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 PUBLIC SERVICE COMPANY OF NEW MEXICO Applicant	Case No. 19-00018-UT

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 CO_2 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 CO_2 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 CO_2 in 2018, accounting for 65% of the electric generation sector's total CO_2 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.

[1] U.S. Energy Information Administration, "How much of U.S. carbon dioxide emissions are associated with electricity generation?", *available at* https://www.eia.gov/tools/faqs/faq.php?id=77&t=11.

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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2.

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.

d. 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.[2] 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 CO_2 Per Year.

Q. What factors determine how much carbon dioxide (CO_2) a coal-fired generator like SJGS will capture in future years?

A. Quite simply, the amount of CO_2 captured is a function of how much CO_2 a coal-fired generator produces and the efficiency with which the carbon dioxide (CO_2 or carbon) capture system actually captures CO_2 emissions.

The first factor, how much CO_2 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

[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 CO_2 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 CO_2 annually is based on two key assumptions.[3] 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 CO_2, and second, that the plant's retrofitted CCS equipment will be able to capture 90% of the CO_2 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 CO_2 capture using a capacity factor range of 85% to 100%.[4] Is it reasonable to expect that SJGS would operate at a 100% capacity factor for a period of 12 years after being retrofitted for CO_2 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.

[3] Prepared Direct Testimony of Dhiraj Solomon, at page 15, lines 10-11.
[4] *Enchant Energy San Juan Generating Station – Units 1 & 4 – CO2 Capture Pre-Feasibility Study*, July 8, 2019, at pages 5-4 and Appendix E, . *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.

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.[5] 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 CO_2 capture.

[5] For example, see *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO2 Capture Rate in Coal-Fired Power Plants*, U.S. DOE, National Energy Technology Laboratory (June 22, 2015), *available at* https://www.netl.doe.gov/projects/files/SupplementSensitivitytoCO2CaptureRateinCoalFiredPowerPlants_062215.pdf.

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

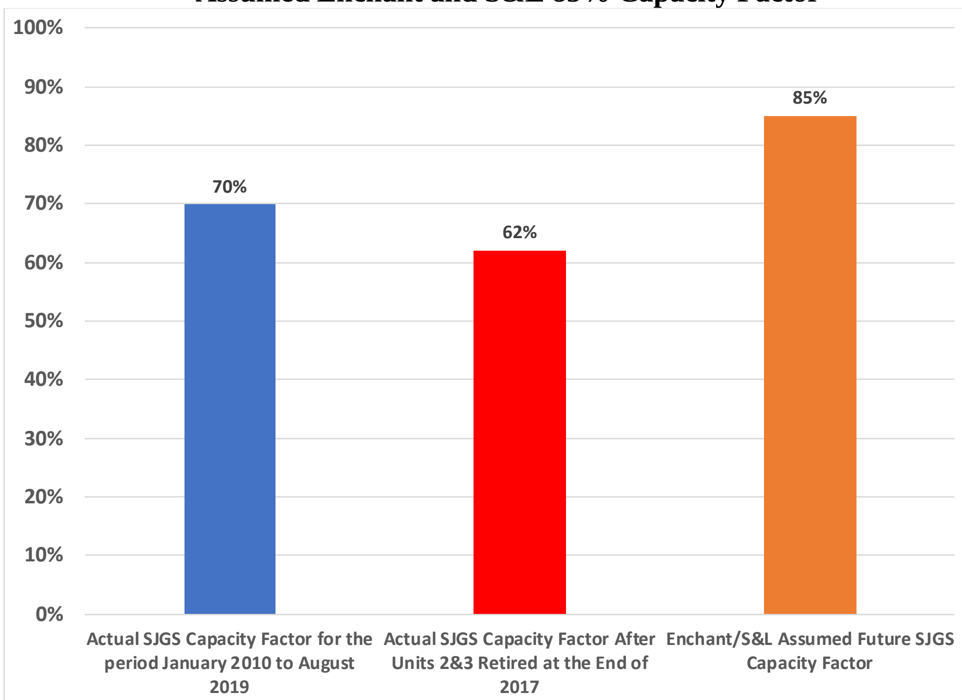


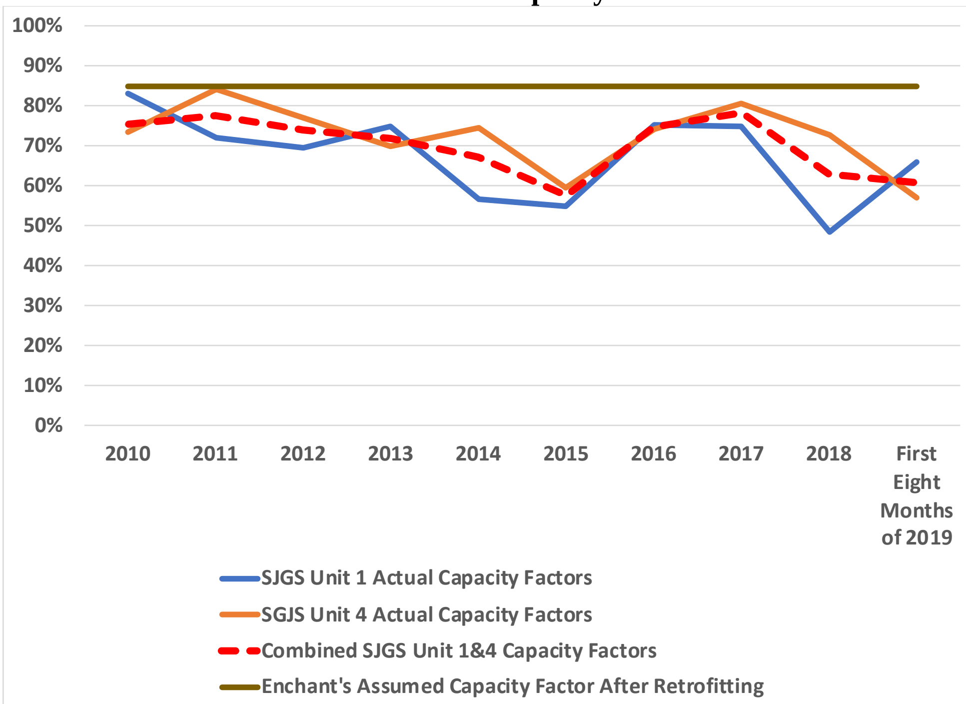
Figure Sources: SJGS data from EIA Form 923, downloaded from S&P Global Market Intelligence on November 1, 2019. Enchant and S&L assumed capacity factor is from Staff Witness Solomon's Exhibit DS-3.

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.

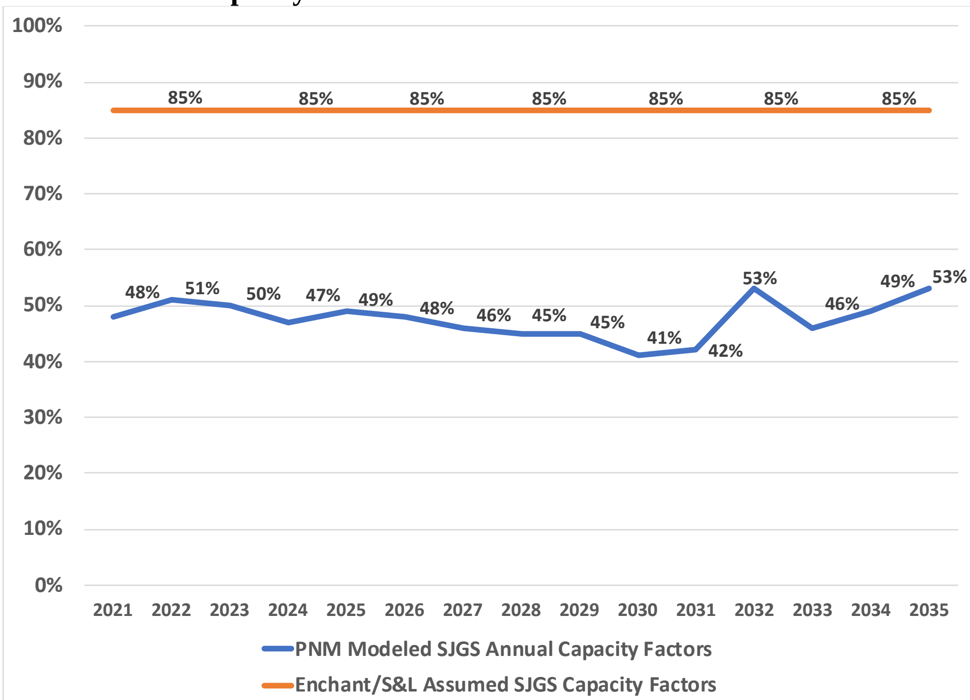
Only Unit 4 achieved a capacity factor above 80% after 2011, and that was an 81% capacity factor for only the single year of 2017.

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]

[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 CO_2 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.

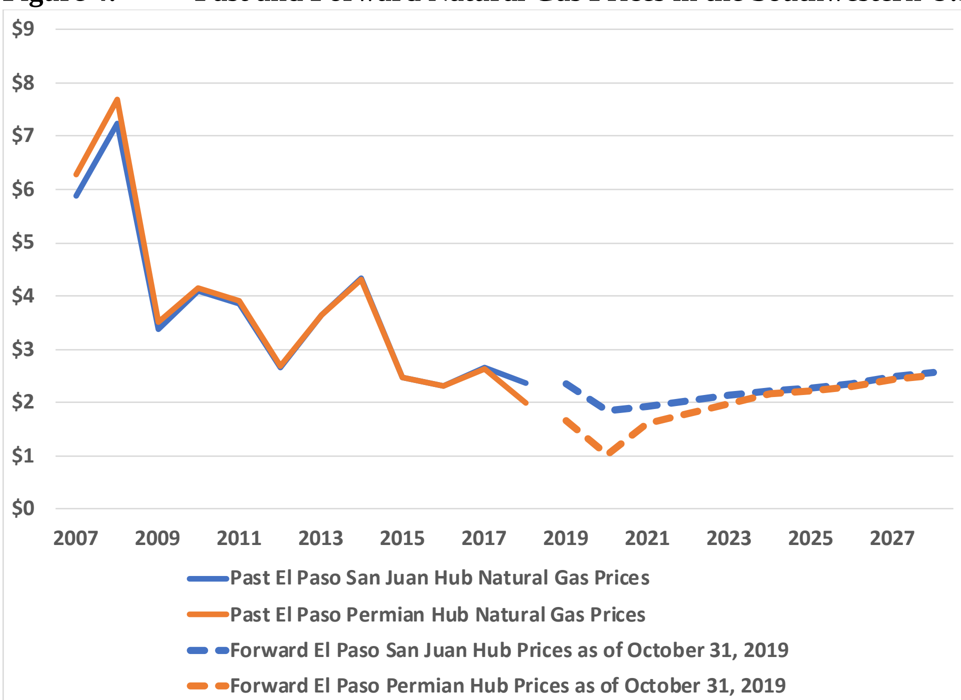
6. The fact that SJGS will be a more complicated plant to operate.

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.



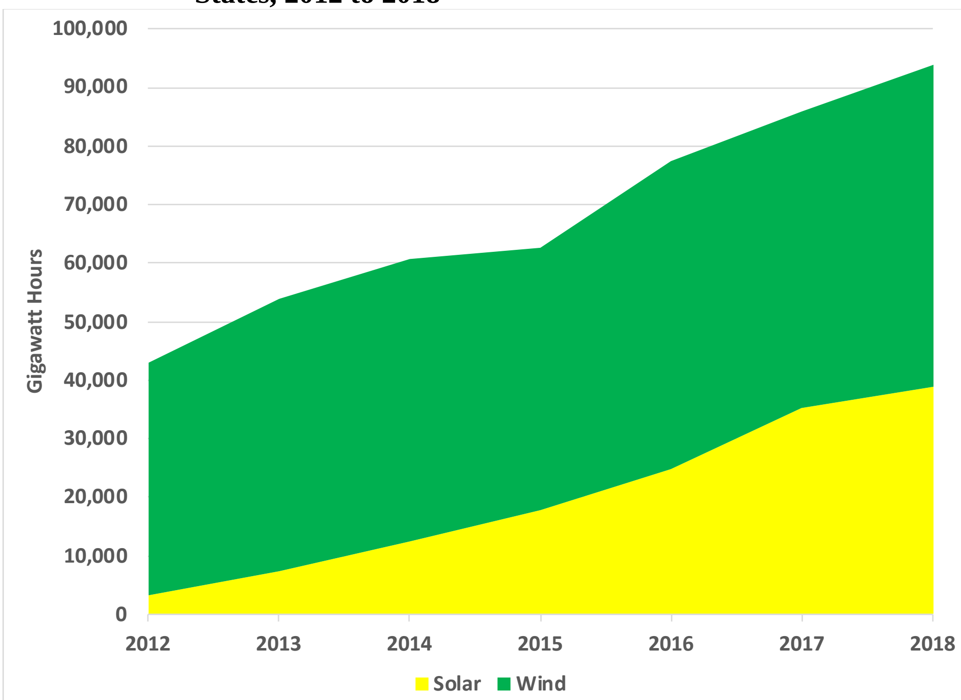
Source: Past Natural Gas Prices downloaded from S&P Global Market Intelligence on October 31, 2019. Forward prices from OTC Global Holdings, also downloaded from S&P Global Market Intelligence on October 31, 2019.

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



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.

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[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."[8] 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.[9] 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.[10]

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."[11] One of

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[8] https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/.

[9] Public Service Company of Colorado, 2016 Electric Resource Plan 2017, All Source Solicitation 30-Day Report (Public Version), CPUC Proceeding No. 16A-0396E (Dec. 28, 2017), *available at* https://cdn.arstechnica.net/wp-content/uploads/2018/01/Proceeding-No.-16A-0396E_PUBLIC-30-Day-Report_FINAL_CORRECTED-REDACTION.pdf.

[10] G. Hering, 'Staggering' prices drive NV Energy's 100% renewables bid amid ballot wrangle, S&P Global Market Intel. (Apr. 13, 2018), *available at* https://www.spglobal.com/marketintelligence/en/news-insights/trending/xrl7pjatkohn-o95bsv1pq2

[11] https://www.westerneim.com/pages/default.aspx.

its goals is to find and deliver the lowest cost energy to consumers.[12] 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.[13] 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

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[12] CAISO, Press Release (Oct. 30, 2019), *available at* http://www.caiso.com/Documents/WesternEIMBenefitsReach801_07MillionSinceLaunchIn2014.pdf.

[13] *See, e.g.*, U.S. Dep't of Energy,Staff Report to the Secretary on Electricity Markets and Reliability at 155 (Aug. 2017), *available at* https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

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).[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.[15] Although the precise cost of such deferred maintenance at SJGS is unknown and would be specific to SJGS, this suggests

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[14] *See* PNM's Response to Discovery Request SC 2-5 in Docket No. 16-00276.
[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% capacity factor.

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.[16]

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_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_2 capture efficiency."[17] Is this accurate?

A. No. Publicly available evidence shows that neither plant captures anywhere near 90% of the CO_2 they produce, contrary to claims by Enchant and S&L that these plants have achieved 90% CO_2 capture rates.[18]

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[16] Source: EIA Form 923 data downloaded from S&P Global Market Intelligence on November 5, 2019.
[17] Prefiled Direct Testimony of Dhiraj Solomon, PE, at page 13, lines 15-17.
[18] Enchant Energy Corporation, Response to Institute for Energy Economics and Financial Analysis report at 2, *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy-Corporation-response-to-Institute-for-Energy-Economics-and-Financial-Analysis-IEEFA-report-dated-July-2019.pdf.

Q. What is the basis for your conclusion that Petra Nova is not capturing 90% of the CO_2 it produces?

A. Petra Nova *intended* to capture "at least" 90% of the CO_2 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 CO_2 (that is, approximately 1.4 million metric tonnes) or about 33% of the total emissions from Unit 8, each year.[19]

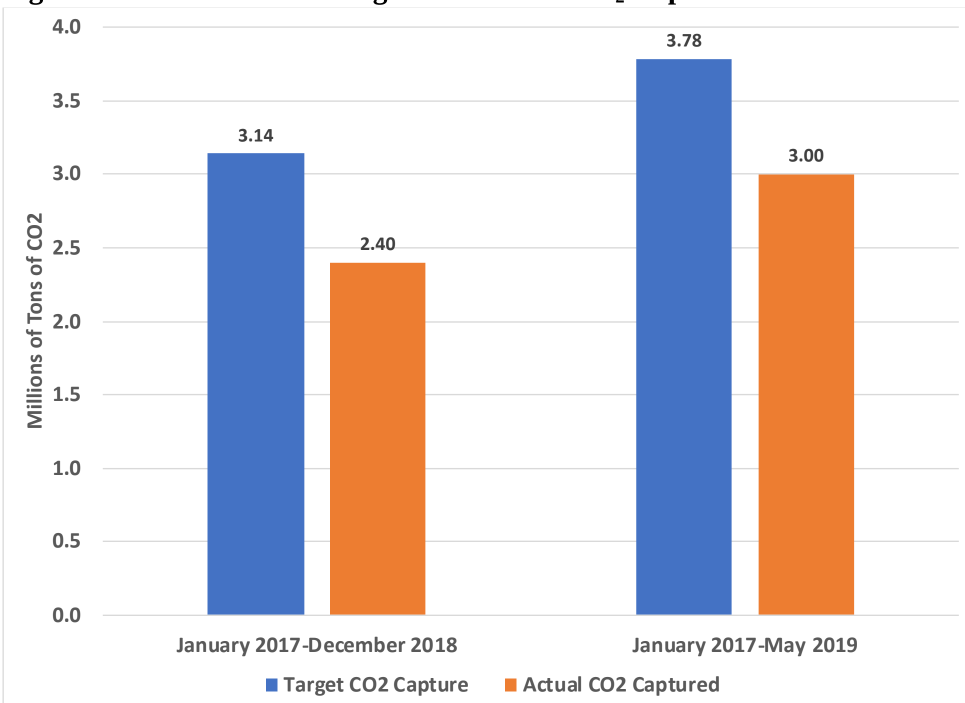
Despite the Petra Nova project's goal of capturing 90% of CO_2 emissions, I could not find any evidence that Petra Nova actually was capturing that much CO_2 or that the technology had been proven to be that effective. Thus, I examined Petra Nova's actual performance in three separate analyses using publicly available information.

First, I investigated whether Petra Nova actually was capturing between 1.54 and 1.6 million tons of CO_2 each year. Unfortunately, NRG, the operator and co-owner of the plant, has not regularly issued detailed reports on the amounts of CO_2 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 CO_2 between its start of operations in January 2017 and December 2018 and (2) almost 3.0 million tons through May 2019.[20]

[19] W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Topical Report at 3, *available at* https://www.osti.gov/biblio/1344080-parish-post-combustion-co2-capture-sequestration-project-final-public-design-report; EIA, Today in Energy, Petra Nova is one of two carbon capture and sequestration power plants in the world, (Oct. 31, 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=33552; National Energy Technology Laboratory, W.A. Parish Post-Combustion CO2 Capture and Sequestration Project (Sept. 2012), available at https://www.netl.doe.gov/sites/default/files/environmental-policy/deis-sept/EIS-0473D_Summary.pdf.
[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 CO_2 are significantly below what would be expected if Petra Nova actually had been capturing 90% of the CO_2 it produced.

Figure 6: Actual vs. Target Amounts of CO_2 Captured at Petra Nova



Source: STC analysis.

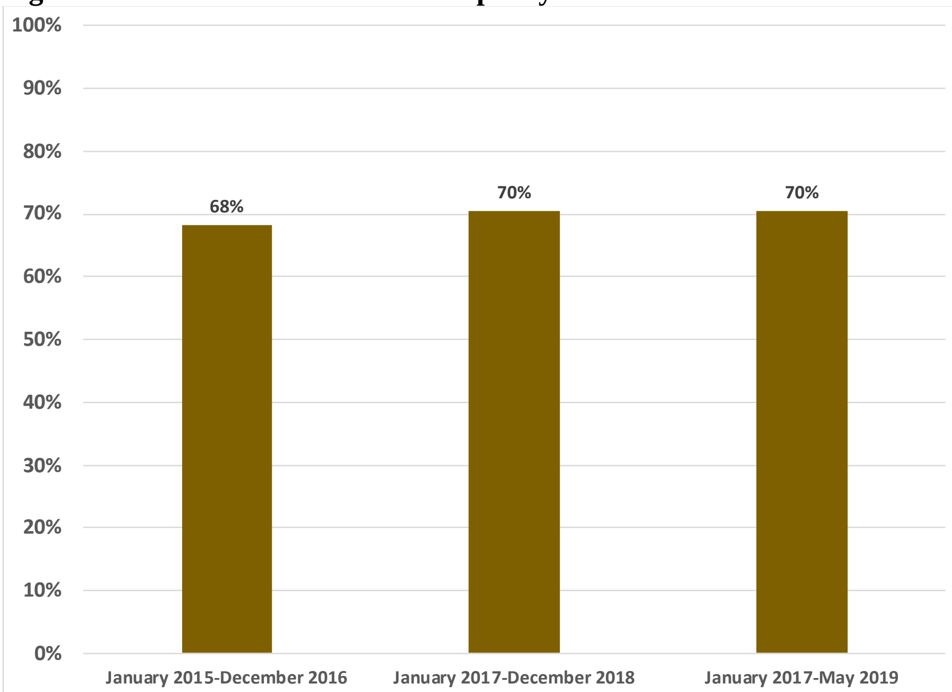
The actual amounts of CO_2 captured at Petra Nova translate into a capture rate of 69% thru December and 71% from January 2017 thru May 2019.

Q. Is it possible that Petra Nova actually was capturing 90% of the CO_2 in the 240 MW slipstream even though it was capturing less CO_2 than projected? In other words, is there any evidence that W.A. Parish Unit 8 was producing less CO_2 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.

Carbon Capture & Geologic Storage Projects in Operation and Lessons Learned, also presented at the same IEA Clean Coal Conference.

Figure 7: W.A. Parish Unit 8 Capacity Factors



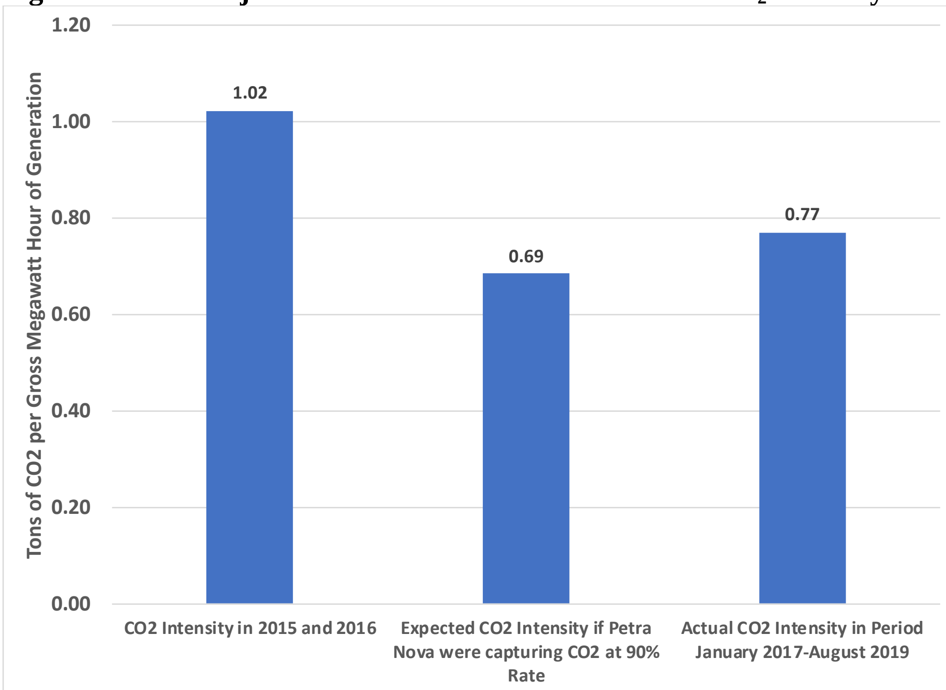
Sources: EIA Form 923 data, downloaded from S&P Global Market Intelligence.

Q. Please describe the second analysis you made to determine if Petra Nova is actually achieving a 90% CO_2 capture rate.

A. As I noted earlier, the U.S. Energy Information Administration (EIA) forecasted that if Petra Nova captured 90% of the CO_2 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 CO_2 intensity (measured as tons of CO_2 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 CO_2 intensity is higher than it would be if Petra Nova actually were capturing 90% of the CO_2 in the 240 MW slipstream.

Figure 8: Projected and Actual W.A. Parish Unit 8 CO_2 Intensity



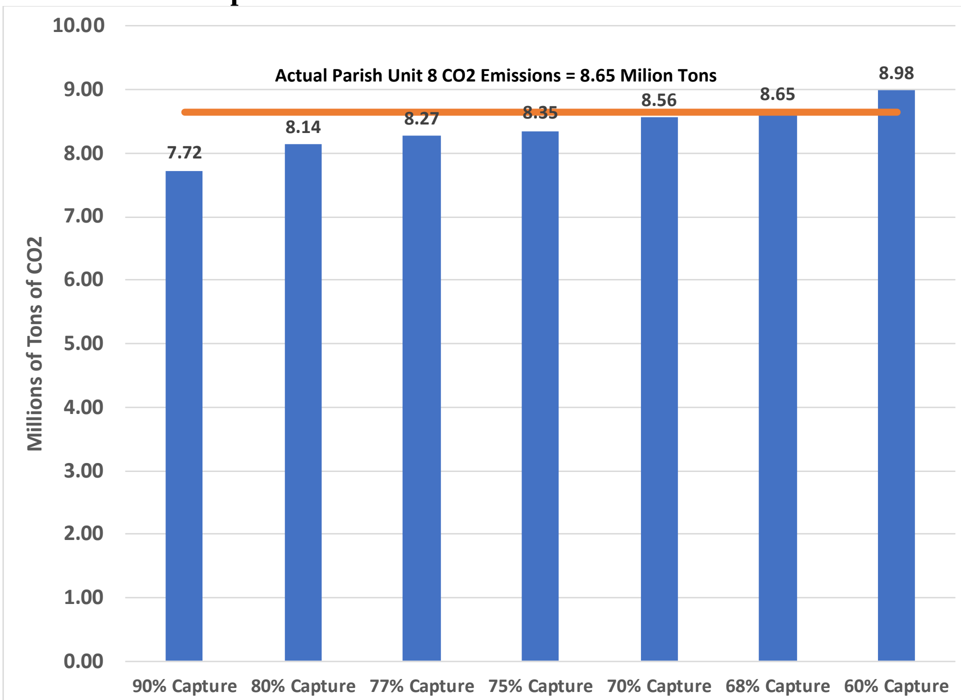
Source: Analysis of W.A. Parish Unit 8 CO2 Emissions and Gross Generation from EPA CEMS database.

The third column, representing the plant's actual performance, shows a CO_2 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 CO_2 capture rate.

A. In the last analysis, I calculated what Parish Unit 8's total CO_2 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% CO_2 capture rate since the project went into operation in January 2017, not the 90% capture rate that Mr. Solomon and others claim.

Figure 9: **Total W.A. Parish Unit 8 CO_2 Emissions Under a Range of Potential Capture Rates**



Source: Analysis of W.A. Parish Unit 8 CO2 Emissions from EPA CEMS database.

Q. **Do you have any other comments on Petra Nova's CO_2 capture rate?**

A. Yes. Unlike the proposed retrofit of SJGS, the power to run the CO_2 capture equipment at Petra Nova is provided by a dedicated natural gas-fired combustion turbine. If the CO_2 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_2 it produces?

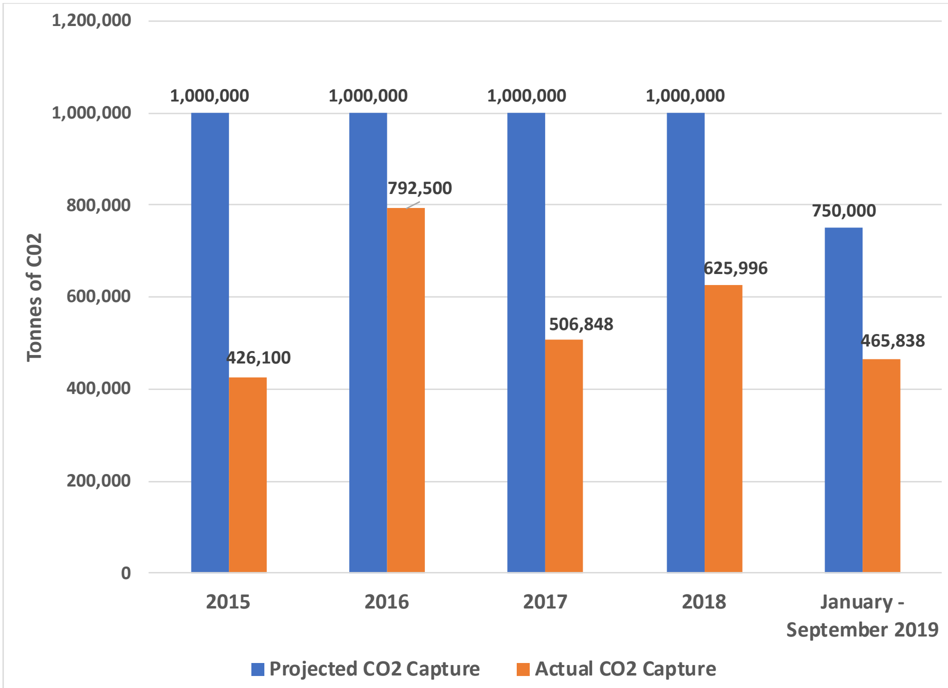
A. Yes. As I mentioned earlier, the Petra Nova and Boundary Dam projects are the only two CO_2 projects in the world operating at power plants.[21] Like Petra Nova, the Boundary Dam project has not been capturing 90% of the CO_2 it produces.

Q. What is the basis for your conclusion that Boundary Dam also is not capturing 90% of the CO_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.

[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.

Figure 10: Boundary Dam Unit 3 Target vs. Actual CO_2 Capture in Tonnes



Source: SaskPower, BD3 Status Updates.[22]

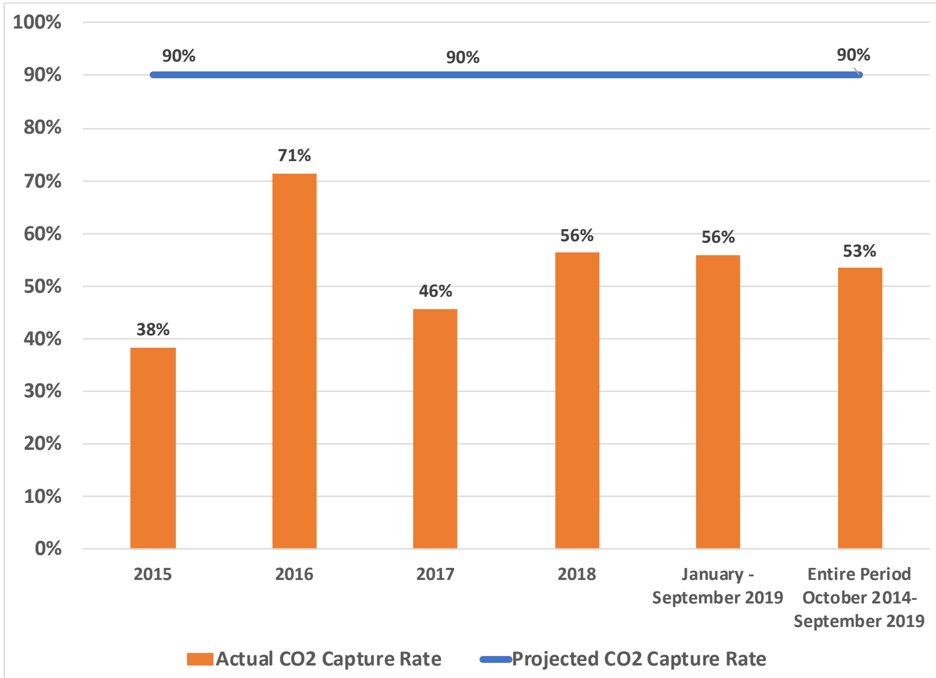
In fact, the plant's carbon capture system only operated at its design capacity of 3200 tonnes per day on 3 days through early 2018.[23]

Consequently, Boundary Dam Unit 3 has failed to achieve a 90% carbon capture rate in any significant period since the plant was retrofitted.

[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 CO_2 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 CO_2 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 CO_2 it produces is due to operating issues unrelated to the CO_2 capture equipment?

A. Yes. Boundary Dam 3 has had significant issues with the CO_2 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.
[25] *SaskPower's 2017-2018 Annual Report* at 36.

million in the years 2015 and 2016 and estimated that it was going to cost another CAN$15 million in 2017.[26]

It is true that Boundary Dam 3 also has experienced some plant outages that were unrelated to its CO_2 capture system. However, these outages account for only a fraction of the plant's failure to come anywhere near an overall 90% CO_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_2 in the year if it had not be shut down for 84 days due to a strong storm and massive power outage.[27] However, in the unlikely event that Boundary Dam had actually captured CO_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_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_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.[28] In 2015, SaskPower paid $7.3 million to Cenovus for failing to deliver the volume of CO_2 it had contractually committed to provide.[29]

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[26] CBC News, "SaskPower looking for help to fix 'high cost' Boundary Dam carbon capture flaw," May 28, 2018, *available at* https://www.cbc.ca/news/canada/saskatchewan/saskpower-looking-for-help-to-fix-high-cost-boundary-dam-carbon-capture-flaw-1.4680993.

[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.

[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/.

[29] CBC News, "SaskPower CEO says $20M worth of carbon capture penalties are in the past," July 14, 2016, *available at* https://www.cbc.ca/news/canada/saskatchewan/saskpower-carbon-capture-penalties-20m-in-past-1.3679405.

Q. Has SaskPower's failure to deliver the contracted amounts of CO_2 had any long-term impacts on the revenues it gets from selling the CO_2 captured at Boundary Dam 3?

A. Yes. It has been reported that in June 2016, the contract for supplying CO_2 from Boundary Dam Unit 3 was renegotiated, reducing the expected annual revenues over the life of the plant by about a third.[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_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_2 capture system affected SaskPower's decisions concerning retrofitting other units for CO_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."[31]

Q. Based on your testimony so far, should a retrofitted SJGS be expected to capture substantially less than six million tonnes of CO_2 per year, on average?

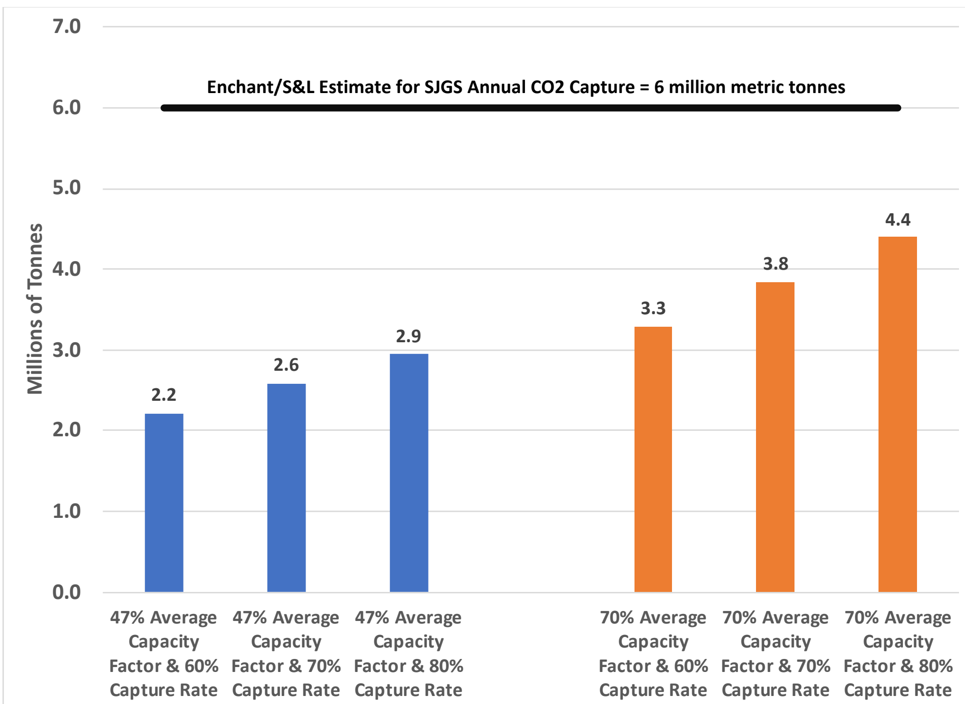
A. Yes. This conclusion is based on (1) the fact that no commercial-scale power plant has achieved 90% (or even 80%) CO_2 capture over any significant period of time and (2) SJGS's actual operating performance and the results of PNM's computer modelling showing lower capacity factors for the plant in future years.

[30] The Global Warming Policy Foundation, The Bottomless Pit: The Economics of Carbon Capture and Storage at 55 (2017), *available at* https://www.thegwpf.org/content/uploads/2017/06/CCS-Report.pdf.
[31] SaskPower Annual Report 2018-2019 at 39, *available at* https://www.saskpower.com/about-us/Our-Company/Current-Reports.

Q. Realistically, how much CO_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_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



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

Q. Why does the amount of CO_2 captured by SJGS matter to the financial feasibility of the proposed carbon capture project?

A. The amount of CO_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_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 CO_2 will mean that SJGS will generate less revenue from the sale of the CO_2 for enhanced oil recovery. Similarly, capturing less CO_2 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 CO_2, 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 CO_2 capture, I have looked at sixteen scenarios that cover a range of reasonable capacity factors, CO_2 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%.
- CO_2 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 CO_2 capture retrofit project at SJGS?

A. S&L estimates a capital cost of approximate $1.295 billion, in 2019 dollars, to retrofit SJGS with CO_2 capture technology.[32] 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.

[32] *Appendix E in S&L's July 8, 2019 CO2 Capture Pre-Feasibility Study, available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.

Table 1
SJGS Retrofit Financing

	Scenario Assumptions	Percentage of Estimated Capital Cost that Could Be Funded through 45Q Credits	Percentage of Estimated Capital Cost that Would Have to Obtained Through Non-45Q Funding
Corrected Enchant & S&L Proposal	$1.40 Billion Capital Cost, 85% CF & 90% CO_2 Capture Rate	81%	19%
Scenario 1	$1.40 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	59%	41%
Scenario 2	$1.40 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	52%	48%
Scenario 3	$1.40 Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	45%	55%
Scenario 4	$2.21 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	38%	62%
Scenario 5	$2.21 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	33%	67%
Scenario 6	$2.21Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	28%	72%
Scenario 7	$3.31 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	25%	75%
Scenario 8	$3.31 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	22%	78%
Scenario 9	$3.31 Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	19%	81%
Scenario 10	$1.40 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	40%	60%
Scenario 11	$1.40 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	35%	65%
Scenario 12	$1.40 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	30%	70%
Scenario 13	$2.21 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	25%	75%
Scenario 14	$2.21 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	22%	78%
Scenario 15	$2.21 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	19%	81%
Scenario 16	$3.31 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	17%	83%
Scenario 17	$3.31 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	15%	85%
Scenario 18	$3.31 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	13%	87%

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 *CO_2 Capture Pre-Feasibility Study* lists the Total Project Cost as $1.295 billion.[33] 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.[34] 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% CO_2 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

[33] *Available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.
[34] Enchant Energy, Carbon Capture Retrofit of San Juan Generating Station Presentation to San Juan County Community at Slide No. 12 (July 16, 2019), , *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-SJGS-Presentation-to-San-Juan-Community-July-2019.pdf.

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 CO_2 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 CO_2 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.

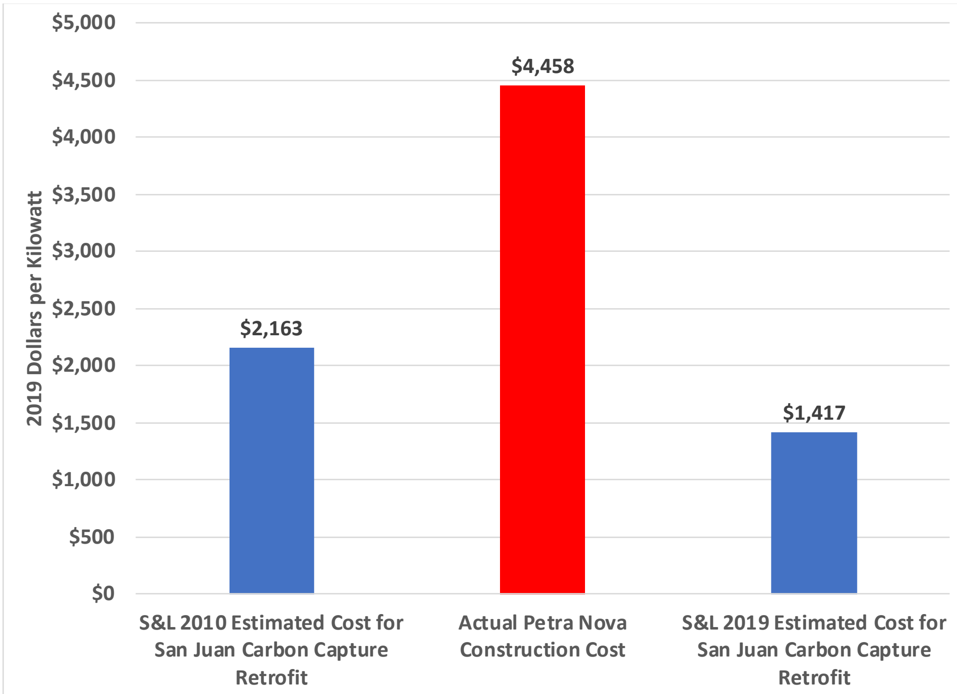
Q. How do S&L's 2010 and 2019 estimated capital costs for retrofitting SJGS with CO_2 capture compare with the actual capital cost of the Petra Nova project which was built in the years 2014 to 2016?

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.
[36] EIA, Today in Energy, "Petra Nova is one of two carbon capture and sequestration power plants in the world," (Oct. 31, 2017), available at https://www.eia.gov/todayinenergy/detail.php?id=33552.

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



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.

[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.[38] 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.[39]

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 <u>over time</u>, Enchant and S&L assumed that the cost of retrofitting SJGS with CO_2 capture, the very next

[38] Lawrence Berkeley National Laboratory, Utility-Scale Solar – Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition, (Sept. 2018), *available at* https://www.researchgate.net/publication/327607147_Utility-Scale_Solar_Empirical_Trends_in_Project_Technology_Cost_Performance_and_PPA_Pricing_in_the_United_States_-_2018_Edition.

[39] U.S. Department of Energy, 2018 Wind Technologies Market Report, (Aug. 2019), *available at* https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf.

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 CO_2 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 CO_2 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 CO_2 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.

[40] Noriaki Shimokata, JX Nippon Oil & Gas Exploration Corporation, "Petra Nova CCUS Project in USA," (June 8, 2018), *available at* https://d2oc0ihd6a5bt.cloudfront.net/wp-content/uploads/sites/837/2018/06/Noriaki-Shimokata-Petra-Nova-CCUS-Project-in-USA.pdf.

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.
[42] NARUC, Carbon Capture, Utilization, and Storage: Technology and Policy Status and Opportunities at 47 (Nov. 2018), *available at* https://pubs.naruc.org/pub/03689F64-B1EB-A550-497A-E0FC4794DB4C.
[43] *Id.*
[44] CATF, Carbon Capture & Storage in the United States Power Sector: The Impact of 45Q Federal Tax Credits at 24-25 (Feb. 2019), *available at* https://www.catf.us/wp-content/uploads/2019/02/CATF_CCS_United_States_Power_Sector.pdf.

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 CO_2 capture is significantly higher than estimated.

Q. What capital cost would be prudent to use to evaluate a proposed retrofit of SJGS with CO_2 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. [45] 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 CO_2 capture technology to the much larger 914 MW SJGS project, which could lead to an even higher cost than Petra Nova.

[45] NARUC, Carbon Capture, Utilization, and Storage: Technology and Policy Status and Opportunities at 47 (Nov. 2018), *available at* https://pubs.naruc.org/pub/03689F64-B1EB-A550-497A-E0FC4794DB4C.

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 CO_2 capture system, order, fabricate and deliver system components, then construct and test the CO_2 capture retrofit before it went into service.

[46] Enchant Energy, Carbon Capture Retrofit of San Juan Generating Station Presentation to San Juan County Community at Slide No. 12 (July 16, 2019), , *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-SJGS-Presentation-to-San-Juan-Community-July-2019.pdf..

[47] *Project Management Plan Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station, Enchant Energy* at 7 (May 9, 2019), *available at* http://ieefa.org/wp-content/uploads/2019/07/PMP-1.pdf.

Q. How long did it take to design and build the Petra Nova CO_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.[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.[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.[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_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

[48] Sargent & Lundy, Enchant Energy, San Juan Generating Station – Units 1 & 4 CO2 Capture Pre-Feasibility Study at 1-2 (July 8, 2019), *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.
[49] Presentation by Petra Nova Parish Holdings on Petra Nova Carbon Capture at the June 2019 IEA Clean Coal Conference, at slide no. 3.
[50] Sargent & Lundy, Enchant Energy, San Juan Generating Station – Units 1 & 4 CO2 Capture Pre-Feasibility Study at 3 (July 8, 2019), *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.

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. *Id.* at 75: 12-15.

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[51] *Id.*

[52] Enchant Energy Corporation, Response to Institute for Energy Economics and Financial Analysis report at 3, *available at* https://www.enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy-Corporation-response-to-Institute-for-Energy-Economics-and-Financial-Analysis-IEEFA-report-dated-July-2019.pdf.

[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 CO_2 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.[54] 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.[55] 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.[56]

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

[54] Enchant Energy, Carbon Capture Retrofit of San Juan Generating Station, Presentation to San Juan County Community at Slide 12 (July 16, 2019), *available at* https://www.powermag.com/wp-content/uploads/2019/08/final-enchant-sjgs-presentation-to-san-juan-community-july-2019.pdf.

[55] *Project Management Plan Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station, Enchant Energy* at PDF page 16 (May 9, 2019), *available at* http://ieefa.org/wp-content/uploads/2019/07/PMP-1.pdf.

[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 CO_2 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 CO_2 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_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_2 at SJGS would be between $39.15 and $43.49 per metric tonne.[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_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_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_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.

[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 CO_2 would be if more reasonable capacity factors, CO_2 capture rates, and capital costs were used?

A. Yes.

Q. What methodology have you used to recalculate the per-tonne SJGS CO_2 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 CO_2 Capture Costs

	Scenario Assumptions	CO_2 Capture Cost (Dollars per Metric Tonne)
Corrected Enchant & S&L Proposal	$1.40 Billion Capital Cost, 85% CF & 90% CO_2 Capture Rate	$45.69
Scenario 1	$1.40 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	$58.90
Scenario 2	$1.40 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	$67.31
Scenario 3	$1.40 Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	$78.53
Scenario 4	$2.21 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	$81.63
Scenario 5	$2.21 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	$93.29
Scenario 6	$2.21Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	$108.84
Scenario 7	$3.31 Billion Capital Cost, 70% CF & 80% CO_2 Capture Rate	$112.84
Scenario 8	$3.31 Billion Capital Cost, 70% CF & 70% CO_2 Capture Rate	$128.97
Scenario 9	$3.31 Billion Capital Cost, 70% CF & 60% CO_2 Capture Rate	$150.46
Scenario 10	$1.40 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	$79.69
Scenario 11	$1.40 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	$91.07
Scenario 12	$1.40 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	$106.25
Scenario 13	$2.21 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	$113.54
Scenario 14	$2.21 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	$129.76
Scenario 15	$2.21 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	$151.39
Scenario 16	$3.31 Billion Capital Cost, 47% CF & 80% CO_2 Capture Rate	$160.03
Scenario 17	$3.31 Billion Capital Cost, 47% CF & 70% CO_2 Capture Rate	$182.89
Scenario 18	$3.31 Billion Capital Cost, 47% CF & 60% CO_2 Capture Rate	$213.38

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 CO_2 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 CO_2 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 CO_2 capture rates means that the plant will capture millions fewer tonnes of CO_2 so the capital cost of the retrofit and the fixed CO_2 capture O&M costs would be spread over fewer tonnes of CO_2 – 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 CO_2 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?

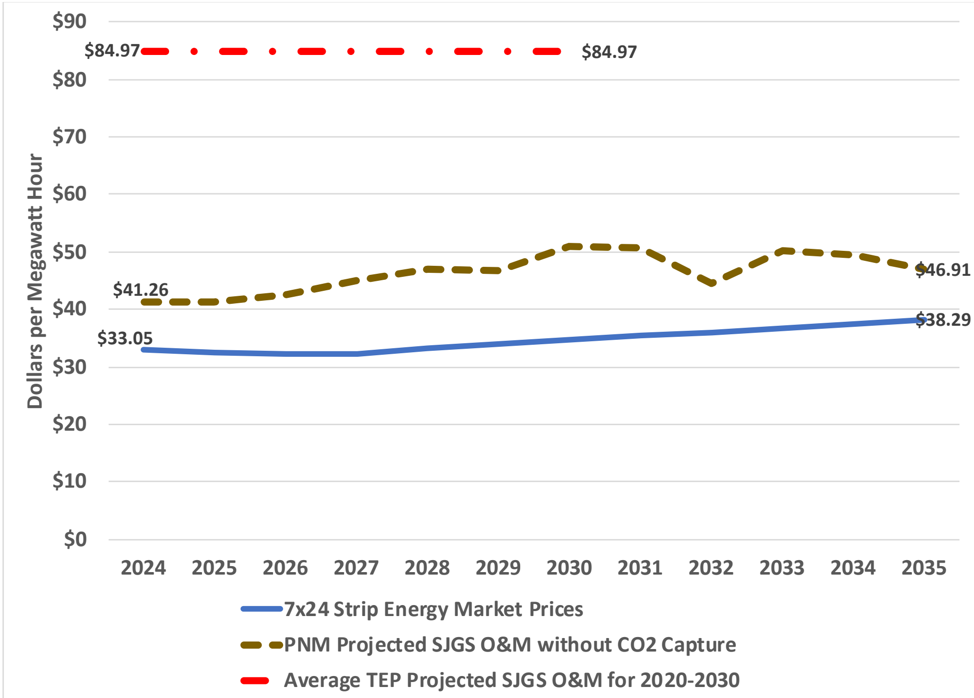
A. SJGS Units 1 and 4 cannot be expected to be low cost-generators after being retrofitted for CO_2 capture, contrary to Enchant's claim.[58]

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:

[58] Enchant Energy, The Economic Case for Power Plant Carbon Capture Retrofits: A Case Study on the San Juan Generating Station – New Mexico, (Sept. 12, 2019), *available at* https://www.usea.org/sites/default/files/event-/USEA%202019%20ESF_Selch.pdf.

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?

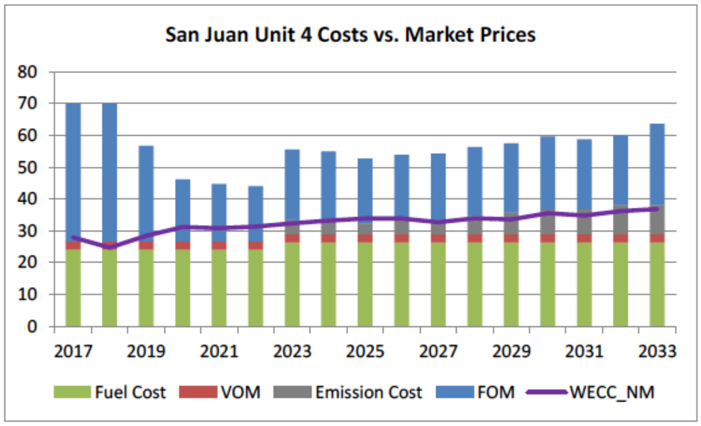
A. The City of Farmington doesn't, and I was unable to find any information about the expectations of the Utah Associated Municipal Power Systems. However, Los Alamos County does not consider SJGS to be a low-cost generator and expects the plant's cost of electricity to remain expensive if it is not 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."[59]

[59] Pace Global, 2017 Integrated Resource Plan Report prepared for Los Alamos County at 46 (June 30, 2017), *available at* https://losalamosnm.us/common/pages/DisplayFile.aspx?itemId=14454077.

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

Exhibit 37: SJGS 4 Costs and Market Prices Comparison



Note: SJGS 4 runs at minimum level during 2017-2033.
Source: Pace Global.

Source: 2017 Integrated Resource Plan prepare for Los Alamos Country, August 1, 2017, at page 46.[60]

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-CO_2 capture costs?

A. With a carbon capture retrofit, SJGS's average per MWh non-CO_2 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 CO_2 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

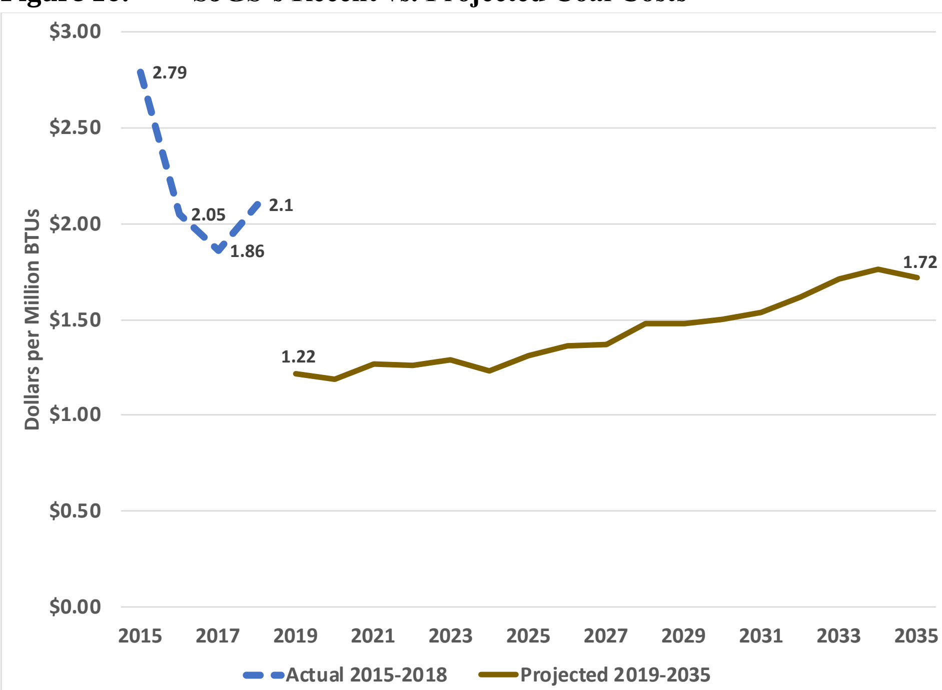
[60] *Available at* https://losalamosnm.us/common/pages/DisplayFile.aspx?itemId=14454077.

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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[61] *Carbon Capture Retrofit of San Juan Generating Station, Presentation to San Juan County Community*, July 16, 2019, at Slide 4, *available at* https://www.powermag.com/wp-content/uploads/2019/08/final-enchant-sjgs-presentation-to-san-juan-community-july-2019.pdf.

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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 prices?

A. It is reasonable to expect that future CO_2 prices most likely will be affected by actual and expected oil prices and by the competition between different CO_2 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 CO_2 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]

[62] NRG Energy, Inc., NRG 10-K for the Year Ended December 31, 2016 at 170, *available at* https://investors.nrg.com/node/25486/html.
[63] NRG Energy, Inc., NRG 10-K for the Year Ended December 31, 2017 at 164, available at https://investors.nrg.com/static-files/7f12dcd9-bc0b-40c7-87aa-78f8616d663e .
[64] Fortune Magazine, "What Donald Trump Didn't Mention About Clean Coal," October 10, 2016, *available at* https://fortune.com/2016/10/10/donald-trump-clean-coal/.
[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 CO_2 each year, would this mean that the overall emissions into the atmosphere would decline by 6 million tonnes?

A. No. The use of captured CO_2 for EOR produces additional oil that, in turn, is burned or used as a chemical feedstock, both of which can be expected to release CO_2 into the atmosphere. For example, *Power Magazine* estimates that every ton of CO_2 used in EOR will bring up roughly 0.76 to 0.91 tons of equivalent CO_2 that will ultimately end up in the atmosphere.[66] And even this might not capture all of the CO_2 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

[66] PowerMag, "Is EOR a Dead End for Carbon Capture and Storage?," April 12, 2016, *available at* https://www.powermag.com/is-eor-a-dead-end-for-carbon-capture/.

the CO_2 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 CO_2 have not captured 90% of their CO_2 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
David A. Schlissel

SUBSCRIBED AND SWORN TO before me on this 13 day of November, 2019 by David A. Schlissel.

Notary Public

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) Case No. 19-00018-UT
GENERATING STATION UNITS 1 AND 4)

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.

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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 NO_x, SO_2 and CO_2. 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.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Montana Public Service Commission (Docket No. D.2018.2.12) – February 2019
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.

Arizona Corporation Commission (Docket No. E-01922A-12-0291 – December 2012
Reasonableness of Tucson Electric Power's proposed Environmental Compliance Adjustor mechanism.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR and 50-286-LR) – June 2012
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.

Missouri Public Service Commission (Case No. EO-2011-0271) – October 2011
Reasonableness of Ameren Missouri's 2011 Integrated Resource Plan filing.

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.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – June, July, and October 2011 and June 2012
Duke Energy Indiana's imprudence and gross mismanagement of Edwardsport IGCC Project.

Kansas State Corporation Commission (Docket No. 11-KCPE-581-PRE) – June 2011
The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

Arizona Corporation Commission (Docket No. E-01345A-10-0474) – May 2011
The reasonableness of Arizona Public Service Company's proposed acquisition of Southern California Edison's share of Four Corners Units 4 and 5.

Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010
The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July, November and December 2010
The reasonableness of Duke Energy Indiana's new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

Oregon Public Utility Commission (Docket LC 48) – May and August 2010
Comments and Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan.

South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010
The reasonableness of Black Hills Power Company's 2007 Integrated Resource Plan and the Company's decision to build the Wygen III coal-fired power plant.

Michigan Public Service Commission (Docket No. U-16077) – April 2010
Comments on the City of Holland Board of Public Works' 2010 Power Supply Study.

Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010
Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010
The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009
The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Public Service Commission of Michigan (Docket No. U-15996) – July 2009
Comments on Consumer Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

Public Service Commission of Michigan (Docket No. U-16000) – Juy 2009
Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008
The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007
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.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008
Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007
The appropriate carbon dioxide ("CO_2") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – May 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.
Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales. [Confidential Testimony]

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - June 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - November 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and June 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) – December 1985 and January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - January 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

How the High Cost of Power from Prairie State is Affecting Bowling Green Municipal Utilities' Customers. July, 2014.

Overpriced Power: Why Batavia is Paying So Much for Electricity. Updated March 2014.

Huntley Generating Station: Coal Plant's Weak Financial Outlook Calls for Corporate & Community Leadership. January 2014. Co-authored with Cathy Kunkel and Tom Sanzillo.

When, Not If: Bridgeport's Future and the Closing of PSEG's Coal Plant.

Changing Course: A Clean Energy Investment Plan for Dominion Virginia Power. Co-authored with Jeff Loiter and Anna Sommer. August 2013.

Mountain State Maneuver: AEP and FirstEnergy try to stick ratepayers with Risky Coal Plants. September 2013. Co-authored with Cathy Kunkel.

Public Utility Regulation without the Public: The Alabama Public Service Commission and Alabama Power. Co-authored with Anna Sommer. March 2013

A Texas Electric Capacity Market: The Wrong Tool for a Real Problem. Co-authored with Anna Sommer. February 2013.

Dark Days Ahead: Financial Factors Cloud Future Profitability at Dominion's Brayton Point Power Plant. Co-authored with Tom Sanzillo. February 2013.

Report on the Kemper IGCC Project: Cost and Schedule Risks. November 2012.

The Prairie State Coal Plant: the Reality vs. the Promise. August 2012.

The Impact of EPA's Proposed 316(b) Existing Facility Rule on Electric System Reliability, July 2011.

The Economics of Existing Coal-Fired Power Plants, Presentation at EUCI Conference in St. Louis, MO, November 2010.

Presentation to the Indiana Utility Regulatory Commission on the Need for the Proposed Duke Energy Indiana Edwardsport IGCC Project, November 2010.

Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan, September 2010.

Presentation to the Oregon Public Utility Commission on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on the Facility Cost Report for Tenaska's Proposed Taylorville IGCC Plant, April 2010.

Comments on City of Holland Board of Public Work's 2010 Power Supply Plan, April 2010.

Phasing Out Federal Subsidies for Coal, April 2010.

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan, October 2009.

The Economic Impact of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia, August 2009.

Energy Future: A Green Energy Alternative for Michigan, report, July 2009.

Energy Future: A Green Energy Alternative for Michigan, presentation, July 2009.

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan, June 2009.

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

An Assessment of Santee Cooper's 2008 Resource Planning, April 2009.

Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead, Report for the Union of Concerned Scientists, March 2009.

New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

The Risks of Building and Operating Plant Washington, Report and Presentation to EMC Board Members, December 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at Georgia Tech University, October 2008.

Nuclear Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Coal-Fired Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Synapse 2008 CO_2 Price Forecasts, Synapse Energy Economics, July 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

Are There Nukes In Our Future, Presentation at the NASUCA Summer Meetings, June 2008.

Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

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.

*Don't Get Burned,*Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, *the New Climate for Coal*, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

The Risks of Building New Nuclear Power Plants, U.S. Senate and House of Representative Briefings, April 20, 2007.

Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues during Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

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.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, <u>Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company</u>, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

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

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

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.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

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.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

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.

2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: 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

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

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 --

Q. Okay.

A. -- and demonstrate that non-extension by other parties is a compelling reason to shut down the plants.

Q. Does it say that in your filed testimony?

A. I did not address that issue, no.

Q. Okay. And did either Mr. Sisneros or Ms. Eschberger address that issue?

A. I don't know.

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?

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 CO_2 emissions regardless or not, but regardless of whether the ETA applies to 19-18 or not.

So that analysis is not a realistic scenario because that scenario is not realistic. You cannot continue operations without installation of CO_2 reduction technology past January 1 of 2023. So the base operation in PNM's application should have been in Nick Phillips' testimony, and Nick Wintermantel's testimony should have been a scenario.

The base case should have been PNM continues the operation of San Juan with CCS installed 45Q tax credits and selling CO_2 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 CO_2 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. 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

technically feasible, it can achieve 90 percent capture, and this is the amount of money that would have to be invested, and gives us a preliminary engineering design of the retrofit, and that's the scope of the report. I don't believe economic feasibility as to the operation is part of the scope of the Sargent & Lundy report. It's outside. It's beyond its scope.

Q. Does the Sargent & Lundy report imply to you that it's economically feasible because of the 45Q tax credits and the CO2 sales revenues?

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

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?

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

approximately that, but yeah, it's 240 megawatts, give or take a few.

Q. All right. And for San Juan, it would be how many megawatts?

A. San Juan would be -- I have to look it up, but it would be bigger.

Q. Maybe we'll turn to that. If you could turn to Page 42.

A. Yes. San Juan's, of course, is bigger.

Q. Are they comparable in scale, Petra Nova and San Juan?

A. San Juan's bigger.

Q. Is it bigger by two to three times?

A. Yes.

Q. Okay. Are you aware of any power plant in the world that is as large as San Juan that currently uses carbon capture?

A. I'll have to look at the NARUC report, and without looking at that, I don't know if there's any CCS installed in 900 megawatts. But I'm not aware of any that I can just think of now.

Q. So you're not aware of any power plant that's as large as San Juan that has CCS?

A. That has CCS installed.

Q. Okay. Would you agree that the proposed

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