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September 25, 2020

TO: Will Rosquist

FROM: Suzanne Snow

RE: Docket No. 2019.12.101 – NorthWestern Energy

Attached please find the redacted direct testimony of Ralph C. Smith and David E. Dismukes on behalf of the Montana Consumer Counsel in the above matter. Please note that unredacted pages and exhibits have been filed under their respective protective orders. Thank you.

c.c. Service List

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF NorthWestern	)	REGULATORY DIVISION
Energy's Application for Approval of	)	
Capacity Resource Acquisition	)	DOCKET NO. 2019.12.101

Redacted

Direct Testimony

of

Ralph C. Smith

on behalf of

The Montana Consumer Counsel

September 25, 2020

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ATTACHMENTS AND EXHIBITS:

Appendix A, Background and Qualifications

Exhibit No.__(RCS-1): Remaining Net Plant in Service amounts for December 31, 2025 through 2042 per NorthWestern's corrected Exhibit ADD-5 confidential Excel files which show the potential for capital expenditures for which NorthWestern is likely to seek future cost recovery.

Exhibit No.__(RCS-2): Recalculations of NorthWestern's revenue requirements for an acquired 92.5 MW interest in CU4 with incremental plant additions depreciated through December 31, 2025 (five year revenue requirement) and through December 31, 2030 (ten year revenue requirement) respectively.

Exhibit No.__(RCS-3): Excerpts from NorthWestern's 2019 FERC Form 1 Annual Report at pages 123.14 and 123.15, which discuss NorthWestern's Asset Retirement Obligations.

Exhibit No.__(RCS-4): NorthWestern's response to MEIC-065 from Docket No. 2018.02.12 concerning Asset Retirement Obligation.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE LARKIN & ASSOCIATES.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation, where the majority of my time for the past 40 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions and where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law. My prior testimonies have included evaluations of numerous utility rate case filings and revenue requirement determinations.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MONTANA PUBLIC SERVICE COMMISSION ("MPSC" OR "COMMISSION")?

A. Yes. I testified before the Commission on behalf of the Montana Consumer Counsel in Docket No. D2017.9.79 concerning Montana-Dakota Utilities' ("MDU") Montana gas distribution utility revenue requirements and in Docket No. D2017.9.80 concerning Energy West Montana and Cut Bank Gas Company to evaluate the impact of the Tax Cuts and Jobs Act of 2017 ("TCJA" or "Act") on the revenue increase request of those utilities. I submitted testimony on the proposed corporate reorganization of MDU and Great Plains Natural Gas Co. in Docket No. D2018.1.6, and in the TCJA cases involving the MDU electric utility (Docket No. D2018.4.22) and NorthWestern Energy

(Docket No. D2018.4.24). I also submitted testimony regarding NorthWestern Energy's request for a rate increase in Docket No. D2018.2.12.

Q. HAVE YOU PREPARED AN ATTACHMENT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND REGULATORY EXPERIENCE?

A. Yes. Appendix A provides details concerning my experience and qualifications.

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Exhibit Nos. ___(RCS-1) through ___(RCS-4) are attached to my testimony.

Q. WHAT IS SHOWN IN EACH OF THOSE EXHIBITS?

A. Exhibit No.__(RCS-1) shows the Net Plant in Service amounts remaining at December 31, 2025 through 2042, according to NorthWestern's corrected Exhibit ADD-5 confidential Excel files. These amounts result from NorthWestern's projected capital expenditures for the share of Colstrip Unit 4 to be acquired from PSE. The summary data presented in Exhibit No. __ (RCS-1) represents a more comprehensive view of the potential cost of the proposed Capacity Acquisition than is presented in NorthWestern's testimony.

Exhibit No.__(RCS-2) shows illustrative recalculations of NorthWestern's revenue requirements for an acquired 92.5 MW interest in CU4 with incremental plant additions depreciated through December 31, 2025 (five year revenue requirement) and through December 31, 2030 (ten year revenue requirement) respectively.

Exhibit No.__(RCS-3) contains excerpts from NorthWestern's 2019 FERC Form 1 Annual Report at pages 123.14 and 123.15, which discuss NorthWestern's Asset Retirement Obligations ("AROs") and show estimated amounts as of December 31, 2018 and 2019, respectively. A portion of NorthWestern's AROs relate to the reclamation and remediation costs at its jointly owned coal-fired generation facilities. Although NorthWestern's FERC Form 1 does not break out ARO amounts separately for its current 222 MW ownership interest in Colstrip Unit 4, I was able to locate that information in NorthWestern's response to Data Request MEIC-065 in Docket No. 2018.02.12, NorthWestern's most recent general rate case. That data request response states that the "Asset Retirement Cost" booked by NorthWestern for its existing Colstrip Unit 4 interest at that time was $12,880,640.

Exhibit No.__(RCS-4) contains NorthWestern's response to MEIC-065 from Docket No. 2018.02.12 concerning its Asset Retirement Obligation balance for CU4.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Montana Consumer Counsel ("MCC" or "Consumer Counsel") to evaluate NorthWestern Energy's ("NorthWestern," "NWE" or "Company") proposed acquisition of Puget Sound Energy's ("PSE" or "Puget") 185 MW share of Colstrip Unit 4 ("CU4") and NorthWestern's revised proposed acquisition of a 92.5 MW share of CU4. Accordingly, I am appearing on behalf of the Consumer Counsel.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the accounting, revenue requirement, and certain ratepayer protection aspects, along with some of the economic implications of the proposed transaction. Another witness for the MCC, Dr. David Dismukes, is addressing in-depth the economic analysis of the proposed transaction.

Q. WHAT TASKS DID YOU PERFORM IN PREPARING YOUR TESTIMONY IN THIS MATTER?

A. In developing this testimony, I have reviewed and analyzed the Company's filing, supporting testimonies, exhibits, filing requirements, and workpapers; the Company's responses to data requests from the PSC Staff, the Consumer Counsel and other intervenors; and other relevant financial documents and data. I also reviewed prior case material and prior Commission Orders.

III. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. Preapproval should be denied because the economics of the proposed acquisition are marginal even with the Puget PPA supporting approximately half the acquired capacity for the first five years, and rapidly deteriorate (from a customer point of view) after the Puget PPA terminates. In addition, the Reserve Fund element of NorthWestern's proposal is utterly inconsistent with sound rate making principles and must be rejected. As an alternative, should the Commission determine to approve the proposed acquisition at all, NorthWestern's "Reserve Fund" proposal would still have to be rejected, and the preapproval for any additional interest in CU4 capacity by NorthWestern should be limited to the five-year term of the Puget PPA. I have reached the following findings and conclusions in this case:

1. The additional capital investments that would necessarily follow the "initial purchase price" of $0.50 for the proposed 92.5 MW capacity acquisition will rapidly overwhelm and reverse the limited benefits to customers from having the Puget PPA and Puget's ongoing cost support for the acquired capacity during the term of the PPA. As shown on Exhibit RCS-2, attached to my testimony, NorthWestern's projections demonstrate that substantial additional capital costs and net plant balances will accompany the additional share in CU4 that it seeks approval to acquire in this proceeding.

2. Significant amounts of capital expenditures are projected for CU4 and will very likely result in future requests for cost recovery by NorthWestern whether or not CU4 is able to operate economically through the service life projected by NorthWestern.

3. The Commission should deny NorthWestern's Application in this proceeding. NorthWestern has not met its burdens of establishing that the acquisition it proposes (a) is in the public interest, and (b) would result in rates that are reasonable and just, and consistent with the objectives established in Sections 69-3-201, 69-3-1201 through 69-3-1209, MCA.

4. NorthWestern's proposed new Reserve Fund is unjustified, not reasonably related to its proposed acquisition of half of Puget's share of CU4, and should be rejected. NorthWestern's proposed amendment to its PCCAM to create a new Reserve Fund (Exhibit ADD-2) would divert all customer credits under the PCCAM to funding environmental remediation and decommissioning liabilities associated with NorthWestern's currently owned interest in CU4. The Commission should not authorize NorthWestern to divert PCCAM credits to fund costs of retirement, decommissioning and environmental remediation related to NorthWestern's current interest in CU4 through the proposed Reserve Fund. With the limited exception of the existing Colstrip Unit 4 asset retirement obligation already embedded in NorthWestern's existing retail rates, there has been no determination that it is just and reasonable for NorthWestern's customers to absorb the liabilities for which NorthWestern proposes to appropriate customer credits under its PCCAM. Nor has NorthWestern made any showing that such additional costs were prudently incurred. Indeed, NorthWestern and its predecessor, the Montana Power Company (MPC),

incurred a large portion (if not all) of these remediation and decommissioning costs during operation of Colstrip Unit 4 on a merchant basis between 1986 and 2009. The Commission therefore should reject NorthWestern's proposed Reserve Fund, under any disposition of NorthWestern's Application in this proceeding.

5. Any revenues, costs and savings related to NorthWestern's proposed acquisition of a 92.5 MW share of CU4 should be accounted for and reflected in a separate allowable generation asset cost of service limited to that 92.5 MW acquisition, and which is not comingled with cost recovery for NorthWestern's current existing ownership share of CU4. This is necessary because the future ratemaking treatments of NorthWestern's current interest and the acquisition proposed in this case may present different ratemaking issues in NorthWestern regulatory proceedings and rate cases.

6. The Commission should further limit any approval by establishing the following allowable generation asset cost of service (§ 69-8-421(6)(d), MCA) for the acquired portion of Puget's interest in CU4:

    a. NorthWestern will have the burden of establishing the justness and reasonableness of any cost recovery associated with the acquired Puget interest after the sunset date of the PPA (December 31, 2025).

b. As part of its burden under item a. above, NorthWestern should be required to demonstrate through a competitive solicitation process in full compliance with § 69-3-1207, MCA both (i) the need that it proposes to fill with any portion of the acquired Puget interest that it seeks to include in rate base after December 31, 2025 and (ii) that such portion of the acquired Puget interest meets the requirements of consumers in the most cost-effective manner consistent with NorthWestern's obligation to serve.

c. The allowed cost of service for that portion of the acquired Puget interest should be limited to the pro forma cost of service set forth in Exhibit ADD-5, striking the footnote in that exhibit (i.e., that portion of the acquired Puget interest that is allowed into rate base), plus NorthWestern's documented historical fuel and variable operation and maintenance costs established in its testimony in support of its Application.

d. NorthWestern must make a one-time adjustment to the base PCC to eliminate 100% of the costs and revenues from power purchases avoided by the acquisition of the Puget interest.

e. The fixed allowed generation cost of service for the 92.5 MW acquisition should be reduced by the $3.616 million of net revenues from the five-year 45MW PPA with Puget forecasted in the supporting testimony of NorthWestern witness Markovich as shown on Company Corrected Exhibit KJM-3.

IV. OVERVIEW OF NORTHWESTERN'S PROPOSED ACQUISITION

Q. PLEASE DESCRIBE COLSTRIP UNIT 4.

A. As stated in NorthWestern's Application on page 5, CU4 is a 740 MW coal-fired generating plant located in Rosebud County, Montana, and is operated in conjunction with Colstrip Unit 3. Colstrip Unit 4 entered commercial operation in 1986. Colstrip Units 1 & 2 and Colstrip Units 3 & 4 share certain common facilities, per the Common Facilities Agreement included as Attachment 1 to the Application.

Q. FROM WHAT SOURCE IS THE COAL SUPPLIED?

A. The Colstrip plant is served by the Rosebud mine, which is located nearby the plant. One of the owners of Colstrip, PacifiCorp, has a contract with [**BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**

Q. PLEASE DISCUSS THE OWNERSHIP OF COLSTRIP UNITS 3 & 4.

A. NorthWestern currently owns 30 percent, or 222 MW, of CU4. From its commissioning in 1986 until 2008, Northwestern and its predecessor, Montana Power Company, operated its interest in Colstrip Unit 4 on a “merchant” basis under a sale-and-leaseback arrangement approved by the Commission in Order No. 5168 in Dkt. No. 85.11.45 (issued November 27, 1985). On November 13, 2008, the Commission issued Order No. 6925f in Dkt. No. D2008.6.69, which approved the inclusion of NorthWestern’s 222 MW interest in Colstrip Unit 4 in rate base. Talen owns 30 percent of Colstrip Unit 3. The other owners of CU3 and CU4 are PSE, Portland General Electric (PGE), Avista, PacifiCorp, and Talen. The Ownership and Operation Agreement and the Reciprocal Sharing Agreement detail Talen and NorthWestern’s agreement to realize a 15 percent share of each unit’s generation for each of Talen and NorthWestern. The remaining ownership percentages of CU3 and CU4 are as follows:

Owner	Ownership Interest
Puget Sound Energy	25%
Portland General Electric	20%
Avista	15%
PacifiCorp	10%

Under the Ownership and Operation Agreement’s right of first refusal provision, if one of the owners is selling its share, the other owners have the right to acquire a portion of that share. As stated above, after the sale of Puget's share to NorthWestern was announced, Talen was the only company to exercise its right of first refusal.

Q. DO THE INTERESTS OF THE CURRENT OWNERS OF CU4 CONCERNING THE FUTURE OPERATION OF THE FACILITY DIFFER?

A. It appears so. Talen is a merchant generator. Talen is not a regulated utility. Talen is currently the operator of the Colstrip plant including CU3 and CU4.

The other owners of CU4, including NorthWestern, PSE, PGE, Avista, and PacifiCorp are regulated utilities. PSE operates in Washington State. Section 3(1)(a) of Washington's 2019 Clean Energy Transformation Act requires that "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity" (Rev. Code Wash. § 19.405.030(1)(a)). NorthWestern provides electric and natural gas service to customers in Montana, South Dakota, and Nebraska, and electric service in Yellowstone National Park. PGE operates in Oregon in the areas of Portland and East Multnomah County. Avista has operations in Washington, Idaho, Montana, and Oregon. PacifiCorp is headquartered in Oregon and provides electric service to portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. Legislation was enacted in Oregon in 2016 requiring PGE and PacifiCorp to remove coal-fired generation from their Oregon rate base by January 1, 2030. (Ore. Rev. Stat. § 757.518). Moreover, the other co-owner, Avista, supplies electricity in Washington, which requires divestiture of coal-fired resources by December 31, 2025. PGE and PacifiCorp[1] may not be able to sell the output of their Colstrip shares into some portion of the wholesale market after January 1, 2030. It is

[1] If and to the extent permitted by laws of the relevant State jurisdictions, PacifiCorp may also be able to reallocate generation from Colstrip to other States. https://billingsgazette.com/news/state-and-regional/colstrip-owner-accelerates-exit-plans-again/article_9d722c23-6ff7-5269-adca-f893b77a802c.html

also noted that PacifiCorp entered into a settlement to remove Colstrip from bills in Washington by the end of 2023.[2]

The Colstrip plant and the coal mine that supplies the plant are both located in Montana, and NorthWestern is a regulated utility operating in Montana. Although NorthWestern provides utility service in Montana and not in Oregon or Washington, developments in the latter two states could affect the economic viability of Colstrip and the co-owners' interests in continuing to operate CU3 and CU4.

Q. WHAT IS NORTHWESTERN REQUESTING IN ITS APPLICATION?

A NorthWestern's Second Supplement to its Application requests Commission preapproval to acquire 92.5 MW of CU4 from Puget Sound Energy, Inc. ("Puget" or "PSE") for the purchase price of $0.50. NorthWestern's Second Supplement to its Application (at pgs. 1-2) summarizes its request as seeking a Commission order authorizing NorthWestern to:

> (i) purchase 92.5 MW of CU4 from Puget and place that asset in rate base;
>
> (ii) sell 45 MW back to Puget for approximately five years pursuant to the power purchase agreement ("PPA");
>
> (iii) include the revenue requirement in rates;
>
> (iv) offset the rates for the revenue requirement with a reduction to the Power Costs and Credits Adjustment Mechanism ("PCCAM") rates;
>
> (v) establish a Reserve Fund with the net proceeds from the PPA and 90% of the savings from the PCCAM, and charge against that fund for

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[2] See, e.g., https://billingsgazette.com/news/state-and-regional/colstrip-owner-accelerates-exit-plans-again/article_9d722c23-6ff7-5269-adca-f893b77a802c.html

expenditures and costs associated with environmental compliance, remediation, decommissioning, and post closure costs; and

(vi) make a compliance filing in approximately five years to reflect the revenue requirement for the capacity associated with the PPA and any corresponding change to PCCAM rates.

NorthWestern's Purchase Power Agreement with PSE

Q. HAS NORTHWESTERN PROJECTED THAT THE PPA WITH PSE WOULD PRODUCE REVENUE IN EXCESS OF COSTS RELATED TO SERVING PSE UNDER THAT PPA?

A. Yes. In the Company's corrected Exhibits KJM-1 through KJM-4, NorthWestern has presented scenarios wherein it projects revenue and costs related to the PPA with PSE. For example, in Corrected Exhibit KJM-3 (and NorthWestern's response to MEIC-079a update), the Company projects that net revenue would exceed costs for the five calendar year period, 2021 through 2025 by $3,615,767 related to a 45 MW sale to PSE, as follows:

NorthWestern Analysis of 45 MW Sale						
03/31/20 Strip	87% EAF, 2024 8 Week Outage, No RSA					
Updated June 2020	2021	2022	2023	2024	2025	
	Calendar Year	Calendar Year	Calendar Year	Calendar Year	Calendar Year	Total
Revenue	$ 9,438,277	$ 9,419,966	$ 9,377,076	$ 7,727,236	$ 9,279,286	$ 45,241,841
Fixed O&M Pmt. from Puget	$ 1,671,005	$ 1,664,564	$ 1,826,894	$ 1,695,354	$ 1,894,343	$ 8,752,161
Total Revenue	$ 11,109,282	$ 11,084,529	$ 11,203,970	$ 9,422,590	$ 11,173,629	$ 53,994,001
Variable Cost	$ 5,648,452	$ 5,648,452	$ 5,648,452	$ 4,719,940	$ 5,648,452	$ 27,313,749
Fixed O&M Base	$ 2,916,391	$ 2,977,767	$ 3,059,814	$ 3,111,275	$ 3,214,718	$ 15,279,966
Variable O&M Other	$ 665,006	$ 595,534	$ 594,625	$ 1,633,152	$ 624,727	$ 4,113,045
Property Taxes	$ 640,346	$ 656,355	$ 672,764	$ 689,583	$ 706,822	$ 3,365,869
MPSC & MCC Taxes	$ 62,879	$ 62,738	$ 63,414	$ 53,332	$ 63,243	$ 305,606
Total Expenses	$ 9,933,075	$ 9,940,847	$ 10,039,069	$ 10,207,281	$ 10,257,962	$ 50,378,234
Net Value	$ 1,176,207	$ 1,143,682	$ 1,164,901	$ (784,691)	$ 915,667	$ 3,615,767

Notably, NorthWestern projects a net loss on the PPA in 2024 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. IS IT POSSIBLE THAT UNSCHEDULED OUTAGES AT CU4, IF THEY OCCUR FOR A DURATION OF SEVERAL WEEKS, COULD CAUSE NET LOSSES ON THE PPA IN OTHER YEARS?

A. Yes, that would be possible.

Q. IS THE "NET VALUE" THAT NORTHWESTERN HAS PROJECTED FOR THE PPA WITH PSE ASSURED?

A. No. As noted above, it appears that the "net value" that NorthWestern has projected for the PPA could be adversely affected if there are some unscheduled outages at Colstrip which prevent the unit from operating at NorthWestern's projected capacity factor during the period of the PPA. As noted above, NorthWestern has projected a negative "net value" for the tracker year 2023/2024 which is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** If unscheduled outages occur, presumably that would also present a risk of having negative "net value" for the PPA for those periods in a similar manner. Such outages have occurred since CU4 was rate based at the beginning of 2009 in 2009, 2013, and 2018.

Q. HOW DOES THE "NET VALUE" OF THE PUGET PPA THAT NORTHWESTERN HAS CALCULATED COMPARE WITH THE RECOVERY OF COSTS ASSOCIATED WITH ANTICIPATED CAPITAL EXPENDITURES UNDER NORTHWESTERN'S PROPOSAL TO ACQUIRE A 92.5 MW INTEREST IN CU4 FROM PSE?

A. Estimates for a 92.5 MW CU4 acquisition from Puget and the corresponding 45 MW sale via a PPA to Puget, are shown on Corrected Exhibit KJM-3 (and NorthWestern's response to MEIC-079a update). The Company projects that net revenue would exceed cost for the five calendar year period, 2021 through 2025 by $3,615,767 as a result of the 45 MW sale to PSE. However, the Company's revenue requirement calculations for a 92.5 MW CU4 capacity acquisition show an unrecovered net book value amount at December 31, 2025 of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as much as the claimed $3,615,767 “net benefit” (more appropriately described as net margin) from the 45 MW sale to Puget via the PPA for the five year period through 2025.

Below I discuss NorthWestern's forecasted revenue requirements for five and ten-year periods and the implications for incurring capital costs substantially in excess of net margins associated with the 92.5 MW share of CU4 which NorthWestern is proposing to acquire from Puget in the next section of my testimony.

NorthWestern's Estimated Revenue Requirement for the Proposed Acquisition of a 92.5 MW Share of CU4

Q. WHAT DOES NORTHWESTERN SHOW FOR THE 2021 REVENUE REQUIREMENT FOR THE PORTION OF CU4 THAT IT WOULD BE ACQUIRING FROM PSE?

A. The Company's corrected Exhibit ADD-5 shows a net revenue requirement of $4,391,331 in 2021 for an acquired 92.5 MW share of CU4.

Q. WHAT IS NORTHWESTERN PROPOSING FOR THE RATEMAKING TREATMENT FOR THE PORTION OF CU4 CAPACITY THAT IT WOULD ACQUIRE FROM PSE?

A. NorthWestern is proposing that instead of increasing rates to reflect recovery of a 2021 Test Period Revenue Requirement in rates for 47.5 net MW (92.5 MW capacity purchase less 45 MW PPA with PSE), the Company would offset the required increase in net revenue requirement with a corresponding reduction of that amount to the Power Costs and Credits Adjustment Mechanism ("PCCAM"). As explained in Company witness Hines' corrected direct testimony at page JDH-7, NorthWestern proposes to offset its calculated 2021 revenue deficiency for the acquired CU4 interest with an equal and offsetting reduction to the PCCAM.

Q. WHAT DOES NORTHWESTERN PROPOSE TO DO WITH ANY ADDITIONAL POWER COST SAVINGS AND PPA REVENUE BEYOND THE AMOUNT THAT IT WOULD USE TO CREDIT TO THE PCCAM?

A. NorthWestern has proposed that 90% of all additional purchased power savings over base projections recorded in future PCCAM true-ups, regardless of the source, and all future PPA revenues would be placed into a new Reserve Fund. I discuss NorthWestern's proposal for a new Reserve Fund in a subsequent section of my testimony and recommend that this part of NorthWestern's proposal in the current docket be rejected whether or not the acquisition of an additional 92.5 MW of CU4 capacity is approved.

Q. WHAT RATIONALE DOES NORTHWESTERN PRESENT FOR THE NEW RESERVE FUND?

A. NorthWestern proposes that the amounts accumulated in the Reserve Fund would be used in each year to reimburse Northwestern for expenditures and costs associated with environmental compliance, remediation, decommissioning, and post-closure associated with its existing share of CU4.[3] After five years, NorthWestern proposes to

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[3] NorthWestern Energy's Application, pages 1 and 3.

submit a compliance filing to reflect the revenue requirement for the 45 MW initially being sold back to PSE and any corresponding reduction in PCCAM rates.[4]

Q. HAS NORTHWESTERN PROVIDED PROJECTIONS FOR ITS PROPOSED ACQUISITION OF CU4 FROM PSE THAT SUGGEST SIGNIFICANT ADDITIONAL COSTS RELATED TO THE ACQUIRED PORTION OF CU4?

A. Yes. NorthWestern has projected rate base, operating income, and revenue requirement changes for years 2021 through 2041 for a 92.5 MW addition of CU4 capacity in the proprietary corrected version of Company witness Durkin's Exhibit ADD-5. Those NorthWestern presentations use the Company's currently authorized depreciation rates for the Company's already owned share of CU4, and are based on a projected retirement date of 2042. Using information from the proprietary corrected version of Company witness Durkin's Exhibit ADD-5, the Company shows remaining undepreciated net book value for the acquired portion of CU4 at the end of each year 2025 through 2042. The unrecovered net book value based on that information at the end of 2025 (five years into the NorthWestern ownership period), at the end of 2030 (ten years) and at 2042 (date that NorthWestern has been using for depreciation of its current interest in CU4) are shown on Exhibit No. __(RCS-1) and are summarized below for the 92.5 MW purchases:

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[4] Id. Page 3

<u>NorthWestern Projected Net Book Value Amounts - 92.5 MW Purchase</u>

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

V. RISKS POSED BY PROJECTED CAPITAL EXPENDITURES FOR COLSTRIP UNIT 4

Q. IS THE $0.50 INITIAL PAYMENT FOR THE 92.5 MW CU4 ACQUISITION THE ONLY CAPITAL INVESTMENT THAT NORTHWESTERN WOULD BE MAKING IN CU4?

A. No, as shown in the confidential corrected versions of NorthWestern's Exhibit ADD-5, and summarized in my Exhibit __(RCS-1), NorthWestern has identified significant amounts of additional capital expenditures that are projected for the Colstrip plant that are well beyond the purchase price amount of $0.50 for half of PSE's interest in CU4. As discussed in my testimony and in the testimony of MCC witness Dismukes, those additional capital expenditure amounts do present substantial risks of future demands for cost recovery by NorthWestern that have not been factored into its Application in this proceeding, and that appear likely to make the proposed acquisition a particularly poor choice for an electric supply resource once the cost support provided by the Puget PPA terminates.

Q. WHAT PROJECTED CAPITAL EXPENDITURES FOR COLSTRIP UNIT 4 HAS NORTHWESTERN IDENTIFIED IN RESPONSES TO DISCOVERY?

A. Projected amounts of capital investment that are being reflected as Plant in Service each year for 2021 through 2042 are shown on the confidential corrected Excel versions of NorthWestern Exhibit ADD-5. By the end of 2042, for the 92.5 MW capacity purchase, NorthWestern projects to have booked **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of gross Plant in Service and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of net Plant in Service. Using NorthWestern's corrected projections from the confidential Excel files provided by the Company for its Exhibit ADD-5, amounts of gross and net plant in service as of December 31 for each year 2025 through 2042 for NorthWestern's proposed acquisition of the 92.5 MW interest in CU4 from Puget are summarized in my Exhibit No.__(RCS-1).

Q. AS THOSE ADDITIONAL CAPITAL EXPENDITURES RELATE TO NORTHWESTERN'S PROPOSED 92.5 MW INTEREST IN CU4, HOW HAS NORTHWESTERN PROPOSED TO ACCOUNT FOR AND DEPRECIATE THOSE COSTS?

A. As shown in NorthWestern's revenue requirement projections (which were provided confidentially in response to MCC-007 and in the Company's Excel files for the corrected versions of its Exhibit ADD-5), NorthWestern would account for the CU4 capital expenditures by recording those as utility Plant in Service as they are placed into service. Once the capital expenditures are recorded as utility Plant in Service, NorthWestern would record Depreciation Expense using its currently authorized depreciation rates (which were established in NorthWestern's last base rate case and reflect a projected retirement date of 2042). The standard utility accounting for Depreciation Expense results in a charge (debit) to Depreciation Expense, account 403, and a credit to Accumulated Depreciation (account 108). The charges to Plant in Service and the credits to Accumulated Depreciation over time result in an amount of net plant in service. The post-acquisition capital expenditures which would be recorded as additions to Plant in Service, are projected to be significant, as described above, and those amounts do present questions about cost recovery that have not been addressed clearly in NorthWestern's Application or supporting testimony.

Q. ARE THERE FACTORS WHICH COULD RESULT IN CU4 BEING RETIRED PRIOR TO 2042?

A. Yes. An array of economic and political factors could result in CU4 being retired prior to 2042. MCC witness Dismukes discusses economic factors including the fixed and variable O&M costs of operating CU4 versus the projected cost of power from other sources which could render the operation of CU4 uneconomic at some point prior to 2042. For example, the other owners of CU3 and CU4, as discussed above, are in different situations than NorthWestern and are thus exposed to a different set of cost and political factors that could lead them to making differing decisions concerning the future operations of CU4.

Q. HAVE YOU CALCULATED AND PRESENTED ALTERNATIVE REVENUE REQUIREMENT CALCULATIONS FOR FIVE AND TEN-YEAR PERIODS, THAT WOULD DEPRECIATE ALL OF THE PLANT ADDITIONS FOR THE ACQUIRED CU4 INTEREST BY THE END OF THOSE FIVE AND TEN-YEAR PERIODS?

A. Yes. Exhibit No.___ (RCS-2), attached to my testimony, presents recalculations of the revenue requirements that were presented by NorthWestern in its Corrected Exhibit ADD-5 (and the Company's supporting confidential Excel workpapers). This presentation reflects a scenario where the projected capital expenditures projected for the acquired CU4 interest were to be subject to recovery within those five and ten-year periods, rather than through 2042.[5] Recalculations are presented for the following:

- 92.5 MW acquisition - five years through December 31, 2025 (Exhibit No. __RCS-2, page 1)
- 92.5 MW acquisition - ten years through December 31, 2030 (Exhibit No. __RCS-2, pages 2-3)

As shown on Exhibit No.___ (RCS-2), under each of these scenarios, the revenue requirement for the acquired share of CU4 would be substantially higher than calculated by NorthWestern for these five and ten-year periods:

[5] NorthWestern's calculations have reflected an assumed service life through 2042, which leaves a significant undepreciated net book value amount remaining at the end of the five and ten-year periods, as shown on Exhibit _-(RCS-1), as well as in 2042.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

VI. NORTHWESTERN'S PROPOSED RESERVE FUND

Q. PLEASE DISCUSS NORTHWESTERN'S PROPOSED RESERVE FUND.

A. NorthWestern witness Crystal Lail's Direct Testimony at pages CDL-4 through CDL-7 and the Direct Testimony of NorthWestern witnesses Michael Barnes and Kevin Markovich discuss the Company's proposed Reserve Fund. NorthWestern proposes to create a new Reserve Fund to set aside funding for environmental compliance, and remediation and decommissioning of the Company's current interest in CU4. NorthWestern proposes to fund its new Reserve Fund with two revenue sources. The first source is 90% of the savings after establishing the new proposed base power costs and credits in the Power Costs and Credits Adjustment Mechanism ("PCCAM"). The second source is the net revenue that NorthWestern would receive from PSE through the Purchased Power Agreement ("PPA").

Q. WHAT DOES NORTHWESTERN PROPOSE TO DO WITH ANY ADDITIONAL POWER COST SAVINGS AND PPA REVENUE BEYOND THE AMOUNT THAT IT WOULD USE TO CREDIT TO THE PCCAM AS AN OFFSET TO THE REVENUE REQUIREMENT?

A. NorthWestern has proposed that 90% of any purchased power savings and PCCAM revenue be placed into NorthWestern's proposed Reserve Fund. Ten percent of any incremental purchased power savings and revenue credits would be kept by NorthWestern. To be clear, the preapproval that NorthWestern has requested is being used as a substitute for a base rate case to approve new resources. In that context, all of the costs and benefits would be reflected in base rates and there would be no "10% sharing" associated with it.

Q. WHAT DOES NORTHWESTERN PROPOSE TO DO WITH THE RESERVE FUND?

A. NorthWestern indicates that the Reserve Fund would be used sometime in the near future to pay for expenditures and costs associated with environmental compliance, remediation, decommissioning, and post-closure costs of NorthWestern's existing, 222 MW interest in Colstrip Unit 4.[6] After five years, NorthWestern proposes to submit a compliance filing to reflect the revenue requirement for the 45 MW initially being sold back to PSE and any corresponding reduction in PCCAM rates.[7]

Q. WHAT DOES NORTHWESTERN PROPOSE FOR THE NEW RESERVE FUND AFTER THE EXPIRATION OF ITS PPA WITH PUGET?

A. At pages CDL-6 to CDL-7 of her Direct Testimony, NorthWestern witness Lail states that:

> NorthWestern proposes to capture the operations and maintenance expenses ("O&M") for compliance with the 2012 Administrative Order on Consent and coal combustion ash residuals regulations, as described in the Barnes Direct Testimony, in a regulatory asset as incurred. Costs captured in the regulatory asset will be limited to amounts in excess of any environmental compliance and remediation costs included in NorthWestern's recent rate review, Docket No. 2018.02.012. NorthWestern will also capture future decommissioning and post-closure costs in the regulatory asset.
>
> Following the expiration of the PPA between Puget and NorthWestern, (4 years and 364 days), NorthWestern will submit a request to charge the costs accumulated in the regulatory asset against the Reserve Fund and be reimbursed, subject to the fund balance. Then, on an annual basis, NorthWestern proposes to submit a compliance filing requesting

[6] NorthWestern Energy's Application, pages 1 and 3.
[7] Id. Page 3

> to charge any costs in the regulatory asset against the Reserve Fund, subject to the fund balance.

If there were to be any funds remaining in the Reserve Fund after charging it with the compliance, remediation, decommissioning and closure costs related to NorthWestern's current interest in CU4 (a situation that seems unlikely), NorthWestern witness Lail states at page 7 of her Direct Testimony that the Company, at that time, would seek direction from the Commission concerning the proper regulatory treatment of any remaining balance of the Reserve Fund.

Q. HOW DOES NORTHWESTERN PROPOSE TO REVISE ITS PCCAM FOR ITS NEWLY PROPOSED "RESERVE FUND" IN THIS PREAPPROVAL DOCKET?

A. NorthWestern's proposed amendment to its PCCAM to create a new Reserve Fund (Exhibit ADD-2) would divert all customer credits under the PCCAM, whether associated with this resource or not, to funding environmental remediation and decommissioning liabilities associated with NorthWestern's currently owned interest in CU4. NorthWestern's Corrected Exhibit ADD-2, at pages 2-3 of 5, proposes to change Schedule No. EPCC-1, paragraph F, Power Costs and Credits Mechanism Annual Adjustment to divert power cost savings into a newly created Reserve Fund, by removing the term "rebated to customers" and replacing that with "deposited into the Reserve Fund ..." as follows:

> The Mechanism's annual adjustment shall be derived by:
>
> 1. Computing the difference between Base Power Costs and Credits Rates Revenues and actual Power Costs and Credits for the period. 90% of the

> difference is recorded as a deferral and ~~rebated to customers~~ deposited into the Reserve Fund, established in Docket 2019.12.101, (when costs are less than revenues), or surcharged to customers (when costs are greater than revenues). Upon the expiration of the power purchase agreement between NorthWestern and Puget Sound Energy, Inc. approved in Docket 2019.12.101, 90% of the difference will be rebated or surcharged to customers.

This is not appropriate because the PCCAM tracker is supposed to be a balanced mechanism to track power costs and fairly recover or rebate both under-recovery (PCCAM cost increase) amounts and over-recovery (PCCAM cost decrease) amounts. NorthWestern's proposal takes all of the over-recovery (PCCAM cost decrease) i.e., the fuel and purchase power cost savings and would apply them for a different purpose. If NorthWestern's proposed treatment were to be adopted, the PCCAM would no longer be a balanced tracker mechanism, but would instead become an automatic funding mechanism for other costs that are not related to or caused by NorthWestern's acquired 92.5 MW interest in CU4.

Q. IS NORTHWESTERN'S REQUEST FOR A NEW "RESERVE FUND" IN ANY WAY SIMILAR TO A REQUEST FOR AN ACCOUNTING ORDER?

A. No. Under an accounting order, the utility does not start collecting revenues immediately, and questions regarding the prudence of the cost incurrence and the use and usefulness of objects of proposed expenditures are deferred.

In this case, the "Reserve Fund" does not currently exist. As proposed by NorthWestern the new "Reserve Fund" would be used to divert funds from what would otherwise be customer rebates flowing through the PCCAM and apply those funds to costs associated with NorthWestern's current 222 MW interest in CU4, including costs for environmental remediation and decommissioning. Under its “Reserve Fund” proposal, in contrast to a real accounting order, NorthWestern would start collecting for excess environmental remediation and decommissioning for its current ownership share of CU4 by charging such amounts against the power cost savings that are being accumulated in the Reserve Fund. Because Puget retains responsibility for its share of the environmental remediation and decommissioning costs associated with the 92.5 MW share of CU4 that would be acquired by NorthWestern from Puget, there is no relationship between the "Reserve Fund" and the acquisition that NorthWestern proposes in this proceeding. Separation, rather than comingling, of the costs associated with NorthWestern's (1) existing 222 MW interest in CU4 and (2) the new 92.5 MW interest proposed to be acquired from Puget, should be required, since different regulatory considerations apply to each.

Q. HAS THE COMMISSION ESTABLISHED CRITERIA FOR REVIEWING A REQUEST BY A UTILITY FOR AN ACCOUNTING ORDER OR OTHER SPECIALIZED ACCOUNTING MECHANISMS?

A. Yes. Typically, when a utility seeks an accounting order from the Commission, there are specific criteria that are supposed to be met for that order to be issued, which are summarized below.

“An accounting order represents an exception to test-year principles. It is the first step in mis-matching expenses incurred in one year with revenues from another year. Therefore, regulatory agencies grant permission to deviate from normal accounting procedures only in limited circumstances." Order No. 7528a, Dkt. No. 2016.11.88 at ¶ 17 (2017).

"The Commission has used the following standard for evaluating requests for accounting orders: (1) Is the amount material? (2) Is the event unplanned? (3) Is the event beyond the utility management's control? and (4) Is the problem unusual, abnormal, and not likely to be repeated?" *Id.* at ¶ 18.

"In determining whether or not the amount is material, this Commission has found persuasive FERC's materiality standard that holds in order to be considered extraordinary, "an item should be more than approximately 5 percent of income, computed before extraordinary items." Order 6829 P 11; Order 7252 PP 6, 9; 18 C.F.R. pt. 101 (2017) (See FERC General Instructions, Section 7, Extraordinary Items)." *Id.* at ¶ 19.

An accounting order then typically provides, with respect to the accounting treatment that it authorizes, that the utility "will have the opportunity, as well as the burden, to demonstrate in its next general rate case: (1) the appropriate level of costs to be recovered through ratemaking; and (2) the proper recovery period for those costs." Order No. 5709d, Dkt. No. 93.6.24 (1994) at ¶ 153.

Q. DOES NORTHWESTERN'S "RESERVE FUND" PROPOSAL SATISFY ANY OF THESE CRITERIA?

A. No, it does not.

Q. SHOULD NORTHWESTERN'S REQUESTED "RESERVE FUND" BE APPROVED BY THE COMMISSION?

A. No. NorthWestern's requested new "Reserve Fund" should be rejected. Moreover, the special accounting treatment and diversion of what would otherwise be customer PCCAM rebate amounts in a power cost true-up account should be rejected even if the Company receives authorization for acquiring the 92.5 MW interest in CU4 from Puget. NorthWestern's “Reserve Fund” proposal (Exhibit ADD-2) seeks to divert all customer credits under the PCCAM to funding NorthWestern's unquantified environmental remediation and decommissioning obligations for its existing 30 percent, 222 MW interest in Colstrip Unit 4. Moreover, NorthWestern's “Reserve Fund” proposal ensures that the Company will take ten percent of any realized benefits from its proposed Capacity Acquisition. The remaining 90 percent of customer credits would be diverted to the Reserve Fund in order to lock in consumers to pay for post-closure liabilities associated with NorthWestern's existing interest in Colstrip Unit 4, without any determination concerning either the prudency of the incurrence of those costs, or the just and reasonable allocation of financial responsibility for them. The initial revenue requirement and cost impacts of a resource rate basing preapproval should not be considered an element of the PCCAM simply because it would require a reset of the PCCAM base amount. NorthWestern's proposal for this "Reserve Fund" thus diverts ratepayer funds for use in paying for post-closure liabilities associated with NorthWestern's existing 222 MW interest in CU4, thus circumventing the normal safeguards associated with an accounting order, including the requirement for the determination of such cost recovery to be made in the future.

Q. ARE THERE OTHER REASONS FOR THE COMMISSION TO REJECT CHANGES TO THE PCCAM TARIFF IN WHAT IS SUPPOSEDLY A PRE-APPROVAL DOCKET?

A. Yes. This proposal by NorthWestern must be rejected because it is an unjustified appropriation of ratepayer benefits. Moreover, because as NorthWestern explains, Puget will continue to fund all remediation and decommissioning obligations associated with the 92.5 MW interest in Colstrip Unit 4 that NorthWestern is proposing to acquire, a new Reserve Fund is not needed to fund those liabilities because they are being retained by Puget.

Typically, the types of remediation and decommissioning costs that NorthWestern seeks to recover from its retail customers through its proposed revision of its PCCAM tariff language in Exhibit ADD-2 via the new "Reserve Fund" are recovered as part of an Asset Retirement Obligation. As explained by NorthWestern in its FERC Form 1, the Company is obligated to dispose of certain long-lived assets, including coal-fired generating facilities, upon their abandonment. NorthWestern recognizes a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditioned upon a future event. Consistent with ARO accounting, NorthWestern measures the liability at fair value when incurred and capitalizes a corresponding amount as part of the book value of the related plant assets, which increases NorthWestern's utility plant and AROs. NorthWestern's FERC Form 1 states further that: "The increase in capitalized book utility plant cost is included in determining depreciation expense over the estimated useful life of these assets." The ARO is thus included in the cost of utility plant and is depreciated over the estimated life of the related asset. This is the practice that NorthWestern says that it follows in its 2019 FERC Form 1 Annual Report at pages 123.14 and 123.15, which have been included in Exhibit __ RCS-3. NorthWestern's AROs include estimated liabilities of $12,880,640 for the remediation, reclamation and removal costs for its current 222 MW capacity ownership of CU4. The source for the existing ARO value is NorthWestern's response to Data Request MEIC-065 in Docket 2018.02.12 (NorthWestern's most recent general rate case), which is presented in Exhibit __ RCS-4.

Instead of subjecting increases in its asset retirement obligations related to its existing 222 MW interest in CU4 to the review and evaluation process of a full rate case, NorthWestern’s Reserve Fund proposal presumes that recovery of all of these remediation, reclamation and decommissioning costs associated with its current 222 MW ownership of CU4 through retail rates is just and reasonable and seeks to create an open-ended funding mechanism (consisting of both the net revenues from the Puget PPA and any other credits that would otherwise reduce customer rates under the PCCAM) to be applied against as yet unquantified costs that are resulting from NorthWestern's current 222 MW ownership share of CU4. The creation and use of a newly created Reserve Fund accounting mechanism for this purpose is unreasonable and unjust and should therefore be rejected.

Q. HOW WERE COSTS RELATED TO DISMANTLEMENT AND ENVIRONMENTAL CLEAN-UP RELATED TO CU4 TREATED IN NORTHWESTERN'S MOST RECENT RATE CASE, DOCKET NO. 2018.02.012?

A. Amounts estimated by NorthWestern were utilized in deriving the Company's revenue requirement related to CU4. In Docket No. 2018.02.012, NorthWestern continued to base its depreciation and the cost of removal/negative net salvage component of depreciation rates for its existing share of CU4 on an anticipated useful life for CU4 continuing through 2042, consistent with expectations at the time of preapproval in 2008. To the extent that the reclamation and decommissioning costs in rates associated with NorthWestern's current 222 MW ownership share in CU4 are not recovering the full extent of those costs or are not recovering such costs over the correct period, that is an issue that should be examined in a NorthWestern base rate case. Recovery of remediation, reclamation and decommissioning costs associated with NorthWestern's current 222 MW ownership share in CU4 should not be provided for in a "Reserve Fund" by diverting savings associated with this proposed resource addition.

NorthWestern seeks, via the creation and application of this new Reserve Fund, to lock in ratepayer responsibility for remediation and decommissioning costs associated with the 30 percent, 222 MW interest in CU4 that NorthWestern placed in rate base in 2009. This is unjustified. There has been no showing what these costs are, what caused the incurrence of these costs, whether that cost incurrence was prudent or why it is just and reasonable to make NorthWestern's Montana retail customers responsible for those costs. Considering NorthWestern represented the plant to be "better than new" with an expected useful life through 2042 when it proposed to rate base its existing share, it is reasonable to expect that recovery of these costs will be disputed if the plant closes early. With the limited exception of the existing Colstrip Unit 4 asset retirement obligation that has already been embedded in NorthWestern's existing retail rates, there has been no determination that it is just and reasonable for NorthWestern's customers to absorb these liabilities. Nor has NorthWestern made any showing that all of the asset retirement and remediation costs associated with its current interest in CU4 have been or will have been prudently incurred. Indeed, NorthWestern and its predecessor caused the need for a large portion of these remediation and decommissioning costs during the operation of Colstrip Unit 4 on a merchant basis between 1986 and 2009.

NorthWestern's proposed revision to its PCCAM tariff (Exhibit ADD-2) via the creation of a new "Reserve Fund" appropriates all savings over the duration of its proposed Power Purchase Agreement with Puget Sound Energy. Of that appropriation of benefits, 90 percent would go to fund NorthWestern's decommissioning and remediation liabilities associated with its current 222 MW ownership interest in Colstrip Unit 4, and the remaining ten percent would simply be appropriated directly by NorthWestern's shareholders under the PCCAM.

The Company's "Reserve Fund" proposal assigns to Montana retail customers the full costs of decommissioning and environmental remediation for a preexisting share of Colstrip Unit 4, without any determination whether those costs are reasonable or were prudently incurred.

The Commission should therefore reject NorthWestern's proposed Reserve Fund, under any disposition of NorthWestern's Application to acquire a 92.5 MW additional interest in CU4 from Puget in this proceeding.

Q. HOW DOES NORTHWESTERN'S AGREEMENT WITH PSE ADDRESS PSE'S RESPONSIBILITY FOR DISMANTLEMENT AND ENVIRONMENTAL CLEAN-UP RELATED TO CU4?

A. NorthWestern maintains that its agreement with PSE does not increase NorthWestern's responsibility for CU4 related coal combustion residuals ("CCR"), CU4 environmental clean-up costs, and CU4 decommissioning and closure costs, because PSE remains responsible for PSE's existing obligations with regard to such costs.[8] As such, NorthWestern is claiming that PSE would retain responsibility for estimated dismantlement and environmental clean-up costs based on PSE's current ownership in CU4. NorthWestern states in its response to NWEC/RNW-008 that PSE would retain that responsibility after its interest in CU4 (or half of PSE's interest in CU4) is transferred to NWE. NorthWestern's statements in this regard are not completely consistent with PSE filings in Washington wherein PSE has indicated that it has

[8] See, e.g., Lail Direct Testimony at CDL-5.

retained the liability for such costs, but has represented in such filings that its liability is being capped.[9] If NorthWestern is correct that PSE is retaining PSE's responsibility for PSE's share of the currently estimated CU4 dismantlement and environmental clean-up costs, there is no need for a new Reserve Fund for such costs, since they are remaining with PSE and are not being transferred to NorthWestern.

Q. SHOULD A CONDITION BE IMPOSED TO ASSURE THAT NORTHWESTERN'S COST FOR COLSTRIP DISMANTLEMENT AND ENVIRONMENTAL CLEAN-UP COSTS ASSOCIATED WITH THE NEWLY ACQUIRED SHARE IN CU4 IS NOT INCREASED AFTER PSE'S OWNERSHIP EXIT?

A. Yes. A condition should be imposed to assure that the cost of dismantlement and environmental clean-up costs and/or other closure costs related to NorthWestern's potential new interest in CU4 do not fall to ratepayers in accordance with the claims asserted by NWE to that effect.

[9] See, Revised Prefiled Direct Testimony of PSE Witness Ronald Roberts, page 15 and Exh. RJR-5C, page 58, in Washington UTC Docket UE-200115.

Q. SHOULD NORTHWESTERN BE REQUIRED TO MAINTAIN A SEPARATE IDENTIFICATION OF COSTS RELATED TO ITS CURRENT EXISTING INTEREST IN CU4, AND WITH THE NEW INTEREST BEING ACQUIRED FROM PSE?

A. Yes. The costs related to NorthWestern's currently existing 222 MW interest in CU4 should be accounted for in a manner that such costs can be separately identified. This is necessary because the future ratemaking treatments of NorthWestern's current 222 MW interest and the newly acquired 92.5 MW interest may present different ratemaking issues in future NorthWestern regulatory proceedings and rate cases.

VII. EXPLANATION OF CONDITIONS REQUIRED TO COMPLY WITH § 69-8-421 (6)(c), MCA

Q. WHY SHOULD A SUNSET PROVISION BE REQUIRED FOR COST RECOVERY FOR THE 92.5 MW CU4 CAPACITY SHARE THAT NORTHWESTERN WOULD ACQUIRE FROM PUGET?

A. The economics of the proposed transaction, as discussed by Dr. Dismukes, are different for the first five years due to the PPA that NorthWestern would have with Puget to sell a 45 MW portion of Puget’s existing ownership share from its total 92.5 MW interest the Company proposes to acquire. The sunset provision would require that the allowed cost recovery for the 92.5 MW of CU4 cease to be of any force or effect on expiration of the proposed PPA with Puget. This is necessary to protect ratepayers from substantial economic risks after the end of that period. Also, as explained by Dr. Dismukes, NorthWestern has failed to carry its burden of demonstrating that its proposal to acquire 92.5 MW of capacity in CU4 will result in rates that are reasonable and just beyond the expiration of the Puget PPA.

Q. WHY SHOULD THE COMMISSION SPECIFY THAT ITS APPROVAL OF THE PROPOSED CAPACITY ACQUISITION IS LIMITED TO THE TERM OF THE PUGET PPA?

A. NorthWestern's Application and the record in this proceeding do not meet NorthWestern's burden of establishing that the proposed capacity acquisition results in rates that are reasonable and just after the Puget PPA expires. There is therefore no basis in the record in this case on which to approve the proposed capacity acquisition for a period that extends beyond the term of the Puget PPA.

Q. WHY SHOULD THE COMMISSION SPECIFY THAT THE BURDEN OF PROOF SHALL REMAIN ON NORTHWESTERN FOR JUSTIFYING ANY COST RECOVERY OF THE 92.5 MW INTEREST IN CU4 BEING ACQUIRED FROM PUGET AFTER THE SUNSET DATE?

A. In the current proceeding, as explained by Dr. Dismukes, NorthWestern has not shown that the acquisition would be economic or in the public interest beyond the initial five-year term to which the PPA with Puget applies. The Commission should therefore state clearly that, to the extent it determines to approve the proposed acquisition at all, that approval extends no further than the expiration of the term of the Puget PPA and the cost support that the PPA provides for the proposed acquisition. Without that cost support from Puget, the proposed acquisition unquestionably fails both the public interest requirement of Section 69-8-421(6)(c)(i), MCA, and the requirement of Section 69-8-421(6)(c)(ii) that the acquisition result in rates that are reasonable and just.

Q. WHY SHOULD THE COMMISSION REQUIRE THAT NORTHWESTERN DEMONSTRATE THROUGH A COMPETITIVE SOLICITATION PROCESS THAT ANY COSTS ASSOCIATED WITH THE 92.5 MW OF CU4 CAPACITY THAT IS BEING PROPOSED TO BE ACQUIRED MEET THE REQUIREMENTS OF § 69-3-1207, MCA, AFTER DECEMBER 31, 2025?

A. NorthWestern characterizes its proposed acquisition of 92.5 MW of CU4 capacity from PSE as an "opportunity purchase" exempted from the competitive procurement requirements of Section 69-3-1207(5)(b) and (6), MCA. However, NorthWestern has not carried its burden of showing that the proposed acquisition is in the public interest, or that it would result in rates that are reasonable and just, at all. NorthWestern has certainly not carried that burden as to its proposed acquisition once the cost support provided by the Puget PPA ends. For these reasons, the Commission should not approve the proposed acquisition, and should certainly not entertain approval of the proposed acquisition for a period beyond the expiration of the cost support provided by the Puget PPA.

To the extent that NorthWestern wishes to extend approval of its proposed acquisition as an electricity supply resource beyond the expiration of the Puget PPA, it will have had ample opportunity to test the value of that acquisition against a competitive procurement process and allow the marketplace to speak. Obviously, the "opportunity purchase" characterization will not apply at that point, assuming for the sake of argument that the characterization applies now. Thus, requiring that approval sunset with the expiration of the Puget PPA and that any subsequent application for approval of the acquisition be supported by the results of a competitive procurement in full compliance with Section 69-3-1207 will ensure that any post-Puget PPA acquisition proposal can meet the requirement that a proposed acquisition be consistent with the requirements and objectives in 69-3-201, and 69-3-1201 through 69-3-1209.

Q. WHY SHOULD THE COMMISSION SPECIFY THE ALLOWED COST OF SERVICE FOR THE ACQUIRED PUGET SHARE OF CU4 CAPACITY?

A. The allowed cost of service for that portion of the acquired Puget interest should be limited to the pro forma cost of service set forth in NorthWestern's Corrected Exhibit ADD-5, striking the footnote in that exhibit (i.e., that portion of the acquired Puget interest that is allowed into rate base), plus NorthWestern's documented historical fuel and variable operation and maintenance costs established in its testimony in support of its Application. Whereas the Company is proposing to track these costs through the PCCAM (and share 10%), for this transaction the costs for the five-year period covered by the PPA with Puget should be fixed. Simply put, the Commission should establish a fixed cost for this generation resource for the five-year period of approval.[10]

[10] See the Direct Testimony of MCC witness David Dismukes for the MCC's proposal for the fixed charge (credit).

The substance of this proposed requirement is to ensure that NorthWestern adheres to the only cost of service it has presented in support of its Application. Put another way, the Commission should place the risk on NorthWestern, rather than on its ratepayers, that the projections on which the cost of service presented in Corrected Exhibit ADD-5 is based prove accurate in reality. This condition also ensures that NorthWestern actually carries its burden of justifying as reasonable and just any capital expenditures and operation and maintenance costs not factored into its cost of service presentation in support of its proposed acquisition.

Q. WHY SHOULD THE COMMISSION SPECIFY THAT NORTHWESTERN RETAINS THE BURDEN OF JUSTIFYING ANY COST RECOVERY RELATED TO THE PROPOSED ACQUISITION ONCE THE PUGET PPA TERMINATES?

A. The Commission's clarification on this point should eliminate any ambiguity as to the scope of an approval – assuming that the Commission determines that any approval is justified on this record – so as to keep any approval strictly co-extensive with the cost support provided by the Puget PPA. Absent such clarification, NorthWestern may attempt to claim in the future that a partial approval of the acquisition for the duration of Puget's cost support somehow changes its burden of establishing the reasonableness and justness of cost recovery beyond that point. To be clear, even an acquisition limited to the duration of Puget's cost support is unsupported – the record in this case demonstrates a very marginal benefit to customers, based on information that appears to be incomplete and skewed. However, if the Commission were to determine to allow the acquisition to proceed, the record clearly does not support an approval for any period in which the cost support provided by the Puget PPA is missing.

Q. WHY SHOULD THE FIXED ALLOWED GENERATION COST FOR THE 92.5 MW OF CU4 CAPACITY BE REDUCED BY THE NET REVENUES FROM THE 45 MW FIVE-YEAR PPA WITH PUGET?

A. A fixed generation cost of service for NorthWestern's 92.5 MW CU4 Capacity Acquisition should be set and that fixed cost of service should be reduced by the net revenues from the five-year 45 MW PPA with Puget. The supporting testimony of NorthWestern witness Markovich as shown on Company Corrected Exhibit KJM-3 has presented the Company's forecasts of net revenue (labeled as "Net Value") for the five-year 45 MW PPA with Puget. The offset related to the five-year 45 MW PPA with Puget should be used because this reflects the impact of the information that NorthWestern has presented to the Commission as the basis for approving the acquisition and its net projected benefits.

Q. HOW SHOULD THE COMMISSION TREAT A PORTION OF NORTHWESTERN'S CALCULATED PUGET PPA "NET VALUE" AS AN ASSURED COST OF SERVICE OFFSET, WHETHER OR NOT THAT "NET VALUE" ACTUALLY MATERIALIZES AS PROJECTED BY THE COMPANY?

A. MCC witness Dismukes is recommending that 50% of the net revenues that have been forecasted by NorthWestern be reflected as an assured partial net benefit from the Puget

PPA. As recommended by Dr. Dismukes, that offset would apply whether or not such actual net revenues from the 45 MW PPA with Puget ultimately materialize as projected by NorthWestern.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments
Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

<u>Partial list of utility cases participated in</u>:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413	
426, 427, 430, 421/	
CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No.	
E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No.	
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No.	
03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363,	
Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM,	
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-	
1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-	
607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-	
060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)

2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015-0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)
Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142*	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322*	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034*	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)

Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Cause No. 45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)
Docket No. D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645 E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
R-2018-3003558, R-2018-3003561	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
Cause No. 45142	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
U-18-043	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
T-03214-17-0305	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. D2018.9.60	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. 4890	Narragansett Bay Commission (Rhode Island PUC)
PUR-2018-00131	Columbia Gas of Virginia (Virginia SCC)
EL18-152-000	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)
A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. D2018.2.12	NorthWestern Energy (Montana PSC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)

PUC Docket No. 49494	AEP Texas, Inc. (Texas PUC)
Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
A-2018-3006061, A-2018-3006062, and A-2018-3006063	Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, and Peoples Gas Company LLC (Pennsylvania PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)
E-01933A-19-0028	Tuscon Electric Power Company (Arizona CC)
G-01551A-19-0055	Southwest Gas Corporation (Arizona CC)
Docket No. 4975	Block Island Utility District d/b/a Block Island Power Company (Rhode Island PUC)
A-2019-3014248	Pennsylvania-American Water Company and Wastewater System Assets of Kane Borough (Pennsylvania PUC)
Docket No. 4994	Providence Water Supply Board (Rhode Island PUC)
19-0791-GA-ALT	Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Ohio PUC)
U-19-070/U-19-071/ U-19-087/U-19-088	Golden Hear Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
20200070-EI	Gulf Power Company (Florida PSC)
20200071-EI	Florida Power & Light Company (Florida PSC)

* Testimony filed, examination not completed
** Issues stipulated
*** Company withdrew case
^ Testimony filed, case withdrawn after proposed decision issued
^^ Issues stipulated before testimony was filed

Northwestern Energy
Remaining Net Book Value: Potential Capital Expenditures for which NorthWestern is Likely to Seek Future Cost Recovery
For NorthWestern's Acquired Share of Colstrip Unit 4 (92.5 MW)
As of Each Date Listed Below

Line No.	Date: As of December 31,	Company Projected Plant	Company Projected Accumulated Depreciation	Net Plant, i.e., Potential Capital Expenditures for which NorthWestern is Likely to Seek Future Cost Recovery Amount	Net Plant, i.e., Potential Capital Expenditures for which NorthWestern is Likely to Seek Future Cost Recovery Amount, Five-Year; Ten-Year and 2042
		(A)	(B)	(C)	(D)
	BEGIN CONFIDENTIAL				
1	[redacted]				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
					END CONFIDENTIAL

Notes and Source:
Northwestern's CORRECTED Exhibit ADD-5 92.5MW

NorthWestern Energy
Revenue Requirement Analysis

Line No.	Description	2021 Year-End	2021 13-Mo Avg	2022 Year-End	2022 13-Mo Avg	2023 Year-End	2023 13-Mo Avg	2024 Year-End	2024 13-Mo Avg	2025 Year-End	2025 13-Mo Avg
1	[redacted]										
2											
3											
4											
5											
6											
7											
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10											
11											
12											
13											
14											
15											
16											
17											
18											

Notes and Source:
NorthWestern's CORRECTED Exhibit ADD-5 92.5MW

Line No.	Description
19	[redacted]
20	
21	
22	
23	
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25	
26	
27	
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29	
30	
31	
32	

NorthWestern Energy
Recalculations of NorthWestern's Revenue Requirements with Incremental Plant Additions Depreciated Through December 31, 2030
For NorthWestern's Acquired Share of Colstrip Unit 4 (92.5 MW)

NorthWestern Energy
Revenue Requirement Analysis

		2021		2022		2023		2024		2025		2026		2027	
Line No.	Description	Year-End	13-Mo Avg	Year-End	13-Mo Avg	Year-End	13-Mo Avg	Year-End	13-Mo Avg	Year-End	13-Mo Avg	Year-End	13-Mo Avg	Year-End	13-Mo Avg
1	[redacted]														
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
13															
14															
15															
16															
17															
18															

Notes and Source:

NorthWestern's CORRECTED Exhibit ADD-5 92.5MW

19	[redacted]
20	
21	
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23	
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NorthWestern Energy
Revenue Requirement Analysis

Line No.	Description	2028 Year-End	2028 13-Mo Avg	2029 Year-End	2029 13-Mo Avg	2030 Year-End	2030 13-Mo Avg
1	[redacted]						
2							
3							
4							
5							
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8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
	NorthWestern's CORRECTED Exhibit ADD-5 92.5MW						
19	[redacted]						
20							
21							
22							
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27							
28							
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30							
31							
32							

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
NorthWestern Corporation	End of 2019/Q4

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2019				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,662	$ 62,565	$ 52,448	$ 311,399
Accumulated depreciation	44,695	35,823	41,765	98,415
December 31, 2018				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,359	$ 60,758	$ 50,325	$ 309,163
Accumulated depreciation	45,894	34,394	41,379	89,734

(7) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our utility plant and asset retirement obligations (ARO). The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2019	2018
Liability at January 1,	$ 40,659	$ 39,286
Accretion expense	2,051	2,031
Liabilities incurred	—	773
Liabilities settled	(46)	(63)
Revisions to cash flows	(215)	(1,368)
Liability at December 31,	$ 42,449	$ 40,659

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation

Name of Respondent NorthWestern Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates.

(8) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2019 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

NorthWestern Energy
Docket No. D2018.2.12
Electric General Rate Review

Montana Environmental Information Center/Sierra Club
Set 5 (061-084)

Data Requests received December 21, 2018

MEIC-065 Witness: Lail Subject: Colstrip Unit 4

Reference Line 17 of page 403.1 of NorthWestern Energy's FERC Form 1 submission for the year ending December 31, 2017. Please explain what the Total Cost figure for Northwestern Energy's share of Colstrip Unit 4 of $104,850,591 represents and why that differs from the Plant in Service figure for the unit.

RESPONSE:

The Total Cost of Colstrip Unit 4 as reported on line 17 of page 403.1 of the FERC Form 1 represents the cost of plant used in generation of electricity at this facility as well as the associated asset retirement obligation ("ARO") balance. This figure differs from the Plant in Service reported in FERC Form 1 as it excludes Construction Work in Process and Plant Acquisition Adjustments and includes the ARO balance. See the following reconciliation:

Item	Colstrip Unit 4
Plant in service FERC Form 1, Page 123.12	**$ 307,711,633**
Plus:	
Asset Retirement Costs	12,880,640
Less:	
Plant Acquisition Adjustment	204,754,039
Construction Work in Process	10,987,643
Total Cost FERC Form 1, Page 403.1, Line 17	**$ 104,850,591**

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF NorthWestern	)	REGULATORY DIVISION
Energy's Application for Approval of	)	
Capacity Resource Acquisition	)	DOCKET NO. 2019.12.101

REDACTED

DIRECT TESTIMONY OF DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE

MONTANA CONSUMER COUNSEL

September 25, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and Director of the Coastal Marine Institute in the College of the Coast and Environment at LSU and a full member of the graduate research faculty at LSU. In addition to my appointment at LSU, I also serve as a Senior Fellow at the Institute of Public Utilities at the Michigan State University where I teach energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. Appendix A provides my academic vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. FOR WHOM ARE YOU APPEARING AND WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Montana Consumer Counsel ("MCC") to provide an expert opinion regarding (1) the acquisition of an additional 92.5 megawatt ("MW") ownership share of Colstrip Unit 4 ("CU4") by NorthWestern Energy ("NorthWestern" or the "Company") from Puget Sound Energy, Inc. ("Puget" or "PSE") and (2) the proposed Purchase Power Agreement ("PPA") between NorthWestern and Puget. My testimony will address the proposed acquisition and its purported benefits.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Overview of the Company's Proposal
- Section IV: Nature of Company's Request
- Section V: Proposed Reserve Fund
- Section VI: Market Test Deficiencies
- Section VII: Evaluation of Benefits
- Section VIII: Increased Ratepayer Cost Exposure
- Section IX: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS?

A. I recommend the Commission reject the Company's CU4 acquisition preapproval request since NorthWestern has neither shown that the proposed acquisition is in the public interest nor that the Company's proposal would result in rates that are reasonable and just. The Company has not shown that the proposed acquisition is both needed and the least cost resource available in the market. The Company has not compared this proposed resource to the results of a competitive bidding process. The purported benefits of the acquisition proposal are tied to a set of highly speculative claims that, in turn, are tied to unreasonable assumptions about CU4's operating costs and the outlook for regional power markets. The Company's supporting analyses do not include the costs of any capital additions for which the Company is likely to seek recovery from Montana ratepayers, thereby understating the capacity acquisition costs. Further, close to half of the proposed capacity acquisition is tied to a PPA with PSE. The Company's request simply asks Montana ratepayers to provide a regulatory backstop for additional CU4 capacity that, in turn, will be marketed to Washington electricity customers. For these reasons, the Commission should reject this proposal.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S RESERVE FUND?

A. Whether or not the Commission authorizes the proposed capacity acquisition, I recommend that the Commission reject the proposed reserve fund. The Fund is a ratemaking measure that should not be part of the current preapproval investigation as it is not even related to the proposed acquisition in CU4. The Commission, to date, has not determined whether or to what extent Montana ratepayers should be responsible for the Company's environmental remediation and plant decommissioning costs for CU4. There has been no Commission determination regarding the prudency of these costs' incurrence. In addition, a significant portion of those costs were incurred during the period between 1986 and 2008, when NorthWestern's share of Colstrip Unit 4 was not devoted to public service. Lastly, specific year-to-year financing of the proposed Fund is left undefined, while additionally presuming prematurely that the liabilities the Fund is designed to address are actually costs for which ratepayers are responsible.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A Yes. If the Commission chooses to approve the capacity acquisition, I offer the following alternative recommendations to bring the proposal more closely into line with the public interest:

- The 92.5 MW capacity acquisition should be approved for a five-year period only. The Company, if it seeks longer term recovery, should (1) request and be required to justify cost recovery at a later date towards the close of the PPA with PSE and (2) should subject the resource to the results of a competitive bidding process to definitively show that the capacity acquisition proposed in this proceeding is the least cost resource available in the market.
- No capital additions should be allowed into rates during the initial five-year period as the Company has not quantified the cost impacts of these capital additions as part of its presentation in support of authorization for its proposed acquisition.[1] The

[1] See Company Response to Data Request MCC-007.

Company's allowed revenue requirement should be fixed at $4.4 million (derived as shown on page 1 of Exhibit DED-3) under the proposed 92.5 MW acquisition.

- The Commission should reject the Company's Reserve Fund proposal in all respects.
- The Commission should require the Company to provide a minimum financial credit to ratepayers that is equal to 50 percent of the market sales, avoided purchases, and PPA revenues estimated in its application. This results in a credit of approximately $4.5 million, derived as shown on page 3 of Exhibit DED-3. When combined with the Company's proposed first-year revenue requirement of approximately $4.4 million, this results in a minimum annual benefit to ratepayers of $140,440.

III. OVERVIEW OF THE COMPANY'S PROPOSAL

Q. PLEASE SUMMARIZE THE COMPANY'S APPLICATION.

A. The Company has filed an original and two supplemental applications in this proceeding. The Company's original application, filed on February 5, 2020, requested approval to acquire a 185 MW ownership share[2] in CU4 from PSE for $1.00.[3] The original application also included a proposal to sell rights associated with a 90 MW share of the proposed acquisition under a PPA to PSE for a five-year period.[4] The remaining 95 MW share of the proposed acquisition was to be used to serve native load

[2] Note that acquisition of an additional 185 MW ownership share in CU4 is equal to acquisition of an additional 25 percent ownership stake in the facility. For convenience purpose the Company often refers to this proposed acquisition of additional ownership interest in CU4 interchangeable in terms of percentages and the associated capacity interest in the facility.
[3] Company's Application, filed February 5, 2020, p.1
[4] *Id.*

and to make opportunity sales to the wholesale market.[5] The Company's original application proposed that the test year revenue requirements not include the portion of the resource used for the Puget PPA and also not include savings generated through avoided market purchases on behalf of its native load customers.[6] However, the Company proposes to place additional purchased power savings and PPA margin revenue in a "Reserve Fund" to address expenditures and costs associated with the Company's existing ownership stake in CU4 related to environmental compliance, remediation, decommissioning, and post-closure costs.[7]

Q. DID THE COMPANY SUPPLEMENT ITS ORIGINAL CU4 ACQUISITION REQUEST?

A. Yes. On April 24, 2020, the Company amended its acquisition request from the original 185 MW request to reflect the announced exercise by Talen Montana, LLC, of its right of first refusal to acquire a portion of the ownership share in CU4 offered by Puget. As a result of Talen's exercise of its right of first refusal, NorthWestern amended its application to request alternative approval in the event of Talen's acquisition to acquire an ownership share in CU4 from PSE equal to at least 92.5 MW for $0.50.[8] The April 24 supplemental filing also proposed under those circumstances to sell rights associated with a portion equal to 45 MW of this acquired ownership back to PSE under a five-year PPA, while using the remaining 47.5 MW share to "directly serve customers."[9] The supplemental application is consistent with the original application with the

[5] *Id.*
[6] *Id.*
[7] *Id.*
[8] Company's Supplemental Application, filed April 24, 2020, p. 1.
[9] *Id.*

exception that the supplemental request contains an alternative that is reduced by half of the amounts identified in the original application. Exhibit DED-1 provides a comparison of the original and April 24 supplemental application filings by the Company.

Q. WHY DID THE COMPANY FILE THE APRIL 24 SUPPLEMENTAL APPLICATION?

A. Various shares of the Colstrip Plant are owned by five companies including NorthWestern, Puget Sound Energy ("PSE"), Portland General Electric Company ("PGE"), the Washington Water Power Company ("Avista"), and Pacific Power & Light Company ("PacifiCorp") through an Ownership and Operation Agreement ("O&O Agreement"). Talen Montana, LLC ("Talen") owns a 30 percent share of CU3,[10] and holds a right of first refusal to acquire an interest in CU4 should it become available.[11] Likewise, the O&O Agreement requires PSE to offer the other co-owners, including Talen, the opportunity to purchase a proportionate interest in its 25 percent share of CU4. At the time of the Company's original application, NorthWestern was the only party that expressed a public interest in the PSE CU4 capacity share. However, before the April 9th acceptance deadline, Talen exercised its right of first refusal under the O&O Agreement to acquire part of the PSE capacity.[12] NorthWestern's April 24 supplement advised the Commission that the 185 MW of Puget's capacity interest in CU4 may then be split equally between NorthWestern and Talen for an acquisition

[10] Company's Application, filed February 5, 2020, at p. 5.
[11] Corrected Direct Testimony of Kevin J. Markovich at 17:13-15.
[12] Corrected Direct Testimony of John D. Hines at 28:7-10.

price of fifty cents each.[13] The Company's April 24 supplement also stated that if Talen failed to consummate the purchase, NorthWestern would continue to request that the Commission approve its original request to purchase the full 185 MW.[14]

Q. HAS THE COMPANY SUBMITTED A SECOND SUPPLEMENTAL FILING TO THE COMMISSION REGARDING THIS PROPOSED ACQUISITION?

A Yes. On August 19, 2020, the Company filed a second supplement to its original filing.[15] This supplement was provided to acknowledge formally that Talen exercised its right of first refusal under the O&O Agreement to acquire half of the PSE capacity. The Company's second supplement includes Amendment No. 1 to the Purchase and Sale Agreement ("PSA") between PSE and the Company.[16] That Amendment No. 1 includes an Amended Exhibit F, a Vote Sharing Agreement among NorthWestern, PSE and Talen as Colstrip owners, which was reported to have been a sticking point in negotiations leading up to the PSA.[17] Finally, the Company's second supplement also introduced the Colstrip Unit 4 Purchase and Sale Agreement between PSE and Talen.

Q. PLEASE DESCRIBE THE PROPOSED PPA BETWEEN PSE AND THE COMPANY.

A. The Company proposes to sell 48.6 percent of its planned acquisition to PSE over a five-year period. This amounts to 45 MW under the Company's supplemental application. The Company will not be obligated to sell any power to PSE under the PPA if CU4 is not operational, regardless of reason. PSE, however, will continue to

[13] *Id.* at 26:14-20.
[14] *Id.* at 28:7-16.
[15] Company's Second Supplemental Application, filed August 19, 2020, at p. 1.
[16] Second Supplemental Direct Testimony of John D. Hines at 2:20.
[17] Company's Response to Data Request MEIC-015, attachment "Operations July 2020.pdf," at 5.

make monthly "base" payments that cover its share of the CU4 fixed costs.[18] The Company proposes that the portion of CU4 capacity that is used to support the PPA not be part of its calculated revenue requirement under its PCCAM. NorthWestern has instead proposed accounting adjustments that would remove from rates the five-year PPA transaction.[19] The Company forecasts $54.0 million in total sales revenues over the five-year term of the 45 MW PPA with PSE.[20] The PPA allows the Company to deliver energy to PSE at either Colstrip or at the Mid-Columbia ("Mid-C") trading hub at the same sales price.[21] Lastly, the PPA contains an hourly floor on the sales price that Puget will pay based on variable costs incurred when CU4 is operating at its minimum level.[22]

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RESERVE FUND.

A. The Company proposes to establish a Reserve Fund against which it proposes to charge unquantified future environmental compliance, remediation, decommissioning, and post-closure costs associated with its existing ownership stake in CU4. The Company proposes that the Reserve Fund would be funded by (1) 90 percent of the savings from the PCCAM regardless of source and (2) the net revenue from the PPA with PSE.[23] The Company proposes to capture what it calls a "regulatory asset," consisting of O&M expenses for compliance with the 2012 Administrative Order on Consent and coal combustion ash residuals regulations as well as future decommissioning and post-

[18] Company's Response to Data Request MCC-078.
[19] Corrected Direct Testimony of Kevin J. Markovich at 11:8.
[20] *Id.*, Corrected Exhibit KJM-3.
[21] Corrected Direct Testimony of John D. Hines at 14:4-6.
[22] Corrected Direct Testimony of Kevin J. Markovich at 11:12-14.
[23] Corrected Direct Testimony of Crystal D. Lail at 4:6-13.

closure costs as those costs may be incurred.[24] Costs "captured" in this regulatory asset are those in excess of environmental compliance and remediation costs included in the Company's recent rate case.[25] During the term of the PPA, NorthWestern proposes to "capture" these costs "as incurred" and charge the costs accumulated in the "regulatory asset" against the Reserve Fund and reimburse itself.[26] Following expiration of the PPA, on an annual basis, the Company says that it will submit a compliance filing requesting to charge any costs in the regulatory asset against the Reserve Fund.[27]

IV. NATURE OF THE COMPANY'S REQUEST

Q. IS THE APPROVAL PERIOD ASSOCIATED WITH THE COMPANY'S PROPOSED CAPACITY ACQUISITION CLEAR?

A. No. The Company's filings obfuscate the full scope of its request in this proceeding. Much of the discussion and the overwhelming part of the analysis supporting the Company's various filings concentrate on a five-year period since this is the period coincident with the PSE PPA. However, unless the Commission explicitly specifies a five-year period for cost recovery approval in this proceeding, NorthWestern may be expected to argue that Commission approval of the CU4 capacity acquisition request implies approval of recovery of all costs for the duration of the resource's useful life and any remaining undepreciated capital expenditures, not limited to the five-year term of the Puget PPA.[28] Thus, while the Company's analytical support for this capacity

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[24] *Id.* at 6:11-18.
[25] *Id.* at 6:14-17.
[26] *Id.* at 6:20-23.
[27] *Id.* at 6:20-7:3.
[28] Corrected Direct Testimony of John D. Hines at 5:1-5.

acquisition request is focused on near-term outcomes (i.e., avoided market purchases, market sales, PPA sales revenues), the Commission's approval will likely be argued to provide for cost recovery over a longer and indeterminate period, unless the Commission restricts its approval. Over time, the Company's own workpapers show that CU4 will become more expensive to operate and require additional capital investment.[29] Likewise, over time, regional wholesale power markets may become more competitive and diverse, which will result in greater pricing stability and lower overall prices. Thus, any arguable customer benefits from this CU4 capacity addition diminish rapidly after the five-year term of the Puget PPA. **#BEGIN CONFIDENTIAL#** [redacted] **#END CONFIDENTIAL#**

Q. WILL THIS ACQUISITION CREATE LONG-TERM RATEPAYER FINANCIAL VALUE?

A. No. The Company estimates that the proposed acquisition will result in added long term costs when compared against the Company's existing resource portfolio. Specifically, the Company estimates that the proposed 92.5 MW addition will result in more than $14 million in additional net costs to ratepayers over 20 years.[30] The Company, however, dismisses these results as "unrealistic," asserting that simply maintaining its current resource portfolio without any additional capacity assets is not

[29] Corrected Direct Testimony of Andrew D. Durkin, Corrected Exhibit ADD-5.
[30] Corrected Supplemental Testimony of Bleau J. LaFave at 50:1-5.

a reasonable option.[31] This argument represents a false dichotomy. It is unsupported by any analysis of market alternatives, and the empirical analyses underlying the Company's application demonstrate that the capacity resource acquisition it proposes in this case will impose higher costs on ratepayers than the status quo.

Q. IS IT REASONABLE FOR THE COMMISSION SIMPLY TO ASSUME THAT THE COMPANY HAS PROPOSED A SHORT-TERM CAPACITY ACQUISITION BECAUSE THE COMPANY'S SUPPORT FOR ITS APPLICATION IS LIMITED TO THE NEAR TERM?

A. No. Unless the Commission specifically limits any authorization, it might be inclined to grant, the Company will likely argue that any authorization for the proposed acquisition should be viewed as a life-of-asset authorization. So viewed, the Company's application should be rejected because the longer run benefits of this proposal do not exceed its costs. The Company's application and supplements, however, place considerable emphasis on near term benefits. As I will show later in my testimony, even the short-term benefits promoted by the Company are at best ephemeral, to the extent that they exist at all. Over the long run, the additional CU4 capacity will not generate benefits that exceed its costs. Once the PSE PPA expires, that fixed cost support for the Company's proposed CU4 acquisition will disappear. Unless the Commission specifically limits its authorization to the five-year term of the PSE PPA, the Company may be expected to argue that the replacement for the cost

[31] *Id.,* at 50:3-5.

support provided by the PSE PPA will have to come from Montana retail electricity customers.

Q. HAS THE COMPANY EXAMINED THE SHORT-TERM CAPITAL EXPENDITURES THAT MAY NEED TO BE MADE FOR THIS ADDITIONAL CU4 CAPACITY?

A. Yes, and I have provided a summary of that analysis in Confidential Exhibit DED-2. Page 1 of this exhibit charts historic and projected capital additions at both CU3 and CU4. Both units have historically seen annual average capital expenditures of close to $24 million per year.[32] **#BEGIN CONFIDENTIAL#** [redacted] **#END CONFIDENTIAL#** The Company's current five-year PPA calculations, however, have not included any of these capital expenditures as a cost that will have to be incurred by ratepayers in the near term (prior to 2025).[33] Page 2 of Exhibit DED-2 estimates the revenue requirements for these capital investments, while page 3 of Exhibit DED-2 presents the effects of the proposed growth of plant in service on the total annual revenue requirement associated with the acquisition. The analysis indicates that the Company will seek to require Montana ratepayers to cover additional costs through an increase in the revenue requirement needed to support these incremental capital expenditures. **#BEGIN CONFIDENTIAL#** [redacted]

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[32] Corrected Direct Testimony of Michael J. Barnes, Exhibit MJB-12.
[33] *See,* Company's Updated Response to Data Request MEIC-079.

[redacted] **#END CONFIDENTIAL#**

Q. DOES THE PSE PPA MAKE THE ECONOMICS OF THE PROPOSED ACQUISITION APPEAR MORE FAVORABLE THAN THEY ACTUALLY ARE OVER A LONGER TERM?

A. Yes. The PSE PPA underscores another problem with the proposed resource acquisition: the Company claims it needs peaking resources, which are generally not the baseload, coal-fired steam generation that is CU4. Steam turbine generation resources of this type are designed to run all the time, not part of the time like a natural gas combustion turbine. The proposed capacity addition will leave a considerable amount of underutilized generation to sell as energy in the market at times when it is unneeded for native load. Indeed, a simple comparison of the Company's estimated benefits from market sales relative to estimated benefits from reduced market purchases show that upwards of more than 89 percent of total generation revenue from the facility will not be used to serve retail customers.[34] The Company needs this PPA, therefore, to justify the acquisition in the near term. As I will explain in Section VI of this testimony, without the fixed cost contribution being made by PSE under the PPA, the CU4 capacity would be uneconomic over any forecast horizon.

[34] Corrected Supplemental Testimony of Kevin J. Markovich at 19.

Q. DOES THE ACQUISITION PROPOSED BY THE COMPANY IMPOSE SUBSTANTIAL RISKS ON MONTANA RATEPAYERS?

A. Yes. The Company's capacity acquisition proposal rests on several speculative benefits that include (1) market sales, (2) avoided wholesale purchases, and (3) PPA revenues. Each of these claimed benefits is a function of (a) the Company's operational efforts and (b) the market. Commission approval of the Company's acquisition of 92.5 MW of CU4 capacity from Puget as proposed by NorthWestern would impose substantial performance and market risk on Montana ratepayers. For example, if the Company's (or Talen's) operation of CU4 is less efficient than NorthWestern has projected in this proceeding, under NorthWestern's proposal, Montana ratepayers would bear the costs of those less efficient operations. As I will show later in my testimony, CU4, while relatively efficient compared to other similar units in the Western Interconnect, is still not as competitive with the market as it has been in years past, and is likely to become even less competitive over time given recent variable cost trends. Further, Western wholesale power markets are becoming more efficient and more integrated,[35] increasing the dispatch of more thermal efficient renewable and natural gas generation. These trends will make it increasingly difficult for steam generators like CU4 to remain economically competitive.

[35] See, "About," Western Energy Imbalance Market, available online at: https://www.westerneim.com/Pages/About/default.aspx.

Q. IS TALEN TAKING A RISK IN ACQUIRING ITS OWNERSHIP SHARE OF THIS CU4 CAPACITY?

A. Yes. However, Talen is an unregulated merchant power supplier not a regulated utility. Talen's ownership share is not being supported by captive retail ratepayers and the risk of acquiring this ownership share rests with Talen and its shareholders.

Q. IS THERE ANY WAY TO MITIGATE THIS RATEPAYER RISK?

A. Yes, this risk can be allocated to the party which can best avoid or diversify away from it, and that is the Company. My primary recommendation is that the Commission should reject the Company's acquisition proposal. However, if the Commission nonetheless authorizes NorthWestern to proceed with the acquisition, it should require the Company to provide a minimum annual credit to ratepayers for the purported benefits included in this proposal. A 50 percent credit related to market sales, avoided market purchases and PPA revenues included in this application would amount to approximately $4.7 million annually. This credit must be passed directly to ratepayers, not siphoned off to a Reserve Fund.

Q. HAVE YOU PREPARED AN ESTIMATE FOR THIS RECOMMENDED ANNUAL RATEPAYER CREDIT?

A. Yes. Exhibit DED-3 presents my estimate of the minimum annual ratepayer credit that should be provided to ratepayers through the PCCAM. As shown by Exhibit DED-3, page 1, the Company estimates a first-year revenue requirement associated with the proposed acquisition to be approximately $4.4 million. On page 2, I estimate a minimum benefit to ratepayers equal to 50 percent of the Company's estimated benefits arising from the proposed acquisition related to market sales, avoided market purchases, and PPA revenues. Finally, page 3 combines the elements of page 1 and 2, along with the remainder of the Company's estimated costs and benefits that will accrue to the PCCAM from the proposed acquisition. I estimate that the Company should flow a minimum annual credit through the PCCAM of $4.5 million. When this minimum annual credit is netted against the Company's proposed first year revenue requirement of $4.4 million, this results in a benefit to ratepayers of $140,440.

V. PROPOSED RESERVE FUND

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RESERVE FUND.

A. The proposed reserve fund is an entirely new ratemaking proposal that has been injected by the Company into this pre-approval request, even though the object of the fund is unrelated to the proposed acquisition. The Company requests that the Commission entirely re-purpose the benefits that its ratepayers currently receive from (a) wholesale market power sales and (b) avoided wholesale market purchases. In the future, the Company requests that these financial benefits, rather than being utilized as bill credits, be used to fund future environmental and decommissioning costs that are unknown, unquantifiable, and unrelated to this proposed acquisition. The Company's proposal, in effect, requests the Commission set up a ratepayer-funded bank account, with a broad and open-ended purpose, that has no restrictions, and has no target fund balance.

Q. WHAT KIND OF COSTS DOES THE COMPANY PROPOSE TO RECOVER FROM THIS RESERVE FUND?

A. The Company states that this fund will be applied to pay future environmental compliance, remediation, decommissioning costs, and other post-closure costs for its current interest in CU4.[36] The Company offers up potential Colstrip coal ash disposal pond remediation costs as an example of the types of expenses that will be paid for with ratepayer proceeds into this fund.[37]

Q. PLEASE DISCUSS THE SPECIFIC RATEPAYER FUNDS THAT WILL BE USED TO FINANCE THIS PROPOSED RESERVE FUND.

A. The Company proposes to utilize two revenue streams that would otherwise be passed along to ratepayers as credits or savings under the PCCAM as currently formulated. First, all net revenues, cost reductions, or financial gains associated with the Company's proposed five-year PSE PPA will be deposited into the Reserve Fund.[38] Second, the Company proposes to place 90 percent of all savings accrued through the Company's PCCAM into the proposed reserve fund.[39] Thus, all gains on wholesale sales or reduction in future power costs that arise from any Company generating resource, not just those related to CU4, will cease to be credited back to current period ratepayers, but will be put into this deferred account for future application to costs that the Commission has not yet determined to have been prudently incurred or to be properly recoverable from Montana retail electricity consumers.

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[36] Corrected Direct Testimony of Crystal D. Lail at 4:6-9.
[37] Corrected Direct Testimony of Michael J. Barnes at 8:6-16.
[38] Corrected Direct Testimony of Crystal D. Lail at 4:13.
[39] *Id.* at 4:10-13.

Q. PLEASE DISCUSS THE SIZE OF THESE POTENTIAL PPA NET REVENUES.

A. The Company estimates that the proposed PPA with PSE will generate approximately $3.6 million in net revenues over five years.[40] Likewise, the Company estimates that the proposed acquisition will reduce its annual power costs recovered from ratepayers through the PCCAM by $8.5 million.[41] These PCCAM benefits exceed by $4.1 million the proposed PCCAM offset of $4.4 million proposed by the Company that as discussed earlier, are not "benefits" but amounts needed to cover the CU4 acquisition's annual revenue requirement.

Q. CAN YOU SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S RESERVE FUND PROPOSAL?

A. Yes. The Company's Reserve Fund proposal suffers from several deficiencies, including:

(1) The proposed Reserve Fund is a ratemaking proposal, unrelated to the proposed resource acquisition, and is not relevant to the issue of whether the proposed CU4 capacity acquisition is in the public interest.

(2) The proposed Reserve Fund ignores substantial issues regarding the assignment of environmental remediation liability that the Commission has not considered, and that should not be considered in this proceeding.

(3) The cost level associated with future environmental liabilities and decommissioning, or even the date these will occur, are not currently known.

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[40] Corrected Supplemental Testimony of Kevin J. Markovich, Corrected Exhibit KJM-3.
[41] Corrected Supplemental Testimony of Kevin J. Markovich at 19.

(4) The method by which the proposed Reserve Fund will be financed shifts performance and market risk away from the Company and onto ratepayers.

Q. WHY SHOULD THE PROPOSED RESERVE FUND NOT BE PART OF THE CURRENT PROCEEDING?

A. The Company is seeking approval of the proposed acquisition of PSE's existing share of CU4 pursuant to MCA § 69-8-421.[42] From a policy perspective, this statute emphasizes determinations of the public interest.[43] However, the proposed Reserve Fund is a ratemaking proposal not required for the Company to acquire the proposed additional interest in CU4. Furthermore, the purported need for the proposed Reserve Fund does not arise from the proposed acquisition, as it addresses existing Company decommissioning and remediation liability.

Q. WHAT SUPPORT DOES THE COMPANY OFFER FOR THIS RESERVE FUND PROPOSAL?

A. The Company attempts to tie this request to post-closure costs and the environmental liability associated with uncertain future coal ash remediation. However, the terms of the purchase with PSE state that it will retain responsibility for all post-closure costs and the environmental liability associated with the acquired interest in CU4.[44] Instead, the Company states that the proposed acquisition and reserve fund will "provide[] a revenue stream to help fund environmental and decommissioning costs associated with <u>NorthWestern's existing 220 MW of CU4.</u>"[45] The Company's existing ownership of

[42] NorthWestern Energy's Application for Approval of Capacity Resource Acquisition at 3.
[43] MCA § 69-8-421(6)(c)(i).
[44] Corrected Direct Testimony of John D. Hines at 12:4-9.
[45] *Id.* at 21:6-11, *emphasis added.*

CU4, and its remediation liabilities, are unrelated to the proposed acquisition and any determination of whether it is in the public interest.

Q. LET'S TURN TO YOUR SECOND CONCERN. ARE THERE VALID POLICY REASONS FOR THE COMMISSION TO DECLINE TO ADDRESS ISSUES ASSOCIATED WITH THE REMEDIATION LIABILITY OF THE COMPANY'S EXISTING OWNERSHIP SHARE OF CU4?

A. Yes. The Commission has not decided the degree, if any, to which the Company's environmental remediation and decommissioning liabilities should ultimately be allocated to retail customers. CU4 has changed hands several times in its 34-year operational history. There has been no finding that these costs were prudently incurred. Further, for a significant portion of this history, the facility was operated on a merchant basis. From its commissioning in 1986 to January 1, 2009, Colstrip Unit 4 had "never been devoted to public service."[46] The Commission's determination as to whether NorthWestern's rates and charges are reasonable and just requires an evaluation of these considerations on an appropriately developed evidentiary record. Importantly, my testimony in this case does not offer any recommendations or findings by the Commission concerning cost responsibility or any environmental remediation, decommissioning or similar costs at this time. The issue is being raised simply to invite the Commission's attention to it as one that (1) has yet to be decided and (2) should be decided as part of a general rate case, and on a fully developed evidentiary record. The

[46] *In the Matter of an Application by NorthWestern Corporation for Approval of its Interest in Colstrip Unit 4 as an Electricity Supply Resource under Certain Terms and Conditions Including Certain Treatment of Net Operating Losses,* Docket No. D2008.6.69, Order No. 6925f at ¶ 247.

Company's proposed Reserve Fund should not be used as a Trojan horse to shift total CU4 environmental responsibility to Montana ratepayers through this preapproval.

Q. LET'S TURN TO YOUR THIRD CONCERN. PLEASE EXPLAIN HOW THE COMPANY ESTIMATED THE FUTURE DECOMMISSIONING COSTS ASSOCIATED WITH CU4.

A. The Company has reviewed publicly available decommissioning studies and concluded that decommissioning costs for coal facilities average $29,469 per MW of installed capacity.[47] For CU4, combined with its sister Unit 3, this translates into an estimated decommissioning requirement of approximately $43.6 million, or $6.5 million for the Company's ownership share. However, in this analysis the Company found that actual decommissioning costs can range from as low as $19,265 per MW to as much as $45,432 per MW.[48] The Company's estimates of future decommissioning requirements are nothing more than estimates, and actual requirements are not known at this time, with particular uncertainty associated with future expenses required to remediate Colstrip coal ash disposal ponds.

Q. WHY WOULD THE CREATION OF THE RESERVE FUND SHIFT REGULATORY RISK FROM THE COMPANY ONTO RATEPAYERS?

A. The creation of a Reserve Fund will simply function as a "catch all" account that will take an unknown amount of money away from ratepayers to pay for unknown costs that may or may not arise at an unknown future date. NorthWestern's proposed Reserve Fund may serve to insulate the Company from a substantial portion of the risks

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[47] Corrected Direct Testimony of Michael J. Barnes, Exhibit MJB-9.
[48] *Id.*

that are associated with these regulatory unknowns by transferring the risks associated with their occurrence presumptively onto ratepayers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ESTABLISHMENT OF THE PROPOSED RESERVE FUND?

A. I recommend that the Commission reject the proposed reserve fund given the concerns and deficiencies I discussed earlier. The Fund is a ratemaking measure that is not necessary to approve to determine whether acquiring additional capacity at CU4 is in the public interest. The Commission, to date, has not defined the environmental liability for which Montana ratepayers should be responsible. The Fund is entirely speculative in terms of the magnitude and nature of its future costs.

VI. MARKET TEST DEFICIENCIES

Q. DOES THE PROPOSED ACQUISITION ARISE FROM A COMPETITIVE BIDDING PROCESS?

A. No. The Company has characterized its proposed acquisition as an "opportunity resource", exempted from the competitive solicitation requirements of Section 69-3-1207, MCA.[49] The proposed acquisition was not identified in the Company's 2019 Resource Procurement Plan filed with the Commission in late August of last year.[50] In addition, the 2019 Plan discusses the intent to evaluate resources submitted in response to the issuance of an initial competitive solicitation for up to 400 MW of long-term capacity followed by additional solicitations.[51]

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[49] Corrected Direct Testimony of John D. Hines at 6:11-14.
[50] 2019 Electric Supply Resource Procurement Plan.
[51] *Id.*, at 1-13.

Q. IS THE COMPANY IN THE PROCESS OF TESTING THE MARKET FOR COMPETITIVELY SOURCED RESOURCES?

A. Yes. In December 2019, NorthWestern announced plans to issue a request for proposals ("RFP") on January 31, 2020 for about 280 megawatts of dispatchable capacity resources starting in 2023.[52] This RFP is based upon the Company's 2019 Plan, which argues that the Company faces a "capacity deficit" of 645 MW relative to estimated levels of Company-owned generation that would be required to meet a one-day-in-ten-year resource adequacy standard relying exclusively on Company-owned generation.[53] The RFP, however, noted that this capacity need (deficit) may be considerably lower, by about 170 MW, if the Company were to acquire a 185 MW unnamed "opportunity resource."[54]

Q. WHAT WAS THE RFP TIMELINE FOR REVIEW?

A. The RFP indicated a series of site walks, conference calls, and question submissions from potential bidders. Final proposals were due from bidders by May 8, 2020. The initial proposal reviews were scheduled to occur in the second and third quarters of 2020, with more detailed evaluations to be undertaken in the remainder of 2020:Q3 and continuing through 2020:Q4. Final resource/bid selection was scheduled for the first quarter of 2021.[55]

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[52] Company's Response to Data Request MEIC-025, Attachment "MEIC 25 a 2020 Capacity RFP" at 3.
[53] *Id.*
[54] *Id.* at 4.
[55] *Id.* at 19.

Q. WHY WAS THE PSE SHARE OF CU4 NOT INCLUDED OR COMPARED TO RESOURCES INCLUDED IN THE CURRENT COMPETITIVE SOLICITATION?

A. The Company claims that the nature of the proposed acquisition makes it "nearly impossible" for it to have been included as part of a competitive solicitation.[56] The Company, for instance, notes that the proposed PPA with PSE, the transmission component of the deal, and the proposed Reserve Fund are all critical components of the CU4 acquisition and are components that would have been difficult to include in a competitive bidding process.[57]

Q. DO YOU AGREE THAT CU4 IS NOT COMPARABLE WITH OTHER COMPETITIVE RESOURCES?

A. No. The "unique components" the Company references should not preclude the proposed acquisition from inclusion in a competitive solicitation. For example, the proposed PSE PPA merely reduces the amount of generation capacity available to serve native load. Further, the Company would have to allocate transmission costs to the delivery of on-system generation and would have to charge itself for transmission for off-system sales. The Company has chosen to characterize the transmission component of this transaction as separate from the capacity acquisition, even though it will need the transmission component of this transaction in order to integrate its proposed capacity acquisition to serve load.[58] Finally, the proposed Reserve Fund is not a necessary part of the proposed acquisition.

[56] Corrected Direct Testimony of John D. Hines at 6:12-14.
[57] *Id.* at 6:14-18.
[58] Company's Response to Data Request MCC-018.

Q. DOES THE FAILURE TO TEST THE MARKET UNDERMINE THE COMPANY'S ASSERTIONS ABOUT THE CU4 ACQUISITION?

A. Yes. The Company claims the proposed CU4 acquisition is the "least cost resource" at its disposal.[59] This assertion cannot be evaluated by the Commission since no alternatives have been compared to the CU4 proposal.

Q. IS THERE A PRECEDENT FOR THE USE OF COMPETITIVE SOLICITATIONS IN MONTANA?

A. Yes. I have reviewed several Montana statutes on this subject. I am not offering a legal opinion on those statutes, but my reading of the plain intent of the statutes, from a policy analyst's perspective, is that there is a strong preference toward the use of market tests to secure new generation resources. For instance, Section 69-8-421(6)(c)(ii), MCA requires that the Commission find that the proposed procurement of a capacity resource is "consistent with the objectives in" Sections 69-3-201 and 69-3-1201 through 69-3-1209. Section 69-3-1204, MCA, requires NorthWestern to perform the following analyses to support resource acquisitions:

> (i) an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs in accordance with 69-3-1209;
>
> (ii) an annual electric demand and energy forecast developed pursuant to commission rules that includes energy and demand forecasts for each year within the planning period and historical data, as required by commission rule;
>
> (iii) an assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to commission rules;
>
> (iv) an assessment of the need for additional resources and the utility's plan for acquiring resources;

[59] Corrected Direct Testimony of Bleau J. LaFave, 3:10-15.

> (v) the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with 69-3-1207; and
>
> (vi) descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the commission.

These provisions strongly support the proposition that any previously deregulated utility seeking approval of an electric supply resource must have subjected the proposed resource to a competitive solicitation as required in Section 69-3-1207, MCA. Section 69-3-1207, MCA also reinforces this requirement, providing detailed descriptions of information a public utility must provide the Commission prior to conducting a competitive solicitation.

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE COMPANY'S FAILURE TO INCLUDE THE PROPOSED ACQUISITION IN ITS RECENTLY ISSUED RFP FOR DISPATCHABLE CAPACITY?

A. Yes. Several distortions in the current RFP process have potentially arisen in light of the Company's failure to include the proposed acquisition within its recently issued RFP for dispatchable capacity. Rather than seek 450 MW of dispatchable capacity indicated by the Company's 2019 Plan, the Company has limited its RFP to only 280 MW due to a then-unnamed opportunity purchase of 185 MW intended to refer to the current proposed acquisition. However, even if the Commission approves the current proposed acquisition, it should be recognized that the Company's current proposed acquisition is limited to 92.5 MW, only 47.5 MW of which will be available to the Company to meet retail requirements for the first five years.

Q. HOW DOES THIS IMPACT THE COMPANY'S CURRENT RFP FOR DISPATCHABLE CAPACITY?

A. Even if one were to accept the Company's arguments about the extent of its capacity needs, the merits of meeting even part of that need with this acquisition, instead of the resources competing in the RFP, are not being adequately tested. This is solely because the Company failed to include the proposed acquisition in its RFP. This problem is entirely of the Company's making as a result of its failure to follow established processes for securing additional generation capacity.

Q. SHOULD THE COMMISSION DEFER ANY DECISIONS ON THE ADDITION OF ANY NEW CAPACITY RESOURCES UNTIL THE COMPANY HAS THOROUGHLY TESTED THE MARKET?

A. Yes. The Commission should not approve the current CU4 capacity acquisition request since it does not comply with the spirit (and arguably not with the letter) of the state policy preference for competitive bidding when preapproval of resources is requested. The Company's failure to seek competitive bids has also hampered the Commission's ability to adequately review the claimed benefits of the proposed acquisition against market alternatives. This is especially true since the Company is actively reviewing competitive bids for dispatchable capacity, which it claims that the proposed capacity acquisition provides.

VII. EVALUATION OF BENEFITS

A. Claimed Market Price Volatility Avoidance Benefits

Q. PLEASE DISCUSS NORTHWESTERN'S CLAIMS CONCERNING VOLATILITY BENEFITS OF THE CU4 ACQUISITION.

A. The Company claims that one of the key parts of the proposed acquisition is its ability to decrease the Company's "reliance upon an increasingly short capacity market."[60] The Company claims that its current generation shortfall leaves it significantly exposed to volatile wholesale energy prices.[61]

Q. IS THIS THE FIRST TIME THE COMPANY HAS EXPRESSED CONCERNS ABOUT ITS WHOLESALE ENERGY MARKET EXPOSURE?

A. No. The Company's 2019 Plan discussed its supposedly heavy market exposure relative to other regional utilities.[62] The 2019 Plan asserts that regional coal plant retirements are making the wholesale market less reliable and prices more volatile.[63]

Q. HAS THE COMPANY PROVIDED ANY EXAMPLES OF THIS MARKET VOLATILITY?

A. Yes. The Company notes that in early March 2019, Mid-C peak power prices reached nearly $1,000 per MWh for the first time since 2000, with natural gas also reaching record high prices.[64] In this filing, the Company provided a back-cast of its potential past PPA revenues that would have arisen during this market event had the PPA been in place at that time, and states that the proposed PSE PPA would have generated more

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[60] Corrected Direct Testimony of John D. Hines at 4:3-5.
[61] Corrected Direct Testimony of Bleau J. LaFave at 13:17-30; citing 2019 Plan at 1-1.
[62] 2019 Plan at 2-13.
[63] 2019 Plan at 1-1.
[64] *Id.*

than $3.7 million in value over the period of March 3 and 4,[65] 2019 alone had the contract been in place during this extreme super-spike in wholesale energy prices.

Q. ARE SUPER-SPIKES IN WHOLESALE ENERGY PRICES COMMON FOR THE MID-C HUB?

A. No. Page 1 of Exhibit DED-4 presents historic Mid-C prices for the period January 2018 through early September 2020. The exhibit shows that while wholesale energy prices do exhibit some volatility, the March 2019 event was a unique price spike relative to recent trends. The March 2019 event, for instance, represented a prominent deviation from other recent high price periods such as the summer of 2018 and the winter of 2019 when for short periods wholesale energy prices exceeded $200 per MWh.

Q. HAVE WHOLESALE ENERGY PRICES BECOME MORE STABLE OVER THE PAST YEAR?

A. Yes. Page 2 of Exhibit DED-4 presents Mid-C prices for the period May 2019 through July 2020. In this more recent period, prices have been much more stable, never exceeding $70 per MWh. Also noticeable in this chart is the fact that wholesale energy prices have been trending downwards throughout most of the year, falling from more than $50 per MWh in late October 2019 to a June 2020 low of less than $5 per MWh.

Q. WHAT CAUSED THE MARCH 2019 PRICE SPIKE?

A. There were several simultaneous factors that drove this event. One factor driving the wholesale price spike was weather. An Arctic blast blanketed the northern U.S.,

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[65] Corrected Direct Testimony of Kevin J. Markovich at 16:2-4.

pushing temperatures to monthly record lows during March 2019.[66] Much of Montana experienced low temperatures between minus-20 to minus-40 degrees Fahrenheit, with wind-chills approaching minus 50 degrees.[67] These abnormally low temperatures coincided with a regional natural gas system strained from an earlier rupture of a pipeline in British Columbia, and reduced availability of hydro, wind, and transmission assets for a variety of reasons.[68] While the Company claims the super-spike pricing event was driven by "decreased market liquidity" it does acknowledge the role that these unique events played on regional energy markets.[69]

Q. PLEASE DISCUSS THE RECENT MID-C PRICING TRENDS.

A. Exhibit DED-4, page 3, presents daily on-peak Mid-C prices for the period July 1, 2020 through September 4, 2020. During this period, the Mid-C Hub experienced two events periods of abnormally high on-peak prices. First, during August 14 to 19, and then a second spike in prices on September 2. Both of these events are tied to the recent wildfires in the Western US. However, during both events, Mid-C prices, while higher than prior month averages, were still contained to under $200 per MWh, and prices have since returned to prior trading ranges.

Q. HAVE YOU EXAMINED MID-C MARKET PRICES RELATIVE TO THE COST OF NATURAL GAS FIRED GENERATION?

A. Yes. Exhibit DED-5 presents the results of an analysis of the implied capacity premium present within the Mid-C wholesale market for the period March 2013-early September

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[66] Pricing Event of March 2019 – System Impact Assessment (August 20, 2019); WECC.
[67] Livingston, Ian (March 4, 2019); "Historically cold March temperatures are freezing a large part of the Lower 48;" Washington Post.
[68] Pricing Event of March 2019 – System Impact Assessment (August 20, 2019); WECC at pp. 6-10.
[69] 2019 Plan at 1-1.

2020. This analysis examines the average daily Mid-C prices compared against the implied fuel costs of an average natural gas combined cycle generation unit. This analysis finds that, in general, there exists limited premium in the Mid-C market over variable fuel costs.

Q. WHAT DOES THIS ANALYSIS IMPLY?

A. The results shown on Exhibit DED-5 imply that, notwithstanding isolated peak events, the volatility expressed in Mid-C markets is generally manageable and not as extreme as suggested by the Company. The avoidance of this wholesale market pricing volatility, in and of itself, does not serve as justification for increasing the Company's capacity position in CU4.

Q. HOW DO THESE GENERAL RESULTS COMPARE TO CU4'S PERFORMANCE AND POTENTIAL BENEFITS?

A. Exhibit DED-6 examines the reported 2019 operating statistics of CU4 against the average market clearing heat rate implied by Mid-C trading. This analysis finds that natural gas prices would have to increase to levels in excess of at least $2.38 per MMBtu to provide a benefit for additional CU4 capacity. Natural gas prices of this level were seen for a limited period during the 2019/2020 winter but have not been consistently reached since January 2015.

Q. HAVE YOU CONDUCTED ANY OTHER ANALYSIS OF CU4?

A. Yes. Exhibit DED-7 examines the potential margin benefits of CU4 during the years 2015 to 2019 (five years). This analysis compares Mid-C prices against reported CU4 variable operating costs by S&P Global to determine an extra margin created during this period. This margin is then compared to the facility's annual fixed costs to determine a margin net of fixed costs. Exhibit DED-7 shows that CU4 (the entire unit) generated approximately $9.4 million in annual average net margin for the years 2015 through 2019. Prorating this calculated margin net of fixed costs for NorthWestern's proposed 92.5 MW ownership share acquisition to the 740 MW total capacity of CU4 translates to a historical average net annual margin of less than $1.2 million associated with the proposed acquisition of an additional 92.5 MW interest in CU4. This relatively small benefit does not offer any compelling support for the acquisition of additional CU4 capacity, particularly where potential alternatives to the proposed acquisition have not been examined.

Q. WHAT DOES YOUR REVIEW OF CU4'S HISTORICAL MARGINS NET OF FIXED COSTS LEAD YOU TO CONCLUDE ABOUT NORTHWESTERN'S PROPOSED ACQUISITION OF AN ADDITIONAL INTEREST IN CU4?

A. The historical margin net of fixed costs appears likely to diminish going forward. CU4 fixed costs are likely to increase above their historical levels during the 2015-2018 period for a variety of reasons. The causes of expected increases in CU4's fixed costs include increasing challenges in maintaining compliance with EPA's Mercury and Air Toxics Standard and other air quality standards, and upcoming major repairs to CU4. At the same time, as noted by Puget in its Application to the Washington Utilities and Transportation Commission for authorization to sell its share of CU4 to NorthWestern, market prices of power are declining in the Northwest as more gas-fired and renewable generation enters the market.[70] The combination of increased fixed costs and lower market prices strongly suggests diminishing future net margins. This, in turn, suggests that even the near-term projected benefits of the proposed acquisition (including the cost support furnished by the PSE PPA) are likely overstated.

B. Claimed Sales Revenue Benefits

Q. PLEASE SUMMARIZE THE COMPANY'S CLAIMED CU4 SALES AND PURCHASE BENEFITS.

A. The Company claims that the CU4 acquisition will facilitate a lower level of market purchases and a higher level of market sales.[71] In total, the Company asserts that the proposed capacity acquisition, if approved, will reduce overall costs since net market sales revenues (which are credits to ratepayer bills) will increase and overall market purchases (which represent ratepayer cost) will go down.

Q. PLEASE EXPLAIN THE COMPANY'S ESTIMATE OF ITS POTENTIAL NET MARKET SALES REVENUES.

A. Company witness Markovich estimates on-system market sales of 286,203 MWh.[72] Company witness Markovich projects that the Company's total revenues from these market sales would be approximately $7.8 million.[73]

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[70] *In the Matter of the Application of Puget Sound Energy for an Order Authorizing the Sale of All of Puget Sound Energy's Interest in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System*; Washington Utilities and Transportation Commission Docket No. UE-200115; Application at 11-12.

[71] Corrected Supplemental Testimony of Kevin J. Markovich at 20:1-3; and Corrected Direct Testimony of John D. Hines at 18:19-21.

[72] Corrected Supplemental Testimony of Kevin J. Markovich at 19; Note, the Company's estimates of PCCAM benefits and costs are exclusive of the proposed PPA portion of its proposed acquisition.

[73] *Id.*

Q. WHAT ARE THE COMPANY'S PROJECTED TOTAL PCCAM BENEFITS?

A. Company witness Markovich predicts total PCCAM benefits of $8.5 million.[74] However, as shown later, the Company's estimate of total PCCAM benefits is likely overstated since the projection of variable costs utilized by the Company in its estimation is significantly lower than historic averages. Furthermore, the market prices utilized by the Company are inconsistent with current forward prices reported in the market.

Q. DOES THE COMPANY PROPOSE TO CREDIT ITS PCCAM TO ACCOUNT FOR THE ANTICIPATED BENEFITS IT ESTIMATES ARE ASSOCIATED WITH THE PROPOSED ACQUISITION?

A. No. While the Company proposes to credit its PCCAM if the proposed acquisition is approved, the Company does not propose that this credit reflect the full amount of the benefits that the Company claims will flow from the proposed acquisition, but rather only an amount sufficient to offset the increase in revenue requirement associated with the proposed acquisition.[75] Specifically, the Company proposes a PCCAM credit equal to $4.4 million which reflects the annual revenue requirement of the new acquisition.[76]

Q. PLEASE EXPLAIN HOW THE COMPANY'S PROJECTED VARIABLE COSTS COMPARE TO ITS HISTORIC TRENDS.

A. Exhibit DED-8 provides a chart that compares the Company's historic variable operating costs relative to forecast costs included in the current application. The chart shows that the Company's variable costs over the period 2014 through 2019 have been

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[74] *Id.*
[75] Corrected Direct Testimony of John D. Hines at 19:17-20.
[76] Corrected Direct Testimony of Andrew D. Durkin at 15:4-8.

increasing by as much as 3.5 percent on an annual average basis. **#BEGIN CONFIDENTIAL#** [redacted] **#END CONFIDENTIAL#**

Q. PLEASE EXPLAIN HOW THE COMPANY'S CURRENT MARKET PRICE OUTLOOK HAS CHANGED SINCE ITS ORIGINAL FILING.

A. The Company has used two different forward curves in estimating the benefits of its proposed CU4 acquisition. Its original application utilized a forward curve that examined the outlook of the market as of October 31, 2019.[77] This forward curve was for energy delivered at the Mid-C hub. The Company updated this forward curve as of March 31, 2020, in its supplemental filing given the changed future market price outlook.[78] The outlook for future power prices (at the Mid-C hub), however, has changed once again since the Company's supplemental filing. Exhibit DED-9 compares the forward curves in each of the Company's applications with the current outlook. Page 1 of this exhibit provides the changes between the Company's (1) original application, (2) its supplemental application and (3) current forward on-peak prices reported as of September 4, 2020. Page 2 of the exhibit provides a comparable analysis for Mid-C off-peak prices.

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[77] Corrected Direct Testimony of Kevin J. Markovich at 14:1-2.
[78] Corrected Supplemental Testimony of Kevin J. Markovich at 19:8-9.

Q. HAS THE COMPANY IDENTIFIED ANY OTHER MARKET SALES BENEFITS FROM THE CU4 CAPACITY ACQUISITION PROPOSALS?

A. Yes. The Company notes there are also wholesale revenue benefits associated with the PSE PPA. The Company proposes to treat the PPA as a stand-alone transaction outside the PCCAM[79] for which no revenue requirement will be presented until five years after the close of the transaction. The Company notes that PSE will pay both for electricity at market prices and will also make a mandatory contribution to fixed costs that includes fixed O&M costs, property taxes, and other regulatory assessments.[80]

Q. HOW MUCH REVENUE DOES THE COMPANY ANTICIPATE COLLECTING UNDER THE PSE PPA OVER ITS FIVE-YEAR TERM?

A. The Company's original application provides two sets of PPA revenues, one on a projected year basis[81] and a second on a "back-cast" basis.[82] The original proposed 90 MW PPA (as corrected on July 2, 2020) is estimated by the Company to produce a total of $7.2 million in "net value" (after costs and taxes) from the PPA over five years.[83] The Company's original filing also includes a five-year back-cast using prices from a single year (2019) when unusual price spikes occurred in the Mid-C market. Exhibits DED-10 and DED-11 provide summaries of these Company-estimated revenues and "net value" calculations. Exhibit DED-10 provides the estimates of the Company's forward-looking analysis while Exhibit DED-11 presents the net value estimates from the Company's "back-cast" analysis.

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[79] Corrected Direct Testimony of Kevin J. Markovich, at 11:8-10.
[80] *Id.* at 12:3-8.
[81] Corrected Exhibit KJM-1; Corrected Exhibit KJM-3.
[82] Corrected Exhibit KJM-2; Corrected Exhibit KJM-4.
[83] Corrected Exhibit KJM-1.

Q. DID THE COMPANY UPDATE THESE PPA NET VALUE ESTIMATES IN ITS SUPPLEMENTAL APPLICATION?

A Yes. The Company updated both the current anticipated net value (based on the lower capacity acquisition level of 92.5 MW) using updated forward prices,[84] and also updated the back-cast using the same historic wholesale power prices, but using the new acquisition level.[85] The Company now estimates a total net value of $3.6 million over five years using updated wholesale power prices.[86] The revised back-cast analysis is estimated to have a net value of $13.5 million over five years.[87]

Q. DO YOU AGREE WITH THE COMPANY'S METHODS FOR ESTIMATING THE NET VALUE OF THE PROPOSED PSE PPA?

A. No. The Company's analysis suffers from several shortcomings all of which tend to overstate PSE PPA net benefits. First, the analysis covers several years and has been done on a nominal future dollar basis, rather than on a net present value ("NPV") basis. Second, the Company uses constant variable costs in its PPA benefits analysis while allowing market prices to vary. Third, the Company's back-cast analysis is done in a fashion entirely inconsistent with most common back-casting approaches. Fourth, wholesale power prices have changed since the Company's supplemental filing, and those changes in market prices need to be incorporated into the analysis. I explain each of these flaws in the Company's arguments, and the manner in which those flaws undercut the credibility of the Company's arguments, below.

[84] Corrected Exhibit KJM-3.
[85] Corrected Exhibit KJM-4.
[86] Corrected Exhibit KJM-3.
[87] Corrected Exhibit KJM-4.

Q. PLEASE DISCUSS THE PROBLEMS WITH THE COMPANY'S FAILURE TO CALCULATE THESE ESTIMATES ON AN NPV BASIS.

A. The Company's analysis fails to consider the time value of money. A dollar in the future, for instance, is not worth as much as a dollar today, and most financial analyses, and other forms of valuation that span multiple years, tend to calculate dollars on an NPV rather than future dollar basis. The use of an NPV that discounts future dollars to a current value finds a "net value" of $3.1 million, approximately 13-14 percent lower than the estimate provided by the Company. This revised NPV calculation has been provided as a separate row in Exhibit DED-10 and Exhibit DED-11. The discount rate used in the calculation is the Company's weighted average cost of capital ("WACC"). This represents the Company's financing costs that are used for ratemaking purposes in the setting of ratepayer rates. The use of the Company's WACC as the discount rate in the NPV calculation is appropriate because ratepayers will be bearing the risks associated with uncertain future returns through the proposed PPA.

Q. PLEASE EXPLAIN THE PROBLEMS WITH THE VARIABLE COST ASSUMPTIONS USED IN THE COMPANY'S PPA NET VALUE ANALYSIS.

A. The Company uses a constant variable cost of $16.47/MWh in its PPA net benefits analysis.[88] As I noted earlier in my testimony, Exhibit DED-8 shows that the Company's variable costs have and will likely continue to increase in the future. Using the same variable cost estimates I discussed earlier in my revised market sales net revenue analysis, the overall margins (net value) created by the PSE PPA are negative

[88] Company's Updated Response to Data Request MEIC-79.

as shown in Exhibit DED-12. These revised estimates show that the Company's five-year total net value of the proposed PPA portion of the 92.5 MW acquisition is negative $11.6 million in future dollar terms and negative $9.2 million in NPV terms.

Q. ARE THERE ANY OTHER ISSUES WITH THE COMPANY'S CONSTANT VARIABLE COST ASSUMPTIONS?

A. Yes. The Company's assumptions do not comport with representations about those same trends offered by one of the CU4 owners which is PSE. For instance, PSE is currently seeking approval for this PPA by its Washington regulators. PSE has provided estimates to its Washington regulators indicating that moving forward with the PPA (with NorthWestern) is better than the continued ownership and operation of the CU4 unit. PSE's analysis before its Washington regulators posits notably higher variable costs to continue to operate CU4. PSE estimates annual total operating costs of CU4 ranging from $38.30/MWh to $44.00/MWh annually for the next five years (May 2021 through May 2025).[89] In terms of variable costs, PSE assumed annual dispatch costs for CU4 generally increasing from $20.70/MWh in the 12 months ending May 2021, to $21.50/MWh in the 12 months ending May 2025.[90]

Q. PLEASE EXPLAIN THE PROBLEMS WITH THE COMPANY'S BACK-CAST ANALYSIS.

A. The Company calculates a five-year back-cast using historic 2019 market prices. The Company's back-cast effectively assumes that 2019 prices will remain in place for a

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[89] *In the Matter of the Application of Puget Sound Energy for an Order Authorizing the Sale of All of Puget Sound Energy's Interest in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System*; Washington Utilities and Transportation Commission Docket No. UE-200115; Direct Testimony of Cindy L. Song; Exhibit CLS-7. (Exhibit DED-17)
[90] *Id.*

five-year period. In other words, the Company's presentation assumes that 2019 prices will be repeated five years in a row. This is not reasonable nor consistent with common back-casting approaches that tend to use information over a comparable term such as using five years of pricing data over a five year period, not one year of pricing data, five times in a row.

Q. HAVE YOU UPDATED THE COMPANY'S CALCULATIONS FOR NEW MARKET PRICES?

A. Yes. Exhibit DED-13 provides a more appropriate back-casting analysis using the prior five-year period (2015-2019) which estimates a lower net value benefit of less than $200,000. These net benefits fall to approximately $140,000 on an NPV basis. This analysis shows that, contrary to the Company's representation, net benefits associated with the proposed PPA with PSE would have been limited even during the previous five years of Colstrip operations, when market prices were higher and variable costs were lower than now forecasted.

Q. ARE NET BENEFITS EVEN AT A LEVEL SUBSTANTIALLY REDUCED FROM THE COMPANY'S PROJECTIONS GUARANTEED TO MATERIALIZE?

A. No. In fact, given my earlier discussion of pressures on CU4's margins net of fixed costs from increasing fixed costs and decreasing market prices for CU4 output, the back-cast shown in Exhibit DED-13 strongly suggests that the proposed acquisition is unlikely to produce a net benefit to consumers even with the cost support from the PSE PPA.

Q. ARE THERE ANY IMPORTANT "TAKE-AWAYS" FOR THE COMMISSION TO CONSIDER IN YOUR REVISED ANALYSES OF THE COMPANY'S WHOLESALE REVENUE BENEFITS?

A. Yes. The Company's analysis of market sales benefits (general market sales and PPA sales) are likely overstated. More importantly, the Company's proposal imposes considerable risk onto ratepayers for this transaction given the uncertainty of market prices and the likelihood that the Company may not attain the revenue streams it anticipates. Ratepayers should not bear the risk of these revenue stream shortfalls either in the short run or after the five-year PPA has expired. Ratepayers will receive no PCCAM benefits in the short term if the Company's wholesale sales do not materialize. As I noted earlier, the purported $4.4 million credit applied to the PCCAM is not a "benefit" but simply reflects an adjustment for the CU4 acquisition's revenue requirement.

Q. WHAT IS THE LONGER-TERM RISK OF THE CU4 ACQUISITION RELATIVE TO THE PSE PPA?

A. The PSE PPA will come off the books in five years. After this period, the Company will likely be required to put any excess capacity associated with this acquisition to the market, particularly in non-peaking time periods. It is also likely the case, as I have shown elsewhere in my testimony, that the Company will have additional required capital expenditures in order to keep CU4 running and viable into the near future (e.g., see Exhibit DED-2). The current PSE PPA has a guaranteed fixed cost contribution that is made by PSE over a five-year period and that fixed cost contribution will end with the termination of the contract. Exhibit DED-14 shows that if this fixed cost contribution were removed, the PPA's net value (overall net revenue contribution) would be negative, even using the Company's own assumptions and calculations. The second page of this Exhibit shows that the net revenue contribution only grows more negative with more realistic assumptions and data as I discussed earlier. This underscores the importance of limiting any approval in this proceeding, to the extent that the Commission concludes that an approval actually satisfies the requirements of § 69-8-421(6)(c), to a five-year period coextensive with the PSE PPA given the overall uncertainty and likelihood that costs will exceed benefits after the PSE PPA expires.

C. Benefit from Avoided Market Purchases

Q. HAS THE COMPANY ASSERTED ANY ADDITIONAL BENEFITS ASSOCIATED WITH THE PROPOSED CU4 ACQUISITION?

A. Yes. The Company states that acquiring the additional share of CU4 would allow it to reduce its reliance on market purchases that it makes on behalf of its retail customers.[91] The Company speculates that its overall electric supply costs may see a net decrease due to these avoided market purchases. The Company estimates that these avoided market purchases will reduce its overall PCCAM costs by $0.9 million if it secures 92.5 MW of CU4.[92]

Q. IS THERE INFORMATION SUPPORTING FUTURE DECLINING MARKET PRICES?

A. Yes. PSE, in its current Washington filing, notes that PSE expects its proposed sale of its share of CU4 capacity to produce approximately $25 to $46 million in net present

[91] Corrected Supplemental Testimony of Kevin J. Markovich at 20:1-3.
[92] *Id.*, at 19.

value savings for PSE.[93] These PSE savings were estimated by comparing estimated CU4 operating costs to estimated costs of replacing displaced energy and capacity requirements from CU4 with market resources for the next five years (May 2021 through May 2025).[94] The forecast prices PSE assumed for these market resources ranged from $25.6/MWh to $28.1/MWh for replacement energy, and $12.0/kw-year to $13.2/kw-year for replacement winter capacity. The forecast prices presented by PSE to the WUTC in support of its proposed sale of its CU4 interest are below the forecast prices on which NorthWestern bases its claims of benefits from avoiding purchases in the same market, as shown in Table 1 below.

Table 1: Comparison of PSE and NorthWestern Estimated Future Market Prices

	2020	2021	2022	2023	2024	2025
			---------- ($/MWh) ----------			
Puget Sound Energy	26.72	26.46	25.64	26.36	28.12	
NorthWestern Energy		28.14	28.96	29.47	29.46	29.72
Percent Difference		**6%**	**13%**	**12%**	**5%**	

Note: Puget Sound Energy estimates are for 12 months ending in May of the succeeding year while NorthWestern Energy estimates are for 12 calendar months.

Q. WOULD ANY AVOIDED PURCHASE BENEFITS BE FLOWED BACK THROUGH THE PCCAM AS A FINANCIAL CREDIT TO REDUCE RATEPAYER BILLS?

A. No. Any financial savings that are generated from the CU4 acquisition would be diverted to the Company's proposed Reserve Fund: ratepayers will get no current or

[93] *In the Matter of the Application of Puget Sound Energy for an Order Authorizing the Sale of All of Puget Sound Energy's Interest in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System*; Washington Utilities and Transportation Commission Docket No. UE-200115; Direct Testimony of Cindy I. Song at 2:22 to 3:5. (Exhibit DED-16)
[94] *Id.*; Exhibit CLS-7. (Exhibit DED-17)

known financial benefit from this CU4 transaction under the Company's proposal. Instead, ratepayers would receive a ledger entry offsetting NorthWestern's future liability for environmental remediation and decommissioning costs for the 30 percent/220 MW share of Colstrip Unit 4 that it currently owns[95] despite the fact that, at this time, the Commission has not ruled on the prudency of these costs, or any other allocation of these costs between the Company's ratepayers and its shareholders. This seems unreasonable considering, among many other reasons, that the Company operated its existing 30 percent share of CU4 on a merchant basis from its commissioning in 1986 until it was placed in rate base in January 2009. As the Commission has observed, during that 1986 to 2009 period, or approximately two-thirds of its operating history, "CU4 has never been devoted to public service."[96]

Q. WILL RATEPAYERS BEAR THE RISK OF THESE AVOIDED MARKET PURCHASES?

A Yes. The Company's estimates are just that, an "estimate." The Company offers no minimum guaranteed credits for its future avoided purchase revenues. Such a guaranteed credit would assist in reducing both future performance and market risk of the CU4 capacity acquisition for ratepayers.

Q. WHAT DO YOU MEAN BY PERFORMANCE RISK?

A. If this transaction is approved by the Commission, it will be up to the Company to market the output from this additional capacity to maximize its market sales revenues. Likewise, it will be up to the Company to aggressively maintain cost and operational

[95] "Our Company;" NorthWestern Energy, available online at: http://www.northwesternenergy.com/our-company.
[96] Order No. 6925f, Docket No. D2008.6.69 at ¶ 247.

efficiencies to assure the plant is competitive with the market to assure avoided market purchase savings (i.e., the more efficient the capacity is, the more likely it will displace market purchases). Any slip in the diligence with which the Company pursues market sales or avoids market purchases will result in the incurrence of additional costs by ratepayers for which they receive no benefit.

Q DOES THE COMPANY ACKNOWLEDGE THE UNCERTAINTY ASSOCIATED WITH THESE AVOIDED PURCHASES (AS WELL AS MARKET SALES)?

A Yes. The Company clearly notes that any PCCAM savings will not be reflected in rates "until the savings are realized" which will occur at a point after the additional share "is added to its supply portfolio."[97] The Company also clearly notes that ratepayers will only receive their share of any PCCAM savings credit "if and when NorthWestern's actual PCC are less than the PCC that NorthWestern recovers."[98] The Company's offer to "credit" $4.4 million to the base PCC is not a true ratepayer financial credit, nor should the Commission consider this a benefit of any kind. The $4.4 million credit is simply an adjustment to cover the cost (revenue requirement) of using the acquired CU4 capacity as part of the Company's supply portfolio.

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[97] Corrected Direct Testimony of Kevin J. Markovich at 8:10-12.
[98] *Id.* at 7:5-8.

VIII. INCREASED RATEPAYER COST EXPOSURE

Q. HAVE ANY OTHER CU4 OWNERS REFLECTED UPON THE CHALLENGES OF OWNING COAL-FIRED GENERATION?

A. Yes. In its application to sell its interest in CU4, PSE remarked about how the growing challenges posed by coal-fired generation have eroded previous benefits from what traditionally has been a low-cost source of power.[99] Specifically, PSE noted that increased compliance costs and declining electricity market prices due to increased competition from low-cost natural gas generation and the proliferation of renewable resources have made it difficult for coal-fired generation units to remain competitive.[100] PSE noted that CU4 reflected these general market trends with continually escalating maintenance and operating costs in a declining electricity market.[101]

Q. WHAT TRENDS RELATED TO COAL ARE MATERIALIZING IN THE PACIFIC NORTHWEST?

A. As recently as last year, 2,868 MW of coal-fired generation capacity from six separate generation units in the region were scheduled to be retired in the near future.[102] These retirements include the Centralia facility in Washington,[103] the Boardman facility in

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[99] In the Matter of the Application of Puget Sound Energy for an Order Authorizing the Sale of All of Puget Sound Energy's Interest in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System; Washington Utilities and Transportation Commission Docket No. UE-200115; Application at ¶¶ 23-24.
[100] *Id.* at ¶ 24.
[101] *Id.*
[102] EIA Form-860, Energy Information Administration.
[103] Brown, Alex and Sophie Quinton (March 9, 2020); "As U.S. Coal Plants Shutter, Centralia Area Tests an Off-Ramp;" The Daily Chronicle.

Oregon,[104] and two of the four generation units comprising the Colstrip Facility.[105] Some of these retirements have since already occurred, with two of the existing generation units at Colstrip, CU1 and CU2, being shuttered on January 5, 2020. Likewise, the Boardman facility in Oregon and one of the two generators at the Centralia facility in Washington will be retired later this year. Additionally, in Montana, Montana Dakota Utilities has announced plans to close its coal-fired Lewis and Clark Station in Sidney sometime this year, and two additional coal-fired generators at Heskett Station in Mandan, North Dakota.[106]

Q. WHAT HAS BEEN DRIVING THE RECENT MOVEMENT AWAY FROM COAL-BASED GENERATION RESOURCES IN THE NORTHWEST?

A. States in the Pacific Northwest and in the Western U.S. have implemented policies that discourage coal-fired generation. Washington, for example, in 2019 passed Senate Bill 5116, which requires all electric utilities operating in the state to eliminate coal-fired resources from their resource portfolios[107] by the end of 2025. In passing Senate Bill 5116, Washington joined Oregon, which in 2016 passed Senate Bill 1547 requiring all electric utilities in the state to eliminate coal-fired resources from their resource portfolios[108] by the end of 2029. Likewise, California in 2018 passed Senate Bill 100

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[104] Flatt, Courtney (January 7, 2019); "PGE Looks to Renewable Energy as Boardman Coal Plant Closes," Northwest Public Broadcasting.
[105] Desroches, Kayla (January 6, 2020); "It's Like Losing a Family Member: Colstrip Power Plant Closes 2 Units;" Montana Public Radio.
[106] Lutey, Tom (February 19, 2019), "MDU to shutter Eastern Montana coal power plant in 2020," Billings Gazette.
[107] Washington Senate Bill 5116 specifically requires state electric utilities to eliminate coal-fired resources from their "allocation of electricity," defined as "the costs and benefits associated with resources used to provide electricity to an electric utility's retail electricity customers."
[108] Oregon Senate Bill 1547 specifically requires state electric utilities to eliminate coal-fired resources from their "allocation of electricity," defined as "the costs and benefits associated with resources used to provide electricity to an electric utility's retail electricity customers."

which modified existing laws to establish that 100 percent of total retail sales of electricity in California must come from eligible renewable energy resources and zero-carbon resources by the end of 2045.

Q. HOW DO THESE CHANGES RELATE TO THE COLSTRIP UNITS?

A. The Company and Talen, PSE, PGE, PacifiCorp, and Avista all own interests in the remaining active Colstrip generation units (CU3, CU4). Each of these owners, except for NorthWestern and Talen, serve retail loads in either Washington or Oregon and are thus subject to these states' future prohibition on coal-based generation. Indeed, PSE's current sale of its interest in CU4 to the Company is driven by its need to divest from coal-based generating resources by 2025.[109]

Q. HOW DO REGIONAL POLICY CHANGES IMPACT COAL GENERATION FROM FACILITIES LIKE COLSTRIP?

A. These policy changes impact facilities like Colstrip in several ways. First, several Colstrip owners will likely need to divest their ownership shares in the facilities, including CU4, in the next few years. Such divestitures are likely to complicate the availability of capital for CU4 or push NorthWestern and Talen into an increasingly untenable position as the "last owners standing" in a resource whose economics are becoming increasingly uncompetitive. Furthermore, these regulatory changes may negatively impact the future marketability of CU4 generation in Western wholesale markets, particularly if the states in the region continue to place prohibitions on coal-

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[109] *In the Matter of the Application of Puget Sound Energy for an Order Authorizing the Sale of All of Puget Sound Energy's Interest in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System*; Washington Utilities and Transportation Commission Docket No. UE-200115; Application at ¶ 2.

fired generation, and particularly if California's carbon pricing regime spreads to other States. This is very important in this proceeding since such a large part of the purported benefits of the proposed acquisition are associated with wholesale power sales. The significant potential cost exposure for Montana ratepayers with the Company's CU4 proposal includes a highly plausible future scenario in which coal-based electric generation is prejudiced or is required to pay for its negative environmental attributes.

Q. ARE THERE OTHER ENVIRONMENTAL RISKS ASSOCIATED WITH CU4?

A. Yes. CU4 has exhibited a number of challenges over the past two years in meeting the Maximum Attainable Technology Standard ("MATS") test pursuant to federal Mercury and Air Toxics Standards.[110] Emissions tests reported to the Montana Department of Environmental Quality ("MDEQ") for June 21, 2018 and June 26, 2018 found that Colstrip was operating in excess of MATS limits for airborne non-mercury hazardous air pollutant emissions, measured by proxy as particulate matter ("PM").[111] CU3 was immediately removed from service on June 28, 2018 while CU4 was removed from service on June 29, 2018.[112] Once these units were taken out of service, Talen conducted limited operations for purposes of evaluation of corrective actions.[113] These units remained out of full service until September 4, 2018, for CU4, and September 11, 2018, for Unit 3.[114] These outages, and the issues associated with the cost incurred for

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[110] Lutey, Tom (August 10, 2018), "Air pollution problems continue to plague Colstrip as 2 largest generators remain shut down," Billings Gazette.
[111] In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Direct Testimony of David E. Dismukes at 9:15 to 10:1.
[112] *Id.* at 10:1-2.
[113] *Id.* at 10:3-5.
[114] *Id.* at 10:5-6.

replacement power during these outages were discussed in detail in Docket No. 2019.09.058.

Q. HOW DO THESE OUTAGES RELATE TO THE ISSUES IN THIS PROPOSED CAPACITY ACQUISITION PROCEEDING?

A. The Company, and its co-owners and operator (Talen), appear to face ongoing PM emissions challenges at Colstrip. Exhibit DED-15, for instance, compares Colstrip's PM emissions relative to other coal units in the Western interconnect and shows that these per MWh emissions are relatively high on an output basis. More important to this proceeding, however, is the Company's testimony before the Commission in Docket 2019.09.058 which clearly noted that it is not unusual for the Colstrip facility to report PM MATS emissions levels at or very near its permitted limit.[115] The Company cited Continuous Emissions Monitoring System ("CEMS") data for the period from February 2018 to June 2018 as evidence of those typically high, but characterized by NorthWestern as non-worrisome, PM emission level trends.[116] The Company's testimony before the Commission noted the continued uncertainty associated with the causes for the June PM test failure and also noted that it could not guarantee that the facility may not exceed its permitted emissions rate in the future.[117] This creates an additional concern in evaluating the CU4 capacity request in this proceeding since it raises the possibility that additional replacement power cost could arise from future PM test failures (and outages). The need for additional replacement

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[115] In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Tr. Day 1 at 152:1-8.
[116] *Id.* at 147:5-8.
[117] *Id.* at 153:4-17.

power, in turn, potentially raises the ongoing costs of operating CU4 and could significantly lower potential capacity acquisition benefits. The Commission needs to consider this possibility in the evaluation of the Company's request.

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS?

A. I recommend the Commission reject the Company's CU4 capacity acquisition preapproval request since NorthWestern has neither shown that the proposed acquisition is in the public interest nor that the Company's proposal would result in rates that are reasonable and just. The Company has not shown that the proposed capacity acquisition is both needed and the least cost resource available in the market. The Company has not compared this proposed resource to the results of a competitive bidding process. The purported benefits of the capacity acquisition proposal are tied to a set of highly speculative claims that, in turn, are tied to unreasonable assumptions about CU4's operating costs and the outlook for regional power markets. The Company's supporting analyses do not include the costs of any capital additions for which the Company is likely to seek recovery from Montana ratepayers, thereby understating the capacity acquisition costs. Further, close to half of the proposed capacity acquisition is tied to a PPA with PSE. The Company's request simply asks Montana ratepayers to provide a regulatory backstop for additional CU4 capacity that, in turn, will be marketed to Washington electricity customers. For these reasons, the Commission should reject this proposal.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S RESERVE FUND?

A. Whether or not the Commission authorizes the proposed capacity acquisition, I recommend that the Commission reject the proposed reserve fund. The Fund is a ratemaking measure that should not be part of the current preapproval investigation as it is not even related to the proposed acquisition in CU4. The Commission, to date, has not determined whether or to what extent Montana ratepayers should be responsible for the Company's environmental remediation and plant decommissioning costs for CU4. There has been no Commission determination regarding the prudency of these costs' incurrence. In addition, a significant portion of those costs were incurred during the period between 1986 and 2008, when NorthWestern's share of Colstrip Unit 4 was not devoted to public service. Lastly, specific year-to-year financing of the proposed Fund is left undefined, while additionally presuming prematurely that the liabilities the Fund is designed to address are actually costs for which ratepayers are responsible.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A Yes. If the Commission chooses to approve the capacity acquisition, I offer the following alternative recommendations to bring the proposal more closely into line with the public interest:

- The 92.5 MW capacity acquisition should be approved for a five-year period only. The Company, if it seeks longer term recovery, should (1) request and be required to justify cost recovery at a later date towards the close of the PPA with PSE and (2) should subject the resource to the results of a competitive bidding process to definitively show that the capacity acquisition proposed in this proceeding is the least cost resource available in the market.

- No capital additions should be allowed into rates during the initial five-year period as the Company has not quantified the cost impacts of these capital additions as part of its presentation in support of authorization for its proposed acquisition.[118] The Company's allowed revenue requirement should be fixed at $4.4 million (derived as shown on page 1 of Exhibit DED-3) under the proposed 92.5 MW acquisition.
- The Commission should reject the Company's Reserve Fund proposal in all respects.
- The Commission should require the Company to provide a minimum financial credit to ratepayers that is equal to 50 percent of the market sales, avoided purchases, and PPA revenues estimated in its application. This results in a credit of approximately $4.5 million, derived as shown on page 3 of Exhibit DED-3. When combined with the Company's proposed first-year revenue requirement of approximately $4.4 million, this results in a minimum annual benefit to ratepayers of $140,440.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY FILED ON SEPTEMBER 25, 2020?

A. Yes.

[118] See Company Response to Data Request MCC-007.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2014-Current	Executive Director
2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-Current	Professor (Joint Appointment with CES)
2010-Current	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor

1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-current	Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2017-Current	Member, National Petroleum Council. U.S. Department of Energy.
2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy,

	Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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18. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

19. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

20. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

21. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: approximately $50,000. Status: Completed.

22. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

23. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

24. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

25. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

26. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Completed.

27. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

28. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

29. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

30. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

31. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

32. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

33. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

34. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

35. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

36. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

37. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

38. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

39. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

40. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

41. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

42. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

43. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

44. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology

Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. “Capacity utilization, efficiency trends, and economic risks for modern CHP installations.” (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. “Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach.” (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. “The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks.” (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. “The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks” (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. “Modifying Renewables Policies to Sustain Positive Economic and Environmental Change” (2015). IEEE Annual Green Technologies (“Greentech”) Conference. April 17.

7. “The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities.” (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. “Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion” (2014). With Siddhartha Narra. American’s Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. “Economies of Scale, Learning Curves, and Offshore Wind Development Costs” (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. “Analysis of Risk and Post-Hurricane Reaction.” (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. “Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials.” (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. “Gulf Coast Energy Infrastructure Renaissance: Overview.” (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. “Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure.” (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

19. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

26. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

27. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

28. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

29. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. “A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry.” (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. “New Paradigms for Power Engineering Education.” (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. “Cogeneration and Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. “The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978.” (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. “Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS.” (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. “Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry” (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

48. “Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries” (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

49. “Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry.” (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

50. “Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators.” (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

51. “Empirical Determinants of Nuclear Power Plant Disallowances.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.
2. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.
3. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
4. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
5. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
6. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
7. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
8. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.
9. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
10. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
11. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Ratepayer benefits of reforming PURPA". (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

2. "Pipeline industry: economic trends and outlook". (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association ("LMOGA") and the Louisiana Oil and Gas Association ("LOGA"). Lake Charles, LA March 5.
3. "The outlook for natural gas: storm clouds ahead?" (2020). National Association of State Utility Consumer Advocates ("NASUCA"). Natural Gas Committee Webinar, February 26.
4. "The 2020 Gulf Coast Energy Outlook". (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.
5. "Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor". (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.
6. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.
7. "2020 Louisiana business climate outlook: the view from the energy sector." (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA
8. "The urgency of PURPA reform in protecting ratepayers." (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.
9. "Louisiana's coast and the energy industry." (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.
10. "Reforming PURPA: implications for ratepayers." (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.
11. "Natural gas outlook: supply, demand and prices." (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.
12. "The economic impacts and outlook for LNG development on the Gulf Coast." (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)
13. "Natural gas outlook: supply, demand, and prices." (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.
14. "Overview of Louisiana LNG issues and trends." (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.
15. "Overview of Louisiana energy issues and outlook." (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.
16. "Gulf Coast Energy Outlook 2019: Regional trends and outlook." (2019). Women's Energy Network. Baton Rouge, LA, April 23.
17. "MISO Grid Vision 2033." (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.
18. "Ratepayer benefits of reforming PURPA." (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

19. "Incentives, risk, and the changing nature of regulation." (2019). NASUCA Water Committee monthly meeting/webinar. March 13.
20. "Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends." (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.
21. "A golden age: energy outlook 2019." (2019). Engineering News Record Webinar. February 13.
22. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.
23. "MISO Grid Vision 2033." (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.
24. "Gulf Coast Energy Outlook 2019." (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.
25. "How LNG is transforming Louisiana's energy economy." (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.
26. "Overview of Louisiana LNG issues and trends." (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.
27. "Infrastructure and capacity: challenges for development." (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
28. "Louisiana industrial cogeneration trends." (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
29. "Gulf Coast industrial development: overview of trends and issues." (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.
30. "Energy outlook – reflection on market trends and Louisiana implications." (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.
31. "Integrated carbon capture and storage in the Louisiana chemical corridor." (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.
32. "The outlook for natural gas and energy development on the Gulf Coast." (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.
33. "Critical energy infrastructure: the big picture on resiliency research." (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.
34. "The changing nature of Gulf of Mexico energy infrastructure." (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.
35. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.
36. "Crude oil and natural gas outlook: Where are we and where are we going?" (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.

37. "Navigating through the energy landscape." (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.

38. "The 2017-2018 Louisiana energy outlook." (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

39. "The Gulf Coast energy economy: trends and outlook." (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

40. "Gulf coast energy outlook." (2017). E.J. Ourso College of Business, Dean's Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

41. "Recent trends in energy: overview and impact for the banking community." (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

42. "How supply, demand and prices have influenced unconventional development." (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

43. "The Basics of Natural Gas Production, Transportation, and Markets." (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

44. "Gulf Coast industrial development: trends and outlook." (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

45. "The future of policy and regulation: Unlocking the Treasures of Utility Regulation." (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

46. "Utility mergers: where's the beef?". (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

47. "Overview of the Clean Power Plan and its application to Louisiana." (2016). Shell Oil Company Internal Meeting. April 12.

48. "Energy and economic development on the Gulf Coast: trends and emerging challenges." (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

49. "Unconventional Oil and Gas Drilling Trends and Issues." (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

50. "Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?" (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

51. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.

52. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

53. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

54. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural

Electric Cooperative Meeting. November 5.

55. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.

56. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

57. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

58. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

59. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

60. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

61. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

62. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

63. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

64. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

65. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

66. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

67. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

68. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

69. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

70. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

71. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

72. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste

Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

73. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

74. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

75. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

76. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

77. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

78. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

79. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

80. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

81. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

82. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

83. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

84. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

85. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

86. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

87. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

88. “Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance.” (2013). International Technical Conference, Houston, TX. October 11.
89. “Natural Gas, Coal & Power Generation Issues and Trends.” (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.
90. “Recent Trends in Pipeline Replacement Trackers.” (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.
91. Discussion Panelist (2013). Think About Energy Summit, America’s Natural Gas Alliance, Columbus Ohio. September 16-17.
92. “Future Test Years: Issues to Consider.” (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.
93. “Industrial Development Outlook for Louisiana.” (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.
94. “Natural Gas & Electric Power Coordination Issues and Challenges.” (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.
95. “Natural Gas Market Issues & Trends.” (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.
96. “Louisiana Unconventional Natural Gas and Industrial Redevelopment.” (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.
97. “Infrastructure Cost Recovery Mechanism: Overview of Issues.” (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.
98. “GOM Offshore Oil and Gas.” (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.
99. “Louisiana Unconventional Natural Gas and Industrial Redevelopment.” (2013). Risk Management Association Luncheon, March 21.
100. “Natural Gas Market Update and Emerging Issues.” (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.
101. “Unconventional Resources and Louisiana’s Manufacturing Development Renaissance.” (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.
102. “New Industrial Operations Leveraged by Unconventional Natural Gas.” (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.
103. “What’s Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff.” (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.
104. “Trends, Issues, and Market Changes for Crude Oil and Natural Gas.” (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.
105. “Game Changers in Crude and Natural Gas Markets.” (2012). Chevron Community

Advisory Panel Meeting. Belle Chase, LA, September 17.

106. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

107. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

108. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

109. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

110. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

111. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

112. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

113. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

114. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

115. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

116. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

117. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

118. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

119. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

120. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative

Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

121. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

122. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

123. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

124. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

125. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

126. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

127. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

128. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

129. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

130. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

131. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

132. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

133. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

134. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau

Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

135. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

136. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

137. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

138. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

139. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

140. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

141. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

142. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

143. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

144. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

145. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

146. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

147. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

148. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

149. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association

of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

150. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

151. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

152. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

153. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

154. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

155. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

156. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

157. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

158. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

159. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

160. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

161. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

162. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

163. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

164. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

165. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

166. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

167. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

168. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

169. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

170. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

171. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

172. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

173. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

174. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

175. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

176. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

177. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

178. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure

and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

179. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

180. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

181. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

182. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

183. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

184. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

185. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

186. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

187. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

188. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

189. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

190. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

191. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

192. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

193. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

194. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

195. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

196. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

197. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

198. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

199. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

200. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

201. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

202. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

203. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

204. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

205. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

206. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

207. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

208. “The Gulf South: Economic Opportunities Related to LNG.” Presentation before the Energy Council’s 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

209. “Natural Gas and LNG Issues for Louisiana.” Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

210. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

211. The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

212. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

213. “Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy.” Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

214. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

215. “Natural Gas Outlook: Trends and Issues for Louisiana.” Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

216. “Natural Gas Outlook” Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

217. “Competitive Bidding in the Electric Power Industry.” Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

218. “Regional Transmission Organization in the South: The Demise of SeTrans” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

219. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.

220. “Natural Gas Outlook.” Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

221. “Issues and Opportunities with Distributed Energy Resources.” Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

222. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

223. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

224. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

225. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

226. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

227. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

228. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

229. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

230. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

231. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

232. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

233. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

234. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

235. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

236. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

237. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

238. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

239. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

240. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

241. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

242. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

243. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

244. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

245. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

246. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

247. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

248. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

249. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

250. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

251. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

252. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

253. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

254. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

255. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

256. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

257. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

258. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

259. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

260. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

261. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

262. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

263. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

264. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

265. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

266. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS,

RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Formal Case No. 1162. (2020). *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.
2. Expert Testimony. Docket No. 17-010-FR. (2020). *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.
3. Expert Testimony. Case No. U-20697. (2020). *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. Issues: cost of service, revenue distribution, rate design.
4. Expert Testimony. Docket No. 2019.09.058. (2020). *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. Issues: purchase power expenses, cost sharing, PCAAM power cost.
5. Expert Testimony. Formal Case No. 1156. (2020). Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal and Sur-Surrebuttal. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.
6. Expert Testimony. Case No. U-20561. (2019). Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.
7. Expert Testimony. Cause No. 45253. (2019). Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.
8. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* Issues: Solar investment, risk assessment, proposed rider.
9. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service

Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* Issues: rate design, reliability, and formula rate plan.

10. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. Issues: Solar project approval, ratepayer risk, cost allocation.

11. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: retail rates, leak analysis, revenue deficiency, investments.

12. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* Issues: load forecasting, least-cost system planning.

13. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

14. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* Issues: economic impact, cost benefit analysis, decoupling mechanisms.

15. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

16. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* Issues: Net-metering, distributed generation.

17. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* Issues: Net-metering, cost of service, revenue distribution, rate design.

18. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. Issues:

merger impacts, rates, tariffs.

19. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

20. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* Issues: rate design, reliability, and formula rate plan.

21. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* Issues: cost of service and rate design.

22. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

23. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* Issues: regulatory policy and cost-benefit analyses.

24. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

25. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. Issues: cost of service, rate design, and alternative regulation.

26. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. Issues: cost of service, rate design, billing determinates.

27. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: cost of service, rate design, alternative regulation, formula rate plan.

28. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. Issues: cost of service, marginal

cost of service, and rate design.

29. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

30. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

31. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

32. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

33. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

34. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

35. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* Issues: rate design, revenue allocation, economic development.

36. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* Issues: cost of service, rate design, alternative regulation, formula rate plan.

37. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission

of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

38. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00*. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

39. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

40. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

41. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

42. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

43. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

44. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Citizens of the State of Florida. Issue: revenue stabilization mechanism, revenue decoupling.

45. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc.,*

Pursuant to APSC Docket No. 15-015-U. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

46. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

47. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

48. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

49. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

50. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

51. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

52. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

53. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

54. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

55. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

56. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

57. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

58. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

59. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

60. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

61. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public

Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

62. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

63. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

64. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

65. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

66. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

67. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

68. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

69. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

70. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

71. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

72. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

73. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

74. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

75. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

76. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

77. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and

Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

78. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

79. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

80. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

81. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

82. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

83. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

84. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

85. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On

the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

86. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

87. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

88. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

89. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

90. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

91. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

92. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch

modeling and plant retirements.

93. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

94. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

95. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

96. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

97. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

98. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

99. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

100. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures,

empirical analysis of demand and usage trends for tariff eligibility requirements.

101. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

102. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

103. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

104. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

105. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

106. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

107. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

108. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

109. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

110. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

111. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

112. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

113. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

114. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

115. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

116. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

117. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

118. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

119. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

120. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

121. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

122. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

123. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

124. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

125. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service

Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

126. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

127. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

128. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

129. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

130. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

131. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

132. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

133. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

134. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public

Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

135. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

136. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

137. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

138. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

139. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

140. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

141. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

142. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

143. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

144. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

145. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

146. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

147. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

148. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

149. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

150. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

151. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

152. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

153. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public

Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

154. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

155. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

156. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

157. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

158. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

159. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

160. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

161. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

162. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

163. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the

Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

164. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

165. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

166. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

167. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

168. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

169. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

170. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

171. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

172. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

173. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and

Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

174. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (“IAEE”), United States Association of Energy Economics (“USAEE”), the National Association for Business Economics (“NABE”), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as “Top 40 Under 40” (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)

Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. “Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South.”

Advisor (2008). National Association of Regulatory Utility Commissioners (“NARUC”). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates (“NASUCA”), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics (“USAEE”) Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics (“IAEE”) Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Exhibits

Title	Exhibit
Comparison of Original and Supplemental CU4 Proposed Acquisition	Exhibit DED-1
Colstrip Units 3-4 Capital Additions	CONFIDENTIAL Exhibit DED-2
Determination of Minimum Ratepayer Credit	Exhibit DED-3
Historic Wholesale Mid-C Price Trends	Exhibit DED-4
Historic Operating Statistics vs. Mid-C Implied Market Clearing Heat Rate	Exhibit DED-5
Mid-C Implied Required Natural Gas Price for CU4	Exhibit DED-6
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Peer Comparison of Historic and Projected Variable O&M Costs	CONFIDENTIAL Exhibit DED-8
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Company Estimated Net Value from Proposed PPA	Exhibit DED-10
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Peer Comparison of Coal Unit PM Emissions	Exhibit DED-15
Excerpt of Direct Testimony of Cindy L. Song; WUTC Docket UE-200115	Exhibit DED-16
Exhibit CLS-7; WUTC Docket No. 200115	Exhibit DED-17

Comparison of Original and Supplemental CU4 Proposed Acquisition: Overview of Proposals

	Original Application	Supplemental Application
Total Acquisition Size (MW)	185.0	92.5
Total Acquisition Price ($)	$ 1.00	$ 0.50
Total PPA Size (MW)	90.0	45.0
Length of PPA (Years)	5.0	5.0
Estimated Avoided Cost ($ per MWh)	$ 28.62	$ 31.21
20-year Capacity Acquisition Costs ($ per MWh)	$ 26.71	$ 23.24

Source: Company Application at 1; Corrected Testimony of Bleau J. LaFave at 33:17-19; Company Supplemental Application at 1; Corrected Testimony of Bleau J. LaFave at 48:18-20.

Comparison of Original and Supplemental CU4 Proposed Acquisition: Total Cost Comparison

	Original Application			Supplemental Application		
	PCCAM Base with CA	PCCAM Base	Difference	PCCAM Base with CA	PCCAM Base	Difference
CU4 Volume (MWh)	2,318,256	1,672,925	645,331	1,995,591	1,672,925	322,666
On System Market Purch (MWh)	246,400	284,159	(37,759)	247,697	284,159	(36,462)
On System Market Sales (MWh)	(1,316,546)	(708,974)	(607,572)	(995,177)	(708,974)	(286,203)
CU4 Variable Costs	$ 38,181,680	$ 27,553,075	$ 10,628,605	$ 32,867,377	$ 27,553,075	$ 5,314,302
On System Market Purch	$ 11,036,236	$ 11,992,327	$ (956,091)	$ 11,057,522	$ 11,992,327	$ (934,805)
On System Market Sales	$ (32,387,997)	$ (15,935,851)	$ (16,452,146)	$ (23,705,165)	$ (15,935,851)	$ (7,769,314)
"INC" Purchases	$ -	$ 5,188,073	$ (5,188,073)	$ -	$ 5,188,073	$ (5,188,073)
Operating Reserves	$ -	$ 1,183,624	$ (1,183,624)	$ -	$ 1,183,624	$ (1,183,624)
Transmission Expense	$ 5,566,794	$ 2,936,008	$ 2,630,786	$ 4,175,268	$ 2,936,008	$ 1,239,260
Total Costs	**$ 134,028,825**	**$ 144,549,367**	**$ (10,520,542)**	**$ 136,027,114**	**$ 144,549,367**	**$ (8,522,253)**

Source: Corrected Testimony of Kevin J. Markovich at pp. 6, 19.

Colstrip Units 3-4 Capital Additions: Historic and Projected

[redacted]

Colstrip Units 3-4 Capital Additions:
CU4 Capital Expenditure Revenue Requirement

[redacted]

Colstrip Units 3-4 Capital Additions:
CU4 Annual Revenue Requirement, Selected Years

[redacted]

Determination of Minimum Ratepayer Credit: CU4 2021 Revenue Requirement

Line No.			Annual Expenses	Source:
1	**(A) CU4 Acquisition Revenue Requirement**			
2	**Required Annual Return on Ratebase Investment**			
3	Net Plant in Service	$	0.50	ADD-5 2021 Revenue Requirement: Line 12
4	Plus Incremental Working Capital		(1,041,539)	ADD-5 2021 Revenue Requirement: Line 19
5	Less Deferred Income Tax		-	ADD-5 2021 Revenue Requirement: Line 16
6	Total Ratebase	$	(1,041,539)	
7	Return on Ratebase		6.92%	ADD-5 2021 Revenue Requirement: Line 23
8	Required Return	$	(72,074)	
9	**Additional Cost of Service**			
10	Incremental Fixed Operating Costs	$	3,780,364	ADD-5 2021 Revenue Requirement: Line 28
11	Depreciation Expense		-	ADD-5 2021 Revenue Requirement: Line 29
12	Incremental Property and Other Taxes		675,921	ADD-5 2021 Revenue Requirement: Line 30
13	MPSC and MCC Tax		24,855	ADD-5 2021 Revenue Requirement: Line 31
14	Deferred Income Tax		-	ADD-5 2021 Revenue Requirement: Line 32
15	Current Income Tax		(17,735)	ADD-5 2021 Revenue Requirement: Line 33
16	Total Additional Cost of Service	$	4,463,405	
17	**Total CU4 Acquisition Revenue Requirement**	$	4,391,331	

Source: Corrected Supplemental Testimony of Andrew D. Durkin, Redacted Exhibit ADD-5

Determination of Minimum Ratepayer Credit : Calculation of PPA and 50 percent Market Benefits

Line No.		Company Estimated Benefits and Costs for 92.5MW Purchase of CU4		Proposed Minimum Ratepayer Credit Associated with 50 Percent of Claimed Benefits		Source:
1	**Market-Related PCCAM Benefits Attributed to Acquisition**					
2	Reduced On-System Market Purchases	$	934,805	$	467,403	KJM Revised Testimony at 19
3	Increased On-System Market Sales		7,769,314		3,884,657	KJM Revised Testimony at 19
4	**Total Market-Related PCCAM Benefits Attributed to Acquisition**	$	8,704,119	$	4,352,060	
5	**Average Annual Estimated Net Value of PPA with PSE**	$	723,153	$	361,577	KJM-3: Line 15
6	**Total Estimated Market Benefits and PPA Net Value**	**$**	**9,427,272**	**$**	**4,713,636**	

Source: Corrected Supplemental Testimony of Kevin J. Markovich at 19 and Exhibit KJM-3.

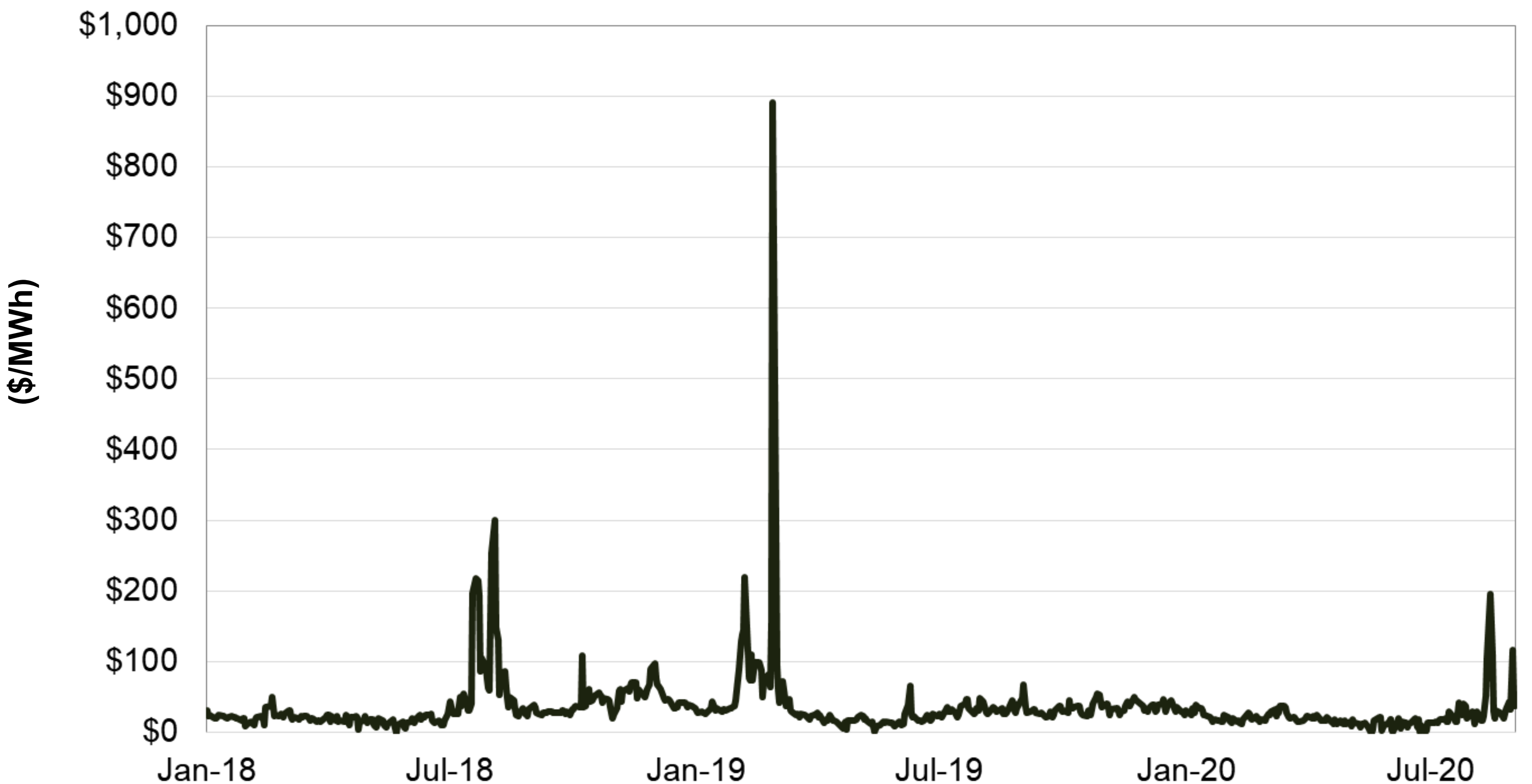
Determination of Minimum Ratepayer Credit: Proposed Annual Net PCCAM Credit

Line No.		Annual PCCAM Fixed Charge (Credit) for 92.5MW Purchase of CU4		Source:	Line Discription:
1	**(A) CU4 Acquisition Revenue Requirement**				
2	**Required Annual Return on Ratebase Investment**				
3	Net Plant in Service	$	0.50	ADD-5 2021 Revenue Requirement: Line 12	Purchase Price of Acquisition
4	Plus Incremental Working Capital		(1,041,539)	ADD-5 2021 Revenue Requirement: Line 19	Increased Gross Cash Requirements
5	Less Deferred Income Tax		-	ADD-5 2021 Revenue Requirement: Line 16	
6	Total Ratebase	$	(1,041,539)		
7	Return on Ratebase		6.92%	ADD-5 2021 Revenue Requirement: Line 23	
8	Required Return	$	(72,074)		
9	**Additional Cost of Service**				
10	Incremental Fixed Operating Costs	$	3,780,364	ADD-5 2021 Revenue Requirement: Line 28	Non-PCCAM Incremental CU4 Operating Expenses
11	Depreciation Expense		-	ADD-5 2021 Revenue Requirement: Line 29	
12	Incremental Property and Other Taxes		675,921	ADD-5 2021 Revenue Requirement: Line 30	Non-PCCAM Incremental CU4 Property and Other Taxes
13	MPSC and MCC Tax		24,855	ADD-5 2021 Revenue Requirement: Line 31	
14	Deferred Income Tax		-	ADD-5 2021 Revenue Requirement: Line 32	
15	Current Income Tax		(17,735)	ADD-5 2021 Revenue Requirement: Line 33	
16	Total Additional Cost of Service	$	4,463,405		
17	**Total CU4 Acquisition Revenue Requirement**	$	4,391,331		
18	**(B) Traditional PCCAM Costs and Credits**				
	Incremental Expenses				
19	Incremental Variable Operating Costs	$	5,314,302	KJM Revised Testimony at 19	PCCAM Incremental CU4 Operating Expenses
20	Increased Transmission Expenses		1,239,260	KJM Revised Testimony at 19	
	Total Incremental Expenses	$	6,553,562		
21	Reduced On-System Market Purchases	$	(467,403)	KJM Revised Testimony at 19	**Note: Represents 50% of Estimated Reduced On-System Market Purchases**
22	Reduced Capacity Reserve Purchases		(1,183,624)	KJM Revised Testimony at 19	
23	Reduced Anciliary Services Purchases		(5,188,073)	KJM Revised Testimony at 19	
	Total Reduced Market Purchases	$	(6,839,100)		
24	Increased On-System Market Sales	$	(3,884,657)	KJM Revised Testimony at 19	**Note: Represents 50% of Estimate Increased On-System Market Sales**
	Total Increased Market Sales	$	(3,884,657)		
25	**Total Traditional PCCAM Costs and Credits**	$	(4,170,195)		
26	**(C) PPA with PSE**				
27	Variable Revenue	$	(9,048,368)	KJM-3: Line 5	Estimated CU4 Generation Sales to PSE
28	PSE Fixed O&M Payment		(1,750,432)	KJM-3: Line 6	PSE Fixed Cost Contribution
29	Total Revenue	$	(10,798,800)		
30	Variable Cost	$	5,462,750	KJM-3: Line 9	PPA-assigned Incremental Vairable Costs
31	Fixed O&M Base		3,055,993	KJM-3: Line 10	PPA-assigned Incremental CU4 Fixed Operating Expenses
32	Variable O&M Other		822,609	KJM-3: Line 11	PPA-assigned Incremental CU4 Variable Operating Expenses
33	Property Taxes		673,174	KJM-3: Line 12	PPA-assigned Incremental Property Taxes
34	MPSC & MCC Taxes		61,121	KJM-3: Line 13	
35	Total Expenses	$	10,075,647		
36	**PPA with PSE Net Expenses (Value)**	$	(361,577)		**Note: Represents 50% of Estimated Net Value of PPA with PSE**
37	**Total Annual PCCAM Fixed Charge (Credit)**	**$**	**(140,440)**		

Source: Corrected Supplemental Testimony of Andrew D. Durkin, Redacted Exhibit ADD-5; Corrected Supplemental Testimony of Kevin J. Markovich at 19 and Exhibit KJM-3

Historic Wholesale Mid-C Price Trends (Jan 2018 to current)

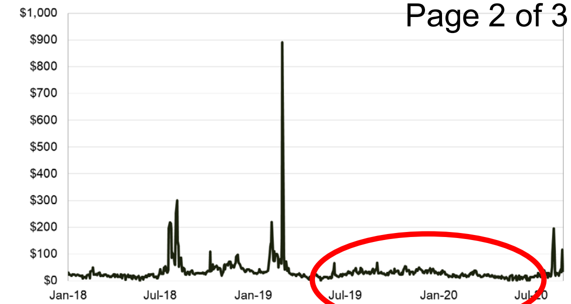
Historically, wholesale prices at the Mid-Columbia ("Mid-C") hub sees only limited occurrences of extreme "needle" type pricing. Recently the occurrence of these events has been limited.

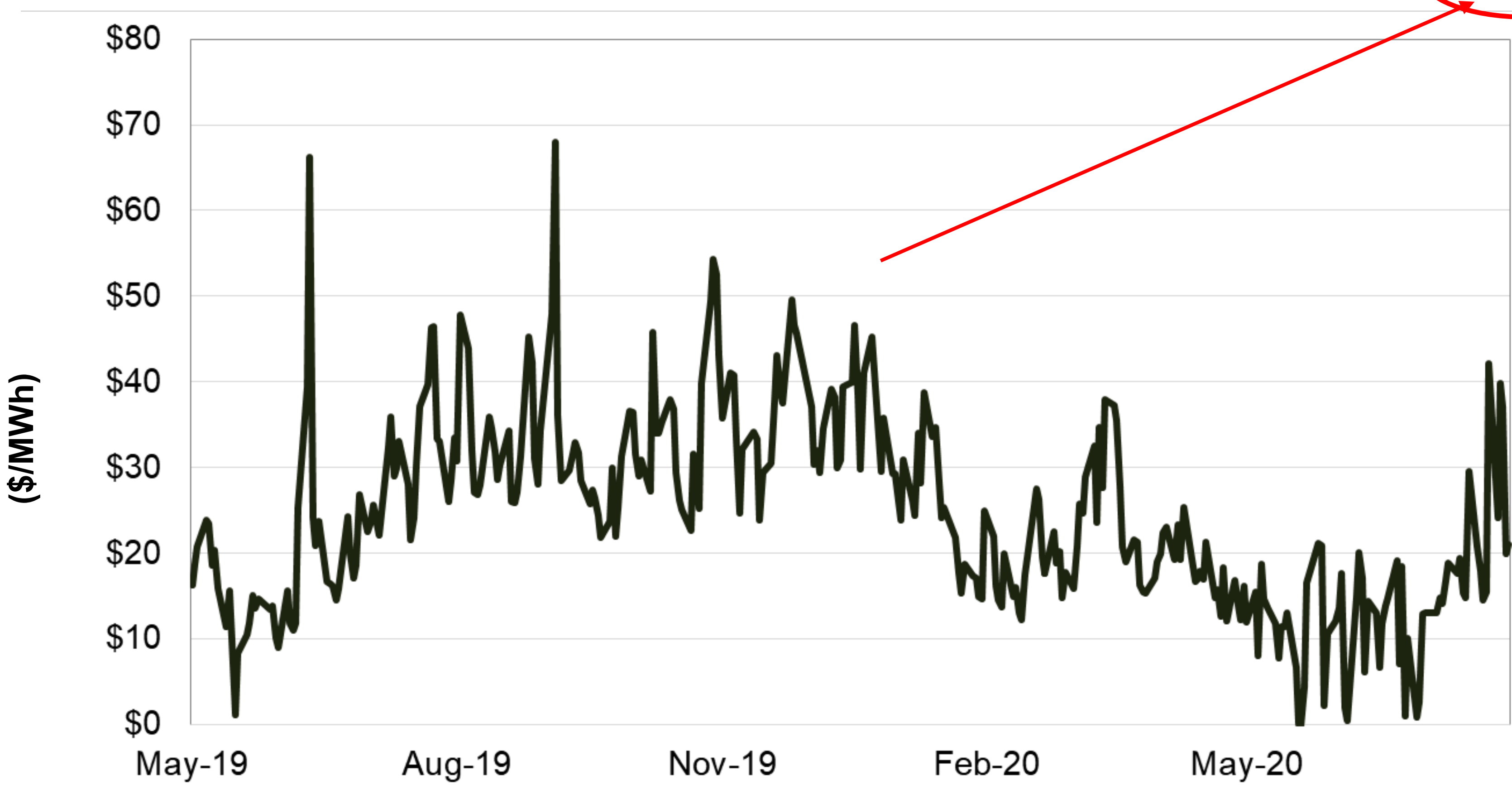


Source: Wholesale Electricity and Natural Gas Market Data, U.S. Energy Information Administration, available online at: "https://www.eia.gov/electricity/wholesale/."

Historic Wholesale Mid-C Price Trends (May 2019-July 2020)

A focus on more recent trends generally shows on-peak prices trading in a reasonable range.

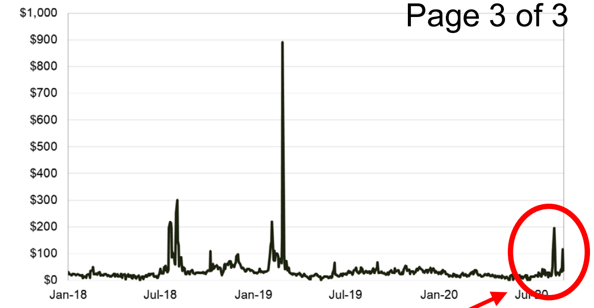


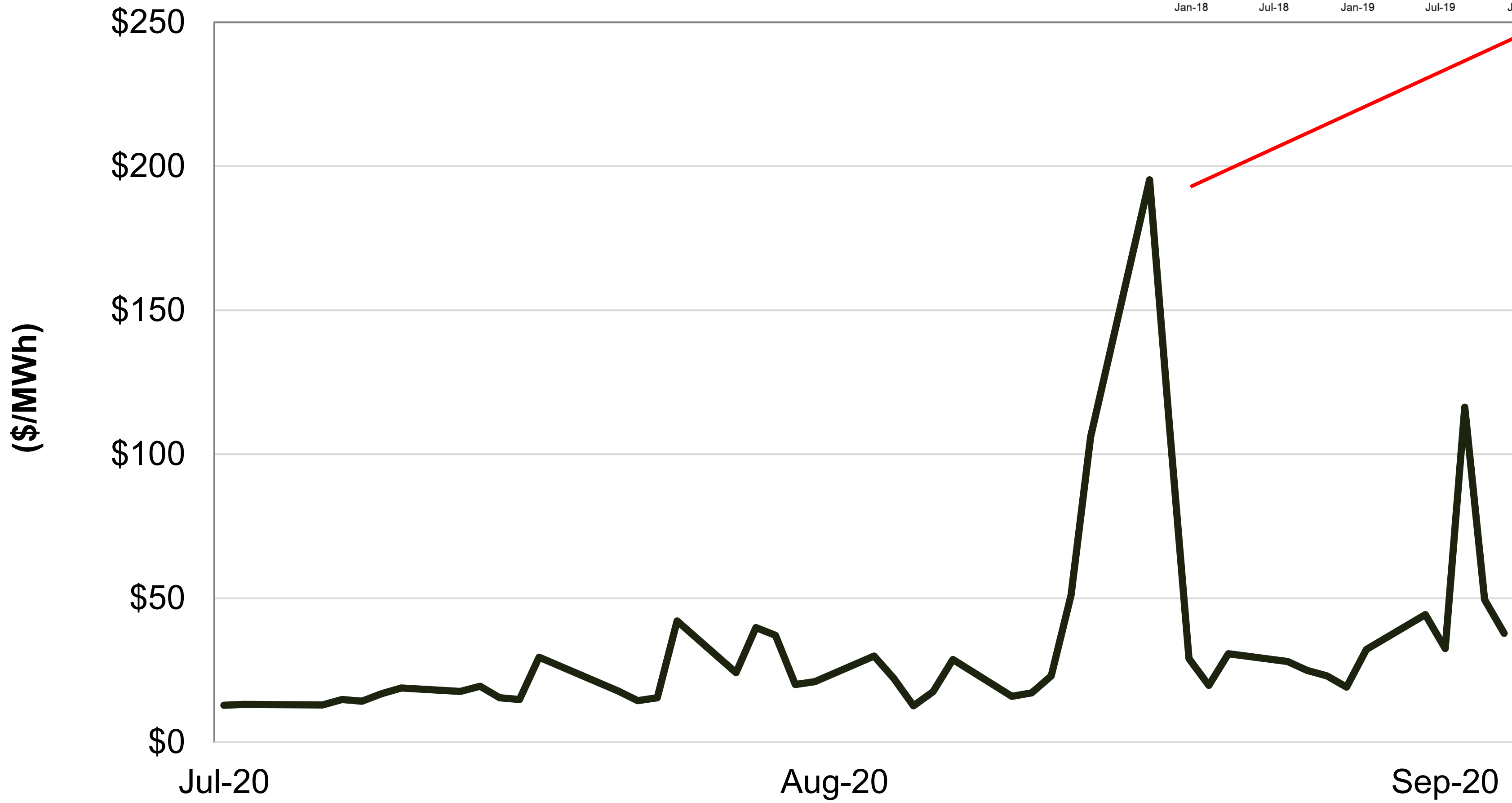


Note: Data is through July 2020 to exclude the temporary impacts associated with recent wild-fire induced price spikes.
Source: Wholesale Electricity and Natural Gas Market Data, U.S. Energy Information Administration, available online at: "https://www.eia.gov/electricity/wholesale/."

Historic Wholesale Mid-C Price Trends (July 2020-Current)

Recent price spikes driven by wildfire events in the region have largely receded and are more moderate in nature compared to previous price spikes.





Source: Wholesale Electricity and Natural Gas Market Data, U.S. Energy Information Administration, available online at: “https://www.eia.gov/electricity/wholesale/."

Historic Operating Statistics vs. Mid-C Implied Market Clearing Heat Rate

	(a) Mid-C Price ($/MWh)	(b) AECO Price ($/MMBtu)	(c = a / b) * 1000 Implied Heat Rate (Btu/kWh)	(d) AECO Price ($/MMBtu)	(e) EIA 2018 NGCC Heat Rate (Btu/kWh)	(f = d * e) / 1000 Implied NGCC Fuel Cost ($/MWh)	Implied Capacity Premium ($/MWh)
Mar. 2013 to Dec. 2013	$ 32.56	$ 3.07	10,593	$ 3.07	7,627	$ 23.45	$ 9.12
2014	$ 33.00	$ 4.07	8,117	$ 4.07	7,627	$ 31.01	$ 1.99
2015	$ 23.11	$ 2.12	10,917	$ 2.12	7,627	$ 16.15	$ 6.97
2016	$ 19.91	$ 1.64	12,162	$ 1.64	7,627	$ 12.48	$ 7.42
2017	$ 21.09	$ 1.67	12,625	$ 1.67	7,627	$ 12.74	$ 8.35
2018	$ 30.25	$ 1.19	25,475	$ 1.19	7,627	$ 9.06	$ 21.19
2019	$ 35.66	$ 1.25	28,612	$ 1.25	7,627	$ 9.51	$ 26.16
Jan. 2020 to Sept. 2020	$ 17.87	$ 1.54	11,596	$ 1.54	7,627	$ 11.75	$ 6.12
Mar. 2013 to Sept. 2020	**$ 26.77**	**$ 2.08**	**12,843**	**$ 2.08**	**7,627**	**$ 15.90**	**$ 10.87**
Average Excluding 2018 and 2019	**$ 24.78**	**$ 2.38**	**10,424**	**$ 2.38**	**7,627**	**$ 18.13**	**$ 6.65**

Source: Platt's Megawatt Daily; and S&P Global; and EIA Average Tested Heat Rates by Prime Mover and Energy Source.

Mid-C Implied Required Natural Gas Price for CU4

	2013	2014	2015	2016	2017	2018	2019	Average	
Summer Capacity (kW)	629,000	629,000	629,000	629,000	629,000	629,000	629,000	629,000	
Fixed O&M Costs ($/kW-Year)	$ 29.13	$ 33.32	$ 28.41	$ 36.54	$ 34.47	$ 27.86	$ 28.67	$ 31.20	
Total Fixed O&M Costs ($000)	$ 18,323	$ 20,958	$ 17,870	$ 22,984	$ 21,682	$ 17,524	$ 18,033	$ 19,625	
Net Generation (MWh)	1,831,810	4,297,201	4,780,705	3,946,017	4,390,782	3,829,005	4,113,332	3,884,122	
Fuel Costs ($/MWh)	$ 16.20	$ 16.93	$ 16.28	$ 18.39	$ 17.30	$ 17.11	$ 19.14	$ 17.34	
Total Fuel Costs ($000)	$ 29,675	$ 72,752	$ 77,830	$ 72,567	$ 75,961	$ 65,514	$ 78,729	$ 67,334	
Non-Fuel Variable O&M Costs ($/MWh)	$ 3.22	$ 2.36	$ 3.05	$ 3.28	$ 3.24	$ 3.87	$ 3.51	$ 3.22	
Total Non-Fuel Variable O&M Costs ($000)	$ 5,898	$ 10,141	$ 14,581	$ 12,943	$ 14,226	$ 14,818	$ 14,438	$ 12,501	
Total O&M costs ($000)	$ 53,897	$103,851	$110,281	$108,494	$111,868	$ 97,856	$111,200	$ 99,460	**Average Excluding**
Total O&M costs ($/MWh)	$ 29.42	$ 24.17	$ 23.07	$ 27.49	$ 25.48	$ 25.56	$ 27.03	$ 25.61	**2018 and 2019**
Mid-C Implied Heat Rate (Btu/kWh)	10,593	8,117	10,917	12,162	12,625	25,475	28,612	15,500	**10,883**
Required Natural Gas Price ($/MMBtu)	$ 2.78	$ 2.98	$ 2.11	$ 2.26	$ 2.02	$ 1.00	$ 0.94	$ 1.65	**$ 2.38**

Source: Platt's Megawatt Daily; and S&P Global.

Historic Operating Margins, (2015 to 2019)

Witness: Dismukes
Docket No. 2019.12.101
Exhibit DED-7

Year	Total Market Value ($000)	Colstrip Unit 4 Fixed Costs $kW-Year	Colstrip Unit 4 Capacity MW	Total Fixed Costs ($000)	Total Market Value Net of Fixed Costs ($000)
2015	$ 19,777	$ 28.41	740	$ 21,021	$ (1,244)
2016	$ 10,567	$ 36.54	740	$ 27,041	$ (16,474)
2017	$ 20,407	$ 34.47	740	$ 25,505	$ (5,099)
2018	$ 54,509	$ 27.86	740	$ 20,619	$ 33,890
2019	$ 57,156	$ 28.67	740	$ 21,213	$ 35,942
Total CU4 Average	**$ 32,483**	**$ 31.19**	**740**	**$ 23,080**	**$ 9,403**
92.5 MW Acquisition	**$ 4,060**	**$ 31.19**	**92.5**	**$ 2,885**	**$ 1,175**

Source: Platt's Megawatt Daily; and S&P Global.

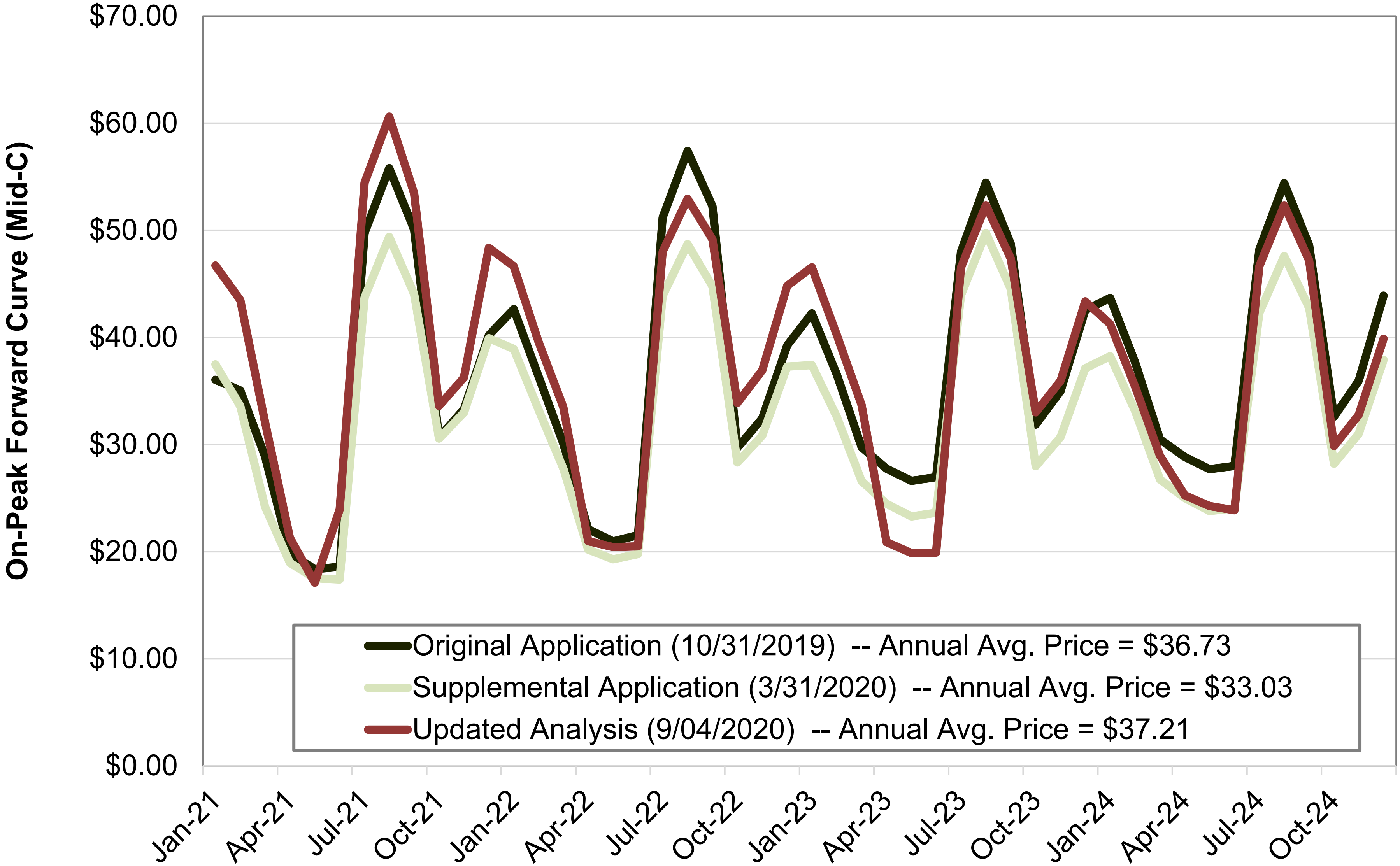
Peer Comparison of Historic and Projected Variable O&M Costs: Non-Fuel Variable O&M ($/MWh)

[redacted]

Peer Comparison of Historic and Projected Variable O&M Costs: Total Fuel Costs ($/MWh)

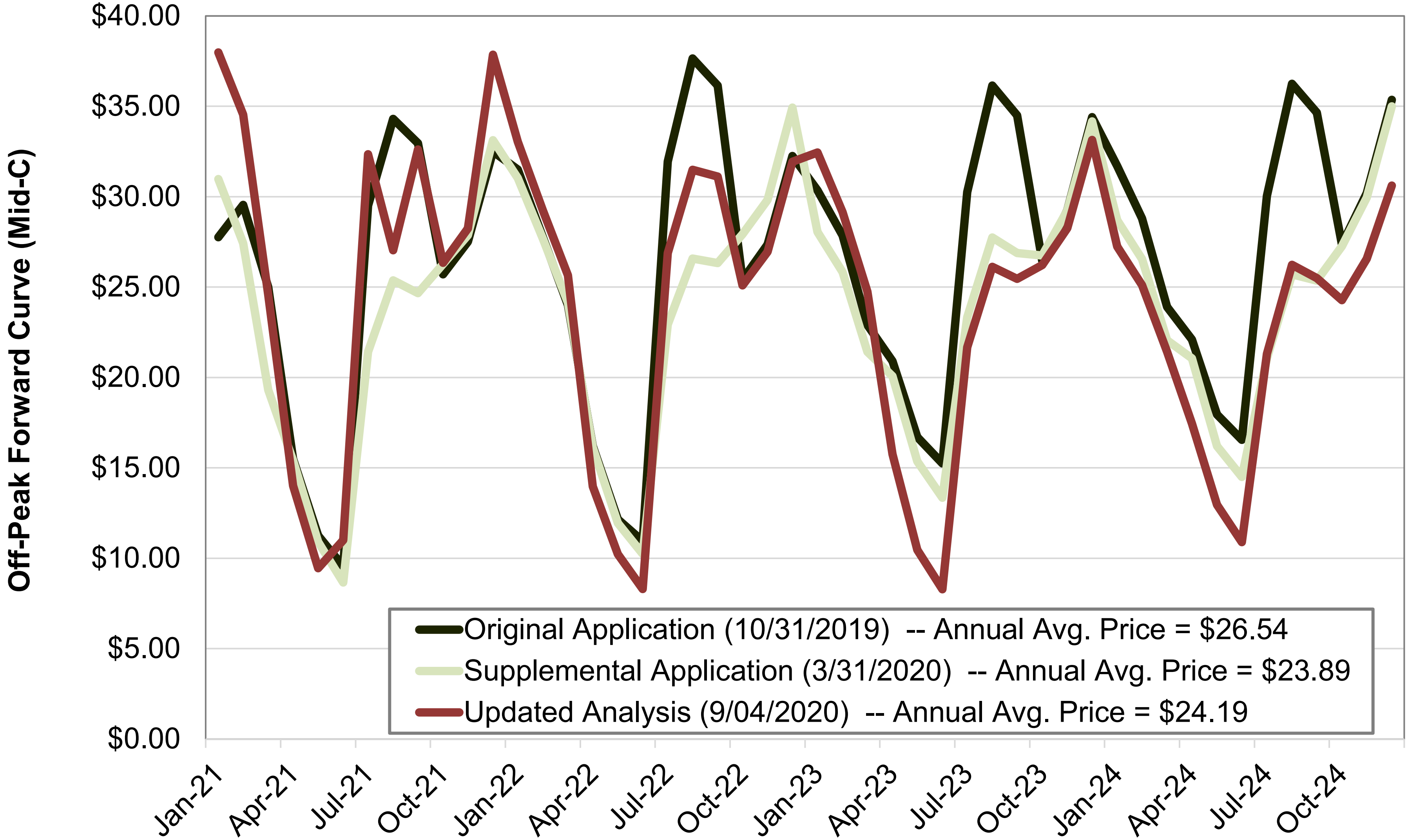
[redacted]

Comparison of Company Proposed and Updated Mid-C Forward Curves: On-Peak Mid-C Forward Curve



Source: Company's Responses to Data Requests MCC-027 and MEIC-079; S&P Global.

Comparison of Company Proposed and Updated Mid-C Forward Curves: Off-Peak Mid-C Forward Curve



Source: Company's Responses to Data Requests MCC-027 and MEIC-079; S&P Global.

Company Estimated Net Value from Proposed PPA

	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 9,438,277	$ 9,419,966	$ 9,377,076	$ 7,727,236	$ 9,279,286	$ 45,241,841
Fixed O&M Payment from PSE	$ 1,671,005	$ 1,664,564	$ 1,826,894	$ 1,695,354	$ 1,894,343	$ 8,752,161
Total Revenue	$ 11,109,282	$ 11,084,529	$ 11,203,970	$ 9,422,590	$ 11,173,629	$ 53,994,001
Variable Cost	$ 5,648,452	$ 5,648,452	$ 5,648,452	$ 4,719,940	$ 5,648,452	$ 27,313,749
Other Costs	$ 4,284,622	$ 4,292,394	$ 4,390,617	$ 5,487,341	$ 4,609,510	$ 23,064,485
Total Expenses	$ 9,933,075	$ 9,940,847	$ 10,039,069	$ 10,207,281	$ 10,257,962	$ 50,378,234
Net Value	$ 1,176,207	$ 1,143,682	$ 1,164,901	$ (784,691)	$ 915,667	$ 3,615,767
Net Value (NPV)						$ 3,108,328

Source: Company's Updated Response to Data Request MEIC-79.

Company Estimated Net Value from Proposed PPA Under Backcast

Witness: Dismukes
Docket No. 2019.12.101
Exhibit DED-11

	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 11,657,930	$ 11,641,871	$ 11,620,975	$ 9,999,524	$ 11,581,525	$ 56,501,825
Fixed O&M Payment from PSE	$ 1,415,814	$ 1,461,131	$ 1,522,282	$ 1,408,680	$ 1,637,735	$ 7,445,642
Total Revenue	$ 13,073,744	$ 13,103,002	$ 13,143,258	$ 11,408,205	$ 13,219,259	$ 63,947,467
Variable Cost	$ 5,648,452	$ 5,648,452	$ 5,648,452	$ 4,704,464	$ 5,648,452	$ 27,298,274
Other Costs	$ 4,295,741	$ 4,303,819	$ 4,401,593	$ 5,498,580	$ 4,621,088	$ 23,120,822
Total Expenses	$ 9,944,194	$ 9,952,271	$ 10,050,046	$ 10,203,044	$ 10,269,541	$ 50,419,096
Net Value	$ 3,129,550	$ 3,150,731	$ 3,093,212	$ 1,205,160	$ 2,949,719	$ 13,528,372
Net Value (NPV)						$ 11,246,452

Source: Company's Updated Response to Data Request MEIC-80.

Revised Estimated Net Value from Proposed PPA – Using Updated Forecasted Market Prices

	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 10,517,995	$ 9,985,262	$ 9,861,072	$ 8,023,891	$ 9,492,404	$ 47,880,625
Fixed O&M Payment from PSE	$ 1,159,365	$ 1,323,481	$ 1,516,955	$ 1,716,581	$ 1,632,753	$ 7,349,135
Total Revenue	$ 11,677,360	$ 11,308,742	$ 11,378,027	$ 9,740,472	$ 11,125,157	$ 55,229,760
Variable Cost	$ 8,371,329	$ 8,696,783	$ 9,039,774	$ 7,856,106	$ 9,783,544	$ 43,747,535
Other Costs	$ 4,287,838	$ 4,293,664	$ 4,391,602	$ 5,489,140	$ 4,609,236	$ 23,071,480
Total Expenses	$ 12,659,167	$ 12,990,446	$ 13,431,376	$ 13,345,246	$ 14,392,779	$ 66,819,015
Net Value	$ (981,807)	$ (1,681,704)	$ (2,053,349)	$ (3,604,774)	$ (3,267,622)	$ (11,589,255)
Net Value (NPV)						$ (9,165,572)

Note: Company's analysis revised to account for increases in variable operating costs shown in Exhibit DED-8.
Source: S&P Global; Company's Updated Response to Data Request MEIC-79.

Revised Estimated Net Value from Proposed PPA – Using Historic Market Prices

	2015	2016	2017	2018	2019	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 8,834,950	$ 8,738,153	$ 9,001,426	$ 9,382,357	$ 11,471,401	$ 47,428,287
Fixed O&M Payment from PSE	$ 2,465,513	$ 2,565,055	$ 2,514,896	$ 1,571,913	$ 1,604,525	$ 10,721,903
Total Revenue	$ 11,300,464	$ 11,303,208	$ 11,516,322	$ 10,954,271	$ 13,075,925	$ 58,150,189
Variable Cost	$ 6,629,845	$ 7,431,880	$ 7,042,667	$ 5,991,174	$ 7,768,450	$ 34,864,016
Other Costs	$ 4,285,705	$ 4,293,632	$ 4,392,385	$ 5,496,011	$ 4,620,277	$ 23,088,009
Total Expenses	$ 10,915,550	$ 11,725,512	$ 11,435,052	$ 11,487,185	$ 12,388,727	$ 57,952,025
Net Value	$ 384,914	$ (422,304)	$ 81,270	$ (532,914)	$ 687,199	$ 198,165
Net Value (NPV)						$ 141,096

Note: Backcast revised to reflect actual operating conditions during the years 2015 through 2019.
Source: Platt's Megawatt Daily; and Company’s Updated Response to Data Request MEIC-80.

Revised Estimated Net Value Removing Fixed Cost Contribution: Company Estimated without Fixed Cost Contribution

	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 9,438,277	$ 9,419,966	$ 9,377,076	$ 7,727,236	$ 9,279,286	$ 45,241,841
Fixed O&M Payment from PSE	$ -	$ -	$ -	$ -	$ -	$ -
Total Revenue	$ 9,438,277	$ 9,419,966	$ 9,377,076	$ 7,727,236	$ 9,279,286	$ 45,241,841
Variable Cost	$ 5,648,452	$ 5,648,452	$ 5,648,452	$ 4,719,940	$ 5,648,452	$ 27,313,749
Other Costs	$ 4,284,622	$ 4,292,394	$ 4,390,617	$ 5,487,341	$ 4,609,510	$ 23,064,485
Total Expenses	$ 9,933,075	$ 9,940,847	$ 10,039,069	$ 10,207,281	$ 10,257,962	$ 50,378,234
Net Value	$ (494,798)	$ (520,881)	$ (661,993)	$ (2,480,045)	$ (978,676)	$ (5,136,394)
Net Value (NPV)						$ (4,057,882)

Source: Company's Updated Response to Data Request MEIC-79.

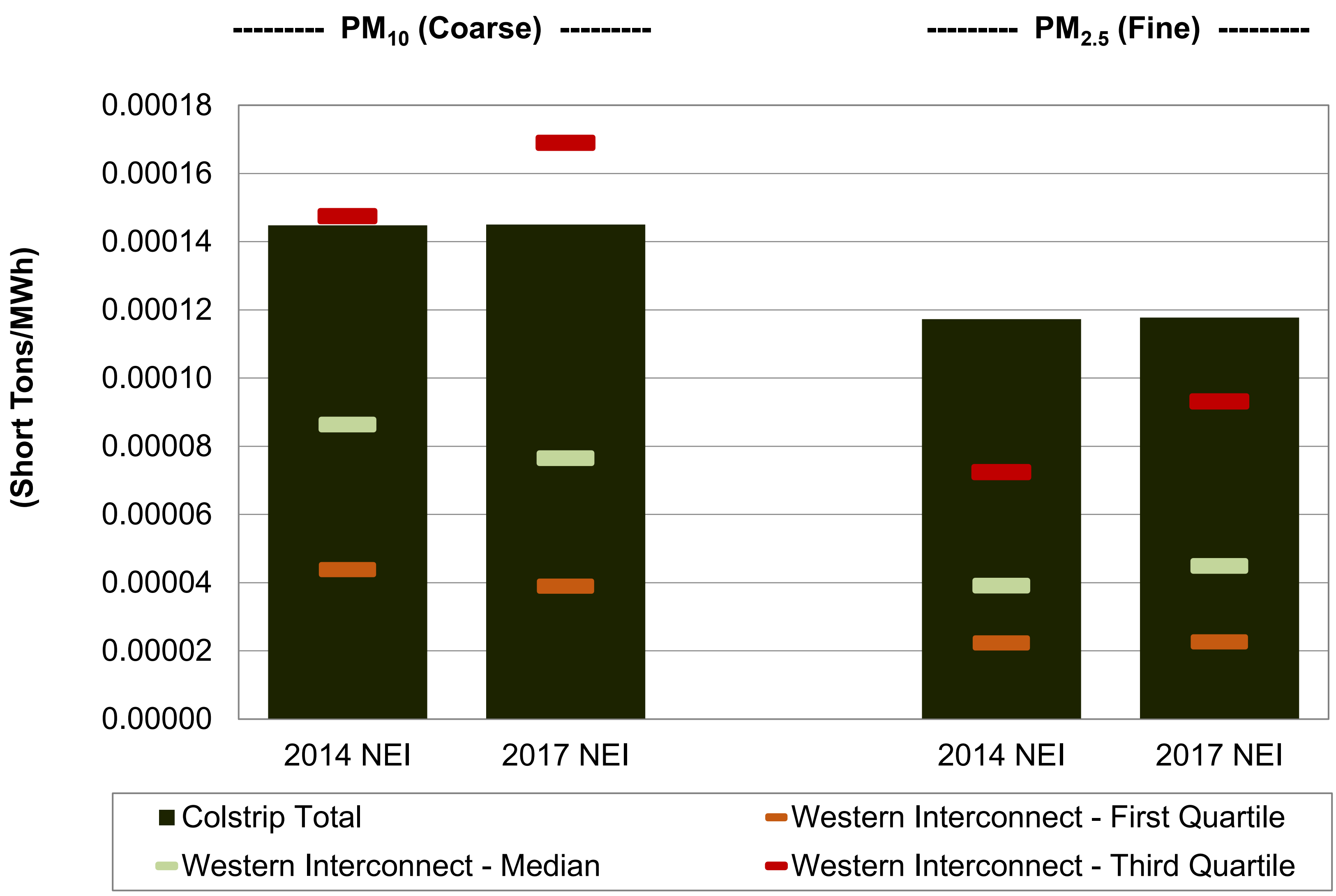
Revised Estimated Net Value Removing Fixed Cost Contribution: Revised Estimate without Fixed Cost Contribution

	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	Total
Proposed PPA Under 92.5 MW Total Acquisition						
Sales Revenue	$ 10,517,995	$ 9,985,262	$ 9,861,072	$ 8,023,891	$ 9,492,404	$ 47,880,625
Fixed O&M Payment from PSE	$ -	$ -	$ -	$ -	$ -	$ -
Total Revenue	$ 10,517,995	$ 9,985,262	$ 9,861,072	$ 8,023,891	$ 9,492,404	$ 47,880,625
Variable Cost	$ 8,371,329	$ 8,696,783	$ 9,039,774	$ 7,856,106	$ 9,783,544	$ 43,747,535
Other Costs	$ 4,287,838	$ 4,293,664	$ 4,391,602	$ 5,489,140	$ 4,609,236	$ 23,071,480
Total Expenses	$ 12,659,167	$ 12,990,446	$ 13,431,376	$ 13,345,246	$ 14,392,779	$ 66,819,015
Net Value	$ (2,141,172)	$ (3,005,184)	$ (3,570,304)	$ (5,321,355)	$ (4,900,375)	$ (18,938,390)
Net Value (NPV)						$ (15,130,398)

Note: Company's analysis revised to account for increases in variable operating costs shown in Exhibit DED-8.
Source: S&P Global; Company's Updated Response to Data Request MEIC-79.

Peer Comparison of Coal Unit Particulate Matter ("PM") Emissions

Witness: Dismukes
Docket No. 2019.12.101
Exhibit DED-15



Note: Data includes only Western Interconnect coal plants.
Source: National Emissions Inventory ("NEI"), Environmental Protection Agency; and U.S. Energy Information Administration.

Excerpt of Direct Testimony of Cindy L. Song; WUTC Docket No. UE-200115

Q. Please summarize your testimony.

A. The purpose of my testimony is to provide the quantitative analysis performed in support of the potential sale of PSE's interests in Colstrip Unit 4. My testimony is focused on the quantitative analysis only. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1T, for a discussion of (i) the qualitative factors considered in the potential sale of PSE's interests in Colstrip Unit 4 to NorthWestern Energy and (ii) all factors considered in the potential sale of (a) an 8.2 percent interest in the Colstrip to Broadview Segment of the Colstrip Transmission System and (b) a 9.1 percent interest in the Broadview to Townsend Segment of the Colstrip Transmission System. Also included in the Prefiled Direct Testimony of Mr. Roberts, Exh. RJR-1T, is a discussion of the contract terms for the transactions described above and for a five-year power purchase agreement with NorthWestern Energy for 90 megawatts (MW) of output from Colstrip Unit 4, commencing June 1, 2020, and expiring on May 15, 2025 (the "NorthWestern Energy PPA"). Collectively, these transactions are referred to as the "Proposed Transactions" throughout this testimony.

Q. What were the results of the quantitative analyses performed in support of the potential sale of PSE's interests in Colstrip Unit 4, and what conclusion did PSE draw from these results?

A. PSE's analyses of the proposed sale of PSE's interests in Colstrip Unit 4 (referred to as the "Proposed Colstrip Unit 4 Sale" throughout this testimony) consistently demonstrated an economic benefit to PSE customers over the status quo. The final

results, which were presented to the Board of Directors in October 2019, project that the Proposed Colstrip Unit 4 Sale would result in a net present value savings of approximately $25 to $46 million[1] compared to a Business As Usual scenario (representing the costs associated with ongoing PSE ownership interests in Colstrip Unit 4). PSE determined from these results that the Proposed Colstrip Unit 4 Sale represents a quantitatively prudent solution to help meet PSE's obligation under the Clean Energy Transformation Act to eliminate coal-fired generation from its resource portfolio before 2026 that presents no harm to customers.

II. BACKGROUND AND TIMING

Q. Please provide a timeline of the quantitative analyses conducted by PSE to support the Proposed Colstrip Unit 4 Sale.

A. NorthWestern Energy first approached PSE in July 2019 regarding the Proposed Transactions. At the time, this was a relatively conceptual offer with few details. Based on this preliminary information presented by NorthWestern Energy, PSE performed an initial quantitative analysis on July 22, 2019 to determine the financial feasibility of the Proposed Colstrip Unit 4 Sale. As the conversation continued with NorthWestern Energy between July and October 2019 and more information became available, PSE continued to refine its analysis of the Proposed Colstrip Unit 4 Sale. This testimony describes PSE's analytical

[1] As used in this testimony, total costs and savings refers to net present value.

Source: In the Matter of the Application of Puget Sound Energy For an Order Authorizing the Sale of All of Puget Sound Energy's Interests in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System; WUTC Docket No. UE-191037; Prefiled Direct Testimony of Cindy L. Song (Redacted) at 2-3.

Exhibit CLS-7;
WUTC Docket No. UE-200115

Witness: Dismukes
Docket No. 2019.12.101
Exhibit DED-17

Scenario 1 - No Hedging

Line	*$ in millions*	12-month ending May 2021	May 2022	May 2023	May 2024	May 2025
1	**90 MW NWE PPA**					
2	NWE PPA capacity	90 MW	90 MW	90 MW	90 MW	90 MW
3						
4	Energy (MWh)	483,692	460,969	457,209	453,600	457,332
5	Market price ($/MWh)	$26.7/MWh	$26.5/MWh	$25.6/MWh	$26.4/MWh	$28.1/MWh
6	Subtotal PPA cost	$13 M	$12 M	$12 M	$12 M	$13 M
7	O&M Adder	$3 M	$3 M	$3 M	$3 M	$3 M
8	**Total PPA**	**$16 M**	**$15 M**	**$15 M**	**$15 M**	**$16 M**
9						
10	**95 MW Replacement**					
11	Energy replacement					
12	Replacement energy (MWh)	510,564	486,579	482,609	478,800	482,739
13	Mid-C price ($/MWh)	$26.7/MWh	$26.5/MWh	$25.6/MWh	$26.4/MWh	$28.1/MWh
14	**Energy replacement**	**$14 M**	**$13 M**	**$12 M**	**$13 M**	**$14 M**
15						
16	Replacement capacity winter only					
17	Capacity (MW)	95 MW	95 MW	95 MW	95 MW	95 MW
18	Capacity charge	$12.0/kw-yr	$12.3/kw-yr	$12.6/kw-yr	$12.9/kw-yr	$13.2/kw-yr
19	**Capacity replacement cost**	**$1 M**	**$1 M**	**$1 M**	**$1 M**	**$1 M**
20						
21	**Total cost (line 8+14+19)**	**$31 M**	**$29 M**	**$28 M**	**$29 M**	**$31 M**
22						
23	Total capacity	185 MW	185 MW	185 MW	185 MW	185 MW
24	Total energy MWh	994,256	947,548	939,818	932,400	940,072
25	Cost $/MWh (line 21 / 24)	$31.3/MWh	$30.8/MWh	$30.0/MWh	$31.3/MWh	$33.3/MWh
26						
27	**Total cost NPV (line 21)**	**$122 M**				
28	**Cost $/MWh (5-year average)**	**$31.3/MWh**				

Source: In the Matter of the Application of Puget Sound Energy For an Order Authorizing the Sale of All of Puget Sound Energy's Interests in Colstrip Unit 4 and Certain of Puget Sound Energy's Interests in the Colstrip Transmission System; WUTC Docket No. UE-191037; Prefiled Direct Testimony of Cindy L. Song (Redacted) at Exhibit CLS-7, tab "No Hedging."

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing direct testimony of Ralph C. Smith and David E. Dismukes on behalf of the Montana Consumer Counsel has been served upon the following persons by email this 25th day of September 2020.

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