Exhibit No. SC-0001

DIRECT TESTIMONY OF PAUL CHERNICK

ON BEHALF OF SIERRA CLUB

Public Version

PUBLIC VERSION

Exhibit No. SC-0001-PUBLIC

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

BASIN ELECTRIC POWER COOPERATIVE		**DOCKET NOS. ER20-2441-002**
		ER20-2442-002
		EL20-68-002
		ER21-426-001
		ER21-768-002
		ER21-682-002
		(CONSOLIDATED)

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

SIERRA CLUB

Resource Insight, Inc.

July 15, 2022

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

BASIN ELECTRIC POWER COOPERATIVE	**DOCKET NOS. ER20-2441-002** **ER20-2442-002** **EL20-68-002** **ER21-426-001** **ER21-768-002** **ER21-682-002** **(CONSOLIDATED)**

SUMMARY OF DIRECT TESTIMONY OF
PAUL CHERNICK
ON BEHALF OF
SIERRA CLUB

Mr. Paul Chernick's testimony reviews the prudence and usefulness of several generation assets of Basin Electric Power Cooperative ("Basin") to determine whether the costs associated with those units included in Basin's 2019 and 2020 rates are just and reasonable.

Mr. Chernick starts with a description of the continuing responsibility of each electric utility to prudently review the prospective costs of existing generation resources and the costs of replacement resources to determine whether replacement of the resource would benefit customers, especially when circumstances change; and the responsibility of electric utilities, when faced with a major investment decision at a given generation resource, to assess whether retirement and replacement of the unit is a less-cost option and should be pursued in lieu of further investment.

Second, Mr. Chernick provides background information on the geographical regions and market structures in which Basin operates, as well as recent trends in retirement and fuel-switching of coal-fired power plants, which should have informed Basin's decisions regarding which economic evaluations it should have been undertaking in the 2010s.

Third, Mr. Chernick reviews Basin's own evaluations of the cost-effectiveness of continued operation of its coal three coal-fired power plants connected to the Eastern Interconnection: Leland Olds, Antelope Valley, and Laramie River 1. He explains that the documents produced by Basin in this proceeding do not demonstrate that Basin engaged in prudent decision-making processes with respect to any of these three generating plants or prudently managed its generation resources.

Mr. Chernick then describes the available information on the costs associated with operating these eastern coal plants, and the costs of replacement resources, including renewables, capacity purchases, and new combustion turbine peakers. He also describes the contribution of renewable resources to meeting Basin's capacity requirements. For comparison with the costs of continued operation of Basin's coal plants, Mr. Chernick constructs models of replacement portfolios with energy and capacity values similar to those coal-fired plants based on resource offers available to Basin during the mid-2010s.

Mr. Chernick then compares, for each of the coal units, the costs of continued operation of the unit to the costs of short-term market purchases and to the costs of constructing new resources, both for routine operation and in the context of major investments (when applicable) that Basin was required to make in order to keep Leland Olds, Antelope Valley and Laramie River 1 in operation.

Mr. Chernick concludes that Basin was imprudent in not conducting cost-benefit analyses of continued operation of the eastern coal plants throughout the 2010s, and that if Basin had conducted such an analysis and acted prudently on the basis of its findings, Basin would have probably have retired at least Leland Olds and likely one or more additional units at Antelope Valley or Laramie River before the beginning of the rate period at issue here. He also concludes that serious analysis and planning would have allowed Basin to avoid capital additions that increased its revenue requirements in 2019 and 2020, as well as some of the costs of operating some of the units in those years. Mr. Chernick finds that Basin's costs in 2019 and 2020 could have been tens of millions of dollars lower if it had acted prudently starting in 2015 or earlier.

Including his testimony, Mr. Chernick sponsors the following seventy-seven exhibits:

Exhibit SC-0001	Direct Testimony of Paul Chernick on Behalf of Sierra Club
Exhibit SC-0002	Paul Chernick Curriculum Vitae
Exhibit SC-0003	CUI-PRIV HC-SC-BEPC-1.029.104
Exhibit SC-0004	SC-BEPC 1.117.046
Exhibit SC-0005	CUI-PRIV-HC SC-BEPC-1.029.098
Exhibit SC-0006	CUI-PRIV-HC-SC-BEPC-1.029.206
Exhibit SC-0007	CUI-PRIV-HC-SC-BEPC-1.029.209

Exhibit SC-0008	CUI-PRIV-HC-SC-BEPC-1.029.049
Exhibit SC-0009	CUI-PRIV-HC SC-BEPC-1.038.001
Exhibit SC-0010	CUI-PRIV-HC-SC-BEPC-1.029.274
Exhibit SC-0011	CUI-PRIV-HC SC-BEPC-1.038.005
Exhibit SC-0012	1.40.44-CUI-PRIV-SC-BEPC
Exhibit SC-0013	CUI-PRIV-HC SC-BEPC-1.038.004
Exhibit SC-0014	CUI-PRIV-HC SC-BEPC-1.038.007
Exhibit SC-0015	SC-BEPC-4.005.001 through SC-BEPC-4.005.010
Exhibit SC-0016	SC-BEPC-4.010
Exhibit SC-0017	MEC-BEPC-2.42.110
Exhibit SC-0018	CUI-PRIV-HC-SC-BEPC-1.029.012
Exhibit SC-0019	CUI-PRIV-HC-SC-BEPC-1.029.067
Exhibit SC-0020	CUI-PRIV-HC-SC-BEPC-1.029.052
Exhibit SC-0021	CUI-PRIV-HC-SC-BEPC-1.047.011
Exhibit SC-0022	CUI-PRIV-HC-SC-BEPC-1.047.023
Exhibit SC-0023	CUI-PRIV-HC-SC-BEPC-1.047.035
Exhibit SC-0024	CUI-PRIV-HC SC-BEPC-1.2.1a
Exhibit SC-0025	FERC Form 1 (2019)
Exhibit SC-0026	FERC Form 1 (2020)
Exhibit SC-0027	SC-BEPC-1.41.2
Exhibit SC-0028	CUI-PRIV-Basin Annual Reports (2013-2021)
Exhibit SC-0029	1.30.1-CUI-PRIV SC-BEPC
Exhibit SC-0030	1.30.2-CUI-PRIV-SC-BEPC
Exhibit SC-0031	CUI-PRIV SC-BEPC 1.038.002
Exhibit SC-0032	CUI-PRIV-HC SC-BEPC-1.038.006
Exhibit SC-0033	CUI-PRIV-HC-SC-BEPC-5.001.006, 5.0001.009, and 5.001.012
Exhibit SC-0034	CUI-PRIV-HC-SC-BEPC-5.001.001, 5.001.004 and 5.001.009
Exhibit SC-0035	CUI-PRIV-HC SC-BEPC-1.038.010
Exhibit SC-0036	CUI-PRIV-HC-SC-BEPC-8.004.049 through .072

Exhibit SC-0061	CUI-PRIV-HC-SC-BEPC-1.029.026
Exhibit SC-0062	SPP Planning Criteria, Revision 2.4 (February 4, 2021), available at www.spp.org/documents/58638/spp%20planning%20criteria%20v2.4.pdf
Exhibit SC-0063	Southwest Power Pool, Solar and Wind ELCC Accreditation (August 2019), available at https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf
Exhibit SC-0064	Southwest Power Pool, 2020 ELCC Wind and Solar Study Report, SPP Resource Adequacy (July 2021)
Exhibit SC-0065	2018 Integrated Resource Plan (2019-2028), Basin Electric Power Cooperative, submitted to the Western Area Power Administration, November 2018
Exhibit SC-0066	1.10.2-CUI-PRIV-HC SC-BEPC
Exhibit SC-0067	South Dakota Ten Year Plan 2020
Exhibit SC-0068	Lawrence Berkeley National Laboratory, Land-Based Wind Market Report: 2021 Edition, Figure 34, available at https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf.
Exhibit SC-0069	CUI-PRIV SC-BEPC 1.64.1a
Exhibit SC-0070	CUI-PRIV-SC-BEPC-1.029.185
Exhibit SC-0071	CUI-PRIV-SC-BEPC-9.004.004
Exhibit SC-0072	SC-BEPC-1.117.38
Exhibit SC-0073	Barry Cassell, “Basin to install SCR on one Laramie River unit for regional haze compliance,” TransmissionHub (January 25, 2016), available at www.transmissionhub.com/articles/2016/01/basin-to-install-scr-on-one-laramie-river-unit-for-regional-haze-compliance.html
Exhibit SC-0074	CUI-PRIV-SC-BEPC-9.004.003
Exhibit SC-0075	SC-BEPC-1.038a
Exhibit SC-0076	1.40.33-CUI-PRIV SC-BEPC
Exhibit SC-0077	SC-BEPC-1.12a
Exhibit SC-0078	1.102.1-CUI-PRIV SC-BEPC

LIST OF ACRONYMS

AVS:	Antelope Valley Station
CCR:	Coal Combustion Residuals
DCC:	Dakota Coal Company
DFS:	Dry Forks Station
DGC:	Dakota Gasification Company
ELCC:	Effective Load Carrying Capacity
ELG:	Effluent Limit Guidelines
FIP:	Federal Implementation Plan
LMP:	Locational Marginal Price
LOS:	Leland Olds Station
LRS:	Laramie River Station
MBPP:	Missouri Basin Power Project
MISO:	Midcontinent Independent System Operator
NWPP:	Northwest Power Pool
O&M:	Operations and Maintenance
PPA:	Power Purchase Agreement
PRB:	Powder River Basin
RMRG:	Rocky Mountain Reliability Group
RTO:	Regional Transmission Organization
SCR:	Selective Catalytic Recovery
SIP:	State Implementation Plan
SNCR:	Selective Non-Catalytic Recovery
SPP:	Southwest Power Pool
TCR:	Transmission Congestion Rights
WECC:	Western Electric Coordination Council
WEIS:	Western Energy Imbalance Service

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DIRECT TESTIMONY OF PAUL CHERNICK
ON BEHALF OF SIERRA CLUB

I. Introduction

A. Identification & Qualifications

Q: Please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., based in Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

In these roles, I have performed and presented analyses addressing the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit SC-0002.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 350 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and two U.S. Federal agencies. My past testimonies have included the review of the economics and prudence of continued operation of several power plants and purchased-power contracts that comprise part of the Basin fleet.

Q: Have you previously testified in other proceedings before the Commission?

A: Yes. I testified or filed affidavits in three proceedings, as listed in my resume.

Q: Have you testified previously regarding performance standards for electric utilities?

A: Yes. Those testimonies are listed in Exhibit No. SC-0002.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the purpose of your testimony?

A: I review the prudence and usefulness of the several generation assets of Basin Electric Power Cooperative ("Basin") to determine whether the costs associated with those units included in Basin's 2019 and 2020 rates are just and reasonable.

Q: Which documents have you reviewed in preparing this testimony?

A: I reviewed Basin's discovery responses to Sierra Club's requests, as well as searching Basin's responses to other parties' discovery requests for relevant materials. I have also reviewed and relied on:

- Basin's reports on FERC Form 1 for 2019, 2020 and 2021 (Basin did not file Form 1 until 2019);
- Basin's Annual Reports for 2010 through 2021;
- Hourly energy prices reported by SPP;
- Hourly output of the Basin coal units from the Environmental Protection Agency's Air Markets Program Data, now called the Clean Air Markets Program Data tool;
- Installed capacity and planned retirement data from the Energy Information Administration's annual Form 860 reports;
- Power plant energy output, fuel use, and fuel sources from the Energy Information Administration's annual Form 923 reports;
- Other Basin reports and press releases.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring Exhibit Nos. SC-0001 through SC-0077, which were relied on by me or people under my direct supervision to prepare my testimony:[1]

Exhibit SC-0001	Direct Testimony of Paul Chernick on Behalf of Sierra Club
Exhibit SC-0002	Paul Chernick Curriculum Vitae
Exhibit SC-0003	CUI-PRIV HC-SC-BEPC-1.029.104 (Resource Planning–Executive Session, June 2017)
Exhibit SC-0004	SC-BEPC 1.117.046 (Basin Board Minutes, September 2016)
Exhibit SC-0005	CUI-PRIV-HC SC-BEPC-1.029.098 (Asset Management, Resource Planning &Rates–Strategic Planning, May 2018)
Exhibit SC-0006	CUI-PRIV-HC-SC-BEPC-1.029.206 (Cooperative Planning Board Presentation, January 2014)
Exhibit SC-0007	CUI-PRIV-HC-SC-BEPC-1.029.209 (Cooperative Planning Board Presentation –Strategic Planning, June 2014)
Exhibit SC-0008	CUI-PRIV-HC-SC-BEPC-1.029.049 (Asset Management, Resource Planning &Rates–Strategic Planning, January 2019)
Exhibit SC-0009	CUI-PRIV-HC SC-BEPC-1.038.001 (Presentation titled “Project Dominoes,” describing the impact of losses at Leland Olds Station, March 2016)
Exhibit SC-0010	CUI-PRIV-HC-SC-BEPC-1.029.274 (Resource Planning Board Presentation –Strategic Planning, February 2018)
Exhibit SC-0011	CUI-PRIV-HC SC-BEPC-1.038.005 (Presentation describing options for the operation of Leland Olds Station Unit 1, May 2018)
Exhibit SC-0012	1.40.44-CUI-PRIV-SC-BEPC (Engineering and Construction Report, September 2016)

[1] In my testimony I refer to those exhibits which consist of documents produced in discovery by the filename associated with the document assigned by Basin (which includes the numerated request to which it is responsive), and have retained this naming convention for the filenames of the exhibits as filed with the Commission as well.

Exhibit SC-0013	CUI-PRIV-HC SC-BEPC-1.038.004 (Calculation of the impact of Leland Olds Station shutdown on margin, July 2017) (Excel workbook)
Exhibit SC-0014	CUI-PRIV-HC SC-BEPC-1.038.007 (Presentation describing options for the operation of Leland Olds Station Unit 1, May 2018)
Exhibit SC-0015	SC-BEPC-4.005.001 through SC-BEPC-4.005.010 (Cost Summary Reports for Basin Gas Units)
Exhibit SC-0016	SC-BEPC-4.010 (Basin response to Sierra Club request relating to materials provided to Burns & McDonnell in relation to Exhibit No. BE-0063)
Exhibit SC-0017	MEC-BEPC-2.42.110 (Basin Board Minutes, November 2013)
Exhibit SC-0018	CUI-PRIV-HC-SC-BEPC-1.029.012 (Asset Management, Resource Planning & Rates–Executive Session, February 2021)
Exhibit SC-0019	CUI-PRIV-HC-SC-BEPC-1.029.067 (Asset Management, Resource Planning & Rates Board Presentation, April 2019)
Exhibit SC-0020	CUI-PRIV-HC-SC-BEPC-1.029.052 (Asset Management, Resource Planning &Rates Board Presentation, March 2019)
Exhibit SC-0021	CUI-PRIV-HC-SC-BEPC-1.047.011 (January 2020 Generator Profit and Loss Report)
Exhibit SC-0022	CUI-PRIV-HC-SC-BEPC-1.047.023 (January 2021 Generator Profit and Loss Report)
Exhibit SC-0023	CUI-PRIV-HC-SC-BEPC-1.047.035 (January 2022 Generator Profit and Loss Report)
Exhibit SC-0024	CUI-PRIV-HC SC-BEPC-1.2.1a (Coal Unit Costs)
Exhibit SC-0025	FERC Form 1 (2019)
Exhibit SC-0026	FERC Form 1 (2020)
Exhibit SC-0027	SC-BEPC-1.41.2 (economic analysis that was conducted in association with the extension of the Antelope Valley Station unit 2 lease)
Exhibit SC-0028	CUI-PRIV-Basin Annual Reports (2013-2021)
Exhibit SC-0029	1.30.1-CUI-PRIV SC-BEPC (2019 Forecast of Dakota Gasification Company Coal Benefits)
Exhibit SC-0030	1.30.2-CUI-PRIV-SC-BEPC (2020 Forecast of Dakota Gasification Company Coal Benefits)

Exhibit SC-0031	CUI-PRIV SC-BEPC 1.038.002 (Calculation of the impacts of Leland Olds Station shutdown, March 2016) (Excel workbook)
Exhibit SC-0032	CUI-PRIV-HC SC-BEPC-1.038.006 (Calculations of the impact of options for the operation of Leland Olds Station Unit 1, May 2018) (Excel workbook)
Exhibit SC-0033	CUI-PRIV-HC-SC-BEPC-5.001.006, 5.0001.009, and 5.001.012 (Workpapers associated with P&L Reports: 2019-2023- 09.2018 Fixed & Variable LOS; Generation Dashboard Full Unit Plant Updates, 3.12.19; and 2019-2023- 9.2018 Fixed & Variable LOS)
Exhibit SC-0034	CUI-PRIV-HC-SC-BEPC-5.001.001, 5.001.004 and 5.001.009 (Workpapers associated with P&L Reports: 2012-2018 Fixed & Variable AVS; 2019-2023-9.2018 Fixed & Variable AVS; and Generation Dashboard Full Unit Plant Updates, 3.12.19)
Exhibit SC-0035	CUI-PRIV-HC SC-BEPC-1.038.010 (Presentation from Process Assessment Team regarding the optimal timing of a Leland Olds Station Unit 1 shutdown, July 2021)
Exhibit SC-0036	CUI-PRIV-HC-SC-BEPC-8.004.049 through .072 (Coteau Coal Invoices, January 2016 through December 2017)
Exhibit SC-0037	1.30-SC-BEPC (Basin response to Sierra Club request for estimates of the effect of DGC retirement on coal prices at Leland Olds and Antelope Valley)
Exhibit SC-0038	1.30.3-CUI-PRIV SC-BEPC (2021 Forecast of Dakota Gasification Company Coal Benefits)
Exhibit SC-0039	1.95.1-CUI-PRIV-SC-BEPC (2019 Forecast of Dakota Gasification Company Benefits)
Exhibit SC-0040	Bakken Energy, “Press Release: MHA Nation Partnering With Bakken Energy And Mitsubishi Power On Great Plains Hydrogen Hub,” available at www.bakkenenergy.com/press-releases/mha-nation-partnering-with-bakken-energy-and-mitsubishi-power-on-great-plains-hydrogen-hub/
Exhibit SC-0041	CUI-PRIV-HC SC BEPC 1.056.140 (Ongoing RFP Analysis Presentation, April 2018)
Exhibit SC-0042	1.14-CUI-PRIV-HC SC-BEPC (Basin response to Sierra Club request regarding unit commitment decision process for eastern coal units)

Exhibit SC-0043	CUI-PRIV-HC SC-BEPC 1.029.279 (Asset Management, Resource Planning & Rates, June 2018)
Exhibit SC-0044	SPP Market Monitoring Unit: Self-Committing in SPP Markets: Overview, impacts, and recommendations (December 2019), available at https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf
Exhibit SC-0045	1.10-CUI-PRIV-HC SC-BEPC (Basin response to Sierra Club request regarding Basin's hourly energy market offers and commitment decisions)
Exhibit SC-0046	1.12.5-CUI-PRIV-HC SC-BEPC (hourly day ahead submitted offers to SPP from January 1, 2017 through October 31, 2019) (Excel workbook)
Exhibit SC-0047	CUI-PRIV-SC-BEPC-1.033.156 (Minutes of MBPP Management Committee Meeting, September 2019)
Exhibit SC-0048	CUI-PRIV-SC-BEPC-1.033.134 (MBPP Draft Policy)
Exhibit SC-0049	SC-BEPC-1.11a (Basin response to Sierra Club request regarding Basin's unit commitment decision process for its coal units)
Exhibit SC-0050	1.12.1-CUI-PRIV-HC SC-BEPC (hourly day ahead submitted offers to SPP from November 1, 2019) (Excel workbook)
Exhibit SC-0051	CUI-PRIV-HC-SC-BEPC-5.001.040 (Workpaper associated with P&L Reports: 2020 CGS)
Exhibit SC-0052	CUI-PRIV-HC-SC-BEPC-5.001.048 (Workpaper associated with P&L Reports: 2020 PGS)
Exhibit SC-0053	CUI-PRIV SC-BEPC-1.51.1 (Asset Appendix: Long-Term Firm Power Purchase Agreements) (Excel workbook)
Exhibit SC-0054	SC-BEPC-1.056 (Basin response to Sierra Club request regarding RFPs issued by Basin)
Exhibit SC-0055	CUI-PRIV-HC-SC-BEPC-1.056.031 (summary of responses to RFPs issued by Basin Electric in 2016) (Excel workbook)
Exhibit SC-0056	FERC Form 1 (2021)
Exhibit SC-0057	CUI-PRIV-HC-SC-BEPC-1.056.032
Exhibit SC-0058	CUI-PRIV-HC-SC-BEPC-1.029.050 (Asset Management, Resource Planning &Rates Board Presentation, January 2019)
Exhibit SC-0059	CUI-PRIV-HC SC-BEPC 1.056.133 (Responses to 11/25/2019 Solar/Wind RFP)

Exhibit SC-0060	CUI-PRIV-HC-SC-BEPC-1.029.179 (Cooperative Planning Board Presentation, April 2015) (Excel workbook)
Exhibit SC-0061	CUI-PRIV-HC-SC-BEPC-1.029.026 (Asset Management, Resource Planning &Rates Board Presentation, June 2020)
Exhibit SC-0062	SPP Planning Criteria, Revision 2.4 (February 4, 2021), available at www.spp.org/documents/58638/spp%20planning%20criteria%20v2.4.pdf
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Exhibit SC-0064	Southwest Power Pool, 2020 ELCC Wind and Solar Study Report, SPP Resource Adequacy (July 2021)
Exhibit SC-0065	2018 Integrated Resource Plan (2019-2028), Basin Electric Power Cooperative, submitted to the Western Area Power Administration, November 2018
Exhibit SC-0066	1.10.2-CUI-PRIV-HC SC-BEPC (Basin Electric Offer Strategy Whitepaper)
Exhibit SC-0067	South Dakota Ten Year Plan 2020
Exhibit SC-0068	Lawrence Berkeley National Laboratory, Land-Based Wind Market Report: 2021 Edition, Figure 34, available at https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf.
Exhibit SC-0069	CUI-PRIV SC-BEPC 1.64.1a (Basin capacity sales and purchases in the SPP region)
Exhibit SC-0070	CUI-PRIV-SC-BEPC-1.029.185 (Transmission Engineering Construction, June 2020)
Exhibit SC-0071	CUI-PRIV-SC-BEPC-9.004.004 (Basin Memorandum, January 2016)
Exhibit SC-0072	SC-BEPC-1.117.38 (Basin Board Minutes, January 2016)
Exhibit SC-0073	Barry Cassell, "Basin to install SCR on one Laramie River unit for regional haze compliance," TransmissionHub (January 25, 2016), available at www.transmissionhub.com/articles/2016/01/basin-to-install-scr-on-one-laramie-river-unit-for-regional-haze-compliance.html

Exhibit SC-0074	CUI-PRIV-SC-BEPC-9.004.003 (Basin Memorandum, January 2016)
Exhibit SC-0075	SC-BEPC-1.038a (Basin response to Sierra Club request for continued operation analyses of coal-fired units)
Exhibit SC-0076	1.40.33-CUI-PRIV SC-BEPC (Engineering & Construction Report, January 2016)
Exhibit SC-0077	SC-BEPC-1.12a (Basin response to Sierra Club request regarding hourly bids and results for eastern coal units)
Exhibit SC-0078	1.102.1-CUI-PRIV SC-BEPC (Coteau Lignite Sales Agreement)

B. Issues

Q: What issues do you address in this testimony?

A: I address the following issues, as well as presenting some background on Basin and its members:

- The role of prudence in determining whether rates are just and reasonable.
- The adequacy of Basin's reviews of the economics of continued operation and major investments at its eastern coal plants.
- The economics of continued operation of Basin's eastern coal plants.
- The economics of alternative sources of energy and capacity available to Basin.
- The economics of certain of Basin's major capital additions compared to alternatives.

- If Basin's requested rates are just and reasonable given the inclusion of costs associated with certain generation units.

II. Summary of Findings

Q: Please summarize your conclusions with respect to the issues you have identified.

A: As an initial matter, nowhere in Basin's rate application or in any of its witness' direct testimony is there any evidence that the underlying costs associated with Basin's power generation were prudently incurred. Basin offered no affirmative testimony as to whether or how it evaluates the economic value of its current generation resources, assesses alternatives to those resources, or conducts retirement analyses when faced with significant capital investment decisions. Absent this evidence as part of its case-in-chief, Basin cannot support the conclusion that its rates are just and reasonable because there is no evidence that its revenue requirement reflects prudently incurred expenses.

Notwithstanding Basin's failure to explain whether and why its revenue requirement reflects the lowest reasonably achievable costs to meet its members' load requirements, Sierra Club submitted extensive discovery requests to determine if Basin had actually prudently managed its generation fleet. My review of the documents produced by Basin revealed that Basin has not engaged in prudent decision-making processes with respect to at least three of its generating assets:

Leland Olds Station, Antelope Valley Station, and Unit 1 of Laramie River Station. I then utilized the information provided by Basin as well as additional, publicly available documents (including information provided by Basin to this Commission and the Environmental Protection Agency pursuant to other regulatory requirements) to evaluate whether a prudent utility would have continued operating these units and made major investments in two plants (Leland Olds and Laramie River) and extended the lease of the third (Antelope Valley) since 2015 and included these costs in the rates at issue in this proceeding.

Based on my review of hundreds of Basin Board minutes and presentations, coal unit costs provided by Basin in discovery, Southwest Power Pool energy prices, and the cost of alternative sources of energy and capacity (new wind, solar, and combustion turbine facilities and bilateral capacity purchases from other utilities), as detailed in my testimony, I concluded that:

1. Basin did not engage in prudent planning practices. Prior to 2019, Basin simply did not consider in the long-term whether it would be prudent to retire one or more units early. This is especially troubling because by 2017, almost all of Basin's coal units in the Eastern Interconnection (Leland Olds, Antelope Valley and Laramie River 1) were operating at a loss relative to the relevant market energy and capacity prices and Basin was well aware of the availability of

competitively priced capacity resources to replace these units from Basin's own resource solicitations to support load growth. The prevailing industry-wide trend of coal plant retirements prompted by environmental compliance costs and rapidly declining cost of renewable energy should have prompted Basin to consider the prospective economics of these units (which it did not) and reevaluate whether continued operation of these units was prudent and in the best interest of its members.

2. Specifically, by at least 2016, Basin's internal analyses showed Leland Olds Unit 1 operated at a loss on an annual basis—its avoidable costs exceeded its value to ratepayers as a source of both energy and capacity. Rather than performing a rigorous alternatives analysis to assess the appropriate timing to retire this unit, Basin relied on a faulty analysis to conclude that **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** made retirement untenable. This conclusion was wrong. Had Basin given serious consideration to retiring or exiting the Leland Olds units along with coal units at Antelope Valley and Laramie River 1, it would have found that alternative sources of energy and capacity—specifically, wind power purchase agreements supplemented by capacity-only

contracts as a bridge to the construction of combustion turbines[2]—could meet its load requirements at significantly lower cost.

3. Basin thus acted imprudently under the continuing operation test for prudence. For example, Basin's eastern coal units operated at a loss between 2016 and 2020, yet Basin never realized that three of these units lost money every time they operated because it failed to assess the economic viability of these units continued operations. As a result of this failure to select a more cost-effective alternative, in the 2019-2020 two-year period, Leland Olds lost more than **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** Laramie River lost close to **[BEGIN CUI//PRIV/HC]**[redacted], **[END CUI//PRIV/HC]** and Antelope Valley lost more than **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** relative to market energy and capacity prices. A prudent utility faced with negative margins would have evaluated alternative sources of energy and capacity to replace those units and conducted a retirement

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[2] Basin could not have reasonably known in 2016 that batteries would become a cost-effective capacity resource by 2022, but depending on the timeline Basin selected for transitioning from contractual capacity to new resources, it may have been able to avoid constructing new thermal generation altogether in favor of storage resources.

analysis that compared continue operation of the money-losing plants to alternatives.

4. Compounding these continuing losses, Basin made major capital investments at Leland Olds and Laramie River after 2015 and extended the lease for Antelope Valley 2, and acted imprudently under the major investment test for prudence. Basin failed to adequately consider or take the opportunity to reduce operating costs and avoid unnecessary capital expenditures or life-extending projects at every one of Basin's eastern coal assets. Specifically, Basin undertook two major environmental compliance projects at Leland Olds (bottom ash dewatering to comply with the Effluent Limit Guidelines Rule and ash pond retrofits to comply with the Coal Combustion Residuals Rule) and one at Laramie River (installation of Selective Catalytic Reduction (SCR) technology to comply with the Regional Haze rule) in lieu of retiring the units, at enormous cost to its members. In 2020, Basin also extended its lease of Antelope Valley 2 to 2030.

Basin's imprudence resulted in the inclusion of excess costs in Basin's 2019 and 2020 rates. Had Basin acted prudently, it would have retired its uneconomic coal units and replaced them with alternative energy and also avoided unnecessary investment associated with those units. Together, these actions would have reduced Basin's proposed 2019 and 2020 rates as follows:

- Had Basin opted for retiring Leland Olds in lieu of the ash handling project, its revenue requirements would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower.
- Had Basin replaced Leland Olds 1 or Leland Olds 2 with renewable and capacity purchases by 2019, its revenue requirement would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and [redacted] **[END CUI//PRIV/HC]** lower, respectively, or **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for the entire plant.
- If Basin had retired Laramie River 1 in lieu of installing SCR, its revenue requirements would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower from the avoided investment and another **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower from reduced operating costs.
- If Basin had retired Antelope Valley 1 in favor of a combination of wind and capacity resources (purchase agreements and/or new combustion turbines), its costs would have been roughly **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower. If that

retirement avoided the lease extension, 2021 rates would be lower by another **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**

Q: Why did you limit your analysis to the eastern coal units?

A: Publicly reported market energy price data for the western system only started to become available in 2021. The Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) energy markets have operated for several years, and forward prices are available for multiple delivery points for multiple years. The western markets just started to be organized, under the SPP WEIS and the CAISO Energy Imbalance Market, so much less historical information is available. The major trading hubs for the western system, such as Palo Verde and Mid-Columbia, are rather remote from the Basin Wyoming plants, geographically and electrically.

For the purpose of this proceeding, I give Basin the benefit of the doubt and accept that it would have been difficult to assess the relative economic merit of its western-connected units. I have not concluded that the construction of Dry Fork and the continued operation of Laramie River Units 2 and 3 were prudent.

III. Prudent Utility Evaluation of Existing Generation Resources

A. Overview

Q: How does the standard of prudency come into play in this docket?

A: Basin has the burden to prove its rates are just and reasonable. This burden of proving a proposed rate is just and reasonable includes showing that the underlying costs were prudently incurred.

Q: What does the Commission consider in a prudence analysis?

A: Prudence analysis tests whether a utility has behaved reasonably, based on industry norms, using all professional tools objectively and competently. Prudence analysis examines whether the process leading to a utility's decision with a material impact on rates was reasonable.

Q: Is there a temporal quality to a prudence analysis?

A: In a prudence analysis hindsight is irrelevant, because a reasonable utility or generation cooperative can act only on facts known or reasonably knowable at the time of its decision. This aspect of such analyses will become important when I discuss what costs a utility should consider in a Major Investment and Continuing Operation Prudency Analysis.

Q: Assuming a utility's decision to build a generation source was prudent, is the utility relieved from further prudence reviews with respect to that source?

A: No, just because a utility prudently constructed and operated a plant does not mean that it is forever immune from reassessing whether it is prudent to maintain the plant in service. A prudent utility responds to changing circumstances that arise during the operating life of an existing asset, periodically reassessing whether its current plan and expenses constitute the reasonably least-cost means of providing reliable service to its ratepayers. A resource that was initially prudent to construct may become imprudent to operate if a utility ignores new circumstances which it knew or should have known of and which should have led to a reevaluation of options.

Q: What types of circumstances would warrant a re-evaluation?

A: There are at least two times when a utility should reevaluate its operational decisions: (1) when the utility is faced with the need for capital investment to continue the lawful operation of a unit or other major decision to make about further financial commitment to sustain operation of the unit; and (2) where changed circumstances warrant a review.

B. Major Investment Prudence Analysis

Q: What is prudent utility operation in the context of a major investment decision at an existing resource?

A: If faced with a major investment decision, a utility should evaluate whether it is more cost-effective to invest in and continue to operate a plant compared to the costs of alternatives. The prudence of a decision to continue operations with further investments is evaluated based on what a reasonable utility manager would do (and not do) in light of the circumstances known or reasonably knowable at the time the investment was made or expense was incurred. To assess whether a utility acted prudently (and thus whether the ongoing costs associated with a unit are justly and reasonably incorporated into rates), I consider whether that utility utilized a reasonable decision-making process and also whether the utility applied good judgment given the situation at the time it made the decision at issue. Throughout the rest of my testimony, I will refer to this as the Major Investment Prudency Test or Analysis.

Q: Please describe what you mean by "a reasonable decision-making process" in the context of Major Investment Prudency Analysis.

A: A reasonable decision-making process includes the appropriate steps to compare investing in the existing asset and alternatives, including identifying all feasible alternatives and comparing them objectively and over an appropriate forward-looking time-frame. The utility should explore alternatives with comparable levels of effort, expertise, and sophistication, as each generation resource poses technical challenges that require different types of technical expertise.

Q: Please describe what you mean by "good judgment given the situation at the time it made the decision at issue" in the context of a Major Investment Prudency Analysis.

A: The manager of a utility exercises good judgment if it applies the appropriate level of risk-assessment and care for both action and non-action alternatives, as a decision locks in costs and may lock out alternatives for a period of time, often decades. So, the utility must address multiple uncertainties, such as accounting for the risk of a lost opportunity, risk of future environmental regulation, fluctuations in regional market prices, and possible fuel-price volatility. Prudence analysis addresses whether the utility identified each future cost uncertainty, and then reasonably quantified its effects on alternative outcomes.

Q: When a utility is faced with a major investment decision with respect to a generation facility (e.g. a large capital investment is required to comply with a new environmental regulatory standard), is it reasonable for the utility to make

the investment without an analysis of the continuing economic value of the unit(s)?

A: Not in most cases. There may be some situations in which it is immediately apparent that there is no alternative to a major investment in an existing resource, but those would be exceptions to the rule. Failing to review plant economics under nonexceptional circumstances is inherently imprudent; whether that imprudence imposes unnecessary and unreasonable costs depends on the outcome.[3]

C. Continuing Operation Prudence Analysis

Q: Why should a utility re-evaluate its operational decision if circumstances change?

A: A decision which is initially prudent may become imprudent if a utility ignores new circumstances which it knew or should have known of and which should have led to a reevaluation of options. Material events—major penetration of renewable energy, cost breakthroughs and market entry by storage, or major changes in long-term market revenues or fuels forecasts—all affect whether continuing to operate an existing unit makes economic sense in light of the projected cost of alternatives. A utility has an obligation to routinely review economics of each resource,

[3] Driving under the influence of alcohol is always imprudent. Sometimes that action results in horrendous costs, sometimes in none.

especially where evidence suggests that changes (retirement, derating, fuel switching, mothballing, etc.) may reduce costs and risks to ratepayers. Throughout the rest of my testimony, I will refer to this as the Continuing Operation Prudency Analysis.

Q: What type of analysis would a utility do to assess the value of continuing to operate a plant in a Major Investment and Continuing Operation Prudency Analyses?

A: The proper comparison is of prospective and avoidable spending only. Sunk costs, prudent or imprudent, should not be included. Like any sunk cost, prior spending becomes irrelevant to the prospective decision. A prudent utility will look at the prospective costs that are avoidable for continuing to operate an existing asset compared to the prospective costs on alternatives. Specifically, the utility would analyze whether the unit's prospective or avoidable operating cost to provide capacity and energy exceeds the all-in (capacity and energy) costs of reasonable alternatives. In essence, the utility should only recover in its rates the avoidable costs associated with operating a unit where those costs result from prudent decisions based upon selecting reliable resources with the lowest total cost.

Q: Are costs the only relevant factor to consider?

A: No, costs are an important factor but not the only factor to consider. One should also consider at least the following: environmental compliance obligations (or the risk of future compliance obligations), electricity deliverability, fuel price volatility or hedging, reliability, ongoing maintenance costs, labor and equipment availability, permitting viability, use of existing transmission assets, and construction timelines.

Q: Does the fact that a generation asset has lost money in recent years mean a decision to change operation of that asset is warranted?

A: Not necessarily. Decisions about whether to retire, refurbish, sell, purchase or build a unit are long-term decisions. If there is good reason to believe that changing circumstances will turn losses into profits or savings, it may be reasonable to lose money for a short period to reap those benefits. But a prudent utility would not ignore these loses and would use the best available information in its long-term forecasting analysis of prospective costs of the existing unit compared to alternatives.

D. Prospective or Avoidable Operating Costs

Q: You mentioned above that prudence analyses for continued operation of existing resources require estimates of the costs that are avoidable by shutting down the unit, compared to the prospective costs on alternatives. Please describe what you mean by avoidable costs.

A: By avoidable cost, I mean any cost that would be avoided if the utility retired the unit. That category would include fixed O&M costs (such as labor costs), variable costs, and any future capital expenditures necessary to keep the plant running and compliant with environmental, reliability, and other rules.

Q: What if a utility can purchase power from the marketplace for a lower price than it can generate power?

A: In the short-term, if purchased energy is less expensive, a utility could meet ratepayers' needs through more purchases and/or reduced off-system sales (in a regional transmission organization, described in greater detail below, any excess of generation above the utility's hourly need can be considered off-system sales) rather than operating the unit in those hours. Even if purchased energy costs more than the short-term variable operating costs (including fuel), it may be imprudent to continue operating the unit if its medium- or long-term costs (which can be avoided over months or years) are higher than market purchases are anticipated to be over that term.

Q: What costs are variable and avoidable in the short term?

A: The distinction between variable and "fixed" costs is difficult because of the ambiguity of the concept of a cost being "fixed." Certain generation costs are called variable because they are short-term marginal costs that vary directly with output. These costs include, among others:

- Most fuel purchasing and waste disposal costs;

- Variable operating costs related to consumables (e.g., water, limestone, activated carbon, ammonia) injected to increase output, reduce emissions or provide cooling to the power plant as it produces energy; and
- Allowances or offsets that must be purchased to emit various pollutants.

Nearly every other utility cost has been described as fixed in one context or another, including capital, labor, materials and contract services. Most of these costs are fixed for the coming year, in the sense that they are committed (investments made, contracts signed, employees hired) and will not be immediately changed by usage levels (energy, demand or number of customers). However, almost all of these cost accounts are avoidable over a period of several years, except for sunk capital costs, and are relevant in determining whether derating, retiring or mothballing generation resources is a better option compared to an alternative resource.

As a result, many costs that a utility may reasonably refer to as "fixed" in some contexts are not truly fixed over the long-term-planning horizon. From an economic perspective more generally, all costs vary in the long run.

Q: Are all the costs associated with an existing power plant avoidable?

A: No. The sunk costs—previous investments in plant and equipment—are not avoidable. Some contractual obligations and allocated overheads may not be immediately avoidable. Retirement may accelerate some decommissioning costs that the owner would eventually bear even with longer operation, depending on how the site is to be used. But almost all fuel, operating and maintenance costs, future investments, and related overheads are avoidable.

Q. Do utilities typically treat all fuel costs as variable?

A. Yes. Most power plants are charged for the amount of fuel they take from their supplier. For plants with fuel stocks (oil, coal, biomass, nuclear), the accounting of the cost of fuel burned may vary, but the fuel used is counted as a cost, even if it was paid for months of years earlier. Similarly, many coal plants have contracts that set minimum delivery levels, but the plant operator will generally report that coal as being a variable cost.

E. Special Challenges in Evaluating Basin's Avoidable Costs

Q: What particular challenges arise in evaluating Basin's avoidable costs?

A: As discussed in Sections IV.B and VI.B, Basin sources all the lignite coal used by Antelope Valley and Leland Olds from its subsidiary Dakota Coal Company, which finances the Freedom Mine. Basin divides Freedom Mine fuel costs **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Importantly, almost all of these "fixed" costs are avoidable in the long-term.

Q: How does the treatment of a portion of Freedom Mine fuel costs as fixed affect prudency tests?

A: For most of the analyses I have seen, Basin treated as avoidable **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** that would have been avoidable if one or more units at Leland Olds or Antelope Valley were to cease taking coal altogether. Thus, Basin could not (and did not) determine whether a unit's prospective or avoidable operating cost to provide capacity and energy exceeded the costs of reasonable alternatives. I will discuss this in depth in Sections IV.B and VI.B. Basin includes only the **[BEGIN CUI//PRIV/HC]** [redacted]" **[END CUI//PRIV/HC]** analyses that it conducted from 2017 onward. Basin includes a **[BEGIN CUI//PRIV/HC]** [redacted] in its [redacted] **[END CUI//PRIV/HC]** analyses, but never fully identifies which fixed costs are avoidable.[4]

Q. Are the short-term variable costs relevant for any Basin decisions?

A: Yes. Basin's definition of variable fuel would be appropriate for making decisions about how to dispatch the units in the short-term energy market. If there are **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** that Basin cannot avoid in the next

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[4] Exhibit No. SC-0020, CUI-PRIV-HC-SC-BEPC-1.029.052, at 67.

week or month, due to its special relationship to the Freedom Mine, those should not be included in the next day's dispatch cost. But those costs should be included in deciding whether to run the unit in the longer term, in which the fixed costs are avoidable.

IV. Basin Background

Q: Please provide a brief overview of Basin's structure and any prior regulatory oversight of its rates.

A: Basin is a generation and transmission cooperative that serves approximately three million member-consumers in nine states (Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming).[5] Basin's members are 131 rural electric cooperatives.[6]

For much of its history, Basin has been exempted from Commission jurisdiction under Section 201(f) of the Federal Power Act because each of its member-cooperatives were themselves exempt. However, effective November 2019, Basin readmitted Tri-State Generation and Transmission Association, a non-exempt generation and transmission cooperative as a Class A member, and, separately, an existing member ceased to qualify for an exemption under Section

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[5] Exh. No. BE-0001 at 9.

[6] *Id.*

201(f). Basin accordingly submitted a petition, pursuant to Section 205 of the Federal Power Act, seeking approval of its Rate Schedule A and Wholesale Power Contracts as just and reasonable. Prior to the submission at issue here, Basin's rates had not been subject to regulatory oversight by the Commission or (so far as I am aware) any state or federal body.

Q: How does Basin make formal decisions about major investments and operating options?

A: Basin is governed by a Board composed of eleven members, of which one represents Tri-State Generation & Transmission Association (a generation and transmission cooperative that owns a large amount of its own generation and serves 45 distribution cooperatives and other entities), one represents eight cooperatives and a municipal utility agency not affiliated with any other generation & transmission cooperatives, and nine represent intermediate generation & transmission cooperatives purchasing all their generation services from Basin.[7]

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[7] Some of these nine intermediate generation & transmission cooperatives own generation entitlements that they resell to Basin for blending into the general power-supply mix.

A. Basin's Participation in Regional Planning Areas and Markets

Q: How does Basin serve member-cooperatives' loads?

A: Broadly, Basin serves customer load through three types of resource: (1) generation assets owned (or leased) and operated by Basin, (2) power purchased under power purchase agreements (PPAs) from generation assets owned by other entities or affiliates, and (3) purchases of SPP or MISO capacity credits and energy from the SPP or MISO markets.

Q: How is does the geographic reach of Basin's load interact with the regional grid system?

A. Basin serves members in both the Eastern Interconnection and the Western Interconnection. Basin's member cooperatives are located in four planning areas within these two interconnections. In the Western Interconnection, often referred to the Western Electric Coordination Council (WECC), Basin has members in western Montana, which is part of the Northwest Power Pool (NWPP), and in Wyoming, Colorado, and New Mexico, which are part of the Rocky Mountain Reliability Group (RMRG).[8] In the eastern connection, Basin serves members in two regional transmission organizations (RTOs): the Southwest Power Pool (SPP) and the

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[8] Basin also identifies the western areas with other names, such as WAPA Upper Missouri (WAUM) for the western part of Montana.

Midcontinent Independent System Operator (MISO). Both of these RTOs include Basin members in parts of Montana, North Dakota, South Dakota, Minnesota and Iowa: All of Basin's Nebraska members are in SPP. Figure 1 shows how Basin's member are spread across the four planning regions.

Figure 1: Basin Planning Regions, by Distribution Member Territory (CONF-Highly Confidential Privileged Material)

[redacted]

Source: Exhibit No. SC-0003, CUI-PRIV HC-SC-BEPC-1.029.104.

The MISO and SPP footprints are not cleanly separated, so a number of Basin's member distribution cooperatives have load in both RTO areas. Some cooperatives serve customers both in SPP and in the Western Interconnection, even though there is no direct connection between the Eastern and Western Interconnections on the alternating-current transmission system.

Q: What is the significance of the division of Basin's power plants and loads between the Eastern and Western Interconnections?

A: The Eastern and Western Interconnections are two of four major interconnections in North America: the others are the Electric Reliability Council of Texas (serving most of Texas) and Quebec. Internally, each of the four interconnections operates in synchrony, with very little variation in the frequency of the alternating-current power. The interconnections have limited electrical connections with one another, and those connections are all through direct-current equipment, so that disturbances on one interconnection cannot destabilize the others.

Basin has some access to the direct-current transfer points between the Eastern and Western Interconnections, which it uses primarily to transfer capacity from the west to the east. For the most part, planning for supply in the two interconnections is separate. In general, Basin plans separately for each of the four markets or areas into which it sells energy (*i.e.* MISO, SPP, NWPP, and RMRG).

Q: Are there any other important organizational differences between the Eastern and Western Interconnections?

A: Both SPP and MISO operate energy markets, in which Basin has been a participant since 2015. Basin has also participated in the MISO capacity market.

In the Basin western territory, there are no similarly organized energy markets. In 2021, SPP started operating a Western Energy Imbalance Service

(WEIS) market, which includes Basin, Tri-State, and the Western Area Power Administration, with additional generation owners committed to join.

Q: How do the SPP and MISO regional transmission organizations work?

A: An RTO coordinates the movement of wholesale electricity in a multi-state region. While the details of RTO operation differ among the seven North American organizations, all of them include an energy market, markets for ancillary services (e.g., operating reserves, automatic generation control, reactive power) and a capacity market or obligation.

The energy market schedules generators to meet load on a day-ahead basis, as well as dispatching resources in real time. The energy market balances supply and demand by continuously matching bids to provide electricity from generators and other resources with forecast or actual load, while maintaining capacity to provide ancillary services. All bids to supply electricity are stacked from lowest to highest, and accepted in that order until all requests for power (demand) have been met. At each location (node or bus) on the system, the market price that results from minimizing bid production cost is the marginal cost of providing one more megawatt of energy to that location or node. This market price is known as the locational marginal price (LMP) and every electricity supplier who "clears" the market is paid the price of the highest-accepted bid regardless of that supplier's actual offer.

Q: In regional transmission organizations, how do utilities' generation resources serve their load?

A: RTOs treat load and generators separately, even if they are associated with the same utility. Generators are dispatched to meet load throughout the market, and the market operator pays economic generators for their output. Meanwhile, utilities and other load-serving entities buy power from the market, supplied by all the dispatched generators, without any specific connection to who owns the resource. Therefore, the cost to serve load will not be the same as the utility's energy revenues.

Q: Please describe how generation assets typically bid their energy into a regional transmission organization, such as MISO and SPP.

A: Generators participating in a marketplace typically offer their power into the marketplace at the "variable" cost of production. Variable production costs include fuel, chemicals for the pollution control systems, water, and operation and maintenance costs that vary with the amount of production.

Q: Why is it important for a generator to offer power into the marketplace at no less than its actual variable cost of production?

A: A generator will recover its variable operating costs through its energy market revenues, as long as it economically and appropriately bids into the market. If a utility does not include all of its variable costs and the relevant locational marginal price is *above* the artificially low bid but *below* the actual marginal cost of generation, the generator will clear and operate, but lose money by generating electricity. Generally speaking, if a utility's variable costs exceed the locational marginal price, it would cost the utility less to purchase than generate electricity, and prudent utility practice would be to cease generation in favor of energy purchases to serve customer load, subject to ramping constraints at that resource.

Any profits on the energy market side—which are realized only when variable operating costs are below the market energy price—can be used to cover fixed costs, like capital costs. Coal-fired plants and others with large fixed and capital costs require significant energy margins—market revenues that far exceed the variable cost of production—to stay competitive on a net basis.

B. Basin's Generation Resources

Q: What is the role of coal in Basin's power supply and revenue requirements?

A: Costs associated with the mining, procurement, and/or use of coal in thermal electric generation are incorporated into Basin's rates in four ways:

- Basin operates, and owns some or all of, four coal-burning power plants: Leland Olds Station (LOS), Antelope Valley Station (AVS), Laramie River Station (LRS) and Dry Fork Station (DFS).
- Basin purchases the entitlement of two member-cooperatives' minority entitlements in three Iowa coal-fired units, George Neal 3, George Neal 4 and Walter Scott 4. These purchases are contracted

through 2075 (which is very likely to be longer than the remaining life of these units).

- Basin's wholly-owned subsidiary, Dakota Coal Company (DCC), finances the Freedom Mine, which currently provides all the lignite coal used by Leland Olds and Antelope Valley.[9]
- The other two Basin-operated coal-fired plants (Dry Fork and Laramie River) purchase Powder River Basin (PRB) coal on the market from multiple mines.
- Basin subsidiary Dakota Gasification Company (DGC) also uses lignite from the Freedom Mine in its Great Plains Synfuels Plant, splitting the fixed and joint costs of the mine with Leland Olds and Antelope Valley.

Q: Please describe Basin's coal-fired power plant entitlements.

A: Table 1 lists the coal-fired units, and for each, its total capacity, Basin's entitlement share of capacity, in-service date, and the market area to which it connects. The capacity values for some resources have changed over time, as I discuss below.

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[9] In the past, Leland Olds and Antelope Valley have burned small amounts of Powder River Basin (PRB) coal, including from the Dry Fork mine, which I will mention again below.

Table 1: Basin Coal Entitlements, as of 2020

Plant	Unit	Summer Capacity (MW)		In-Service Date	State	Market
		Total	Basin			
Leland Olds	1	221.0	221.0	1966	ND	SPP North
	2	445.0	445.0	1976	ND	SPP North
Antelope Valley	1	450.0	450.0	1984	ND	SPP North
	2	450.0	450.0	1985	ND	SPP North
Laramie River	1	560.0	92.0	1980	WY	SPP North
	2	570.0	313.5	1981	WY	RMRG
	3	570.0	313.5	1982	WY	RMRG
Dry Fork	1	390.0	362.3	2012	WY	RMRG
Neal	4	653.8	104.0	1979	IA	MISO Zone 3
Walter Scott	3	702.4	26.2	1978	IA	MISO Zone 3
Walter Scott	4	818.9	44.2	2007	IA	MISO Zone 3

Sources: Data from ER20-1505 Notice of Change in Status for SPP Region, Document Accession #: 20200407-5082; US Energy Information Administration, Form 860 (2020).
Regional detail from zonal maps.

Notes: Laramie River 1 capacity dropped from 570 MW (the same as the other Laramie River units) to 560 MW in 2019, due to the parasitic power load of the SCR installed that year. Exhibit No. SC-0004, SC-BEPC 1.117.046, at 21.

The regions in the western interconnection are identified by different names and abbreviations. The Rocky Mountain Reliability Group (RMRG) is one designation of the area including Basin's Wyoming plants and some of Basin's western load.

Q: Please explain the ownership structure of the coal-fired units in which Basin has an entitlement.

A: Basin is the sole owner and operator for Leland Olds 1 and 2 and has been since they were constructed. Basin originally financed Antelope Valley 1 in part with a leveraged lease, which it bought out in 2002.[10] Basin owned 92.9% of Dry Fork until 2021, when it bought out the minority owner.

The ownership of Antelope Valley 2, Laramie River, and the Iowa units are somewhat more complicated, as I discuss below.

Q: Please summarize Basin's other supply resources.

A: Table 2 summarizes Basin's other supply resources owned by purchased capacity in 2019 and/or 2020. Some of the contracts started or ended in this period, so not all of this capacity was available in every month of those years.

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[10] Stelter, S., *Generation for Generations, The 50-year history of Basin Electric Power Cooperative*, 2011, available at www.basinelectric.com/_files/pdf/Basin-Electric-50th-History-Book.pdf, at 200.

Table 2: Basin Non-Coal-Fired Resources 2019–2020 (MW)[11]

Type	Owned	Purchased
Wind	286	1,447
Combustion Turbine	866	
Internal Combustion	293	
Combined Cycle	324	
Member Assets		166
Capacity Only Contracts		1,140
Other		279
Total		3,031

Q: Please describe the ownership of Antelope Valley 2.

A: Basin operates, and has always operated, Antelope Valley 2 and receives all of its energy and capacity. Antelope Valley 2 was financed with six sale and leaseback agreements.[12] The leases were originally intended to terminate on December 30, 2015, but in 1992 Basin Electric extended the leases by an additional five-year term to December 30, 2020.[13] In May 2020, Basin agreed to two successive lease-extension terms (from December 30, 2020 to December 30, 2025, and from

[11] Asset Appendix: Generation Assets, Triennial Market Power Update for the SPP Region, Docket No. ER20-1505-004, Accession #202106290-5271, Attachment A.

[12] BEPC Application for Authority to Transfer Jurisdictional Facilities, FERC Docket No. EC21-22-000, Doc. Access. # 20201117-5179 at 9.

[13] *Id.* Exhibit I-3 at 2.

December 30, 2025 through December 30, 2030) with Antelope Valley 2's remaining three owners and trustee. Under the terms of the lease, Basin Electric must preserve the condition and operating efficiency of the unit (ordinary wear and tear excepted) in accordance with "prudent utility practice," but may otherwise operate the unit and make capital improvements at its discretion. Basin bought out **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the Antelope Valley 2 lease in **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[14]

Under the terms of the original Antelope Valley 2 lease agreements, Basin Electric had the option after 1995 to terminate the lease on 360 days' written notice if Basin Electric's Board of Directors certifies that the unit is "surplus to [its] requirements, …uneconomic to the Lessee or…economically obsolete due to a burdensome Applicable Law."[15] As part of the two-term renewal agreement signed in May 2020, this provision (Section 14) was revised to allow early termination of the lease after December 30, 2023 under the prior three circumstances *or* the retirement of Antelope Valley 2, provided that Basin Electric also retired Unit 1 or

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[14] Exhibit No. SC-0005, CUI-PRIV-HC SC-BEPC-1.029.098.

[15] BEPC Application for Authority to Transfer Jurisdictional Facilities, FERC Docket No. EC21-22-000, Doc. Access. # 20201117-5179 Exhibit I-1 at 30.

the circumstances making Unit 2 economically obsolete did not apply to Unit 1.[16] In other words: Basin Electric may terminate its lease of Antelope Valley 2 for economic obsolescence or retire the unit beginning in December 2023, notwithstanding the lease extension, so long as it *also* retires or fully divests itself of Unit 1 or the circumstances making Unit 2 economically obsolete do not apply to Unit 1.

Q: Please describe the ownership and cost-sharing arrangements for Laramie River Station.

A: In discussing the ownership and cost sharing for Laramie River Station, it is important to recall that Laramie River 1 is electrically connected to SPP in the Eastern Interconnection, while the other two units are connected to the RMRG region in the Western Interconnection. Even though they are physically quite similar and share a site, coal sources, and common facilities, the units operate in very different markets.

Basin has an undivided ownership share of about 42.27% in the Missouri Basin Power Project (MBPP), which includes Laramie River Station, the Grayrocks

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[16] BEPC Application for Authority to Transfer Jurisdictional Facilities, FERC Docket No. EC21-22-000, Doc. Access. # 20201117-5179. Exhibit I-3 at 3.

Dam and Reservoir, and transmission lines on both the Eastern and Western interconnections.[17] Capital and O&M costs for Laramie River (as well as the rest of the Missouri Basin Power Project) are shared by MBPP participants in proportion to their entitlement (*i.e.*, Basin pays 42.27% of those costs, regardless of which unit incurs the investment), while fuel and other energy-related expenses are allocated in proportion to each participant's monthly fuel requirement to produce its net scheduled energy. Each owner provides its own financing, including both interest during construction and once the investment enters service.

However, the entitlement shares to generation and capacity among the MBPP members vary between Laramie River 1, on the one hand, and Units 2 and 3 on the other. Basin is entitled to about 16.4% of Unit 1 output,[18] and 55% of the output from Units 2 and 3.[19]

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[17] MBPP Tariff Filing, Document Accession #: 20200710-5056, Cover Letter to Secretary Bose, at 5-6, 10; MBPP Participation Agreement Sections 11.2, F-1 and F-2. The capacity of the units and the ownership shares in the units have changed over time, and unit ownership mix and capacity factor vary among units. Thus, Basin's share of the MBPP capacity and energy may not be exactly 42.27% in any particular year.

[18] Basin owned 8.42% of Laramie River 1 through 2018, but increased its share to 16.43% in 2019 by purchasing a co-owner's share.

[19] US Energy Information Administration, Form 860 (2021).

Q: Please explain Basin's responsibility for investment decisions at Laramie River Station.

A: Basin serves as the Operating Agent of the MBPP, and in this capacity is responsible for "the operation and maintenance of the MBPP," including Laramie River Station.[20] In its role as Operating Agent, Basin is also responsible for all operations and maintenance at Laramie River Station, which includes all expenditures incurred or authorized after the date of commercial operation.[21] Under the current MBPP agreement, the votes of three of the four co-owners are required for action by the Management and Engineering and Operating Committees, provided the total ownership interest of those three members exceeds 50%.[22]

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[20] MBPP Tariff Filing, Document Accession #: 20200710-5056, MBPP Participation Agreement, Sections 11.2, F-1 and F-2.

[21] MBPP Participation Agreement Sections 11.1, 12.2, Document Accession #: 20210528-5391 Attachment A at 18-19; MBPP Operating Agreement Sections 4.1, 5, Document Accession #: 20210528-5391 Attachment C.

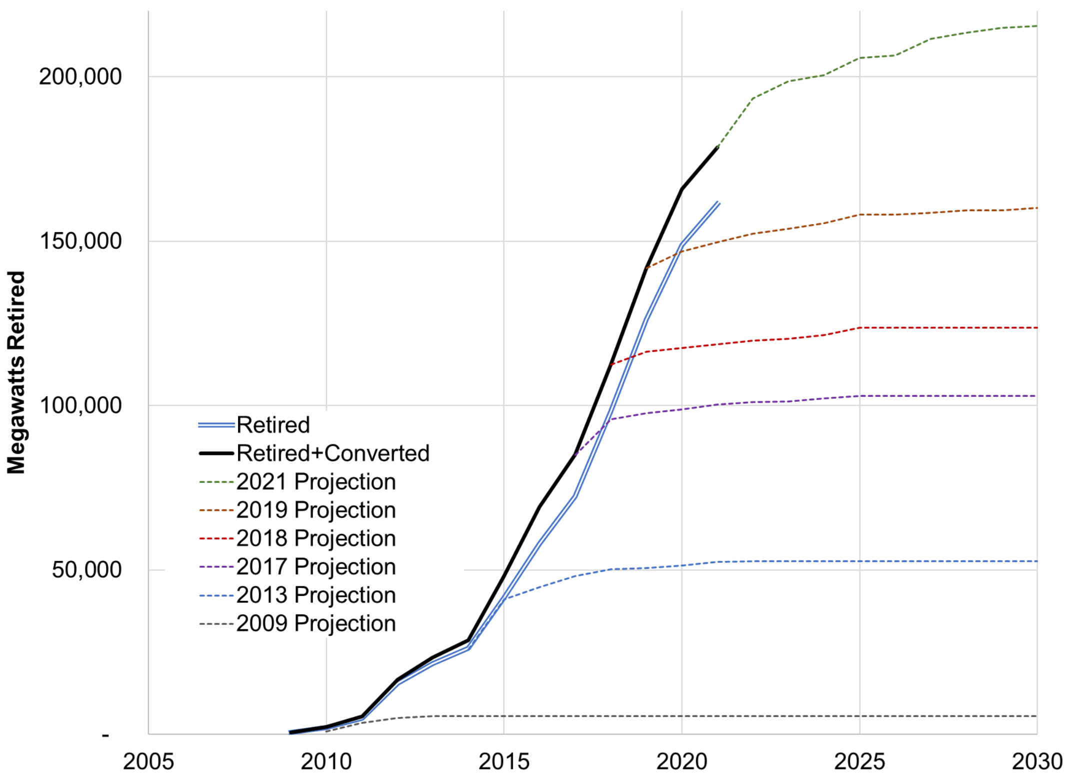
[22] MBPP Operating Agreement Sections 6.1, 6.8, Document Accession #: 20210528-5391 Attachment A at 9, 12; MBPP Participation Agreement Section 12.2.

C. National History of Coal Plant Conversion and Retirement

Q: Have utilities been accelerating the retirement of coal plants over the past decade?

A: Yes. Figure 2 shows the capacity of the coal plants retired or converted to other fuels in each year and those forecast to be retired, by the year of projection (2009 through 2021) and for retirements through 2030.[23]

Figure 2: Planned and Actual Retirement of Coal Plants



Source: Compiled from US Energy Information Administration, Form 860 (2001-2021).

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[23] The data are primarily from the EIA Form 860 data base, supplemented by some news reports. Generation owners do not always report their planned retirements to the EIA:

Q: Is there a pattern in these retirements?

A: Yes. In 2009, the rate of retirements was relatively low, few future retirements were planned, and the units retired were small and old. By 2012, the rate of retirement was rising rapidly, and the retirements included much larger and younger units.

Table 3: Largest and Youngest Coal Unit Retired by Year (Nationwide)

	Largest Retirement	Youngest Retirement, >100 MW	
	MW	In-Service Date	Age
2009	227	1964	45
2010	156	1970	40
2011	279	1964	47
2012	790	1989	23
2013	530	1972	41
2014	414	1990	24
2015	800	1987	28
2016	607	1993	23
2017	628	1994	23
2018	750	1988	30
2019	850	1983	36
2020	971	1995	25
2021	672	1996	25

Source: Compiled from US Energy Information Administration, Form 860 (2001-2021).

Q: How do the coal units retired in 2012–2021 compare to the Basin coal units?

A: Other than Dry Fork and Walter Scott 4, the coal units to which Basin has an entitlement entered service in 1966 to 1985, and so were of roughly comparable age to those units retired beginning in 2012. Leland Olds 1 is smaller than the largest coal unit retired in each year beginning in 2011, and Leland Olds 2, Antelope Valley 1 and 2, and Laramie River 1, 2, and 3 are all smaller than the largest unit retired each year beginning in 2015.

V. Basin Review of Coal Plant Economics

Q: Did Basin present direct testimony in this case to attempt to demonstrate that its requested rates are just and reasonable, by showing that the costs associated of power generation were prudently incurred?

A. No. Basin's direct testimony in this case presents no evidence regarding whether the underlying costs associated with its power generation were prudently incurred. Its testimony simply never addresses this issue. Specifically, although testifying in her capacity as Director of Long-Term Utility Planning,[24] Basin witness Rebecca Kern does not address Basin's resource mix at all, or what steps Basin has taken to evaluate or minimize its revenue requirement with respect to its load obligations.[25]

Shawn Deitz, who serves as the sponsor for Basin's Life Appraisal studies for its coal- and gas-fired units (discussed below), and who addresses the derivation of Basin's operating budget, also offers no affirmative testimony as to Basin's

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[24] Exhibit No. BE-0001, at 1.

[25] *See* Exhibit No. BE-0001, at 65-66 (discussing derivation of revenue requirement).

prudence with respect to its capital expenditures or choice of generation resources. Ms. Deitz's discussions of Dakota Gasification Company, the Dakota Coal Company, and Coteau are entirely bereft of any economic analysis, or even mention of the **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** between the Great Plains Synfuel Plant, Antelope Valley, and Leland Olds that has driven Basin's decision-making around those plants' retirements since 2016.[26] Ms. Deitz's remaining testimony about the derivation of Basin's budget is focused entirely on financial issues, such as the difference between RUS and FERC accounting and how Basin determines depreciation rates. Nowhere in her discussion is any mention of whether or how Basin assesses the economic value of its generation unit or its efforts (if any) to minimize the cost per MWh or kW-day to supply Basin's member-ratepayers with energy and capacity.

The only mention of *any* economic analysis of resources in Basin's direct testimony is by Darla Jensen, Manager of Financial Reporting and Planning, who alludes to a "dispatch modeling process" used to "incorporate[] additional

[26] *See* Exhibit No. BE-0061, at 7-10. Ms. Deitz's discussion of the financial arrangements between Basin, its subsidiaries, and Coteau is limited to stating that lignite coal is purchased from the Freedom Mine at cost, and that no fair market value exists for this lignite.

generation resources needed to meet its load obligations," and claims that with respect to *new* resources, Basin will only incorporate such new resources "if the generation resource is determined to be the most economic resource."[27] Ms. Jensen does not offer any illustration or example of how Basin carries out this process of selecting between new resources and power purchase agreements. Crucially, she does not state that Basin engages in any similar process with respect to its existing units, only that capital expenditures at those units are integrated into Basin's financial forecasts.[28]

In sum, Basin has offered no affirmative testimony as to whether or how it evaluates the economic value of its current generation resources, assesses alternatives to those resources, or conducts retirement analyses when faced with significant capital investment decisions. Basin provides no testimony or evidence as part of its case-in-chief to support the conclusion that its rates are just and reasonable because its revenue requirement reflects only prudently incurred expenses.

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[27] Exhibit No. BE-0067, at 9-10.

[28] *Id.*, at 9.

Q. Even though Basin's direct testimony never discusses why the costs for power generation underlying its rates were prudently incurred, did you attempt to determine if Basin had actually prudently managed its generation fleet?

A. Yes, Sierra Club asked extensive discovery to determine what analyses Basin undertook and whether those analyses met the prudency standards.

Q: Has Basin prudently reviewed the economics of its existing coal-fired power plants?

A: No. From 2012 through 2019, Basin never considered whether the long-run continued operation of its existing coal-fired power plants was prudent. It failed to do this despite knowing, from at least in 2016 onward, that at least one unit was persistently uneconomic on a short-term basis. Moreover, Basin was well aware of the declining costs of renewable energy, as discussed in Section VII.C, and should have been aware of the widespread early retirements of coal plants by other utilities discussed in Section IV.C. Observation of these trends, coupled with short-term economic losses, should have prompted Basin to reevaluate its options.

Second, throughout the past decade, Basin was confronted with a series of major decisions regarding investment in its coal plants. These major investment decisions should have provided Basin with further impetus to reevaluate its options to determine if extending the life of these units was in the best interest of its member cooperatives. Again, Basin failed to adequately analyze whether such investments in existing units was a prudent decision.

In 2019, Basin finally started to look at the economics of the eastern units, although it never performed a retirement analysis that compared the forward-going avoidable costs at these units to alternative sources of energy and/or capacity, as I will discuss in Section VIII.B. Although these analyses found that four of Basin's eastern coal units operated at a short-term loss in 2017 and the fifth barely broke even, Basin never adequately compared the prospective cost to continue to operate these plants (including overheads and capital additions) to the costs for replacement energy and capacity. This is especially troubling because Basin was well aware of available low-cost alternatives through its efforts to procure resources to meet new load and replace expiring power purchases.

Q: On what basis do you believe that Basin failed to prudently review the economics of its coal plants?

A: Because Basin presented no evidence on this issue in its direct testimony, I reviewed all of the information provided in response to our discovery. The bulk of the relevant documents were Basin staff presentations to the Basin Board of Directors. I reviewed over 280 presentations provided to the Basin Board of Directors since 2012 regarding (a) the value and/or going-forward value of any Basin coal units, environmental compliance costs, environmental compliance planning, or generation planning; or (b) the economics of continued operation of any of Basin's coal units.[29]

These presentations failed to meet the rigors of a prudent analysis because:

- During the first six years for which documents were produced, I found no evidence that Basin paid any attention to the economics of continuing to run its existing coal-fired power plants.
- In 2014, Basin undertook a resource planning exercise that reviewed the costs of alternative new generation resources for capacity expansion, but Basin has not shown that it examined the economics of continuing to run any of its existing units.[30] An October 2014 presentation described the new supply options and other inputs that Basin used in assembling its capacity expansion plan, but the only consideration of existing resources was a review of capacity needs in **[BEGIN CUI//PRIV/HC]** [redacted]

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[29] The presentation slides appear to have been prepared in anticipation of an accompanying oral presentation. The process of determining the details of the analyses described is complicated and often impossible to complete, even when I was able to review contemporaneous meeting minutes.

[30] Exhibit No. SC-0006, CUI-PRIV-HC-SC-BEPC-1.029.206.

[redacted] **[END CUI//PRIV/HC]** if the coal unit lives were extended by **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[31]

- I did not find any Basin presentations or other evidence prior to 2016 examining the net avoidable cost of continued operation or the savings from accelerated retirement of any of its coal-fired units.
- In 2016, Basin started to examine some of the economics of Leland Olds 1, its least-economic unit. This analysis failed to address the prudence of continued operation, because it only looked at short-term losses at this unit.
- In 2019, Basin began to review the economics of all of its eastern coal-fired generation and expanded its analysis beyond the shortest-term margins. This analysis was woefully inadequate, as it addressed **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and did not examine whether any the units were still under-performing or whether they were likely to become competitive with the costs of reasonable alternatives.

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[31] Exhibit No. SC-0007, CUI-PRIV-HC-SC-BEPC-1.029.209, at 29.

In an industry climate dominated by announcements of early coal retirements and the growth of ever lower-cost renewables, Basin failed to adequately analyze whether continued operation of its coal units was in the best interest of its members.

Q: Did Basin understand the need for a long-term analysis of the costs and benefits of an existing generation asset?

A: Yes, at least at times. In describing its Long-Term Controllable P&L approach, Basin said that the analysis **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** the following questions:[32]

- **[BEGIN CUI//PRIV/HC]** [redacted]
- [redacted]?
- [redacted]? **[END CUI//PRIV/HC]**

Unfortunately, although Basin acknowledged the value of long-term planning, Basin does not appear to have implemented an approach in any systematic manner

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[32] Exhibit No. SC-0008, CUI-PRIV-HC-SC-BEPC-1.029.049, at 32.

that would allow it to adequately consider the value of its existing generation compared to alternatives.

A. History of Basin's Review of its Coal Plant Economics

Q: How did Basin evaluate the economics of its coal plants between 2016 and 2019?

A: In 2016, Basin finally started to assess the economics of operating Leland Olds 1, its worst performing unit. Those analyses consisted primarily of short-term margin estimates that **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** This comparison would determine whether the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** were being recovered from market revenue.

As discussed in Section IV.A, this short-term margin or **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** is the minimum standard for dispatching a generating unit. If the utility is not able to recover these short-term variable costs, then the units should generally be run in fewer hours or days. A unit that persistently operates at a loss considering only short-term costs, is very likely to be uneconomic to run on a long-term basis.

1. Basin's Flawed Retirement Analysis for Leland Olds Unit 1

Q: When Basin first evaluated the cost-effectiveness of Leland Olds 1, what did it find and when was Basin's Board informed?

A: Although I found some early investigations related to the economics of dispatching of Leland Olds 1 dated as early as March 2016,[33] it was not until early 2018 that the Board was presented with evidence that Leland Olds 1 was operating with a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in late 2015 (when Basin joined SPP and faced market energy prices), 2016 and 2017.[34] The losses **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** The presentation concluded that the margin Basin achieved in 2017 for Leland Olds 1 was a loss of **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** and compared that to an estimate of **[BEGIN CUI//PRIV/HC]** [redacted] in **[BEGIN**

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[33] Exhibit No. SC-0009, CUI-PRIV-HC SC-BEPC-1.038.001.

[34] The presentation is undated, but it appears to have been for the February 2018 Strategic Planning meeting. Exhibit No. SC-0010, CUI-PRIV-HC-SC-BEPC-1.029.274, at 16–19. The all-in margin did not include capacity revenues, but did include most other costs and benefits.

CUI//PRIV/HC] "[redacted]."

[END CUI//PRIV/HC][35]

This comparison has at least two problems. First, the cost and revenue components Basin lists add to a loss of **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** not **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[36] Second, the **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** includes **[BEGIN CUI//PRIV/HC]** [redacted], [redacted]. **[END CUI//PRIV/HC]** Since the revenues are subtracted from the loss computation and added to the "Costs," Basin double-counted revenues. Just correcting that error, and Basin's math, leaves a comparison of a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** loss from operation and **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for cost remaining, so shut-down would be **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** less expensive than operation. As discussed above, even Basin recognizes that some of the "fixed" coal costs are avoidable, so a substantial portion of the fixed fuel costs should be

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[35] Exhibit No. SC-0010, CUI-PRIV-HC-SC-BEPC-1.129.274, at 18, 19.

[36] Basin's computation for 2016 does not have this problem, so it may be just a tabulation error.

subtracted from the **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** And it does not appear that Basin accounted for all the costs of operation (including **[BEGIN CUI//PRIV/HC]** [redacted]). **[END CUI//PRIV/HC]** Thus, Basin's apparent position that **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** does not stand up to scrutiny.

Q: When Did Basin recognize that something was amiss with the economics of Leland Olds 1?

A: The first acknowledgement by Basin to the Board that its **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** scenario included **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** occurred in a June 2017 Board presentation.[37] That presentation included a scenario with **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and mentioned the potential for shutdown of Leland Olds 1 in **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and Leland Olds 2 in **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[38] Even so, the presentation did not

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[37] Exhibit No. SC-0003, CUI-PRIV-HC-SC-BEPC-1.029.104, at 34.

[38] *Id.* at 35, 38.

identify optimal replacement resources, merely noting that, **[BEGIN CUI//PRIV/HC]** "[redacted]." **[END CUI//PRIV/HC]**[39] While Basin recognized the possibility that **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** coal units might be desirable, there is no indication that Basin performed any economic analysis of its options. Acknowledging the existence of a problem and not acting to resolve the problem is not prudent.

Basin presented some cost-effectiveness results for Leland Olds Unit 1 in April 2018, with very little documentation and no comparison to the costs of alternatives.[40] The analysis found that **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** under a range of cost assumptions.[41] Yet the only recommended action was **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**[42]

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[39] *Id.* at 38.

[40] Exhibit No. SC-0011, CUI-PRIV-HC SC-BEPC-1.038.005; Exhibit No. SC-0005, CUI-PRIV-HC-SC-BEPC-1.029.098.

[41] Exhibit No. SC-0011, CUI-PRIV-HC SC-BEPC-1.038.005, at. 5–7.

[42] *Id.*, at 9.

Q: Please explain how Basin incorporated fixed costs at the Freedom Mine into its operational decisions at Leland Olds.

A: Basin operates Antelope Valley, Leland Olds, and Dakota Gasification based on a very short-term view of costs. In March 2016, Basin staff completed an internal project ("Project Dominoes") that **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[43]

As stated in the September 2016 Board minutes, Basin assumed that **[BEGIN CUI//PRIV/HC]** "[redacted]" and that "[redacted] **[END CUI//PRIV/HC]**[44] Based on this assumption, Basin calculated the variable cost of generation at the Leland Olds units to be **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[45] This dispatch price does not cover **[BEGIN**

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[43] Exhibit No. SC-0009, CUI-PRIV-HC SC-BEPC-1.038.001; Exhibit No. SC-0012, 1.40.44-CUI-PRIV-SC-BEPC, at 23.

[44] Exhibit No. SC-0005, CUI-PRIV-SC-BEPC 1.117.46, at 15. Basin makes a similar statement in Exhibit No. SC-0014, 1.40.44-CUI-PRIV-SC-BEPC, at 18.

[45] Exhibit No. SC-0009, CUI-PRIV-HC SC-BEPC-1.038.001, at 17.

CUI//PRIV/HC] [redacted] [redacted] **[END CUI//PRIV/HC]** that SPP did not allow Basin to include in its bid price **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[46] Dispatch of Leland Olds 1 after Project Dominoes resulted in an **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Consistent with Project Dominoes, Basin generally assumed that **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** costs associated with the Freedom Mine should not be considered in operating decisions for any of the facilities it supplies with, including Leland Olds. **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**[47] Basin inappropriately and imprudently applied this short-term perspective to such questions as the long-term shutdown of Leland Olds 1 and

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[46] Exhibit No. SC-0013, CUI-PRIV-HC SC-BEPC-1.038.004.

[47] Exhibit No. SC-0014, CUI-PRIV-HC SC-BEPC-1.038.007, at 2.

the Great Plains Synfuel Plant (or divestment from the Dakota Gasification Company).

Basin's rates include cost recovery for the fixed costs associated with the operation of the Freedom Mine, allocated among the Antelope Valley and Leland Olds power plants and the Dakota Gasification manufacturing operations. Basin's operational dispatch decisions only considered a portion of fuel costs that went into rates. Basin does not appear to have systematically addressed the more fundamental question as to what costs at the Freedom Mine are avoidable on a longer-term basis if one or more of the units (including Leland Olds 1 and/or 2) were retired, other than the partial analyses described below, and it never adequately assess reasonable alternative costs.

Q: Was the Project Dominoes result consistently supported by evidence?

A: No. Although the Project Dominoes approach appears to have persisted in Basin's decision-making regarding potential unit shutdowns, it is not clear that the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for retiring one or more units actually exists. The presentations on Project Dominoes are mostly conceptual, rather than analytic; the effects were apparently assumed, rather than computed.

In September 2016, the Board was informed that Project Dominoes determined that if Leland Olds were shut down, then Antelope Valley and Dakota

Gasification would **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** This equates to about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** used by the remaining facilities, **[BEGIN CUI//PRIV]** "[redacted]" **[END CUI//PRIV]**[48] This **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for a roughly **[BEGIN CUI//PRIV/HC]** [redacted] in Freedom Mine sales is roughly proportional to the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** if Dakota Gasification is closed.

Yet in July 2017, Basin produced a financial forecast evaluating a shutdown of Leland Olds 1 that showed the shift in fixed fuel costs would have **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** on coal prices at the other four units. For example, the coal price for Antelope Valley would **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** over five years.[49]

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[48] Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC, at 19

[49] Exhibit No. SC-0013, CUI-PRIV-HC SC-BEPC-1.038.004.

2. Basin's Economic Analyses of Other Eastern Coal Plants

Q: When Basin completed its life extension analyses in 2012-15 (Exhibit No. BE-0063), did Basin provide adequate materials to the third-party contractor it asked to make such an assessment?

A: No. When Basin requested a "Physical Life Appraisal" of its gas-fired units (Groton Generating Station, Culbertson Generating Station, Deer Creek Generating Station, Pioneer Generating Station, and Lonesome Creek Station) in 2015 from Burns & McDonnell, it provided "the planned economic dispatch, fuel costs, production costs, and annual O&M cost" for each of these units.[50] But Basin did not provide any of this information for its coal-fired units to Burns & McDonnell when Burns & McDonnell performed physical life appraisals for the Leland Olds, Antelope Valley, and Laramie River units between 2012 and 2014.[51] In effect, Basin ignored the economics of these units when assessing their remaining lifespan.

When asked in discovery why it did not provide the same information about the coal units economic as it did about its gas units, Basin attributed the discrepancy

[50] Exhibit Nos. BE0063-7, at 6-1; BE0063-8 at 6-1; BE0063-9, at 6-1; BE0063-10, at 6-1; BE0063-11, at 6-11; *see* Exhibit No. SC-0015, SC-BEPC-4.005.001 through SC-BEPC-4.005.010.

[51] Exhibit No. SC-0016, SC-BEPC-4.010.

to the fact that Basin only considered economic dispatch in anticipation of joining a regional transmission organization (which it did in October 2015).[52] In its discovery response, Basin claimed that economic information about the coal units was not "germane" to their appraisals, which were focused on "reliability and physical longevity."[53] But in conducting all of these physical life appraisals, Burns & McDonnell's recognized that "*the actual life* of a facility is dictated by economic viability."[54] Moreover, the Burns & McDonnell reports for Antelope Valley and Laramie River were completed in April 2014, just 15 months before the July 2015 completion of the reports for the gas units. Basin was contemplating joining SPP since at least 2011, so economic viability was just as relevant in 2014 as in 2015.[55]

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[52] Power plants can be uneconomic outside of RTOs, and Basin's coal plants would probably be losing money compared to alternative generation resources or energy and capacity purchases, even if Basin were not a member of SPP and MISO.

[53] Exhibit No. SC-0016, SC-BEPC-4.010.

[54] Exhibit Nos. BE0063-3, at 1-2 (discussing Laramie River); BE-0063-4, at 1-2 (discussing Antelope Valley); BE0063-5, at 1-1 (discussing Dry Forks) (emphasis added in each).

[55] In 2014 SPP reported that Basin and associated "entities have been discussing since 2011 the possibility of joining a Regional Transmission Organization (RTO) to increase options for buying and selling power." Press Release: "FERC approves Integrated System joining SPP" (November 12, 2014), available at www.spp.org/newsroom/press-releases/ferc-approves-integrated-system-joining-spp/ [last accessed July 14, 2022]. The SPP 2012 State of the Market report shows 333 MW of Basin SPP peak load in 2012. SPP Market Monitoring Unit, *2012 State of the*

It is clear that Basin was not thinking about whether its coal units were currently economic or whether the plants would be economically viable in the medium- or long-term. This blind spot may have contributed to Basin's failure to seriously consider shutdown of those units when it became clear they were not cost-effective and the less expensive resources were available.

Q: When did Basin staff begin presenting margin assessments for all of its coal units to its Board?

A: Not until 2019 did Basin begin presenting margin assessments for all its coal units, not just Leland Olds 1. Around this time Basin expanded its reporting practices to also include long-term margin analyses. These long-term analyses compared a broader range of revenues to a broader range of costs to determine whether the plants were making money on an annual basis. Basin defined this Long-Term Margin as the difference between the benefits **[BEGIN CUI//PRIV/HC]** ([redacted], [redacted]

Market (17 May 2013), available at www.spp.org/documents/22328/2012%20state%20of%20the%20market%20report.pdf [last accessed July 14, 2022], at Table I.10. Minutes from the November 2013 Board meeting indicated that Basin was negotiating with SPP on legal language changes and that the Board expected a recommendation on a final decision by May or June of 2014. Exhibit No. SC-0017, MEC-BEPC-2.42.110.

[redacted]) **[END CUI//PRIV/HC]** and costs **[BEGIN CUI//PRIV/HC]** [redacted]). **[END CUI//PRIV/HC]**[56]

Q: What did the Board learn from these long-term margin assessments?

A: The May 2018 Asset Management, Resource Planning & Rates – Strategic Planning presentation reports various types of 2017 margins for each of the eastern coal plants, including **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**[57] That analysis showed both Antelope Valley units to be operating at **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** both Leland Olds units to be operating at **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** and Laramie River Station 1 to be operating at **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]** These results may have understated the losses, since Basin did not appear to include **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]** The presentation **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** at Antelope Valley or Leland Olds 2. Again, a prudent utility would have compared the full prospective avoidable cost of all the units to the costs of alternatives.

[56] Exhibit No. SC-0008, CUI-PRIV-HC-SC-BEPC-1.029.049, at 31.

[57] Exhibit No. SC-0005, CUI-PRIV-HC-SC-BEPC-1.029.098, at 24.

In January 2019, the Board was shown **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** for all coal plants. This presentation showed that in 2017, **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of Basin's eastern coal units were **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** or at **[BEGIN CUI//PRIV/HC]** [redacted] (just [redacted] was [redacted]). **[END CUI//PRIV/HC]**[58]

The focus, however, remained on Leland Olds 1: the Board was shown additional detail for that plant, including historical 2016 and 2018 data and forecasts for 2019–2021.[59]

Continuing through 2021, the Board continued to receive **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the economics of Leland Olds 1. By February 2021, the Board was presented with long-term margin analyses for both Leland Olds 1 and 2.[60] These presentation showed that the long-term margins for Leland Olds 1 had **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]**

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[58] Exhibit No. SC-0008, CUI-PRIV-HC-SC-BEPC-1.029.049, at 33.

[59] *Id.*, at 34-36.

[60] Exhibit No. SC-0018, CUI-PRIV-HC-SC-BEPC-1.029.012, at 7, 8.

would be even more **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**[61] The base long-term margins for Leland Olds 2 were **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**in 2018 and 2019, going **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**in 2020, with **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** continuing through the forecast years.

B. Assessment of Basin's Evaluation Practices

Q: What is the relevance of these 2019-2021 Board presentations to this rate case?

A: Prior to filing the instant rate case before the Commission, Basin's Board does not appear to have been very well-informed as to the **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** (I will present evidence on these **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** later, in Section VIII.A.) But once the Board began to receive these presentations, particularly in 2021, the evidence was quite clear **[BEGIN CUI//PRIV/HC]** [redacted]

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[61] Basin's base-price assumption was that capacity cost would be a **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]**

[redacted] **[END CUI//PRIV/HC]**

Although my review of the documents produced by Basin and SPP energy prices does not indicate significant uneconomic dispatch (dispatching a plant at prices below the short-run variable costs) of the eastern coal plants, it is my opinion that had the Board been presented with similar findings by 2016 or earlier, it would have seen similarly compelling evidence that extending the life of its coal-fired power plants was not reasonable and that taking them out of service was a better decision for its members.

Q: Did Basin use best practices in its long-term margin analyses?

A: No, it did not meet the industry standards for prudence for several reasons. First, Basin never analyzed the prospective avoidable costs for its existing uneconomic units. As discussed previously, Basin's economic analyses treated a **[BEGIN CUI//PRIV]** [redacted], **[END CUI//PRIV]** which was one factor causing the short-term analyses to understate the true avoidable losses. I cannot determine whether **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in the long-term margin analyses as they are vague about the **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** In spite of extensive discovery requests for presentations and supporting analyses, I have not located any documents that clearly spell out how Basin classified costs as variable, fixed but avoidable, or sunk in these long-term margin analyses. An appropriate analysis will ignore truly sunk costs and reflect all prospective, avoidable costs.

Even though its analysis of costs is muddled—through doing my own analysis it has become clear that Basin did not account for all avoidable costs in its analyses—Basin has unquestionably failed with respect to the next step in prudently analyzing existing units: a reasonable assessment of alternatives costs. Basin never adequately compares the prospective costs of its existing generation to the costs of reasonable alternatives, as it only vaguely discusses replacement costs.

Q: Did Basin ever conduct any type of margin analyses for other resources?

A: Yes. In April 2019, Basin began conducting long-term profit and loss analyses for renewable energy resources.[62] But most subsequent evaluations of renewable energy resources focused on short-term benefits. Typical evaluations simply compared **[BEGIN CUI//PRIV/HC]** [redacted]; **[END CUI//PRIV/HC]** for example, those analyses **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** or the benefit of shutting down the uneconomic coal units.

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[62] Exhibit No. SC-0019, CUI-PRIV-HC-SC-BEPC-1.029.067.

Q: Did Basin routinely consider coal unit retirements in its long-term capacity forecasts?

A: No. When forecasting the addition of new resource options, Board presentations usually include forward projections of capacity assuming continuation of existing resources, including existing coal resources. Basin only broke out the Leland Olds capacity when retirement options were specifically under consideration (although not in a manner that is consistent with prudency standards). I did not locate any Board presentations that specifically evaluated the potential retirement of other coal units, despite the 2019 presentation that showed long-term margins were **[BEGIN CUI//PRIV/HC]** [redacted] for [redacted] **[END CUI//PRIV/HC]** eastern coal resources.[63] This presentation format communicates a strong commitment to maintaining the operation of existing assets, (with the possible exception of Leland Olds 1 and 2) for the foreseeable future, irrespective of the economics.

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[63] Exhibit No. SC-0008, CUI-PRIV-HC-SC-BEPC-1.029.049. These continued in, *e.g.*, Exhibit No. SC-0020, CUI-PRIV-HC-SC-BEPC-1.029.052; Exhibit No. SC-0021, CUI-PRIV-HC-SC-BEPC-1.047.011; Exhibit No. SC-0022, CUI-PRIV-HC-SC-BEPC-1.047.023; and Exhibit No. SC-0023, CUI-PRIV-HC-SC-BEPC-1.047.035.

Q: Do you believe that Basin has demonstrated reasonable planning practices regarding its existing coal units?

A: No. Prior to 2019, Basin simply did not consider whether it would be prudent to retire one or more units early. This is especially troubling given by 2017, almost all of Basin's eastern coal units were operating at a loss. Basin was well-aware of the availability of competitively priced capacity resources as it evaluated capacity alternatives to meet load growth. However, Basin completely failed to evaluate whether a combination of capacity and energy resources could cost-effectively replace its aging and money-losing coal units.

Basin should have made such an evaluation in response to the prevailing trends in the industry, the rapidly declining cost of renewable energy, and the impetus of whatever margin analyses it was conducting. Furthermore, the major investments it made during the past decade, particularly since 2015, should have triggered such a review, which I will discuss in detail in Section IX.

Since 2019, Basin appears to have increased the scope of its evaluations, but I still do not see evidence that Basin has conducted a comprehensive resource planning evaluation to determine whether its coal plants are cost-effective in the long-term compared to alternatives or to establish an optimal schedule for their retirement.

VI. Coal Resource Costs

A. Coal-Unit Cost Inputs

Q: What coal-plant cost components did you include in the analysis of the economics of the plants?

A: I included the following categories:

- Non-fuel operation and maintenance (O&M) costs, divided between fixed costs incurred to keep the unit available and variable costs incurred as a function of hours of operation or MWh or output, from Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a.
- Fuel costs, from Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a. While almost all fuel costs are variable for most generators (including Laramie River), **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**
- Continuing capital additions, from Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a. The costs of sunk investments are not included in any of my analyses. Capital additions are included both for the projects required only for the individual unit and for the units' share

of common capital additions for equipment serving the entire plant, including fuel handling, waste handling, cooling water supply, and the like. The sizing (or frequency of replacement) of some common capital additions may be increased by total capacity and expected output, and thus are avoidable by reduced usage or retirement of individual units. Other capital projects may be required in order for any continued operation at the plant.

- Overheads, from the 2019 and 2020 FERC Form 1 reports (Exhibit Nos. SC-0025 and 0026, respectively), specifically Benefits from page 323, line 18, and Payroll taxes charged from page 262. I allocated these costs among the generation units in proportion to labor, from Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a; total Basin labor costs are from the FERC Forms page 354, line 28. I included only the labor-related overheads. Continued operation will generally impose costs in additional categories, such as legal and regulatory, but I have not attempted to assign those costs to the coal units.
- Property taxes and insurance directly attributable to each plant, from Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a.

Table 4 lists the cost inputs for Basin's SPP coal units. The Laramie River 1 data are for Basin's 8.42% share of the unit through 2018 and 16.43% in 2019 and beyond.

Table 4: Historical Coal Unit Cost Inputs ($M) (HIGHLY CONF)
[BEGIN CUI//PRIV/HC]

			2016	2017	2018	2019	2020
Antelope Valley 1	O&M	Variable	[redacted]				
		Fixed					
	Fuel	Fixed					
		Variable					
	Cap adds	Unit					
		Common					
	Property Taxes						
	Property Insurance						
	Overheads						
	Total						
Antelope Valley 2	O&M	Variable					
		Fixed					
	Fuel	Variable					
		Fixed					
	Cap adds	Unit					
		Common					
	Property Taxes						
	Property Insurance						
	Overheads						
	Total						
Leland Olds 1	O&M	Variable					
		Fixed					
	Fuel	Variable					
		Fixed					
	Cap adds	Unit					
		Common					
	Property Taxes						
	Property Insurance						
	Overheads						
	Total						
Leland Olds 2	O&M	Variable					
		Fixed					
	Fuel	Variable					
		Fixed					
	Cap adds	Unit					
		Common					
	Property Taxes						
	Property Insurance						
	Overheads						
	Total						
Laramie River 1	O&M	Variable					
		Fixed					
	Fuel	Variable					
	Cap adds	Unit					
		Common					
	Property Taxes						
	Property Insurance						
	Overheads						
	Total						

[END CUI//PRIV/HC]

Q: What did you assume for the cost of capital for Basin-owned assets?

A: I used a 4% interest rate, which is consistent with the 4% interest rate assumed by Basin.[64] As shown in Table 5, this is consistent with the average cost of debt reported by Basin in its Annual Reports for each year 2012–2021. I also noted that Basin's interest rate **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** with long-term Treasury rates.

Table 5: Basin Cost of Debt Compared to 30-Year Treasury Bond (in %)[65]

[BEGIN PARTIAL CUI//PRIV]

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Basin Average Interest	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30-Year Treasury Bond	2.92	3.45	3.34	2.84	2.59	2.89	3.11	2.58	1.56	2.06

[END PARTIAL CUI//PRIV]

64 Exhibit No. SC-0027, SC-BEPC-1.41.2.

65 Basin Interest rates from Exhibit No. SC-0028, Basin Annual Reports for 2013, 2017, and 2021, at 38, 20, and 29 respectively. Treasury rates are from www.govinfo.gov/content/pkg/ERP-2022/xls/ERP-2022-table42.xls.

Q: What did you assume for inflation rates?

A: I assumed 2%, based on the Energy Information Administration's 2016 Annual Energy Outlook. (As discussed in much greater detail below, Leland Olds began operating at a loss relative to market energy and capacity prices by 2016 and Basin should have begun evaluating the merits of retiring Leland Olds and its other eastern coal-fired units at least by 2016.) That value is also supported by the difference between nominal and inflation-protected returns on Treasury securities.

B. Interrelated Coal Operations

Q: What are the coal supplies for the western Basin plants?

A: Dry Fork and Laramie River burn sub-bituminous coal. Dry Fork coal comes from the unaffiliated Dry Fork Mine, while Laramie River burns coal from a number of Wyoming mines, including the Dry Fork Mine. Those purchases are made at market prices from mines that are not affiliated with Basin.

Q: How is coal supplied to Leland Olds and Antelope Valley?

A: As discussed above, Leland Olds and Antelope Valley (as well as the Great Plains Synfuel Plant) are supplied by the Freedom Mine. The Freedom Mine is owned by the Coteau Properties Company (a subsidiary of North American Coal Corporation). The mine is located adjacent to Antelope Valley and Dakota Gasification's Great Plains Synfuel Plant. Freedom Mine lignite coal is also shipped by rail about 30 miles to Leland Olds. Basin's Dakota Coal Company subsidiary provides financing for the mine and markets the lignite coal to the other Basin operations and (to a limited extent) other parties.

The costs of the Freedom Mine are divided among Antelope Valley, Leland Olds, and the Great Plains Synfuel Plant (Dakota Gasification Company). Each facility is charged **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** in addition to a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** level that Basin expects to need for its facilities.

Q: **Please provide a brief overview of the relationship between coal supplied by Freedom Mine and Basin subsidiaries.**

A: Freedom Mine supplies coal to three Basin subsidiaries. As shown in Table 6, the largest portion of the coal is delivered to Dakota Gasification, followed by Antelope Valley and Leland Olds.

Table 6: Freedom Mine Coal Use (tons)
[BEGIN PARTIAL CUI//PRIV]

Facility	Typical Coal Use	Coteau Study	2016 Actual	Average 2013–2021
	a	*b*	*c*	*d*
Antelope Valley 1			[redacted]	18.6%
Antelope Valley 2			[redacted]	18.4%
Antelope Valley Station	[redacted]		[redacted]	36.9%
Leland Olds 1			[redacted]	7.4%
Leland Olds 2			[redacted]	14.5%
Leland Olds Station	[redacted]		[redacted]	21.9%
Dakota Gasification Company	[redacted]	[redacted]	[redacted]	41.2%

[END PARTIAL CUI//PRIV]
Sources:
a: Exhibit No. SC-0029, 1.30.1-CUI-PRIV SC-BEPC; Exhibit No. SC-0030, 1.30.2-CUI-PRIV-SC-BEPC.
b: *Id*.
c: Exhibit No. SC-0031, CUI-PRIV SC-BEPC 1.038.002.
d: Coal plant use from EIA 923, total from Coteau Annual Reports, Dakota Gasification from total minus power plants.

The annual coal consumption of these facilities has varied with the economics of the various coal plants and outages, but roughly speaking, **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** of the Freedom Mine lignite coal is used at Dakota Gasification, **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** at the two

Antelope Valley units, **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** at Leland Olds 2 and **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** at Leland Olds 1.[66]

Basin relies on its contract with Freedom Mine to classify **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** at least in the short term.

Q: How do the operation of the various facilities using Freedom Mine lignite coal affect the price of coal for the other facilities using that mine?

A: Because Basin, through its subsidiary Dakota Coal Company, is responsible for **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** at the Freedom Mine, eliminating or reducing coal use at any of the five units will increase the per-ton cost of coal to the remaining units as the **[BEGIN CUI//PRIV]** [redacted]. **[END CUI//PRIV]**

The fact that some of these costs are "fixed" in the short term does not mean these costs are unavoidable in the longer term by retiring one or more of the units that obtains coal from the Freedom Mine. It does not appear that Basin analyzed what portion of the coal costs designated as "fixed" could be avoided by retirements until 2019, at the earliest, and does not appear to have conducted any analysis as to what mining costs were avoidable if all five facilities were to cease operation.

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[66] *See* Table 6.

Q: Does Basin ever identify what portion of these "fixed costs" from the Freedom Mine are avoidable in the long-term?

A: Basin's treatment of fixed and variables is internally inconsistent and often different from how Coteau treats those costs. In some documents, Basin estimates that only a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the Leland Olds and Antelope Valley fuel costs are variable.

- An analysis of Leland Olds 1 costs shows that Basin considers about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of Freedom Mine fuel charges to be variable.[67]
- In its Profit & Loss (P&L) statements, Basin also treats some of the costs of the Dakota Coal Company, the Leland Olds rail system and coal handling at the plants as variable. It reports that about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of total Leland Olds fuel costs are variable,[68] and that only about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of fuel costs for

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[67] I computed that fraction from the Leland Olds 1 data provided in Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, tabs "2017 costs" and "VOM".

[68] Exhibit No. SC-0033, CUI-PRIV-HC-SC-BEPC-5.001.006, 5.0001.009, and 5.001.012.

Antelope Valley (which has much lower coal transportation costs) are variable.[69]

- In 2021, Basin reported that **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the cost of coal from the Freedom Mine is variable.[70]

In other documents, Basin and Coteau consider **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the Leland Olds and Antelope Valley fuel costs to be variable.

- Coteau's billings to Basin show that Coteau considers **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of fuel costs to be variable than Basin does. Over February 2016 to December 2017, the monthly variable cost portion varied from **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**[71]

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[69] Exhibit No. SC-0034, CUI-PRIV-HC-SC-BEPC-5.001.001, 5.001.004 and 5.001.009.

[70] Exhibit No. SC-0035, CUI-PRIV-HC SC-BEPC-1.038.010, at 30.

[71] Exhibit No. SC-0036, CUI-PRIV-HC-SC-BEPC-8.004.049 through .072.

- In one of its workpapers, Basin estimates that **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the "fixed" costs from Freedom Mine are avoidable costs if a generator is shut down for the long term.[72]

Basin did conduct several partial analyses of the impact of retirements of one or more facilities on coal prices at the remaining units. In 2019, 2020, and 2021, Basin conducted analyses of the impact of ceasing operation at Dakota Gasification on coal prices at Leland Olds and Antelope Valley based on a Coteau study.[73] According to Basin's 2019 analysis, ceasing coal deliveries to Dakota Gasification from the Freedom Mine would reduce the total tonnage by **[BEGIN CUI//PRIV]** 6,218,000 tons **[END CUI//PRIV]** and **[BEGIN CUI//PRIV]** increase **[END**

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[72] Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, Coal tab. For example, for 2018, the Leland Olds 1 fixed coal cost would be **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** while **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of Coteau costs **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** It is not clear how long it would take to eliminate those costs. Basin recognizes that shutting Leland Olds 1 would result in write-off of some costs of **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** but less than **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** for a plant with a **[BEGIN CUI//PRIV/HC]** [redacted] annual fuel bill. *See* Exhibit No. SC-0012, 1.40.44-CUI-PRIV-SC-BEPC, at 23.

[73] *See* Exhibit No. SC-0037, 1.30-SC-BEPC and Exhibit No. SC-0029, 1.30.1-CUI-PRIV SC-BEPC-1.30.1, Exhibit No. SC-0030, 1.30.2-CUI-PRIV SC-BEPC, and Exhibit No. SC-0038, 1.30.3-CUI-PRIV SC-BEPC.

CUI//PRIV] the per ton price for the remaining tonnage to Leland Olds and Antelope Valley by **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** However, total coal costs for Basin would be **[BEGIN CUI//PRIV]** [redacted]**.[END CUI//PRIV]** Projecting forward through 2029 these numbers stayed roughly consistent, with a shutdown of Dakota Gasification causing a **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** for the remaining facilities. In other words, **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** total production at the mine by **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** (corresponding to the percentage of production attributable to Dakota Gasification) would **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** Basin's coal costs by approximately **[BEGIN CUI//PRIV/HC]** [redacted]**.[END CUI//PRIV/HC]**[74]

In May 2018, Basin also performed an analysis of the impact of retiring Leland Olds 1 on coal prices at the remaining units. Basin concluded that permanent retirement of Leland Olds 1 would **[BEGIN CUI//PRIV/HC]** [redacted] **[END**

[74] If a **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** output reduction reduces costs by **[BEGIN CUI//PRIV]** [redacted], **[END CUI//PRIV]** reducing output 100% (eliminating all variable costs) would reduce costs by **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** *See* Exhibit No. SC-0029, 1.30.1-CUI-PRIV SC-BEPC; Exhibit No. SC-0030, 1.30.2-CUI-PRIV SC-BEPC; and Exhibit No. SC-0038, 1.30.3-CUI-PRIV SC-BEPC. The same study supports the detailed analysis in Exhibit No. SC-0039, 1.95.1-CUI-PRIV-SC-BEPC.

CUI//PRIV/HC] the total "fixed" costs associated with the Coteau mine by**[BEGIN CUI//PRIV/HC]** [redacted],**[END CUI//PRIV/HC]** and that that this **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in 2030 based on Basin's projections) constituted **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** corresponding to coal production for Leland Olds 1.[75] In other words: Almost all of the "fixed" costs associated with coal production for Leland Olds 1 would be avoidable over the next decade if the unit was retired. That reduction would be offset somewhat by a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in Freedom Mine variable lignite coal costs to remaining customers.[76]

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[75] Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, Coal tab. For example, for 2018, the Leland Olds 1 fixed coal cost would be **[BEGIN CUI//PRIV/HC]** [redacted]." **[END CUI//PRIV/HC]**

[76] Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, VOM tab. Compared to a total Leland Olds 1 coal cost of **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Q: What would be the impact of the sale or retirement of Dakota Gasification on the economics of Leland Olds and Antelope Valley?

A: It has been clear for many years that Dakota Gasification is uneconomic.[77] It is now under agreement to be sold to Bakken Energy in 2023 and converted to a natural-gas-fired hydrogen-production operation.[78] If the theory laid out in Project Dominoes is correct, coal prices for Antelope Valley and Leland Olds will **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** as Dakota Gasification stops using lignite coal. As discussed in Section V.A.1, Basin recognized by April 2018 that Leland Olds 1 faced **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** and included **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** at the end of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in its resource scenarios.[79] Basin

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[77] Losses reported in Exhibit No. SC-0028, Basin Annual Reports 2013, 2015-2019, 2021, at 38 (2013 Report at 38), 120 (2015 Report at 48), 194 (2016 Report at 38), 246 (2017 Report at 20), 295 (2018 Report at 19), and 327 (2019 Report at 24). Basin recorded impairments of its Dakota Gasification investment in 2018–2020, totaling more than **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

[78] Exhibit No. SC-0040, Bakken Energy, "Press Release: MHA Nation Partnering With Bakken Energy And Mitsubishi Power On Great Plains Hydrogen Hub, available at www.bakkenenergy.com/press-releases/mha-nation-partnering-with-bakken-energy-and-mitsubishi-power-on-great-plains-hydrogen-hub/ [last accessed July 12, 2022].

[79] Exhibit No. SC-0041, CUI-PRIV-HC SC BEPC 1.056.140. In May, Basin assumed that it would keep the unit for the **[BEGIN CUI//PRIV/HC]** "[redacted]." Exhibit No. SC-0032, CUI-PRIV-HC SC BEPC 1.038.006.

recognized that Leland Olds 1 was operating at a loss as early as its first evaluation of the unit's economics in 2016, and by 2019, Basin recognized that both Leland Olds units and Antelope Valley were operating at a loss. As soon as Dakota Gasification stops using Freedom Mine coal, the **[BEGIN CUI//PRIV/HC]** "[redacted]" **[END CUI//PRIV/HC]** would make the economics of Leland Olds and Antelope Valley even **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** Retirement of Leland Olds would **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** at that plant, but **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of Antelope Valley.

It thus appears that the five units supplied by the Freedom Mine were likely collectively uneconomic to operate as early as **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and Basin recognized that **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of these five units were operating at a loss by **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]** However, because Basin assumed that the retirement of any one facility would **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** Basin maintained the operation of all units. This belief was erroneous, as Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, and Exhibit No. SC-0029, 1.30.1-CUI-PRIV SC-BEPC, discussed above, show that **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** Moreover, Basin's perspective seems to have arisen from the conflation of a **[BEGIN CUI//PRIV/HC]** [redacted] of [redacted], **[END CUI//PRIV/HC]** which was the focus of the Project Dominoes analysis, with retirement of some or all the coal-using units.

Q: How did you estimate the effect of Dakota Gasification's sale on costs for Leland Olds and Antelope Valley?

A: I extrapolated the data that Basin provided on the price effect of ending coal use at Dakota Gasification to the reductions in coal output from retirements of Dakota Gasification alone, Dakota Gasification and Leland Olds 1, or Dakota Gasification and Leland Olds 1 and 2.[80] I scaled the effect from Coteau's estimate that a **[BEGIN CUI//PRIV]** [redacted]. **[END CUI//PRIV]**[81] I used fuel-use data from the 2016 EIA Form 923 for splitting Coteau's data between units.

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[80] Exhibit No. SC-0029, 1.30.1-CUI-PRIV SC-BEPC.

[81] *Id*. So long as Freedom Mine has any truly fixed costs, reducing usage increases the cost per ton, even as total costs (and even the total of the costs that basin treats as

Table 7: Effect of Reduced Freedom Mine Sales on Costs by Unit ($M) (HIGHLY CONF)
[BEGIN CUI//PRIV/HC]
[redacted]
[END CUI//PRIV/HC]

In the short-term, without Dakota Gasification Company, this analysis predicts that the cost of running Leland Olds 1 would **[BEGIN CUI//PRIV/HC]** [redacted] by [redacted] **[END CUI//PRIV/HC]** annually; without Dakota Gasification and Leland Olds 1, the cost of Leland Olds 2 would **[BEGIN CUI//PRIV/HC]** [redacted];**[END CUI//PRIV/HC]** and without Dakota Gasification or Leland Olds 1 and 2, the costs of running Antelope Valley would

fixed) decline. If the unavoidable costs are **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** as suggested in Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC-1.038.006, those effects may be **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** which would negate Basin's argument that it should keep the coal plants operating to **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

[BEGIN CUI//PRIV/HC] [redacted] **[END CUI//PRIV/HC]** about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Unit 1 and **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Unit 2.

Q: What if the vast majority of the fuel costs are actually avoidable?

A: In that case, as suggested in at least one Basin analysis, there would be no significant **[BEGIN CUI//PRIV/HC]** "[redacted]," **[END CUI//PRIV/HC]** and Basin's concern with that effect would be misplaced, making Basin's failure to retire Leland Olds 1 as early as 2016 even more misguided.[82]

VII. Replacement Power Costs

Q: What is the significance of replacement energy and capacity costs in assessing the prudence of Basin's decisions with respect to its coal units?

A: Whether a utility acted prudently in continuing to rely on a resource for generation (the Continuing Operation Prudency Test) or to make a major capital investment in that unit (the Major Investment Prudency Test) depends on what alternatives were available to that utility at the time the decision was made. To assess whether Basin acted imprudently by failing to retire one or more of its eastern coal units before 2019 or by making major capital expenditures at those units during the relevant

[82] Exhibit No. SC-0032, CUI-PRIV-HC SC-BEPC 1.038.006.

period (2015–2019), I considered what alternative sources of generation were available to Basin to meet its load obligations to its member-cooperatives.

These load obligations include both energy (which Basin purchases from the SPP market, offset by sales from its resources to SPP) and capacity, *i.e.*, Basin's allocated responsibility for accredited capacity under SPP rules. If Basin could have produced and/or procured sufficient reliable energy and capacity to replace one or more eastern coal units at lower cost, Basin's members have been paying more than necessary and the costs underlying its rates were not prudently incurred. Similarly, if Basin has made investments to keep operating plants that should be shut down, Basin's rates are unnecessarily high. And if Basin's decisions not to retire those units, and to continue investing in their continued operation was imprudent, then its current rates are not just or reasonable.

Q: Please summarize your findings with respect to Basin's eastern coal units.

A: By at least 2015, Basin should have given serious consideration to retiring or exiting coal units at Antelope Valley, Leland Olds, and Laramie River Unit 1. If Basin had undertaken those analyses, I believe that it would have found that these units were candidates for near-term retirement and that continued operation and investment was imprudent.

Basin would then have had the 2016–2020 period to procure multi-year capacity and energy contracts to span the period until new resources could be brought on line in the 2020s. Had Basin assessed alternatives to its eastern coal units beginning in 2015, it would have found that capacity contracts and wind power purchase agreements were available to serve Basin's load at less cost than its eastern coal-fired units, enabling Basin to build its own longer-term renewable and combustion turbine resources to begin operation after the expiration of the above-described contractual arrangements.

Importantly, this retirement strategy could have enabled Basin to avoid capital expenditures at its eastern coal units totaling as much as **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in major investment and **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in smaller projects, as discussed in Section IX. Since Basin did not perform these analyses, it imprudently continued to operate and invest in these units, and the depreciation and carrying costs of these imprudent investments have been passed on to ratepayers, including as part of the 2019-2020 rates at issue here. This has resulted in proposed rates that are not just and reasonable.

Q: What replacement energy and capacity resources can be compared to the costs of Basin's eastern coal units?

A: In the period relevant to this analysis, Basin could have considered (and in some cases, did consider) the economics of the following resource categories:

- Short-term energy prices in the SPP market for energy.[83]
- The prices for longer-term capacity contracts, particularly in the SPP markets.[84]
- The prices of purchased-power agreements for energy and capacity from new renewable resources
- The cost of constructing new generation capacity.

For purposes of both the continued operation and major investment tests, I will focus on information available to Basin in the 2016-2017 timeframe.

Q: Why have you focused on the 2016-2017 timeframe?

A: As discussed in Section IV.C, by 2015 many North American utilities had committed to early retirement of coal units. Early retirement decisions were triggered in part due to environmental compliance obligations which would have necessitated capital investments. As will be discussed in Section IX, Basin was also considering how to comply with key environmental regulations at this time.

While Basin should have been considering the prudency of continued operation, these investment decision points should have spurred Basin to do a major

[83] The same prices are relevant for energy that is no longer generated by the coal plants and replace supplies from the market.

[84] To some extent, capacity resources in MISO can be used to serve load in SPP.

investment prudency analysis. Because multiple of its eastern coal-fired units were in economic distress at this time, Basin should have recognized that avoiding investments or other financial commitments in multiple coal units and pursuing alternative sources of energy and capacity was in the best interest of its member cooperatives.

It is likely that a reasonable analysis of the units' economics would have resulted in Basin seeking out additional capacity resources (mostly as purchases or co-ownership in existing plants) in 2016 and procuring long-term wind and solar replacement energy in the 2017–2018 period. The slower pace for acquiring renewable energy resources would have been reasonable, given that prices were falling and that available resources far exceeded Basin's potential need. Some of the capacity resources procured in 2016 would have expired in the 2020s, at which point Basin would have the option of adding gas-fired capacity or battery storage.

A. Replacement Energy Costs

Q: What market energy prices are relevant to the economic evaluation of Basin coal plants?

A: The most relevant market comparator for Basin's eastern units on an hourly basis are SPP northern nodal prices for the Leland Olds 1 and 2, Antelope Valley 1 and 2, and Laramie River 1.

Although I did not perform an analysis of Basin Electric's units within the MISO market and Western Interconnection, the relevant energy alternatives for assessing the economic value of those units are as follows:

- For Basin's entitlements in Neal and Walter Scott, MISO Zone 3 prices; and
- For Laramie River Units 2 and 3 and Dry Fork, prices in WAPA's Rocky Mountain region, reflecting both short-term transactions with other generators and the settlement of imbalances by the SPP Western Energy Imbalance Service market.

Market prices at other locations within these regions and other zones (such as MISO Zone 1 in Minnesota) are also relevant to the extent Basin could replace its coal-fired units with new generation or energy and capacity purchases from these regions.

Q: Please describe Basin's participation in the SPP energy market.

A: Basin's Eastern units (Leland Olds Units 1 and 2, Antelope Valley Units 1 and 2, and Laramie River Unit 1) participate in the SPP energy market. Basin acts as both a seller and buyer of energy within the market, selling generation based on its day-ahead and real-time bids and (for dispatch above a unit's minimum operating level and when using the "market" commitment status) locational marginal prices, and purchasing sufficient load from the SPP market to serve its customer load.

Depending on load and output, Basin may be a net seller or net buyer of electricity within SPP on an hourly or sub-hourly basis.

Since at least October 1, 2015, Basin has submitted both day-ahead and real-time bids for each of these five units into SPP's Integrated Energy Market.[85] The offer for each unit incorporates physical operating constraints (including an economic minimum) and a price curve for generation above that minimum.[86]

During the time period for which Basin provided bid information (*i.e.*, January 2017 through October 2021), Basin utilized four commitment statuses: self, market, outage, and reliability. Under a "self" commitment status energy is generated by the units at the relevant economic minimum regardless as to whether the local marginal prices exceed or fall below that unit's marginal cost of generation. Under a "market" commitment status, "a unit is available for centralized unit commitment through its price sensitive (merit-based) price quantity offers."[87] When a unit is bid under a "market" status, it is only switched on by the grid operator

[85] Exhibit No. SC-0077, SC-BEPC-1.12a.

[86] Exhibit No. SC-0042, 1.14-CUI-PRIV-HC SC-BEPC; Exhibit No. SC-0043, CUI-PRIV-HC SC-BEPC-1.029.279, at 47.

[87] Exhibit No. SC-0044, SPP Market Monitoring Unit: *Self-Committing in SPP Markets: Overview, Impacts, and Recommendations* (December 2019), at 11. Available at https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

(SPP) when locational marginal prices exceed the unit's offer curve. A unit committed with a "reliability" status is only available in the case of reliability issues, and a unit in "outage" status is wholly unavailable.[88]

Q: How are offer curves for SPP energy market bids for Leland Olds, Antelope Valley, and Laramie River determined?

A: The offer curve reflects the increase in cost (for both variable fuel-related and non-fuel O&M) due to increased generation. To determine this marginal increase, Basin classifies operational expenditures at these units as fixed or variable—that is, as varying with hourly energy production.[89] Basin **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**[90] Notably, **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Leland Olds and Antelope Valley are considered "fixed" because the cost of coal for these two plants is **[BEGIN CUI//PRIV/HC]** "[redacted]

[88] *Id*.

[89] Exhibit No. SC-0045, 1.10-CUI-PRIV-HC SC-BEPC.

[90] Exhibit No. SC-0066, 1.10.2-CUI-PRIV-HC SC-BEPC.

[redacted].”**[END CUI//PRIV/HC]**[91]

Q: Can you summarize Basin’s commitment practices for its eastern coal units?

A: Basin only provided hourly day-ahead and real-time offers to SPP for the four eastern units from January 1, 2017 onward. From January 1, 2017 through October 31, 2019, Basin Electric **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** the Antelope Valley and Leland Olds units as **[BEGIN CUI//PRIV/HC]** “[redacted]” **[END CUI//PRIV/HC]** when the units were in service.[92] Although Laramie River Unit 1 was **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** as well,[93] in

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[91] Exhibit No. SC-0045, 1.10-CUI-PRIV-HC SC-BEPC.

[92] *See* Exhibit No. SC-0046, 1.12.5-CUI-PRIV-HC SC-BEPC. During the 2017-2019 time period Antelope Valley Unit 1 was committed with a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** on October 20, 2019. Leland Olds Unit 1 was committed with a **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**

[93] *See* Exhibit No. SC-0046, 1.12.5-CUI-PRIV-HC SC-BEPC. Laramie River Unit 1 was committed as **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** on the following dates between January 1, 2017 and October 31, 2019: **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**

September 2019 the Management Committee of the Missouri Basin Power Project authorized a **[BEGIN CUI//PRIV]** "[redacted]," **[END CUI//PRIV]** whereby Laramie River Unit 1 could be committed **[BEGIN CUI//PRIV]** [redacted]. **[END CUI//PRIV]**[94] In implementing this policy, Basin Electric (in its capacity as Operating Agent for MBPP) relies on **[BEGIN CUI//PRIV]** [redacted], which it compares to [redacted]. **[END CUI//PRIV]**[95]

Basin Electric also began performing forward-looking locational marginal prices forecasts for use in determining whether to commit the Antelope Valley and Leland Olds units as "market" or "self" in 2020.[96] The use of these forecasts is reflected **[BEGIN CUI//PRIV/HC]** [redacted]

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[94] Exhibit No. SC-0047, CUI-PRIV-SC-BEPC-1.033.156, at 6; *see also* Exhibit No. SC-0048, CUI-PRIV-SC-BEPC-1.033.134 (draft policy). Although the **[BEGIN CUI//PRIV]** "[redacted]" **[END CUI//PRIV]** was not approved by MBPP until September 2019 and **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** Basin did perform LMP forecasts for Laramie River Unit 1 dating back to 2017.

[95] *Id.*

[96] Exhibit No. SC-0049, SC-BEPC-1.11a.

[redacted] **[END CUI//PRIV/HC]** at each of the four units.[97]

Q: What are the implications of Basin Electric's use of a short-term economic shutdown for its coal-fired units' overall economic value?

A: The use of short-term economic shutdowns allows a prudent utility to avoid incurring excess generation costs by selling energy into the market at a loss. Whenever a unit's offer curve exceeds the relevant locational marginal price, energy can be bought on the market for less than the cost of generation at that unit. Thus, prolonged periods of economic shutdown may be a signal to a utility that the unit is no longer competitive within the energy market and that less expensive sources of energy may be available. To more comprehensively assess the economic value of

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[97] Antelope Valley Unit 1 was committed as "market" from **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** Antelope Valley Unit 2 was committed as "market" from **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** Leland Olds Unit 1 was committed as "market" from **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** Leland Olds Unit 2 was committed as "market" from **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** *See* Exhibit No. SC-0050, 1.12.1-CUI-PRIV-HC SC-BEPC. (These periods include **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]**)

Basin's coal plants during the relevant period, I compared Basin's costs to energy market prices (and Basin energy sales revenue).

Q: Please summarize how you compared the costs of energy and capacity market purchases to the costs of running Basin's eastern coal units.

A: To determine whether Basin could have reduced rates going forward (including its 2019-2020 rates at issue in this proceeding) by replacing its eastern coal units with energy and capacity market purchases, I considered both the energy market prices at the node into which each coal unit sold energy, and bilateral capacity purchases within the SPP footprint. I considered the prevailing prices during the historical time period in which Basin should have assessed its units' economics, and offers of capacity resources for the future. Specifically, I used SPP's Leland Olds, Antelope Valley, and Laramie River pricing nodes, weighted by the gross hourly unit output from EPA's Air Markets Program Database, now called the Clean Air Markets.[98]

Q: Can you summarize the historical energy price data you used?

A: The hourly price data are too voluminous to reproduce here. Table 8 summarizes the annual historical market energy prices that I used for the five units for which I reviewed the economics of continued operation.

[98] Data derived from https://ampd.epa.gov/ampd/. This is the standard data source for hourly output, fuel use, emissions and other characteristics of generating units with air emissions regulated by EPA.

Table 8: Annual Market Energy Prices by Plant ($/MWh)

Year	Antelope Valley 1	Antelope Valley 2	Leland Olds 1	Leland Olds 2	Laramie River 1
2016	$18.75	$19.40	$19.19	$19.41	$14.04
2017	$19.39	$19.17	$20.11	$20.03	$16.73
2018	$22.53	$22.79	$24.01	$23.95	$17.44
2019	$19.97	$19.92	$21.71	$20.60	$13.23
2020	$15.75	$15.32	$17.29	$17.24	$16.97

B. Capacity Resource Costs

Q: Why did you consider capacity prices as well as energy prices?

A: For Basin to meet its obligations as a member of SPP, it must demonstrate that it has sufficient capacity to meet the peak load of its members. To replace the eastern coal units, Basin would therefore need to purchase capacity from existing resources, enter into power purchase agreements with generation developers, and/or build new generation resources to meet this capacity requirement. Energy purchases alone would not be sufficient.

Q: If Basin had retired one or more coal-fired units before or during the rate period at issue in this proceeding, was there excess capacity available in SPP to bridge the time period until Basin could bring on new capacity?

A: Yes. Depending on how long in advance Basin had decided to retire the coal-fired units, it might well have constructed new resources to replace that capacity, without any need for bridge purchases. But if it needed additional capacity, there was ample capacity available.

In 2016, Basin could have procured enough capacity to retire at least three of its uneconomic eastern units over a five-year time horizon. At a minimum, sufficient capacity was available to immediately replace the 216-MW (nameplate) Leland Olds 1, Basin's least cost-effective coal plant, at a lower cost to member-ratepayers. The amount of cost-effective capacity resources readily available to Basin in 2016 was also sufficient to retire Leland Olds 2 and Laramie River 1 by 2019 or 2020. Capacity credits for renewable energy resources would allow further retirements.

Based on my review of Basin's actual costs of capacity and market offers that Basin received in response to request for proposals, Basin could have acquired that replacement capacity through 2030 at **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in 2021, with that cost escalating at a modest rate through 2030.

1. Peaking Units as Capacity Alternative

Q: How do gas-fired peaking generating units function as an alternative source of capacity?

A: One option for replacing the capacity provided by the eastern coal units would be to construct and operate combustion turbines, or "peakers." In general, a peaking unit or peaker is a generator whose economics (and sometimes technical characteristics) limit it to operating a limited number of hours per year, at time of peak demand or reduced availability of other resources. Ideally, peakers are able to rapidly start up and increase output when needed, but some definitions of peakers include gas-fired steam plants with long response times.[99] Peakers provide capacity accreditation while a utility obtains energy on a day-to-day basis or during low- and medium-load periods from the RTO market or energy-only power purchase agreements.

To assess whether the construction of new combustion turbines presented Basin with a cost-effective alternative to the continued reliance on coal resources, I evaluated the net cost associated with those combustion turbines Basin *did* build during the relevant period.

Q: What is the net cost of capacity for Basin's existing peaking units?

A: Basin Electric operates combustion turbine peakers at several locations, including the 95 MW Culbertson combustion turbine unit, built in 2010, and the 135 MW at Pioneer, built in 2013–2014, for which we have detailed costs.[100] Basin also

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[99] If Basin were procuring peaking resources today, the least-cost choice would probably be battery storage.

[100] Cost data produced in discovery is attached as Exhibit No. SC-0051, CUI-PRIV-HC-SC-BEPC-5.001.040 and Exhibit No. SC-0052, CUI-PRIV-HC-SC-BEPC-5.001.048. The capital cost of the Lonesome Creek plant from 2013–2017 is somewhat less than that of Culbertson and Pioneer, but I do not have as complete cost data for that plant.

operates internal-combustion-engine peakers at Pioneer, and some storage resources can operate as peakers. From the discovery responses, I estimated the net cost of capacity for 2018–2020 of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Culbertson and **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Pioneer 1–3.

Q: How did you determine the net cost of capacity for these units?

A: The net cost of capacity is calculated as total costs minus total revenues, divided by the capacity and expressed on a monthly basis for the time period (annual or three-year average). Total costs include the following:

- Variable Costs and Major Maintenance:
    - Fuel,
    - Operations & Maintenance, and
    - Major Maintenance
- Fixed Costs:
    - Labor, Insurance, Property Taxes, and Other,
    - Administrative, and
    - Depreciation and Interest.

These cost data were obtained from Basin Electric.[101]

Because Basin Electric has not provided unit-specific annual revenue values, I estimated annual revenue by multiplying the load-weighted average hourly market price, calculated as described in Section VII.A, by each unit's annual net generation.

As noted above, net capacity cost is calculated as total annual costs minus total estimated annual revenues. Basin Electric receives very little in market revenues to cover non-fuel costs. I estimate that SPP market revenues, net of fuel costs, offset about 26% of fixed costs for Culbertson and 33% for Pioneer 1-3, respectively, during 2018–2020. I incorporated these offsets in estimating the net capacity cost of these units above.

This calculation is very similar to what is known as a net cost of new entry (Net CONE) for a new facility, used by most of the independent system operators and regional transmission organizations.

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[101] Exhibit No. SC-0051, CUI-PRIV-HC-SC-BEPC-5.001.040 (Culbertson) and Exhibit No. SC-0052, CUI-PRIV-HC-SC-BEPC-5.001.048 (Pioneer 1-3).

2. Capacity-only Contracts as Alternative

Q: What costs has Basin actually incurred to procure capacity?

A: A second relevant comparator to assess the cost of alternative capacity for the eastern coal units is the price Basin actually paid for capacity purchases during the relevant time frame. As shown in Table 9, Basin purchased hundreds of megawatts of capacity with starting dates in 2014–2023, priced at or below \$61/kW-year, or \$5.08/kW-month. (The table excludes renewable and member resources).[102]

[102] Exhibit No. SC-0053, CUI-PRIV SC-BEPC-1.51.1 provides the capacity prices for some contracts with later start dates, including Dairyland and Manitoba Hydro in 2023, and the Minnesota Power purchases in 2022 and 2021, along with data on price escalation, where applicable.

Table 9: Basin Non-renewable Purchases, Starting 2014–2023
[BEGIN PARTIAL CUI//PRIV]

Seller	Amount (MW)	Market	Start Date	End Date		Capacity $/kW-year		
						2019	2020	2020
Cargill Power Market	50	NWMT	10/1/17	12/31/21				
Cargill Power Market	50-75	NWMT	5/1/20	12/31/25				
$	75-175	MISO	6/1/19	5/31/23	C	$43	$60	$61
Dairyland Power Cooperative	75	MISO	6/1/23	5/31/33	c			
Evergy Kansas Central, Inc	101-151	SPP	6/1/21	5/31/24	C			[redacted]
Great River Energy	75	MISO	6/1/20	5/31/23	C		[redacted]	$59
Great River Energy	25	MISO	6/1/14	5/31/19	C	$16		
Manitoba Hydro-Electric	50	MISO	6/1/18	5/31/20	C	$48	$53	
Manitoba Hydro-Electric	50	MISO	6/1/20	5/31/21	C			$23
Manitoba Hydro-Electric	50-80	MISO	6/1/23	5/31/28	c			
Minnesota Power	75-125	MISO	6/1/22	5/31/25	c			
Minnesota Power	100	MISO	6/1/25	5/31/28	c			
Minnesota Power	50	MISO	6/1/17	5/31/19	C	$16		
Minnesota Power	50	MISO	6/1/18	5/31/19	C			
Minnkota Power Cooperative	100	MISO	3/1/19	5/31/22				
Minnkota Power Cooperative	100-200	SPP	1/1/16	12/31/18				
Missouri River Energy Services	150	SPP	6/1/17	5/31/23	C	$43	$45	$47
Missouri River Energy Services	35-185	SPP	10/1/20	9/30/35	C		[redacted]	[redacted]
Morgan Stanley Capital Group	100-150	NWMT	1/1/19	12/31/27	C	$18	$18	$23
North Iowa Muni Coop	~70	MISO	1/1/11	5/31/25	C	$36	$40	$36
Northern States Power	25	MISO	6/1/14	5/31/19	C	$15		
NRG Power Marketing	75	MISO	6/1/23	5/31/25	c		$55	
PPL Energy Plus, LLC	50	NWMT	5/1/17	4/30/20				

Note: Purchases marked with *c* are capacity-only, with no energy delivery or energy charges
Purchases marked with *C* are capacity-only, with deliveries in some part of 2019–2021
Capacity and dates from ER20-1505 Notice of Change in Status for SPP Region, Document Accession #: 20200407-5082.
Prices are from FERC Form 1 at 326, unless marked confidential.
Confidential prices are from Exhibit No. SC-0053, CUI-PRIV SC-BEPC-1.51.1.

[END PARTIAL CUI//PRIV]

Q: Could Basin have made additional capacity purchases between 2016 and 2019 to replace the eastern coal units' capacity?

A: Yes, there were additional near-term capacity resources available to Basin in the SPP footprint available for purchase. Basin solicited proposals for capacity and/or energy in 2012, 2013, 2014, 2015, 2016, 2017, 2018, 2019 and 2021.[103] Basin received offers in response to all of these requests for proposals. For example, in 2016 Basin received offers to purchase or contract for up to **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity for delivery to its SPP territory, as follows:[104]

- **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of gas combined-cycle capacity at **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** which would be about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for capital cost over 10 years, or **[BEGIN**

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[103] Exhibit No. SC-0054, SC-BEPC-1.056.

[104] Exhibit No. SC-0055, CUI-PRIV-HC-SC-BEPC-1.056.031. Sierra Club received the first, partial response to SC-BEPC-1.056 on June 28, less than three weeks before the due date for this testimony. Basin did not provide its economic analyses of these offers, so I cannot review the assumptions about transmission costs or other factors.

CUI//PRIV/HC] [redacted] **[END CUI//PRIV/HC]** over a remaining life of 20 years.[105] The cost of owning the plant **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** (perhaps $3/kW-month), but it would be reduced by the net energy margin on energy and ancillary services.

- Contract for **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity in 2021–2030 beginning at **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and escalating annually at **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**
- Contract for **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity for 2021-2041 at a price of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** The bid also **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**
- Contract for **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity in 2021-2040 beginning at **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and

[105] Calculations assume a capital cost of 4%.

escalating annually at **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

If Basin had contracted for all four of these resources, it could have obtained up to **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity at a cost of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in 2021 (with adjustments up and down for the combined-cycle costs and benefits), escalating at less than **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** As part of the replacement of a coal plant at a 75% capacity factor, this price would be equivalent to about **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Basin also received multiple offers for capacity and energy in MISO and its western territories.

C. New Energy Resource Costs

Q: Which types of new energy resources could Basin have considered as alternatives to the coal plants in the 2015-2017 time period?

A: In addition to the combustion turbine units discussed in the previous section, Basin has added or will be adding wind and solar purchased power contracts in the period 2014–2023.

1. Purchased Wind Power

Q: What did purchased-power contracts for wind energy cost in the 2015-2017 time period?

A: Basin could have acquired sufficient wind power to replace all of the eastern coal units for less than $20/MWh in 2017. I reached this conclusion based on a number of sources, including Basin's existing contracts, Lazard, and responses to the request for proposals evaluated by Basin in 2017.

Q: What were the costs of Basin's purchases from wind farms in recent years?

A: As shown in Table 10, Basin's post-2010 wind contracts had an average cost of $20/MWh to $23/MWh.[106] Based on FERC Form 1 data, the prices for those contracts appear to be escalating at about 2%; Exhibit No. SC-0053, CUI-PRIV-HC SC-BEPC 1.51.1, clarifies that the escalation rate is **[BEGIN CUI//PRIV/HC]** [redacted] for most contracts, **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** contracts, and

[106] The 2021 FERC Form 1 (Exhibit No. SC-0056) does not have data on the Burleigh County and Campbell County farms, at least by those names. The 2023 price for Aurora is from Exhibit No. SC-0053, CUI-PRIV-HC SC-BEPC 1.51.1, and I note that it is significantly **[BEGIN CUI//PRIV/HC]** lower **[END CUI//PRIV/HC]** than the offer as represented in Exhibit No. SC-0057, CUI-PRIV-HC-SC-BEPC-1.056.032. Exhibit No. SC-0053, CUI-PRIV-HC SC-BEPC 1.51.1 provides similar prices for 2020. Slight differences might result from payment dates and accounting conventions.

[BEGIN CUI//PRIV/HC] [redacted]. **[END CUI//PRIV/HC]**

Table 10: Basin Wind Contract Prices by Start Date (¢/kWh)

[BEGIN PARTIAL CUI//PRIV/HC]

Seller	Start Date	2019	2020	2021	2023
FPL South Dakota	10/1/03	2.519	2.610	3.398	
FPL North Dakota	10/1/03	2.325	2.357	2.772	
FPL Burleigh County	12/1/05	2.985	2.383		
FPL Wilton Wind 2	11/1/09	4.955	4.467	4.314	
FPL Day County Wind	4/1/10	4.898	4.716	4.449	
FPL Energy Baldwin Wind	12/1/10	4.393	4.391	3.961	
Campbell County Wind	12/1/15	2.377	2.393		
Brady Wind	11/1/16	2.385	2.426	2.480	
Sunflower Wind I	12/1/16	2.387	2.395	2.515	
Brady Wind II	12/1/16	2.131	2.173	2.231	
Lindahl Wind	4/1/17	2.373	2.420	2.495	
Prevailing Wind Farm	4/20/20		1.487	1.685	
Northern Divide Wind	12/22/20		1.733	1.850	
Aurora Wind Project	1/1/23				[redacted]

[END PARTIAL CUI//PRIV/HC]

Sources: Start date from Notice of Change in Status for SPP Region, ER20-1505, Document Accession #: 20200407-5082, Attachment C.
Prices from FERC Form 1, 2019–2021 (Exhibit Nos. SC-0025, SC-0026, SC-0056), pages 326–327; except Aurora 2023 from Exhibit No. SC-0053, CUI-PRIV-HC SC-BEPC 1.51.1.

In January 2019, Basin reported prices for its existing contracts **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** those in Table 10.[107]

Q: Were the prices obtained by Basin for its existing wind generation beginning in 2015 competitive?

A: Yes. It appears Basin had offers for wind power purchase agreements at prices **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** the national average. As shown in Figure 3, Lazard's annual report of the cost of energy resources shows that the "low" levelized cost of energy from wind were around $30/MWh in 2017.[108] Lazard reports the price range for the entire country, from low-cost resources in SPP, ERCOT and the inland West, to high-cost resources in California, New England and the Mid-Atlantic. As suggested by other evidence, even these low prices may overstate average costs in the Basin footprint.

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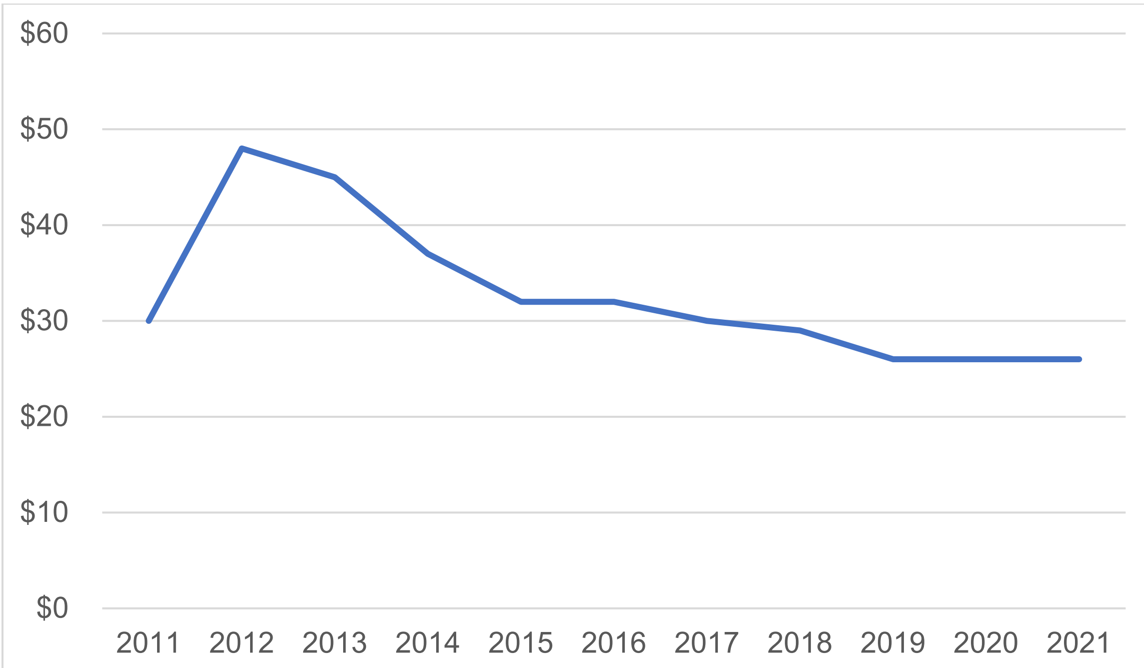
[107] Exhibit No. SC-0058, CUI-PRIV-HC-SC-BEPC-1.029.050, at 93.

[108] Lazard, *Levelized Cost of Energy Analysis,* versions 5.0 through 15.0 (2009-2021).

Figure 3: Lazard Nationwide "Low" Wind Cost by Contract Year ($/MWh)



Q: What were market prices for wind power available to Basin in 2017?

A: In June 2016, Basin reported that it had received offers from **[BEGIN CUI//PRIV/HC]** [redacted] projects, totaling [redacted] at [redacted] capacity factors, at PPA prices of [redacted]. **[END CUI//PRIV/HC]**[109]

In 2017, Basin evaluated many responses to recent requests for proposals. Considering **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the most cost-effective wind PPA offers, totaling **[BEGIN CUI//PRIV/HC]** [redacted]

[109] Exhibit No. SC-0062, CUI-PRIV-HC SC-BEPC 1.056.133.

[END CUI//PRIV/HC] Basin could have obtained enough energy to replace all of the energy delivered by Antelope Valley, Leland Olds, and Basin's portion of Laramie River 1 at a cost of less than **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[110]

Basin's Board was made aware of these very low costs in January 2019, when Basin reported to its Board that unnamed new wind would cost about **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[111]

Q: Why did Basin not take advantage of these low-cost wind power purchase offers?

A: I do not see any clear explanation for Basin's reluctance to acquire additional wind resources in 2016 or 2017, beyond the 400 MW it procured for 2020.[112] Basin seemed to be limiting its acquisitions to amounts necessary for load growth and contract termination, and may have been reluctant to acquire resources that would clearly make the coal plants unnecessary.

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[110] Exhibit No. SC-0057, CUI-PRIV-HC-SC-BEPC-1.056.032.

[111] Exhibit No. SC-0058, CUI-PRIV-HC-SC-BEPC-1.029.050, at 93.

[112] *See* Table 10 (Prevailing Wind and Northern Divide Wind projects).

2. Purchased Solar Power

Q: What did purchase power contracts for solar energy cost in the 2015-2017 time period?

A: Basin could have acquired solar power for $30-40/MWh in 2017. I reached this conclusion based on a number of sources, including Basin's existing contracts, Lazard, and responses to requests for proposals (RFPs) evaluated by Basin in 2017.

Q: What are the costs of Basin's solar PPAs?

A: As shown in Table 11, Basin has four large solar projects under contract, with starting prices in the **[BEGIN CUI//PRIV/HC]** [redacted] range (with some contracts [redacted]), **[END CUI//PRIV/HC]** with 128 MW due to come on line late this year and 170 MW due in late 2023. Notably, the least expensive projects are in Montana, even though Montana solar has a much lower insolation than states further south (see Figure 4). Additional low-cost solar should be available throughout Basin's footprint, and solar resources in South Dakota and further south are likely to be even less expensive. Sunlight does not appear to be a limiting factor for solar development in this region.

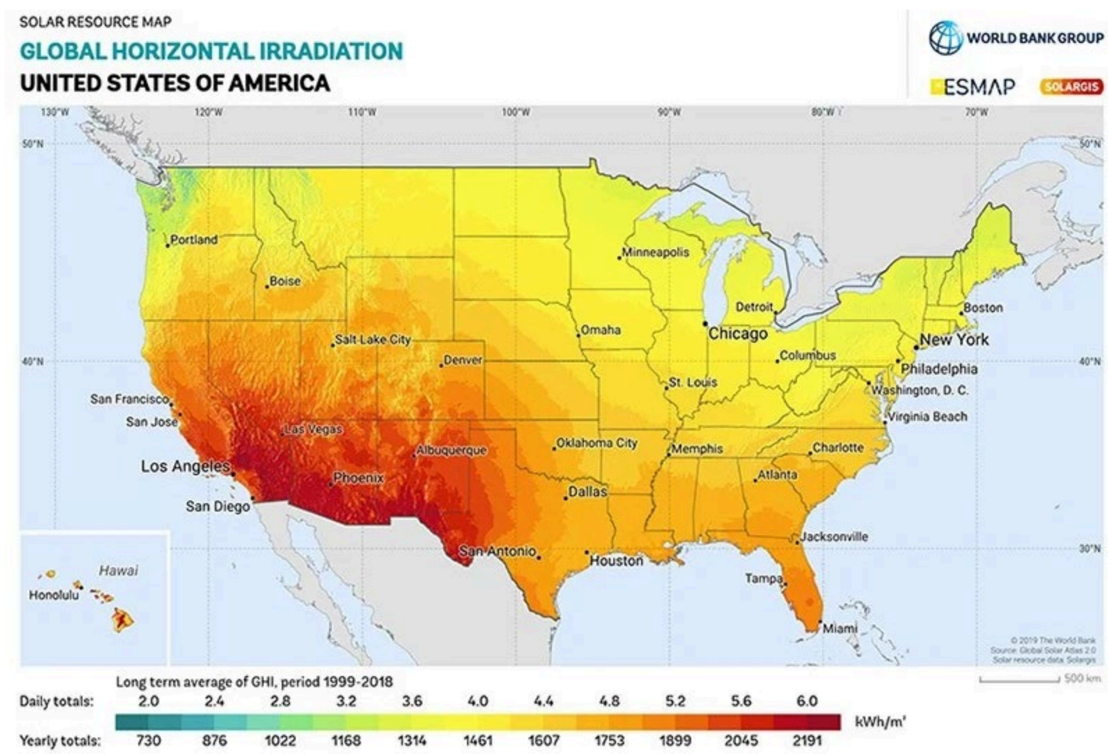
Table 11: Basin Solar Contracts (HIGHLY CONF)[113]

[BEGIN CUI//PRIV/HC]

Project	MW	Market / State	Term	Starting Price	Price Escalation
Wild Springs	128	SPP/SD	2023-2037	[redacted]	[redacted]
Cabin Creek I	75	SPP/MT	2024-2038	[redacted]	[redacted]
Cabin Creek II	75	SPP/MT	2024-2038	[redacted]	
Custer	20	NWPP/MT	2024-2045	[redacted]	[redacted]

[END CUI//PRIV/HC]

Figure 4: Average Insolation Levels



[113] Notice of Change in Status for SPP Region, ER20-1505, Document Accession #: 20200407-5082, Attachment C (Basin Electric Asset Appendix), Document Accession #: 20200407-5082; and Exhibit No. SC-0053, CUI-PRIV-HC SC-BEPC 1.51.1.

Q: What prices for solar purchases did Lazard report?

A: As shown in Table 12, Lazard's annual report of the cost of energy resources shows that the "low" solar PPA prices were around \$46/MWh in 2017 and \$31/MWh in 2020. Compared with the contract prices in Table 11, Lazard's "low" solar PPA prices appear to **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** Basin's actual pricing by **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Table 12: Lazard Reported Solar PPA Offers by Contract Year (\$/MWh)

Year	Crystalline		Thin Film	
	Low	High	Low	High
2011	\$109	\$124	\$89	\$179
2012	\$102	\$149	\$102	\$142
2013	\$91	\$104	\$89	\$99
2014	\$72	\$86	\$72	\$86
2015	\$58	\$70	\$50	\$60
2016	\$49	\$61	\$46	\$56
2017	\$46	\$53	\$43	\$48
2018	\$40	\$46	\$36	\$44
2019	\$36	\$44	\$32	\$42
2020	\$31	\$42	\$29	\$38
2021	\$30	\$41	\$28	\$37

Q: What solar power prices were offered to Basin and considered in 2017?

A: In 2017, Basin evaluated a number of responses to its recent requests for proposals. Considering the five most cost-effective offers, totaling **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** (and assuming a 50% capacity factor), Basin could have obtained enough energy to replace about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the power delivered by Antelope Valley, Leland Olds, and Basin's portion of Laramie River 1 combined at a cost of less than **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**[114]

D. Capacity Value of Renewable Resources

Q: What is the significance of the capacity value of renewables in evaluating the economics of replacing the Basin coal plants?

A: As discussed above, in addition to producing or purchasing enough energy to meet its members' requirements, Basin must maintain sufficient capacity, as accredited by the regional transmission organizations, to meet its reserve obligations. The more capacity value attributed to the renewables that replace a coal unit, the less purchased or owned peaking capacity will be needed.

While most of Basin's eastern load is in SPP, renewables in MISO can serve Basin's load there; allow the transfer of MISO capacity to SPP, as Basin has done

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[114] *See* Exhibit No. SC-0057, CUI-PRIV-HC-SC-BEPC-1.056.032.

with the capacity of its coal entitlements in Iowa;[115] or allow Basin to reduce the amount of SPP capacity that needs to be transferred back to MISO.

Q: What SPP capacity credit do you consider reasonable for economic analysis of alternatives to the Basin coal plants?

A: I find that reasonable capacity values that could have been used for Basin's SPP resources in 2016 would have been 25% for wind and 60% for solar. These values are primarily informed by SPP's accredited capacity values, but I have revised them downward slightly to reflect Basin's somewhat more conservative assumptions.

Q: Is it straightforward to determine the capacity value that should be attributed to renewables for the purpose of meeting reliability requirements?

A: No, that turns out to be a rather complicated question. The capacity attributed to wind and solar resources varies:

- between SPP and MISO,
- between applications for each RTO,
- between summer and winter,
- depending on the performance of the specific projects (which will vary with location),

[115] *See* Exhibit No. SC-0008, CUI-PRIV-HC-SC-BEPC-1.029.049, at 22; Exhibit No. SC-0060, CUI-PRIV-HC-SC-BEPC-1.029.179, at 32; Exhibit No. SC-0061, CUI-PRIV-HC-SC-BEPC-1.029.026, at 9.

- as a function of the penetration of solar and wind capacity in a particular market,
- with the accumulation of historical data on the correlation of renewable (particularly wind) output with load, and
- as the RTOs change their computational methods.

In any case, the accredited capacity value used in determining compliance with the RTO requirements is generally expressed as a percentage of nameplate capacity.

Q: What information do you have from SPP on its treatment of wind and solar capacity?

A: Generally, SPP has used unit-specific capacity valuations. Where no output or modeling data are available, SPP uses a default 5% credit for wind and 10% for solar.[116] Actual valuations have been much higher.

SPP recently transitioned from valuing capacity using planning criteria to an effective load carrying capacity (ELCC) modeling approach. SPP does not appear to publish much detail on the ratio of accredited capacity to nameplate capacity, but does provide some system-wide averages. SPP's ELCC studies incorporating past

[116] Exhibit No. SC-0062, SPP Planning Criteria, Revision 2.4 (February 4, 2021) (excerpts), at 11-12. Available at www.spp.org/documents/58638/spp%20planning%20criteria%20v2.4.pdf.

averages provide some information as to how Basin might have reasonably anticipated wind and solar would have been accredited in 2015–2017, when Basin should have been comparing Leland Olds Unit 1 and other challenged units to alternative energy and capacity resources.

The 2019 ELCC study reports an accredited value of 28% for the older planning-criteria approach.[117] As shown in Table 13, the 2021 ELCC study found somewhat lower system-average capacity values, particularly in the winter. It is not clear when SPP planned to transition to the ELCC method for accreditation, or when the transition occurred.

Table 13: SPP Wind System-Average ELCC Results[118]

	Summer				Winter			
Capacity Deployed	12,634	15,141	26,885	40,000	11,270	15,141	26,885	40,000
ELCC	21.9%	23.2%	21.1%	17.1%	14.4%	21.2%	16.8%	14.3%

[117] Exhibit No. SC-0063, Southwest Power Pool, Solar and Wind ELCC Accreditation (August 2019), Figure 3. Available at https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf.

[118] Exhibit No. SC-0064, Southwest Power Pool, 2020 ELCC Wind and Solar Study Report, SPP Resource Adequacy (July 2021), Table 2. Available at spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pdf.

Q: What assumptions was Basin making during the relevant time period about wind and solar capacity accreditation?

A: In Basin's 2018 IRP filed with the Western Area Power Authority (WAPA), it reported that "[w]ind in the summer months is often time only receiving 10-12% capacity accreditation. Solar accreditation in SPP is averaging approximately 80% accreditation."[119] Basin did not report the accreditation at winter peak.

In January 2019, Basin reported to its Board that **[BEGIN CUI//PRIV/HC]** [redacted]" **[END CUI//PRIV/HC]** in SPP.[120]

Figure 5 shows the accredited capacity that Basin reported to its Board in April 2019.

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[119] Exhibit No. SC-0065, 2018 Integrated Resource Plan (2019-2028), Basin Electric Power Cooperative, submitted to the Western Area Power Administration, November 2018, at 151.

[120] Exhibit No. SC-0008, CUI-PRIV-HC SC-BEPC-1.029.206, at 22.

Figure 5: Basin Estimates of Seasonal Accredited Capacity (HIGHLY CONF)[121]
[BEGIN CUI//PRIV/HC]

[redacted]

[END CUI//PRIV/HC]

The wind value appears to be **[BEGIN CUI//PRIV/HC]** [redacted] since Basin highlighted the [redacted] **[END CUI//PRIV/HC]** even though Basin's peak load occurs in the winter,[122] during which time Basin reports wind capacity benefits of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** the value Basin selected. For solar, SPP appears to use the summer capacity for solar, so Basin's selected solar capacity value is at the **[BEGIN CUI//PRIV/HC]** [redacted]

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[121] Exhibit No. SC-0019, CUI-PRIV-HC-SC-BEPC-1.029.067, at 26.

[122] Exhibit No. SC-0067, Basin South Dakota Ten Year Plan 2020, Exhibits 1 and 2.

[redacted], **[END CUI//PRIV/HC]** as shown in Figure 5. In sum, Basin's planning relied on unduly conservative estimates as to wind accreditation.

E. Modeling Alternatives to the Eastern Coal Units

Q: How should Basin have approached the question of whether retiring one or more of the eastern coal units was cost-effective in 2016 or 2017?

A: Had Basin acted prudently, it would have considered how a mix of the above-described resources (contracts for existing resources, new peakers to meet capacity obligations, wind and/or solar power purchase agreements for energy and capacity, and energy market purchases) might be combined to replace the energy and capacity provided by one or more of the eastern coal units.

I identified a portfolio of representative resources to replace the energy output and the accredited capacity of each eastern coal unit to determine if the costs of that alternative portfolio would have been lower than the prospective avoidable costs of existing coal eastern units.

Q: How did you model the costs of new generation to replace retiring coal units?

A: For purposes of evaluating Basin's decision to continue investing in its coal plants in 2015–2017, I have selected a simple model of replacing the output of coal plants with wind energy and supplementing the accredited capacity requirement with market-priced capacity, primarily sourced from combustion turbines. I assume that, to the extent that retirement dates and procurements require short-term bridging, both energy and capacity would be available from the market, as discussed in Sections VII.A and VII.B.2.

The amount of wind capacity required to replace the energy of the coal plant depends on the capacity factor of both plants.[123]

The ratio of the average hourly energy output of a power plant to its nameplate capacity is called the capacity factor. For new Basin wind plants, I assumed an average 45% capacity factor. A recent analysis by Lawrence Berkeley National Lab found a 40–50% average capacity factor for post-2014 wind plants in all the states most relevant to Basin (MT, WY, ND, SD, NE, KS, MN).[124] Figure 35 of that report shows that the wind plants' capacity factors have been trending higher due to taller, larger wind turbines. My analysis of recently-added wind farms serving

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[123] Note that the capacity factor for actual energy output is distinct from the capacity *accreditation*, which is administratively determined by SPP (or MISO, for generation in that RTO). Some resources have accredited capacity (as a percent of nameplate) that is much higher than their capacity factors (e.g., peakers, SPP summer solar), while others have accredited capacity lower than their capacity factor (e.g., wind).

[124] Exhibit No. SC-0068, Lawrence Berkeley National Laboratory, Land-Based Wind Market Report: 2021 Edition, Figure 34. Available at https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf.

Basin indicates actual capacity factors close to 50%, making the 45% assumption conservative.

As discussed above, Basin had the opportunity to procure**[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of wind resources in 2017, which could have **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** generated by Antelope Valley, Leland Olds, and Laramie River 1.[125] As shown in Table 14, based on a capacity *accreditation* of 25% for wind, a wind procurement with the same energy output as the coal unit could have satisfied between **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of the required replacement capacity for each unit. Had Basin waited until after 2019 to retire one or more units and replace them with wind, using SPP's ELCC-based approach, it would have faced something more like the 20% capacity credit, also shown in Table 14.

Table 14 shows the average capacity for each of the coal units and the amount of wind capacity required to provide the same energy as one MW of coal-plant capacity

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[125] Basin might have decided to delay some of the procurements, given the downward trend in contract costs although Basin would have needed to weigh the potential risks and benefits of spreading out procurement. In the event, delay would have further reduced costs.

Table 14: Capacity Value of Wind Energy Replacing Basin Eastern Coal Units

Unit	Capacity Factor	Wind:Coal Capacity Ratio for Equal Energy	Capacity Value of Replacement Wind per MW Coal	
			25% Capacity Credit	20% Capacity Credit
	a	*b*	*c*	*d*
Antelope Valley 1	80%	1.78	44%	36%
Antelope Valley 2	78%	1.73	43%	35%
Leland Olds 1	63%	1.40	35%	28%
Leland Olds 2	63%	1.40	35%	28%
Laramie River 1	58%	1.29	32%	26%

Notes: a. 2012–2019 average, energy from EIA 923 database; capacity from ER20-1505 Notice of Change in Status for SPP Region, Document Accession #: 20200407-5082.
b. a ÷ 45%
c. b × 25%
d. b × 20%

For example, over the period 2012–2019, the 450 MW of Antelope Valley 1 operated at an 80% capacity factor, producing 3,155 GWh annually. To produce that much energy, Basin would need 800 MW of wind at a 45% capacity factor. At a 25% capacity accreditation, the 800 MW of wind would provide 200 MW of capacity credit, or 44% of the capacity of Antelope Valley 1, as shown in Table 14.

Table 15 applies the coefficients from Table 14 to determine the additional capacity required, in addition to the wind necessary to replace the coal-unit energy. That additional capacity can be capacity-only purchased power or the equivalent in combustion turbines or other peakers.

Table 15: Replacement Capacity Mix for Eastern Coal Units (MW)

Units	Unit Capacity	Wind Credit	Additional Need
Antelope Valley 1	450	198	252
Antelope Valley 2	450	194	257
Leland Olds 1	221	77	144
Leland Olds 2	445	156	289
Laramie River 1	92	29	63

The next section compares the cost of those replacement resources with the costs of continuing to operating the coal units though 2020.

VIII. Continued Operation Test Results

A. Comparison of Coal Plant Costs to Market, 2016–2020

Q: Were Basin's eastern coal plants operating at an economic loss during the 2016-2020 time period?

A: Yes, for the most part. Laramie River 1 and Leland Olds were consistently operating at an economic loss, as shown in Table 16 and Table 17.

Table 18 shows how both Antelope Valley units vacillate between **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** year-to-year, during the study period, with these units operating in the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** most of the time.

Q: How did you estimate the historical net losses of Basin's coal plants?

A: I compared the total prospective and avoidable costs of each unit to an estimated net benefit from all available costs and revenues. Total revenues consist of the annual capacity and energy revenues and the Auction Revenue Rights, Transmission Congestion Rights, and ash and byproducts sales.

Energy revenue is calculated as the sum of each hour's market price times that hour's generation.

I calculated the capacity revenue by multiplying the market capacity price (provided by Basin in Exhibit No. SC-0069, CUI-PRIV SC-BEPC 1.64.1a) by the operational capacity of the unit. Costs included all values outlined in Section VI.A.

For Antelope Valley and Leland Olds, I also considered the effect **[BEGIN CUI//PRIV/HC]** [redacted]) on [redacted] **[END CUI//PRIV/HC]** estimated in Table 7. Even without the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** Leland Olds 1, Leland Olds 2, and Laramie River 1 had **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and the Antelope Valley units had **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**Had Basin retired Leland Olds 1 and 2 to avoid **[BEGIN CUI//PRIV/HC]** [redacted]

[END CUI//PRIV/HC] (and retired Dakota Gasification, which operated at a loss throughout this period), the **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** the remaining Antelope Valley units would have made the Antelope Valley units **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** to operate than they **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in revenue during this period.

Table 16: Leland Olds: Comparison of Costs to Market Value ($ M/year) (HIGLY CONF)
[BEGIN CUI//PRIV/HC]

Unit		2016	2017	2018	2019	2020
Leland Olds 1	[redacted]					
Leland Olds 2						
Leland Olds Total						

[END CUI//PRIV/HC]

Table 17: Laramie River 1: Comparison of Basin Costs to Market Value ($ M/year) (HIGHLY CONF)

[BEGIN CUI//PRIV/HC]

Unit		**2016**	**2017**	**2018**	**2019**	**2020**
Laramie River 1	[redacted]					

[END CUI//PRIV/HC]

Table 18: Antelope Valley: Comparison of Costs to Market Value ($ M/year) (HIGHLY CONF)

[BEGIN CUI//PRIV/HC]

Unit		**2016**	**2017**	**2018**	**2019**	**2020**
Antelope Valley 1	[redacted]					
Antelope Valley 2						
Antelope Valley Total						

[END CUI//PRIV/HC]

Q: What is the significance of these findings?

A: Had Basin conducted an analysis of its eastern coal units economic viability at any point between 2016 and 2020, it would have realized that **[BEGIN**

CUI//PRIV/HC] [redacted].**[END CUI//PRIV/HC]** A prudent utility, faced with the fact of negative net margins, would have looked to alternative sources of energy and capacity to replace these units and reduce costs to their members or ratepayers.

However, as discussed above, negative net market value is an indicator that continued operation of the unit may be unreasonable. A prudent utility would conduct a retirement analysis that compared continued operation of the plants to alternatives before acting on their apparent economic unviability.

B. Comparison of Coal Plant Costs to New Resources, 2016–2020

Q: How would the costs of new generation have compared to the costs of continuing to operate the Basin eastern coal units, had Basin made this comparison at some point between 2016 and 2018?

A: The costs of the coal units was generally higher than the costs of new resources sufficient to meet an equal portion of Basin's energy load and capacity requirements.

I addressed this question using information very similar to what Basin would have known if it had conducted a full retirement analysis. I compared the actual operating costs of Basin's eastern coal units to the procurement cost of replacement wind power and market capacity.

Based on the documents provided in response to discovery requests, it does not appear that Basin ever conducted this analysis and so did not produce any forecasts for the 2020–2030 period in the crucial period for the rates at issue in this proceeding (*i.e.*, 2015 through 2017).

Q: What would have been the cost of replacement wind power and market capacity for each unit?

A: As I as I showed in Section VII.C.1, especially Table 10, in 2017 Basin procured wind power contracts at less than $20/MWh, and could have procured more. These wind resources would have also provided capacity to the Basin system. Furthermore, as I showed in Section VII.B.2, in **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** Basin could have procured capacity contracts for less than **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]** I have applied these costs to the energy and capacity requirements for each of the coal units below.

The cost of replacement wind power and market capacity is shown in Table 19. The quantity of replacement energy is the average 2016–2018 output of each unit.

Table 19: Annual Replacement Costs with New Resources Using 2020 PPA Costs

[BEGIN PARTIAL CUI//PRIV/HC]

Unit	Basin Capacity	Average Energy 2016-18	Wind Cost ($M)	Wind Capacity Value (MW)	Supplemental Capacity MW	Capacity Cost ($M)	Total Cost ($M)
	(a) Table 1	(b) EIA 923	(c) (b) * $20/MWh	(c) Table 15	(d) (a) – (c)	(f) (d)×[redacted]/kW-mo	(g) (c) + (f)
Antelope Valley 1	450	3,386	[redacted]	198.9	251.1	[redacted]	[redacted]
Antelope Valley 2	450	3,265	[redacted]	195.2	254.8	[redacted]	[redacted]
Leland Olds 1	216	1,380	[redacted]	76.8	144.2	[redacted]	[redacted]
Leland Olds 2	445	2,761	[redacted]	154.5	290.5	[redacted]	[redacted]
Laramie River 1	92	261	[redacted]	29.7	62.3	[redacted]	[redacted]
Total	1,658	11,053	[redacted]	655.2	1,002.8	[redacted]	[redacted]

[END PARTIAL CUI//PRIV/HC]

As noted in Section VII.B.2, Basin had received market offers for an additional **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of capacity for delivery to its SPP territory, and would need additional capacity resources if it were to replace all the coal-plant energy with wind. Basin could have acquired additional capacity by moving forward on building peaking units (which, as I discussed above in Section VII.B.1, would have a net capacity cost of about **[BEGIN CUI//PRIV/HC]** [redacted]). **[END CUI//PRIV/HC]**

Basin could also have procured some of its energy from solar power, rather than wind power. Solar has capacity factors around half those of Basin's wind resources, and gets a capacity credit (as a fraction of nameplate) about three times that of wind. Hence, every GWh of solar energy would provide about six times as much capacity accreditation as the same amount of wind. Procuring as little as 10% of the replacement energy from solar might have been enough to bring capacity accreditation up to that of all Basin's coal units. And Basin could have delayed the retirement of some coal units beyond 2020, to give it time to develop resources and for the costs of alternative to fall further.

Q: How do the coal unit operating costs compare to the replacement generation unit costs?

A: As shown in Table 20, under the cost scenarios analyzed here, Basin could have **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**

Table 20: Average Annual Operating Cost, 2016-2018, Eastern Coal Units ($M) (HIGHLY CONF)[126]
[BEGIN PARTIALCUI//PRIV/HC]

	Antelope Valley 1	Antelope Valley 2	Leland Olds 1	Leland Olds 2	Laramie River 1
Coal Units (2016-18 costs)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replacement (at 2020 costs)	88.8	86.7	39.7	79.6	10.5
Potential Savings (Costs)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END PARTIAL CUI//PRIV/HC]

Q: Should Basin have removed one or more of its eastern coal units from service by 2020?

A: Yes. Based on the amount of capacity available in the market, I conclude that Basin should reasonably have initiated procurement of replacement power and capacity to

[126] The annual costs for each coal unit are the averages of the 2016–2018 total costs in Table 16, Table 17, and Table 18.

remove three units from Basin service. Those three units might well have been Leland Olds 1, Leland Olds 2, and Antelope Valley 2 which, as shown in Table 19, would have required 697 MW of market capacity in addition to the capacity value provided by approximately 2,621 MW of wind PPAs.[127] This would have resulted in net savings of approximately **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** per year by 2020.

Q: What actions should Basin have taken with respect to the other two eastern coal units?

A: A prudent utility would have initiated a planning process to enable removal of the other two units (in the example above, Antelope Valley 1 and Laramie River 1) from service, including issuing further request for proposals for additional replacement capacity. Indeed, once the Leland Olds units were retired, Basin should have moved with urgency to fully close Antelope Valley. As discussed in Section VI.B, closure of Leland Olds units would have resulted in **[BEGIN CUI//PRIV/HC]** [redacted]

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[127] I chose Antelope Valley 2 because at that time, Basin's lease was scheduled to terminate at the end of 2020, which would have provided substantial savings. Furthermore, Laramie River 1 would be complicated by the requirement to work with the other MBPP co-owners. Since they would face economics similar to Basin's, retirement should have been in their collective self-interest, but the internal process might have delayed retirement. Basin certainly should have brought the possibility of retiring Laramie River 1 to the MBPP Management Committee in its capacity as Operating Agent.

"[redacted] **[END CUI//PRIV/HC]** onto Antelope Valley units, increasing their **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** Moreover, had Basin retired Dakota Gasification along with the Antelope Valley and Leland Olds units, it would have been able to avoid forward-going fixed costs entirely at the Freedom Mine **[BEGIN CUI//PRIV]** [redacted].**[END CUI//PRIV]**[128] While planning for the rapid retirement of Antelope Valley 1 and Laramie River 1 may not have substantially impacted Basin's operating costs by 2020, they would have been prudent actions to reduce Basin's operating losses as expeditiously as possible.

IX. Major Investment Test Results

Q: Which major investment decisions in the late 2010s should have triggered review of the future of Basin coal units?

A: Even as Leland Olds and Laramie River 1 were operating **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** and seemed likely to continue losing money, Basin pursued large investments in these units. First, Basin invested about **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]**

[128] Exhibit No. SC-0078, 1.102.1-CUI-PRIV SC-BEPC, at 30-31.

mostly in 2018 and 2019, on a bottom ash dewatering project at Leland Olds that was formally completed in 2020.[129] The Board was still considering whether to commit to the project or to retire Leland Olds as late as September 2016.[130]

Second, Basin committed to spend $145 million on its share of the Laramie River 1 selective catalytic recovery (SCR) pollution control equipment, out of a total $337 million cost for the joint owners.[131] The SCR was formally completed in 2019. The actual costs appear to have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Basin, out of a total cost of **[BEGIN CUI//PRIV/HC]** [redacted] .**[END CUI//PRIV/HC]**[132] The initial decisions to go forward with that project were made in 2016, although the project might well have been cancellable for another year or two.[133]

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[129] Exhibit No. SC-0070, CUI-PRIV-SC-BEPC-1.029.185, at 2.

[130] Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC.

[131] Exhibit No. SC-0072, SC-BEPC-1.117.38, at 13. Basin was also installing much less expensive selective non-catalytic reduction (SNCR) controls on Laramie River 2 and Laramie River 3 in the same period, so some cost data may include those projects. Exhibit No. SC-0071, CUI-PRIV-SC-BEPC-9.004.004, shows an approved cost for the SCR alone of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in late 2015.

[132] Exhibit No. SC-0070, CUI-PRIV-SC-BEPC-1.029.185.

[133] Exhibit No. SC-0073, Barry Cassell, "Basin to install SCR on one Laramie River unit for regional haze compliance," *TransmissionHub* (January 25, 2016), available at

Both of these projects could have been avoided by retiring the relevant generators. In my experience, most similarly-situated utilities faced with significant expenditures to meet new environmental standards conducted some form of comparison of investment and continued operation to market or self-build alternatives. In many cases, such reviews were required to obtain regulatory approval to invest in the capital project or secure cost recovery, although other utilities have undertaken those reviews out for financial prudence. These reviews drove much of the rapid increase in actual retirements discussed in Section IV.C.

Q: Were there major financial commitments at Antelope Valley in the 2015–2020 period?

A: Yes. Basin spent **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in a separated-overfire-air system installed in 2015 and 2016, to reduce NOx emissions, and in 2020 extended the leases on Antelope Valley 2 for 2021–2030, at a cost of **[BEGIN CUI//PRIV/HC]** [redacted].**[END CUI//PRIV/HC]** The Antelope Valley NOx controls would have been evaluated before Basin joined SPP (perhaps in 2012), and I have not been able to review the contemporaneous economics of that decision. I have not seen any indication that Basin reviewed the

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www.transmissionhub.com/articles/2016/01/basin-to-install-scr-on-one-laramie-river-unit-for-regional-haze-compliance.html; Exhibit No. SC-0072, SC-BEPC-1.117.38, at 13.

cost-effectiveness of continued operation of Antelope Valley with the NOx investment. The extension of the Antelope Valley Unit 2 leases increased Basin's revenue requirement beginning in 2021, after the period for the rates I address. However, during the relevant period for my analysis, Basin was engaged in a negotiation process with the lessors, which included some economic analysis. Basin presentations occasionally mentioned the need to procure resources if the lease extension failed (as Basin expected in the late 2010s), but I have not seen any evidence that Basin actually undertook any process to identify replacement resources for Antelope Valley 2 or other elements of an adequate major investment prudency analysis.

Q: Could Basin have avoided further costs if it had decided to retire Leland Olds 1 and 2 and Laramie River 1 rather than continue investing in them?

A: Yes. As shown in Table 21, Basin invested **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** from 2016 to 2020 in those three units. It also invested **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** at Antelope Valley. The bulk of this capital investment could have been avoided, reducing rates in 2019 and 2020, if Basin had reviewed the economics of the units around 2015 and initiated planning for replacement resources.

With a 4% interest rate, the levelized cost of $100 million spread over 10 years (a generous remaining life for Leland Olds or Laramie River Unit 1) would be over $12 million annually and over 20 years would be over $7 million. Avoiding all the Leland Olds and Laramie River investments, could have saved customers over **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in 2020. While Basin would likely have needed to make some of the investments listed in Table 21, the avoided investments are in addition to the avoidable O&M costs and had a significant impact on Basin's rates.

Table 21: Basin Eastern Coal Capital Additions, 2016-2020 ($M) (HIGHLY CONF)

[BEGIN CUI//PRIV/HC]

Unit	2016	2017	2018	2019	2020	Total
Antelope Valley 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Antelope Valley 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Antelope Valley Common	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Leland Olds 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Leland Olds 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Leland Olds Common	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Laramie River 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Leland Olds and Antelope Valley 2 (total)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Leland Olds and Laramie River 1 (total)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END CUI//PRIV/HC]

Source: Exhibit No. SC-0024, CUI-PRIV-HC SC-BEPC-1.2.1a.

Q: Would Basin have been required to shut down Leland Olds and Laramie River Unit 1 immediately if it had not made those investments?

A: No. The Leland Olds bottom-ash project was undertaken to comply with the EPA's September 2015 Final Rule updating the Effluent Limitation Guidelines for steam electric plants, known as the "ELG Rule."[134] That rule required retrofit of wet ash handling systems with dry systems, or shutdown of the coal plants generating the waste by 2023. Basin was aware, as early as September 2016, that it had until 2023 to retire Leland Olds in lieu of replacing its bottom ash water system, and might have been able to reduce expenditures related to the Coal Combustion Residuals (CCR) Rule requiring retrofit of ash ponds by retiring the unit by that date as well.[135] In 2020, EPA extended the deadline for the retirement option for compliance with the ELG Rule to 2028. Had Basin elected to retire this unit by 2028, it could have continued to operate those units without incurring those additional compliance costs.

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[134] *See* 80 Fed. Reg. 67,837.

[135] *See* Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC, at 10-11 **[BEGIN CUI//PRIV]**("[redacted]").**[END CUI//PRIV]**

The Laramie River 1 SCR was required under the Federal Implementation Plan for Wyoming for the Regional Haze rule, which required installation of the SCR by March 2019.[136] However, in general, the EPA has been willing to allow six to eight years of additional operation for plants that committed to retire. For example, in the same Federal Implementation Plan (FIP) that imposed an SCR requirement on Laramie River 1, EPA allowed Unit 3 of the Dave Johnstone to retire in 2027 to meet regional haze standards, as an alternative to a 2019 deadline to install controls.[137]

A. Leland Olds Bottom Ash System Investment Analyses

Q: When and why did Basin commit to the Leland Olds bottom ash dewatering project?

A: In September 2016, Basin's Board approved a $63 million budget for capital investments at Leland Olds Station to comply with the Effluent Limitations Guideline (ELG) Rule and the Coal Combustion Residuals (CCR) Rule, specifically to eliminate discharges from its bottom ash system through either converting to dry ash handling or constructing a closed cycle system (bottom ash "dewatering").[138]

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[136] 79 Fed. Reg. at 5,039, 5,221.

[137] *See* 79 Fed. Reg. at 5,038, 5,045.

[138] Exhibit No. SC-0004, 1.117.046-SC-BEPC, at 19.

Q: Did Basin consider retirement as an alternative to the bottom ash dewatering project?

A: Only superficially, and it rejected the retirement alternative on the basis of incomplete and faulty analysis.

In September 2016, the Board was presented with three options: (a) to "do nothing" and cease operations at Leland Olds by 2020, (b) to formally commit to cease operations by 2023, and (c) to complete the project.[139] Basin took a very selective view of the consequential cost increases and reductions in surplus sales due to options (a) or (b). The total financial impact of retirement was estimated as $1.1 billion, plus the plant write-off.[140] That $1.1 billion estimate is a gross overstatement, since it included **[BEGIN CUI//PRIV]** [redacted] for the capital cost of [redacted] of [redacted]. **[END CUI//PRIV]**[141] That cost (which works out to **[BEGIN CUI//PRIV]** [redacted]) **[END CUI//PRIV]** seems rather high: Lazard estimated a combined-cycle cost of about $1,000/kW to $1,300/kW in 2016, even with 7.7% cost of capital (nearly

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[139] Exhibit No. SC-0004, 1.117.046-SC-BEPC, at 18.

[140] Exhibit No. SC-0004, SC-BEPC 1.117.46, at 18.

[141] Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC, at 22.

[BEGIN CUI//PRIV] [redacted] **[END CUI//PRIV]** Basin's interest rate),[142] while EIA reported a little over $1,000/kW for combined-cycle units completed in 2016.[143] Even if Basin's high estimate of the cost of the unit were correct, Basin ignored the benefits of a new plant, including increased energy margins and reduction in O&M costs.[144] Basin also failed consider the least-cost mix of replacement resources, limiting its alternatives comparison to a **[BEGIN CUI//PRIV]** [redacted].**[END CUI//PRIV]**

Other components of the estimate include **[BEGIN CUI//PRIV]** [redacted]. **[END CUI//PRIV]** Basin will need to perform remediation when the units retire, which Basin should have expected in the foreseeable future; the remediation cost might be largely mitigated by use of the plant site for storage, solar, peakers, and/or wind integration. Basin also assumed that only **[BEGIN**

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[142] Lazard's Levelized Cost Of Energy Analysis — Version 10.0, 2016. pp. 6, 11, and 14.

[143] Energy Information Administration, *Generators installed in 2016 by major energy source* (August 6, 2018), Average Construction Cost, www.eia.gov/electricity/generatorcosts/archive/2016/ [last accessed July 12, 2022].

[144] Basin acknowledges that an **[BEGIN CUI//PRIV]**"[redacted] **[END CUI//PRIV]** of remaining life assumed for Leland Olds. Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC, at 22.

CUI//PRIV] [redacted] ,**[END CUI//PRIV]** even though coal plants commonly use up their fuel stocks before retiring. Finally, the **[BEGIN CUI//PRIV]** "[redacted]" **[END CUI//PRIV]** that Basin added to the supposed $1.1 billion in retirement costs should not be considered as part of any alternatives' analysis, as this is the net book value, which is not an additional cost of retirement. Basin would charge the members for depreciation of that amount if the plant continued operating, as Basin recognizes.[145]

On January 6, 2016, the Project Review Committee reported with respect to the bottom ash dewatering project that: **[BEGIN CUI//PRIV]** "[redacted]."**[END CUI//PRIV]**[146] There is no evidence that Basin performed any "internal rate of return calculations" for this project, as Basin did not produce any in response to Sierra Club's discovery requests.[147] It does not appear that Basin actually compared the cost of the bottom

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[145] Exhibit No. SC-0012, 1.40.44-CUI-PRIV SC-BEPC, at 23.

[146] Exhibit No. SC-0074, CUI-PRIV-SC-BEPC-9.004.003.

[147] For example, Request SC-BEPC 1.029 asked Basin to "Produce each presentation provided to the Basin Board of Directors since January 1, 2008 regarding: a. the value and/or going-forward value of any Basin coal units, environmental compliance costs, environmental compliance planning, or generation planning; b. economics of

ash dewatering project to the net benefit (if any) of continued operation of Leland Olds. Basin's analysis does not amount to a serious retirement analysis.

Q: Did Basin conduct a detailed retirement analysis for LOS before making the decision to proceed with the bottom ash system investment?

A: No. It appears that the first time that Basin staff completed a retirement analysis for Leland Olds was in July 2017, after the Board approved the bottom ash dewatering investment. Even then, Basin looked only at **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** which would not have avoided the ash-handling investment.

Basin's 2017 analysis considered **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** of Leland Olds Unit 1, assuming replacement power **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** The analysis also included **[BEGIN CUI//PRIV/HC]** [redacted]

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continued operation of any of Basin's coal units." The response did not provide computations for internal rate of return. A search for the phrase "internal rate of return" in discovery yields very few matches, including just two that consider capital projects (in Exhibit No. SC-0004, SC-BEPC 1.117.046) and none of which address choices between investing in a resource or retiring it.

[redacted], **[END CUI//PRIV/HC]** and considerable amount of other operating costs. This analysis resulted in a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in 2019–2030 cash flows.[148]

However, if **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** is excluded from the analysis, the shutdown would have a benefit of about **[BEGIN CUI//PRIV/HC]** $[redacted]. **[END CUI//PRIV/HC]** Including future **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** would make the shutdown option even more favorable. And eliminating the cost of the dry ash project by retiring Leland Olds 2 by 2023 would save another **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

In other words, in **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** Basin staff were aware that as a standalone unit, Leland Olds 1 would be operating at a **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** through the end of its useful life. Basin staff forecast revenues for Leland Olds 1 at levels **[BEGIN CUI//PRIV/HC]** [redacted]

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[148] Present values computed from Exhibit No. SC-0013, CUI-PRIV-HC SC-BEPC-1.038.004, Tabs "Summ – No Other Gen" and "Summ – No Other Gen (2)".

[END CUI//PRIV/HC] the unit from 2021–2030, and those revenues were **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** As I discussed in the previous paragraph, Basin appeared to overstate the costs of retirement and understate costs of operation. The justification for continuing to operate Leland Olds 1 was an ever-shifting perspective on whether its shutdown would cause **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**[149]

The **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** analysis did not reflect fundamentally new conditions. If Basin had conducted a similar study in 2015 (or perhaps even earlier) before committing to the bottom ash dewatering project, it would very likely have reached **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]**—that Leland Olds was uneconomic. If it

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[149] Basin has continued to revisit its Leland Olds 1 retirement analysis since the 2017 study, and each time concluded Leland Olds was a net economic liability for member-ratepayers. In March 2018, for example, Basin staff presented the Board with evidence that Leland Olds 1 had a **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]** Exhibit No. SC-0010, CUI-PRIV-HC-SC-BEPC-1.029.274. Then in May 2018, a study was conducted "for purposes of determining if a more in-depth study regarding the margin impact of a Leland Olds Station shutdown should be conducted." Exhibit No. SC-0075, SC-BEPC-1.038a, at 2-3. And in July 2021, Basin conducted a study of "optimal timing" to retire Leland Olds 1, assuming the sale of Dakota Gasification Company to Bakken Energy. Exhibit No. SC-0075, SC-BEPC-1.038a, at 3.

had also compared those perspective and avoidable costs to replacement power, it would have determined that there were reliable lower-cost options to replace Leland Olds.

Q: What do you conclude from Basin's analysis of the Leland Olds bottom ash system investments?

A: When Basin began **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** to investigate whether early retirement of Leland Olds 1 made sense, the answer was clearly "yes." This analysis was years overdue, and Basin has continued to dither over the past five years. Clearly, Basin's planning process and decision-making has failed to put its members first. Whatever Basin's motivations are for keeping Leland Olds 1 in service, there is no evidence that Basin has ever made a credible case to its Board that Leland Olds 1 costs less than reasonable, available alternative resources, or—crucially—that its economic value warranted the additional **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** investment for converting coal ash handling that could have been avoided by retiring the unit by 2023, which EPA later bumped back to 2028

This appears to be a textbook case of imprudently retaining a money-losing generating unit in service.

B. Laramie River 1 SCR Investment

Q: Please summarize Basin's analysis of the Laramie River Unit 1 SCR investments.

A: In January 2016, Basin's Board approved the installation of SCR at Laramie River 1.[150] (Less expensive SNCR controls would later be approved for installation at Laramie River 2 and 3.) The project was approved to comply with Regional Haze rules to reduce NOx emissions. The SCR system was expected to cost about **[BEGIN CUI//PRIV]** [redacted] **[END CUI//PRIV]** of which Basin's share would be **[BEGIN CUI//PRIV]** [redacted]; **[END CUI//PRIV]** Basin booked capital additions of **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for Laramie River 1 and about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** more at the other Laramie River units and common plant.[151]

The Board discussion of the project appeared to be limited and I did not locate any consideration of whether further investment in Laramie River 1 was reasonable compared to any alternatives, the current or forecast unit margins, or similar topics.

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[150] The Laramie River Station SCR summary is based on Exhibit No. SC-0072, SC-BEPC-1.117.38 and Exhibit No. SC-0076, 1.40.33-CUI-PRIV SC-BEPC.

[151] It is not clear why the capital additions in 2019 do not equal to Basin's full share of the SCR cost.

Q: What do you conclude from Basin's analysis of the Laramie River 1 SCR investment?

A: Basin's failure to even consider early retirement of Laramie River 1 in light of the major investment it approved in 2016 is an act of imprudence. As with Leland Olds 1, and indeed most of its coal-fired power plants, Basin neglected analysis of alternatives to continued operation. The process by which this investment decision was made is further evidence that Basin was not paying sufficient attention to minimizing its revenue requirements.

X. Prudence of Coal-Plant Management

Q: Please summarize the reasons that you believe Basin's management of its eastern coal-fired power plants has not been prudent.

A: Since at least 2015, Basin has failed to seriously consider or, more importantly, take the opportunity to reduce, operating costs and avoid unnecessary capital expenditures at every one of Basin's eastern coal assets. All of those assets—Leland Olds, Antelope Valley, and Laramie River 1—cost more than alternatives that Basin knew were available in 2016 and 2017. In the case of Dakota Gasification, simply ceasing operations would have relieved customers of the losses associated with an asset that is wholly unrelated to providing electric service.

Of course, it would not have been practical for Basin to simply close all of those facilities in 2015. Capacity and wind power purchase agreement would have required time to negotiate, and those resources would have required some further time to come into service. As I described above, while the wind power market was essentially limitless during the 2016-17 period, the available accredited capacity in the near term in the SPP market was limited.

Q: What might Basin have done about replacing the coal plants, had it acted prudently?

A: Given the uncertainties about exactly what resources Basin would have acquired in 2016–2020, I assumed that Basin would have:

- Avoided the Leland Olds bottom ash dewatering system installation, by committing to retire the plant by 2023, saving **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** in investment.
- Retired Leland Olds 1 by 2019 and replaced it with wind and short-term capacity, reducing revenue requirements by about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** annually in 2019 and 2020.
- Worked with its co-owners to avoid the Laramie River 1 SCR investment, resulting in retirement of that unit sometime in the mid to late 2020s and saving **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for the SCR and about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** annually by replacing the

uneconomic generation with short-term capacity purchases and wind contracts.

- Reduced capital additions and maintenance at Leland Olds 2 (if it continued operating through 2020) and Antelope Valley, anticipating the closure of those units in the 2020s.

These would have been low-risk decisions. If circumstances warranted, such as a spike in market prices or a delay in completion of some replacement resources, Basin could have kept the Antelope Valley units in operation past their planned retirement dates, until conditions stabilized.

Q: Would Basin's proposed 2019 and 2020 rates have been lower if it had replaced the uneconomic coal units discussed above with alternative energy and capacity resources?

A: Yes. The components that would have been reduced include the following:

- If Basin had avoided the Leland Olds coal ash handling project, its revenue requirements would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower.
- If Basin had replaced Leland Olds 1 or Leland Olds 2 with renewable and capacity purchases, its rates would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END**

CUI//PRIV/HC] lower, respectively, or **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** for the entire plant.

- If Basin had avoided installing the Laramie River 1 SCR and retired the unit instead, its revenue requirements would have been about **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower from the avoided investment and another **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower from reduced operating costs.
- If Basin had retired an Antelope Valley unit, its costs would have been roughly **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower. If that retirement avoided the lease extension, 2021 rates would be lower by another **[BEGIN CUI//PRIV/HC]** [redacted]. **[END CUI//PRIV/HC]**

Depending on the mix of avoided investments and retired units, revenue requirements could have been **[BEGIN CUI//PRIV/HC]** [redacted] **[END CUI//PRIV/HC]** lower in 2019 and 2020. Those excess costs are unjust and unreasonable.

Q: What action do you recommend that FERC take in response to your findings?

A: FERC should:

1. Affirm that, in order for rates to be just and reasonable, the rates must be based on prudent action by the generation and transmission cooperative.
2. Find that, given its ongoing prudence obligation, a generation and transmission cooperative must analyze whether the continued operation of its generation asset(s) is in the best interest of its member cooperatives when changed circumstances, such as changes in the short-term economics or changes is its competitiveness of its generation assets in an energy or capacity marketplace, warrant such analysis.
3. Find that, given its prudence obligation, a generation and transmission cooperative must, prior to moving forward with a major capital investment, analyze whether the investment is prudent by comparing the prospective costs of continuing to operate the unit, including the proposed new capital costs, to the costs of reasonable alternatives.
4. Clarify that the cooperative should examine the prospective and avoidable costs in both the ongoing prudency and major investment test prudency analyses.
5. Find that Basin's acted imprudently when it failed to evaluate the prudency of continuing to operate Leland Olds, Antelope Valley and Laramie River 1 in light of changed circumstances, including the economic degradation and reduced competitiveness of these units.

6. Find that Basin's acted imprudently when it failed to adequately evaluate the prudency of making major investment decisions in Leland Olds and Laramie River 1 and extending the lease in Antelope Valley instead of considering options such as retiring the units and replacing them with alternative power supply.
7. Find that Basin imprudently failed to take the opportunity in or about 2015 to begin the process of removing Leland Olds from service and avoiding the bottom ash dewatering investment, given the plant's ongoing operating losses.
8. Find that Basin imprudently failed to analyze options for retiring Laramie River 1 and avoiding the SCR investment, and to work with the MBPP co-owners to secure the retirement of Laramie River 1 by the mid-2020s in lieu of SCR installation.
9. Find that Basin's proposed rates are not just and reasonable because they are based on imprudent action by Basin.
10. Reduce Basin's 2019 and 2020 revenue requirement by approximately **[BEGIN CUI//PRIV/HC]** [redacted], **[END CUI//PRIV/HC]** reflecting the imprudently incurred costs.

Q: Does this conclude your testimony?

A: Yes.

Verification

Pursuant to 28 U.S.C § 1746 (2018), I state under penalty of perjury that the foregoing testimony is true and correct to the best of my information, knowledge and belief.

Executed this 15th day of July, 2022.

Paul Chernick

Paul Chernick
President
Resource Insight, Inc.