PATRICIA E. SCHMID (#4908)
JUSTIN C. JETTER (#13257)
Assistant Attorney Generals
Counsel for the DIVISION OF PUBLIC UTILITIES
SEAN D. REYES (#7969)
Attorney General of Utah
160 E 300 S, 5th Floor
P.O. Box 140857
Salt Lake City, UT 84114-0857
Telephone (801) 366-0380
pschmid@agutah.gov
jjetter@agutah.gov

BEFORE THE PUBLIC SERVICE COMMISION OF UTAH	
APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	Docket No. 20-035-04 Post Hearing Brief of the Utah Division of Public Utilities

Pursuant to the November 12, 2020 Amended Scheduling Order in this docket,[1] the Utah Division of Public Utilities (Division) files its brief addressing issues raised by Rocky Mountain Power's (RMP or the Company) general rate case filed May 8, 2020. The first portion of this brief will address cost of capital; the second will address revenue requirement; and the third will address cost of service and rate design.

1 The Amended Scheduling Order was clarified on November 20, 2020.

A. Cost of Capital

Division witness Casey J. Coleman provided testimony concerning the mixed questions of law and fact addressing the Company's return on equity (ROE), capital structure, and the cost of long term debt. The Division's analysis shows a 9.25 percent ROE for the Company is reasonable, not the higher 9.8 percent requested by the Company. The Company's proposed capital structure is supported by the Division and the Division has concluded that the Company's proposed cost of long term debt is reasonable.

1. Return on Equity

The Division's proposed 9.25 percent return on equity (ROE) is consistent with legal precedent and past Commission decisions and will result in just and reasonable rates. The Company initially proposed a ROE of 10.2 percent, but later revised it to 9.8 percent, the ROE authorized in the Company's last general rate case. Even the Company's revised ROE is too high to be reasonable, is inconsistent with legal precedent and past Commission decisions, and will not result in just and reasonable rates.

The Commission has relied upon the U.S. Supreme Court decisions in Hope[2] and Bluefield[3] for guidance in determining a regulated utilities' ROE. The Commission has also considered analytical models, ROEs awarded in other jurisdictions, investor expectations, and other factors.[4] Most recently, the Commission addressed ROE issues in its February 25, 2020

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2 *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 602-603, (1944) (*Hope*).
3 *Bluefield Water Works & Improvement Company v P.S.C. of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).
4 See *In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges*, Docket No. 02-057-02, Report and Order (December 30, 2002) at pages 20-21 citing *Hope* and *Bluefield*).

decision in the Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications, Docket No. 19-057-02 (2020 DEU Order).

In the 2020 DEU Order, the Commission stated that it would consider all evidence supporting ROE recommendations[5] and that "no single financial model or set of data inputs can conclusively calculate a specific utility's appropriate ROE. Accordingly, there is no conclusive weighting that we can apply to the results of various financial models."[6] Thus, it appears that the Commission's seemingly prior preference for the DCF models and its reluctance to apply results of CAPM models has been superseded. Accordingly, it is appropriate to examine and evaluate the inputs applied to the various models and the results of each model. This examination and evaluation is guided not only by inputs and outputs, but also by the Commission's judgment and discretion.[7] The Division's analysis below focuses only on a few critical underpinnings of Company witness Ann E. Bulkley's and Division witness Casey J. Coleman's ROE analysis.

Ms. Bulkley's ROE recommendation fails to recognize several important points. For example, she "excludes results below 7.0 percent because they don't provide a sufficient risk premium above long term debt cost."[8] This ignores the conclusion of well-respected regulatory economist Dr. James C. Bonbright who states that the minimum floor for a regulated utility should be the cost of equity, which is then adjusted for other policy considerations.[9] By discarding results below 7.0 percent while retaining others, Ms. Bulkley raises the minimum

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5 DEU 2020 Order at p. 6.
6 *See* DEU 2020 Order at p. 7.
7 2020 DEU Order at p. 7.
8 *See* Direct Testimony of Ann E. Bulkley, footnote 74.
9 *See* Surrebuttal Testimony of Casey J. Coleman at lines 39-45.

floor, resulting in skewed results after the remaining results are adjusted for other policy considerations.

Additionally, Ms. Bulkley's recommended ROE is far above ROEs awarded in 2020. Mr. Coleman's DPU SR-02 updates awarded ROEs and shows that the average ROE was 9.5 percent. Applying Dr. Bonbright's principle discussed above, it follows that the ROE results were lower than 9.5 percent prior to being adjusted for policy considerations. Considering ROEs awarded in other jurisdictions is consistent with Hope, Bluefield, and the 2020 DEU Order.

Certain other aspects of Ms. Bulkley's analysis invite skepticism. Her DCF approach has not been published and has not been peer reviewed.[10] Although the Commission recently has indicated its willingness to look at CAPM models, upon evaluation, the Commission should disregard the results of Ms. Bulkley's CAPM analysis. By using her own equity risk premium in her CAPM model, rather than one from a recognized source,[11] it is difficult to compare her CAPM model results directly with those using well known sources from other ROE witnesses. Also, in her direct testimony, Ms. Bulkley also relies upon projected data rather than currently available data,[12] Given that projections are naturally suspect, these results should be viewed with skepticism.

Contrastingly, Mr. Coleman relies upon the principles set forth by Dr. Bonbright, information from Duff and Phelps, actual recently awarded ROEs, and currently available, rather than projected, data. Mr. Coleman's testimony provides substantial evidence to support a Commission finding of a 9.25 percent ROE for the Company.

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10 Hr'g Tr 114:4-22, Sept. 29, 2020.
11 *See* Direct Testimony of Casey J. Coleman at lines 301-308.
12 Rocky Mountain Power Ms. Ann E. Bulkley Direct Testimony Exhibit RMP AEB-5.

Mr. Coleman's analysis recognizes that it is appropriate to begin with an ROE "floor" as noted by Dr. Bonbright. This approach allows consideration of a wide range of results, rather than arbitrarily disregarding some results.

Duff and Phelps' analysis was relied upon by the Division, with good cause. Duff and Phelps evaluated a wide range of risks, considerations, and influences. RMP failed to show that it had a higher rate of risk when compared to other companies. In addition, Duff and Phelps' Cost of Capital in the Current Environment analysis considered the impact of COVID upon markets.[13] Using Duff and Phelps data helped affirm that the Division's recommended ROE of 9.25 percent was reasonable.[14]

Mr. Coleman's recital of recent ROE's correctly included companies Ms. Bulkley sought to exclude. She claimed that certain current ROEs were from settlements or contained step increases. These facts do not serve to exclude these companies from the analysis – instead, they provide a well-rounded snapshot of Commission decisions and are consistent with Dr. Bonbright's principle that the allowed return is adjusted from the cost of equity. Therefore, what matters is that the analyzed ROE's resulted from Commission decisions, whether they be from a fully litigated case or a Commission approval of a settlement.

The Division's recommended ROE of 9.25 percent is reasonable. The Commission is tasked with determining rates that are just and reasonable, meaning in part that the opportunity for a utility to earn a rate of return does not come at too high a cost for the ratepayers.

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13 *See* Surrebuttal Testimony of Casey J. Coleman at lines 90-95.
14 *Id*. at lines 102-107.

2. Capital Structure and Cost of Debt

The Company proposed a capital structure of 53.67 percent common equity, cost of long term debt of 4.81 percent, and cost of preferred stock of 6.75 percent.[15] The Division supports the Company's proposed capital structure as being reasonable for a vertically integrated electric utility, and notes that the proposed capital structure contains a higher percentage of equity than in the past.[16] The Division also concludes that RMP's proposed cost of long term debt is reasonable.[17]

B. Revenue Requirement

1. Legal Issues

The Division has provided testimony on two issues that are mixed questions of law and fact. First, AMI meters are not used and useful during the test period and should not be included in rates until they become used and useful. Second, the production tax credits ("PTCs") are not power costs and should not be shared through the EBA, but rather should be set in base rates.

a) AMR Meters Will Not Be Used and Useful During the Test Period and Should Not be Included in Rates.

The Commission should not include recovery for AMI meters and AMI infrastructure in rates in this rate case. The Division is not opposing the installation of the AMI meters and recognizes the potential benefits of such metering infrastructure. The Commission should deny recovery in this rate case for the AMI meters because the meters are not used and useful now, and they will not be used and useful during the future test year. The timing and risk of

15 *See* Direct Testimony of Nikki L. Kobliha at lines 18-20.
16 *See* Direct Testimony of Casey J. Coleman, lines 67-69.
17 *Id.* at 70-72.

completion of the AMI meter system does not support inclusion in rates resulting from this general rate case.

It has been a long time since either this Commission or a Utah court has had the opportunity to address the application of the principle that the utility may only recover for assets that are used and useful. However, the principle has long been part of Utah's utility regulation framework and the Commission should not abandon that principle now. The Commission has recognized the continued application of the principle in relatively recent decisions. For example, as recently as 2002 in *In the Matter of the Application of Pacificorp for A Certificate of Convenience & Necessity Authorizing Constr. of A Res. Addition*, this Commission recognized the continued application in Utah rate regulation although it did opine on the bounds of the principle.[18] This Commission applied the principle in a 1994 water company case ordering in part that "it must be absolutely clear that the rate-payer is not being asked to cover the cost of a system which is larger than needed (and thus not used and useful) and could be utilized by the developer/water company to serve other customers on this or other property in the future."[19] A comprehensive summary of Utah's used and useful case law can be found in the 2012 Bar Journal article by Vicki M. Baldwin & J. Robert Malko, *Used and Useful Principle: Still Relevant in Utah*.[20]

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[18] *In the Matter of the Application of Pacificorp for A Certificate of Convenience & Necessity Authorizing Constr. of A Res. Addition*, (Order issued Jan. 31, 2002, at p. 5), Docket No. 01-035-37, ("all other regulatory ratemaking questions, including those touching on the issue of whether plant is used and useful... are open for examination in the appropriate docket.")
[19] *In Re Scsc, Inc*., (Order issued September 15, 1994), Docket No. 94-2196-01.
[20] Utah B.J., January/February 2012, at p. 32.

The general principle that utility investors provide the capital and remain at risk at least until such time as the assets are actually used and actually useful for utility service provides a valuable tool in the decision of when customers begin to pay investors for the use of those assets. And this timing of recovery should be symmetrical. Capital that is anticipated to be taken out of service beyond the end of the rate effective period is generally not removed from current rates until it is taken out of service either through the next rate case or by function of an interim rate adjustment.

RMP acknowledges that the AMI meter system will only provide partial functionality until it is completed by the end of 2022.[21] While the installed meters may be technically "used" in some capacity as utility meters, they will not be useful in providing the benefits that are relied on to justify the costs. Specifically, they will only be useful for providing customer access to data on hourly consumption for some customers, providing limited customer service information, and reducing some estimated bills. Because the system will be incomplete, those benefits would be limited to some subset of the general customer population. And importantly, RMP has not testified that those benefits would justify the expense of the AMI metering system.

The cost of the AMI system for those limited benefits has not been demonstrated to be prudent. And the AMI system is not used and useful for the range of benefits that would be necessary for a showing of prudence. As a result the costs are not justified by the limited benefits during the test period and the AMI meter infrastructure will not be used and useful for the functionality that justifies the cost until long after the test year has concluded. RMP witness Curtis Mansfield testified that the system is projected for completion by the end of 2022.[22]

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[21] Mansfield Phase I Rebuttal Testimony at lines 92-94.
[22] Hr'g Tr. 203:5-6 Nov 03, 2020.

The timing of the AMI metering becoming used and useful does not support inclusion in rates as part of this rate case. This is not a harsh or undue burden on the utility. The use of a future test year allows RMP to look into the near future for known forecast changes to the base year. The AMI metering system completion is not only incomplete during the base year, but will also be incomplete during the test year, and is simply too far into the future to capture under the traditional ratemaking principles. The Commission should apply the long standing used and useful principle and deny inclusion in rates of the AMI metering costs until those assets are fully functional for the set of benefits that justify the costs, or at least expected to be functional during the future test year.

b) Production Tax Credits are Not Power Costs and Should Not be Recovered in the Energy Balancing Account

Production tax credits ("PTC") should be set in base rates and should not be included in the energy balancing account ("EBA") mechanism. The Commission is statutorily authorized to create the EBA to recover "some or all components of [RMP's] actual power costs."[23] The costs listed specifically include fuel, purchased power, and wheeling expenses.[24] The list of the three categories of costs is not exclusive.[25] However, the EBA recover is limited to "power costs." The threshold question that must be answered is whether PTCs are power costs.

PTCs are not direct power costs. Rather, they are tax credits that are tied to the production output of specific qualifying generation facilities. Therefore, while the PTCs share a common relationship with power costs in that the PTCs vary based on generation output, they

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[23] Utah Code Ann. § 54-7-13.5(1)(b).

[24] *Id*.

[25] *See* Utah Code Ann. §68(3)(12)(1)(f) ("'Include,' 'includes,' or 'including' means that the items listed are not an exclusive list, unless the word "only" or similar language is used to expressly indicate that the list is an exclusive list.")

also differ from typical power costs in meaningful ways. The purchase and sales of fuel, power, or transmission wheeling vary not only in volume during the rate effective period, but they also vary in value. The cost of fuel for thermal resources is subject to rapid changes in the market. The volume of energy traded in or out of the system and the market prices for that energy are subject to significant and difficult to predict change. As a result, the EBA provides an exception to the traditional rule against single-item or single-issue ratemaking and provides interim adjustment for those costs. The argument in favor of the EBA is that it avoids otherwise unnecessary rate cases.

PTCs on the other hand are not subject to the same variability net power costs because they are not power costs. PTCs will vary based on production, but PTCs have a known value for each unit of production. And there is evidence that the annual wind production being slightly higher or lower than the test year would result in a change in forecast production that would necessitate more frequent rate cases. Rather, RMP forecasts generation output using models based on longer term averages and if PTCs are set in base rates over a series of years the over and under generation years will average out.[26] The same is not true for traditional net power costs.

Additionally, the risks related to PTCs are better born by RMP who is in the best position to mitigate them. Inclusion of the PTCs in the EBA functions as a mechanism for reducing the volatility of the PTCs for shareholders. RMP is in the best position to maximize PTC production given that it will be operating the generation equipment, dispatching the system, and is ultimately responsible for maintenance and repairs of equipment if or when it goes out of service. For these

[26]Hr'g Tr. 134:17-24, Nov. 03, 2020.

reasons, the Commission should find that the PTCs do not meet the definition of power costs and should not include the PTCs in the EBA.

As explained in Division witness Smith's testimony it is shareholders that are compensated for the risk and should therefore experience the volatility of the PTCs. PTCs are not a component of net power costs and should not be included in the EBA. Doing so transfers additional risk of underperformance and risk of non-typical outage events to customers.

2. Summary of Division Recommended Adjustments to Revenue Requirement

RMP has the burden to prove that its costs are prudently incurred.[27] Lack of evidence to the contrary or failure to challenge does not bypass the utility's burden. Rather, the "utility bears the burden of presenting the evidence necessary to support the Commission's "essential finding[s]". [28] And in utility regulation in Utah "a fundamental principle is: the burden rests heavily upon a utility to prove it is entitled to rate relief and not upon the Commission, the Commission staff, or any interested party or protestant, to prove the contrary."[29] The Division has recommended the following adjustments to the case as filed and updated by RMP. For the following adjustments RMP has failed to meet its burden of proof and the Commission should adjust its filed revenue requirement request accordingly.

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[27] *Utah Office of Consumer Servs. v. Pub. Serv. Comm'n of Utah*, 2019 UT 26, ¶ 46, 445 P.3d 464, 473 citing to *Comm. of Consumer Servs. v. Pub. Serv. Comm'n of Utah*, 2003 UT 29, ¶ 14, 75 P.3d 481; *Utah Dep't of Bus. Regulation v. Pub. Serv. Comm'n*, 614 P.2d 1242, 1245 (Utah 1980).
[28] *Utah Dep't of Bus. Regulation v. Pub. Serv. Comm'n*, 614 P.2d 1242, 1245 (Utah 1980).
[29] *Id*.

a) AMI Meters

As explained *supra* the AMI meters will not be used and useful during the test period. The Division recommends an adjustment to the revenue requirement to remove the AMI metering costs until they become used and useful. The Division does not object to the AMI meter program but disagrees with RMP on the timing of recovery.

b) Expense Adjustments

Division witness Eric Orton recommended multiple expense adjustments that have not been demonstrated by RMP as prudent expenses and should not be included in rates. Additionally, one recommended adjustment by the Division has been withdrawn after additional evidence was provided at hearing.

The Division withdraws its recommended adjustment for removal of expenses related to RMPs membership in the Edison Electric Institute ("EEI"). At hearing counsel for RMP provided information to Mr. Orton regarding the accounting treatment of the EEI membership in FERC account 426 that is not passed through to customers.[30] The Division accepts the evidence from RMP that the EEI expense was not included in the proposed customer rates and withdraws its recommended adjustment.

The Division continues to recommend its adjustments to incentives and perks. RMP has not provided testimony or other evidence on the record that demonstrates the prudence of the expenses identify in Mr. Orton's recommended adjustment of $173,804. RMP has not provided evidence on the record to justify these expenses and they should be disallowed from recovery. The Division's summary of those adjustments can be found in DPU Exhibit 5.2 SR.

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[30] Hr'g Tr. 208-210, Nov. 04, 2020.

The Division also continues to recommend the adjustment for removal of expenses for participation in civic memberships as set forth in DPU Exhibit 5.2 DIR. When asked if RMP could identify a specific actionable piece of information it received from participation in the Chamber of Commerce RMP witness Mr. McDougal, agreed that RMP could not identify one.[31] With respect to the customer feedback basis for justifying the membership costs Mr. McDougal testified that the company could get the same information from the utilities customer service employees. [32] The Division's recommended adjustment for civic membership expenses is $84,351 and is summarized in DPU Exhibit 5.1 DIR.

c) Pryor Mountain Wind Farm

Division witness Dr. Joni Zenger testified in her Direct testimony that there were significant concerns with the actions of RMP in its acquisition of the Pryor Mountain wind project in Montana and recommended not approving of the project in rates.[33] In Surrebuttal testimony Dr. Zenger had completed further analysis of the Company's actions and recommended that the Commission find that the decision to pursue the Pryor Mountain project was imprudent and that the costs be disallowed.[34] After hearing the live testimony of Company witness Chairman Levar asked whether the new information on timing of decisions that was discussed earlier in the hearing had changed Dr. Zenger's recommendation. Dr. Zenger testified that it did change her understanding of the timeline and whether a reasonable utility would have pursued the project.[35] The Division is no longer recommending disallowance of the Pryor

[31] *Id.* at 111:4-6.
[32] *Id* at 112:2-3.
[33] DPU Exhibit 8.0 DIR at Line 377-78.
[34] DPU Exhibit 8.0 SR at lines 395-404.
[35] Hr'g Tr. 66:3-16, Nov. 05, 2020.

Mountain wind farm on the basis of imprudence at the time that decisions were made to proceed with the acquisition and development.

The Division remains concerned with the process that led to the acquisition and the bypass of the regulatory pre-approval options that were available to RMP as Dr. Zenger testified. Additionally, the Division has significant concerns about whether the Pryor Mountain project was the least cost alternative. This is particularly troubling when RMP is simultaneously representing that the avoided cost of similar projects for third party QFs is significantly lower than the cost for Pryor Mountain.[36] Without the processes that are designed to ensure that large capital projects are in fact done at the lowest possible cost it is somewhere between difficult and effectively impossible to challenge a resource decision without demonstrating that a lower cost resource was actually available to RMP.

d) Production Tax Credits

As explained s*upra* the production tax credits are not power costs and should therefore not be included in the EBA. In addition to the legal arguments in favor of PTC sharing though base rates rather than in the EBA, Division witness Gary Smith's testimony explained the public policy reasons for the inclusion of PTCs in base rates without a true up mechanism. PTCs should be shared back with customers through base rates.

e) Decommissioned WTG Equipment Should be Depreciated Over 10 Years

Division witnesses testified that the decommissioned wind turbine generation equipment ("WTG") should be depreciated over 10 years to match the production tax credits that were the primary driver of the decommissioning of the WTG equipment. In total there are 11 repowered

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[36] *See ex.* Hr'g Tr. 16:1-25, 59:5-25, Nov 04, 2020.

wind projects approved in Docket No. 17-035-39 plus the Leaning Juniper repowering that was not approved in that docket but repowered during the same time.[37] Parties to this docket have disagreed on whether to depreciate the WTG equipment taken out of service over the 10 years that match the PTCs or over the remaining service life of the new replacement equipment.[38]

Division witness Gary Smith recommends that the Commission use a 10-year depreciation life matching the PTCs. The Division's 10-year recommendation is not supported by any other party. No party has testified or submitted any general accounting rules or standards that would require either the 10-year or 30-year depreciation life. Similarly, there is no factual dispute that the value of the PTCs results in the total benefits of the WTG replacement program being front loaded during the first 10 years.[39] The facts on the record support the Division's recommended 10-year depreciation life. The PTCs were the primary economic driver of the repowering and will offer little or no value to customers beyond the end of the PTC period. The Division recognizes that today's customers would typically prefer to have future customers pay higher rates rather than pay down the depreciation with the near-term benefits. However, paying off the WTG equipment with the up-front returns from the PTCs is a better match between the benefits and the costs of the decision to repower.

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[37] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, (Report and Order issued May 25, 2018), Docket No. 17-035-39.

[38] *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, (Direct testimony on issues related to the second phase of the Depreciation Docket Testimony of Steven R. McDougal, June 19, 2020, lines 75 - 115.0), Docket No. 18-035-36.

[39] Hr'g Tr. 226:3-6, Nov. 05, 2020.

f) Lakeside 2 Unit 3 Outage

Division witness Brenda Salter testified in Phase II surrebuttal testimony in response to testimony presented by OCS witness Philip Hayet regarding the August 18, 2019 Lake Side 2 Unit 3 outage. As Ms. Salter testified, the root cause analysis was inconclusive, and a second analysis is being conducted. RMP is responsible for proving that it is entitled to the recovery of the outage costs and it is not the burden of the Division or other parties to prove otherwise.[40] The undisputed evidence on the record is that the investigation by Siemens indicated that the scenario with the least contradictions was the presence of a foreign object. Unfortunately, no party currently has evidence as to what the true cause of the outage was. Given that the burden rests on RMP to demonstrate prudence, the Division continues to recommend the disallowance of the outage costs in the confidential amount as identified in DPU exhibit 3.0 SR at line 61.

g) Property Tax Adjustment

Division witness JJ Alder presented a recommended property tax adjustment in DPU Exhibit 6.0 DIR. Division witness JJ Alder recommended that the Commission use a historical average year over year increase to forecast a future test year property tax charge. This method proposed by the Division is less complex than that used by RMP. However, it is important to recognize that the method used by RMP, while more mathematically complicated is also a forecast, not simply a pure calculation of future taxes. Mr. McDougal testified at hearing that RMP's tax forecasts are "not precise; they are a forecast." [41] Moreover Mr. McDougal explained that "sometimes in the years [the forecasts are off]…it has to deal with what happens on our

[40] *Comm. of Consumer Servs. v. Pub. Serv. Comm'n of Utah,* 2003 UT 29, ¶ 14, 75 P.3d 481, 486.
[41] Hr'g Tr. 108:3-4, Nov. 04, 2020.

appeals because we are constantly appealing property taxes."[42] Given the variability between forecasts and results and uncertainty with respect to the appeals that may result in lower tax burdens than projected, the Division recommends the use of a historical trend based property tax value for setting rates in the test year. The Division's recommended value is confidential and can be found at DPU Exhibit DIR 6.0 at line 107.

3. Class Allocation and Rate Design

The Division presented three witnesses in Cost of Service ("COS") phase of this docket. The Division generally found that RMP followed costing methods that were consistent with industry practice and the NARUC manual.[43] Division witnesses Robert Camfield and Bruce Chapman filed testimony with numerous recommendations for consideration in future analysis prior to the next general rate case. With respect to the rates set in this rate case, the Division continues to support the 75/25 demand energy split that matches the MSP allocation to Utah but recommends that there be more evaluation of this prior to the next rate case. [44]The Division, as stated in live testimony by Division witness Robert Davis, does not oppose the removal of the 3rd tier for residential retail rates.[45] The Division continues to support the peak and off-peak periods proposed by RMP.

Conclusion

The Division recommends the Commission set a 9.25 percent ROE for the Company. The Company's proposed capital structure is supported by the Division and the Division has concluded that the Company's proposed cost of long-term debt is reasonable. The Commission

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[42] *Id*. at 108:12-16.
[43] See DPU Exhibit 10.0 DIR, lines 127-134.
[44] Hr'g Tr. 110:22-25, Nov. 17, 2020.
[45] *Id.* at 98:20-99:03.

should find that the AMI metering is incomplete and will not be used and useful during test period. The Commission should find that the PTCs are not power costs and do not belong in the EBA. And the Commission should adopt the remaining adjustments to RMP's allowed revenue requirement as summarized in this post hearing brief.

Submitted this 30th day of November 2020.

/s/ Justin C. Jetter

Justin C. Jetter
Assistant Attorney General
Utah Division of Public Utilities