IN THE MATTER OF PUBLIC SERVICE
COMPANY OF NEW MEXICO’S
ABANDONMENT OF SAN JUAN
GENERATING STATION UNITS 1 AND 4
PUBLIC SERVICE COMPANY OF NEW
MEXICO

Case No. 19-00018-UT

Applicant

Prepared Rebuttal Testimony of David A. Schlissel

On Behalf Of

Sierra Club

NOVEMBER 15, 2019
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I. Introduction

Q. Please state your name and business address.

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc. My business address is 45 Horace Road, Belmont, MA 02478.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Sierra Club.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford Law School. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly owned utilities, and private organizations in 38 states to prepare expert testimony and analyses on engineering, economic and financial issues related to electric utilities. My clients have included state utility commissions, attorneys general, and consumer advocates, publicly owned utilities, and local, national and international environmental and consumer organizations.

I have filed expert testimony before state regulatory commissions in Arizona, Arkansas, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Vermont, Virginia, West Virginia, and Wisconsin; before the U.S. Federal Energy Regulatory Commission and Atomic Energy Commission; and in state and federal court proceedings.
A copy of my current resume is included as Attachment DAS-1. Additional information about my work is available at www.schlissel-technical.com and www.ieefa.org.

Q. Have you previously testified before this Commission?
A. Yes. I testified before the New Mexico Public Regulation Commission in Case 2146, Part II. I also prepared a report in Case No. 05-00275-UT as a consultant to the Commission.

Q. What is the purpose of your testimony in this proceeding?
A. I have been asked to evaluate whether retrofitting San Juan Generating Station (SJGS) with a system to capture the plant’s carbon dioxide emissions, compress the captured CO₂ and then sell it to oil companies for use in enhanced oil recovery activities is a feasible scenario as Public Regulation Commission Staff witness Dhiraj Solomon has testified.

Q. Please explain the rationale behind carbon capture and storage or reuse (CCS or CCUS).
A. Coal-fired electric generation facilities emit large quantities of CO₂ during operation. According to the Energy Information Administration, a unit of the Department of Energy, coal plants in the U.S. released 1,150 million metric tons of CO₂ in 2018, accounting for 65% of the electric generation sector’s total CO₂ emissions nationwide.¹ At the same time, coal only supplied 28% of the electricity generated during the year. This mismatch has become increasingly problematic for the industry as concerns about climate change have grown and cleaner alternatives, particularly zero-carbon renewable options such as wind and solar, have become commercially viable.

To address these concerns, some coal industry proponents have been pushing for the development of systems that can capture the fuel’s carbon emissions, and either store that captured carbon underground or reuse it in other applications, particularly to improve the amount of oil recovered from older producing sites.

Despite billions of dollars of federal research funds, only one such carbon capture project has been built at a coal-fired electric power facility in the U.S. – the Petra Nova project in Texas. A second, smaller carbon capture unit is also in operation in Canada at Boundary Dam Unit 3. Both of these projects, as I will show later, have failed to meet their promised performance goals, undercutting assertions by backers of the SJGS CCS retrofit that they will be using commercially proven technology.

Q. Please summarize your findings.

A. My main findings are as follows:

1. Contrary to Mr. Solomon’s testimony, continuing to operate SJGS after being retrofitted for CCS is not a feasible financial or economic scenario and is not a plausible scenario that PNM should have been required to evaluate in order to present a prima facie case for abandonment.

2. The reports by Enchant Energy (Enchant) and Sargent & Lundy (S&L) on which Staff witness Solomon is relying are based on a significant number of overly optimistic or incorrect assumptions:

   a. That after operating at an average 70% capacity factor for almost the past decade, SJGS Units 1 and 4 will run for at least 12 years at an 85% to 100% capacity factor after being retrofitted for CO₂ capture. This assumption is overly optimistic given continuing low natural gas prices, growing competition from increasingly low-cost renewable resources and energy storage, and the potential for declining performance due to plant aging.
b. That capturing CO₂ at a 90% rate at commercial-scale power plants for extended periods has been “proven” or “demonstrated” when, in fact, neither Petra Nova nor Boundary Dam 3 has done so – in spite of unsupported industry claims that they have.

c. That a retrofitted SJGS will capture 6 million metric tonnes of CO₂ a year.

d. That SJGS can be retrofitted at a capital cost that would be 68% low than the capital cost of the Petra Nova project.

e. That the SJGS retrofit could be designed, planned, built and tested in at least two years less time than Petra Nova and be online by mid-2023.

f. That the cost of capturing CO₂ at SJGS will fall between $39.15 and $43.49 per metric tonne.

3. Mr. Solomon and Enchant and S&L have ignored entirely the substantial costs and risks facing any SJGS owner(s) and/or investors that seeks to continue to operate SJGS with carbon capture:

a. The need to pay for maintenance that the current owners of the plant are deferring due to their proposal to abandon SJGS in 2022.

b. The likely need to pay the plant’s fixed costs for at least a year to eighteen months between the shutdown of SJGS in mid- to late-2022 and its restart following the retrofit, a period when the plant will not be producing any revenues from the sale of electricity or of captured CO₂.

c. The fact that it is extremely unlikely that SJGS will be a low-cost generator after the retrofit and, subsequently, that any plant owner(s) will lose hundreds of millions of dollars from the sale of
electricity. This will be because the cost of generating power at the
plant will be higher than the prices at which it can be sold.

That the revenues from selling captured CO\(_2\) for enhanced oil
recovery will be very uncertain due to volatility in the oil markets.

Q. What materials did you review and what analyses did you prepare as part of
the preparation of your testimony?

A. I have reviewed the Prepared Direct Testimony of Staff Witness Solomon and the
documents he has included as his exhibits. In addition, I have reviewed a number
of presentations on the proposed carbon capture retrofit of SJGS from Enchant
Energy, Inc. I also have reviewed the publicly available information on the only
two operating power plants in the world that have been retrofitted for CO\(_2\)
capture: the Petra Nova project in Texas and Boundary Dam 3 in Saskatchewan,
Canada. Finally, my recent work has included investigating natural gas and
energy market prices in the Southwest and the development of renewable
resources and energy storage in the Mountain and Pacific states.

I also have analyzed the feasibility of continuing to operate SJGS after the plant is
retrofitted using a range of more reasonable capacity factors, CO\(_2\) capture rates,
and retrofit capital costs.

Q. Did Mr. Solomon conduct his own analysis of either the technical or
economic feasibility of carbon capture at SJGS?

A. No, he did not. In his testimony, Mr. Solomon relies entirely on claims made by
Enchant Energy, the private company that has proposed the retrofit project at
SJGS, as well as preliminary estimates from Sargent & Lundy (S&L).

Q. Does Mr. Solomon have an opinion on whether it is economically feasible to
install and operate carbon capture technology at SJGS?

A. No, apparently not. Mr. Solomon admits that he provided an opinion on only the
technical feasibility of carbon capture, and did not evaluate the economic
feasibility of carbon capture at SJGS. Exhibit DAS-2, D. Solomon Depo. Tr. at 61: 8-16, 61:19 to 62:10. Furthermore, Mr. Solomon admits that he does not know if it would be cheaper to run SJGS with carbon capture than the alternatives that PNM has put forward to abandon and replace SJGS. *Id.* at 62:21 to 63:2. And Mr. Solomon has no evidence that it would be cost-effective to recover the capital costs of carbon capture technology at SJGS over 12 years, as Enchant has proposed to do. *Id.* at 96: 11-16.

Q. What is the relevance of the claims made by Enchant and S&L to the issue of whether it would be feasible for PNM to operate SJGS with carbon capture?

A. Mr. Solomon argues that PNM should have analyzed continuing to operate to SJGS with carbon capture, because that is allegedly a “feasible” scenario. Mr. Solomon’s primary support for his claim that carbon capture is feasible at SJGS are the statements made by Enchant and S&L. By showing that Enchant’s and S&L’s claims are inaccurate, I will show that there is no evidence that it is economically or financially feasible for anyone, including PNM, to continue to operate SJGS with carbon capture technology.

II. It is Extremely Unrealistic to Assume that a Retrofitted SJGS Would Capture 6 Million Metric Tonnes of CO₂ Per Year.

Q. What factors determine how much carbon dioxide (CO₂) a coal-fired generator like SJGS will capture in future years?

A. Quite simply, the amount of CO₂ captured is a function of how much CO₂ a coal-fired generator produces and the efficiency with which the carbon dioxide (CO₂ or carbon) capture system actually captures CO₂ emissions.

The first factor, how much CO₂ the plant generates is, in turn, largely dependent on how much it operates. The term capacity factor reflects how much power a plant produces in a given period, say a month or a year, versus how much it would

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2 Mr. Solomon’s deposition was taken on November 13, 2019.
have generated if it had operated at 100% power for all of the hours of the period. The higher the capacity factor, the more power is generated by the plant. Conversely, the lower the capacity factor, the lower the amount of power generated by the plant. Similarly, the amount of CO₂ produced by a coal plant goes up as its capacity factor increases.

Mr. Solomon’s testimony that a retrofitted San Juan will capture 6 million tonnes of CO₂ annually is based on two key assumptions. First, that San Juan Units 1 and 4 will operate at an average 85% to 100% capacity factor each year, thereby producing large amounts of CO₂, and second, that the plant’s retrofitted CCS equipment will be able to capture 90% of the CO₂ produced. As I will demonstrate in this testimony, neither of these assumptions is reasonable.

A. A Retrofitted SJGS Cannot Be Expected to Operate at an 85% to 100% Annual Capacity Factor for An Extended Number of Years.

Q. Enchant and S&L evaluate the feasibility of their proposed retrofit of SJGS for CO₂ capture using a capacity factor range of 85% to 100%. Is it reasonable to expect that SJGS would operate at a 100% capacity factor for a period of 12 years after being retrofitted for CO₂ capture?

A. No. It is simply fantasy to believe that any commercial scale power plant will operate at full power in every hour of the year for an extended period of time, let alone for twelve years. I have not seen any evidence that any coal-fired generator similar in size to SJGS Units 1 or 4 has operated at a 100% capacity factor for such a period of years.

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Q. Did Enchant and/or S&L conduct any SJGS plant-specific analysis or modeling to evaluate at what capacity factor SJGS can be expected to operate in future years?

A. No, not that I’ve seen.

Q. What then do you believe is the basis for the 85% low-end of the capacity factor range at which Enchant and S&L claim SJGS will operate?

A. At best, they used the 85% coal plant capacity factor that has been used in some generic federal studies of carbon capture. At worst, they chose an assumed capacity factor that gave them the result they needed to show that the project might be economically viable -- that is, that SJGS would capture on the order of 6 million metric tonnes per year. Either way, neither SJGS Unit 1 or Unit 4 have operated at an 85% capacity over the long-term or in recent years.

Q. At what capacity factors have SJGS Units 1 and 4 operated in recent years?

A. As shown in Figure 1, below, the two units achieved an average 70% capacity factor between January 1, 2010 and August 31, 2019, which clearly is far below the 85% average capacity factor that Enchant and S&L claim the plant will achieve starting in 2023, after being retrofitted for CO₂ capture.

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Figure 1: Average SJGS Unit 1 and 4 Capacity Factors Since 2010 vs. Assumed Enchant and S&L 85% Capacity Factor

Figure Sources: SJGS data from EIA Form 923, downloaded from S&P Global Market Intelligence on November 1, 2019. Enchant and S&L assumed capacity factor is from Staff Witness Solomon’s Exhibit DS-3.

Figure 1 also shows that the overall performance of SJGS Units 1 and 4 actually declined after Units 2 and 4 were retired at the end of 2017, achieving only a 62% capacity factor in the twenty months between January 2018 and August 2019.

Q. Have SJGS Units 1 and 4 achieved an 85% capacity factor in any year since 2010?

A. As shown in Figure 2 below, SJGS Units 1 and 4 did achieve 85% capacity factors in 2010 and 2011, respectively, but have failed to reach that level in any subsequent year.
Figure 2: Annual SJGS Unit 1 and 4 Capacity Factors Since 2010 vs. Assumed Enchant and S&L 85% Capacity Factor

Sources: SJGS data from EIA Form 923, downloaded from S&P Global Market Intelligence on November 1, 2019.

Only Unit 4 achieved a capacity factor above 80% after 2011, and that was an 81% capacity factor for only the single year of 2017.

Q. What does PNM project for SJGS’s future operating performance if Units 1 and 4 are not retired in 2022?

A. PNM’s recent modeling of continued SJGS operation forecasts that Units 1 and 4 will achieve an average 47% capacity factor between 2023 and 2035, with the highest annual capacity factors for the units being only 53%.\(^6\)

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\(^6\) See the Output Reports provided in PNM’s Response to Discovery Request NEE 1-72.
Figure 3: PNM Modeling Results vs. Enchant and S&L’s Assumed 85% Capacity Factor for SJGS Units 1 and 4

Sources: Scenario 1 Output Reports provided in PNM’s Expedited Response to NEE Interrogatory 1-72 in Case No. 19-00018-UT.

Q. Did PNM’s modeling of continued operation of SJGS reflect the plant’s retrofit with carbon capture?

A. No.

Q. Is it reasonable to expect that SJGS’s future capacity factors will be substantially lower than 85% if the plant continues to operate after 2022?

A. Yes. There are a number of factors which, I believe, are likely to lead to a significant decline in SJGS operating performance if the new owner(s) attempt to continue to run the plant after retrofitting it for CO₂ capture. These include:

1. Continued low natural gas prices.
2. Growing competition from renewable resources, including energy storage.
3. Increasing integration of the western power grid.
4. The impact of plant aging.
5. The impact of reduced spending on maintenance by the current owners.
6. The fact that SJGS will be a more complicated plant to operate. I will explain each of these factors in greater detail below.

Q. What are the market’s expectations for future natural gas prices at trading hubs in the Southwest?

A. Similar to what has happened throughout the U.S., natural gas prices at trading hubs in the Southwest have declined significantly since 2008 and are expected to remain low for the foreseeable future, as can be seen in Figure 4, below.

**Figure 4:** Past and Forward Natural Gas Prices in the Southwestern U.S.

[Graph showing past and forward natural gas prices from 2007 to 2027 for El Paso San Juan Hub and Permian Hub, with prices declining significantly and expected to remain low for the foreseeable future.]


Continued low gas prices will undermine the financial viability of projects like retrofitting San Juan with CCS by reducing fuel costs for the natural gas plants with which San Juan competes. This, in turn, will lead to (a) lower energy market prices and (b) increased generation at gas-fired plants, thereby displacing generation that otherwise would be produced at San Juan.
Q. Has generation from wind and solar resources grown significantly in the western U.S. in recent years?

A. Yes. As prices have declined dramatically, the generation from solar more than doubled just between 2012 and 2018.

Figure 5: Rapid Growth in Wind and Solar Generation in the Western United States, 2012 to 2018

[Graph showing growth in wind and solar generation from 2012 to 2018.]

Source: EIA Electric Power Monthly.

And significantly more renewable resources are likely to be added in the western U.S. in coming years. For example, California now mandates that 33% of electricity sales in 2020 and 60% of sales in 2030 be from renewable resources.\(^7\) In addition, utilities in other states in the region also are planning to add substantial amounts of new wind and solar resources, as are independent power producers. Many of these resources will compete with San Juan and displace generation that the plant would otherwise produce.

\(^7\)Stats. 2018, Ch. 312, Sec. 2. (SB 100) (effective Jan. 1, 2019); Cal. Pub. Util. Code § 399.11.
Q. What has happened to wind and solar PPA prices in recent years?

A. Wind and utility-scale solar PPA prices have declined sharply in recent years. From 2009 to 2016, average levelized wind PPA prices fell from $70 per MWh to about $20. Average levelized solar PPA prices declined by 75% from 2009 to 2016 and were about $35 per MWh for new projects in 2016.

Solar and wind PPA prices have dropped further in 2017 and 2018. In December 2017, Xcel Energy reported that a power-generation solicitation in Colorado drew bids for renewable power that were “incredible.” The median bid for 17,380 MW of wind projects received by Xcel Energy was $18.10 per MWh; for 5,097 MW of wind-plus-battery storage projects, the median bid was $21 per MWh; the median bid for 13,345 MW of solar projects was $29.50 per MWh; for 10,813 MW of solar-plus-storage, the median bid was $36 per MWh. And Nevada Energy reported receiving “staggering” prices in more than 100 bids for biomass, geothermal, solar, wind and battery storage projects in response to a request for proposals, with battery-backed solar projects priced below $30 per MWh.

Q. How will increasing regional integration of electricity markets hurt future SJGS operating performance?

A. Efforts have been under way in recent years to better integrate western electric markets. For example, a western Energy Imbalance Market (EIM) has been launched. The EIM is “a real-time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when needed.”

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its goals is to find and deliver the lowest cost energy to consumers. Another goal is that by optimizing resources from a larger and more diverse pool, it is able to better facilitate the integration of renewable energy that otherwise may be curtailed at certain times of the day. There are currently nine members in the EIM, including the California Independent System Operator (CAISO), and APS and NV Energy in the Southwest. Salt River Project, PNM, and Tucson Electric Power are scheduled to join by 2022, meaning that participants representing 77 percent of the Western Electricity Coordinating Council’s total load will be active in the EIM.

The growth of the EIM amplifies the risk to San Juan from low-cost renewable resources in California and the rest of the West, as it will mean increased exposure to renewables prices that may be lower than San Juan’s marginal costs.

Q. What is the significance of plant aging on the expected future operating performance of SJGS Units 1 and 4?

A. San Juan Unit 1 is currently 43 years old. Unit 4 is 37. By 2023, the Units will be 47 and 41 years old, respectively. By 2030, they will be 54 and 48 years old. This is important because older plants, on average, tend to cost more to operate and maintain and are less reliable according to analyses by the U.S. Department of Energy’s Argonne National Laboratory and the National Energy Technology Laboratory, which have found that coal plant heat rates increase with plant age, while plant availability declines. Heat rate is a measure of a power plant’s efficiency in generating electricity; a higher heat rate means that a plant is less efficient. And, in general power plants tend to become less efficient as they age. Plant availability measures the percentage of possible operating hours in which a
plant was actually available to generate power, and plants tend to become less
available to generate power as they age, in part because they tend to experience
more unanticipated problems and unplanned outages.

At the same time, older plants tend to cost more to maintain, as equipment and
components degrade or fail and must be repaired or replaced. These factors must
be considered by potential plant owners and investors as they decide to participate
in retrofit projects at aging coal plants such as SJGS.

Q. Are there any other factors that could lead to lower SJGS capacity factors in
the future after the plant is retrofitted for carbon capture?

A. Yes. For example, I understand that in Docket No. 16-00276, PNM was pressed
to avoid and defer capital spending for SJGS through 2022 that was not required
for regulatory compliance or that were not needed for health and safety. In
response to Sierra Club discovery in that case, PNM stated it was cancelling two
projects it had previously planned: San Juan Common C&D Coal Reclaim System
(ID# 76617317) and San Juan Common Auxiliary Boiler (ID# 76616917).\textsuperscript{14}

The actions of PNM and the other co-owners (except for Farmington) are
consistent with common sense and what I have seen other utilities do: they stop
spending money on major maintenance projects in the years leading up to an
expected retirement date. For example, at the Navajo Generating Station, by May
2017, the Salt River Project (SRP) and the other Navajo Generating Station
owners already had started to plan to reduce their maintenance spending to
prepare for the plant’s announced retirement in December 2019. SRP has said that
the amount of deferred maintenance for all three units at NGS was about $132
million, or $44 million per unit.\textsuperscript{15} Although the precise cost of such deferred
maintenance at SJGS is unknown and would be specific to SJGS, this suggests

\textsuperscript{14} See PNM’s Response to Discovery Request SC 2-5 in Docket No. 16-00276.
\textsuperscript{15} Arizona Republic, “10 Obstacles to keeping the Navajo coal plant open,” May 22, 2017, available at
https://www.azcentral.com/story/money/business/energy/2017/05/22/arizona-10-challenges-keeping-
navajo-generating-station-open/332911001/.
that any owner(s) of SJGS who would try to continue to operate SJGS past 2022
would have to pay a significant amount for maintenance work that previously
would have been deferred by the current owners.

Q. What would be the risk if the owner(s) of SJGS tried to continue operating
SJGS past 2022 but failed to pay for this deferred maintenance?

A. There would be a heightened risk of future equipment degradation and
breakdowns, and more frequent and longer plant outages and deratings. This
would both make it more expensive to operate and maintain the plant in the future
and more difficult to achieve the higher capacity factors that will be needed to
obtain the tax credits promised to investors.

Q. What is your conclusion about the likely operating performance of SJGS if
the plant were retrofitted for carbon capture?

A. In their pre-feasibility analyses, Enchant and S&L assume that the operating
performance of SJGS, which has averaged a 70% capacity factor over the past
decade, will improve dramatically after being retrofit for carbon capture, and will
average 85% or higher annual capacity factors for an entire twelve year period.
This assumption is very unrealistic. It is far more likely that SJGS’s post-retrofit
average annual capacity factors would fall somewhere in the range between a
70% high end (reflecting its recent operating performance) and a low end of the
47% average capacity factor forecast in PNM’s modeling analyses.

Q. Is it possible that the plant’s operating performance could be even worse
than this?

A. Yes. As a result of the factors I have discussed above, PNM (or Enchant’s
investors and the new SJGS owner) would be exposed to the not-insignificant risk
that the plant’s operating performance could be worse than an average 47%
Q. How many existing coal-fired generators actually have achieved 85% capacity factors in recent years?

A. It has been extremely rare in recent years that a coal-fired generator has achieved an 85% capacity factor in a single year, let alone over several years. In fact, only thirteen of the 390 coal-fired units in operation in 2018, or barely three percent, achieved 85% or higher capacity factors in 2018. Fifty seven units, or four times as many, failed to achieve even a 30% capacity factor in the same year.\footnote{Source: EIA Form 923 data downloaded from S&P Global Market Intelligence on November 5, 2019.}

Similarly, only four of the 390 coal-fired generators operating in 2018, or just one percent, achieved 85% or higher average capacity factors during the four-year period 2015 to 2018. Only 10 units had average capacity factors of 80% or higher. At the same time, 36 units had average capacity factors of 30% or lower during the same period.

B. 90% CO\textsubscript{2} Capture Has Not Been Proven.

Q. Staff witness Solomon testified that both the Petra Nova project at NRG’s W.A. Parish Unit 8 plant outside Houston, TX, and Boundary Dam Unit 3 located in Saskatchewan, Canada, “operate at 90% CO\textsubscript{2} capture efficiency.”\footnote{Prefiled Direct Testimony of Dhiraj Solomon, PE, at page 13, lines 15-17.} Is this accurate?

Q. What is the basis for your conclusion that Petra Nova is not capturing 90% of the CO₂ it produces?

A. Petra Nova intended to capture “at least” 90% of the CO₂ from a 240 MW equivalent slip stream from the flue gas emitted by the 654 MW coal-fired W.A. Parish Unit 8. This has been variously translated into an expectation that Petra Nova would capture somewhere between 1.54 and 1.6 million tons of CO₂ (that is, approximately 1.4 million metric tonnes) or about 33% of the total emissions from Unit 8, each year.¹⁹

Despite the Petra Nova project’s goal of capturing 90% of CO₂ emissions, I could not find any evidence that Petra Nova actually was capturing that much CO₂ or that the technology had been proven to be that effective. Thus, I examined Petra Nova’s actual performance in three separate analyses using publicly available information.

First, I investigated whether Petra Nova actually was capturing between 1.54 and 1.6 million tons of CO₂ each year. Unfortunately, NRG, the operator and co-owner of the plant, has not regularly issued detailed reports on the amounts of CO₂ captured at Petra Nova. However, representatives from the company and from the U.S. DOE (which supplied $190 million of the $1 billion cost of the project) spoke at the IEA Clean Coal Conference held in Houston and revealed that Petra Nova had captured (1) 2.4 million tons of CO₂ between its start of operations in January 2017 and December 2018 and (2) almost 3.0 million tons through May 2019.²⁰

²⁰ PETRA NOVA Carbon Capture, June 2019, IEA Clean Coal Conference, Greg Kennedy, NRG’s Senior Project Manager at Petra Nova and Status Update of U.S. Department of Energy Major Fossil Energy
As shown in Figure 6, below, these amounts of captured CO₂ are significantly below what would be expected if Petra Nova actually had been capturing 90% of the CO₂ it produced.

**Figure 6: Actual vs. Target Amounts of CO₂ Captured at Petra Nova**

![Bar chart showing actual vs. target CO₂ capture amounts at Petra Nova.](chart.png)

*Source: STC analysis.*

The actual amounts of CO₂ captured at Petra Nova translate into a capture rate of 69% thru December and 71% from January 2017 thru May 2019.

**Q.** Is it possible that Petra Nova actually was capturing 90% of the CO₂ in the 240 MW slipstream even though it was capturing less CO₂ than projected? In other words, is there any evidence that W.A. Parish Unit 8 was producing less CO₂ after January 2017 because the unit was operating less?

**A.** No. Figure 7, below, shows that Parish Unit 8 actually had a slightly higher capacity factor after January 2017 than it did in the previous two years.
Q. Please describe the second analysis you made to determine if Petra Nova is actually achieving a 90% CO₂ capture rate.

A. As I noted earlier, the U.S. Energy Information Administration (EIA) forecasted that if Petra Nova captured 90% of the CO₂ emitted from the 240 MW equivalent flue gas slipstream, that would be capturing about 33% of the total emissions from Parish Unit 8. To see whether this was happening, I compared the CO₂ intensity (measured as tons of CO₂ per MWh of generation) of the emissions from Unit 8 for the period January 2017 through August 2019 (the most recent data from the EPA’s Continuous Emissions Monitoring System [CEMS] database that was available) with the emissions during the two years before Petra Nova went into operation.

Figure 8, below, shows that Unit 8’s actual CO₂ intensity is higher than it would be if Petra Nova actually were capturing 90% of the CO₂ in the 240 MW slipstream.
The third column, representing the plant’s actual performance, shows a CO₂ intensity that would be expected if Petra Nova operated at a 69% capture efficiency through August 2019, which confirms the results of our first analysis.

Q. Please describe your third analysis of Petra Nova’s CO₂ capture rate.

A. In the last analysis, I calculated what Parish Unit 8’s total CO₂ emissions during the period January 2017 through August 2019 would have been under a range of alternative capture rates for the 36.7% of the flue gas stream that could potentially be captured. The results are presented in Figure 9, below. These results confirm that Petra Nova has achieved about a 70% CO₂ capture rate since the project went into operation in January 2017, not the 90% capture rate that Mr. Solomon and others claim.
Q. Do you have any other comments on Petra Nova’s CO₂ capture rate?

A. Yes. Unlike the proposed retrofit of SJGS, the power to run the CO₂ capture equipment at Petra Nova is provided by a dedicated natural gas-fired combustion turbine. If the CO₂ emissions from this CT were included in the analysis, Petra Nova’s net capture rate would be substantially lower, perhaps as low as 60% or even 50%.
Q. Is it correct that similar to Petra Nova, the Boundary Dam power plant in Canada also is not capturing 90% of the CO\textsubscript{2} it produces?

A. Yes. As I mentioned earlier, the Petra Nova and Boundary Dam projects are the only two CO\textsubscript{2} projects in the world operating at power plants.\textsuperscript{21} Like Petra Nova, the Boundary Dam project has not been capturing 90% of the CO\textsubscript{2} it produces.

Q. What is the basis for your conclusion that Boundary Dam also is not capturing 90% of the CO\textsubscript{2} it produces?

A. The carbon capture system at the 110 MW Boundary Dam Unit 3 in Saskatchewan, Canada, began operating in October 2014. Although the system was designed to capture 1 million tonnes a year reflecting a 90% capture rate, it has failed to achieve this goal in the 45 months between October 2014 and July 2019.

\textsuperscript{21} The proposed SJGS Carbon Capture project would be 3.8 times larger than Petra Nova. Mr. Solomon acknowledges that no power plant in the world as large as SJGS has installed carbon capture technology. Exhibit DAS-2, D. Solomon Depo. Tr. at 83: 15-24.
In fact, the plant’s carbon capture system only operated at its design capacity of 3200 tonnes per day on 3 days through early 2018. Consequently, Boundary Dam Unit 3 has failed to achieve a 90% carbon capture rate in any significant period since the plant was retrofitted.

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22 The most recent update is available at https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-october-2019. Previous updates containing information on CO₂ captured in prior years are available at SaskPower’s blog.

23 Boundary Dam 3: Upgrades, updates and performance optimization of the world’s first fully integrated CCS plant on coal, presented by Corwin Bruce from the International CCS Knowledge Centre at the 2019 Clean Coal Technologies Conference on June 5, 2019. The International CCS Knowledge Centre is 50% owned by SaskPower, the owner of Boundary Dam Unit 3.
Figure 11: Boundary Dam Unit 3 Targeted vs. Actual CO2 Capture Rates

Source: Analysis using CO2 capture performance data in Boundary Dam 3 Status Reports on SaskPower website.

Q. Is it possible that some of Boundary Dam’s failure to capture 90% of the CO2 it produces is due to operating issues unrelated to the CO2 capture equipment?

A. Yes. Boundary Dam 3 has had significant issues with the CO2 capture equipment that have adversely impacted its ability to capture emissions and led to increased maintenance costs and plant downtime. For example, the carbon capture portion of the plant worked only about 40% of the time in much of 2014 and 2015 with the CCS plant being shut down for a nearly two-month maintenance outage in the fall of 2015.24 And the plant was shut down for 96 days in 2017 to complete projects designed to improve the reliability of the CCS plant.25 SaskPower has said that the cost of fixing Boundary Dam 3’s carbon capture flaws cost CAN$32

24 Carbon Capture and Sequestration @ MIT and SaskPower’s 2015-2016 Annual Report at 59.
million in the years 2015 and 2016 and estimated that it was going to cost another
CAN$15 million in 2017.\textsuperscript{26}

It is true that Boundary Dam 3 also has experienced some plant outages that were
unrelated to its CO\textsubscript{2} capture system. However, these outages account for only a
fraction of the plant’s failure to come anywhere near an overall 90% CO\textsubscript{2} capture
rate.

For example, SaskPower has claimed that 2018 was a strong year for carbon
capture and storage at Boundary Dam Station, saying that the plant would have
captured more than 625,996 tonnes of CO\textsubscript{2} in the year if it had not be shut down
for 84 days due to a strong storm and massive power outage.\textsuperscript{27} However, in the
unlikely event that Boundary Dam had actually captured CO\textsubscript{2} at it maximum daily
rate of 3,200 tonnes (a goal it achieved for just 3 days in its first 40 months after
being retrofitted) for all of the 84 days of this outage, the plant’s CO\textsubscript{2} capture rate
still would have been only 80%, not 90%.

Q. Did SaskPower have to pay any contract penalties because it was unable to
provide the amounts of CO\textsubscript{2} it has committed to providing to buyers?

A. Yes. SaskPower has reported that in 2014, it paid $12 million in penalties to
Cenovus Energy for failing to deliver sufficient quantities of carbon dioxide from
Boundary Dam 3.\textsuperscript{28} In 2015, SaskPower paid $7.3 million to Cenovus for failing
to deliver the volume of CO\textsubscript{2} it had contractually committed to provide.\textsuperscript{29}

\textsuperscript{26}CBC News, “SaskPower looking for help to fix ‘high cost’ Boundary Dam carbon capture flaw,” May 28,
cost-boundary-dam-carbon-capture-flaw-1.4680993.

\textsuperscript{27}SaskPower. Press Release, “Strong Year for Carbon Capture and Storage at Boundary Dam Power
Station,” January 22, 2019, available at https://www.saskpower.com/about-us/media-information/news-
releases/Strong-year-for-carbon-capture-and-storage-at-Boundary-Dam-Power-Station.

\textsuperscript{28}The Energy Mix, “Saskatchewan Pays $12 Million Penalty for Slow Production at CCS Plant,” Nov. 4,
2015, available at https://theenergymix.com/2015/11/04/saskatchewan-pays-12-million-penalty-for-slow-
production-at-ccs-plant/.

\textsuperscript{29}CBC News, “SaskPower CEO says $20M worth of carbon capture penalties are in the past,” July 14,
20m-in-past-1.3679405.
Q. Has SaskPower’s failure to deliver the contracted amounts of CO\textsubscript{2} had any long-term impacts on the revenues it gets from selling the CO\textsubscript{2} captured at Boundary Dam 3?

A. Yes. It has been reported that in June 2016, the contract for supplying CO\textsubscript{2} from Boundary Dam Unit 3 was renegotiated, reducing the expected annual revenues over the life of the plant by about a third.\textsuperscript{30}

Q. Have you seen any evidence that Mr. Solomon or Enchant and S&L have analyzed the impact that post-retrofit plant outages, needed upgrades, or higher CO\textsubscript{2} capture O&M costs would have on the financial viability of the retrofit they are proposing for SJGS?

A. No.

Q. Has the underperformance of Boundary Dam 3’s CO\textsubscript{2} capture system affected SaskPower’s decisions concerning retrofitting other units for CO\textsubscript{2} capture?

A. Yes. “After careful evaluation, SaskPower has made the decision to not retrofit Boundary Dam Power Station Units #4 and #5 with CCS technology.”\textsuperscript{31}

Q. Based on your testimony so far, should a retrofitted SJGS be expected to capture substantially less than six million tonnes of CO\textsubscript{2} per year, on average?

A. Yes. This conclusion is based on (1) the fact that no commercial-scale power plant has achieved 90% (or even 80%) CO\textsubscript{2} capture over any significant period of time and (2) SJGS’s actual operating performance and the results of PNM’s computer modelling showing lower capacity factors for the plant in future years.


Q. Realistically, how much CO\textsubscript{2} do you think the carbon capture system at SJGS would capture each year, on average?

A. Based on the evidence I have reviewed, and the analyses I have discussed earlier, I believe a retrofitted SJGS should be expected to capture no more than 2.2 to 4.4 million tonnes of CO\textsubscript{2} per year. And even that assumes that there are no significant issues encountered in scaling up the capture technology from the 240 MW-equivalent Petra Nova project to the proposed 914 MW SJGS project.

**Figure 12:** Tonnes of Captured Carbon that Can Be Expected from a Retrofitted SJGS

![Bar chart showing Enchant/S&L Estimate for SJGS Annual CO2 Capture = 6 million metric tonnes.]

Source: Analysis based on methodology from Appendix E in S&L July 8, 2019 Pre-Feasibility Study.

Q. Why does the amount of CO\textsubscript{2} captured by SJGS matter to the financial feasibility of the proposed carbon capture project?

A. The amount of CO\textsubscript{2} that is captured is critical to the project’s financial feasibility because it affects both the tax credits for which the project would be eligible and the revenue that would be generated from selling the captured CO\textsubscript{2}.
Q. What is the significance of projecting that SJGS would only be able to capture 2.2 to 4.4 million metric tonnes a year instead of the 6.0 million tonnes that Enchant claims?

A. Capturing less CO₂ will mean that SJGS will generate less revenue from the sale of the CO₂ for enhanced oil recovery. Similarly, capturing less CO₂ will mean that the project will be eligible for far fewer 45Q tax credits. This, in turn, will mean that additional funds will have to be borrowed to pay for the retrofitting of SJGS. This will raise both the total capital cost of the retrofit and the cost per metric tonne of capturing CO₂, as I will describe in detail later in this testimony.

Q. Have you evaluated how much additional funding would be required?

A. Yes. Because of the significant uncertainty associated with the future performance of SJGS and the cost of retrofitting CO₂ capture, I have looked at sixteen scenarios that cover a range of reasonable capacity factors, CO₂ capture rates and capital costs. These include:

- Two sets of annual capacity factors with a high set of 70% and a low set which averages 47%.
- CO₂ capture rates of 80%, 70% and 60%.
- Capital costs in 2023 dollars that range from a low capital cost of $1.40 billion (representing the 2019 S&L estimated cost); a mid-capital cost of $2.21 billion (representing 50% of the cost of building Petra Nova); and a high capital cost of $3.31 billion (representing 75% of the actual Petra Nova cost).

Q. What discount rate have you used in this analysis to calculate the present value of the 45Q tax credits that investors in the SJGS retrofit could expect to receive?

A. Based on the recommendation of David Posner, who is submitting separate testimony, I have used a 15% discount rate.
Q. What is the 45Q tax credit?
A. As witness David Posner describes in greater detail in his testimony, the 45Q tax credit refers to federal tax credits available to certain carbon capture and sequestration projects.

Q. What capital costs do Enchant and S&L estimate for the CO₂ capture retrofit project at SJGS?
A. S&L estimates a capital cost of approximate $1.295 billion, in 2019 dollars, to retrofit SJGS with CO₂ capture technology. This is $1,417 per kW.

Q. What are the results of your analysis?
A. Table 1, below, shows the percentages of the capital cost of retrofitting SJGS that can be expected to be obtained through tax equity financing from 45Q credits and the percentage of the estimated capital costs that would have to be funded from other sources in each of the scenarios I have examined.

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Table 1
SJGS Retrofit Financing

<table>
<thead>
<tr>
<th>Scenario Assumptions</th>
<th>Percentage of Estimated Capital Cost that Could Be Funded through 45Q Credits</th>
<th>Percentage of Estimated Capital Cost that Would Have to Be Obtained Through Non-45Q Funding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrected Enchant &amp; S&amp;L Proposal</td>
<td>$1.40 Billion Capital Cost, 85% CF &amp; 90% CO2 Capture Rate</td>
<td>81%</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>$1.40 Billion Capital Cost, 70% CF &amp; 80% CO2 Capture Rate</td>
<td>59%</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>$1.40 Billion Capital Cost, 70% CF &amp; 70% CO2 Capture Rate</td>
<td>52%</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>$1.40 Billion Capital Cost, 70% CF &amp; 60% CO2 Capture Rate</td>
<td>45%</td>
</tr>
<tr>
<td>Scenario 4</td>
<td>$2.21 Billion Capital Cost, 70% CF &amp; 80% CO2 Capture Rate</td>
<td>38%</td>
</tr>
<tr>
<td>Scenario 5</td>
<td>$2.21 Billion Capital Cost, 70% CF &amp; 70% CO2 Capture Rate</td>
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<td>Scenario 6</td>
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<td>Scenario 7</td>
<td>$3.31 Billion Capital Cost, 70% CF &amp; 80% CO2 Capture Rate</td>
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<td>Scenario 9</td>
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<td>Scenario 10</td>
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<td>Scenario 11</td>
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<td>Scenario 12</td>
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<td>Scenario 13</td>
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<td>25%</td>
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<td>Scenario 14</td>
<td>$2.21 Billion Capital Cost, 47% CF &amp; 70% CO2 Capture Rate</td>
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<td>Scenario 18</td>
<td>$3.31 Billion Capital Cost, 47% CF &amp; 60% CO2 Capture Rate</td>
<td>13%</td>
</tr>
</tbody>
</table>

Q. Why is the first row of Table 1 described as the “Corrected Enchant & S&L Proposal?”

A. Appendix E in S&L’s July 8, 2019 CO2 Capture Pre-Feasibility Study lists the Total Project Cost as $1.295 billion. On page 5-3 of the same document, this cost is clearly presented as being in 2019 dollars. However, the earliest date Enchant offers for the restart of SJGS after the retrofit is mid-2023. Therefore, I have corrected the S&L analysis by converting the estimated S&L total project cost to $1.40 billion in 2023 dollars.

Q. What do you conclude from Table 1?

A. The S&L Base Case is completely unrealistic because the project is extremely unlikely to achieve either an 85% average annual capacity factor or a 90% CO2 rate. In addition, as I will explain in the next section, the project’s capital cost will very likely exceed S&L’s $1.295 billion estimate (in 2019 dollars). But even with

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these unrealistic assumptions, tax equity financing would likely be able to provide only about 81% of the funds needed to retrofit SJGS with carbon capture. The remaining funding would have to come from other sources.

In scenarios with more realistic assumptions, at least 41% of the cost of retrofitting SJGS for carbon capture would have to be raised from what might be even more expensive sources of financing than tax equity.

III. Retrofitting SJGS for CO₂ Capture is Likely to be Much More Expensive than Claimed in the Enchant and S&L Reports that Mr. Solomon Relies On.

Q. Staff witness Solomon has testified that “The 2019 Sargent & Lundy report shows that the technology has improved, capital costs have gone down and auxiliary power and steam consumption needs are lower.” ³⁵ Do you agree?

A. No. Mr. Solomon is comparing the 2019 S&L estimate with the 2010 S&L estimate. He is not comparing actual plant construction costs. Thus, the mere fact that the more recent 2019 S&L report estimates a lower capital cost for retrofitting SJGS for CO₂ capture does not offer any proof that the actual cost of retrofitting the plant will be any lower than S&L estimated in 2010. At the same time, the lower 2019 S&L capital cost estimate also provides no guarantee that the actual cost of retrofitting SJGS, in fact, will not be higher than S&L estimated back in 2010.

Q. How do S&L’s 2010 and 2019 estimated capital costs for retrofitting SJGS with CO₂ capture compare with the actual capital cost of the Petra Nova project which was built in the years 2014 to 2016?

A. The actual cost of building Petra Nova was $1 billion, or $4,200 per kW for a 240 MW facility. ³⁶ Figure 13 below shows that this was substantially more expensive

³⁵ Prepared Direct Testimony of Dhiraj Solomon, PE, at page 14, lines 20-22.
than S&L estimated in both 2010 and 2019 for the cost of retrofitting SJGS.$^{37}$

This is approximately three times the cost estimate from S&L that Mr. Solomon relies upon.

**Figure 13:** Actual Petra Nova Cost vs. S&L Estimates for Retrofitting SJGS with CO$_2$ Capture

![Graph depicting Actual Petra Nova Cost vs. S&L Estimates for Retrofitting SJGS with CO$_2$ Capture](image)

*Source: Analysis based on costs from EIA Today in Energy for October 31, 2017 and Exhibits DS-1 and DS-2 to the Prepared Direct Testimony of Dhiraj Solomon.*

Figure 13 shows that the actual cost of designing and building the only existing commercial-scale CO$_2$ capture project in the U.S. was significantly higher, on a per kW basis, than S&L estimated for retrofitting SJGS in both 2010 and 2019.

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$^{37}$ Note that the actual $4,200 per kW cost of Petra Nova and both the 2010 S&L estimate in Figure 13 have been converted to 2019 dollars to be on a comparable basis as the 2019 S&L estimate.
Q. What does the comparison shown in Figure 13 say about the reasonableness of the S&L 2019 cost estimate for retrofitting SJGS on which Mr. Solomon relies?

A. The theory underlying the development of new technologies, such as carbon capture at commercial scale power plants, is that, over time, lessons learned from the construction and operation of new plants will drive down the prices for building and running each successive unit.

For example, the cost of installing new utility-scale solar capacity declined by 2/3 between 2007-2009 and 2017, as a result of the lessons learned in the building and installation of 24.7 GW of new solar capacity. Similarly, the prices of installing new wind capacity fell by 40% between 2009/2010 and 2018, as a result of the lessons learned during the installation of 56 GW of new wind capacity.

However, carbon capture technology today is not like solar and wind technology. Solar and wind prices declined because of many factors, including significant research and development, robust competition among suppliers, and an extremely large number of commercial projects around the world. By contrast, there are only two carbon capture projects at power plants in the entire world. Unlike the situation for solar and wind technologies, there are not a large number of projects either operating, under construction, or in the pipeline that could be expected to drive down costs before the retrofit of SJGS is under way.

Moreover, instead of assuming that the cost of retrofitting new carbon capture technology to existing coal-fired generators would decline over time, Enchant and S&L assumed that the cost of retrofitting SJGS with CO₂ capture, the very next

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commercial-scale power plant in the U.S. to be retrofitted with carbon capture technology, would immediately be 68% lower (on a dollar per kW basis) than the cost of building the Petra Nova plant in Texas.

It is possible that the cost of retrofitting SJGS with CO₂ capture will achieve some cost savings from (1) the experience gained at Petra Nova, (2) the reuse of facilities at SJGS and (3) economies of scale. However, it also is quite possible that unanticipated problems will be experienced in scaling up the CO₂ capture technology from the 110 MW Boundary Dam and the 240 MW Petra Nova projects to the much larger 914 MW SJGS.

Q. Are there any other CO₂ capture projects currently being built at commercial-scale power plants in the U.S. or that can otherwise be expected to come online before the proposed retrofit of SJGS?

A. No, I have not seen evidence of any such projects.

Q. Did Petra Nova gain any cost-related benefits that would not be available to a company such as Enchant or PNM that tried to retrofit SJGS with carbon capture?

A. Yes. The U.S. Department of Energy provided $190 million of the $1 billion cost of building Petra Nova. In addition, approximately 30% of the financing for the project was insured by Nippon Export and Investment Insurance.⁴⁰ Both of these factors reduced the total cost of the project. Mr. Solomon did not provide any evidence that similar funding would be available to retrofit SJGS with carbon capture.

Q. Did the 2019 S&L cost estimate for SJGS exclude any significant costs?

A. Yes. S&L’s 2019 $1.295 billion capital cost for retrofitting SJGS excluded escalation, AFUDC, right of way and land purchase costs, and site security.\(^{41}\)

Q. Have you seen any CO\(_2\) retrofit cost estimates that would suggest a higher capital cost for the SJGS retrofit?

A. Yes. For example, the International Energy Agency, an active advocate for carbon capture, has estimated that the next generation of power plant CCS projects (that is, those after Petra Nova) will achieve 25 to 30 percent reductions in both capital and operating costs.\(^{42}\) NARUC has noted that the IEA’s projected reductions in the next generation of power plant CCS reductions, “…support the idea that costs will come down with more facilities.”\(^{43}\)

Similarly, the Clean Air Task Force (CATF), also an active advocate of CCS, believes that the capital cost of retrofitting existing coal plants for CCS will come down over time as later retrofits “benefit from the prior experience of the earlier projects.”\(^{44}\) CATF estimated that the capital cost for retrofits would decline to a range of $1,501 to $1,724 per kW by the sixth new project undertaken. However, the SJGS project, would be only the third carbon capture project at a power plant, not the sixth project, as CATF was discussing. And even CATF’s cost estimate for the sixth carbon capture project is higher than the $1,417 per kW that S&L assumes for SJGS, which as I’ve noted, would be just the third CO\(_2\) retrofit undertaken at a commercial-scale power plant.

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\(^{41}\) Exhibit DS-1 to the Prepared Direct Testimony of Dhiraj Solomon, Appendix D.


\(^{43}\) Id.

Q. What risks does such an overly optimistic capital cost estimate raise for plant owner(s) and investors?

A. Using very low capital cost estimates to entice investors into new projects exposes them to the risk of substantial losses if the actual capital cost of retrofitting a coal-fired generator for CO₂ capture is significantly higher than estimated.

Q. What capital cost would be prudent to use to evaluate a proposed retrofit of SJGS with CO₂ capture?

A. Given the great uncertainty regarding the likely capital cost of retrofitting SJGS, it would be prudent to look at a fairly wide range of capital costs. For example, I would recommend looking at a range from a low cost of $1.40 billion (S&L’s 2019 estimate in 2023 dollars) to a high cost of $3.31 billion (25% lower than Petra Nova) with a middle cost of $2.21 billion (50% of Petra Nova), all in 2023 dollars.

The low end of these costs represents S&L’s 2019 estimate, on a per kW basis, escalated to 2023 dollars. The high end represents a 25% reduction in the actual capital cost of the Petra Nova project, again in 2023 dollars – this reflects the savings that the International Energy Administration has estimated can be expected in the next generation of power plant CCS projects. Finally, the middle cost reflects a reduction of 50% of the actual Petra Nova capital cost.

It is important to emphasize that these costs are conservative and do not represent in any sense a “worst case” scenario in which significant unanticipated difficulties are encountered in scaling-up CO₂ capture technology to the much larger 914 MW SJGS project, which could lead to an even higher cost than Petra Nova.

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IV. It is Extremely Unlikely that a Retrofit of SJGS Could be Completed and Come Online before 2024.

Q. What in-service date has Enchant claimed it will be able to achieve for a retrofitted SJGS?

A. Enchant claims that the retrofit of San Juan with CCS could be financed, designed, the carbon capture system competitively bid, constructed, and pre-operationally tested in less than four years, with an online date in June 2023, if the project can be financed by mid-2020.46

Q. Do you agree that this schedule is reasonable?

A. No. Enchant’s claim about a mid-2023 in-service date is unreasonably optimistic. There simply is too much to do to be able to have the project online so quickly.

Q. Please explain the basis for your conclusion that it is unrealistic to assume carbon capture can be completed and online at SJGS by mid-2023.

A. The funding for the FEED (Front End Engineering and Design) study for the retrofit of San Juan with carbon capture has just been approved. Enchant’s Project Management Plan for what it terms the “Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station” assumes that the final report for this study will not be submitted to the DOE until mid-April 2021.47 Even if enough engineering were completed by mid-April 2021 to start some construction, that would leave only slightly more than two years to competitively bid the CO₂ capture system, order, fabricate and deliver system components, then construct and test the CO₂ capture retrofit before it went into service.


Q. How long did it take to design and build the Petra Nova CO\textsubscript{2} capture project?

A. The application for DOE funding for the 240 MW Petra Nova project was submitted in 2009, with the DOE grant awarded in 2011. This suggests that design for the project began at least three years before construction. S&L confirms this when it cites its experience working on the Petra Nova project from 2011 to 2017.\textsuperscript{48}

The 240 MW Petra Nova project then began construction in the middle of 2014, and had an online date at the end of 2016, a construction schedule of approximately 2½ years.\textsuperscript{49} Thus Petra Nova had a total project length of about six years, from the awarding of the DOE funding in 2011 to the online date in January 2017.

Q. Do you think it is realistic to assume that a carbon capture project at the 914 MW SJGS site can be completed in significantly less time than the smaller, 240 MW project at Petra Nova?

A. No. Enchant is claiming that it could design and build a much larger project (914 MW at SJGS versus 240 MW at Petra Nova) in less time, that is, under four years, than it took to design and build Petra Nova, which took six years.\textsuperscript{50} However, it is extremely doubtful that Enchant and S&L’s very aggressive June 2023 online date would allow adequate time for the successful completion of what would be a much larger CO\textsubscript{2} capture retrofit project.

PNM would be in a similar situation as Enchant if it were to try to retrofit SJGS with carbon capture, meaning that it is extremely unlikely PNM could bring

\begin{itemize}
  \item \textsuperscript{49} Presentation by Petra Nova Parish Holdings on Petra Nova Carbon Capture at the June 2019 IEA Clean Coal Conference, at slide no. 3.
\end{itemize}
carbon capture online at SJGS before 2024. Mr. Solomon provides no evidence that PNM (or anyone else) could complete a carbon capture project prior to 2024.

Q. Does Enchant acknowledge that SJGS could return to service later than mid-2023?

A. Yes. Enchant has included some wiggle room in the projected online date by saying that the “plant could experience a 6-12 month shut-down before restart with [carbon capture].”\(^{51}\) This appears to be based on a 30 to 36 month construction schedule and an additional 14-20 months to complete the Front End Engineering Design study.\(^{52}\) This would mean an online date for the retrofitted San Juan plan in 2024, which, while still very aggressive, is more realistic than June 2023. This would mean an 18-24 month, or longer, shutdown between the end of 2022 and its restart with carbon capture in 2024 or later.\(^{53}\)

Q. Does Mr. Solomon have any evidence that carbon capture can be installed and operational prior to January 1, 2023, the deadline by which SJGS must meet a CO\(_2\) emissions standard?

A. No. Mr. Solomon admits has no evidence that carbon capture can be installed and operational at SJGS by January 1, 2023, the deadline for meeting the CO2 emission standard in the ETA. Exhibit DAS-2, D. Solomon Depo. Tr. at 75: 6-11. In addition, Mr. Solomon is unaware that Enchant has said that carbon capture cannot be operational at SJGS by January 1, 2023, the deadline for meeting the CO2 emission standard in the ETA. \textit{Id.} at 75: 12-15.

\(^{51}\) \textit{Id.}  
\(^{53}\) My understanding is that the Energy Transition Act requires SJGS to meet a CO\(_2\) emission standard by January 1, 2023. If the carbon capture project does not come online by that date, and no variance or extension of the deadline is granted, then the plant would have to shut down until the carbon capture system is operational and the CO\(_2\) performance standard can be met.
Q. Does Mr. Solomon recognize that SJGS must be shut down on January 1, 2023 if a carbon capture system is not operational on that date?

A. Yes, he does. Mr. Solomon admits that unless carbon capture technology is installed and operational at SJGS, the plant cannot meet the CO₂ emission standard in the ETA that goes into effect on January 1, 2023 and must therefore shut down. Exhibit DAS-2, D. Solomon Depo. Tr. at 35:14-18, 39:19 to 40:20.

Q. By when does Enchant claim that it will have the funding in place for the SJGS retrofit?

A. Enchant makes contradictory assumptions about the schedule for developing the financing of the San Juan retrofit as it ties the achievement of a June 2023 online date to acquiring all of the needed financing of the project by June 2020. However, Enchant apparently believes that it will be able to acquire all of the financing needed for the retrofit without demonstrating the financial viability of the project to potential investors as its project plan assumes that the “Feasibility of Coal Plant with CCUS” analysis won’t be completed until April 2021, or nearly ten months after investors are expected to commit well over a billion dollars to the project. This feasibility study “will determine if the project will move forward into final design and implementation” and would seem to be an important analysis that investors would want to evaluate before they commit to the project.

Q. Why is the date by which carbon capture at SJGS could come online so important?

A. The online date for any potential carbon capture project is important for several reasons. First, the longer it takes to build a plant, the greater the impact that

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56 Id. at PDF page 10.
escalation and financing costs will have on the total project cost. Second, the plant owner(s) and/or investors in any San Juan CO₂ capture retrofit would have to pay the plant’s fixed costs during any shutdown of San Juan Units 1 and 4 between 2022 and its restart with carbon capture, whether in 2023, 2024 or even later. These fixed costs could total as much as $180 to $200 million if the retrofitted SJGS units did not restart until mid-2024 and would have to be borne by plant owner(s) and/or investors during a period when the plant would have no incoming revenues as it would not be generating any electricity that could be sold or capturing any CO₂ for sale for EOR.

Q. Have Mr. Solomon or Enchant and S&L accounted in their analyses for the costs of having to shut down SJGS for an extended period before the carbon capture system could become operational?

A. No. I did not see any place in Mr. Solomon’s testimony where he acknowledged the increased costs that any owner(s) would have to bear due to having to shut down SJGS either in 2022 when the current non-Farmington owners want to exit the project or on January 1, 2023 to meet the requirements of the Energy Transition Act. As mentioned above, during any such shutdown, the plant owner(s) would still need to spend money to maintain the plant in good operating condition. In addition, the owner(s) might need to pay for a coal supply, as coal contracts often have “take or pay” clauses that require the buyer to pay for coal even if it is not needed.
Mr. Solomon does not acknowledge these costs, nor does he explain why he thinks it would be reasonable for PNM to analyze a scenario in which ratepayers would have to pay potentially tens or hundreds of millions of dollars in fixed costs for SJSG to sit idle and not generate any electricity while a CCS system is built.

V. The Cost of Capturing CO\textsubscript{2} at SJGS Can Be Expected to be Much Higher Than the Enchant and S&L Cost Estimates that Mr. Solomon Relies On.

Q. Enchant and S&L claim that the cost of capturing CO\textsubscript{2} at SJGS would be between $39.15 and $43.49 per metric tonne.\textsuperscript{57} Do you agree that this is a reasonable range of possible capture costs for a retrofitted SJGS?

A. No.

Q. Please explain.

A. There are several reasons why the range of future CO\textsubscript{2} capacity costs forecast by Enchant and S&L are not realistic.

First, the $39.15 per tonne low end of the range is based on the completely unrealistic assumption that SJGS would operate at a 100% capacity factor, as was discussed earlier in this testimony.

Second, and most importantly, the CO\textsubscript{2} capture costs claimed by Enchant and S&L are based on three unreasonable assumptions: (1) that after running at an average 70% capacity factor between 2010 and 2019, SJGS Units 1 and 4 will operate at an average 85% annual capacity factor after being retrofitted; (2) that SJGS will achieve on a sustained basis an unproven 90% CO\textsubscript{2} capture efficiency; and (3) that the cost of retrofitting SJGS will be 68% lower than the cost of designing and building the Petra Nova project.

\textsuperscript{57} See Appendix E to Exhibit DS-1 to the Prepared Direct Testimony of Dhiraj Solomon.
Q. Have you recalculated what the cost per-tonne of capturing CO₂ would be if more reasonable capacity factors, CO₂ capture rates, and capital costs were used?

A. Yes.

Q. What methodology have you used to recalculate the per-tonne SJGS CO₂ capture costs?

A. I used the same methodology as is presented in Appendix E of the S&L July 2019 Pre-Feasibility Study. I only modified the analysis to include the 18 scenarios, reflecting reasonable ranges of capacity factors, capture rates and capital costs, that I used in the analysis presented in Table 1, above.

Q. What were the results of your analysis?

A. The results of my analysis are presented in Table 2, below. As can be seen, the per-tonne capture costs can be expected to be significantly higher than Enchant and S&L are claiming.
### Table 2
Projected SJGS CO₂ Capture Costs

<table>
<thead>
<tr>
<th>Scenario Assumptions</th>
<th>CO₂ Capture Cost (Dollars per Metric Tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrected Enchant &amp; S&amp;L Proposal</td>
<td>$45.69</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>$58.90</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>$67.31</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>$78.53</td>
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<td>Scenario 5</td>
<td>$93.29</td>
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<tr>
<td>Scenario 6</td>
<td>$108.84</td>
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<tr>
<td>Scenario 7</td>
<td>$112.84</td>
</tr>
<tr>
<td>Scenario 8</td>
<td>$128.97</td>
</tr>
<tr>
<td>Scenario 9</td>
<td>$150.46</td>
</tr>
<tr>
<td>Scenario 10</td>
<td>$79.69</td>
</tr>
<tr>
<td>Scenario 11</td>
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<tr>
<td>Scenario 12</td>
<td>$106.25</td>
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<tr>
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<td>Scenario 15</td>
<td>$151.39</td>
</tr>
<tr>
<td>Scenario 16</td>
<td>$160.03</td>
</tr>
<tr>
<td>Scenario 17</td>
<td>$182.89</td>
</tr>
<tr>
<td>Scenario 18</td>
<td>$213.38</td>
</tr>
</tbody>
</table>

#### Q. Why is the Base Case capture cost in Table 1 ($45.69 per metric tonne)
higher than the $43.49 cost in Appendix E of S&L’s July 2019 Pre-Feasibility Study?

#### A.
The Total Project Cost that S&L used in its analysis to calculate the cost of CO₂ capture is in 2019 dollars. I escalated this cost to 2023 dollars as that is what Enchant is claiming could be the online date for the retrofitted SJGS.

#### Q. Why are the CO₂ capture costs in Table 1, above, so much higher than the costs claimed by Enchant and S&L even in the scenarios which use the S&L estimated capital cost?

#### A.
Assuming more realistic plant capacity factors and CO₂ capture rates means that the plant will capture millions fewer tonnes of CO₂ so the capital cost of the retrofit and the fixed CO₂ capture O&M costs would be spread over fewer tonnes of CO₂ – see Figure 12, above. This means a higher cost of capture per tonne.
VI. Any Owner(s) of SJGS Can Expect to Suffer Substantial Losses in the Sale of Electricity after 2023.

Q. Did Staff Witness Solomon discuss the risks that any SJGS owner(s) and/or investors would have to pay for maintenance that had been deferred by the current owners and for the plant’s fixed O&M costs if the plant closes in 2022 and is then restarted following the completion of the CO₂ capture retrofit?

A. No.

Q. Are there any other significant risks that also should be considered when evaluating whether retrofitting SJGS is feasible?

A. Yes. The analysis must consider whether the electricity generated at the plant will be sold at prices at least equal to the costs of producing that electricity.

Q. Is it reasonable to expect that any owner(s) of SJGS will be able to sell the electricity it produces at a profit?

A. No. It is far more likely that SJGS’s owner(s) would incur substantial losses in the sale of the plant’s electricity.

Q. What is the basis for this conclusion?

A. SJGS Units 1 and 4 cannot be expected to be low cost-generators after being retrofitted for CO₂ capture, contrary to Enchant’s claim.⁵⁸

Q. What do the current owners of SJGS project for the future costs of generating electricity at SJGS if the plant is not retired in 2022?

A. PNM and TEP have both forecasted that SJGS will continue to be a high-cost generator if the plant is not retired in 2022, as shown in Figure 14, below:

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Figure 14: PNM and TEP Projected SJGS Operating and Maintenance Costs vs. Market Prices

Sources: Forward Energy Market Prices downloaded from S&P Global Market Intelligence on November 1, 2019; Tucson Electric Power’s projected SJGS costs of energy are from the company’s April 28, 2018 response to the Notice of Inquiry in Arizona Corporation Commission Docket No. E-00000Q-16-0289; and PNM’s projected costs are from the output reports provided in response to Data Request NEE 1-72.

Q. Do the other SJGS owners agree that the plant is not a low-cost generator and will not become one in the future?

A. The City of Farmington doesn’t, and I was unable to find any information about the expectations of the Utah Associated Municipal Power Systems. However, Los Alamos County does not consider SJGS to be a low-cost generator and expects the plant’s cost of electricity to remain expensive if it is not retired in 2022, as was noted in a 2017 Integrated Resource Plan Report (IRP) prepared for the County: “SJGS 4 incurs high fixed costs and is not economic to dispatch under current market conditions.”

The Los Alamos County IRP also included an exhibit that illustrated the plant’s high costs.

**Figure 15**: Los Alamos County Projected SJGS Operating & Maintenance Costs

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**Exhibit 37: SJGS 4 Costs and Market Prices Comparison**

![San Juan Unit 4 Costs vs. Market Prices](source)

*Note: SJGS 4 runs at minimum level during 2017-2033.*

*Source: Pace Global.*

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Q. Do the O&M projections in Figures 14 and 15 reflect a retrofit of SJGS to capture CO2?

A. No.

Q. What impact could such a retrofit be expected to have on the plant’s non-CO2 capture costs?

A. With a carbon capture retrofit, SJGS’s average per MWh non-CO2 capture costs would be higher than is shown in Figures 14 and 15. This is due to the very high parasitic loads due to the internal plant power that is used to run the CO2 capture equipment. This high parasitic load would decrease the plant’s net capacity from 847 MW pre-retrofit to just 601 MW post-retrofit. This means that the plant’s

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non-CO$_2$ capture-related fixed O&M costs must be spread over fewer MWh of output, and this raises the cost of each MWh that the owner(s) would be seeking to sell. As a result, electricity from SJGS would be even more expensive and less competitive than Figures 14 and 15 suggest.

Q. But doesn’t Enchant claim that there will be cost savings from an improved coal contract?

A. Yes, Enchant does make that claim.$^{61}$ However, PNM’s projected O&M costs presented in Figure 14 and included in my analysis already reflect that SJGS’s future coal prices are expected to be much lower than they have been in recent years, as shown in Figure 16, below:

Figure 16: SJGS’s Recent vs. Projected Coal Costs

Sources: PNM FERC Form 1 Filings and Scenario 1 Output Reports provided in PNM’s Expedited Response to NEE Interrogatory 1-72 in Case 19-00018-UT

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Q. What is the range of potential losses that you have calculated that the owner(s) of SJGS can reasonably be expected to suffer from the sale of electricity in the years 2024-2035, if SJS were retrofit with carbon capture technology?

A. The owner(s) of SJGS can expect to experience losses of between $474 and $704 million from the sale of high-cost electricity produced at SJGS during the years 2024-2035.

Q. Do these losses include the cost impact of any capital expenditures that owner(s) would have to spend on CO₂ capture or balance-of-plant maintenance or repairs?

A. No. In my experience coal plant owner(s) typically spend on maintenance-related capex projects until the plants are near retirement. However, the amounts they spend are very plant-specific. I have not included in this analysis any estimate of what those costs might be for SJGS for CO₂ capture or balance-of-plant maintenance or repairs. My estimated range of potential losses is, then, conservative or low.

VII. The Owner(s) of SJGS Would Be Exposed to Oil Market Volatility and Risks if They Retrofit SJGS with Carbon Capture Technology.

Q. Are the market values for CO₂ cited by Mr. Solomon at page 15, lines 17-18, of his Prepared Direct Testimony prices that any owner(s) of SJGS would be guaranteed to receive for the sale of the CO₂ captured at the plant?

A. No. They are simply projected values based on one of the oil price forecasts included in the EIA’s 2018 Annual Energy Outlook. There is no guarantee that actual CO₂ prices will be anywhere near these values, or even as high as the $17.50 per tonne price assumed by Enchant and S&L in their marketing materials for the SJGS retrofit.
Q. What factors are likely to determine future CO₂ prices?

A. It is reasonable to expect that future CO₂ prices most likely will be affected by actual and expected oil prices and by the competition between different CO₂ sources.

Q. Have you seen any evidence that changing oil markets have rendered Petra Nova less profitable than NRG anticipated when it undertook the project?

A. Yes. Although using the CO₂ captured at Petra Nova for enhanced oil recovery has increased the amount of oil produced at the company’s West Ranch oil field, it appears that the project has not been nearly as profitable as NRG expected when it was adding carbon capture to the existing W.A. Parish coal-fired generator in Houston.

In 2016, NRG took an impairment of $140 million on its $300 million investment in its subsidiary Petra Nova Parish Holdings due to a continued decline in oil prices.⁶² NRG then took another impairment of $69 million in its investment in Petra Nova in 2017 based on a revised view of oil production expectations.⁶³ Even though Petra Nova was completed on schedule and on budget, in October 2016, even before the project began operations, NRG said that the project would be its last clean coal plant due to a drop in oil prices.⁶⁴ Fortune Magazine noted that NRG Energy’s Petra Nova project “may be completed, but it’s unlikely to set a precedent for profitability.”⁶⁵

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⁶⁵ Id.
Q. Should this Petra Nova project experience serve as a warning to the owners of SJGS and potential investors in retrofitting the plant with carbon capture?

A. Yes.

Q. Finally, even if SJGS did capture 6 million tonnes of CO₂ each year, would this mean that the overall emissions into the atmosphere would decline by 6 million tonnes?

A. No. The use of captured CO₂ for EOR produces additional oil that, in turn, is burned or used as a chemical feedstock, both of which can be expected to release CO₂ into the atmosphere. For example, Power Magazine estimates that every ton of CO₂ used in EOR will bring up roughly 0.76 to 0.91 tons of equivalent CO₂ that will ultimately end up in the atmosphere. And even this might not capture all of the CO₂ emitted by the additional oil produced with EOR.

VIII. Conclusions

Q. Please summarize your testimony.

A. In arguing that PNM should have conducted a new analysis of continuing to operate SJGS with carbon capture, Mr. Solomon did not produce his own analysis of the engineering, economic, or financial feasibility of carbon capture at the plant. Instead, Mr. Solomon relies on claims made by Enchant and S&L. But the SJGS retrofit proposal submitted by Enchant Energy relies on a series of assumptions that are little more than wishful thinking. Enchant’s proposal hinges on the assumption that the retrofitted facility would be able to capture 6 million metric tonnes of carbon annually—a number that simply cannot be achieved. To capture that much carbon each year would require the facility to capture 90% of

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the CO₂ it produces and operate at an annual capacity factor of at least 85% for 12 years, both of which are unrealistic.

As my testimony has shown, the only two existing power plants in the world that capture CO₂ have not captured 90% of their CO₂ emissions, and it is unrealistic to expect that carbon capture at SJGS could do so either. Equally important, it is totally unrealistic to assume that the retrofitted SJGS facility would be able to achieve an annual capacity factor of at least 85% for the first 12 years of its operation when neither of the two units at the plant have hit that level since 2011. Age-related reliability issues and competition from renewable energy resources are almost certain to prevent the plant from operating anywhere near the 85% level assumed by Enchant.

Beyond these two problems, the Enchant proposal significantly understates the project’s probable capital cost, assuming reductions from the first two units that are not tenable. Moreover, Enchant’s claims as to when carbon capture could come online at SJGS are unlikely to be met. As this testimony has shown, more realistic assumptions about the construction costs and commercial completion date would substantially increase the project’s cost, making it financially unviable from the outset.

Q. Consequently, do you agree with Mr. Solomon that carbon capture and sequestration is an economically and financially feasible option at SJGS that should have been analyzed in PNM’s abandonment application?

A. No. Based on the evidence I have reviewed and the analyses I presented above, I do not believe that carbon capture and sequestration is financially feasible at SJGS. For the same reasons, I disagree with Mr. Solomon that a scenario involving carbon capture should have been modeled by PNM.

Q. Does this complete your testimony?

A. Yes.
BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE
COMPANY OF NEW MEXICO'S
ABANDONMENT OF SAN JUAN
GENERATING STATION UNITS 1 AND 4

Case No. 19-00018-UT

VERIFICATION

STATE OF MASSACHUSETTS
COUNTY OF Middlesex

David A. Schlissel, first being sworn on his oath, states:

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

David A. Schlissel

SUBSCRIBED AND SWORN TO before me on this 8th day of November, 2019 by David A. Schlissel.

My commission expires: Nov 20, 2021

MAURICIO BURGOS
Notary Public
Commonwealth of Massachusetts
My Commission Expires November 20, 2021
BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE
COMPANY OF NEW MEXICO'S
ABANDONMENT OF SAN JUAN
GENERATING STATION UNITS 1 AND 4

) Case No. 19-00018-UT

CERTIFICATE OF SERVICE

I CERTIFY that on this date I caused to be sent to the parties and individuals listed below, via email only, a true and correct copy of the Prepared Rebuttal Testimony of David Schlissel on Behalf of Sierra Club.

Stacey Goodwin
Ryan Jerman
Richard Alvidrez
Dan Akenhead
Mark Fenton
Carey Salaz
Steven Schwebeke
Heather Allen
Mariel Sanasi
David Van Winkle
Aaron El Sabrout
Joan Drake
Lisa Tormoen Hickey
Jason Marks
Matthew Gerhart
Katherine Lagen
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Camilla Feibelman
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Nann M. Winter
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Dahl Harris
Peter Auh
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Douglas J. Howe
Bruce C. Throne
Rob Witwer
Jeffrey Albright
Amanda Edwards
Michael L. Garcia
Greg Sonnenfeld
Charles F. Noble
Stephanie Dzur
Vicky Ortiz
Stacey.Goodwin@pnmresources.com;
Ryan.Jerman@pnmresources.com;
Ralvidrez@mslaw.com;
DAkenhead@mslaw.com;
Mark.Fenton@pnm.com;
Carey.salaz@pnm.com;
Steven.Schwebeke@pnm.com;
Heather.Allen@pnmresources.com;
Mariel@seedsbeneaththesnow.com;
Davidvanwinkle2@gmail.com;
Aaron@newenergyeconomy.org;
jdrake@modrall.com;
lisahickey@newlawgroup.com;
lawoffice@jasonmarks.com;
matt.gerhart@sierracub.org;
Katherine.lagen@sierracub.org;
Ramona.blaber@sierracub.org;
Camilla.Feibelman@sierracub.org;
MGoggin@gridstrategiesllc.com;
nwinter@stelznerlaw.com;
khermann@stelznerlaw.com;
dahlharris@hotmail.com;
pau@abcwua.com;
JGarcia@stelznerlaw.com;
akharriger@sawvel.com;
deguen@sawvel.com;
jaherez@sawvel.com;
smichel@westernresources.org;
April.Elliott@westernresources.org;
pat.ooconnell@westernresources.org;
dhowe@highrocknm.com;
bthroteatty@newmexico.com;
witwerr@southwestgen.com;
JA@jallaw.com;
AE@jallaw.com;
migarcia@bermco.gov;
greg@sonnenfeldconsulting.com;
Noble.ccae@gmail.com;
Stephanie@Dzur-law.com;
Vortiz@montand.com;
Mike Eisenfeld
Sonia Grant
Carol Davis
Robyn Jackson
Thomas Manning
Debra S. Doll
Katherine Coleman
Thompson & Knight
Jeremy Cottrell
Jane L. Yee
Larry Blank, Ph.D.
Saif Ismail
David Baake
Germaine R. Chappelle
Senator Steve Neville
Senator William Sharer
Rep. James Stricker
Rep. Anthony Allison
Rep. Rod Montoya
Rep. Paul Bandy
Patrick J. Griebel
Richard L. C. Virtue
Carla R. Najjar
Philo Shetlon
Robert Cummins
Kevin Powers
Steven Gross
Martin R. Hopper
Cholla Khoury
Gideon Elliot
Robert F. Lundin
Elaine Heltman
Andrea Crane
Douglas Geagax
Michael C. Smith
Bradford Borman
John Bogatko
Marc Tupler
Beverly Eschberger
Georgette Ramie
mike@sanjuancitizens.org;
sonia@sanjuancitizens.org;
caroljdavis.2004@gmail.com;
choo@bitsi@ad.gov;
cfcrelenergy@ai@yahoo.com;
Debra@doll-law.com;
Katie.coleman@tklaw.com;
Tk.eservice@tklaw.com;
jcottrell@westmoreland.com;
jyee@cabq.gov;
lb@tahoeconomics.com;
sismail@cabq.gov;
david@baakelaw.com;
Gchappelle.law@gmail.com;
steven.neville@nmlegis.gov;
bill@williamsharer.com;
jamesstricker@msn.com;
Anthony.Allison@nmlegis.gov;
roddmontoya@gmail.com;
paul@paulbandy.org;
patrick@marrslegal.com;
rvirtue@virtuelaw.com;
Csnajjar@virtuelaw.com;
Philo.Shetlon@lacnm.us;
Robert.Cummins@lacnm.us;
Kevin.Powers@lacnm.us;
gross@portersimon.com;
mhopper@nsrpower.org;
ckhoury@nmag.gov;
gelliot@nmag.gov;
rlundin@nmag.gov;
Eheltman@nmag.gov;
ctcolumbia@aol.com;
dgegax@nmu.edu;
Michael.smith@state.nm.us;
Bradford.Borman@state.nm.us;
John.Bogatko@state.nm.us;
Marc.Tupler@state.nm.us;
Beverly.Eschberger@state.nm.us;
Georgette.Ramie@state.nm.us;
SUMMARY
I have worked since 1974 as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

PROFESSIONAL EXPERIENCE
Electric Resource Planning - Analyzed the financial and economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the financial, economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NOx, SO2 and CO2. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA’s Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.
Electric System Reliability - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Nuclear Power – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Electric Industry Regulation and Markets - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Whether $303 million represents the current fair market value of Northwestern Energy’s 30 percent ownership share of Colstrip Unit 4.

Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 17) – July and October 2018
The operating performance of the Edwardsport Integrated Gasification Combined Cycle Plant, and the economic impact that the plant has had, and will continue to have, on Duke Energy Indiana’s ratepayers.

West Virginia Public Service Commission (Case No. 17-0296-E-PC) – August 2017
The reasonableness of Monongahela Power’s proposed acquisition of the 1,300 MW Pleasants Power Plant.

Indiana Utility Regulatory Commission (Cause No. 44794) – October & December 2016
The economic viability of proposed environmental upgrades at the Petersburg Power Station.

Montana Public Service Commission (Docket Nos. D2013.5.33 and D2014.5.46) – May 2015
The circumstances surrounding the extended outage of Colstrip Unit 4 from July 1, 2013 through January 23, 2014.

Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 12 & 13) – December 2014
Whether Duke Energy Indiana’s Edwardsport IGCC Project was in service between June 7, 2013 and March 31, 2014 and the Project’s current operational performance and cost status and future prospects.

Public Service Commission of West Virginia (Case No. 14-0546-E-PC) – August 2014
The reasonableness of American Electric Power’s proposed transfer of 50 percent of the Mitchell Coal Plant to its regulated affiliates in West Virginia.

Mississippi Public Service Commission (Docket No. 2013-UN-189) – March and June 2014
The prudence of Mississippi Power Company’s management of the planning for the Kemper County IGCC Plant.

Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 8, 10, and 12) – June 2012, April 2013 and April 2014
Startup and pre-operational testing delays at Duke Energy Indiana’s Edwardsport IGCC Project.

Public Service Commission of West Virginia (Case No. 12-1655-E-PC) – June 2013 and July 2013
The reasonableness of Appalachian Power Company’s proposed acquisition of 2/3 of Unit 3 of the John E. Amos power plant and ½ of the two unit Mitchell power plant.
Public Service Commission of West Virginia (Case No. 12-1571-E-PC) – April 2013
The reasonableness of Monogahela Power Company’s proposed acquisition of 80 percent of the Harrison Power Station.

Virginia State Corporation Commission (Case No. PUE-2012-00128) – March 2013
Whether Dominion Virginia Power’s proposed Brunswick Project natural gas-fired combined cycle power plant is needed and in the public interest.

Reasonableness of Tucson Electric Power’s proposed Environmental Compliance Adjustor mechanism.

Reply to testimony filed by Entergy Nuclear and NRC Staff concerning the relicensing of Indian Point Units 2 and 3.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – March 2012
Petition to Reopen the docket for the Kemper County IGCC Plant based on changed circumstances.

Mississippi Public Service Commission (Docket No. 2009-UA-279) – February 2012
The financial and economic risks of retrofitting Mississippi Power Company’s Plant Daniel Coal Plant.

Georgia Public Service Commission (Docket No. 34218) – November 2011
The reasonableness of Georgia Power Company’s proposed fossil plant decertification/retirement plan.

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Maryland Public Service Commission (Case No. 9271) – October 2011
The reasonableness of Constellation Energy Group’s proposed divestiture of three coal-fired power plants as mitigation for market power concerns arising from its proposed merger with Exelon Corporation.

Minnesota Public Utilities Commission (Docket No. E017/M-10-1082) – August and September 2011
Whether the proposed addition of the Big Stone Plant Air Quality Control System is a lower cost alternative for the ratepayers of Otter Tail Power Company than retirement of the Plant and replacement by a natural gas-fired combined cycle unit possibly combined with new wind capacity.

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Duke Energy Indiana’s imprudence and gross mismanagement of Edwardsport IGCC Project.
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The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

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The reasonableness of Public Service of Colorado’s proposed Emissions Reduction Plan.

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AMP-Ohio’s application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

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Appalachian Power Company’s application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007
Whether Interstate Power & Light Company’s adequately considered the risks associated with building a new coal-fired power plant and whether that Company’s participation in the proposed Marshalltown plant is prudent.

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Don’t Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation to the New York Society of Securities Analysts, February 26, 2008.


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Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA’s Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.


Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation’s telephone cable repair and replacement programs, May, 1996.


**OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK**

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy’s repowering of its Astoria Generating Station. October 2002 through February 2003.


Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.


Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.
Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.
WORK HISTORY

2012 - Director of Resource Planning Analysis, Institute for Energy Economics and Financial Analysis
2010 - President, Schlissel Technical Consulting, Inc.
1983 - 1994: Director, Schlissel Engineering Associates
1979 - 1983: Private Legal and Consulting Practice
1975 - 1979: Attorney, New York State Consumer Protection Board
1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

• New York State Bar since 1981
Exhibit DAS-2

Q. So is your answer you do not know if any staff witness assessed whether it's more cost effective to retire and abandon San Juan Units 1 and 4 in this case?

A. I said I'm not the economics expert. They are. So you can pose that question to them.

Q. I'm asking you "yes" or "no." Do you know if any staff witness addressed that question? And if you don't know if they did, you can say I don't know.

A. I don't know.

Q. Okay. Can you explain your understanding of how the ETA affects the San Juan Generation retirements decision?

A. The ETA requires San Juan Generating Station to -- subjects it to a CO2 emission limit of 1,100 pounds per megawatt hour beginning January 1 of 2023, which the plant cannot meet without installation of some carbon dioxide controls.

Q. And which staff witnesses assesses the ETA rationale for San Juan abandonment?

A. There's different aspects to San Juan abandonment. One is the emissions. The other aspects are environmental, which I know, and the other are economic impacts, and then there is the securitization financing, which is Marc Tupler who has analyzed the application. So there's three different staff -- four different staff witnesses who have different parts of the ETA that we have evaluated.

Q. Okay. Which staff witness evaluates the CO2 emissions limit?

A. That would be me.

Q. And then -- and please explain your understanding of how discontinuance by other plant owners to operate the plant beyond 2022 affects the San Juan Generating Station retirement decision?

A. Mr. Fallgren's testimony is that the other parties have decided not to extend their ownership of San Juan, and based on that, he asserts that PNM, therefore, cannot continue the plant. And my understanding is that currently the City of Farmington owns a little over 5 percent of the plant and the remaining owners because of their non-extension of their ownership, the remaining portion of the plant would go to the City of Farmington. That's just my cursory understanding of the -- I'm not a contracts expert, so I don't know, but this is my layman's understanding of the ownership.

Q. Is it your understanding that if PNM continued and City of Farmington continued, Farmington would pick up all the departing owners' shares?

A. That I don't know.

Q. Okay.

A. I'm not a contracts expert.

Q. Does your testimony assess --

MS. CHAPPELLE: I'm just confused by the question. Did you say if PNM continued and Farmington continued?

MR. MARKS: That was the question.

MS. CHAPPELLE: Okay.

MR. MARKS: And he said he didn't know.

MS. CHAPPELLE: Thank you.

Q. Does your testimony address whether the discontinuance by other plant owners is a compelling reason to abandon San Juan?

A. I don't know.

Q. You don't know if your testimony addresses that question?

A. In the past, I believe some owners have pulled out, and their ownership has been taken over by the other parties, I believe by PNM and Tucson Electric Power. And so I don't know. Like I said, I'm not a contracts expert, so I don't know.
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<th>Page 38</th>
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<tr>
<td>Q. I think you misunderstood my question. My question is, does your filed direct testimony address that question of whether the discontinuance by Tucson Electric and other owners is a compelling reason to abandon San Juan? Is it in your filed testimony?</td>
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<td>A. I believe PNM can take over ownership of the non-extenders.</td>
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<td>Q. Where does that say that in your testimony?</td>
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<td>A. It doesn't, but I do believe that they could. It's not a compelling reason.</td>
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<td>Q. Okay. Does your --</td>
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<td>A. But Mr. Fallgren does state that is one of the reasons, and I have cited that.</td>
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<td>Q. Aside from the mention on Page 5, Line 18, do you discuss that topic anywhere else in your filed direct testimony?</td>
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<td>A. I don't know. I'll have to read the entire testimony to see if it does.</td>
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<td>Q. Okay.</td>
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<td>A. I can't recall.</td>
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<td>Q. You can't recall. And can you recall whether you provide any -- other than your vague knowledge that PNM could take over from the other owners, did you assess a scenario in which PNM operates more of the plant?</td>
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<td>A. I believe it's PNM's responsibility to provide that kind of analysis for review and show that it would not be feasible to continue operations under that scenario --</td>
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<tr>
<td>Q. Okay.</td>
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<td>A. -- and demonstrate that non-extension by other parties is a compelling reason to shut down the plants.</td>
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<td>Q. Does it say that in your filed testimony?</td>
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<td>A. I did not address that issue, no.</td>
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<tr>
<td>Q. Okay. And did either Mr. Sisneros or Ms. Eschberger address that issue?</td>
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<td>A. I don't know.</td>
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<td>Q. So did you read in PNM's testimony that the company projects hundreds of millions of dollars in savings to rate payers by replacing San Juan with alternative resources putting aside carbon emissions and environmental benefits?</td>
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<td>A. PNM states that PNM does a net present analysis in Nick Phillips' testimony where they compare Scenario 1 and Scenario 2 to a scenario that San Juan continues operation. And as I have pointed out in my testimony, that's an unrealistic scenario because San Juan cannot continue operations as is past January 1 of 2023 because the emissions portion of the ETA applies to CO2 emissions regardless or not, but regardless of whether the ETA applies to 19-18 or not.</td>
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<td>So that analysis is not a realistic scenario because that scenario is not realistic. You cannot continue operations without installation of CO2 reduction technology past January 1 of 2023. So the base operation in PNM's application should have been in Nick Phillips' testimony, and Nick Wintemantel's testimony should have been a scenario.</td>
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<td>The base case should have been PNM continues the operation of San Juan with CCS installed 45Q tax credits and selling CO2 to an oil and gas company and to get that scenario as the base scenario, and then compare it to its replacement scenarios, and that would have been a proper analysis. PNM did not do that analysis. Instead the analysis that Nick Phillips presented is base case San Juan continues operation, which is unrealistic under the ETA. They cannot operate San Juan anymore.</td>
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<td>Q. Did you find that it would cost less to operate San Juan with carbon capture and the CO2 being sold for EOR than it would to operate San Juan under its current configuration?</td>
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<tr>
<td>A. That's what my testimony tells PNM to do.</td>
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PNM should present that analysis so we can review it and give an assessment of whether or not it's -- that's the case. You're asking me a question which PNM should have submitted as part of this abandonment filing. They did not. And for those reasons, I have recommended denial. The application is incomplete, and for those reasons I'm recommending denial of the application. PNM should present that analysis. |
| Q. Do you have any reason to believe that it would cost the same or less to operate the plant with CCS than it would cost to operate in its current configuration? |
| A. I don't know. I need to see that analysis in order to -- if PNM would present it, then I could look at it and make that determination, but PNM has not submitted that analysis. PNM needs to provide that, and that's the whole gist of my testimony is that where is that analysis. PNM operating and selling carbon at those rates that are provided in the NARUC literature as to how many tons you can sell CO2 to. Take an average and present that as part of the application. I don't know. |
| Q. Okay. Do you have any reason to dispute that the findings by PNM in their 2017 IRP and their findings in the current modeling that it's cheaper to
Q. I think you misunderstood my question. My question is, does your filed direct testimony address that question of whether the discontinuance by Tucson Electric and other owners is a compelling reason to abandon San Juan? Is it in your filed testimony?

A. I believe PNM can take over ownership of the non-extenders.

Q. Where does that say that in your testimony?

A. It doesn’t, but I do believe that they could. It’s not a compelling reason.

Q. Okay. Does your --

A. But Mr. Fallgren does state that is one of the reasons, and I have cited that.

Q. Aside from the mention on Page 5, Line 18, do you discuss that topic anywhere else in your filed direct testimony?

A. I don’t know. I’ll have to read the entire testimony to see if it does.

Q. Okay.

A. I can’t recall.

Q. You can’t recall. And can you recall whether you provide any -- other than your vague knowledge that PNM could take over from the other owners, did you assess a scenario in which PNM operates more of the plant?

A. I don’t know. I don’t have the ETA applies to CO2 emissions regardless or not, but regardless of whether the ETA applies to 19-18 or not.

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The base case should have been PNM continues the operation of San Juan with CCS installed 45Q tax credits and selling CO2 to an oil and gas company and to get that scenario as the base scenario, and then compare it to its replacement scenarios, and that would have been a proper analysis. PNM did not do that analysis. Instead the analysis that Nick Phillips presented is base case San Juan continues operation, which is unrealistic under the ETA. They cannot operate San Juan anymore.

Q. Did you find that it would cost less to operate San Juan with carbon capture and the CO2 being sold for EOR than it would to operate San Juan under its current configuration?

A. That’s what my testimony tells PNM to do.
Q. Did Sargent & Lundy do any analysis of the impact of these two items that we agree are parasitic load on ETA compliance?
A. I mean, they have clearly stated that this will be 246 megawatts. Once the net power output is reduced by 246 megawatt, you do the retrofit at 100 percent capacity. Now, these need to be assessed at different capacity utilizations in it. They shouldn't do that. So that would be part of a more detail engineering analysis, which I would have expected, again, from PNM to provide all that and show that the parasitic load is too much, and that for those reasons, they may not be feasible or not a viable technology, and then take that and translate it into the economics and show us that complete analysis at different loads. These are -- this is a study which shows it at 85 percent, 100 percent capacity utilization. This number is at 100 percent utilization, the reduction in overall net power -- overall power, and is reduced by 246 megawatt at 100 percent capacity. The plant will not always operate at 100 percent capacity. That's not a realistic scenario again.

So these need to be assessed at different capacity utilizations, 85, 75, 50, lower than 50, and that you had?
A. The primary goal -- the primary data point that I needed from this was whether or not it was technically feasible and whether or not they could get a certain capture efficiency over 50 percent which would allow the plant to operate post January 1 of 2023, and the report clearly states that it is. So that was my primary goal in reviewing the report. And that's what I got out of it, that it's technically feasible, it's a viable technology.

And then they point out that it's operating in Petra Nova and at Boundary Dam for some years. So they clearly point out that this is being retrofitted successfully. And NARUC says the NARUC report says that they're operating successfully. So based on that, there is definitely a -- it merits further investigation and evaluation by PNM in their application.
Q. Would you agree with me even if it's technically feasible, it has to be economically feasible?
A. Yes.
Q. Okay. And economically feasible means that it costs less than the alternatives?
A. Yes.

Q. Thinking out loud here, maybe a better way to say it, it has to be cost effective by costing less than the alternatives?
A. And reliable. That's the other criteria.
So knowing that it's coal-fired or designed for base load generation, you have to factor in the reliability criteria as well.
Q. Okay. And did you form any conclusion as to whether even if -- as to whether if the Sargent & Lundy estimates were correct, this would be economically feasible, this project would be economically feasible?
A. As I've said multiple times, I'm waiting for the submittal from PNM so I can form that conclusion one way or another, but I don't have that from PNM. So I can't make that determination.
Q. So --
A. And that's my testimony.
Q. And you did not form any opinion about the economic feasibility based on Sargent & Lundy information?
A. We don't have that information in the Sargent & Lundy report as to the detailed economic feasibility analysis. Sargent & Lundy is simply an engineering report which tells us this technology is...
Q. Do you have any reason to believe that the [text cut off]

Q. I don't know. That's why I've said I need [text cut off]

A. It points out that there is a revenue [text cut off]

A. Yes, plus the sale of the electricity [text cut off]

A. Whoever operates the plant.

Q. For who to sell the electricity to some [text cut off]

A. Whoever operates the plant.

Q. Case is not about Farmington and [text cut off]

Q. Can you turn to Page 11 of your testimony [text cut off]
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to see that analysis from PNM in order to answer that question.

Q. So you think it's possible it could cost
less to operate it with CCS than it would in its current configuration?

A. It's possible that with the credit in the revenue stream that comes out of it, it could.

Q. So it would depend on the credit of the revenue stream. But putting those aside, as just a power generating facility, is it at all plausible it will cost less to run?

A. Yes, plus the sale of the electricity that's generated. That would be another factor. That would be another revenue stream. If it was possible to sell the electricity generated to some buyer, then all those considered, it's possible.

Q. For who to sell the electricity to some buyer?

A. Whoever operates the plant.

Q. Are you thinking of Farmington and Enchant doing that?

A. Whoever operates the plant.

Q. This case is not about Farmington and Enchant's operation of San Juan carbon capture, is it?

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A. I don't know. That's why I've said I need

capture retrofit would be less than the cost of net cost of operating San Juan with this carbon

Q. Do you have any reason to believe that the proposed in their abandonment filing.

A. It points out that there is a revenue stream associated with the CO2. It gives numbers which can be verified with the NARUC study, and it also points out the 45Q tax credits. And all those would be economic benefits for the rate payers of New Mexico. And that's my testimony, that PNM needs to evaluate that and show us that scenario would still not be a greater benefit than the scenarios they proposed in their abandonment filing.

Q. Do you have any reason to believe that the net cost of operating San Juan with this carbon capture retrofit would be less than the cost of operating it in its current configuration?

A. I don't know. That's why I've said I need

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Q. So it would depend on the credit of the revenue stream. But putting those aside, as just a power generating facility, is it at all plausible it will cost less to run?

A. Yes, plus the sale of the electricity that's generated. That would be another factor. That would be another revenue stream. If it was possible to sell the electricity generated to some buyer, then all those considered, it's possible.

Q. For who to sell the electricity to some buyer?

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Q. Are you thinking of Farmington and Enchant doing that?

A. Whoever operates the plant.

Q. This case is not about Farmington and Enchant's operation of San Juan carbon capture, is it?

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A. I don't understand your question.

Q. Okay. I'll ask it a different way. Is this case about PNM's continued operation of San Juan?

A. PNM has asked for abandonment. As part of the abandonment, PNM must provide all feasible scenarios that are possible, and they provided a scenario that's not realistic as a base operation to which they've compared their four replacement scenarios. Scenarios 1 through 4, which have been compared to continue to operate San Juan past 2023, which is not a realistic scenario because they cannot operate that without some pollution control technology.

So PNM needs to make its base scenario the continued operation of San Juan past 2023 with CCS technology, 45Q tax credits, sale of CO2, and the potential benefits that would accrue from those, plus the potential sale of the electricity that's generated to some buyer. And that needed to be the base scenario in the abandonment filing, and then that needed to be evaluated. And PNM did not -- chose not to do that, so the application is incomplete.

Q. What's your basis for believing that it's

PNM's obligation to look at every alternative scenario? Does the abandonment statute say that?

A. If we don't look at every feasible alternative, how do we determine what's most cost effective and what's the lowest cost? If you eliminate a feasible scenario in your analysis, how do I know that one wasn't the most cost effective that wouldn't have constituted the lowest cost which would have benefited the rate payer? If I ignore a scenario, how do I know that that's not the lowest cost effective? I'm not saying you have to accept it. I'm saying you have to evaluate it as part of your application.

Q. And my question is, is the abandonment standard to abandon a plant, you have to replace it with the most cost effective replacement?

A. I don't know the answer to that. It's up to the commission to decide what they agree to. But staff -- as staff, it is my duty to -- it's my obligation to rate payers to evaluate every feasible alternative that I'm aware of, to evaluate it to see whether or not it would be more cost effective or would constitute lower cost compared to what's being presented by PNM, both cost and reliability.

Q. Can you turn to Page 11 of your testimony
So reliability definitely is a criteria even under the Energy Transition Act.

Q. I think you and I would agree that the Energy Transition Act requires the utilities to move to a renewables based portfolio that's cost effective and reliable; correct?

A. Over a period of time and in a phased-in manner, yes.

Q. So I'm not understanding why you object to utilities having the objective of anticipated development of renewable energy.

MR. MARKS: I'm going to object. That's not a question.

MR. BORMAN: I'm just going to move on.

Q. You talked about the ETA's CO2 emission standard. Do you agree with me that that goes into effect January 1, 2023?

A. That is correct.

Q. All right. Is it your opinion that carbon capture and sequestration controls can be installed and put into operation at San Juan by that date?

A. That's why I've pointed out multiple times we needed that study from PNM. If there was a time limitation, then PNM can do that analysis and the study and present it to us stating that it's not feasible within the time limitations or that it's not technically feasible at or that it's not economically viable. Until I have that in the application, I can't make that determination. So I can't answer the question one way or another. It may or may not be.

Q. Do you have any evidence that you have now that carbon capture and sequestration can be installed and put into operation by that date?

A. I need PNM to submit that evidence so I can make that determination. To answer your question at this time, I don't have anything.

Q. Okay. Are you aware that Enchant has stated that CCS cannot be operational at San Juan by January 1, 2023?

A. I was not aware of that.

Q. Okay. Would that change your assessment of the feasibility of this as an alternative?

A. What would change my opinion would be if PNM conclusively comes in with a study and conclusively tells me that it's not feasible by that date. That would change my opinion. But I need to have that study from PNM. So that's -- I need the utility to say that it's a plan because they're the ones who know the plant, they've built the plant, they have operated the plant for 50 years. They need to do that study using their owner's engineer, whoever that may be, HDR or Sargent & Lundy or whoever they hire, and to tell us that it's not feasible and state reasons why it's not feasible or not -- they can't get that installed or retrofitted by January 1 of 2023.

Q. Okay. But you --

A. That study must come from PNM.

Q. But would you agree that if this all can't be installed and made operational by that date, then it becomes an infeasible alternative?

A. Under the Energy Transition Act, and if there are no extensions, then yes, it would be.

Q. Okay. I would like to explore how you came to the position that PNM needs to evaluate CCS as an alternative. Is that wholly your own opinion or did you engage with other members of the Utility Division staff in coming to this opinion?

A. Like I said, you know, you asked me to read Page 8 of my testimony and said there should be a showing that there are no other feasible alternatives that better serve the public interest, and retrofitting San Juan with CCS may be that feasible alternative that provides the greatest public benefit. And if that's the case, then it needs to be evaluated.

Q. Okay.

A. It cannot be ignored. It needs to be evaluated, and PNM needs to submit that evaluation to staff so staff can inform the commission as to whether or not that's a feasible alternative that derives the greatest public benefit to the rate payer.

Q. I understand that's your opinion. You've explained it to me very well. Thank you. And I appreciate that. I understand your testimony better than I did before we started this.

MR. BORMAN: If you say something that's privileged, I will raise the privilege.

MS. CHAPPELLE: Isn't that backwards,
Q. Turn to Page 13 of your testimony, Lines 12 to 15. You state that, "The retrofit of amine-based technologies," such as what we talked about earlier, "are commercially available and proven in large scale operations." Do you see that?
A. Yes.
Q. Okay. Do you agree that CCS is commercially available and proven on large scale operations?
A. Yes, based upon the application at the Petra Nova Project and Sask Power Project and Boundary Dam in Canada, yes.
Q. How does the scale of Petra Nova compare to what's envisioned for San Juan?
A. It's slightly smaller or smaller.
Q. Approximately what size is the -- would you agree with me that Petra Nova is approximately 245 megawatts worth of flue gas that's being processed by the CCS technology?
A. Repeat your question, please.
Q. Would you agree with me that Petra Nova is approximately 245 megawatts worth of flue gas that's being processed through carbon capture?
A. Petra Nova project is 240 megawatts, I believe. I'll have to look at the NARUC report. So...
A. Yes, it is less.
Q. Okay. Would that affect your assessment of the financial viability of this project?

A. To some degree, yes.
Q. Okay. Do you know what the cost of or the price is today for CO2 piped to the Permian Basin through the Cortez pipeline?

A. I believe it's in this range, 15 to 20. It's about 20. It's about 20, yes.
Q. And where have you seen that?
A. That's based on conversation with oil and gas consultants.
Q. Have you seen any estimates for future prices of naturally sourced CO2?
A. I have not. I have relied on the NARUC reports.
Q. Okay. Do you have any evidence that there will be demand for the specific CO2 that would be captured at San Juan?
A. The Sargent & Lundy report is evidence.
Q. Do you have any evidence that there will be space on the Cortez pipeline for CO2 from San Juan?
A. I am told by Mr. Selch that there is.
Q. Okay.
A. Both demand and space.

Q. Did you review any information that's skeptical of CCS in preparing your testimony?
A. I have not seen any reports that are skeptical of CCS technology, and that's why I sent out a discovery request to PNM asking about CCS, and whether or not they have evaluated it or not. And if they haven't evaluated it, why they haven't they evaluated it. And I didn't get a satisfactory answer. I want to, you know, quash any skepticism about the technical feasibility of CCS, and that's why I sent out the entire discovery request to PNM.
Q. All right. Have you heard about a study from a group called IEEFA that was specifically directed at the San Juan Project and is skeptical of it?
A. I have not.
Q. Okay. On Page 16 on Line 18, you state that, "PNM should have evaluated San Juan with carbon capture through the year 2034." Do you see that?
A. I do.
Q. How did you select the year 2034?
A. Well, the 45Q tax credit had a 12-year window, so I added 12 to January 1 of 2023, which is the beginning of the emission limitation. And so I did the math wrong. So instead it should have been 2023, 12 years from there. So it should have been 2035. And that's one of the errata which I'll probably be filing in this testimony at some date.
Q. So under that scenario, what would happen to San Juan in 2035?
A. That's what I want PNM to tell me as to whether they can continue that and whether they can fit that into -- those are all answers fro PNM which I requested in my discovery, but unfortunately, I didn't get a satisfactory response.
Q. Do you have any evidence that it would be cost effective to recover all the capital costs of CCS in that 12-year period?
A. I do not, and that's why I asked PNM to provide that, and I will still ask PNM to provide that. I continue to ask.
Q. And I think we covered this, but would you agree with me that you did not do an economic analysis of whether any of this is economically feasible?
MS. CHAPPELLE: That was definitely asked and answered.
MR. MARKS: I'll take your word for it.
Thank you, Germaine.
MS. CHAPPELLE: He said he's not an economist, and he cited to other folks on the staff.
MS. GOODWIN: There's a pending question on the record. You can object as to form.
MR. MARKS: I'll withdraw the question.
Let's move forward.
Q. If it turns out this carbon capture retrofit makes some sort of sense, then you understand that PNM would be investing $1.2 billion there, correct, assuming Sargent & Lundy's numbers are correct?
A. Assuming Sargent & Lundy's numbers are accurate, yes.
Q. And do you understand how that would affect PNM's rates?
A. And that's why I'm asking for the analysis from PNM as to what the impact would be, would it be 1.2 billion, what would their credits be, what would the revenue stream be, all that analysis. They haven't provided anything. It is the applicant's responsibility to provide that analysis and make a persuasive case as to why this should not be done. It is at least worthy of evaluation, if nothing else.
Q. In that scenario, the undepreciated book value of the current plant, would PNM be allowed to continue to recover that and earn a return on that?