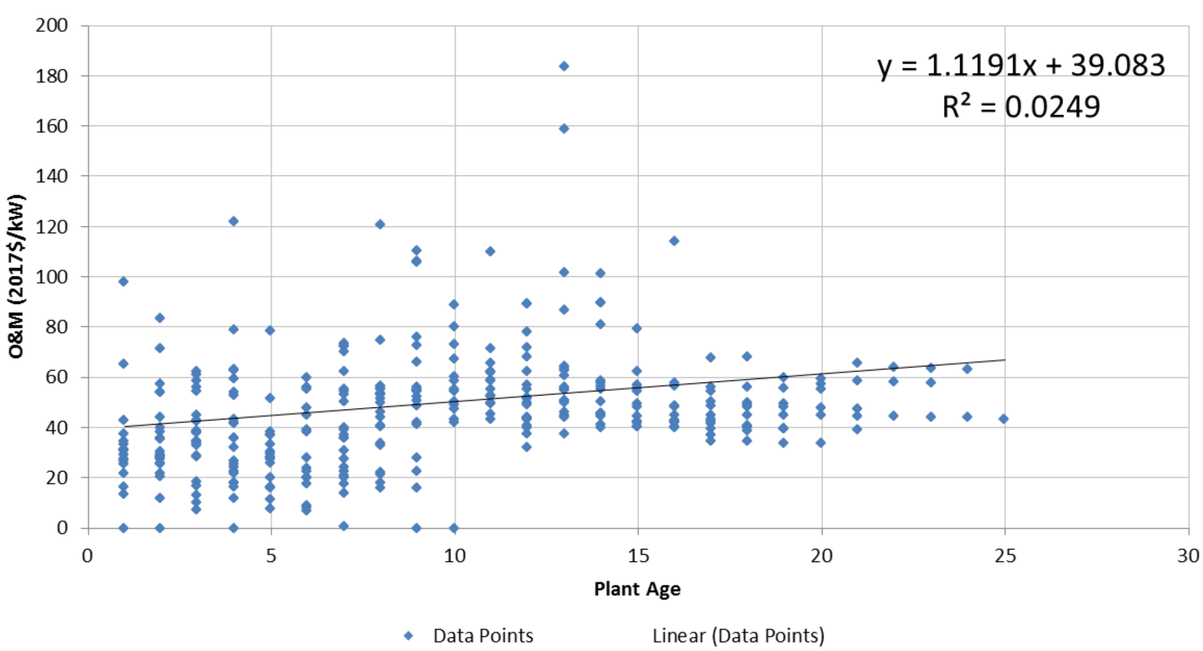
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 39.083 + (1.119 × age)

Table J-10 — Regression Statistics – Wind O&M for 0-100 MW

		t Statistic	*p-value*
Observations	339		
Simple Average ($/kW)	49.888		
Intercept	39.083	9.0574	1.10E-17
Slope	1.119	2.9310	3.61E-03
R^2	0.02486		

Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes



100-200 MW

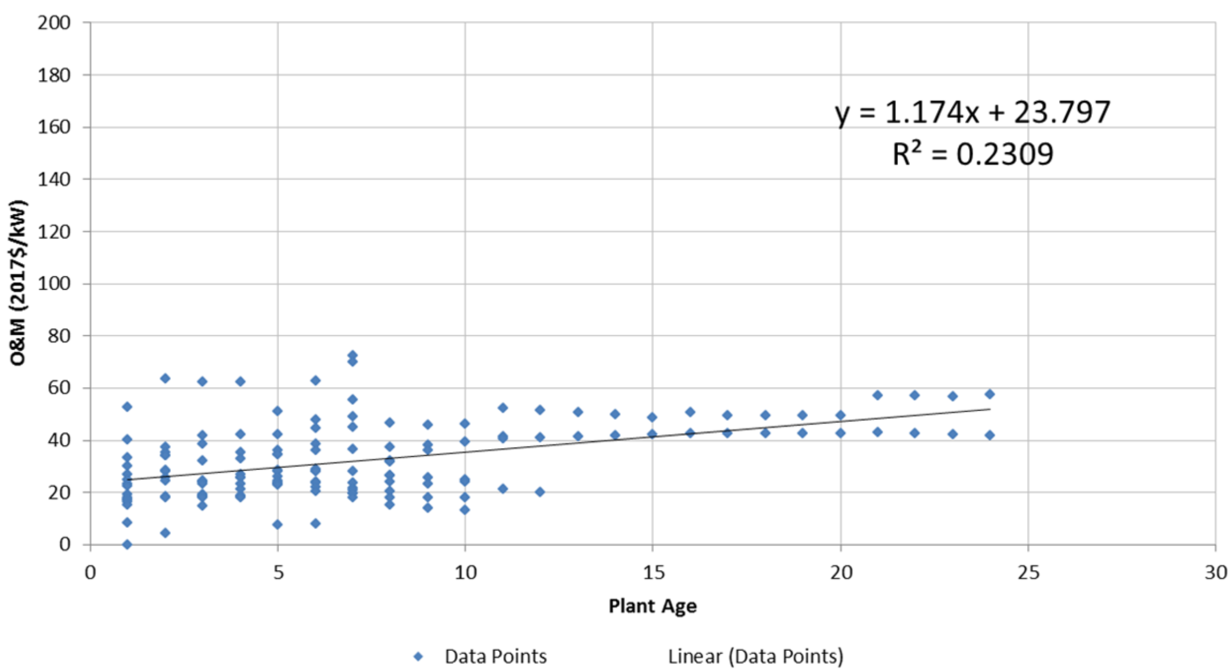
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 23.797 + (1.174 × age)

Table J-11 — Regression Statistics – Wind O&M for 100-200 MW

		t Statistic	*p-value*
Observations	147		
Simple Average ($/kW)	35.645		
Intercept	23.797	14.1919	3.27E-29
Slope	1.174	6.5971	7.33E-10
R^2	0.23086		

Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes



Greater than 200 MW

The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 26.783 + (0.925 × age)

Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW

		t statistic	*p-value*
Observations	124		
Simple Average ($/kW)	35.645		
Intercept	26.783	17.5334	3.90E-35
Slope	0.925	7.0885	9.55E-11
R^2	0.29171		

Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW

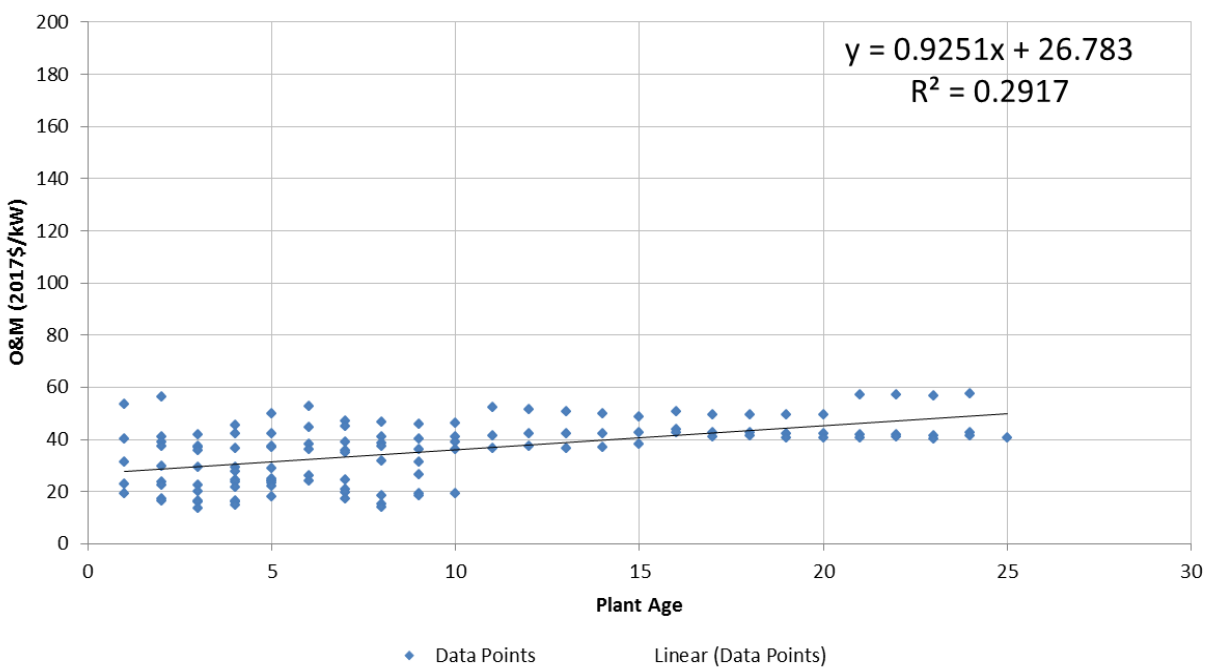


Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

Asset Class	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
Steam Production	$ 39,843,569	$ 11,029,215
Other Production	1,210,856	335,181
Electric Transmission	256,772,854	52,507,979
Electric Distribution	100,309,251	35,534,299
Electric General	42,013,242	11,663,475
Electric Intangible	18,371,298	5,101,149
Grand Total	**$ 458,521,070**	**$ 116,171,298**

Witness	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
Harkness	$ 27,021,325	$ 7,502,520
Bick	8,221,359	2,282,366
Lytal	42,028,513	11,634,816
Meeks	111,597,408	38,668,052
Cooley	269,652,466	56,083,543
Grand Total	**$ 458,521,070**	**$ 116,171,298**

Production Assets allocated using 12CP-PROD (27.68%).
Transmission Assets primarily allocated using 12CP-TRAN (20.45%). Radial Line assets direct assigned.
Distribution Assets direct assigned according to location.
General Plant allocated using LABXAG (27.76%).
Intangible Plant primarily allocated using LABXAG (27.76%) with one project allocated by CUST-RET (31.08%).

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
1	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rpl MDBFP DischargeVlv	$ 178,334	$ 49,365
2	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rpl Boiler Frt Elevator	3,175	879
3	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rpl BlrDrm E Center Sfty	25,208	6,978
4	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C- Rpl West Main Stm Sfty	(9,986)	(2,764)
5	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-HydrogenGen Power Sys	49,176	13,613
6	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rwd W Blr Circ Pmp Mtr	100,489	27,817
7	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rpl CT Partition Walls	238,005	65,883
8	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-Rpl Reactor 1 Inlet Pipe	23,986	6,640
9	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C- Rewind Generator Rotor	2,175,648	602,248
10	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rpl MillF MainVrt Shaft	1,374,614	380,511
11	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C-Gen Stator Rewedge	271,793	75,236
12	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C-Inst RealTmXfmr DisGasAnly	46,282	12,811
13	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C-Rpl Bull Ring Assmbly	23,363	6,467
14	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-Inst Rectifier RMU	2,666	738
15	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rewind CT Cell #6 Motor	7,820	2,165
16	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rewind CT Cell #14 Motor	7,418	2,053
17	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-Rewind CT Cell #18 Motor	7,558	2,092
18	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-Inst SwingGates&LadderProt	208,917	57,831
19	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-Rpl SSBAC Oil Cooler	8,864	2,454
20	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C-Rpl Center AuxCirc Dis Vlv	16,949	4,692
21	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL2C-Rpl Bull Ring Assmby 2C	20,245	5,604
22	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-Rpl Horz Well 99E Pump	83,440	23,097
23	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL0C-S SBAC OVH 2017-22573	(881)	(244)
24	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.500	TOL1C-W Rev Gas Mtr Rwnd	(294)	(81)
25	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.035	HAR3C-Rpl Boiler Economizer	4,189,538	1,159,718
26	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR2C-Rpl S Cond Pump Element	80,736	22,349
27	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl CT Cell #2 Mechanicals	6,004	1,662
28	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR1C-Rpl W #2 O2 Probe	226	63
29	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR1C-W Circ Pmp Wire Replaced	73,552	20,360
30	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Install Eye Wash Station	23,337	6,460
31	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-CT N Circ Pump Mtr Rewind	136,535	37,795
32	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR2C-Rpl O2 Probes	21,631	5,988
33	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR1C-CTMU Pump Rpl Rotating Assy	19,678	5,447
34	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR2C-Rpl W FD Fn Oil Clr Tubes	22,246	6,158
35	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR0C-Rpl Pond 7 Floating Pump	14,866	4,115
36	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR0C-Rpl ACI Diverter Valves	12,891	3,568
37	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR1C-SUBFP Motor Rewind	211,706	58,603
38	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR0C-CESP BFP Element	168,304	46,589
39	Steam Production	Lytal	Environmental Compliance	A.0001550.500	HAR3C-Rpl Bghse Inlet Duct Exp Jnts	131,949	36,525
40	Steam Production	Lytal	Environmental Compliance	A.0001550.500	HAR2C-Rpl Deflation Fan Motors	17,716	4,904
41	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl #2 FWH 2B Valve	40,365	11,174
42	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-3D SBAC Motor Rewind	170,101	47,086
43	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl N CT Circ Pump cable	56,955	15,766
44	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR0C-Swing gates and ladder	118,168	32,710

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
45	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR2C-Inst CT Cable tray	59,589	16,495
46	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Aux Clg Wtr Pmp Mtr Rwd	60,012	16,612
47	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR0C-Inst Vlv on BD Recovery	80,571	22,303
48	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl FWH3 Steam Separator	10,673	2,954
49	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl W#4 O2 Probe	11,002	3,046
50	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-N ACW Pump Mtr Rwnd	17,393	4,815
51	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-C BCP Mtr Rwnd	46,210	12,791
52	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl N Cond Bstr Pump Cable	20,253	5,606
53	Steam Production	Lytal	Environmental Compliance	A.0001550.500	HAR1C-Rpl Dust Spprssn Pump Cable	25,697	7,113
54	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl FWH3 Shell relief vlv	8,758	2,424
55	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR2C-W Seal Trough Wtr Pump Rpl	5,485	1,518
56	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR1C-Rpl #2 Corner Tilt Drives	48,276	13,363
57	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.500	HAR3C-Rpl FWH2 Steam Separator	10,058	2,784
58	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.283	HAR3C-Rpl APH Baskets	1,623,841	449,500
59	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.296	TOL2C-Rpl Main Pwr Transformer	1,603,155	443,774
60	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.475	HAR3C-Rpl CT Bottom Structure	1,227,170	339,696
61	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.226	TOL2C-Rpl Mill E Gearbx & Jour	1,175,533	325,403
62	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.113	TOL0C-Rpl RR Ties PH 3 of 5	1,123,730	311,063
63	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.257	TOL1C-UpgDCSOprStn& CntrlProc	1,105,121	305,912
64	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.093	TOL0C-Rpl RR Ties PH 4 of 5	1,036,417	286,894
65	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.223	TOL1C-Rpr MillC GearBx & Jrnls	856,916	237,206
66	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.309	HAR3C-H3 Upgrd DCS Opr stn	776,877	215,050
67	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.597	TOL1C-Rpl Coal Pipe & Elbows	776,483	214,941
68	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC0C-Waste Water Pond Pump	203	56
69	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC2C-Sprht Spray Blck Vlv	26,817	7,423
70	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC0C-Rpl Gas Sys SRV	37,149	10,283
71	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC2C-Anodamine CF System	1,139	315
72	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC0C-MaxiVolt Equipment	12,058	3,338
73	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC2C-HRH Piping Abate&Reins	530,070	146,730
74	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC2C-Rpl Firing Valve	13,138	3,637
75	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC2C-Rpl Elevator Gearbox	63,842	17,672
76	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.500	CHC0C-inst Ladder Swing Gates	53,990	14,945
77	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Fire System Iso Vlvs	502	139
78	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Rpl UF Modules	40,559	11,227
79	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Rpl Diesel Fire Pmp Vlv	13,540	3,748
80	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Install Rectifier RMU	3,774	1,045
81	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Smart Pig Test	472,480	130,788
82	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON1C-Rpl HP FWH #1 & #2	27,941	7,734
83	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl HP FWH #2	27,485	7,608
84	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl CT Motor Cell #3	12,939	3,582
85	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl CT Motors	23,786	6,584
86	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Inst Ladder Swing Gates	34,174	9,460
87	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl Aux Blr Wtr Vlv	11,187	3,097
88	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON0C-Rpl Fire Sys Chk Vlv	10,658	2,950

Exhibit DG-7

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
89	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl Gas Density Anlyzr	5,394	1,493
90	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-E Rpl CT Bypass Vlv	139	39
91	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.500	JON2C-Rpl Economizer Exp Jnts	(731)	(202)
92	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD1C-Rpl Main Stm SealReg Vlv	26,341	7,291
93	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD2C-Rwnd DC Lube Oil Motor	(255)	(71)
94	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD1C-Rpl Basement Heater	839	232
95	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD0C-Rpl Main Pinnacle Gas Vlv	27,802	7,696
96	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD0C-Inst Ladder Swing Gates	24,324	6,733
97	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.500	MAD1C-Rpl HRH Terminal Tubes	601,878	166,608
98	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.157	PLX0C-Rpl 50T-5T Turb Crane-20816	668,393	185,020
99	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.043	TOL1C-Rpl Burner Assemblies	581,360	160,928
100	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.006	HAR2C-H2 Install Ash Silo Elev	565,909	156,651
101	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.067	MAD1C-Rpl #1 HP FWH-20820	529,643	146,612
102	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.117	NIC0C-Rpl Roof-Turb High	523,645	144,952
103	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.244	HAR0C-Rpl SBAC Controls	486,622	134,703
104	Steam Production	Lytal	Environmental Compliance	A.0001555.089	TOL2C-Rpl Baghouse Bags 2018	475,735	131,690
105	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.446	HAR1C- CT Fan Stacks	468,675	129,735
106	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.450	HAR2C- Rpl CT Fan Stacks	464,132	128,478
107	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.123	NIC3C-CT Mechanicals Phase 1	461,611	127,780
108	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.122	CHC2C-Upg DCS Hardware	427,632	118,374
109	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.024	MAD1C-Rpl CS APH Basket&Seals	397,843	110,128
110	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.250	HAR1C-Rpl CT Mechanicals Ph2	387,719	107,326
111	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.032	MAD1C-Rpl M1 Elevator	381,966	105,733
112	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.118	NIC0C-Rpl Roof-Turb Low	364,669	100,945
113	Steam Production	Lytal	Environmental Compliance	A.0001550.458	HAR3C- Rpl Bghse Doors	364,027	100,767
114	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.253	JON1C-BFP Elem Comp Rpl-21019	343,739	95,152
115	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.035	CHC2C-Rpl BFP Discharge vlvs	342,703	94,865
116	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.287	JON2C-Rpl CT Makeup Piping	332,687	92,092
117	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.366	TOL1C-T1 #1FWH valves	317,076	87,771
118	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC2C-BFP Element Refurb	1,553	430
119	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Inst #6 Slaker RR Supply	2,447	677
120	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC3C-Rpl SJAE Throttle Valve	(817)	(226)
121	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC2C-Rpl Boiler Sump Pipe	656	182
122	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC3C-Rpl SSR Bypass Actuator	21,990	6,087
123	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC3C-Rpl Reverse Power Relays RP1-	14,204	3,932
124	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC1C-Rewind N FD Motor *Corrected*	46,343	12,828
125	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC2C-Rpl Hogging Jet Valves	16,788	4,647
126	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Swing gates and ladders	76,463	21,166
127	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Rpl Demin Sump Drain Line	21,059	5,829
128	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Pond 18 Motor Rpl	15,300	4,235
129	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-House Air Comp Mtr	6,169	1,708
130	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC1C-Rpl CT Makeup Cntrl Vlv	(35)	(10)
131	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Rpl System Lab HVAC	9,398	2,602
132	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.500	NIC0C-Rpl Aux Boiler Feed Pump	58,501	16,194

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Line No.	(A) Asset Class	(B) Witness	(C) Project Category	(D) WBS Level 2	(E) Project Description (WBS Level 2 Description)	(F) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	(G) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
133	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX1C-Rpl DA Pressure Rel Vlv	(0)	(0)
134	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX2C-Rpl Yarway DrumLvl Xmtr	24,922	6,899
135	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX2C-Rpl West Blowdown Vlv	10,031	2,777
136	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX3C-Rpl SH/RH Spray block Vlv	5,791	1,603
137	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX4C-Rpl Bldn Throttling Vlv	6,491	1,797
138	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX4C-Rpl Inst Air Comp	81,211	22,480
139	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX0C-Inst SwingGates&LadderProt	23,690	6,558
140	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX4C-Rpl SH/RH SpayAuto BlkVLV	29,904	8,278
141	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX4C-Rpl HP Heater Safeties	14,537	4,024
142	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX0C-Replace Water Wells	30,780	8,520
143	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.500	PLX3C-E FD Fan Motor Rwd	51,768	14,330
144	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.252	TOL0C-Rpl Receiving WH Roof	273,849	75,805
145	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.031	CHC2C-Rpl BFP Fluid Drives	270,951	75,003
146	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.479	HAR3C-Rpl EHC Pump Sys	261,741	72,453
147	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.115	NIC0C-Install Demin Wtr Supply	260,255	72,042
148	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.021	HAR0C-Rpl Paving Phase 5/6	252,260	69,829
149	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.057	MAD1C-Rpl Air Prehtr Exp Joint	243,217	67,326
150	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.455	HAR3C- ACW Heat Exchangers	234,268	64,848
151	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.120	TOL0C-Inst Perimet FencePonds	232,148	64,262
152	Steam Production	Lytal	Environmental Compliance	A.0001586.265	JON2C-CEM's Upgrade-19975	216,486	59,926
153	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.028	HAR2C-Rpl CT Acid Tank	210,340	58,225
154	Steam Production	Lytal	Environmental Compliance	A.0001586.264	JON1C-CEM's Upgrade-19976	208,087	57,601
155	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.370	TOL2C-RPL Boiler Sump Line T2	203,910	56,445
156	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.073	JON0C-Inst Backflow Prvt on HT	193,923	53,680
157	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.034	HAR0C-Rpl Paving Phase 6/6	180,040	49,837
158	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.595	TOL1C-Cooling Tower Bypass	173,448	48,013
159	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.285	JON2C-Rpl Circ Pump Suc Hood	170,659	47,241
160	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.254	TOL1C-Rpl SSC Chain 2018	165,793	45,894
161	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.083	HAR3C-H3 Rpl Lab Analyzers 201	151,767	42,011
162	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.172	PLX0C-Rpl Lab Analyzers	140,631	38,929
163	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.594	TOL1C-Int Online Vib Mntr Sys	140,414	38,868
164	Steam Production	Lytal	Environmental Compliance	A.0001550.151	HAR3C-H3 Rebag Partial 2018	132,478	36,672
165	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.599	TOL2C-Inst Online Vib Mntr Sys	120,957	33,483
166	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.060	TOL0C-Rpl Water Well Pmp 2018	118,257	32,735
167	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.079	NIC3C-Rpl Lab Analyzers	111,612	30,896
168	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.358	TOL1C-RPL Boiler Sump Line	107,985	29,892
169	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.254	CHC2C-Rpl Burner Titls-21235	104,421	28,905
170	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.255	CHC2C-Rpl CT Suction Screens-21237	100,689	27,872
171	Steam Production	Lytal	Environmental Compliance	A.0001550.443	HAR1C- ESP Re-build TR-sets PH2	91,868	25,430
172	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.473	HAR3C-Inst Online Vib Mntr Sys	88,416	24,475
173	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001560.116	NIC0C-Rpl Roof-Maint Shop	82,782	22,915
174	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.073	CHC0C-Rpl Waterwell Pmp Mtr	80,176	22,194
175	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.300	CHC0C-Rpl Lab Analyzers	73,779	20,423
176	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.171	PLX0C-Roof Drains Header	73,699	20,401

Exhibit DG-7

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
177	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.082	HAR3C-H3 Rpl Drag Chain 2018	71,344	19,749
178	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.083	CHC0C-Rpr Water Well Mtr 2017	71,264	19,727
179	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.363	TOL1C- Rpl rev gas expansion joints	69,636	19,276
180	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.305	CHC2C-Rpl Lab Analyzers	65,132	18,029
181	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.046	CHC0C-Refurb Plant Bathroom	60,166	16,655
182	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.257	CHC0C-Rpl TUCO Roof-21291	56,709	15,698
183	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.185	PLX3C-Condensate Suction Pipe	53,483	14,805
184	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.190	PLX4C-Rpl Feedwater Analyzers	51,241	14,184
185	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.036	MAD1C-Rpl Turbine Oil Centrifu	46,676	12,920
186	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.481	HAR0C-Trng Cntr Fire Detection	42,399	11,737
187	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.184	PLX3C-Rpl Feedwater Analyzers	40,505	11,212
188	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.304	CHC2C-Inst Onln Vib Mntr Sys	37,599	10,408
189	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.072	JON2C-Rpl Gas Firing Valve	37,199	10,297
190	Steam Production	Lytal	Environmental Compliance	A.0001550.461	HAR0C-Inst Above Grade Fuel Tanks	31,468	8,711
191	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.052	MAD0C-Tornado Shelter	28,874	7,993
192	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.260	JON1C-CT Sec pH Probe-21239	27,971	7,743
193	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.278	TOL0C-Drill Horizontal WaterWell	27,463	7,602
194	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.170	PLX0C-Rpl Relay & ComptrRmFloors	26,704	7,392
195	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.259	JON2C-CT Sec pH Probe-21238	26,343	7,292
196	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.364	TOL1C-Rpl east rev gas fan damper	23,338	6,460
197	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.262	HAR1C-SBAC 1B Mjr Rebld 2017	18,120	5,016
198	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001545.303	CHC1C-Rpl Lab Analyzers	13,664	3,782
199	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.194	HAR2C-Rpl H2 Mill E Exhauster	11,862	3,283
200	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.174	PLX1C-Rpl Boiler PH Analyzers	11,589	3,208
201	Steam Production	Lytal	Environmental Compliance	A.0001555.090	TOL1C-Rpl Baghouse Bags 2017	9,754	2,700
202	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001534.178	PLX2C-Rpl Boiler pH Analyzers	8,442	2,337
203	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.596	TOL1C-Rpl Lab Sample System	8,000	2,215
204	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.212	TOL0C-Rpl Water Well Pmp 2019	7,085	1,961
205	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.142	JON1C-Rpl Oil Circ Brkr JK00	4,923	1,363
206	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.055	JON1C-Abate & Reinsulate DA	2,288	633
207	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.057	TOL0C-Rpl Water Well Pmp 2017	1,492	413
208	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.262	JON1C-Circ Water Struct Liner-19992	1,025	284
209	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001529.065	MAD1C-Rpl Lab Analyzers-21292	508	141
210	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.261	JON1C-Replace CP's-19974	485	134
211	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.129	JON1C-Rpl Rosemount 1151 XMTRS	210	58
212	Steam Production	Lytal	Environmental Compliance	A.0001550.462	HAR0C-Remove UG Fuel Tanks	186	51
213	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.030	TOL0C-TolkX Water Well Ph 7	176	49
214	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.283	JON1C-Rpl CT Bypass Vlv	160	44
215	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.275	HAR2C-Rpl SH Spray Valves	37	10
216	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.014	JON2C-E Rpl Mech Draft 3&8	28	8
217	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.137	HAR2C-H2 Rpl Lab Analyzers 201	10	3
218	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.142	HAR1C-Cooling Tower Structure	(1)	(0)
219	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001555.219	TOL1C-Rpr MillB GearBx & Jrnl	(210)	(58)
220	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.141	JON1C-Rpl IPs with DVC	(314)	(87)

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

Line No.	(A) Asset Class	(B) Witness	(C) Project Category	(D) WBS Level 2	(E) Project Description (WBS Level 2 Description)	(F) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	(G) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
221	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001550.109	HAR1C-H1 Rpl Condenser Circ Pi	(327)	(91)
222	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.295	JON0C-Portable Vibration DAS	(7,958)	(2,203)
223	Steam Production	Lytal	Reliability & Performance Enhancement	A.0001586.081	JON1C-Rpl Seamed HRH Piping	(123,637)	(34,224)
224	Steam Production	Lytal	Environmental Compliance	A.0001555.088	TOL1C-Rpl Baghouse Bags 2018	(137,462)	(38,051)
225	**Steam Production Total**					$ 39,843,569	$ 11,029,215
226	Other Production	Lytal	Reliability & Performance Enhancement	A.0001586.291	JON3C-Rpl Exh Expansion Joint	$ 230,300	$ 63,750
227	Other Production	Lytal	Reliability & Performance Enhancement	A.0001545.501	CHC3C-Rpl GT Inlet Air Filters	76,209	21,096
228	Other Production	Lytal	Reliability & Performance Enhancement	A.0001545.501	CHC4C-Rpl GT Inlet Air Filters	76,406	21,150
229	Other Production	Lytal	Reliability & Performance Enhancement	A.0001545.501	CHC3C-Rpl Submersible Pump	9,320	2,580
230	Other Production	Lytal	Reliability & Performance Enhancement	A.0001545.501	CHC3C-Rpl Generator Prot Relays	25,357	7,019
231	Other Production	Lytal	Reliability & Performance Enhancement	A.0001545.501	CHC4C-Rpl Generator Prot Relays	26,138	7,235
232	Other Production	Lytal	Reliability & Performance Enhancement	A.0001586.294	JON4C-Rpl Exh Expansion Joint	209,394	57,963
233	Other Production	Lytal	Reliability & Performance Enhancement	A.0001529.501	MAD2C-Xfmr Rewind and Wire	82,853	22,935
234	Other Production	Lytal	Reliability & Performance Enhancement	A.0001529.501	MAD2C-Rpl Fuel Cntrl Vlv	48,541	13,437
235	Other Production	Lytal	Reliability & Performance Enhancement	A.0001529.501	MAD2C-Rpl Crane Pwr Supply	19,101	5,287
236	Other Production	Lytal	Reliability & Performance Enhancement	A.0001529.501	MAD2C-Rpl AC Units Elec Pkg	9,834	2,722
237	Other Production	Lytal	Reliability & Performance Enhancement	A.0001529.080	MAD3C-Rpl Exhaust Stack	152,634	42,251
238	Other Production	Lytal	Reliability & Performance Enhancement	A.0001586.501	JON4C-Rpl Turning Gear Gearbox	142,393	39,416
239	Other Production	Lytal	Reliability & Performance Enhancement	A.0001586.501	JON3C-Rpl Gen Cooler Bypass Act	9,973	2,761
240	Other Production	Lytal	New Generation	A.0001577.002	Hale-Land & Land Rights	55,028	15,233
241	Other Production	Lytal	Reliability & Performance Enhancement	A.0001554.501	QUA1C-Rpl Starting Diesel Rad	22,987	6,363
242	Other Production	Lytal	Reliability & Performance Enhancement	A.0001554.003	QUA2C-Rpl Emergency Diesel Generato	14,249	3,944
243	Other Production	Lytal	Reliability & Performance Enhancement	A.0001621.001	GMS0C-Gaines Cty Gen Project	139	39
244	**Other Production Total**					$ 1,210,856	$ 335,181
245	Electric Transmission	Cooley	RE	A.0000424.085	Kiowa-North Loving 345kV Line_	$ 22,495,220	$ 4,600,091
246	Electric Transmission	Cooley	RE	A.0000424.087	N Loving-China Draw 345kV Line	18,636,556	3,811,025
247	Electric Transmission	Cooley	RE	A.0000540.001	Atoka-Eagle Creek 115 kV Line	14,045,213	2,872,133
248	Electric Transmission	Cooley	RE	A.0001310.003	Walkemeyer 345/115 Sub	11,791,330	2,411,232
249	Electric Transmission	Cooley	SR	A.0000499.013	SPS ELR 115kV TX 2016	10,999,197	2,249,247
250	Electric Transmission	Cooley	RE	A.0000519.001	Roosevelt County Substation	9,502,265	1,943,137
251	Electric Transmission	Cooley	RE	A.0000511.003	Carlisle to Wofforth Carlisle	8,172,345	1,671,179
252	Electric Transmission	Cooley	RE	A.0000424.165	N Loving Sub Xfmr 345kV/115kV_	6,809,314	1,392,450
253	Electric Transmission	Cooley	RE	A.0000424.095	Road Runner Sub Xfmr 345kV_UID	6,793,459	1,389,208
254	Electric Transmission	Cooley	RE	A.0000424.167	C Draw 345kV Sub N Loving Term	6,154,882	1,258,624
255	Electric Transmission	Cooley	RE	A.0000424.091	Kiowa Sub Xfmr Bus/Potash Ter	6,133,566	1,254,265
256	Electric Transmission	Cooley	RE	A.0000673.022	TUCO-Yoakum 345kV ROW_UID 5044	5,720,536	1,169,803
257	Electric Transmission	Cooley	RE	A.0000424.169	C Draw Sub Xmfr 345kV/115kV_UI	5,434,106	1,111,231
258	Electric Transmission	Cooley	SR	A.0000499.011	SPS ELR 115kV NM 2016	5,430,058	1,110,403
259	Electric Transmission	Cooley	RE	A.0000424.163	N Loving Sub Kiowa/C Draw Term	5,426,930	1,109,763
260	Electric Transmission	Cooley	RE	A.0000296.005	NE Hereford to New Center St.	4,541,034	928,605
261	Electric Transmission	Cooley	LI	A.0001008.002	Inst 230kV Sw Station XcelPortion	4,112,432	840,959
262	Electric Transmission	Cooley	RE	A.0000424.144	OPIE Potash-Livingston Ridge	3,869,519	791,286

Southwestern Public Service Company
Capital Additions
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
263	Electric Transmission	Cooley	RE	A.0000199.001	Custer Mountain-Ochoa Reconductor	3,761,552	769,207
264	Electric Transmission	Cooley	SR	A.0000303.007	SPS 2016 S&E B 230kV Line	3,660,266	748,495
265	Electric Transmission	Cooley	RE	A.0000296.008	NE Hereford Sub	3,649,792	746,353
266	Electric Transmission	Cooley	SR	A.0000303.045	SPS S&E 115kV Line TX 2016	3,609,270	738,067
267	Electric Transmission	Cooley	RE	A.0000463.008	South Portales-Market Street L	3,333,790	681,733
268	Electric Transmission	Cooley	SR	A.0001267.001	345/115kV 448MVA XfmrspareSub	3,252,815	665,174
269	Electric Transmission	Cooley	RE	A.0001319.006	W40 Rebuild Dawn to Panda Tap	3,135,356	641,155
270	Electric Transmission	Cooley	RE	A.0000494.001	Seminole Xfmr 1	3,024,673	618,521
271	Electric Transmission	Cooley	OT	A.0000710.003	SPS Physical Security Sub Infrastru	2,880,609	589,061
272	Electric Transmission	Cooley	RE	A.0000860.003	Curry Co Dist Xfmr Conversion	2,819,976	576,662
273	Electric Transmission	Cooley	RE	A.0000194.001	Cochran 115 Cap Bank	2,631,416	538,103
274	Electric Transmission	Cooley	RE	A.0000424.093	Road Runner Sub 345kV Conv_UID	2,611,864	534,105
275	Electric Transmission	Cooley	RE	A.0000424.143	IMC1-Intrepid West 115kv Recd	2,467,078	504,498
276	Electric Transmission	Cooley	RE	A.0000424.136	Monument-Byrd 115kvRecond Line	2,442,386	499,448
277	Electric Transmission	Cooley	RE	A.0001326.001	Yoakum 230/115 Xfmr 1 Upgrade	2,325,506	475,547
278	Electric Transmission	Cooley	RE	A.0002049.001	Potash Sub 115 kV Terminal Sub	2,173,554	444,474
279	Electric Transmission	Cooley	RE	A.0001300.014	Wreckout Rebuild 115KV LineT24	2,064,695	422,214
280	Electric Transmission	Cooley	SR	A.0000640.023	AMOCO Breaker Rplmnt	2,049,755	419,158
281	Electric Transmission	Cooley	RE	A.0000424.160	Kiowa 345kV Sub N Loving Term_	1,916,371	391,882
282	Electric Transmission	Cooley	RE	A.0000481.012	New 230/115kV Transformer	1,910,284	390,638
283	Electric Transmission	Cooley	SR	A.0000499.015	SPS 230kV ELR TX 2016	1,848,868	378,079
284	Electric Transmission	Cooley	RE	A.0000424.037	OPIE 3_Hobbs-Kiowa 345kV Line_	1,826,818	373,570
285	Electric Transmission	Cooley	RE	A.0001272.001	Cargill 14.4 Mvar Cap Bank	1,784,111	364,836
286	Electric Transmission	Cooley	RE	A.0001319.005	W40 Rebld Panda Tap Deaf Smith	1,758,973	359,696
287	Electric Transmission	Cooley	RE	A.0000424.089	Kiowa 345kVSub Road Runner Ter	1,737,417	355,288
288	Electric Transmission	Cooley	SR	A.0000469.015	SPS Major Line Refurb 69kV TX 2016	1,692,109	346,023
289	Electric Transmission	Cooley	RE	A.0001283.001	Lea Co. Plains Sw. Cap Bank	1,683,000	344,160
290	Electric Transmission	Cooley	RE	A.0000194.008	Cochran Whiteface Z26 Rebuild	1,628,544	333,024
291	Electric Transmission	Cooley	RE	A.0000846.001	Denver City 115 kV Breaker Add	1,609,843	329,200
292	Electric Transmission	Cooley	SR	A.0000220.006	SPS 2016 S&E Sub	1,585,100	324,140
293	Electric Transmission	Cooley	RE	A.0000424.145	Potash-Intrepid West 115kvRecd	1,572,678	321,600
294	Electric Transmission	Cooley	SR	A.0000303.044	SPS S&E 69kV Line TX 2016	1,458,291	298,209
295	Electric Transmission	Cooley	RE	A.0000781.012	Outpost Highside	1,436,966	293,848
296	Electric Transmission	Cooley	SR	A.0000640.020	Texas Co Rpl Breakers 800, 804	1,382,769	282,765
297	Electric Transmission	Cooley	RE	A.0001300.013	Roswell Intg 115KVBkr One Half	1,309,966	267,877
298	Electric Transmission	Cooley	RE	A.0000424.040	Kiowa 345kV Sub H Term/Reactor	1,255,718	256,784
299	Electric Transmission	Cooley	RE	A.0000616.001	Soncy Dist. Transformer Conv.	1,143,366	233,809
300	Electric Transmission	Cooley	RE	A.0000424.137	Monument-Byrd ROW	976,827	199,753
301	Electric Transmission	Cooley	RE	A.0001285.001	NEF-Targa Reconductor	968,907	198,134
302	Electric Transmission	Cooley	RE	A.0000616.002	115kV Line Tap to Soncy Line	962,879	196,901
303	Electric Transmission	Cooley	SR	A.0000303.050	SPS S&E 345kV Line KS 2016	962,702	196,865
304	Electric Transmission	Cooley	RE	A.0000296.006	New Centre St 115kV Sub	890,170	182,033
305	Electric Transmission	Cooley	RE	A.0000522.009	Z09 69kV Line Removal Trans	861,651	176,201
306	Electric Transmission	Cooley	SR	A.0000893.001	Finney Holcomb Relay Upgrade	840,491	171,874

Southwestern Public Service Company
Capital Additions
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
307	Electric Transmission	Cooley	RE	A.0001310.002	Reterm 345KV Line Old J7	747,384	152,834
308	Electric Transmission	Cooley	RE	A.0001310.001	Reterm 345KV Line J7	746,883	152,732
309	Electric Transmission	Cooley	SR	A.0001273.020	Roosevelt Breaker 4K65 Replacement	740,745	151,476
310	Electric Transmission	Cooley	RE	A.0000290.005	Cunningham Intg, Upgrade Eddy 230kV	735,193	150,341
311	Electric Transmission	Cooley	GI	A.0000736.005	Tolk Needmore Retermination	690,440	141,189
312	Electric Transmission	Cooley	RE	A.0002049.002	Potash Kiowa 115kV Line	651,515	133,230
313	Electric Transmission	Cooley	RE	A.0000424.120	N Loving-S Loving 115 kVROW	647,472	132,403
314	Electric Transmission	Cooley	OT	A.0000795.001	SPS Sub Comm Network Group 1 L	629,734	128,775
315	Electric Transmission	Cooley	GI	A.0000105.007	Plant X Terminal Upgrades TX	629,421	128,711
316	Electric Transmission	Cooley	RE	A.0000424.088	Kiowa-Road Runner 345kV Line_U	617,448	126,263
317	Electric Transmission	Cooley	SR	A.0000499.018	Line ELR SPS OK 115kV	601,494	123,001
318	Electric Transmission	Cooley	SR	A.0000286.005	Horz Cap and Pin Replacement TX	593,242	121,313
319	Electric Transmission	Cooley	RE	A.0000513.005	Denver City Breaker W900 Replacemen	567,130	115,973
320	Electric Transmission	Cooley	OT	A.0000710.001	NM Physical Security Sub Infrastruc	554,950	113,483
321	Electric Transmission	Cooley	GI	A.0001183.006	RO6 NEEDMORE TO YOAKUM 230KV LINE	549,752	112,420
322	Electric Transmission	Cooley	RE	A.0001319.007	W40 Recond Canyon WDeaf Smith	509,341	104,156
323	Electric Transmission	Cooley	RE	A.0000511.021	Carl-Wolf Sundown Relay at Wo	502,881	102,835
324	Electric Transmission	Cooley	RE	A.0000916.010	Plant X 230kV LRU to Deaf Smith	496,684	101,568
325	Electric Transmission	Cooley	RE	A.0000513.004	Denver City Breaker W970 Replacemen	484,085	98,991
326	Electric Transmission	Cooley	RE	A.0000916.007	Remote End Upgrade for ring bus add	471,351	96,388
327	Electric Transmission	Cooley	SR	A.0000499.012	SPS ELR 69kV TX 2016	431,058	88,148
328	Electric Transmission	Cooley	RE	A.0000519.004	Oasis Relay Upgrade Sub	418,996	85,681
329	Electric Transmission	Cooley	RE	A.0000424.055	Custer Mt 115kV Sub Ponderosa	403,189	82,449
330	Electric Transmission	Cooley	LI	A.0001008.009	R11 230kV BRU Mahoney TLINE	400,415	81,882
331	Electric Transmission	Cooley	SR	A.0001067.001	Lubbock East K57 Relay Upgrade	382,017	78,119
332	Electric Transmission	Cooley	RE	A.0000511.001	Carlisle to Wolfforth 230 kVLi	364,982	74,636
333	Electric Transmission	Cooley	RE	A.0000463.002	Portales Interchange Sub	359,947	73,606
334	Electric Transmission	Cooley	GI	A.0000736.006	Yoakum Needmore Retermination	359,027	73,418
335	Electric Transmission	Cooley	RE	A.0000126.004	Artesia Cty Club Switch	350,231	71,619
336	Electric Transmission	Cooley	GI	A.0000736.001	Needmore Substation TOIF	349,078	71,384
337	Electric Transmission	Cooley	SR	A.0000220.018	SPS 2016 NM S&E Sub	344,910	70,531
338	Electric Transmission	Cooley	LI	A.0001008.010	R12 230kV AWOR Mahoney TLINE	343,735	70,291
339	Electric Transmission	Cooley	RE	A.0001319.011	Deaf Smith W40 Term Upgr	338,211	69,161
340	Electric Transmission	Cooley	RE	A.0000658.001	Yoakum	335,589	68,625
341	Electric Transmission	Cooley	RE	A.0000511.004	Carlisle to Wofforth Wolfforth	333,755	68,250
342	Electric Transmission	Cooley	RE	A.0000513.002	Castro Co Breaker 8829 Replacement	333,142	68,125
343	Electric Transmission	Cooley	RE	A.0000424.150	OPIE PTJU Intrepid Term Sub	333,124	68,121
344	Electric Transmission	Cooley	SR	A.0000153.006	V02 Switch 2915 Replacement	313,476	64,103
345	Electric Transmission	Cooley	SR	A.0000153.008	V77 Switch 4963 Replacement NM	304,985	62,367
346	Electric Transmission	Cooley	SR	A.0001067.004	Lubbock South K64 Relay Upgrade	304,349	62,237
347	Electric Transmission	Cooley	RE	A.0000290.006	Seven Rivers Intg, Upgrade Eddy 230	301,696	61,694
348	Electric Transmission	Cooley	RE	A.0000540.016	Atoka to Eagle Creek 115kV ROW	299,680	61,282
349	Electric Transmission	Cooley	SR	A.0000427.016	W14 Y98 Clearance Violations	296,067	60,543
350	Electric Transmission	Cooley	SR	A.0000153.005	NM Trans Switch Replace Line 69kV	290,042	59,311

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)		(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness		Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
351	Electric Transmission	Cooley	RE		A.0000488.009	Ochoa Terminal Work	271,959	55,613
352	Electric Transmission	Cooley	RE		A.0001300.022	Relay Upgr Roswell City Rosw Intg	266,550	54,507
353	Electric Transmission	Cooley	GI		A.0000350.005	Lost Draw to Cochran Retermination	263,538	53,891
354	Electric Transmission	Cooley	LI		A.0001126.002	Inst 3 1 Way 115kV Switch	252,239	51,581
355	Electric Transmission	Cooley	RE		A.0000424.099	China Draw-Wood Draw 115kV Lin	250,317	51,188
356	Electric Transmission	Cooley	SR		A.0000640.021	W07 Tx Cty SS Fr DCB to DCUB Rpl SE	249,194	50,958
357	Electric Transmission	Cooley	RE		A.0000658.003	Terry Co	246,342	50,375
358	Electric Transmission	Cooley	RE		A.0000663.001	Sundown Sub, Amoco Terminal	245,645	50,232
359	Electric Transmission	Cooley	GI		A.0000350.006	Lost Draw to Lea Co Plains Retermin	242,304	49,549
360	Electric Transmission	Cooley	SR		A.0000427.014	K21 Clearance Violations	236,935	48,451
361	Electric Transmission	Cooley	RE		A.0001310.013	Hitchland J26 Terminal UPLC	235,592	48,177
362	Electric Transmission	Cooley	RE		A.0001319.010	Dawn Sub Terminal Upgrades	231,429	47,325
363	Electric Transmission	Cooley	RE		A.0000424.044	Hobbs Sub Xfmr 345kV/230kV_UID	223,515	45,707
364	Electric Transmission	Cooley	LI		A.0001008.001	Inst 230kV Sw Station TOIFPortion	210,708	43,088
365	Electric Transmission	Cooley	RE		A.0000658.002	Seagraves	207,192	42,369
366	Electric Transmission	Cooley	RE		A.0000194.005	Cochran Z26 Terminal	205,865	42,098
367	Electric Transmission	Cooley	SR		A.0001273.015	Deaf Smith Breaker 2K20 Replacement	203,986	41,713
368	Electric Transmission	Cooley	RE		A.0000767.003	Osage Substation	203,983	41,713
369	Electric Transmission	Cooley	SR		A.0000220.007	SPS 2017 S&E Sub	191,951	39,253
370	Electric Transmission	Cooley	RE		A.0001310.012	Finney J25 Terminal UPLC	184,926	37,816
371	Electric Transmission	Cooley	RE		A.0000463.015	Market St.-South Portales ROW	182,693	37,359
372	Electric Transmission	Cooley	RE		A.0000979.004	115 ROW ROW Portion ROW	180,749	36,962
373	Electric Transmission	Cooley	RE		A.0001300.009	Reterm 115KV Roswell City	177,640	36,326
374	Electric Transmission	Cooley	LI		A.0001008.005	AWOR Relay Upgrade Sub	176,958	36,186
375	Electric Transmission	Cooley	RE		A.0000979.011	K56 Structure Raise	174,471	35,678
376	Electric Transmission	Cooley	RE		A.0000489.003	Install Capacitor Bank at Kiser Sub	173,970	35,575
377	Electric Transmission	Cooley	SR		A.0001078.001	Yoakum UPLC Upgrade	165,180	33,778
378	Electric Transmission	Cooley	RE		A.0000290.003	K23 Retermination, Eddy Co Sub	163,239	33,381
379	Electric Transmission	Cooley	GI		A.0001183.001	Cochran Terminal Upgrade Sub	156,433	31,989
380	Electric Transmission	Cooley	RE		A.0000663.002	Amoco Sub, Sundown Terminal	151,731	31,028
381	Electric Transmission	Cooley	SR		A.0000640.034	COCO 115kV Brkr 9910 Replacement	149,864	30,646
382	Electric Transmission	Cooley	RE		A.0001271.004	Cardinal-Teague Recond 115kV	144,758	29,602
383	Electric Transmission	Cooley	GI		A.0001183.004	U19 Plains to LTDW Line Side	139,621	28,551
384	Electric Transmission	Cooley	RE		A.0000488.004	RDRN 115kV Line Terminal Upgrade	133,258	27,250
385	Electric Transmission	Cooley	RE		A.0001300.025	Wreckout Rebuild Z09 Dble Ckt	127,913	26,157
386	Electric Transmission	Cooley	RE		A.0001300.023	T24 ROW	123,925	25,342
387	Electric Transmission	Cooley	LI		A.0001008.006	BRU Relay Upgrade Sub	122,515	25,053
388	Electric Transmission	Cooley	SR		A.0001000.001	Hutchinson LTC Replacement	121,866	24,921
389	Electric Transmission	Cooley	RE		A.0001319.008	W40 Rebuild ROW	109,876	22,469
390	Electric Transmission	Cooley	SR		A.0000286.014	LNCO Rplc 69kV Bypass Switches	107,435	21,970
391	Electric Transmission	Cooley	SR		A.0001273.017	Jones Transformer Pad	101,886	20,835
392	Electric Transmission	Cooley	RE		A.0001188.002	Amoco Oxy UF Relay	93,599	19,140
393	Electric Transmission	Cooley	SR		A.0001078.002	Tolk UPLC Upgrade	88,685	18,135
394	Electric Transmission	Cooley	RE		A.0000126.003	Artesia Cty Club Line ROW	83,836	17,144

Southwestern Public Service Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
395	Electric Transmission	Cooley	GI	A.0001183.005	U20 LTDW to Cochran Line Side	80,559	16,474
396	Electric Transmission	Cooley	SR	A.0000401.049	Seven Rivers BPRO Upgrade	79,161	16,188
397	Electric Transmission	Cooley	SR	A.0000303.041	SPS S&E 115kV Line NM 2016	78,777	16,109
398	Electric Transmission	Cooley	RE	A.0000663.005	K03 Structure Upgrade	78,006	15,952
399	Electric Transmission	Cooley	RE	A.0000511.020	Carl-Wolf Lubbock S Relay at	77,986	15,948
400	Electric Transmission	Cooley	SR	A.0000303.040	SPS S&E 69kV Line NM 2016	77,767	15,903
401	Electric Transmission	Cooley	RE	A.0000781.016	U16 Bushland to Outpost	75,471	15,433
402	Electric Transmission	Cooley	RE	A.0000781.017	U17 Coulter to Outpost	74,085	15,150
403	Electric Transmission	Cooley	SR	A.0000303.047	SPS S&E 115kV Line OK 2016	71,040	14,527
404	Electric Transmission	Cooley	RE	A.0000424.068	L Ridge Sub 115kV Conv/S Brush	65,806	13,457
405	Electric Transmission	Cooley	SR	A.0000401.025	Carlsbad 115kV (C900)Sub	64,126	13,113
406	Electric Transmission	Cooley	SR	A.0000153.004	SPS Trans Switch Rplmnt 115kV	63,304	12,945
407	Electric Transmission	Cooley	GI	A.0000105.008	K45 Reconductor Transmission Portio	62,682	12,818
408	Electric Transmission	Cooley	SR	A.0000220.024	SPS 2015 KS SE Sub	61,270	12,529
409	Electric Transmission	Cooley	RE	A.0000424.157	Whitten Sub Terminal Upgrades	60,690	12,411
410	Electric Transmission	Cooley	SR	A.0001273.012	Amoco Switch Replacement	60,116	12,293
411	Electric Transmission	Cooley	OT	10695269	E&S Elec Trans Lines_SPS	59,099	12,085
412	Electric Transmission	Cooley	RE	A.0000424.155	Custer Mt-Whitten Rebuild Line	56,590	11,572
413	Electric Transmission	Cooley	RE	A.0000673.041	Yoakum 345 kV Land	53,024	10,843
414	Electric Transmission	Cooley	RE	A.0001051.001	Hale V72 Treminal Upgrade	50,372	10,301
415	Electric Transmission	Cooley	RE	A.0000424.045	Hobbs 345kV Sub Reactor/Kiowa_	47,419	9,697
416	Electric Transmission	Cooley	RE	A.0002033.002	Market St Sub Greyhound 50565	47,290	9,670
417	Electric Transmission	Cooley	GI	A.0000706.001	Hitchland-New 345kV Terminal -	46,918	9,594
418	Electric Transmission	Cooley	RE	A.0000511.022	Carl-Wolf Tuco Relay at Carl	46,285	9,465
419	Electric Transmission	Cooley	SR	A.0000220.026	SPS 2015 OK SE Sub	45,306	9,265
420	Electric Transmission	Cooley	RE	A.0001325.004	ROW W77/T75	45,183	9,240
421	Electric Transmission	Cooley	OT	A.0001003.001	Lighthouse Switch Install Transmiss	42,247	8,639
422	Electric Transmission	Cooley	GI	A.0000902.001	Hale Co Wind 230kV Terminal at	41,968	8,582
423	Electric Transmission	Cooley	SR	A.0000401.024	Bushland 230kV (2K05)Sub	41,285	8,443
424	Electric Transmission	Cooley	SR	A.0001273.005	Facil UpgSub Ancillary Eq2016	39,461	8,069
425	Electric Transmission	Cooley	TI	A.0000974.012	Optima Land	32,699	6,687
426	Electric Transmission	Cooley	RE	A.0000522.005	Chaves-Price-Capitan 115 kV C	31,178	6,376
427	Electric Transmission	Cooley	GI	A.0000768.006	Floyd Relay Upgrade for Blanco	31,096	6,359
428	Electric Transmission	Cooley	RE	A.0000463.010	Market St.-Portales Line	30,360	6,208
429	Electric Transmission	Cooley	RE	A.0000511.015	Carl-Wolf K-24 Reterm at Carl	29,536	6,040
430	Electric Transmission	Cooley	RE	A.0001283.004	Lea Plains Metering	27,459	5,615
431	Electric Transmission	Cooley	SR	A.0001078.003	Needmore UPLC Upgrade	26,428	5,404
432	Electric Transmission	Cooley	GI	A.0000350.007	Cochran 115kV Sub Term Upg	26,371	5,393
433	Electric Transmission	Cooley	RE	A.0000424.060	L Ridge-Sage Brush 115kV Line_	26,369	5,392
434	Electric Transmission	Cooley	SR	A.0000401.039	Wipp Cap Bank Volt Diff NM	25,931	5,303
435	Electric Transmission	Cooley	RE	A.0000424.070	Potash Sub Rly Mods Livingston	25,125	5,138
436	Electric Transmission	Cooley	GI	A.0000350.002	Lost Draw TOIF	24,251	4,959
437	Electric Transmission	Cooley	RE	A.0000511.026	K39 LPL Line Reterm at Carlisle	23,636	4,833
438	Electric Transmission	Cooley	RE	A.0000424.104	China Draw-Wood Draw 115kV ROW	21,947	4,488

Southwestern Public Service Company
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
439	Electric Transmission	Cooley	RE	A.0000424.232	S Brush 115kV Sub Liv Line Terminal	20,315	4,154
440	Electric Transmission	Cooley	RE	A.0000463.009	Kilgore-Portales Reterm Line	19,918	4,073
441	Electric Transmission	Cooley	RE	A.0000673.026	TX/NM Border-Hobbs 345kV ROW_U	19,836	4,056
442	Electric Transmission	Cooley	RE	A.0000424.071	WIPP Sub Relay Mods Livingston	14,481	2,961
443	Electric Transmission	Cooley	SR	A.0001068.001	T97 Structure Relocate	14,155	2,895
444	Electric Transmission	Cooley	RE	A.0000463.006	Oasis T-32 Relay Upgrade Sub	13,685	2,799
445	Electric Transmission	Cooley	EC/TI	A.0000665.005	TUCO Mooreland Woodward TX RO	13,267	2,713
446	Electric Transmission	Cooley	RE	A.0000424.102	W Draw 115kV Sub /C Draw Term_	12,952	2,649
447	Electric Transmission	Cooley	RE	A.0001319.009	Canyon West Sub W40 Term Upgr	12,863	2,630
448	Electric Transmission	Cooley	RE	A.0000424.226	OPIE Potash Livingston Ridge ROW	11,346	2,320
449	Electric Transmission	Cooley	RE	A.0000463.007	Oasis-Portales T-32 Reterm Lin	10,285	2,103
450	Electric Transmission	Cooley	RE	A.0000424.063	S Brush-Cardinal 115 ROW_UID 5	10,277	2,102
451	Electric Transmission	Cooley	GI	A.0000768.005	Crosby Relay Upgrade for Blanc	10,271	2,100
452	Electric Transmission	Cooley	SR	A.0001273.013	Mustang Switch Repalcement	10,219	2,090
453	Electric Transmission	Cooley	RE	A.0000424.058	T38 Potash Re-Term_UID 50924	10,116	2,069
454	Electric Transmission	Cooley	RE	A.0000767.005	South Georgia Substation	10,108	2,067
455	Electric Transmission	Cooley	RE	A.0001312.003	Targa Cardinal Sub	8,753	1,790
456	Electric Transmission	Cooley	SR	A.0000220.005	SPS 2015 S&E Sub	7,825	1,600
457	Electric Transmission	Cooley	RE	A.0000522.013	Roswell Interchange W49 Relay	7,442	1,522
458	Electric Transmission	Cooley	RE	A.0000767.004	Randall County Interchange Sub	6,699	1,370
459	Electric Transmission	Cooley	RE	A.0000223.001	Carlisle 230/115kV Xfmr Upgrade	6,135	1,254
460	Electric Transmission	Cooley	RE	A.0000511.016	Carl-Wolf K-02 Reterm at Wolf	5,803	1,187
461	Electric Transmission	Cooley	RE	A.0001310.004	Walkemeyer 345/115 Sub Land	5,428	1,110
462	Electric Transmission	Cooley	LI	A.0001270.001	Bensing 115/12.47KV Dist(TAM)	5,183	1,060
463	Electric Transmission	Cooley	RE	A.0000424.062	S Brush-Cardinal 115kV L_UID 5	4,851	992
464	Electric Transmission	Cooley	SR	A.0000427.007	W20_Line Capacity Work	4,849	992
465	Electric Transmission	Cooley	RE	A.0000224.005	Zodiac Substation sub	4,814	984
466	Electric Transmission	Cooley	RE	A.0000424.105	W-39 Reterm at Wood Draw_UID 5	4,765	974
467	Electric Transmission	Cooley	RE	A.0000087.001	Roosevelt T33 Terminal Upgrade	4,601	941
468	Electric Transmission	Cooley	RE	A.0000424.049	Ponderosa-Custer Mt 115kV Line	4,438	907
469	Electric Transmission	Cooley	SR	A.0000220.031	SPS OK S&E Sub	4,376	895
470	Electric Transmission	Cooley	RE	A.0000866.033	Lamb County Land	4,076	834
471	Electric Transmission	Cooley	RE	A.0000424.183	Intercont Potash Conn 230kV Li	3,894	796
472	Electric Transmission	Cooley	RE	A.0000540.018	W-92 ROW	3,692	755
473	Electric Transmission	Cooley	RE	A.0000157.003	Eagle Creek Project(Artesia Tw	3,501	716
474	Electric Transmission	Cooley	RE	A.0000616.006	69kV Line Tap to Soncy Line	3,343	684
475	Electric Transmission	Cooley	RE	A.0000511.008	Carlisle to Wofforth ROW	3,239	662
476	Electric Transmission	Cooley	RE	A.0000296.013	NE Hereford- New Centre St 115	2,372	485
477	Electric Transmission	Cooley	RE	A.0000424.107	Potash Junction 230/115 Auto U	2,069	423
478	Electric Transmission	Cooley	RE	A.0000421.013	Newhart to Lamton ROW	1,690	346
479	Electric Transmission	Cooley	GI	A.0000105.005	Tolk Terminal Upgrades	1,656	339
480	Electric Transmission	Cooley	RE	A.0000463.005	Roosevelt T-33 Relay Upgrade S	1,584	324
481	Electric Transmission	Cooley	RE	A.0000424.086	Kiowa-North Loving 345kV ROW_U	1,420	290
482	Electric Transmission	Cooley	SR	A.0000401.034	Potter 230kV K59 Sub	1,285	263

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
483	Electric Transmission	Cooley	RE	A.0000424.225	Roadrunner Kiowa J23 ROW	1,263	258
484	Electric Transmission	Cooley	RE	A.0000511.009	Carl-Wolf K-10 Reterm at Wolf	1,187	243
485	Electric Transmission	Cooley	RE	A.0000424.219	Hopi to Copano Hopi Substation	1,162	238
486	Electric Transmission	Cooley	RE	A.0000916.002	Deaf Smith Reterm K21 Line	690	141
487	Electric Transmission	Cooley	RE	A.0000424.032	China Draw-Yeso Hills 115kV RO	670	137
488	Electric Transmission	Cooley	LI	A.0000062.002	Z86 New Tap to Oxy Cedar Lake ROW	476	97
489	Electric Transmission	Cooley	RE	A.0000673.024	Yoakum-TX/NM Border 345kV ROW_	458	94
490	Electric Transmission	Cooley	RE	A.0000463.013	Market St.-Portales ROW	412	84
491	Electric Transmission	Cooley	SR	A.0000258.049	Plant X Rpl SPW 111 PT	357	73
492	Electric Transmission	Cooley	RE	A.0000616.008	Soncy ROW	266	54
493	Electric Transmission	Cooley	RE	A.0000424.185	West Jal Sub	257	53
494	Electric Transmission	Cooley	RE	A.0000610.004	Curry to Bailey 115kV - Curry	253	52
495	Electric Transmission	Cooley	RE	A.0000424.131	N. Loving 115kV terminal -Chin	185	38
496	Electric Transmission	Cooley	RE	A.0000646.001	Wade SubstationSub	177	36
497	Electric Transmission	Cooley	LI	A.0000675.001	Pringle Dist Transformer Sub	177	36
498	Electric Transmission	Cooley	SR	A.0000499.004	Line ELR SPS 2016 Line	156	32
499	Electric Transmission	Cooley	RE	A.0000767.011	T-66 Reterm Line	89	18
500	Electric Transmission	Cooley	SR	A.0000303.028	SPS 2015 S&E TX B 69kV Line	78	16
501	Electric Transmission	Cooley	OT	A.0000820.006	SPS Physical Security	75	15
502	Electric Transmission	Cooley	SR	A.0000514.003	Rocky Point Switch Replmnt	69	14
503	Electric Transmission	Cooley	RE	A.0000424.100	China Draw 115kV Sub WDraw Ter	50	10
504	Electric Transmission	Cooley	RE	A.0000424.010	Potash Junction 115/69 Xfmr Up	25	5
505	Electric Transmission	Cooley	RE	A.0000424.187	Potash to West Jal 230kV ROW	25	5
506	Electric Transmission	Cooley	SR	A.0000427.003	Lidar Oklahoma SPS Line	20	4
507	Electric Transmission	Cooley	RE	A.0000481.011	New Ink Basin 230/115kV Substation	19	4
508	Electric Transmission	Cooley	RE	A.0000853.001	Hereford High Side Sub	18	4
509	Electric Transmission	Cooley	GI	11495216	Campbell St. Bus Modification,Sub	18	4
510	Electric Transmission	Cooley	RE	A.0000224.006	Kilgore Sub Highside Sub	11	2
511	Electric Transmission	Cooley	RE	A.0000424.076	Cardinal 115kV Sub Sage Brush	(2)	(0)
512	Electric Transmission	Cooley	LI	A.0000936.003	South Springlake-T28 Tap&Switc	(5)	(1)
513	Electric Transmission	Cooley	RE	A.0001310.006	Finney Relay Settings	(6)	(1)
514	Electric Transmission	Cooley	RE	A.0000424.016	Wreckout of Z22.2 Structures	(10)	(2)
515	Electric Transmission	Cooley	RE	A.0001310.007	Hitchland Relay Settings Texas	(10)	(2)
516	Electric Transmission	Cooley	RE	A.0000540.004	Seven Rivers Relay Sub	(27)	(5)
517	Electric Transmission	Cooley	RE	A.0000574.005	Inst Arms at Puckett W TapT37	(40)	(8)
518	Electric Transmission	Cooley	SR	A.0000427.001	SPS Line Capacity Line	(213)	(44)
519	Electric Transmission	Cooley	RE	A.0000224.007	Zodiac Substation NM Line	(254)	(52)
520	Electric Transmission	Cooley	SR	A.0000298.001	Eddy County SVC ControlsSub	(274)	(56)
521	Electric Transmission	Cooley	RE	A.0000540.003	Atoka Substation	(301)	(61)
522	Electric Transmission	Cooley	RE	A.0000610.007	Curry to Bailey 115kV NM ROW	(390)	(80)
523	Electric Transmission	Cooley	RE	A.0000773.001	Andrews County Substation	(613)	(125)
524	Electric Transmission	Cooley	RE	A.0000463.016	Roosevelt-Portales T-33 Reterm	(1,300)	(266)
525	Electric Transmission	Cooley	RE/SR	A.0000080.001	Oasis T32 Terminal Upgrade	(1,672)	(342)
526	Electric Transmission	Cooley	RE	A.0000488.008	Opie Roadrunner Agave Ochoa Pre Con	(1,700)	(348)

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
527	Electric Transmission	Cooley	RE	A.0000522.002	Price-Chaves 115 kV Line Line	(2,137)	(437)
528	Electric Transmission	Cooley	RE	A.0000707.002	Graham Intg-Add 115/69 Transfo	(2,595)	(531)
529	Electric Transmission	Cooley	LI	A.0000858.001	T38 Bopco 3Way Sw Inst Str#41	(3,021)	(618)
530	Electric Transmission	Cooley	GI	A.0000537.001	Novus Wind IV - Hitchland Sub	(4,044)	(827)
531	Electric Transmission	Cooley	RE	A.0000610.002	Curry to Bailey 115kV New Line	(4,536)	(928)
532	Electric Transmission	Cooley	RE	A.0000610.027	Curry to Bailey 115kV NM Line	(4,545)	(929)
533	Electric Transmission	Cooley	RE	A.0000463.003	Market St. Substation	(5,055)	(1,034)
534	Electric Transmission	Cooley	RE	A.0000767.014	V-04 Circuit Removal	(5,549)	(1,135)
535	Electric Transmission	Cooley	SR	A.0000287.035	Potash 4920 Breaker Rplmnt	(6,108)	(1,249)
536	Electric Transmission	Cooley	RE	A.0000533.002	Nichols 115kV BFR - Dumas 19th	(7,652)	(1,565)
537	Electric Transmission	Cooley	GI	A.0000768.003	Floyd-Blanco Retermination-115	(7,789)	(1,593)
538	Electric Transmission	Cooley	RE	A.0000424.059	T38 WIPP Re-Term_UID 50924	(7,884)	(1,612)
539	Electric Transmission	Cooley	SR	A.0000287.036	Carlsbad C900 Breaker Rplmnt	(9,276)	(1,897)
540	Electric Transmission	Cooley	LI	A.0001076.001	Xcel Install 3 Way Switch	(9,390)	(1,920)
541	Electric Transmission	Cooley	RE	A.0000424.073	S Brush 115kV Sub Liv Cardinal	(9,857)	(2,016)
542	Electric Transmission	Cooley	RE	A.0000463.001	Portales 115kV Loop Line	(17,463)	(3,571)
543	Electric Transmission	Cooley	RE	A.0000533.006	Nichols 115kV BFR - East Plant	(18,145)	(3,711)
544	Electric Transmission	Cooley	RE	A.0000919.001	Happy Intg. auto upgrades Sub	(19,053)	(3,896)
545	Electric Transmission	Cooley	OT	10695288	E&S Elec Trans Subs_SPS	(25,595)	(5,234)
546	Electric Transmission	Cooley	SR/LI	A.0000851.001	Pringle Substation Sub	(26,327)	(5,384)
547	Electric Transmission	Cooley	LI	A.0001156.001	Int 1 Way 115kV Switch Tap	(26,443)	(5,407)
548	Electric Transmission	Cooley	LI	A.0001097.002	Inst Z77 60kV Switch Reimb TOIF	(26,467)	(5,412)
549	Electric Transmission	Cooley	RE	A.0001312.004	TargaCardinal Recond115kV Line	(29,330)	(5,998)
550	Electric Transmission	Cooley	SR	A.0000220.017	SPS 2015 NM S&E Sub	(31,196)	(6,379)
551	Electric Transmission	Cooley	RE	A.0000354.001	Crobsy Co. 115kV Cap Bank Sub	(33,106)	(6,770)
552	Electric Transmission	Cooley	LI	A.0000711.002	LOA U06 Slack Spans Cust Portion	(39,132)	(8,002)
553	Electric Transmission	Cooley	RE	A.0000767.008	East Plant Relay Sub	(39,483)	(8,074)
554	Electric Transmission	Cooley	RE	A.0000215.012	Pleasant Hill to Roosevelt Co.	(45,306)	(9,265)
555	Electric Transmission	Cooley	LI	A.0000424.194	Pecos Dist Add/115kV Breaker a	(48,546)	(9,927)
556	Electric Transmission	Cooley	LI	A.0000553.001	Diamondback Lyntegar TerminalS	(50,429)	(10,312)
557	Electric Transmission	Cooley	RE	A.0000367.002	Bowers 2nd Auto Sub	(51,121)	(10,454)
558	Electric Transmission	Cooley	RE	A.0000361.004	KC Substation Sub	(52,037)	(10,641)
559	Electric Transmission	Cooley	RE	A.0000603.001	Crosby County Transformer #1Su	(58,784)	(12,021)
560	Electric Transmission	Cooley	RE	A.0000424.177	Hopi Breaker Install Pecos Ter	(59,865)	(12,242)
561	Electric Transmission	Cooley	RE	A.0000463.011	Kilgore-South Portales ROW	(60,765)	(12,426)
562	Electric Transmission	Cooley	RE	A.0000361.001	KC Sub-Sulpher Springs 115kV T	(62,647)	(12,811)
563	Electric Transmission	Cooley	RE	A.0000407.004	Howard Substation	(70,153)	(14,346)
564	Electric Transmission	Cooley	LI	A.0001002.002	115kV N loving Sub Ter Upg Xcel Por	(72,600)	(14,846)
565	Electric Transmission	Cooley	OT	A.0001106.001	WIPP W38 Structure Relocate	(72,878)	(14,903)
566	Electric Transmission	Cooley	RE	A.0000407.002	Bowers Substation sub	(76,302)	(15,603)
567	Electric Transmission	Cooley	LI	A.0000634.001	Higg East igh Side(Sub Portion	(80,057)	(16,371)
568	Electric Transmission	Cooley	RE	A.0000424.174	North Loving 115kV Bkr Ring Su	(82,511)	(16,873)
569	Electric Transmission	Cooley	SR	A.0000401.033	Potash Junction 115kV 4920	(87,662)	(17,926)
570	Electric Transmission	Cooley	RE	A.0000522.004	Chaves-Price-Capitan 115 kV Ca	(87,971)	(17,989)

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

Line No.	(A) Asset Class	(B) Witness	(C) Project Category	(D) WBS Level 2	(E) Project Description (WBS Level 2 Description)	(F) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	(G) Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
571	Electric Transmission	Cooley	RE	A.0000522.001	Capitan-Price 115 kV Line, Li	(91,059)	(18,621)
572	Electric Transmission	Cooley	RE	A.0000424.028	PCA Terminal Upgrade_Sub	(103,247)	(21,113)
573	Electric Transmission	Cooley	RE	A.0000215.002	Pleasant Hill 345/230kV NM Sub	(111,148)	(22,729)
574	Electric Transmission	Cooley	RE	A.0000357.001	Grassland XFMR Sub	(118,701)	(24,273)
575	Electric Transmission	Cooley	RE	A.0000409.004	Cherry St Intg Hastings-E.Plt	(124,356)	(25,430)
576	Electric Transmission	Cooley	RE	A.0000424.015	China Draw High Side Substatio	(125,536)	(25,671)
577	Electric Transmission	Cooley	SR	A.0000645.001	115/69 kV Mobile Sub, Sub	(144,380)	(29,525)
578	Electric Transmission	Cooley	RE	A.0000646.004	Ochiltree - BookerROW	(149,002)	(30,470)
579	Electric Transmission	Cooley	RE	A.0000426.004	Plainview City Exp, Cox, Sub	(171,541)	(35,079)
580	Electric Transmission	Cooley	RE	A.0000302.002	Dallam Co. 230/115 kV sub	(176,484)	(36,090)
581	Electric Transmission	Cooley	RE	A.0000914.001	Drinkard 115 Cap Bank Sub	(179,497)	(36,706)
582	Electric Transmission	Cooley	SR	A.0000153.001	SPS Trans Switch Replmnt Line	(197,508)	(40,389)
583	Electric Transmission	Cooley	EC/TI	A.0000417.003	Tuco to Mooreland (Woodward) R	(209,175)	(42,775)
584	Electric Transmission	Cooley	EC/TI	A.0000417.015	TUCO-Mooreland Woodward TX ROW 2017	(229,301)	(46,890)
585	Electric Transmission	Cooley	RE	A.0000407.001	Bowers - Howard ROW	(230,393)	(47,114)
586	Electric Transmission	Cooley	RE	A.0000301.002	Lynn Co. Dist. Load Conversion	(231,421)	(47,324)
587	Electric Transmission	Cooley	EC/TI	A.0000244.002	Hitchland to Woodward 345 kV S	(268,840)	(54,976)
588	Electric Transmission	Cooley	RE	A.0000421.006	Newhart Intg Hart Ind-Lamton11	(285,397)	(58,361)
589	Electric Transmission	Cooley	LI	A.0001126.001	Inst Temp Switch Reimb TOIF	(320,517)	(65,543)
590	Electric Transmission	Cooley	GI	A.0000768.002	Crosby-Blanco Retermination-11	(330,204)	(67,524)
591	Electric Transmission	Cooley	LI	A.0001002.001	115kV N loving Sub TOIF Lucid Porti	(471,792)	(96,478)
592	Electric Transmission	Cooley	SR	A.0000303.046	SPS S&E 345kV Line TX 2016	(552,009)	(112,881)
593	Electric Transmission	Cooley	GI	A.0000768.001	GEN-2011-025 Fiber Wind Blanco	(704,828)	(144,132)
594	Electric Transmission	Cooley	GI	A.0000105.001	R27 Reconductor	(991,467)	(202,747)
595	Electric Transmission	Cooley	RE	A.0000424.029	V21_Quahada 115kV Reconductor	(1,046,782)	(214,059)
596	Electric Transmission	Cooley	RE	A.0000890.001	Eddy Co. 230/115 Xfmr #1 Upgra	(1,064,791)	(217,741)
597	Electric Transmission	Cooley	SR	A.0000427.011	K83_Line Capacity Work	(1,092,475)	(223,402)
598	Electric Transmission	Cooley	GI	A.0000350.001	Lost Draw Substation	(1,606,213)	(328,458)
599	Electric Transmission	Cooley	SR	A.0000776.002	Security Resilience Spare TR	(1,786,008)	(365,224)
600	Electric Transmission	Cooley	GI	A.0000564.002	Tuco 345 Trsf Rplmnt Sub Portion	(2,203,625)	(450,624)
601	Electric Transmission	Cooley	GI	A.0000736.002	Needmore Substation	(2,282,270)	(466,706)
602	**Electric Transmission Total**					$ 256,772,854	$ 52,507,979
603	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010017.001	TX - OH Rebuild Blanket	$ 9,759,736	$ -
604	Electric Distribution	Meeks	New Business	A.0010002.001	NM - OH Extension Blanket	9,050,623	9,050,623
605	Electric Distribution	Meeks	Purchases	D.0005014.009	TX Electric Distribution Transforme	7,325,623	-
606	Electric Distribution	Meeks	New Business	A.0010001.001	TX - OH Extension Blanket	5,043,139	-
607	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.130	Convert Soncy to 115/13.2kV 50	4,996,621	-
608	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005583.001	TEXAS MAJOR STORM RECOVERY	4,169,374	-
609	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010017.007	TX - Pole Blanket	4,128,697	-
610	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.370	Install 115/12.47kV 14MVA substatio	3,798,784	3,798,784
611	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010018.001	NM - OH Rebuild Blanket	3,358,925	3,358,925
612	Electric Distribution	Meeks	Purchases	D.0005014.011	NM Electric Distribution Transforme	3,204,394	3,204,394
613	Electric Distribution	Meeks	New Business	A.0010001.002	TX - UG Extension Blanket	2,954,609	-

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
614	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.015	Outpost Substation 115-13.2kV 28MVA	2,945,627	-
615	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.259	Convert Centre Street Replace	2,840,066	-
616	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.258	Install New 34.5kV Source book	2,722,944	-
617	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.211	Convert Curry Co. Interchange	2,439,579	2,439,579
618	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.004	Tx N-Dist Substation Equip Rep	2,339,009	-
619	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010017.005	TX - OH Street Light Rebuild Blanke	1,999,307	-
620	Electric Distribution	Meeks	Purchases	D.0005014.028	TX-Electric Meter Blanket	1,970,023	-
621	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010156.001	Install Preston West Substation - L	1,726,698	-
622	Electric Distribution	Meeks	New Business	A.0010002.002	NM - UG Extension Blanket	1,605,710	1,605,710
623	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005584.001	Convert 4kV Load out of RIAC East a	1,490,201	1,490,201
624	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0000781.020	Install Outpost Substation 115-13.2	1,445,465	-
625	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010018.007	NM - Pole Blanket	1,433,712	1,433,712
626	Electric Distribution	Meeks	New Business	A.0005500.051	Cnturion Jal Orig Pmp Stn PME/Oxy M	1,095,058	1,095,058
627	Electric Distribution	Meeks	New Business	A.0010001.004	TX - UG New Services Blanket	1,068,676	-
628	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010033.001	TX - OH Reinforcement Blanket	1,033,451	-
629	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.200	NM - Subs Equipment Replace	873,726	873,726
630	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010138.001	Land purchase for Western St Sub	831,102	-
631	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010017.002	TX - UG Conversion/Rebuild Blanket	775,292	-
632	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005517.024	Substation Land - New Mexico	674,045	674,045
633	Electric Distribution	Meeks	New Business	A.0010059.001	SEM/RING ENERGY/5.7 MILE RECONDUCTO	662,233	-
634	Electric Distribution	Meeks	New Business	A.0010060.002	EUNICE/SAGE BRUSH 556 EXT	606,001	606,001
635	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.085	Feeder breaker degradation - S	599,725	-
636	Electric Distribution	Meeks	New Business	A.0010060.005	JAL/ GWS DEEP POSEIDON SWD/ RECON &	581,119	581,119
637	Electric Distribution	Meeks	Purchases	A.0005517.013	NM-Elec-Easement	570,765	570,765
638	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010092.004	Reconductor Intrepid Potash Pond	565,257	565,257
639	Electric Distribution	Meeks	New Business	A.0010060.003	CIMAREX WHITE CITY PME	536,443	536,443
640	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005584.002	NEW MEXICO MAJOR STORM RECOVERY	523,036	523,036
641	Electric Distribution	Meeks	New Business	A.0010002.004	NM - UG New Services Blanket	482,572	482,572
642	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010076.001	JAL/ JAL ORIGINATION PUMP/3PH RCND	476,927	476,927
643	Electric Distribution	Meeks	Purchases	D.0005014.030	NM-Electric Meter Blanket	438,814	438,814
644	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005583.005	TX Mixed Work Adjustment	422,109	-
645	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010123.004	Damron Transformer Replacement	411,441	-
646	Electric Distribution	Meeks	New Business	A.0010060.006	Mesquite Services, LLC- Cypress SWD	391,721	391,721
647	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010123.002	Repl Failed Kite Transfrmr 69/13.2	387,573	-
648	Electric Distribution	Meeks	New Business	A.0005500.047	JAL/SE SEC6T24R31/ OXY MESA VER/ RE	384,087	384,087
649	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010018.005	NM - OH Street Light Rebuild Blanke	364,543	364,543
650	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0000296.002	Replace existing Hereford 69/1	353,737	-
651	Electric Distribution	Meeks	New Business	A.0010060.001	SUMMIT MIDSTREAM PARTNERS	334,871	334,871
652	Electric Distribution	Meeks	New Business	A.0010001.003	TX - OH New Services Blanket	332,463	-
653	Electric Distribution	Meeks	New Business	A.0010002.003	NM - OH New Services Blanket	318,684	318,684
654	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005583.002	TEXAS POLE INSPECTIONS	245,252	-
655	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.052	Install Market St 12.5kV Feede	243,496	243,496
656	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010017.003	TX - OH Services Renewal Blanket	228,205	-
657	Electric Distribution	Meeks	Purchases	A.0005517.015	TxN-Elec Easement	211,270	-

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
658	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005517.025	Substation Land - TX	198,094	-
659	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010010.001	NM - OH Relocation Blanket	190,629	190,629
660	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005522.006	Replace Existing Substation Breaker	173,392	173,392
661	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.086	ELR - Substation Relays - SPS	168,354	-
662	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.186	Rebuild Planview City 69/2.4kV	163,638	-
663	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010018.003	NM - OH Services Renewal Blanket	161,682	161,682
664	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010034.001	NM - OH Reinforcement Blanket	148,047	148,047
665	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010009.001	TX - OH Relocation Blanket	147,804	-
666	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010018.002	NM - UG Conversion/Rebuild Blanket	140,471	140,471
667	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005584.006	NM Mixed Work Adjustment	138,150	138,150
668	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010124.005	Replace Failed Urton XFR	136,684	136,684
669	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010017.006	TX - UG Street Light Rebuild Blanke	131,369	-
670	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0000646.019	Convert Town of Booker to 34.5	116,413	-
671	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.183	Conv Portales So to 115/4.2kV	109,620	109,620
672	Electric Distribution	Meeks	Purchases	A.0005517.017	TxS-Elec Easement	98,050	-
673	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010002.006	NM - UG New Street Light Blanket	96,395	96,395
674	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.184	Conv Market St to 115/12.5kV 2	90,453	90,453
675	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0001300.053	Install 2 12.47kV OH lines from Sie	85,671	85,671
676	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010001.006	TX - UG New Street Light Blanket	68,800	-
677	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010001.005	TX - OH New Street Light Blanket	67,137	-
678	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.153	SPS-TX Convert Obsolete Vltg D	65,298	-
679	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.087	ELR - Substation Regulators -	63,109	-
680	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010002.005	NM - OH New Street Light Blanket	62,606	62,606
681	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0000860.005	Convert Curry Co. Interchange 69kV	61,151	61,151
682	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010009.002	TX - UG Relocation Blanket	58,730	-
683	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010018.004	NM - UG Services Renewal Blanket	55,062	55,062
684	Electric Distribution	Meeks	New Business	A.0005505.009	Txn-(0025) Ug Services	53,048	-
685	Electric Distribution	Meeks	Purchases	A.0005584.004	SPS-NM CAPITALIZED ELECTRIC LOCATES	50,873	50,873
686	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010017.004	TX - UG Services Renewal Blanket	46,841	-
687	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010026.002	NM - FPIP Blanket	37,862	37,862
688	Electric Distribution	Meeks	Purchases	A.0005583.003	SPS-TX CAPITALIZED ELECTRIC LOCATES	36,209	-
689	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005584.003	NEW MEXICO POLE INSPECTIONS	34,207	34,207
690	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010025.001	TX - REMS Blanket	31,413	-
691	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0005506.009	TXOH Street Lights-TX	28,906	-
692	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.225	SENM	26,407	26,407
693	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0010018.006	NM - UG Street Light Rebuild Blanke	18,391	18,391
694	Electric Distribution	Meeks	New Business	A.0005501.116	AMARILLO/TIMES SQUARE VILLAGE 1/BAC	18,298	-
695	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.223	Convert Hereford 69/13.2kV to	18,248	-
696	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.106	Conver Wade to 115/12.5KV &MVA	18,204	-
697	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.179	Convert Town of Booker to 34.5	17,159	-
698	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.218	Convert Livingston Ridge #1 69	13,916	13,916
699	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.182	Convert Centre Street - Remova	13,854	-
700	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005518.095	Sps-Poor Perf Fdr Replace Blkt	12,188	-
701	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010025.002	TX - FPIP Blanket	10,363	-

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
702	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005509.011	TXUG ConvrsnsRebuilds-TX	9,769	-
703	Electric Distribution	Meeks	New Business	A.0005505.007	NMUG Services-NM	9,137	9,137
704	Electric Distribution	Meeks	New Business	A.0005504.008	TXOH Services-TX	8,273	-
705	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.232	Inst Muleshoe East 12.5/2.4 3-	7,147	-
706	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0005506.008	NMOH Street Lights-NM	6,761	6,761
707	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005510.007	NMOH Relocations-NM	6,687	6,687
708	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0010033.002	TX - UG Reinforcement Blanket	6,261	-
709	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010009.003	TX - UG Service Conversion Blanket	5,499	-
710	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.202	Replace Substation Relays-NM	4,573	4,573
711	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005511.011	NMUG Relocations-NM	3,353	3,353
712	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.140	Potash #2 Replace Failed XFMR	2,964	2,964
713	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.073	Reinf Price T1 69 to 115 kV 2	2,917	2,917
714	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0000860.004	Convert Curry Co. Interchange	2,677	2,677
715	Electric Distribution	Meeks	New Business	A.0005504.007	NMOH Services-NM	2,344	2,344
716	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0010010.002	NM - UG Relocation Blanket	2,044	2,044
717	Electric Distribution	Meeks	New Business	A.0005501.011	TXUG Extension-TX	1,825	-
718	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005503.008	TXUG Reinforcements-TX	1,642	-
719	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005511.012	TXUG Relocations-TX	1,530	-
720	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.260	Reinforce Pringle Oil Field 10	1,493	-
721	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005509.010	NMUG ConvrsnsRebuilds-NM	1,341	1,341
722	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005510.021	Txn Blanket-Oh Relocations	1,246	-
723	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.247	Install Sunset 13.2kV Feeders	1,157	-
724	Electric Distribution	Meeks	New Business	A.0005500.009	NMOH Extension-NM	894	894
725	Electric Distribution	Meeks	Distribution Line and Substation Capacity	11789422	Purch Land for Higg East Sub	542	-
726	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.357	Install Ponderosa #1 115/25KV	324	324
727	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.188	Order new system spare 115/12k	252	-
728	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.031	Txn-(022) Oh Rebuilds	159	-
729	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005518.013	Reliability Monitoring System	159	-
730	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.101	Inspect/Replace Poles_Texas	3	-
731	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005518.087	Reliability Monioring System	3	3
732	Electric Distribution	Meeks	New Business	A.0005504.009	Txs-(023) Oh Services	(1)	-
733	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005519.023	TX North-UG Service Conv	(119)	-
734	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005584.005	SPS NM Targeted OH Rebuild - A	(129)	(129)
735	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005510.008	TXOH Relocations-TX	(144)	-
736	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005510.072	TX Pole Transfers	(168)	-
737	Electric Distribution	Meeks	New Business	A.0005505.011	0025 Blanket - New Mexico Ug S	(191)	(191)
738	Electric Distribution	Meeks	Purchases	A.0005516.033	Scrap Sale Credits-SPS	(218)	-
739	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.011	Purchase 115/25KV 50 MVA reserve tr	(511)	(511)
740	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005521.012	Replace North Hobbs T2 - 28MVA	(664)	(664)
741	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.175	Construct Kilgore115/4.2kV 14M	(710)	(710)
742	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.263	Install New 115/12.5kV Bensing	(883)	(883)
743	Electric Distribution	Meeks	New Business	A.0005500.024	Txs Blanket-Oh Extension	(1,270)	-
744	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.007	NMOH Rebuilds-NM	(1,670)	(1,670)
745	Electric Distribution	Meeks	New Business	A.0005505.008	TXUG Services-TX	(2,277)	-

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
746	Electric Distribution	Meeks	Purchases	A.0005511.048	Capitalized Locating Costs-Ele	(3,838)	-
747	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005509.037	Nm Blanket-Ug Conv/Rebuilds	(6,945)	(6,945)
748	Electric Distribution	Meeks	New Business	A.0005500.025	NM Blanket-Oh Extension	(9,031)	(9,031)
749	Electric Distribution	Meeks	New Business	A.0005500.023	Tx Blnkt-Overhead Extensions	(12,170)	-
750	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.009	TXOH Reinforcements-TX	(17,433)	-
751	Electric Distribution	Meeks	New Business	A.0005500.007	TXOH Extension-TX	(17,735)	-
752	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.007	Wood Draw Pad Expansion	(21,958)	(21,958)
753	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.105	Inst China Draw 69/12.5kV 28MV	(23,296)	(23,296)
754	Electric Distribution	Meeks	Outdoor/Area Lighting	A.0005507.006	NMUG Street Lights-NM	(42,601)	(42,601)
755	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.177	Inst Camex 115/13.2kV 28MVA T3	(44,813)	-
756	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.077	Convert Zodiac T1 69 to 115 kV	(61,323)	(61,323)
757	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.178	Inst Higg East 115/12.5kV 28MV	(80,931)	-
758	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0000302.016	Conv Channing to 230/35kV 2-28	(96,646)	-
759	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005522.127	Inst Battle Axe115/12.5kV 28MV	(107,731)	(107,731)
760	Electric Distribution	Meeks	New Business	A.0006062.010	Distribution CIAC TX Elec	(119,885)	-
761	Electric Distribution	Meeks	New Business	A.0005500.043	BUSHLAND/ 26511 N US HIGHWAY 287/ N	(175,186)	-
762	Electric Distribution	Meeks	Distribution Line and Substation Capacity	A.0005502.231	Install Battle Axe 12.5kV Feed	(239,996)	(239,996)
763	Electric Distribution	Meeks	Distribution Line and Substation Reconstruction	A.0005508.008	TXOH Rebuilds-TX	(280,170)	-
764	Electric Distribution	Meeks	New Business	A.0006062.011	Distribution CIAC NM Elec	(1,668,842)	(1,668,842)
765	**Electric Distribution Total**					$ 100,309,251	$ 35,534,299
766	Electric General	Bick	Building & Infrastructure	D.0001813.061	Canyon Service Center - New	$ 7,485,131	$ 2,077,979
767	Electric General	Meeks	Purchases	A.0006056.213	TX-DIST Fleet New Unit Purchases	4,441,545	1,233,036
768	Electric General	Cooley	OT	A.0006056.224	Fleet New Unit El Trans TX	2,556,508	709,723
769	Electric General	Meeks	Purchases	A.0006059.006	TX-Dist Electric Tools and Equip	2,514,101	697,950
770	Electric General	Harkness	Aging Technology	D.0001839.827	Purch Eddy County MW Equip NM	2,323,748	645,106
771	Electric General	Cooley	OT	A.0001118.006	Lock and Key System TX	1,418,821	393,885
772	Electric General	Meeks	Purchases	A.0006059.016	TX-Dist Subs Tools and Equip	1,340,173	372,051
773	Electric General	Meeks	Purchases	A.0006056.214	NM-DIST Fleet New Unit Purchase El	1,101,616	305,824
774	Electric General	Harkness	Aging Technology	D.0001821.290	2018 Unplanned PC SPS	1,045,629	290,281
775	Electric General	Meeks	Purchases	A.0005549.009	SPS-Dist Sub Communication Equ	985,469	273,580
776	Electric General	Cooley	OT	A.0000710.008	SPS Physical Security Comm	951,084	264,035
777	Electric General	Harkness	Cyber Security	D.0002000.008	Purch CIP Appl SPS	819,010	227,369
778	Electric General	Harkness	Aging Technology	D.0001821.311	2018 Planned PC SPS	775,703	215,346
779	Electric General	Cooley	OT	A.0000588.011	Moore Co 115kV RTU Rplmnt	766,987	212,927
780	Electric General	Cooley	RE	A.0000424.164	N Loving 345kV Sub Comms_UID 5	567,117	157,440
781	Electric General	Cooley	OT	A.0001118.007	Lock and Key System NM	481,955	133,797
782	Electric General	Cooley	SR	A.0000220.030	Amoco RTU Replacement	456,110	126,623
783	Electric General	Harkness	Aging Technology	D.0002016.017	Purch T&D MPLS - Unplanned (2017) N	450,721	125,127
784	Electric General	Harkness	Aging Technology	D.0002021.004	Purch Facility IT Investments HW SP	445,784	123,756
785	Electric General	Cooley	RE	A.0000424.168	China Draw 345kV Sub Comms_UID	381,692	105,963
786	Electric General	Cooley	OT	A.0006059.063	SPS Sub Comm Tool Blanket	377,140	104,700
787	Electric General	Meeks	Purchases	A.0005549.010	NM-Dist Sub Communication Equi	374,135	103,865
788	Electric General	Cooley	RE	A.0000511.017	Carl-Wolf Carisle Comm	366,956	101,872

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
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789	Electric General	Meeks	Purchases	A.0006059.007	NM-Dist Electric Tools and Equip	347,200	96,388
790	Electric General	Harkness	Aging Technology	D.0001783.021	Purch LMR Radio HW TX	321,210	89,172
791	Electric General	Cooley	RE	A.0000296.009	NE Hereford Comm	312,659	86,799
792	Electric General	Cooley	OT	A.0000948.004	TX Frame Relay Comm	302,571	83,998
793	Electric General	Cooley	OT	A.0000948.003	NM Frame Relay Comm	297,380	82,557
794	Electric General	Harkness	Aging Technology	D.0001821.307	2018 EMS Infra Refresh SPS	289,475	80,362
795	Electric General	Bick	Security - Controls & Monitoring	D.0001781.049	790 Buchannan Security System	277,391	77,008
796	Electric General	Bick	Building & Infrastructure	D.0001834.039	Carlsbad Roof Seal-Safety System	272,224	75,573
797	Electric General	Harkness	Aging Technology	D.0001821.278	2018 IT INFS Network Refresh S	257,063	71,364
798	Electric General	Cooley	RE	A.0001300.020	Roswell Intg New 115kV Terminal Com	252,009	69,961
799	Electric General	Cooley	GI	A.0000736.003	Needmore Communication	244,912	67,991
800	Electric General	Harkness	Enhance Capabilities	D.0001804.397	Purch Wireless HW SPS	239,605	66,518
801	Electric General	Cooley	RE	A.0000194.006	Cochran RTU, Comm	228,136	63,334
802	Electric General	Cooley	RE	A.0001310.008	Walkemeyer 345/115 Sub Comm	217,960	60,509
803	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.689	GMSOC-TX Lab Instruments	217,876	60,486
804	Electric General	Cooley	RE	A.0000296.007	New Centre St Comm	212,859	59,093
805	Electric General	Harkness	Aging Technology	D.0001839.148	2018 Storage Annual Refresh SP	207,751	57,675
806	Electric General	Harkness	Aging Technology	D.0002016.004	Purch T&D MPLS - Unplanned (2017) S	197,841	54,923
807	Electric General	Harkness	Aging Technology	D.0002014.001	Purch WAN HW SPS-BSPRJ0001170	197,774	54,905
808	Electric General	Cooley	OT	A.0006059.500	EPZ Mats NM	190,062	52,764
809	Electric General	Cooley	OT	A.0006059.499	EPZ Mats TX	185,713	51,557
810	Electric General	Cooley	RE	A.0000540.017	Atoka Comm Sub Portion Comm	181,320	50,337
811	Electric General	Harkness	Enhance Capabilities	D.0001804.396	Purch Wireless HW NM	175,180	48,632
812	Electric General	Lytal	Reliability & Performance Enhancement	A.0006056.227	GSMOC Purchase Vehicles	173,296	48,109
813	Electric General	Cooley	SR	A.0000499.017	PS ELR 115kV NM Comm	169,242	46,984
814	Electric General	Harkness	Enhance Capabilities	D.0001804.327	Purch Wireless HW SPS	167,034	46,371
815	Electric General	Harkness	Aging Technology	D.0001840.004	2017 Network Refresh SPS	164,421	45,646
816	Electric General	Cooley	OT	A.0000795.003	SPS Sub Comm Network Group 1 C	163,179	45,301
817	Electric General	Cooley	GI	A.0001351.003	Roswell Comm	160,460	44,546
818	Electric General	Cooley	RE	A.0000658.007	Seagraves Comm	147,339	40,904
819	Electric General	Harkness	Aging Technology	D.0002014.002	Purch WAN HW NM	146,254	40,602
820	Electric General	Cooley	GI	A.0000350.004	Lost Draw Comm	143,270	39,774
821	Electric General	Cooley	RE	A.0001353.001	Roosevelt Comm	140,839	39,099
822	Electric General	Cooley	GI	A.0000902.002	TUCO RTU Addition Comm	135,542	37,629
823	Electric General	Cooley	OT	A.0000710.007	NM Physical Security Comm	132,175	36,694
824	Electric General	Harkness	Cyber Security	D.0001840.114	Purch Sec Camera HW TX	114,721	31,848
825	Electric General	Cooley	RE	A.0000658.006	Terry Co Comm	114,109	31,678
826	Electric General	Cooley	LI	A.0001008.004	Inst 230kV Sw Station Comm	111,870	31,057
827	Electric General	Meeks	Purchases	A.0005549.034	TX Frame Relay Replacement	111,566	30,972
828	Electric General	Cooley	OT	A.0006059.432	Tool Blanket TX Line	108,292	30,063
829	Electric General	Cooley	SR	A.0001067.002	Lubbock South Communication	103,192	28,647
830	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.684	TOLOC - Purch Misc Tools	98,438	27,328
831	Electric General	Cooley	SR	A.0001067.003	Lubbock East Communication	97,429	27,048
832	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.668	HAROC-Purch Plant Tools	95,600	26,540

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
833	Electric General	Harkness	Aging Technology	D.0001821.538	Purch Mobile Handheld HW SPS	93,656	26,000
834	Electric General	Cooley	RE	A.0000488.005	OCHOA Comm	92,896	25,789
835	Electric General	Cooley	SR	A.0000499.016	Line ELR SPS 2016 Comm	91,691	25,455
836	Electric General	Cooley	SR	A.0000153.003	SPS Trans Switch Comm	83,308	23,127
837	Electric General	Cooley	LI	A.0000854.003	Install Switch and Tap Comm	80,896	22,458
838	Electric General	Cooley	RE	A.0000494.003	Seminole Xfmr East Comm	79,541	22,082
839	Electric General	Cooley	LI	A.0000424.173	W39 Inst Switch for Enterprise	71,768	19,924
840	Electric General	Bick	Building & Infrastructure	D.0001823.084	Misc Bldg - Electric - Dumas - Rout	65,419	18,161
841	Electric General	Cooley	RE	A.0001283.003	Business System Equip for Eng Acces	65,343	18,140
842	Electric General	Harkness	Aging Technology	D.0001821.537	2018 IT INFS Network Ref HW NM	64,721	17,968
843	Electric General	Cooley	RE	A.0001272.002	Cargill 14.4 Mvar Cap Bank Comm	63,180	17,540
844	Electric General	Cooley	RE	A.0000424.043	OPIE 3_Hobbs 345kV Sub Comms_U	62,076	17,233
845	Electric General	Cooley	OT	A.0006059.436	SPS Ops Engineering Tools	59,245	16,447
846	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.692	GMSOC-MMR Instruments	56,118	15,579
847	Electric General	Cooley	RE	A.0000511.018	Carl-Wolf Wolfforth Comm	54,102	15,020
848	Electric General	Cooley	OT	A.0000588.001	SPS RTU EMS Upgrade	53,949	14,977
849	Electric General	Cooley	RE	A.0000290.008	Cunningham Intg Upgr Eddy Term Comm	53,801	14,936
850	Electric General	Bick	Building & Infrastructure	D.0001813.022	Amarillo Tower New Lease	51,606	14,327
851	Electric General	Harkness	Enhance Capabilities	D.0001804.325	Purch Wireless Hobbs NM SPS	51,522	14,303
852	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.691	GMSOC-TRaC Tools	49,357	13,702
853	Electric General	Cooley	RE	A.0000194.007	Cochran Comm Equiup	49,254	13,674
854	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.429	JONOC-Rpl Milling Machine	48,276	13,402
855	Electric General	Cooley	RE	A.0000424.222	Quahada Communication	45,354	12,591
856	Electric General	Lytal	Reliability & Performance Enhancement	A.0001550.460	HAROC-Purchase PMI Analyzer	39,628	11,001
857	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.673	JONOC-Capital Tools	37,899	10,521
858	Electric General	Cooley	OT	A.0006056.223	Fleet New Units El Trans NM	36,470	10,125
859	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.677	PLXOC-Purch Misc Plant Tool	35,068	9,735
860	Electric General	Harkness	Aging Technology	D.0001839.406	Microwave Crossroads/Towers SP	34,563	9,595
861	Electric General	Cooley	OT	A.0006059.437	SPS COM Tools (BU 8371)	34,545	9,590
862	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.674	MADOC-Purchase Cap Tools	34,414	9,554
863	Electric General	Cooley	RE	A.0000424.221	PCA Communication	33,396	9,271
864	Electric General	Bick	Tools & Equipment	A.0006059.489	Tools & Equipment - Electric - NM	32,469	9,014
865	Electric General	Harkness	Aging Technology	D.0001839.621	Purch Avaya Server HW SPS	32,451	9,009
866	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.693	GMSOC-PMO Equipment	28,270	7,848
867	Electric General	Cooley	SR/LI	A.0000851.002	Pringle Substation Comm	25,223	7,002
868	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.690	GMSOC-E&C Tools	23,823	6,614
869	Electric General	Cooley	LI	A.0000905.002	Install Switch and Tap Comm	22,101	6,136
870	Electric General	Cooley	RE	A.0002033.001	Portales Interchange Sub Comm	21,825	6,059
871	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.675	NICOC-Purch Plant Tools	21,541	5,980
872	Electric General	Cooley	OT	A.0000924.011	SPS CIP 5 RooseveltCo NM Comm	21,412	5,944
873	Electric General	Cooley	RE	A.0000424.233	Hopi Bkr Inst pecos Term Sub Comm	21,368	5,932
874	Electric General	Bick	Building & Infrastructure	D.0001810.057	Amarillo NESC Evidence Storage Faci	21,098	5,857
875	Electric General	Cooley	OT	A.0006059.434	SPS Training Center Tools	18,804	5,220
876	Electric General	Harkness	Aging Technology	D.0001800.939	Purch Verint Server HW SPS	17,848	4,955

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877	Electric General	Harkness	Aging Technology	D.0002016.018	Purch T&D MPLS - Unplanned (2017) O	17,683	4,909
878	Electric General	Meeks	Purchases	A.0005549.028	NM-Elec Dist Communication Equip	17,563	4,876
879	Electric General	Cooley	OT	A.0001118.009	Lock and Key System OK	17,284	4,798
880	Electric General	Meeks	Purchases	A.0005014.110	Remodel SPS Lubbock Dist Control Ce	16,427	4,560
881	Electric General	Cooley	RE	A.0000424.069	L Ridge 115kV Sub Comms_UID 50	13,979	3,881
882	Electric General	Cooley	OT	A.0000924.010	SPS CIP 5 Potter Co Comm	13,796	3,830
883	Electric General	Harkness	Aging Technology	D.0001839.370	Purch SPS Gold Elite Console H	13,782	3,826
884	Electric General	Cooley	OT	A.0000924.009	SPS CIP 5 Plant X Sta Comm	13,595	3,774
885	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.688	GMS0C-Training Tools	13,165	3,655
886	Electric General	Harkness	Enhance Capabilities	D.0002007.008	Purch Digital Signage HW SPS	12,390	3,440
887	Electric General	Meeks	Purchases	A.0006056.019	NM-DIST Fleet New Unit Purchase El	12,286	3,411
888	Electric General	Cooley	OT	A.0000588.010	Grassland RTU Replacement	11,139	3,092
889	Electric General	Meeks	Purchases	A.0005555.002	NM - Frame Relay Replacement	10,356	2,875
890	Electric General	Cooley	OT	A.0006059.081	Tools Sys Protection Comm Eng	9,332	2,591
891	Electric General	Harkness	Aging Technology	D.0001822.010	Purch Sub Frame Relay Equip SP	9,182	2,549
892	Electric General	Meeks	Purchases	A.0005014.076	SPS-Subs Furniture Blanket	8,831	2,452
893	Electric General	Harkness	Aging Technology	D.0001822.057	Purch Sub Frame BAU Sites TX SPS	8,784	2,439
894	Electric General	Cooley	OT	A.0005014.109	Gen Plt Ofc Furn TX	7,594	2,108
895	Electric General	Bick	Building & Infrastructure	D.0001806.086	Mechanical - Dumas - Routine	7,465	2,072
896	Electric General	Bick	Security - Controls & Monitoring	D.0001781.041	Security Projects - Electric -	6,739	1,871
897	Electric General	Cooley	SR	A.0000589.009	Tuco 115 House RTU Replacement Comm	6,509	1,807
898	Electric General	Cooley	RE	A.0000890.002	Eddy Co. Xfmr #1 Communication	5,939	1,649
899	Electric General	Harkness	Aging Technology	D.0001822.008	Purch Sub Frame Relay Equip NM	5,850	1,624
900	Electric General	Meeks	Purchases	A.0006059.105	NM-Transportation Tools & Equi	5,480	1,521
901	Electric General	Cooley	RE	A.0000846.002	Denver City RTU Comm	5,171	1,436
902	Electric General	Harkness	Cyber Security	D.0001804.126	Purch Network Appl Camera Upgr SPS	4,412	1,225
903	Electric General	Cooley	OT	A.0005014.084	New Mexico Substation Furnitur	4,364	1,211
904	Electric General	Harkness	Aging Technology	D.0001821.232	2017 Unplanned PC Refresh SPS	4,179	1,160
905	Electric General	Cooley	LI	A.0000907.002	Kiser Distribution Add Comm	3,605	1,001
906	Electric General	Harkness	Aging Technology	D.0001797.009	Purch Sub Frame Relay OK SPS	3,395	942
907	Electric General	Cooley	GI	A.0000768.004	Blanco Comm	2,316	643
908	Electric General	Harkness	Aging Technology	D.0001783.010	Purch LMR HW SPS	2,278	633
909	Electric General	Harkness	Aging Technology	D.0001822.058	Purch Sub Frame BAU Sites NM SPS	2,142	595
910	Electric General	Cooley	RE	A.0000424.229	OPIE POTASH LIVINGSTON RIDGE RECOND	2,055	571
911	Electric General	Bick	Building & Infrastructure	D.0001810.035	Amarillo Tower - Structual	1,742	484
912	Electric General	Cooley	SR	A.0000220.029	SPS NM SE Comm	1,731	481
913	Electric General	Cooley	OT	A.0000924.014	SPS CIP 5 Yoakum Co Comm	1,646	457
914	Electric General	Meeks	Purchases	A.0006056.010	TX-DIST Fleet New Unit Purchases	1,408	391
915	Electric General	Harkness	Aging Technology	D.0001840.019	2017 Network Ref NM	1,320	366
916	Electric General	Lytal	Reliability & Performance Enhancement	A.0003000.663	CHC0C-Cunningham Tools	1,318	366
917	Electric General	Harkness	Aging Technology	D.0001804.022	Purch Corp Network Core HW SP	1,314	365
918	Electric General	Cooley	RE	A.0000424.223	Hopi Comm	1,312	364
919	Electric General	Harkness	Aging Technology	D.0001839.675	Purch Roosevelt MW NM SPS	1,265	351
920	Electric General	Harkness	Aging Technology	D.0001828.004	Purch NS T&D Network Equip SPS	1,122	311

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921	Electric General	Cooley	OT	A.0002048.003	Higg Inst New SCADA Radio Comm	969	269
922	Electric General	Cooley	RE	A.0000574.007	Coulter Relay Mod, Sub, COMM	923	256
923	Electric General	Cooley	RE	A.0000906.001	Lynn Co RTU Replacement Comm	815	226
924	Electric General	Cooley	RE	A.0000424.129	China Draw Sub Comm	737	205
925	Electric General	Cooley	RE	A.0000424.074	Sage Brush 115kV Sub Comms_UID	600	167
926	Electric General	Harkness	Aging Technology	D.0001703.009	Purch EMS DEMS Ph2 HW SPS	508	141
927	Electric General	Harkness	Aging Technology	D.0001839.055	2016 IT INFS Network Refresh S	334	93
928	Electric General	Harkness	Aging Technology	D.0001821.401	2015 IT INFS Refresh Communica	264	73
929	Electric General	Cooley	RE	A.0000532.003	TPL BFR V31 Riverview Comm	119	33
930	Electric General	Cooley	RE	A.0000424.018	Potash Junct 115/69 Xfmr UpgrC	76	21
931	Electric General	Cooley	RE	A.0000424.130	North Loving RTU - comm	76	21
932	Electric General	Bick	Building & Infrastructure	D.0001814.046	Electrical - Borger - Routine	71	20
933	Electric General	Cooley	OT	11302945	Fleet New Units 2011 El Tran, SPS	65	18
934	Electric General	Harkness	Aging Technology	D.0001822.001	Purch Corp Frame Relay HW SPS	25	7
935	Electric General	Bick	Building & Infrastructure	D.0001806.080	Mechanical - Lubbock - Routine	3	1
936	Electric General	Bick	Building & Infrastructure	D.0001806.001	Mechanical	1	0
937	Electric General	Harkness	Aging Technology	D.0001839.679	Purch Net Core Rte Amarillo SPS	(5)	(1)
938	Electric General	Cooley	OT	A.0005014.069	AC Unit 2015 for Subs	(24)	(7)
939	Electric General	Harkness	Aging Technology	D.0001839.063	2015 IT INFS Network Refresh S	(56)	(15)
940	Electric General	Harkness	Aging Technology	D.0001797.010	Purch Sub Frame Relay KS SPS	(293)	(81)
941	Electric General	Harkness	Aging Technology	D.0001821.185	2016 Unplanned PC Refresh SPS	(478)	(133)
942	Electric General	Cooley	GI	A.0000706.002	Hitchland Firewheel Comm	(6,987)	(1,940)
943	Electric General	Harkness	Aging Technology	D.0001821.208	2017 Planned PC SPS	(15,724)	(4,365)
944	Electric General	Cooley	RE	A.0000421.052	Swisher Sub. Communications	(22,846)	(6,342)
945	Electric General	Harkness	Cyber Security	D.0001839.832	Purch Net Sec HW SPS	(57,274)	(15,900)
946	Electric General	Cooley	RE	A.0000352.016	Yoakum 230 kV Bus Rebld, Commu	(313,944)	(87,155)
947	Electric General	Cooley	RE	A.0000424.041	OPIE 2 Kiowa 345kV Sub Comms U	(820,831)	(227,875)
948	**Electric General Total**					**$ 42,013,242**	**$ 11,663,475**
949	Electric Intangible	Harkness	Aging Technology	D.0001805.004	Next Gen MSFT LIC SW SPS-10692	$ 3,401,180	$ 944,216
950	Electric Intangible	Harkness	PTT	D.0001787.009	Customer Mgmt SPS	2,932,094	813,991
951	Electric Intangible	Harkness	Aging Technology	D.0001826.191	Demand Response Manage SW SPS	1,041,852	289,233
952	Electric Intangible	Harkness	PTT	D.0001787.004	SAP Financial Mgmt SPS	966,479	268,308
953	Electric Intangible	Harkness	Enhance Capabilities	D.0001839.391	Sharepoint 2013 Ph2 SW SPS	949,163	263,501
954	Electric Intangible	Harkness	Aging Technology	D.0002002.007	NMS 1.12 Upgrade SW SPS-10669	759,942	210,971
955	Electric Intangible	Harkness	Aging Technology	D.0001804.151	Interval Complex Billing SW SP	668,146	185,487
956	Electric Intangible	Harkness	Enhance Capabilities	D.0001826.247	2015 RPAM Phase 3 Amort SW SPS	610,205	169,402
957	Electric Intangible	Harkness	Aging Technology	D.0001796.018	Netwrk Tools Telecom Exp SW TX -106	560,993	155,740
958	Electric Intangible	Harkness	Aging Technology	D.0001744.019	IrthNet Damage Prevent SW SPS	506,452	140,598
959	Electric Intangible	Harkness	Aging Technology	D.0002090.013	Microfocus SW SPS-10721	450,595	125,091
960	Electric Intangible	Harkness	Aging Technology	D.0002003.010	2018 Oracle SW SPS-10701	409,078	113,566
961	Electric Intangible	Harkness	Aging Technology	D.0002003.014	2019 Oracle SW SPS-10748	404,749	112,364
962	Electric Intangible	Harkness	Aging Technology	D.0002097.007	UAST Ph1 SW SPS-10689	353,544	98,149
963	Electric Intangible	Harkness	Cyber Security	D.0002099.007	Firewall Rule Mgmt SW SPS-10707	345,214	95,836

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
964	Electric Intangible	Harkness	Cyber Security	D.0001771.007	Certificate Key Mgmt SW SPS	336,074	93,299
965	Electric Intangible	Harkness	Cyber Security	D.0001825.098	Advanced Endpoint SW SPS-10685	330,844	91,847
966	Electric Intangible	Harkness	Aging Technology	D.0002067.004	OSI Ent Agree SW SPS-10726	276,433	76,742
967	Electric Intangible	Harkness	PTT	D.0002020.014	SAP Cont Improve R18 SW SPS-10706	265,485	73,702
968	Electric Intangible	Harkness	Aging Technology	D.0001826.161	Verint Workforce SW SPS	259,315	71,990
969	Electric Intangible	Harkness	Enhance Capabilities	D.0002090.004	IT Service Request SW SPS-10699	246,023	68,300
970	Electric Intangible	Harkness	PTT	D.0001726.058	Work and Asset Phase 1 SW SPS	245,902	68,266
971	Electric Intangible	Harkness	Aging Technology	D.0002162.004	Microsoft Core Server SW SPS-10727	241,869	67,146
972	Electric Intangible	Harkness	Aging Technology	D.0001839.379	RedSky e911 SW SPS	221,184	61,404
973	Electric Intangible	Harkness	Cyber Security	D.0002098.004	CyberArk PAM SW SPS-10694	217,277	60,319
974	Electric Intangible	Harkness	Cyber Security	D.0002001.014	Sailpoint Ph3 SW SPS-10717	211,607	58,745
975	Electric Intangible	Harkness	Aging Technology	D.0002004.014	SAP Data Mart Ph2 SW SPS-10690	195,305	54,219
976	Electric Intangible	Harkness	Aging Technology	D.0002066.004	Bus Obj Ref SW SPS-10698	170,644	47,373
977	Electric Intangible	Harkness	Cyber Security	D.0002008.004	Ent DataBase Security Ph2 SW SPS-10	147,637	40,986
978	Electric Intangible	Harkness	Enhance Capabilities	D.0001796.025	Netwrk Tools Mgmt SW SPS-10700	141,841	39,377
979	Electric Intangible	Harkness	Enhance Capabilities	D.0001792.176	Rational SW SPS-10715	123,015	34,151
980	Electric Intangible	Harkness	Cyber Security	D.0001818.108	Emergency Mass SW SPS-10709	118,012	32,762
981	Electric Intangible	Harkness	Aging Technology	D.0001839.851	RedSky Ph2 SW SPS Direct	74,307	20,629
982	Electric Intangible	Harkness	Cyber Security	D.0002101.006	eGRC Ph3 SW SPS-10719	71,328	19,802
983	Electric Intangible	Harkness	Aging Technology	D.0001839.613	CRS CM SW SPS-10644	30,556	9,497
984	Electric Intangible	Harkness	Aging Technology	D.0001826.381	Mobile App Ph2 SW SPS-10695	25,338	7,034

Exhibit DG-7

Southwestern Public Service Company
Capital Additions
April 1, 2018 through March 31, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Asset Class	Witness	Project Category	WBS Level 2	Project Description (WBS Level 2 Description)	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) Total Company	Additions to Plant-in-Service (April 1, 2018 - March 31, 2019) NM Retail
985	Electric Intangible	Harkness	Cyber Security	D.0001747.008	Data Loss Ph2 SW SPS	21,882	6,075
986	Electric Intangible	Harkness	Aging Technology	D.0001792.008	Data Warehouse Env Ref SW SPS	21,105	5,859
987	Electric Intangible	Harkness	Aging Technology	D.0001770.020	Sec File Ph3 SW SPS-10716	21,023	5,836
988	Electric Intangible	Harkness	Aging Technology	D.0002034.004	CEC-TCPA Do Not Call SW SPS-10703	20,746	5,759
989	Electric Intangible	Harkness	Enhance Capabilities	D.0002182.004	Sharepoint RFP SW SPS-10739	17,090	4,744
990	Electric Intangible	Harkness	Cyber Security	D.0001818.090	SIEM Extension SW SPS-10679	10,188	2,828
991	Electric Intangible	Harkness	Aging Technology	D.0001770.014	Secure File&Transfer Ph 2 SW SPS-10	8,826	2,450
992	Electric Intangible	Harkness	Cyber Security	D.0001804.365	eGRC Security SW SPS -10660	4,399	1,221
993	Electric Intangible	Harkness	Cyber Security	D.0001804.376	EGRC Security Ph2 SW SPS-10668	3,635	1,009
994	Electric Intangible	Harkness	Aging Technology	D.0001792.162	Informatica New Ver-10673 SW SPS	2,354	654
995	Electric Intangible	Harkness	Aging Technology	D.0001744.027	ITSM Ph4 SW SPS	1,282	356
996	Electric Intangible	Harkness	Aging Technology	D.0002004.004	SAP Data Mart SW SPS-10675	1,123	312
997	Electric Intangible	Harkness	Cyber Security	D.0001755.007	Identity & Access Mgmt Sailpoi	987	274
998	Electric Intangible	Harkness	Aging Technology	D.0001839.821	DMZ Airwatch SW SPS-10664	701	195
999	Electric Intangible	Harkness	Enhance Capabilities	D.0001804.369	Integrated Talent Ph4 SWSPS-10637	352	98
1000	Electric Intangible	Harkness	Aging Technology	D.0001792.152	XE.COM Optimization Ph2 SW SPS-1066	315	88
1001	Electric Intangible	Harkness	Cyber Security	D.0001761.007	Database Security SW SPS	233	65
1002	Electric Intangible	Harkness	Cyber Security	D.0001839.642	Network Security Protect SW SPS-106	194	54
1003	Electric Intangible	Harkness	Enhance Capabilities	D.0001792.141	10634-eGERC NERC SW SPS	156	43
1004	Electric Intangible	Harkness	Cyber Security	D.0001818.077	Vulnerability NexPose SW SPS-10665	114	32
1005	Electric Intangible	Cooley	OT	A.0002062.001	GIST-IV Computer Software SPS	56	16
1006	Electric Intangible	Harkness	Aging Technology	D.0001744.044	Teradata HW SW SPS	26	7
1007	Electric Intangible	Harkness	Enhance Capabilities	D.0001826.233	Solar Energy Grid SW SPS	4	1
1008	Electric Intangible	Harkness	Aging Technology	D.0001822.036	TD Ciena Network SW SPS-10642	3	1
1009	Electric Intangible	Harkness	Enhance Capabilities	D.0001763.014	ITSM Secure Ticket SW SPS-10676	1	0
1010	Electric Intangible	Harkness	Cyber Security	D.0001783.017	WebSense SW SPS-10670	(10)	(3)
1011	Electric Intangible	Harkness	Enhance Capabilities	D.0001738.014	GeoSpatial Integration SW SPS-10653	(43)	(12)
1012	Electric Intangible	Harkness	Aging Technology	D.0001743.007	Upgrade IEE 5.3 to IEE 8.1 SW	(59)	(16)
1013	Electric Intangible	Harkness	Aging Technology	D.0001759.007	Fleet Focus SW SPS	(140)	(39)
1014	Electric Intangible	Harkness	Enhance Capabilities	D.0001839.635	VMware Private Cloud SW SPS -10647	(209)	(58)
1015	Electric Intangible	Harkness	Enhance Capabilities	D.0001804.306	Federated Records SW SPS-10640	(267)	(74)
1016	Electric Intangible	Harkness	Cyber Security	D.0001818.084	Vulnerability AppSpider SW SPS-1066	(442)	(123)
1017	Electric Intangible	Harkness	Aging Technology	D.0001826.064	Mobile Application Customer SW	(548)	(152)
1018	Electric Intangible	Harkness	Enhance Capabilities	D.0001815.043	Renewable Energy SW SPS-10649	(617)	(171)
1019	Electric Intangible	Harkness	Enhance Capabilities	D.0001826.241	SAP BI Suite SW SPS	(786)	(218)
1020	Electric Intangible	Harkness	Enhance Capabilities	D.0001741.007	Data Quality Tool SW SPS	(1,623)	(451)
1021	Electric Intangible	Harkness	Aging Technology	D.0002007.004	Digital Signage SW SPS-10671	(2,161)	(600)
1022	Electric Intangible	Harkness	Aging Technology	D.0001767.007	Self Service and PAF SW SPS	(2,483)	(689)
1023	Electric Intangible	Harkness	Enhance Capabilities	D.0001826.211	ITSA Pole Ph3 SW SPS	(2,570)	(713)
1024	Electric Intangible	Harkness	Cyber Security	D.0001754.007	Identity & Access Mgmt QAS SW	(2,738)	(760)
1025	Electric Intangible	Harkness	Cyber Security	D.0002001.007	SailPoint Extension SW SPS-10667	(60,483)	(16,791)
1026	**Electric Intangible Total**					$ 18,371,298	$ 5,101,149
1027	**Grand Total**					$ 458,521,070	$ 116,171,298