finder, is charged with sifting through all of the information to reach a well-reasoned decision. In doing so, the Commission uses its experience, technical competence, and specialized knowledge to determine the credibility of each witness and the persuasiveness of highly technical evidence presented on each issue.

Revenue Requirement

The applicant filed an application for a limited electric reopener for the 2024 test year consistent with the Commission's December 22, 2022 Final Decision. The applicant estimated that the base rate impact of the reopener was an increase in revenue requirement of $8.6 million, or 0.5 percent for the applicant's electric customers. However, that increase was offset by a decrease in fuel costs of $36.9 million, resulting in an overall reduction in revenue requirement of $28.3 million or approximately 2.0 percent. The applicant concluded its current electric rates were excessive and proposed a base rate decrease in 2024. Commission staff reviewed the 2024 test year filing information during its financial review.

The applicant claimed the main drivers impacting the electric revenue requirement for the 2024 test year reopener included increased costs due to capital investments associated with the applicant's Generation Reshaping Plan (GRP) that will achieve commercial operations in 2023 and 2024, and decreased 2024 fuel costs.

Income Statement

The parties and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates for the applicant's 2024 electric operations. Significant issues pertaining to the income statement are addressed separately below.

Fuel Costs

Pursuant to Wis. Admin. Code § PSC. 116.03, each of the five major, investor-owned Wisconsin electric utilities must file a proposed fuel cost plan for each calendar year, known as the plan year, as part of a general rate case proceeding, or if the utility does not file a general rate case, as a proceeding limited in scope to fuel cost. This fuel cost plan must include a calculation of certain fuel costs as described in Wis. Admin. Code § PSC 116.02, as well as the other information required by Wis. Admin. Code § PSC 116.03(2). After a hearing, the Commission approves the utility's fuel cost plan and establishes the utility's rates in accordance with the approved fuel cost plan. Wis. Admin. Code § PSC 116.03(3).

The Commission finds that a reasonable estimate of the applicant's 2024 Fuel Cost Plan monitored fuel costs is $318,005,308, which reflects the costs of generation and purchased energy, minus revenues from opportunity sales of energy and capacity. The 2024 monitored fuel costs divided by the 2024 estimate of native energy requirements of 11,697,749 MWh results in an average net monitored fuel cost per MWh of $27.19. Appendix C shows the monthly fuel costs to be used for monitoring purposes.

It is reasonable to monitor the applicant's fuel costs using a plus or minus 2.00 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

The applicant shall file for its 2025 Fuel Cost Plan in 2024 in accordance with Wis. Admin. Code ch. PSC 116.

Uncontested Fuel Adjustments

Commission staff and the applicant proposed various adjustments to the applicant's filed 2024 fuel costs that were not contested by any party. These adjustments included: (1) a decrease in fuel costs of approximately $5,465,715 to reflect updating of natural gas pricing as of June 15, 2023; (2) a decrease in fuel costs of approximately $4,232,852 to reflect updating the delivered cost of coal, (3) an increase in fuel costs of approximately $2,056,509 to reflect the correction of a series of generating plant assumptions for various units; (4) a decrease in fuel costs of approximately $196,793 to reflect Midcontinent Independent System Operator, Inc. capacity sales pricing updates; (5) a decrease in fuel costs of approximately $7,748,664 to reflect various Back-End cost changes.

The Commission finds it reasonable to accept all of the above uncontested fuel adjustments.

Powder River Basin (PRB) Coal Blend

Commission staff proposed that the PRB coal blend for 2024 reflect the actual 2022 results. The applicant provided updated information of the 2023 ERGS performance during commissioning of the new Effluent Limit Guidelines (ELG) and found it unlikely to achieve a 2024 PRB blend greater than what was filed. (PSC REF#: 480216 confidential, PSC REF#: 480217 public.) Commission staff reviewed the applicant's information and withdrew this adjustment. In light of the additional information supplied by the applicant, the Commission finds that the appropriate PRB coal blend for ERGS is as filed by the applicant.

West Riverside Option 2

The applicant included the acquisition by WEPCO of West Riverside Option 2 in the 2024 Fuel Cost Plan. Consistent with past Commission practice which does not assume future approvals or denials, Commission staff excluded the impact of the proposed acquisition of West Riverside Option 2 as this purchase had not yet been authorized by the Commission.

(PSC REF#: 478306 confidential, PSC REF#: 480217 public.) The applicant testified that both the applicant and WP&L believed that it is reasonable to assume that this second option will be approved. However, the applicant agreed that removing the Option 2 acquisition would be consistent with how the first West Riverside option was treated for ratemaking.

The Commission finds it reasonable to accept Commission staff's adjustment to remove the purchase of West Riverside Option 2 in the modeling of 2024 fuel costs. This approach is consistent with past Commission practice which does not assume either approval or denial of a proposed project or acquisition. This adjustment had no detectable impact on the applicant's 2024 monitored fuel costs.

Outage Rate for West Riverside

Commission staff proposed using the EFOR from the CPCN for the West Riverside units in modeling of 2024 costs. (PSC REF#: 478306.) The applicant argued that since WP&L will continue to be majority owner and operator of West Riverside in 2024, the EFOR that is adopted in WP&L's 2024 Fuel Cost Plan in docket 6680-UR-124 should control the outage rate used in this proceeding. (PSC REF#: 481359.) The applicant indicated that it supported WP&L's contention that the CPCN's EFOR was inappropriate to use as it does not reflect outages or consider the actual performance of West Riverside. (PSC REF#: 480216 confidential, PSC REF#: 480217 public.) While West Riverside has continued to experience some operational challenges, improvement is expected in 2024 and it is anticipated that West Riverside will continue to move toward more normal operations. As a result, the Commission finds it reasonable to accept Commission staff's proposed adjustment to use the CPCN's EFOR rate. This adjustment reduced the applicant's 2024 monitored fuel costs by approximately $994,000.

Chairperson Valcq dissents.

NYMEX and Other Updates

Consistent with past Commission practice, Commission staff proposed a final update to the applicant's 2024 fuel cost forecast to reflect updates to fuel costs including NYMEX commodity futures settlement prices for natural gas and fuel oil as of October 17, 2023 index values, Argus spot coal prices as of October 13, 2023, associated railroad escalations per existing contracts, new fuel-related contracts and dispatch pricing adjustments to limit coal-fired generation given anticipated 2024 coal rail delivery performance, to forecast the applicant's 2024 monitored fuel costs. As part of the information the applicant provides to the Commission to construct the final 2024 forecast, the applicant included a $450,000 potential rail contract liquidated damages claim by a railroad. Commission staff excluded this adjustment since it had not been discussed previously in the audit. The remaining adjustments were not contested by any party and increased the 2024 monitored fuel costs by approximately $7.8 million. (PSC REF#: 485154.) Commission staff filed a delayed exhibit including these updates and adjustments. The Commission finds that it is reasonable to accept these adjustments as part of the final monitored fuel cost update.

Commissioner Huebner dissents and would not include the dispatch adders for the Columbia Energy Center.

Capital Investments

The applicant requested a total company incremental revenue requirement increase for the addition of new electric generation that would achieve commercial operation in 2023 or 2024. The assets in question are the Paris Solar and Paris BESS authorized in docket 5-BS-254, the Darien Solar and Darien BESS authorized in docket 5-BS-255, the Weston RICE project authorized in docket 5-CE-153, and the reduced O&M expense associated with future coal plant retirements. Commission staff reviewed and verified the incremental costs and applied the applicant's authorized economic cost of capital of 9.13 percent to determine the revenue requirement impact of each project and found no concerns with the applicant's estimated revenue requirement impacts.

The Commission finds that the applicant followed the spirit and letter of the limited reopener and therefore finds it reasonable to include the incremental impacts of Paris, Darien, Weston RICE, and the reduced O&M expense associated with the future retirements, in the 2024 test year electric revenue requirement.

Distribution Connected Solar Projects

The applicant included in its application smaller DCS projects. While due to their size and cost these facilities do not require a Certificate of Authority (CA) for purchase or construction, these facilities have been included in all of the generation planning modeling performed by the applicant that has been evaluated by the Commission in various GRP dockets. (Direct-WPSC-Stasik-6-p.)

CUB witness Ted Callon stated that the applicant had not provided sufficient evidence to warrant including the DCS projects in rate base and that the Commission should consider having the applicant provide more detailed evidence to show that the benefits of the DCS projects are in line with the benefits of large-scale utility projects. Although CUB's witness initially raised concerns, the applicant provided further evidence of customer benefits of DCS projects in rebuttal testimony, which CUB acknowledged showed positive net benefits plus reliability benefits, largely resolving CUB's concerns.

Because the projects initially did not rise to the level of requiring statutory authorization, the Commission is limited to reviewing the costs in determining whether or not they were prudent and whether their estimated incremental revenue impact was also reasonable and prudent.

The Commission finds it reasonable for the applicant to include the incremental impact of the DCS projects in the 2024 test year electric revenue requirement.

Weston RICE – Materials and Supplies

The applicant's witness Richard Stasik filed supplemental direct testimony identifying that the applicant inadvertently omitted from their original application the materials and supplies inventory necessary to support the reliable and safe operation of the Weston RICE Units approved in docket 5-CE-153. The applicant identified that the material and supplies inventory amounts are appropriate to include in the limited reopener according to Order Condition 12 of the December Order. Order Condition 12 states, in part, "The applicant is authorized to file a limited reopener for the 2024 test year electric operations to address additional capital investment through the [Generation Reshaping Plan] GRP that will achieve commercial operation in 2023. . ." The applicant stated that the materials and supplies inventory for the Weston RICE Units is a capital investment through the GRP that achieved commercial operation in 2023. (Direct-WPSC-Stasik-s-3.) Due to the late timing of the request, the impact was not included in Commission staff's estimated 2024 revenue requirement.

Because materials and supplies are part of rate base, and because Commission staff found no concerns with the calculation of the incremental increase related to the inclusion of the Weston RICE materials and supplies inventory, the Commission finds it reasonable for the applicant to include the material and supplies inventory associated with Weston RICE in the 2024 test year electric revenue requirement.

Paris Solar and Paris BESS

The Commission granted a CPCN for Paris Solar and Paris BESS in docket 9801-CE-100. The Paris Solar and BESS acquisition was approved by the Final Decision dated May 25, 2022, in docket 5-BS-254. (PSC REF#: 438529.) On September 5, 2023, the applicant filed a *force majeure* notification for Paris Solar and Paris BESS. Although the applicant has not requested recovery of the identified Paris Solar *force majeure* cost increase in this proceeding, the *force majeure* filing identified an extension to the guaranteed in-service date to December 31, 2024, with efforts underway for a potential in-service date of June 2024. Commission staff's rate base estimate reflected an in-service date for Paris Solar of November 2023 and an in-service date for Paris BESS of December 2025.

Commission staff suggested the Commission may wish to consider deferring the incremental revenue requirement impact, including, but not limited to O&M, rate base, depreciation, and tax components, to reflect the difference between the Commission authorized in-service date and the actual in-service date of Paris Solar and Paris BESS, with or without carrying costs.

The applicant stated that it would begin escrowing amounts included in rates related to Paris during 2024 until Paris achieves commercial operation. Specifically, the applicant would escrow the incremental revenue requirement impact of the delayed in-service dates, including but not limited to O&M, rate base, depreciation, and tax components. Commission staff proposed a deferral of the amounts associated with Paris and not an escrow. The applicant noted that if the

Commission authorizes regulatory accounting, then it is not opposed to Commission staff's proposal of carrying costs at the economic cost of capital for capital investments and at the short-term debt rate for any non-capital components.

Consistent with dockets 3270-UR-125 and 5-UR-110, the Commission finds it reasonable for the applicant to defer the incremental revenue requirement impact of the change to the in-service date for Paris Solar and Paris BESS with carrying costs using the applicant's short-term debt rate, to a future rate proceeding.

Infrastructure Investment Jobs Act (IIJA) of 2021

On November 15, 2021, the IIJA, also known as the Bipartisan Infrastructure Law, was signed into law. At this time, it is unknown if there will be any potential impacts resulting from this Act. Therefore, the Commission finds it reasonable that the applicant defer any impacts of the IIJA when impacts are incurred or received, with carrying costs at the applicant's short-term debt rate, to a future rate proceeding. Deferral accounting treatment ensures both the applicant, and its customers remain whole as deferral captures any cost increases or savings that might arise from the IIJA.

Summary of Incremental Revenue Requirement Impacts

After factoring in the adjustments discussed above, the Commission determined the incremental revenue requirement impact in this limited reopener proceeding is as follows:

	WPSC Electric	
	Electric ($ in 000's)	Electric WI Jur ($ in 000's)
Applicant Filed Incremental Revenue Requirement Impact	$ (28,300)	$ (25,207)
Incremental Revenue Requirement Adjustments		
Fuel Adjustments	(8,539)	(7,674)
Weston RICE M&S	144	129
Total Incremental Revenue Requirement Adjustments	(8,395)	(7,545)
Total Incremental Revenue Requirement Impact	**(36,695)**	**(32,752)**
Sales at Present Rates	1,344,764	1,265,661
Required Percentage Rate decrease	-2.73%	-2.59%

Electric Cost of Service and Rates

Electric Cost of Service

The applicant did not sponsor a COSS as part of this limited reopener. Ordinarily, the results of several COSS are utilized by the applicant, intervening parties, and Commission staff in order to provide a reasonable range for cost allocation and informing rate design in rate case proceedings. In this limited reopener proceeding, Commission staff commented that this does not pose an issue in this proceeding as it is Commission staff's position that revenue allocation and rate design are outside the scope of the limited reopener. The Commission finds that a COSS is not necessary in this proceeding due to the limited scope of the reopener. Further, the Commission finds it reasonable that the applicant, parties, or Commission staff should make a request for the inclusion of COSS when the request is made for a limited reopener.

Electric Revenue Allocation

The applicant, WIEG, CUB, and Commission staff provided testimony regarding electric revenue allocation. The applicant, WIEG, and Commission staff also provided updated revenue allocations. The applicant and Commission staff maintained the allocation methodology employed in the initial revenue allocation in this proceeding. The applicant's revenue allocation was based on the applicant's originally-filed test year revenue requirement at -1.99 percent. Commission staff's revenue allocation was based on Commission staff's audit-adjusted test year revenue requirement at -3.15 percent. WIEG stated that the allocation should be based off of class energy usage as the decrease was largely driven by reduced fuel costs.

Given that consideration of revenue allocation is outside of the scope of the limited reopener, the Commission finds it reasonable to approve the electric revenue allocation initially proposed by Commission staff in Direct-PSC-Meulemans-5, and shown in Appendix B, as adjusted for the final revenue requirement.

Electric Rate Design

The applicant, WIEG, CUB, and Commission staff provided rate design updates that include rates for all customer classes. The applicant, WIEG, and Commission staff supported achieving the revenue requirement through changes only to energy rates. CUB stated its support for the revenue allocation and rate design offered by the applicant but expressed that the Commission should be explicit in how they reach their decision on revenue allocation and rate design. Given that the consideration of rate design is outside the scope of the limited reopener, the Commission finds it reasonable to accept the comprehensive rate design proposed by Commission staff in Direct-PSC-Meulemans-5, adjusted for final revenue requirement. The authorized rates appear in Appendix B.

Order

1. By January 1, 2024, the applicant shall revise its existing rates and tariff provisions for electric utility service for 2024, substituting the rate modifications and tariff provisions that expand the terms of services and reduce rates, as described in this Final Decision on Reopening. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

2. The applicant shall prepare bill messages that properly identify the rates authorized in this Final Decision. The applicant shall provide the message to customers no later than the first billing containing the rates authorized in this Final Decision on Reopening, and shall file copies of these bill messages with the Commission before it provides the message to customers.

3. The applicant shall file tariffs consistent with this Final Decision on Reopening.

4. The electric fuel costs in Appendix C shall be used for monitoring the applicant's 2024 monitored fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

5. All 2024 fuel costs shall be monitored using a plus or minus 2.00 percent tolerance band.

6. The applicant shall file its 2025 Fuel Cost Plan in 2024 consistent with Wis. Admin. Code § PSC 116.

7. The applicant shall defer the incremental revenue requirement impact of the change to the in-service date for Paris Solar and Paris BESS with carrying costs using the applicant's short-term debt rate, to a future rate proceeding.

8. The applicant shall defer any impacts of the IIJA when the impacts are incurred or received, with carrying costs at the applicant's short-term debt rate, to a future rate proceeding.

9. The requirements in prior Commission orders that are not expressly addressed in this Final Decision on Reopening remain in effect and are not superseded by this Final Decision.

10. This Final Decision on Reopening takes effect one day after the date of service.

11. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 20th day of December, 2023.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:KBS:jlt:arw DL:01969726

Attachments

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
4822 Madison Yards Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[4] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

[4] *See Currier v. Wisconsin Dep't of Revenue*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

APPENDIX A

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Electric Revenue Yield - Test Year 2024

Rate Schedule	Booked Energy MWh	Authorized 2023 Revenues	Revenue Yield in 2024 With Authorized Rates	Percent Change in 2024 Over Current Rates
Rg1	2,889,611	$478,840,654	$467,659,552	-2.34%
Rg3-OTOU	82,957	$11,793,211	$11,439,324	-3.00%
Rg5-OTOU	21,908	$3,409,867	$3,316,334	-2.74%
Rg RR	3,449	$505,034	$491,249	-2.73%
Total Residential & Farm	2,997,924	$494,548,766	$482,906,459	-2.35%
Cg1	807,993	$117,613,393	$114,599,577	-2.56%
Cg1 RR	15	$2,630	$2,548	-3.11%
Cg3-OTOU	98,112	$13,178,619	$12,712,160	-3.54%
Total Small General Secondary	906,120	$130,794,641	$127,314,285	-2.66%
Total Small Customer Class	**3,904,045**	**$625,343,408**	**$610,220,744**	**-2.42%**
Cg5	241,646	$29,779,185	$28,694,194	-3.64%
Cg5 RR	0	$0	$0	0.00%
Total Medium Customer Class	**241,646**	**$29,779,185**	**$28,694,194**	**-3.64%**
Cg-20	2,736,301	$282,145,427	$272,368,761	-3.47%
Cg-20RR	54,930	$5,793,931	$5,580,080	-3.69%
Cp-Secondary	710,647	$65,840,246	$64,268,363	-2.39%
Cp-Primary	1,067,791	$88,735,020	$86,478,814	-2.54%
Cp-Transmission	962,359	$67,703,593	$65,736,314	-2.91%
Cp-Secondary RR	68,866	$6,056,344	$5,906,452	-2.47%
Cp-Primary RR	108,475	$8,699,137	$8,448,434	-2.88%
Cp-Transmission RR	162,115	$12,091,367	$11,746,442	-2.85%
NLMP	272,776	$16,955,541	$16,955,541	0.00%
RTMP	637,344	$43,269,754	$43,269,754	0.00%
Total Large Customer Class	**6,781,603**	**$597,290,359**	**$580,758,954**	**-2.77%**
Ls-1	40,306	$12,992,372	$12,984,978	-0.06%
Total Street Lighting & Other	**40,306**	**$12,992,372**	**$12,984,978**	-0.06%
COEV-R	0	$24,777	$24,777	0.00%
WHEV-R	0	$723	$723	0.00%
EV-C	0	$25,728	$25,728	0.00%
Total EV Customer Class	0	$51,228	$51,228	0.00%
Naturewise-Residential		$67,410	$67,410	0.00%
Naturewise-C&I		$28,824	$28,824	0.00%
Automatic transfer switch		$85,056	$85,056	0.00%
Parallel generation		$24,020	$24,020	0.00%
Total Misc Customer Class	0	$205,311	$205,311	0.00%
Total Wisconsin Retail	**10,967,600**	**$1,265,661,863**	**$1,232,915,409**	**-2.59%**

Electric Rate Design - Test Year 2024
Wisconsin Public Service Corporation

	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Residential Flat Rate - Rg1							
Customer charge							
Single PH per day	145,772,731	$0.58915	$85,882,004	145,772,731	$0.58915	$85,882,004	0.00%
Energy charge	2,889,173,768	$0.13600	$392,927,632	2,889,173,768	$0.13213	$381,746,530	-2.85%
Fuel cost adjustment	2,889,173,768	$0.00000	$0	2,889,173,768	$0.00000	$0	0.00%
Other							
Tax credit	2,889,173,768	$0.00000	$0	2,889,173,768	$0.00000	$0	0.00%
Revenue sharing	2,889,173,768	$0.00000	$0	2,889,173,768	$0.00000	$0	0.00%
Act 141 capped credits	297,485	-$0.00227	-$675	297,485	-$0.00227	-$675	0.00%
Act 141 capped contribution	297,485	$0.00062	$185	297,485	$0.00062	$185	0.00%
Total Revenue: Residential Flat Rate - Rg1			**$478,809,147**			**$467,628,045**	
Residential Small Optional 2TOU - Rg3							
Customer charge							
Single PH per day	2,515,007	$0.58915	$1,481,716	2,515,007	$0.58915	$1,481,716	0.00%
Energy charge							
On-peak	22,336,830	$0.24979	$5,579,517	22,336,830	$0.24122	$5,388,090	-3.43%
Off-peak	60,619,755	$0.07806	$4,731,978	60,619,755	$0.07538	$4,569,517	-3.43%
					0.96560		
Fuel cost adjustment							
Adjustment	82,956,585	$0.00000	$0	82,956,585	$0.00000	$0	0.00%
Other							
Tax credit	82,956,585	$0.00000	$0	82,956,585	$0.00000	$0	0.00%
Revenue sharing	82,956,585	$0.00000	$0	82,956,585	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00227	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 2TOU - Rg3			**$11,793,211**			**$11,439,324**	
Residential Small Optional 3TOU - Rg5							
Customer charge							
Single PH per day	917,225	$0.58915	$540,383	917,225	$0.58915	$540,383	0.00%
Energy charge							
On-peak	3,407,971	$0.31224	$1,064,105	3,407,971	$0.30152	$1,027,572	-3.43%
Shoulder	6,235,783	$0.13600	$848,066	6,235,783	$0.13213	$823,934	-2.85%
Off-peak	12,263,804	$0.07806	$957,313	12,263,804	$0.07538	$924,446	-3.43%
Fuel cost adjustment							
Adjustment	21,907,558	$0.00000	$0	21,907,558	$0.00000	$0	0.00%
Other							
Tax credit	21,907,558	$0.00000	$0	21,907,558	$0.00000	$0	0.00%
Revenue sharing	21,907,558	$0.00000	$0	21,907,558	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00227	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 3TOU - Rg5			**$3,409,867**			**$3,316,334**	

Electric Rate Design - Test Year 2024
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	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Residential Response Rewards - RgRR							
Customer charge							
Single PH per day	128,942	$0.58915	$75,966	128,942	$0.58915	$75,966	0.00%
Energy charge							
On-peak	788,338	$0.27399	$215,997	788,338	$0.26458	$208,578	-3.43%
Off-peak	2,639,448	$0.07025	$185,432	2,639,448	$0.06784	$179,065	-3.43%
Critical peak	21,229	$1.30198	$27,639	21,229	$1.30198	$27,639	0.00%
Fuel cost adjustment							
Adjustment	3,449,014	$0.00000	$0	3,449,014	$0.00000	$0	0.00%
Other							
Tax credit	3,449,014	$0.00000	$0	3,449,014	$0.00000	$0	0.00%
Revenue sharing	3,449,014	$0.00000	$0	3,449,014	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00227	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Response Rewards - RgRR			**$505,034**			**$491,249**	
Residential Charger Only EV - COEV-R							
Fixed service and administration charge							
Bundled service per month	1,093	$20.00000	$21,862	1,093	$20.00000	$21,862	0.00%
Pre-paid service per month	364	$8.00000	$2,915	364	$8.00000	$2,915	0.00%
Energy charge							
On-peak (summer)	8,745	$0.25145	$2,199	8,745	$0.25145	$2,199	0.00%
On-peak (non-summer)	8,745	$0.13786	$1,206	8,745	$0.13786	$1,206	0.00%
Intermediate-peak (summer)	13,117	$0.13786	$1,808	13,117	$0.13786	$1,808	0.00%
Intermediate-peak (non-summer)	13,117	$0.13786	$1,808	13,117	$0.13786	$1,808	0.00%
Off-peak (summer)	196,755	$0.06223	$12,243	196,755	$0.06223	$12,243	0.00%
Off-peak (non-summer)	196,755	$0.06223	$12,243	196,755	$0.06223	$12,243	0.00%
Fuel cost adjustment	437,233	$0.00000	$0	437,233	$0.00000	$0	0.00%
Other							
Tax credit	437,233	$0.00000	$0	437,233	$0.00000	$0	0.00%
Total Revenue: Residential Charger Only EV - COEV-R			**$56,284**			**$56,284**	
Residential Whole Home EV - WHEV-R							
Fixed service and administration charge							
Bundled service per month	32	$20.00000	$638	32	$20.00000	$638	0.00%
Pre-paid service per month	11	$8.00000	$85	11	$8.00000	$85	0.00%
Total Revenue: Residential Whole Home EV - WHEV-R			**$723**			**$723**	

Electric Rate Design - Test Year 2024
Wisconsin Public Service Corporation

	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Commercial Electric Vehicle EV-C							
Fixed service and administration charge							
Bundled-single port, per month per port A	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port B	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port C	96	$25.00000	$2,400	96	$25.00000	$2,400	0.00%
Bundled-dual port, per month per port A	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port B	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port C	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Pre-paid-single port, per month per port A	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port B	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port C	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-dual port, per month per port A	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port B	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port C	0	$2.00000	$0	0	$2.00000	$0	0.00%
Total Revenue: Commercial Electric Vehicle EV-C			**$25,728**			**$25,728**	
General Secondary Flat Rate - Cg1 (<50 kW)							
Customer charge							
Single PH per day	12,449,872	$0.90840	$11,309,463	12,449,872	$0.90840	$11,309,463	0.00%
Three PH per day	4,679,636	$1.45350	$6,801,851	4,679,636	$1.45350	$6,801,851	0.00%
Energy charge	807,993,354	$0.12318	$99,528,621	807,993,354	$0.11945	$96,514,806	-3.03%
Fuel cost adjustment	807,993,354	$0.00000	$0	807,993,354	$0.00000	$0	0.00%
Other							
Tax credit	807,993,354	$0.00000	$0	807,993,354	$0.00000	$0	0.00%
Revenue sharing	807,993,354	$0.00000	$0	807,993,354	$0.00000	$0	0.00%
Act 141 capped credits	16,076,484	-$0.00236	-$37,941	16,076,484	-$0.00236	-$37,941	0.00%
Act 141 capped contribution	16,076,484	$0.00071	$11,397	16,076,484	$0.00071	$11,397	0.00%
Total Revenue: General Secondary Flat Rate - Cg1 (<50 kW)			**$117,613,393**			**$114,599,577**	
General Secondary Flat Rate Response Rewards - Cg1RR							
Customer charge							
Single PH per day	0	$0.90840	$0	0	$0.90840	$0	0.00%
Three PH per day	365	$1.45350	$531	365	$1.45350	$531	0.00%
Energy charge							
On-peak	5,736	$0.23536	$1,350	5,736	$0.22566	$1,294	-4.12%
Off-peak	9,319	$0.06822	$636	9,319	$0.06541	$610	-4.12%
Critical peak	96	$1.17680	$113	96	$1.17680	$113	0.00%
Fuel cost adjustment							
Adjustment	15,151	$0.00000	$0	15,151	$0.00000	$0	0.00%
Other							
Tax credit	15,151	$0.00000	$0	15,151	$0.00000	$0	0.00%
Revenue sharing	15,151	$0.00000	$0	15,151	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00236	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg1RR			**$2,630**			**$2,548**	

Electric Rate Design - Test Year 2024
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	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
General Secondary Small Optional TOU - Cg3OTOU							
Customer charge							
Single PH per day	1,770,028	$0.90840	$1,607,894	1,770,028	$0.90840	$1,607,894	0.00%
Three PH per day	167,461	$1.45350	$243,405	167,461	$1.45350	$243,405	0.00%
Energy charge							
On-peak	27,174,498	$0.23877	$6,488,455	27,174,498	$0.22894	$6,221,330	-4.12%
Off-peak	70,937,396	$0.06822	$4,839,349	70,937,396	$0.06541	$4,640,015	-4.12%
					0.95875		
Fuel cost adjustment							
Adjustment	98,111,894	$0.00000	$0	98,111,894	$0.00000	$0	0.00%
Other							
Tax credit	98,111,894	$0.00000	$0	98,111,894	$0.00000	$0	0.00%
Revenue sharing	98,111,894	$0.00000	$0	98,111,894	$0.00000	$0	0.00%
Act 141 capped credits	334,129	-$0.00236	-$789	334,129	-$0.00236	-$789	0.00%
Act 141 capped contribution	334,129	$0.00091	$305	334,129	$0.00091	$305	0.00%
Total Revenue: General Secondary Small Optional TOU - Cg3OTOU			**$13,178,619**			**$12,712,160**	
General Secondary Flat Rate - Cg5 (50 < kW > 100)							
Customer charge							
Single PH per day	116,673	$2.07120	$241,652	116,673	$2.07120	$241,652	0.00%
Three PH per day	405,829	$3.31400	$1,344,916	405,829	$3.31400	$1,344,916	0.00%
Energy charge	241,646,165	$0.11674	$28,209,773	241,646,165	$0.11225	$27,124,782	-3.85%
Fuel cost adjustment	241,646,165	$0.00000	$0	241,646,165	$0.00000	$0	0.00%
Other							
Tax credit	241,646,165	$0.00000	$0	241,646,165	$0.00000	$0	0.00%
Revenue sharing	241,646,165	$0.00000	$0	241,646,165	$0.00000	$0	0.00%
Act 141 capped credits	8,954,287	-$0.00236	-$21,132	8,954,287	-$0.00236	-$21,132	0.00%
Act 141 capped contribution	8,954,287	$0.00044	$3,975	8,954,287	$0.00044	$3,975	0.00%
Total Revenue: General Secondary Flat Rate - Cg5 (50 < kW > 100)			**$29,779,185**			**$28,694,194**	
General Secondary Flat Rate Response Rewards - Cg5RR							
Customer charge							
Single PH per day	0	$2.07120	$0	0	$2.07120	$0	0.00%
Three PH per day	0	$3.31400	$0	0	$3.31400	$0	0.00%
Energy charge							
On-peak	0	$0.18761	$0	0	$0.17988	$0	-4.12%
Off-peak	0	$0.06822	$0	0	$0.06541	$0	-4.12%
Critical peak	0	$1.17256	$0	0	$1.17256	$0	0.00%
Fuel cost adjustment							
Adjustment	0	$0.00000	$0	0	$0.00000	$0	0.00%
Other							
Tax credit	0	$0.00000	$0	0	$0.00000	$0	0.00%
Revenue sharing	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00236	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg5RR			**$0**			**$0**	

Electric Rate Design - Test Year 2024
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	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Commercial and Industrial Demand - Cg20 (100-1000 kW)							
Customer charge							
Secondary	1,463,006	$3.05750	$4,473,140	1,463,006	$3.05750	$4,473,140	0.00%
Primary	11,113	$5.58900	$62,112	11,113	$5.58900	$62,112	0.00%
Energy charge					0.93685		
On-peak	952,218,782	$0.07767	$73,958,833	952,218,782	$0.07278	$69,302,483	-6.30%
Off-peak	1,784,082,188	$0.04569	$81,514,715	1,784,082,188	$0.04282	$76,394,399	-6.28%
Demand charge							
On-peak (summer)	2,589,291	$18.44900	$47,769,830	2,589,291	$18.44900	$47,769,830	0.00%
On-peak (non-summer)	4,554,380	$11.99200	$54,616,125	4,554,380	$11.99200	$54,616,125	0.00%
Standby	5,872	$2.25100	$13,218	5,872	$2.25100	$13,218	0.00%
Customer maximum	9,228,786	$2.39900	$22,139,858	9,228,786	$2.39900	$22,139,858	0.00%
Fuel cost adjustment							
Adjustment	2,736,300,970	$0.00000	$0	2,736,300,970	$0.00000	$0	0.00%
Other							
Energy limiter		$0.19524	-$1,699,945		$0.18847	-$1,699,945	-3.47%
Primary discount			-$98,726			-$98,726	
Tax credit	2,736,300,970	$0.00000	$0	2,736,300,970	$0.00000	$0	0.00%
Revenue sharing	2,736,300,970	$0.00000	$0	2,736,300,970	$0.00000	$0	0.00%
Act 141 capped credits	299,508,191	-$0.00236	-$706,839	299,508,191	-$0.00236	-$706,839	0.00%
Act 141 capped contribution	299,508,191	$0.00034	$103,107	299,508,191	$0.00034	$103,107	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20 (100-1000 kW)			**$282,145,427**			**$272,368,761**	
Commercial and Industrial Demand - Cg20RR (100-1000 kW)							
Customer charge							
Secondary	13,892	$3.05750	$42,474	13,892	$3.05750	$42,474	0.00%
Primary	1,126	$5.58900	$6,295	1,126	$5.58900	$6,295	0.00%
Energy charge							
On-peak	18,590,751	$0.05695	$1,058,743	18,590,751	$0.05337	$992,188	-6.29%
Off-peak	34,416,547	$0.04112	$1,415,208	34,416,547	$0.03854	$1,326,414	-6.27%
Critical peak	1,922,493	$0.48408	$930,640	1,922,493	$0.45365	$872,139	-6.29%
Demand charge							
On-peak (summer)	62,172	$13.83700	$860,269	62,172	$13.83700	$860,269	0.00%
On-peak (non-summer)	107,790	$8.99400	$969,463	107,790	$8.99400	$969,463	0.00%
Standby	0	$2.25100	$0	0	$2.25100	$0	0.00%
Customer maximum	220,817	$2.39900	$529,740	220,817	$2.39900	$529,740	0.00%
Fuel cost adjustment							
Adjustment	54,929,791	$0.00000	$0	54,929,791	$0.00000	$0	0.00%
Other							
Primary discount			-$10,664			-$10,664	
Tax credit	54,929,791	$0.00000	$0	54,929,791	$0.00000	$0	0.00%
Revenue sharing	54,929,791	$0.00000	$0	54,929,791	$0.00000	$0	0.00%
Act 141 capped credits	4,032,509	-$0.00236	-$9,517	4,032,509	-$0.00236	-$9,517	0.00%
Act 141 capped contribution	4,032,509	$0.00032	$1,279	4,032,509	$0.00032	$1,279	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20RR (100-1000 kW)			**$5,793,931**			**$5,580,080**	

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	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Cp Large C&I (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	37,353	$21.86300	$816,649	37,353	$21.86300	$816,649	0.00%
Customer charge per day-primary voltage	18,461	$25.51230	$470,983	18,461	$25.51230	$470,983	0.00%
Customer charge per day-transmission voltag	3,104	$58.29040	$180,933	3,104	$58.29040	$180,933	0.00%
Energy charge-secondary voltage							
On-peak	362,743,982	$0.07149	$25,932,567	362,743,982	$0.06872	$24,927,766	-3.87%
Off-peak	347,903,241	$0.04205	$14,629,331	347,903,241	$0.04042	$14,062,249	-3.88%
Energy charge-primary voltage							
On-peak	517,359,480	$0.06939	$35,899,574	517,359,480	$0.06671	$34,513,051	-3.86%
Off-peak	550,431,783	$0.04082	$22,468,625	550,431,783	$0.03924	$21,598,943	-3.87%
Energy charge-transmission voltage					0.96125		
On-peak	427,522,515	$0.06852	$29,293,843	427,522,515	$0.06587	$28,160,908	-3.87%
Off-peak	534,836,319	$0.04031	$21,559,252	534,836,319	$0.03875	$20,724,907	-3.87%
Demand charge-secondary voltage							
Peak (summer)	407,540	$20.23500	$8,246,576	407,540	$20.23500	$8,246,576	0.00%
Peak (non-summer)	735,173	$11.24200	$8,264,811	735,173	$11.24200	$8,264,811	0.00%
Intermediate (summer)	15,074	$15.17600	$228,766	15,074	$15.17600	$228,766	0.00%
Intermediate (non-summer)	25,691	$8.43200	$216,629	25,691	$8.43200	$216,629	0.00%
Variable interruptible (summer)	138,428	$12.19600	$1,688,270	138,428	$12.19600	$1,688,270	0.00%
Variable interruptible (non-summer)	275,287	$7.22200	$1,988,125	275,287	$7.22200	$1,988,125	0.00%
Customer maximum	1,921,599	$2.20900	$4,244,812	1,921,599	$2.20900	$4,244,812	0.00%
Demand charge-primary voltage							
Peak (summer)	639,480	$19.78500	$12,652,108	639,480	$19.78500	$12,652,108	0.00%
Peak (non-summer)	1,251,822	$10.99200	$13,760,024	1,251,822	$10.99200	$13,760,024	0.00%
Intermediate (summer)	5,246	$14.83900	$77,850	5,246	$14.83900	$77,850	0.00%
Intermediate (non-summer)	651	$8.24400	$5,368	651	$8.24400	$5,368	0.00%
Variable interruptible (summer)	157,642	$11.74600	$1,851,663	157,642	$11.74600	$1,851,663	0.00%
Variable interruptible (non-summer)	302,146	$6.97200	$2,106,559	302,146	$6.97200	$2,106,559	0.00%
Customer maximum	3,001,035	$1.92600	$5,779,993	3,001,035	$1.92600	$5,779,993	0.00%
Demand charge-transmission voltage							
Peak (summer)	97,615	$19.76200	$1,929,065	97,615	$19.76200	$1,929,065	0.00%
Peak (non-summer)	220,858	$10.97900	$2,424,800	220,858	$10.97900	$2,424,800	0.00%
Intermediate (summer)	140,879	$14.82200	$2,088,102	140,879	$14.82200	$2,088,102	0.00%
Intermediate (non-summer)	279,339	$8.23400	$2,300,080	279,339	$8.23400	$2,300,080	0.00%
Variable interruptible (summer)	297,319	$11.72300	$3,485,475	297,319	$11.72300	$3,485,475	0.00%
Variable interruptible (non-summer)	589,996	$6.95900	$4,105,783	589,996	$6.95900	$4,105,783	0.00%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	2,740,797,320	$0.00000	$0	2,740,797,320	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	1,800,000	$0.50000	$900,000	1,800,000	$0.50000	$900,000	0.00%
Power factor discount			-$217,836			-$217,836	
Tax credit	2,740,797,320	$0.00000	$0	2,740,797,320	$0.00000	$0	0.00%
Load factor credit	321,106,216	-$0.00500	-$1,605,531	321,106,216	-$0.00500	-$1,605,531	0.00%
Act 141 capped credits	2,663,123,376	-$0.00236	-$6,284,971	2,663,123,376	-$0.00236	-$6,284,971	0.00%
Act 141 capped contribution	2,663,123,376	$0.00030	$790,581	2,663,123,376	$0.00030	$790,581	0.00%
Total Revenue: Cp Large C&I (> 1,000 kW)			**$222,278,859**			**$216,483,491**	

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	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Cp Large C&I Response Rewards (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	3,497	$21.86300	$76,455	3,497	$21.86300	$76,455	0.00%
Customer charge per day-primary voltage	2,555	$25.51230	$65,184	2,555	$25.51230	$65,184	0.00%
Customer charge per day-transmission voltag	730	$58.29040	$42,552	730	$58.29040	$42,552	0.00%
Energy charge-secondary voltage							
On-peak	34,728,522	$0.05305	$1,842,348	34,728,522	$0.05097	$1,770,113	-3.92%
Off-peak	32,451,087	$0.03745	$1,215,293	32,451,087	$0.03597	$1,167,266	-3.95%
Critical peak	1,686,297	$0.45085	$760,267	1,686,297	$0.43328	$730,639	-3.90%
Energy charge-primary voltage							
On-peak	48,677,139	$0.05149	$2,506,386	48,677,139	$0.04948	$2,408,545	-3.90%
Off-peak	55,450,128	$0.03634	$2,015,058	55,450,128	$0.03492	$1,936,318	-3.91%
Critical peak	4,347,394	$0.43763	$1,902,550	4,347,394	$0.42058	$1,828,427	-3.90%
Energy charge-transmission voltage							
On-peak	66,542,323	$0.05084	$3,383,012	66,542,323	$0.04886	$3,251,258	-3.89%
Off-peak	90,428,711	$0.03589	$3,245,486	90,428,711	$0.03449	$3,118,886	-3.90%
Critical peak	5,143,868	$0.43214	$2,222,871	5,143,868	$0.41531	$2,136,300	-3.89%
Demand charge-secondary voltage							
Peak (summer)	57,002	$15.17600	$865,062	57,002	$15.17600	$865,062	0.00%
Peak (non-summer)	96,473	$8.43200	$813,460	96,473	$8.43200	$813,460	0.00%
Intermediate (summer)	1,359	$11.38200	$15,466	1,359	$11.38200	$15,466	0.00%
Intermediate (non-summer)	2,964	$6.32400	$18,743	2,964	$6.32400	$18,743	0.00%
Customer maximum	203,372	$2.20900	$449,249	203,372	$2.20900	$449,249	0.00%
Demand charge-primary voltage							
Peak (summer)	69,078	$14.83900	$1,025,048	69,078	$14.83900	$1,025,048	0.00%
Peak (non-summer)	119,100	$8.24400	$981,860	119,100	$8.24400	$981,860	0.00%
Intermediate (summer)	0	$11.12900	$0	0	$11.12900	$0	0.00%
Intermediate (non-summer)	0	$6.18300	$0	0	$6.18300	$0	0.00%
Customer maximum	262,412	$1.92600	$505,406	262,412	$1.92600	$505,406	0.00%
Demand charge-transmission voltage							
Peak (summer)	97,343	$14.82200	$1,442,816	97,343	$14.82200	$1,442,816	0.00%
Peak (non-summer)	177,997	$8.23400	$1,465,629	177,997	$8.23400	$1,465,629	0.00%
Intermediate (summer)	0	$11.11700	$0	0	$11.11700	$0	0.00%
Intermediate (non-summer)	0	$6.17600	$0	0	$6.17600	$0	0.00%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	339,455,470	$0.00000	$0	339,455,470	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	578,001	$0.50000	$289,001	578,001	$0.50000	$289,001	0.00%
Power factor discount			-$5,031			-$5,031	
Tax credit	339,455,470	$0.00000	$0	339,455,470	$0.00000	$0	0.00%
Revenue sharing	339,455,470	$0.00000	$0	339,455,470	$0.00000	$0	0.00%
Act 141 capped credits	147,537,265	-$0.00236	-$348,188	147,537,265	-$0.00236	-$348,188	0.00%
Act 141 capped contribution	147,537,265	$0.00034	$50,864	147,537,265	$0.00034	$50,864	0.00%
Total Revenue: Cp Large C&I Response Rewards (> 1,000 kW)			**$26,846,847**			**$26,101,327**	

Electric Rate Design - Test Year 2024
Wisconsin Public Service Corporation

	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
General Primary Service - New Load Market Pricing (NLMP)							
Customer charge							
Scheduling per day	1,095	$6.00000	$6,570	1,095	$6.00000	$6,570	0.00%
Energy charge							
Hourly LMP	272,775,580	$0.05242	$14,299,808	272,775,580	$0.05242	$14,299,808	0.00%
Embedded cost adder	272,775,580	$0.00050	$136,388	272,775,580	$0.00050	$136,388	0.00%
Demand charge							
Peak (summer)	304,004	$0.01559	$4,739	304,004	$0.01559	$4,739	0.00%
Transmission demand	304,004	$8.25000	$2,508,036	304,004	$8.25000	$2,508,036	0.00%
Total Revenue: General Primary Service - New Load Market Pricing (NLMP)			**$16,955,541**			**$16,955,541**	
General Primary Service - Real-Time Market Pricing (RTMP)							
Customer charge							
Scheduling per month	96	$1,000.000	$96,000	96	$1,000.000	$96,000	0.00%
Energy charge							
Hourly LMP	637,344,147	$0.05367	$34,207,484	637,344,147	$0.05367	$34,207,484	0.00%
Embedded cost adder	637,344,147	$0.00550	$3,505,393	637,344,147	$0.00550	$3,505,393	0.00%
Demand charge							
Transmission demand	1,089,995	$5.01000	$5,460,877	1,089,995	$5.01000	$5,460,877	0.00%
Total Revenue: General Primary Service - Real-Time Market Pricing (RTMP)			**$43,269,754**			**$43,269,754**	

Electric Rate Design - Test Year 2024
Wisconsin Public Service Corporation

	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Ls-1 Lighting Service							
Company Owned							
Sodium Vapor							
5,670 Lumens (70W)	2,556	$18.12000	$46,315	2,556	$18.11000	$46,289	-0.06%
9,000 Lumens (100W) (Closed)	189,660	$17.88000	$3,391,121	189,660	$17.87000	$3,389,224	-0.06%
14,000 Lumens (150W) (Closed)	141,123	$20.03000	$2,826,694	141,123	$20.02000	$2,825,282	-0.05%
27,000 Lumens (250W) (Closed)	82,759	$24.28000	$2,009,389	82,759	$24.26000	$2,007,733	-0.08%
45,000 Lumens (400W)	6,180	$32.54000	$201,097	6,180	$32.52000	$200,974	-0.06%
9,000 Lumens (100W) - Area	57,123	$15.75000	$899,687	57,123	$15.74000	$899,116	-0.06%
14,000 Lumens (150W) - Area	10,031	$18.60000	$186,577	10,031	$18.59000	$186,476	-0.05%
27,000 Lumens (250W) - Directional	5,091	$29.67000	$151,050	5,091	$29.65000	$150,948	-0.07%
45,000 Lumens (400W) - Directional (Close	25,899	$36.29000	$939,875	25,899	$36.27000	$939,357	-0.06%
Metal Halide							
8,500 Lumens (150W)	456	$28.62000	$13,051	456	$28.60000	$13,042	-0.07%
26,000 Lumens (350W)	180	$31.48000	$5,666	180	$31.46000	$5,663	-0.06%
36,000 Lumens (400W) - (Closed)	36	$33.38000	$1,202	36	$33.36000	$1,201	-0.06%
26,000 Lumens (350W) - Directional	1,356	$35.29000	$47,853	1,356	$35.27000	$47,826	-0.06%
36,000 Lumens (400W) - Directional (Close	4,584	$37.39000	$171,396	4,584	$37.37000	$171,304	-0.05%
110,000 Lumens (1000W) - Directional	1,836	$54.14000	$99,401	1,836	$54.10000	$99,328	-0.07%
LED							
Class B Low Output Security		$13.35000	$0	0	$13.34000	$0	-0.07%
Class C Low Output Roadway	18,540	$14.78000	$274,021	18,540	$14.77000	$273,836	-0.07%
Class D Med Output Roadway	20,628	$18.36000	$378,730	20,628	$18.35000	$378,524	-0.05%
Class E High Output Roadway	19,884	$22.89000	$455,145	19,884	$22.88000	$454,946	-0.04%
Class G Med Output Flood		$26.71000	$0	0	$26.69000	$0	-0.07%
Class H High Output Flood		$32.43000	$0	0	$32.41000	$0	-0.06%
Class H Med Output Post Top		$23.85000	$0	0	$23.83000	$0	-0.08%
Class K Med Output Post Top		$27.66000	$0	0	$27.64000	$0	-0.07%
Class M Med Output Post Top		$31.48000	$0	0	$31.46000	$0	-0.06%
Customer Owned (closed)							
Sodium Vapor							
9,000 Lumens (100W)	1,476	$12.90000	$19,040	1,476	$12.89000	$19,026	-0.08%
14,000 Lumens (150W)	7,908	$14.95000	$118,225	7,908	$14.94000	$118,146	-0.07%
27,000 Lumens (250 W)	7,668	$18.80000	$144,158	7,668	$18.79000	$144,082	-0.05%
45,000 Lumens (400W)	1,368	$22.90000	$31,327	1,368	$22.89000	$31,314	-0.04%
Metal Halide							
8,500 Lumens (150W)	48	$17.90000	$859	48	$17.89000	$859	-0.06%
26,000 Lumens (350W)	0	$22.10000	$0	0	$22.09000	$0	-0.05%
Common							
Wood Poles	70,812	$5.24000	$371,055	70,812	$5.24000	$371,055	0.00%
Fiberglass Poles 25' / 20'	264	$8.74000	$2,307	264	$8.73000	$2,305	-0.11%
Fiberglass Poles 30' / 25'	384	$11.29000	$4,335	384	$11.28000	$4,332	-0.09%
Fiberglass Poles 35' / 30'	288	$14.14000	$4,072	288	$14.13000	$4,069	-0.07%
Fiberglass Poles 40' / 35'	0	$23.51000	$0	0	$23.49000	$0	-0.09%
Spans	83,508	$2.32000	$193,739	83,508	$2.32000	$193,739	0.00%
Excess Footage - Mast Arm	27,348	$0.24000	$6,564	27,348	$0.24000	$6,564	0.00%
Fuel cost adjustment	40,306,330	$0.00000	$0	40,306,330	$0.00000	$0	0.00%
Other							
Tax credit	40,306,330	$0.00000	$0	40,306,330	$0.00000	$0	0.00%
Revenue sharing	40,306,330	$0.00000	$0	40,306,330	$0.00000	$0	0.00%
Act 141 capped credits	3,976,368	-$0.00236	-$9,384	3,976,368	-$0.00236	-$9,384	0.00%
Act 141 capped contribution	3,976,368	$0.00196	$7,806	3,976,368	$0.00196	$7,806	0.00%
Total Revenue: Ls-1 Lighting Service			**$12,992,372**			**$12,984,978**	

Electric Rate Design - Test Year 2024
Wisconsin Public Service Corporation

	Authorized Rate - Year 2023			Authorized Rate - Year 2024			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2024
Nature Wise							
NAT-R per 100 kWh block	52,788	$1.27700	$67,410	52,788	$1.27700	$67,410	0.00%
NAT-C per 100 kWh block	22,572	$1.27700	$28,824	22,572	$1.27700	$28,824	0.00%
Total Revenue: Nature Wise			**$96,235**			**$96,235**	
Automatic Transfer Switch ATS							
Customer charge							
Option 1 per month	216	$236.000	$50,976	216	$236.000	$50,976	0.00%
Option 2 per month	48	$710.000	$34,080	48	$710.000	$34,080	0.00%
Total Revenue: Automatic Transfer Switch ATS			**$85,056**			**$85,056**	
Parallel Generation							
Pg-Solar Customer Charge per day	0	$0.06580	$0	0	$0.06580	$0	0.00%
Pg-BioGas Customer Charge per day (Secondary)	0	$1.00270	$0	0	$1.00270	$0	0.00%
Pg-BioGas Customer Charge per day (Primary)	0	$1.91670	$0	0	$1.91670	$0	0.00%
Customer Charge per day (Pg-2A, Pg-2B & Pg-2C)	36,533	$0.65750	$24,020	36,533	$0.65750	$24,020	0.00%
Total Revenue: Parallel Generation			**$24,020**			**$24,020**	

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Rg1 -- Residential Service			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
Energy Charge - Base	$0.13600	$0.13213	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg3 -- Residential Service 2TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.24979	$0.24122	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.07806	$0.07538	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg5 -- Residential Service 3TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.31224	$0.30152	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Shoulder Peak Energy Charge - Base	$0.13600	$0.13213	per kWh
Off-Peak Energy Charge - Base	$0.07806	$0.07538	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
RgRR -- Residential Response Rewards			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.27399	$0.26458	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.30198	$1.30198	per kWh
Off-Peak Energy Charge - Base	$0.07025	$0.06784	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1 -- General Secondary Service			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
Energy Charge - Base	$0.12318	$0.11945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1RR -- General Secondary Service Response Rewards			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.23536	$0.22566	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17680	$1.17680	per kWh
Off-Peak Energy Charge - Base	$0.06822	$0.06541	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Cg3 -- General Secondary Service - Optional TOU			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.23877	$0.22894	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.06822	$0.06541	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5 -- General Secondary Service - Flat			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
Energy Charge - Base	$0.11674	$0.11225	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5RR -- General Secondary Service - Response Rewards			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
On-Peak Energy Charge - Base	$0.18761	$0.17988	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17256	$1.17256	per kWh
Off-Peak Energy Charge - Base	$0.06822	$0.06541	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Cg20 -- Commercial and Industrial Demand			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.07767	$0.07278	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.04569	$0.04282	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$18.449	$18.449	per kW
On-Peak Demand Charge - Base (Non-summer)	$11.992	$11.992	per kW
Standby Demand - Base	$2.251	$2.251	per kW
Customer Demand Charge	$2.399	$2.399	per kW
Energy Limiter	$0.19524	$0.18847	per kWh
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand
Cg20RR -- Commercial and Industrial Demand - Response Rewards			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.05695	$0.05337	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$0.48408	$0.45365	per kWh
Off-Peak Energy Charge - Base	$0.04112	$0.03854	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$13.83700	$13.83700	per kW
On-Peak Demand Charge - Base (Non-summer)	$8.99400	$8.99400	per kW
Standby Demand - Base	$2.25100	$2.25100	per kW
Customer Demand Charge	$2.39900	$2.39900	per kW
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Naturewise (NAT)			
NAT-R	$1.27700	$1.27700	per 100 kWh block
NAT-C	$1.27700	$1.27700	per 100 kWh block
Automatic Transfer Switch (ATS)			
Customer Charge - Total	$236.00000	$236.00000	per Month
Customer Charge - Maintenance	$710.00000	$710.00000	per Month
Parallel Generation			
Pg-Solar Customer Charge	$0.06580	$0.06580	per Day
Pg-BioGas Customer Charge (Secondary)	$1.00270	$1.00270	per Day
Pg-BioGas Customer Charge (Primary)	$1.91670	$1.91670	per Day
Customer Charge (Pg-2A & Pg-2B)	$0.65750	$0.65750	per Day
COEV-R -- Residential Electric Vehicle Charger Only			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
Energy charge			
On-peak (summer)	$0.25145	$0.25145	per kWh
On-peak (non-summer)	$0.13786	$0.13786	per kWh
Intermediate-peak (summer)	$0.13786	$0.13786	per kWh
Intermediate-peak (non-summer)	$0.13786	$0.13786	per kWh
Off-peak (summer)	$0.06223	$0.06223	per kWh
Off-peak (non-summer)	$0.06223	$0.06223	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
WHEV-R -- Residential Electric Vehicle Whole Home			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
EV-C -- Electric Vehicle Commercial			
Fixed service and administration charge			
Bundled-single port A	$24.00000	$24.00000	per Month, per Port
Bundled-single port B	$24.00000	$24.00000	per Month, per Port
Bundled-single port C	$25.00000	$25.00000	per Month, per Port
Bundled-dual port A	$26.00000	$26.00000	per Month, per Port
Bundled-dual port B	$26.00000	$26.00000	per Month, per Port
Bundled-dual port C	$26.00000	$26.00000	per Month, per Port
Pre-paid-single port A	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port B	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port C	$4.00000	$4.00000	per Month, per Port
Pre-paid-dual port A	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port B	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port C	$2.00000	$2.00000	per Month, per Port

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Cp -- Large Commercial and Industrial			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.07149	$0.06872	per kWh
On-Peak Energy Charge - Base (Primary)	$0.06939	$0.06671	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.06852	$0.06587	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.04205	$0.04042	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.04082	$0.03924	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.04031	$0.03875	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$20.235	$20.235	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$19.785	$19.785	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$19.762	$19.762	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$11.242	$11.242	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$10.992	$10.992	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$10.979	$10.979	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$15.176	$15.176	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$14.839	$14.839	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$14.822	$14.822	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$8.432	$8.432	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$8.244	$8.244	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$8.234	$8.234	per kW
On-Peak Demand Charge - Summer Variable Int (Secondary)	$12.196	$12.196	per kW
On-Peak Demand Charge - Summer Variable Int (Primary)	$11.746	$11.746	per kW
On-Peak Demand Charge - Summer Variable Int (Transmission)	$11.723	$11.723	per kW
On-Peak Demand Charge - Non-summer Variable Int (Secondary)	$7.222	$7.222	per kW
On-Peak Demand Charge - Non-summer Variable Int (Primary)	$6.972	$6.972	per kW
On-Peak Demand Charge - Non-summer Variable Int (Transmission)	$6.959	$6.959	per kW
Customer Demand Charge (Secondary)	$2.209	$2.209	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW
Interruptible Demand Credit - Summer (Secondary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Primary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Transmission)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Non-Summer (Secondary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Primary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Transmission)	$4.02000	$4.02000	per kW
Load Factor Credit	($0.00500)	($0.00500)	per kWh

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
CpRR -- Large Commercial and Industrial Response Rewards			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.05305	$0.05097	per kWh
On-Peak Energy Charge - Base (Primary)	$0.05149	$0.04948	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.05084	$0.04886	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base (Secondary)	$0.45085	$0.43328	per kWh
Critical Peak Energy Charge - Base (Primary)	$0.43763	$0.42058	per kWh
Critical Peak Energy Charge - Base (Transmission)	$0.43214	$0.41531	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.03745	$0.03597	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.03634	$0.03492	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.03589	$0.03449	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$15.176	$15.176	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$14.839	$14.839	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$14.822	$14.822	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$8.432	$8.432	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$8.244	$8.244	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$8.234	$8.234	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$11.382	$11.382	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$11.129	$11.129	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$11.117	$11.117	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$6.324	$6.324	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$6.183	$6.183	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$6.176	$6.176	per kW
Customer Demand Charge (Secondary)	$2.209	$2.209	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
New Load Market Pricing (NLMP)			
Scheduleing Charge	$6.00000	$6.00000	per Day
Transmission Demand	$8.25000	$8.25000	per kW
Embedded Cost Adder	$0.00050	$0.00050	per kWh
Real Time Market Pricing (RTMP)			
Scheduling Charge	$1,000.00	$1,000.00	per Month
Embedded Cost Adder	$0.00550	$0.00550	per kWh
Transmission Demand	$5.01000	$5.01000	per kW

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Ls1 Lighting Service			
Company Owned			
Sodium Vapor			
5,670 Lumens (70W)	$18.12000	$18.11000	per Month
9,000 Lumens (100W) (Closed)	$17.88000	$17.87000	per Month
14,000 Lumens (150W) (Closed)	$20.03000	$20.02000	per Month
27,000 Lumens (250W) (Closed)	$24.28000	$24.26000	per Month
45,000 Lumens (400W)	$32.54000	$32.52000	per Month
9,000 Lumens (100W) - Area	$15.75000	$15.74000	per Month
14,000 Lumens (150W) - Area	$18.60000	$18.59000	per Month
27,000 Lumens (250W) - Directional	$29.67000	$29.65000	per Month
45,000 Lumens (400W) - Directional (Closed)	$36.29000	$36.27000	per Month
Metal Halide			
8,500 Lumens (150W)	$28.62000	$28.60000	per Month
26,000 Lumens (350W)	$31.48000	$31.46000	per Month
36,000 Lumens (400W) - (Closed)	$33.38000	$33.36000	per Month
26,000 Lumens (350W) - Directional	$35.29000	$35.27000	per Month
36,000 Lumens (400W) - Directional (Closed)	$37.39000	$37.37000	per Month
110,000 Lumens (1000W) - Directional	$54.14000	$54.10000	per Month
LED			
Class B Low Output Security	$13.35000	$13.34000	per Month
Class C Low Output Roadway	$14.78000	$14.77000	per Month
Class D Med Output Roadway	$18.36000	$18.35000	per Month
Class E High Output Roadway	$22.89000	$22.88000	per Month
Class G Med Output Flood	$26.71000	$26.69000	per Month
Class H High Output Flood	$32.43000	$32.41000	per Month
Class H Med Output Post Top	$23.85000	$23.83000	per Month
Class K Med Output Post Top	$27.66000	$27.64000	per Month
Class M Med Output Post Top	$31.48000	$31.46000	per Month
Customer Owned (Closed)			
Sodium Vapor			
9,000 Lumens (100W)	$12.90000	$12.89000	per Month
14,000 Lumens (150W)	$14.95000	$14.94000	per Month
27,000 Lumens (250 W)	$18.80000	$18.79000	per Month
45,000 Lumens (400W)	$22.90000	$22.89000	per Month
Metal Halide			
8,500 Lumens (150W)	$17.90000	$17.89000	per Month
26,000 Lumens (350W)	$22.10000	$22.09000	per Month
Common			
Wood Poles	$5.24000	$5.24000	per Month
Fiberglass Poles 25' / 20'	$8.74000	$8.73000	per Month
Fiberglass Poles 30' / 25'	$11.29000	$11.28000	per Month
Fiberglass Poles 35' / 30'	$14.14000	$14.13000	per Month
Fiberglass Poles 40' / 35'	$23.51000	$23.49000	per Month
Spans	$2.32000	$2.32000	per Month
Excess Footage - Mast Arm	$0.24000	$0.24000	per Month per Foot
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2024	
Embedded Credits for Line Extensions			
Rg1, Rg3, & Rg5	$1,371	$1,371	per Customer
Cg1, Cg3, & Cg5	$2,603	$2,603	per Customer
Cg20 & Cp	$60.47	$60.47	per kW
Act 141 Costs Embedded in Base Rates			
Rg1, Rg3, & Rg5	$0.00227	$0.00227	per kWh
Cg1, Cg3, & Cg5	$0.00236	$0.00236	per kWh
Cg20 & Cp	$0.00236	$0.00236	per kWh
Standard Street Lighting	$0.00236	$0.00236	per kWh
Earnings Sharing Credit			
Rg1	$0.00000	$0.00000	per kWh
Rg3	$0.00000	$0.00000	per kWh
Rg5	$0.00000	$0.00000	per kWh
RgRR	$0.00000	$0.00000	per kWh
Cg1	$0.00000	$0.00000	per kWh
Cg1RR	$0.00000	$0.00000	per kWh
Cg3	$0.00000	$0.00000	per kWh
Cg5	$0.00000	$0.00000	per kWh
Cg5RR	$0.00000	$0.00000	per kWh
Cg20	$0.00000	$0.00000	per kWh
Cg20RR	$0.00000	$0.00000	per kWh
Cp	$0.00000	$0.00000	per kWh
CpRR	$0.00000	$0.00000	per kWh
Ls1	$0.00000	$0.00000	per kWh

Comparison of Bills for Residential

A	B	C	D	E	F	G

Rg1

Monthly Use (kWh)	Typical Bills					
	Current Rates		Authorized 2024		Authorized 2024 Change	
	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
350	$65.52	$786.24	$64.17	$770.04	-2.06%	-$1.35
450	$79.12	$949.44	$77.38	$928.56	-2.20%	-$1.74
550	$92.72	$1,112.64	$90.59	$1,087.08	-2.30%	-$2.13
660	**$107.68**	**$1,292.16**	**$105.13**	**$1,261.56**	**-2.37%**	**-$2.55**
750	$119.92	$1,439.04	$117.02	$1,404.24	-2.42%	-$2.90
1,000	$153.92	$1,847.04	$150.05	$1,800.60	-2.51%	-$3.87
2,000	$289.92	$3,479.04	$282.18	$3,386.16	-2.67%	-$7.74
3,000	$425.92	$5,111.04	$414.31	$4,971.72	-2.73%	-$11.61

Wisconsin Public Service Corporation
Docket 6690-UR-127
Monitored Fuel Costs for 2024

	Total Fuel Rules Cost	System Requirements	Monthly $/kWh	Cumulative $/kWh
January	$ 31,249,555	1,012,102	$ 30.88	$ 30.88
February	$ 27,528,588	958,401	$ 28.72	$ 29.83
March	$ 24,511,261	964,855	$ 25.40	$ 28.37
April	$ 22,942,050	896,964	$ 25.58	$ 27.72
May	$ 21,397,698	901,764	$ 23.73	$ 26.96
June	$ 22,040,561	973,685	$ 22.64	$ 26.22
July	$ 25,727,114	1,115,320	$ 23.07	$ 25.71
August	$ 27,615,376	1,092,938	$ 25.27	$ 25.65
September	$ 27,964,376	959,587	$ 29.14	$ 26.02
October	$ 26,423,018	864,673	$ 30.56	$ 26.43
November	$ 31,732,416	970,889	$ 32.68	$ 26.99
December	$ 28,873,296	986,573	$ 29.27	$ 27.19
Total	$ 318,005,308	11,697,749	$ 27.19	

Docket No. 20000-___-ER-23
Witness: Ann E. Bulkley

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Ann E. Bulkley

March 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Wyoming Public Service Commission ("Commission") on behalf of PacifiCorp d/b/a Rocky Mountain Power ("RMP" or the "Company"), which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy ("BHE").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings is attached as RMP Exhibit 4.1 to this testimony.

Q. Have you previously testified before the Commission or other regulatory authorities?

A. Yes. A list of proceedings in which I have provided testimony is provided in RMP Exhibit 4.1 to this testimony.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity ("ROE") for RMP's electric utility operations in Wyoming and to provide an assessment of its proposed capital structure to be used for ratemaking purposes.

Q. Are you sponsoring any exhibits in support of your direct testimony?

A. Yes. My analyses and recommendations are supported by the data presented in RMP Exhibit 4.2 through RMP Exhibit 4.11, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed more in Section VII in developing my ROE recommendation, I estimated the Company's cost of equity by applying several traditional estimation methodologies to a proxy group of comparable utilities, including the Constant Growth Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Bond Yield Risk Premium ("BYRP" or "Risk Premium") approach. My recommendation also takes into consideration: (1) RMP's capital expenditure requirements; (2) the regulatory environment in which RMP operates; and (3) RMP's planned investments in renewable generation assets compared to its current generation portfolio. Finally, I considered RMP's proposed capital structure as compared to the capital structures of the proxy companies.[1] While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into

[1] The selection and purpose of developing a group of comparable companies will be discussed in detail in Section VI of my direct testimony.

consideration in aggregate when determining where the RMP's ROE falls within the range of analytical results.

Q. How is the remainder of your direct testimony organized?

A. Section III provides a summary of my analyses and conclusions. Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital. Section V discusses current and projected capital market conditions and the effect of those conditions on RMP's cost of equity. Section VI explains my selection of the proxy group of electric utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for RMP. Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case. Section IX discusses the capital structure of the Company as compared with the proxy group. Section X presents my conclusions and recommendations for the market cost of equity.

III. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. What is your conclusion regarding the appropriate authorized ROE for RMP in this proceeding?

A. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, as well as the level of regulatory, business, and financial risk faced by RMP's electric operations in Wyoming relative to the proxy group, I believe a range from 9.90 to 11.00 percent is reasonable. Within that range, the Company is requesting a return of 10.30 percent, which is reasonable.

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. The key factors that I considered in my cost of equity analyses and recommended ROE for the Company in this proceeding are:

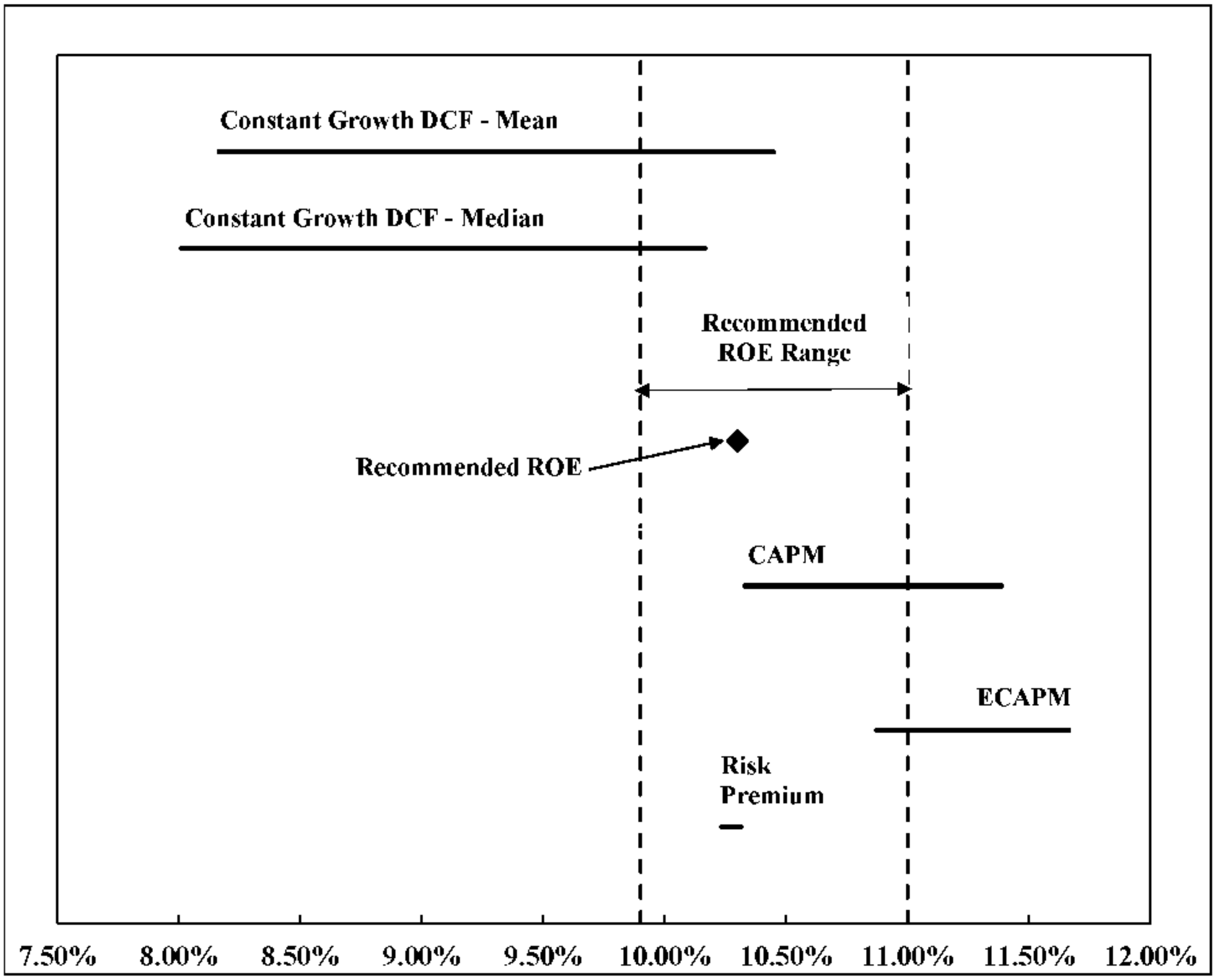
- The United States Supreme Court's *Hope* and *Bluefield* decisions[2] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).
- Although the companies in my proxy group are generally comparable to RMP, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the cost of equity for Rocky Mountain Power?

A. Figure 1 summarizes the range of results produced by the DCF, CAPM, ECAPM, and Risk Premium analyses based on data through the end of January 2023.

[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1 (and in RMP Exhibit 4.2), the range of results produced by the models used to estimate the cost of equity is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies. As a result, my ROE recommendation considers the range of results of the Constant Growth DCF model, as well as the results of the CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses. My ROE recommendation also considers RMP's company-specific risk factors and current and prospective capital market conditions.

Q. Are prospective capital market conditions expected to affect the results of the cost of equity for the Company during the period in which the rates established in this proceeding will be in effect?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.
- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, and since utility stock prices are inversely related to changes in interest rates, it is likely that utility share prices will decline.
- Rating agencies have responded to the risks of the utility sector, with Moody's Investors Service ("Moody's") most recently indicating its outlook for the industry in 2023 is "negative", citing increasing interest rates, inflation and high natural gas prices, all of which create pressure for customer affordability and prompt rate recovery.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.
- Consequently, the results of the DCF model, which relies on current utility share prices, is likely to understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for RMP.

Q. Is Rocky Mountain Power's requested capital structure reasonable and appropriate?

A. Yes. Comparing the Company's proposed equity ratio of 51.27 percent to the proxy group demonstrates that the Company's requested equity ratio is well within the range of equity ratios for the proxy group, and slightly below the average equity ratio. Further, the Company's proposed equity ratio is reasonable considering that credit rating agencies have identified the outlook for the utility sector as "negative" due to the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and commodity costs, and the pressure that those factors place on customer affordability and utilities' prompt rate recovery.

IV. REGULATORY PRINCIPLES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The United States ("U.S.") Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's authorized ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[3]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. In Docket No. 20000-ER-03-198, RMP's 2003 rate case, the Commission stated that:

> Consistent with the discretion given to the Commission in examining cases and reaching a just result (discussed generally, infra), there are no precise bases in Wyoming law to guide the Commission in determining a utility's rate of return on equity. Therefore, the Commission must apply its informed judgment to all of the evidence in the case. In this traditional rate-base rate-of-return case, the Commission must determine the cost of capital, and we are guided by the earnings and

[3] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> capital attraction standards of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U. S. 679 (1923); and Federal Power Comm'n v. Hope Natural Gas Co., 320 U. S. 391 (1944); accepted in Wyoming in In re Northern Utilities, 70 Wyo. 275, 249 P.2d 769 (Wyo. 1952). A public utility remains entitled to rates which will permit it a reasonable opportunity to earn a return on its investment properly reflecting the risk of the business and which will reasonably preserve the financial soundness of the company and allow it to raise the capital needed to provide service in the public interest. Having said that, we also acknowledge that the measurement of the required level of return is not a matter of simple mathematics but is a matter requiring judgment and the employment of discretion. The United States Supreme Court, in Hope, supra, noted that a "just and reasonable end result" is the desired outcome and that it is the end reached, rather than the method employed in achieving it, that should control.[4]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for RMP, including the principle that an allowed rate of return must be sufficient to enable regulated companies like RMP to attract capital on reasonable terms.

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. A return that is adequate to attract capital at reasonable terms enables the utility to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost. To the

[4] *In the Application of PacifiCorp for a Retail Electric Utility Rate Increase of $41.8 Million Per Year,* Docket No. 20000-ER-03-198 (Record No. 8310), Order at 13 (Feb. 28, 2004).

extent the Company has the opportunity to earn its market-based cost of capital, a reasonable balance will be achieved between customers' and shareholders' interests.

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric and natural gas utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, over the same time period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other electric and natural gas utilities can inhibit the utility's ability to attract capital for investment.

Q. Is the regulatory framework and the authorized ROE and equity ratio, important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically, regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The models used to estimate the cost of equity rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE and the recommended ROE for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q. What effect do current and prospective market conditions have on the cost of equity for RMP?

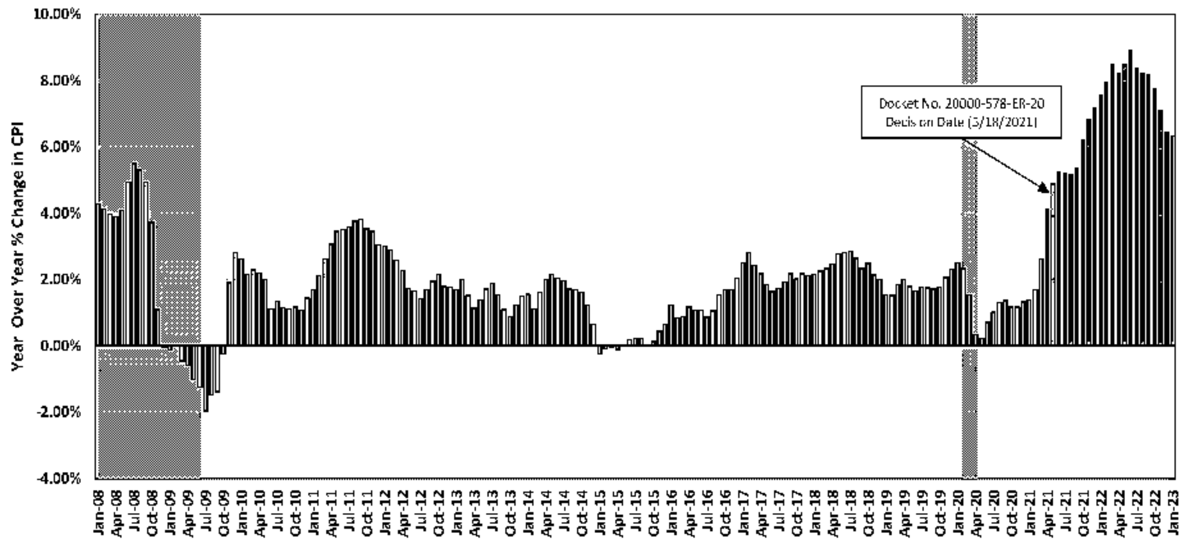
A. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation, and the Federal Reserve's changes in monetary policy contribute to an expectation of increased market risk and an increase in the cost of the investor-required return. It is essential that these factors be considered in setting the forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased significantly from pandemic-related lows seen in 2020, are expected to continue to remain relatively high in direct response to the Federal Reserve's use of monetary policy to combat inflation. Since there is a strong historical inverse correlation between interest rates and the share prices of utility stocks, it is reasonable to expect that utility investors' cost of equity is increasing (*i.e.*, as utility share prices decline, utility dividend yields increase). Because the cost of equity in this proceeding is being estimated for the future period that the Company's rates will be in effect, and because the cost of equity is expected to increase over the near term for utilities, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, will likely understate the cost of equity during the future period that the Company's rates will be in effect.

A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q. Has inflation increased significantly over the past year?

A. Yes. As shown in Figure 2, the year-over-year ("YOY") change in the Consumer Price Index ("CPI") published by the Bureau of Labor Statistics has increased steadily since the beginning of 2021, rising from 1.37 percent in January 2021 to reaching a YOY change high of 9.0 percent in June 2022, which was the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008. As shown in Figure 2, since that time, while inflation has declined in response to the Federal Reserve's monetary policy, inflation continues to remain elevated.

Figure 2: YOY Percent Change in the Consumer Price Index, January 2008 – January 2023[5]



Q. What are the expectations for inflation over the near-term?

A. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level over at least the next year and that it will continue to increase short-term interest rates to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in February 2023 anticipated further increases in the federal funds rate, and observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target:

> We continue to anticipate that ongoing increases will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> . . . . .
>
> Inflation remains well above our longer-run goal of 2 percent. Over the 12 months ending in December, total PCE prices rose 5.0 percent; excluding the volatile food and energy categories, core PCE prices rose 4.4 percent. The inflation data received over the past three months show a welcome reduction in the monthly pace of increases. And while recent developments are encouraging, we will need substantially more evidence to be confident that inflation is on a sustained downward path.
>
> . . . . .

[5] Bureau of Labor Statistics, shaded area indicates a recession.

> With today's action, we have raised interest rates by 4-1/2 percentage points over the past year. We continue to anticipate that ongoing increases in the target range for the federal funds rate will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> .....
>
> At the December meeting, we all wrote down our best estimates of what we thought the ultimate level would be [of the federal funds rate], and that's obviously back in December. And the median for that was between five and five and a quarter percent. At the March meeting, we're going to update those assessments. We did not update them today. We did, however, continue to say that we believe ongoing rate hikes will be appropriate to attain a sufficiently restrictive stance of policy to bring inflation back down to 2 percent. We think we've covered a lot of ground, and financial conditions have certainly tightened. I would say we still think there's work to do there. We haven't made a decision on exactly where that will be. I think, you know, we're going to be looking carefully at the incoming data between now and the March meeting and then the May meeting. I don't feel a lot of certainty about where that will be. It could certainly be higher than we're writing down right now. If we come to the view that we need to write down to -- you know, to move rates up beyond what we said in December we would certainly do that. At the same time, if the data come in, in the other direction then we'll -- you know, we'll make data-dependent decisions at coming meetings, of course.[6]

B. The Use of Monetary Policy to Address Inflation

Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. As of the FOMC meeting on January 31 and February 1, 2023, the Federal Reserve has taken the following actions:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[7]

[6] Transcript, Chair Powell Press Conference, Feb. 1, 2023; clarification added.

[7] Federal Reserve Bank of New York, https://www.newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.

- Increased the target federal funds rate beginning in March 2022 through a series of increases from a target range of 0.00 to 0.25 percent to a target range of 4.50 percent to 4.75 percent;[8]
- Anticipates ongoing increases in the target range will be appropriate to achieve its goals of maximum employment at the inflation rate of 2.00 percent over the long-run;[9]
- Began reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022.[10] The Federal Reserve is reducing the size of its balance sheet by only reinvesting principal payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury securities, the cap is currently set at $60 billion per month. The cap for mortgage-backed securities is currently set at $35 billion per month.[11]

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q. What effect will inflation and the Federal Reserve's normalization of monetary policy have on long-term interest rates?

A. Inflation and the Federal Reserve's normalization of monetary policy are expected to result in long-term interest rates remaining relatively high over at least the next year. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect inflation to remain relatively high, they will require higher yields to compensate for the increased risk of inflation, which means interest rates will also remain relatively high.

[8] Press Releases, Federal Reserve (Mar. 16, 2022); Transcript, Chair Powell Press Conference, Feb. 1, 2023.
[9] Transcript, Chair Powell Press Conference, Feb. 1, 2023.
[10] Press Release, Federal Reserve (May 4, 2022).
[11] Press Release, Federal Reserve, Plans for Reducing the Size of the Federal Reserve's Balance Sheet (May 4, 2022).

Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A. Yes. At the FOMC meetings throughout 2022 and thus far into 2023, the Federal Reserve has continued to note its concerns over the sustained increased levels of inflation and has continued to accelerate the process of normalizing monetary policy to combat inflation. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bond has more than doubled, increasing from 1.47 percent on December 15, 2021 to 3.52 percent on January 31, 2023. Further, interest rates have increased nearly 200 bps since the Company's last rate determination. The increase is due to the Federal Reserve's announcements at each of the meetings since December 2021 and the continued elevated levels of inflation.

Figure 3: 10-Year Treasury Bond Yield, January 2021 – January 2023[12]

Q. What have equity analysts said about long-term government bond yields?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the end of 2023. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.50 percent through the first quarter of 2024.[13]

[12] S&P Capital IQ Pro.
[13] Blue Chip Financial Forecasts, Vol. 42, No. 2, Feb. 1, 2023.

Q. Do recent changes in the Gross Domestic Product ("GDP") affect the current outlook for inflation and interest rates?

A. No. While FOMC participants have recently reduced their projections for economic activity for real GDP growth to 0.5 percent in 2023,[14] which is well below the median estimate for the longer-run normal GDP growth rate, the Federal Reserve has highlighted that the labor market continues to be extremely tight, and in fact, the unemployment rate reached 3.4 percent in January 2023, the lowest it has been in over 50 years.[15] Therefore, with a tight labor market and persistently high inflation, the Federal Reserve has indicated its need to continue a restrictive monetary policy to moderate demand to better align it with supply.[16]

Q. How have interest rates and inflation changed since the Company's last rate case?

A. As shown in Figure 4, when the Commission authorized an ROE of 9.50 percent in the Company's 2020 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 2.30 percent and inflation was 4.94 percent. However, since the Company's last rate proceeding, long-term interest rates have increased 1.5 times, and, as discussed, inflation is also substantially higher.

[14] FOMC, Summary of Economic Projections, Dec. 14, 2022.
[15] Lucia Mutikani, *U.S. reports blowout job growth; unemployment lowest since 1969*. Reuters (Feb. 3, 2023).
[16] Transcript, Chair Powell, Press Conference, Dec. 14, 2022.

Figure 4: Change in Market Conditions Since RMP's Last Rate Case[17]

Docket	Decision Date	Federal Funds Rate	30-Day Average Of 30-Year Treasury Bond Yield	Inflation Rate	Authorized ROE
20000-578-ER-20	5/18/2021	0.06%	2.30%	4.94%	9.50%
Current	1/31/2023	4.33%	3.70%	6.35%	

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[18]

Q. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A. Equity analysts project that utilities will underperform the broader market given the increases in interest rates. Fidelity classifies the utility sector as underweight,[19] and *Morningstar* recently noted that many of the market conditions that supported the premium

[17] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.
[18] Justina Lee, *Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks*. Bloomberg.com (Mar. 11, 2021).
[19] Fidelity, *First Quarter 2023 Investment Research Update*. (Feb. 8, 2023).

valuation of utilities over the last decade mainly low inflation, interest rates and energy prices are currently reversing:

> Utilities' relative outperformance in 2022 while the market frets about the economy suggests that utilities remain a defensive haven. Utilities also outperformed ahead of the 2001 and the 2007-09 recessions. However, we think utilities' weak total returns in 2022 should concern investors. For the first time in a decade, the tailwinds supporting utilities' earnings growth and premium valuations (low inflation, low interest rates, and low energy price) are reversing
>
> Utilities' growth prospects are our biggest concern going into 2023. Utilities no longer offer a yield premium as bond yields climbed to their highest level in 15 years. Without that yield premium, the only advantage utilities offer investors is earnings growth. This is why high inflation and rising interest rates loom large for utilities in 2023. Inflation, including higher energy prices, will raise customer bills and could force utilities to re-evaluate their growth plans. Higher interest costs will sap cash flow and make infrastructure investments more expensive.[20]

Additionally, the *Wall Street Journal* noted that the S&P Utilities Index was down 14 percent between September and October 2022, attributing the decline to the recent increase in long-term treasury yields:

> A big draw of utility stocks has become less attractive as interest rates have climbed. Utility stocks are known for their sizable dividends, offering investors a regular stream of income. Companies in the S&P 500 utilities sector offer a dividend yield of 3.3%, among the highest payout percentages in the index, according to FactSet.
>
> But the outsize dividends of utility stocks are no match for climbing bond yields. The yield on the benchmark 10-year Treasury note finished above 4% on Monday for a second consecutive session. Friday marked the 10-year yield's first close above the 4% level since 2008 and 11 straight weeks of gains. Treasurys are viewed as essentially risk-free if held to maturity.
>
> "The 10-year is repricing everything. I've got something that's even safer and yields even more," said Kevin Barry, chief investment officer at Summit Financial, comparing Treasurys and utility stocks.[21]

[20] Travis Miller, *Can Utilities Maintain Growth Against Macroeconomic Headwinds?* Morningstar (Jan. 3, 2023).
[21] Hannah Miao, *Utility Stock stumble as treasury yields climb*. The Wall Street Journal (Oct. 18, 2022).

Similarly, Barron's noted that the decline in share prices can be attributed to the relatively high valuations and low dividend yields of utilities as compared to other asset classes such as Treasuries.[22] According to Barron's, even after the recent decline in share prices, the Utilities Select ETF was yielding 2.85 percent, which is a yield that will not "lure in buyers when the ultrasafe 10-year Treasury note yields close to 4%."[23] Therefore, Barron's currently recommends not buying utility stocks.

Q. Why do equity analysts expect the electric utility sector to underperform over the near-term?

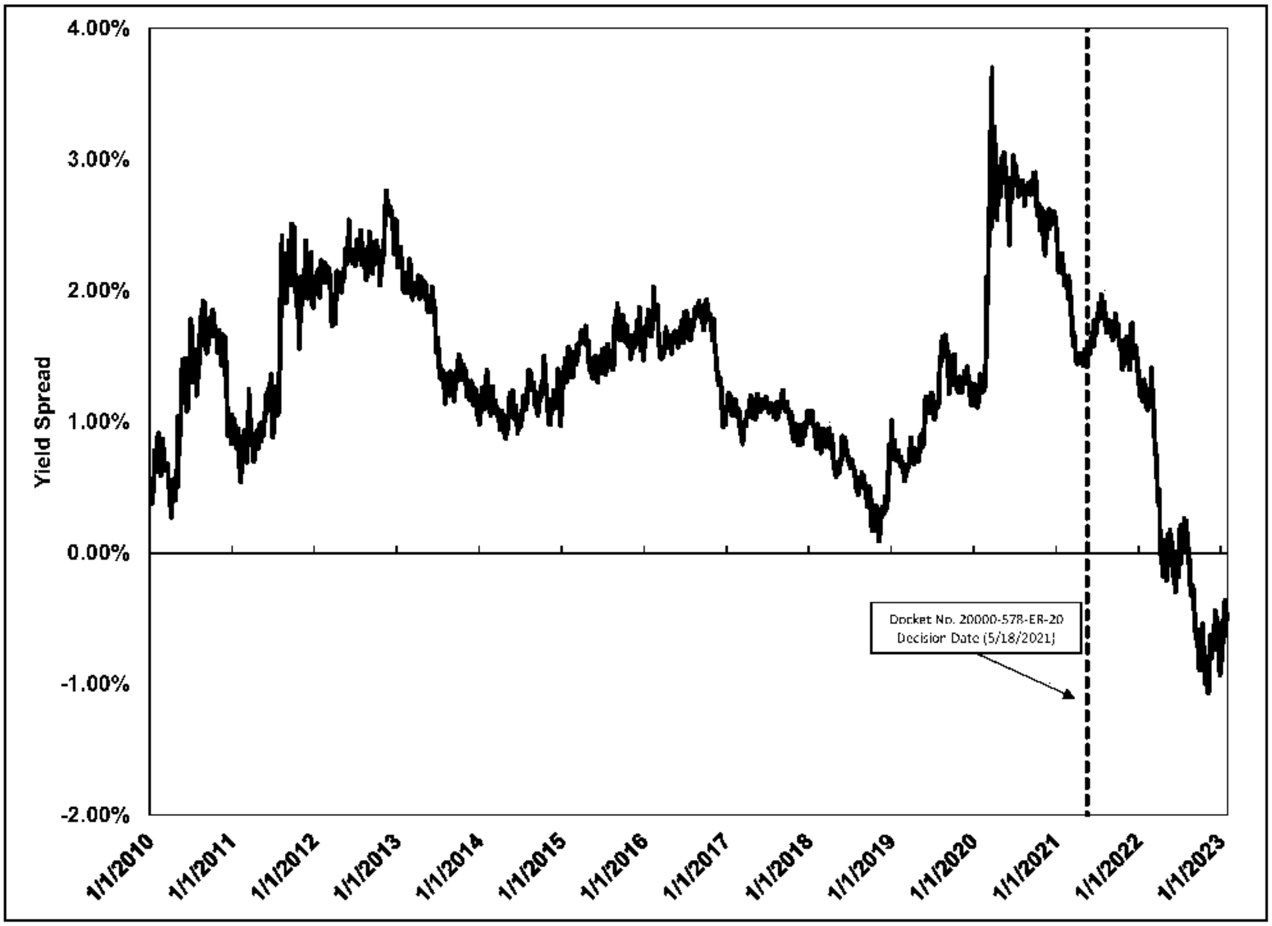
A. While interest rates have increased substantially over the past year, the valuations of utilities have remained elevated and have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through January 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds. As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of January 31, 2023 is -0.49 percent. However, the long-term average yield spread from 2010 to 2023 is 1.36 percent. Therefore, the current yield spread is well below the long-term average, and well below the yield spread at the time of the Company's last rate proceding. This means that investors can earn higher yields on

[22] Jacob Sonenshine, *Utilities Stocks Have Fallen off a Cliff. They Just Got Downgraded, Too.* Barron's (Oct. 17, 2022).
[23] *Id.*

Treasury bonds than on the S&P Utility Index, which is a higher risk investment in equities. It is rational to expect that investors will rotate into Treasuries from utilities if they can achive higher yields at lower risk. This suggests that using historical prices in the DCF model may understate the COE over the period that RMP's rates will be in effect.

For further context as to how unlikely it is to have a yield spread of -0.49 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of -0.49 percent has a z-score of -2.51, indicating that a yield spread of -0.49 percent is over 2 standard deviations from the mean of 1.36 percent. In other words, 95 percent of the daily yield spread observations from 2010 to 2023 fall between -0.11 percent and 2.83 percent and the current yield spread of -0.49 percent is outside of that range. Thus, the current yield spread could be considered an outlier, which is why equity analysts do not expect this current level to hold. Since long-term bond yields are expected to remain elevated at current levels over the near-term, equity analysts expect utilities to underperform, and thus the dividend yields for utilities will increase. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – January 2023[24]



Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A. If interest rates remain relatively high as expected, then the share prices of utilities, which have been strong in 2022 relative to the market, would be expected to decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity.

[24] S&P Capital IQ Pro and Bloomberg Professional.

Q. Have regulatory commissions acknowledged that the DCF model might understate the COE given current capital market conditions?

A. Yes. For example, in its May 2022 decision in establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") specifically concluded that the current capital market conditions of high inflation and increasing interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[25]

[25] *Penn. Pub. Util. Comm'n et.al. v. Aqua Penn. Wastewater Inc.*, Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order at 154–155 (May 12, 2022).

. . . . .

> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[26]

E. Conclusion

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for RMP?

A. Through 2023, investors expect long-term interest rates to remain relatively high in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already substantially greater than utility stock dividend yields, the share prices of utilities will likely decline, which is the reason a number of equity analysts have classified the utility sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

[26] *Id.*, at 177–178.

VI. PROXY GROUP SELECTION

Q. Please provide a brief profile of RMP.

A. RMP is an electric utility, which is an indirect, wholly owned subsidiary of BHE. PacifiCorp provides electric utility service to approximately 2.0 million residential, commercial and industrial customers in California, Idaho, Oregon, Utah, Washington and Wyoming.[27] In Wyoming, RMP provides electric service to approximately 150,000 residential, commercial, and industrial customers.[28] As of December 31, 2021, RMP owned net utility electric plant in Wyoming of approximately $2.76 billion.[29] RMP's electric operations in Wyoming represented 15 percent of PacifiCorp's electric sales in 2021.[30] PacifiCorp currently has a long-term rating of A (Outlook: Stable) from S&P and A3 (Outlook: Stable) from Moody's.[31]

Q. Why have you used a proxy group of publicly traded companies to estimate the cost of equity for the Company?

A. One of the purposes of this proceeding is to estimate the cost of equity for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because RMP's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if the Company was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a

[27] Berkshire Hathaway Energy Co, 2021 Form 10-K at 3.
[28] Direct Testimony of Gary W. Hoogeveen.
[29] Rocky Mountain Power Company, 2021 Annual Report to the Wyoming Public Service Commission, at 6 & 8.
[30] Berkshire Hathaway Energy Co., 2021 (Annual Report Form 10-K) at 3 (Dec. 31, 2021).
[31] PacifiCorp local currency LT issuer rating, S&P Global and Moody's.

proxy group is that it moderates the effects of unusual events that may be associated with any one company. The companies included in the proxy group all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for RMP.

Q. How did you select the companies included in your proxy group?

A. I began with the group of 36 companies that *Value Line* classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends because such companies cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- own regulated generation assets;
- derive at least 40 percent of generation from owned generation;
- derive at least 60 percent of the Company's regulated operating income from regulated electric operations;
- derive at least 60 percent of the Company's operating income from regulated operations; and
- were not party to a merger or transformative transaction during the analytical period considered.

Q. Did you exclude any other companies from the proxy group?

A. Yes. I excluded Hawaiian Electric Industries, Inc. ("HE") on the basis that its operations are concentrated on the islands of Hawaii, and therefore, the company faces geographic concentration risk for both its regulated and substantial unregulated operations not applicable to the other utilities considered. As HE noted in its 2021 Form10-K:

> The Company is subject to the risks associated with the geographic concentration of its businesses and current lack of interconnections that

> could result in service interruptions at the Utilities or higher default rates on loans held by ASB [American Savings Bank].[32]

The increased risk of service interruptions resulting from HE's geographic location that could result in revenue loss and increased costs is a risk unique to HE and would not apply to utilities located on the U.S. mainland. Furthermore, HE's unregulated operations, which represent approximately 33 percent of the company's operation income in 2021 are concentrated in the banking sector through the ownership of American Savings Bank ("ASB").[33] ASB also only operates on Hawaii; thus, all of the company's consumer and commercial loans are to customers on Hawaii. If Hawaii were to face an adverse economic or political event, ASB could face severe financial effects given the company's geographic concentration in Hawaii.[34] As a result, I have excluded HE from my proxy group considering HE's unique geographical risks.

Q. What is the composition of your proxy group?

A. My proxy group consists of the 17 companies shown in Figure 6.

[32] Hawaii Electric Industries, Inc., 2021 Form 10-K, at 23.
[33] *Id.*, at 86.
[34] *Id.*, at 20.

Figure 6: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation[35]	OTTR
Portland General Electric	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

[35] Otter Tail Corporation had one year of anomalous financial results, causing their operating income from regulated electric operations to fall below 70 percent (Page 4 of Otter Tail's 2021 10-K states, "Our 2021 earnings mix was impacted by significantly higher earnings in our Plastics segment as unique supply and demand conditions during the year in the PVC pipe industry led to earnings levels not previously experienced. We expect our earnings mix to return back to our targeted 70% from the Electric segment and 30% from Manufacturing and Plastics segment over the long term as this industry conditions subside." Given these anomalous conditions, Otter Tail was included in the proxy sample.

Q. How is the required cost of equity determined?

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company in the context of the proxy group, in particular.

Q. What methods did you use to establish your recommended ROE in this proceeding?

A. I considered the results of the constant growth DCF model, the CAPM, the ECAPM, and the Bond Yield Plus Risk Premium approach. As discussed in more detail below, a reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. Is it important to use more than one analytical approach to estimate the cost of equity?

A. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many wellregarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[36] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[37] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. Do current market conditions support your reliance on more than one analytical approach?

A. Yes. As I discussed above, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. The benefit of using multiple models is that each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. As discussed previously, the CAPM and Bond Yield Plus Risk Premium method address effect of expected changes in interest rates, whereas the effect of changes in interest rates particularly the recent increase in interest rates may not be captured as well in the DCF model at this time. Therefore, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

Q. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A. Yes. It is my understanding that the Commission has emphasized that "[t]he determination of cost of capital in rate proceedings, as noted above, combines economic science, economic art and sound judgment as to what yields the most reasonable result."[38]

[36] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[37] Eugene Brigham and Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994) at 341.

[38] Docket No. 20000-ER-03-198 (Record No. 11573), Order, at ¶ 34 b1 (Feb. 28, 2004).

Moreover, in Docket No. 20000-ER-02-184, the Commission concluded that the ROE should not be set based on one specific model or a variation of a specific model and encouraged the evolution of economic thought be presented in future cases.[39]

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To

[39] Docket No. 20000-ER-02-184 (Record No. 10469), Order, at ¶ 260 (March 6, 2003).

the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data do you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended January 31, 2023.

Q. Why do you use 30-, 90-, and 180-day averaging periods?

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to consider a variety of sources in arriving at a singular long-term earnings growth rate for the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Yahoo! Finance; and (3) *Value Line*.

Q. How did you calculate the range of results for the Constant Growth DCF Models?

A. I calculated a low end result for my DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the Zacks, Yahoo Finance, and Value Line projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. The mean results were calculated using the average growth rate from all three sources for each proxy group company.

Q. What are the results of your DCF analyses?

A. Figure 7 summarizes the results of my DCF analyses. As shown in Figure 7, the mean DCF results using the average growth rates range from 9.40 percent to 9.54 percent, and the mean results using the maximum growth rates range from 10.39 percent to 10.53 percent.

While I also summarize the DCF results using the minimum growth rates, given the expected underperformance of utility stocks going forward and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 7: Discounted Cash Flow Results

Constant Growth DCF			
	Mean using Low Growth Rate	Mean using Average Growth Rate	Mean using High Growth Rate
30-Day Average	8.11%	9.40%	10.39%
90-Day Average	8.25%	9.54%	10.53%
180-Day Average	8.14%	9.44%	10.42%
Average	8.17%	9.46%	10.45%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the DCF models is a constant price-to-earnings ratio. That assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF models with caution. Therefore, while I have given weight to the results of the Constant Growth DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

C. CAPM Analysis

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required market ROE;

β = beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term (r_m – r_f) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate do you use in your CAPM analysis?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds, which is 3.71 percent;[40] (2) the average projected 30-year

[40] Bloomberg Professional, as of Jan. 31, 2023.

Treasury bond yield for the second quarter of 2023 through the second quarter of 2024, which is 3.82 percent;[41] and (3) the average projected 30-year Treasury bond yield for 2024 through 2028, which is 3.90 percent.[42]

Q. What beta coefficients do you use in your CAPM analysis?

A. As shown on RMP Exhibit 4.5, I use the beta coefficients for the proxy group companies as reported by Bloomberg and *Value Line*. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated using five years of weekly returns relative to the New York Stock Exchange ("NYSE") Composite Index. Additionally, as shown on RMP Exhibit 4.5 and RMP Exhibit 4.6, I also considered an additional CAPM analysis that relies on the long-term average beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2022.

Q. How do you estimate the market risk premium in the CAPM?

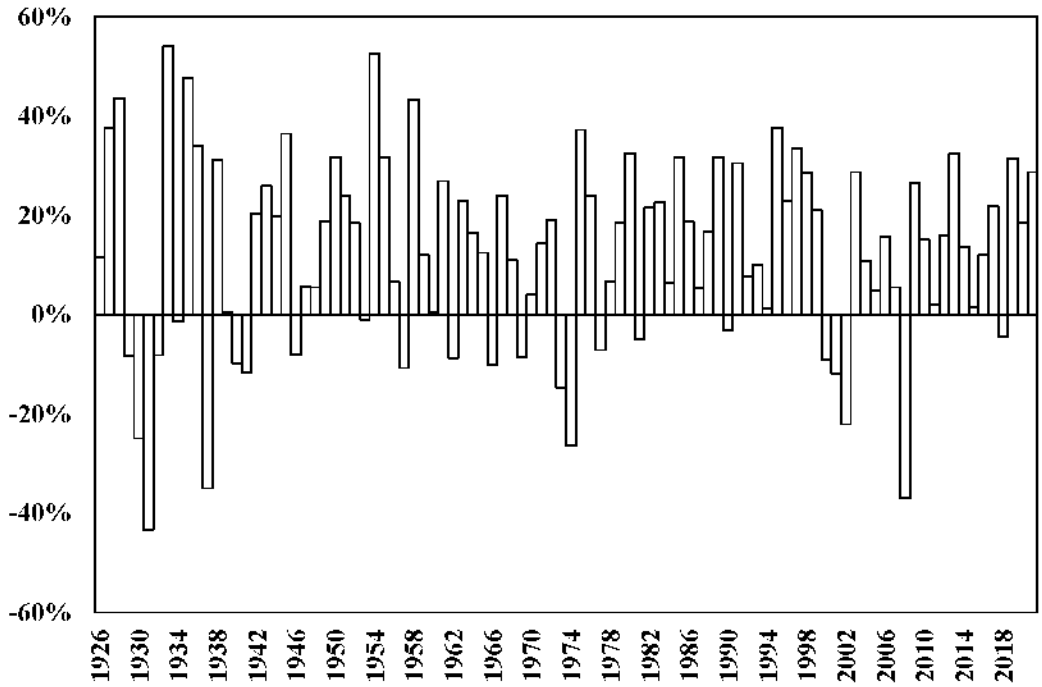
A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in RMP Exhibit 4.7, the expected market return is calculated using the constant growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.75 percent and a weighted long-term growth rate of 10.65 percent, the estimated required market return for the S&P 500 Index as of January 31, 2023 is 12.50 percent. Based on the three risk-free rates considered, the market risk premium ranges from 8.60 percent to 8.79 percent.

[41] Blue Chip Financial Forecasts, Vol. 42, No. 2, Feb. 1, 2023, at 2.
[42] Blue Chip Financial Forecasts, Vol. 41, No. 12, Dec. 2, 2022, at 14.

Q. How does the current expected market return compare to observed historical market returns?

A. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.50 percent is not unreasonable. As shown, in 50 out of the past 96 years (or roughly 52 percent of observations), the realized equity market return was at least 12.50 percent or greater.

Figure 8: Realized U.S. Equity Market Returns (1926-2021)[43]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM analysis in estimating the cost of equity for RMP.[44] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model

43 Depicts total annual returns on large company stocks, as reported in the 2022 Kroll SBBI Yearbook.

44 *See, e.g.,* Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 189.

then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE
β = Adjusted Beta coefficient of an individual security
r_f = the risk-free rate of return
r_m = the required return on the market as a whole

In essence, the ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[45]

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier used as the risk-free rate, and the current Bloomberg and *Value Line* and long-term *Value Line* beta coefficients.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 9 (*see* also RMP Exhibit 4.5), my traditional CAPM analysis produces a range of returns from 10.33 percent to 11.38 percent, and the ECAPM analysis results range from 10.87 percent to 11.66 percent.

[45] *Id.*, at 191.

Figure 9: CAPM and ECAPM Results

	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
	CAPM		
Value Line Beta	11.36%	11.37%	11.38%
Bloomberg Beta	10.77%	10.79%	10.81%
Long-term Avg. Beta	10.33%	10.36%	10.38%
	ECAPM		
Value Line Beta	11.64%	11.65%	11.66%
Bloomberg Beta	11.20%	11.22%	11.23%
Long-term Avg. Beta	10.87%	10.89%	10.91%

D. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. In other words, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for vertically integrated electric companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs for electric utilities serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[46]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those authorizations as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 10, from 1992 through January 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year Treasury bonds)

a = intercept term

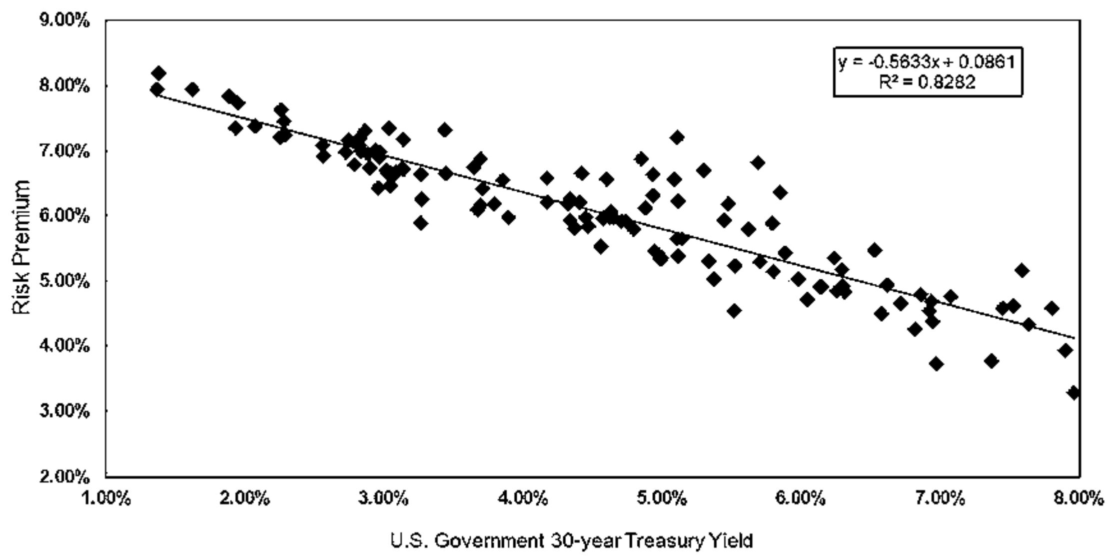
b = slope term

[46] See e.g., S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March 1998) (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, Spring 1986, at 66.

T = 30-year Treasury bond yield

Data regarding authorized ROEs were derived from all vertically integrated electric rate cases from 1992 through January 2023 as reported by Regulatory Research Associates ("RRA").[47] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 10: Risk Premium Regression Analysis



Q. What are the COE estimates that result from this equation?

A. As shown in RMP Exhibit 4.8, based on the current 30-day average of the 30-year Treasury bond yield, the risk premium would be 6.52 percent, resulting in an estimated cost of equity of 10.23 percent. Based on the consensus estimate of the near-term (*i.e.*, Q2/2023 – Q2/2024) projected 30-year Treasury bond yield (*i.e.*, 3.82 percent), the risk premium would be 6.46 percent, resulting in an estimated cost of equity of 10.28 percent. Based on a consensus estimate of the longer-term (*i.e.*, 2024 – 2028) projection of the 30-year

[47] This analysis began with over 1,441 cases and was screened to eliminate limited issue rider cases, transmission-only cases, distribution-only cases and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data from 704 cases.

Treasury bond yield (*i.e.*, 3.90 percent), the risk premium would be 6.42 percent, resulting in an estimated cost of equity of 10.32 percent.

Q. How did the results of the Bond Yield Plus Risk Premium analysis inform your recommended ROE for Rocky Mountain Power?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE range for the Company. As noted, investors consider the authorized ROE of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the U.S.

VIII. REGULATORY AND BUSINESS RISKS

Q. Taken alone, do the results from the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range for the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Capital Expenditures

Q. Please summarize PacifiCorp's capital expenditure requirements.

A. PacifiCorp's current projections for 2023 through 2027 include approximately $20.8 billion in capital investments for the period.[48] Based on PacifiCorp's net utility plant of

[48] Data provided by PacifiCorp for Capital Expenditures 2023-2027.

approximately $21.1 billion as of June 30, 2022, the $20.8 billion anticipated capital expenditures are approximately 98.6 percent.[49]

Q. How is PacifiCorp's risk profile affected by its capital expenditure requirements?

A. As with any utility facing increased capital expenditure requirements, PacifiCorp's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[50]

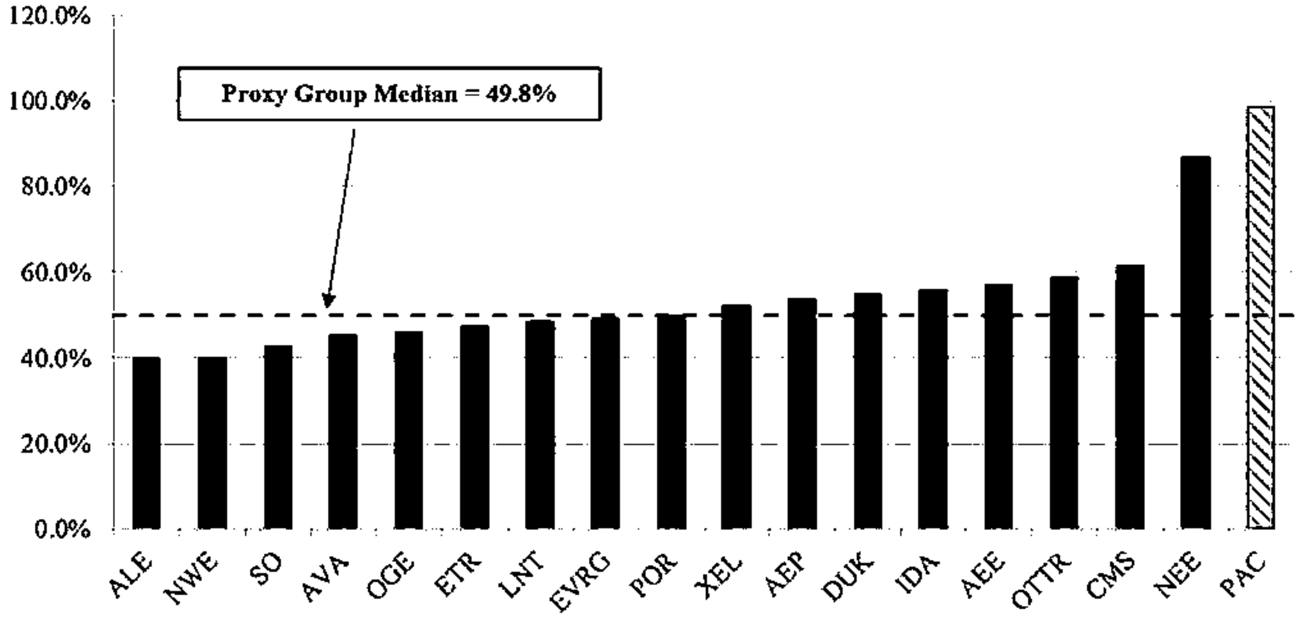
[49] Data provided by PacifiCorp.
[50] S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 7 (Aug. 10, 2016).

While RMP is not currently rated by the credit rating agencies, the Company's business risk is also increased as a result of elevated capital expenditures. Therefore, to the extent that the Company's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, it will face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do PacifiCorp's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in RMP Exhibit 4.9, I calculated the ratio of expected capital expenditures to net utility plant for PacifiCorp and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2023-2027 by its total net utility plant as of December 31, 2022. As shown in RMP Exhibit 4.9 (*see* also Figure 11 below), PacifiCorp's ratio of capital expenditures as a percentage of net utility plant of 98.6 percent is approximately 1.98 times the median for the proxy group companies of 49.78 percent. This result indicates greater risk relative to the companies in the proxy group.

Figure 11: Comparison of Capital Expenditures - Proxy Group Companies



Q. Does RMP have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. No. RMP does not recover capital investment costs between rate cases utilizing a capital tracking mechanism. RMP has received approval for deferral accounting treatment of certain generation investments to minimize regulatory lag; however, RMP still depends on rate case filings for all capital cost recovery. Increased capital expenditure programs like RMP's often receive cost recovery through capital trackers in other jurisdictions. As shown in RMP Exhibit 4.10, 69.41 percent of the proxy group utilities recover costs through capital tracking mechanisms. Since RMP currently does not have a capital tracking mechanism to recover its significant capital expenditure costs, RMP's risk relative to the proxy group is significantly increased.

Q. What are your conclusions regarding the effect of the PacifiCorp's capital spending requirements on its risk profile and cost of capital?

A. PacifiCorp's capital expenditure requirements as a percentage of net utility plant are increasing and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, RMP does not have a comprehensive capital tracking mechanism to recover projected capital expenditures. Therefore, RMP's plans for increased capital expenditures and limited ability to recover the capital investment on an as-incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

B. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally-generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Both Moody's and S&P consider the overall regulatory framework in establishing credit ratings. Specifically, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[51]

[51] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[52] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[53]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[54] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[55]

[52] Standard & Poor's Global Ratings, Ratings Direct, *U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others*, at 2 (June 25, 2018).
[53] *Id.*, at 1.
[54] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, at 6 (June 23, 2017).
[55] *Id.*

Q. Have you conducted any analysis of the regulatory framework in Wyoming relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Wyoming considering three factors which are important to ensuring RMP maintains access to capital at reasonable terms. As I will discuss in more detail below, the three factors are: (1) cost recovery mechanisms which allow a utility to recover costs in a timely manner between rate cases and provide the utility the opportunity to earn its authorized return; (2) comparable return standard because an awarded ROE that is significantly below the ROEs awarded to other utilities with comparable risks can affect the ability of a utility to attract capital at reasonable terms; and (3) the ability of the Company to earn its authorized ROE because while an authorized ROE may be consistent with the authorized ROEs of other comparable vertically integrated electric utilities, if the Company is unable to earn its authorized ROE, RMP's ability to attract capital at reasonable terms could be affected. The results of these analyses demonstrate that RMP has greater regulatory risk relative to the proxy group.

1. Cost Recovery Mechanisms

Q. Have you conducted any analysis to compare the cost recovery mechanisms of Wyoming to the cost recovery mechanisms approved in the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A. Yes. I selected four mechanisms that are important to provide a regulated utility an opportunity to earn its authorized ROE. These are: (1) fuel cost recovery; (2) test year convention (*i.e.*, forecast vs. historical); (3) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and (4) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in RMP Exhibit 4.10) and are summarized below.

- Fuel and Energy Cost Recovery: RMP has an Energy Cost Adjustment Mechanism ("ECAM") to recover power costs. Under this mechanism, only 80 percent of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates.[56] As a result, the ECAM does not fully mitigate the power cost risk for RMP.[57] RMP is proposing in this proceeding to recover the full cost of fuel and power costs. As shown in Exhibit 4.10, the full recovery of power costs is consistent with the recovery mechanisms that are relied on by the majority of the proxy group operating companies. According to S&P Capital IQ Pro, there are only eight states (*i.e.*, Arizona, Idaho, Missouri, Montana, Oregon, Vermont, Washington and Wyoming) that have fuel cost recovery mechanisms with sharing bands.[58] The remaining 42 states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs. Finally, 88.24 percent of the operating companies held by my proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands and sharing bands.
- To the extent that RMP's request to fully recover all power costs were not to be approved, this would result in higher overall business and financial risk as compared with the proxy group. Fuel and purchased power costs typically account for 50 - 60 percent of the total operating costs for a regulated utility.

[56] Berkshire Hathaway Energy Company, 2021 Form 10-K, at 41.
[57] *Id.*
[58] Source: S&P Capital IQ Pro, Commission Profiles as of January 31, 2023.

Therefore, a mechanism that does not provide for full recovery of these costs increases the financial risk for the Company.

- Test year convention: RMP has been able to use a test year containing forecasted data, which is generally consistent with 48.24 percent of the operating companies held by the proxy group that provide service in jurisdictions that use a fully or partially forecast test year.
- Volumetric Risk: RMP does not have protection against volumetric risk in Wyoming. In contrast, 58 percent of the operating companies held by the proxy group have some form of protection against volumetric risk through either a partial or full revenue decoupling mechanism that mitigates the effect of fluctuations in volume on revenues.
- Capital Cost Recovery: As discussed above, RMP does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, 69.41 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

2. Earned ROE

Q. Is there evidence that RMP has been unable to earn its authorized return on equity?

A. Yes. As shown in Figure 12, RMP has under-earned its authorized ROE in each year since 2017. Over this period, the Company's average earned ROE was 8.70 percent as compared with the average authorized ROE of 9.50 percent, for an average under-earning of 80 basis points per year. This under-earning is due in part to the regulatory environment in Wyoming where, as discussed above, a limited number of adjustment mechanisms have historically been available to utilities. While the Company relies on a test year that contains forecasted data, the Company does not have protection against volumetric risk nor does RMP have a capital cost recovery mechanism to recover capital expenditures costs on a timely basis. The prior under earning and the near-term effect of inflation, highlights the importance of a constructive outcome in the current proceeding so that RMP has the opportunity to earn its authorized ROE.

Figure 12: Earned vs. Authorized ROE

	Earned ROE[59]	**Authorized ROE**	**Earnings differential (bps)**
2017	9.26%	9.50%	(0.24%)
2018	9.23%	9.50%	(0.27%
2019	7.74%	9.50%	(1.76%)
2020	8.60%	9.50%	(0.90%)
2021	8.68%	9.50%	(0.82%)
Average	**8.70%**	**9.50%**	**(0.80%)**

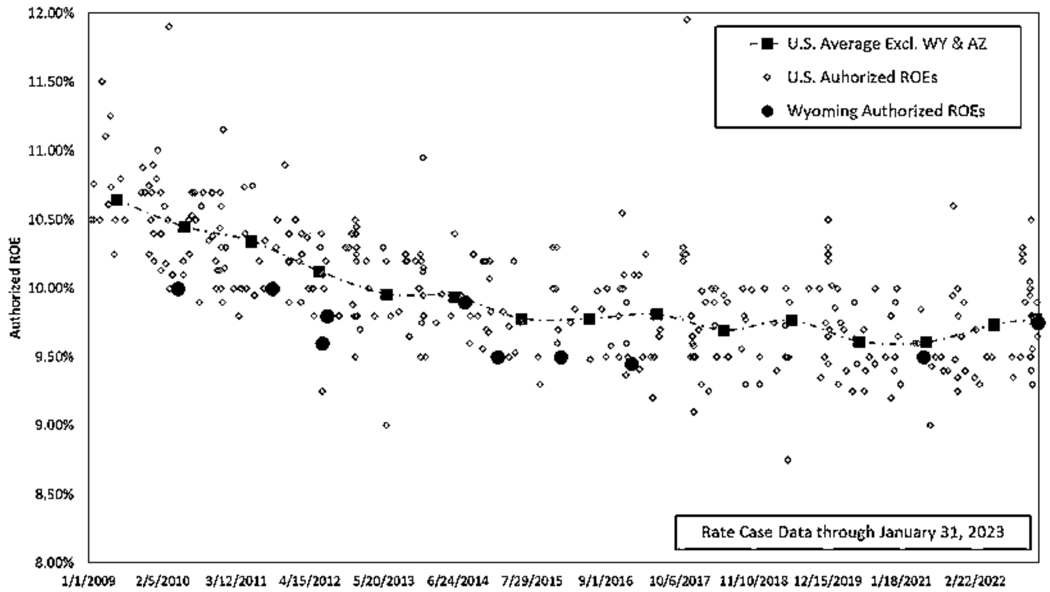
3. Authorized ROEs

Q. How do recent returns in Wyoming compare to the authorized returns in other jurisdictions?

A. The authorized ROEs for electric utilities in Wyoming, while partially the result of settlement agreements approved by the Commission, have been below the average authorized ROEs for vertically integrated electric utilities across the U.S. Figure 13 below shows the authorized returns for vertically integrated electric utilities in other jurisdictions since January 2009, and the returns authorized in Wyoming for electric companies. As shown in Figure 13, the authorized returns for electric utilities in Wyoming have been at the low end of the range produced by the authorized ROEs from other state jurisdictions for 2009 through January 2023.

[59] Rocky Mountain Power Company, Annual Reports to the Wyoming Public Service Commission, 2017-2021.

Figure 13: Comparison of Wyoming and U.S. Authorized Electric Returns



Q. How are credit rating agencies currently viewing the utility sector?

A. Credit rating agencies have indicated that the industry overall has increased risk, has responded with close scrutiny of the financial coverage ratios of the sector, and has a negative outlook on the industry overall for 2023. Therefore, it is critically important to consider these factors and to recognize that the investor-required ROE would be higher today than at the time of Commission decisions in the recent past. As discussed in more detail in Section V, current market conditions demonstrate greater risk than at the time the Commission authorized returns in the recent past.

Q. Do credit rating agencies consider the authorized ROE in the overall risk assessment of a utility?

A. Yes, they do. To the extent that the returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. It is important to consider credit ratings because they affect the overall cost of borrowing, and they act as a signal to equity investors about the risk of investing in the equity of a company. Therefore, lower credit ratings can affect both the cost of debt and equity. Examples of recent credit rating agency responses include ALLETE, Inc., and PNW. Moody's downgraded ALLETE, Inc. from A3 to Baa1 primarily based on the less than favorable outcome in Minnesota Power's last fully litigated rate case in Minnesota which included what Moody's noted was a below average authorized ROE of 9.25 percent.[60] In addition, FitchRatings recently downgraded and maintained a negative outlook for APS and its parent, PNW, following the hearings conducted by the Arizona Corporation Commission ("ACC") in October 2021 regarding APS' current rate case proceeding.[61] While the ACC had not issued a final order in APS' rate case at the time, FitchRatings noted that the developments at the hearing in October indicate a likely credit negative outcome that will negatively affect the financial metrics of both APS and PNW. It is also important to note that both S&P and Moody's downgraded PNW's and APS' credit rating and put the companies on credit watch negative following the Commission's November vote that officially authorized the 8.70 percent ROE.[62]

Q. Are you aware of any utilities whose market data has been affected by adverse rate case developments?

A. Yes, I am. The market has responded negatively to recent returns authorized by the ACC. As noted above, the most recent ROE determination in Arizona was for APS. The Recommended Opinion and Order ("Order") issued in the APS rate proceeding on August 2, 2021, recommended an ROE of 9.16 percent. In October 2021, that recommendation

[60] Moody's Investors Service, Credit Opinion: ALLETE, Inc. Update following downgrade, at 3 (Apr. 3, 2019).

[61] FitchRatings, Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative (Oct. 12, 2021).

[62] *See* S&P Capital IQ and Moody's Investors Service, Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative (Nov. 17, 2021).

was amended to reduce the company's ROE to 8.70 percent. The final ROE that was established for APS was 8.70 percent.[63] The market reacted strongly to the proposed order and subsequent amendment and final decision. Guggenheim Securities LLC, an equity analyst that follows PNW, the parent company of APS, informed its clients that

> [T]he "Arizona Corporation Commission is now confirmed to be the single most value destructive regulatory environment in the country as far as investor-owned utilities are concerned".[64]

S&P Global Market Intelligence ("Regulatory Research Associates") noted that this decision was "among the lowest ROEs RRA had encountered in its coverage of vertically integrated electric utilities in the past 30 years."[65]

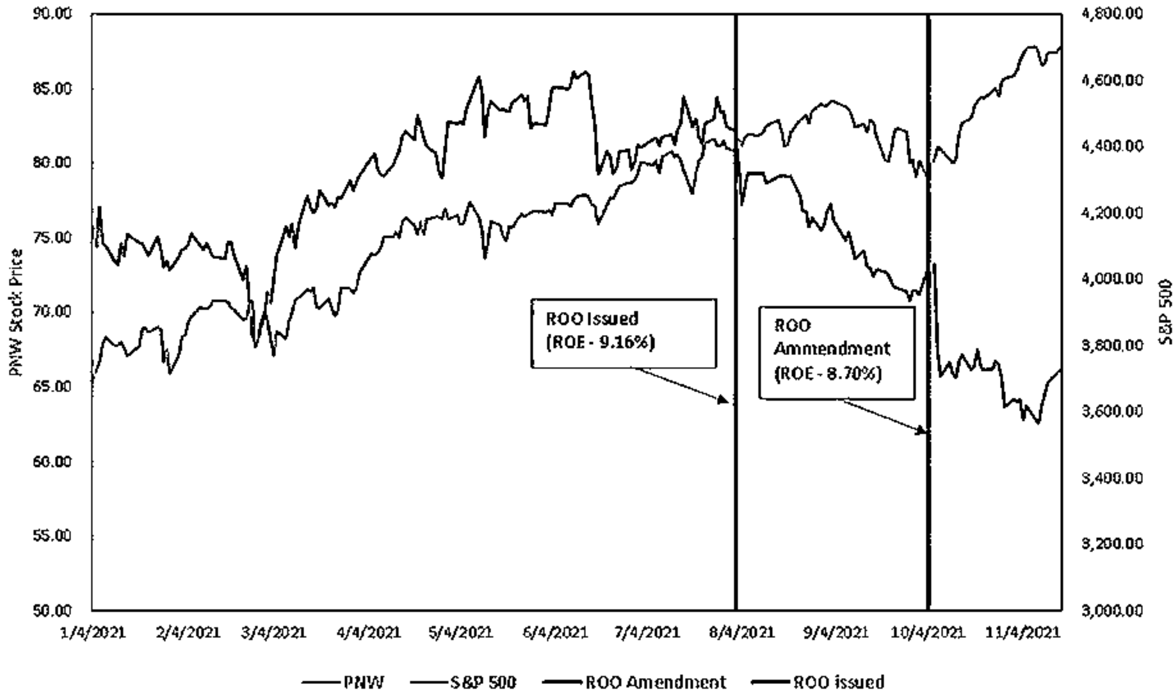
As shown in Figure 14 below, PNW's stock price declined approximately 24 percent from August 2, 2021 to November 4, 2021 following the issuance of the Order, which recommended an ROE of 9.16 percent, and then the subsequent amendment to that opinion recommending the 8.70 percent ROE ultimately adopted by the ACC. Moreover, the Value Line five-year projected EPS growth rates for this company have fallen from 5.0 percent in July 2021, prior to the deliberations in the rate proceeding to "Nil" in October 2021 and most recently 0.5 percent in January 20, 2023. For PNW, the APS decision has had a significant effect on the share price and growth rate assumptions used in the DCF model.

[63] *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return,* Arizona Corporation Commission Docket No. E-01345A-19-0236, Commissioner Olson Proposed Amendment No. 1 to the Recommended Opinion and Order (Oct. 4, 2021).

[64] S&P Global Market Intelligence, *Pinnacle West shares tumble after regulators slash returns in rate case* (Oct. 7, 2021).

[65] S&P Global Market Intelligence, RRA Regulatory Focus, *Commission accords Arizona Public Service Company a well below average ROE* (Oct. 8, 2021).

Figure 14: Pinnacle West Capital Stock Price VS. S&P 500



Q. How should the Commission use the information regarding authorized ROEs in other jurisdictions in determining the ROE for RMP?

A. As discussed above, the companies in the proxy group operate in multiple jurisdictions across the U.S. Since RMP must compete directly for capital with investments of similar risk, it is appropriate to review the authorized ROEs in other jurisdictions. The comparison is important because investors are considering the authorized returns across the U.S. and are likely to invest equity in those utilities with the highest returns. Furthermore, investors are also likely to consider business and financial risks for a company like RMP which faces increased risk as a result of its capital expenditure plan and limited cost recovery mechanisms. Therefore, authorizing an ROE for RMP that is equivalent to the average authorized ROE for other vertically integrated electric utilities is not sufficient to compensate investors for the added risk of RMP. As such, it is important that the

Commission consider, as I have in my recommendation, the additional risk of RMP and place the authorized ROE for RMP towards the high end of authorized ROEs for other vertically integrated electric utilities.

Q. What are your conclusions regarding the risks related to the Wyoming regulatory environment?

A. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Many of the companies in the proxy group have timely cost recovery through forecasted test years, capital cost recovery trackers, and non-volumetric rate designs/revenue stabilization mechanisms. Wyoming is relatively restrictive compared to other commissions on certain factors. For instance, the Company's fuel cost recovery mechanism does not fully mitigate power cost risk nor does the Company have either protection against volumetric risk or the ability to recover capital expenditures on an as incurred basis. Additionally, the Company has not earned its authorized ROE since 2017. Finally, authorized ROEs in Wyoming have been below the average authorized ROEs for vertically integrated electric utilities across the U.S. For these reasons, I conclude that the authorized ROE for RMP should be higher than the proxy group mean.

C. Generation Ownership

Q. How does the business risk of vertically integrated electric utilities compare to the business risk of other regulated utilities?

A. According to Moody's, generation ownership causes vertically integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies.[66] As a result of this higher business risk, integrated electric utilities typically require a higher ROE or percentage of equity in the capital structure than other electric or gas utilities.

Q. Are there other risk factors specific to vertically integrated electric utilities that the credit rating agencies consider when determining the credit rating of a company that owns generation?

A. Yes. As discussed above, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The third factor diversification, which Moody's assigns a 10.00 percent weighting in the overall assessments of a company's business risk, considers the fuel source diversity of a utility with generation. Moody's notes:

> For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.
>
> For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.[67]

[66] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, at 21-22 (June 23, 2017).
[67] *Id.*, at 16.