–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF THE 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. UT 20-035-04** **Exhibit No. DPU 11.0 R**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Rebuttal Testimony of

BRUCE R. CHAPMAN

October 16, 2020

INTRODUCTION

Q. Would you please state your name and business address?

A. My name is Bruce R. Chapman. My business address is 800 University Bay Drive, Suite 400, Madison, WI 53705.

Q. By whom are you employed and in what capacity?

A. I am employed by Christensen Associates Energy Consulting, LLC (CA Energy Consulting) in the capacity of Vice President.

Q. Are you the same Bruce Chapman who provided direct testimony in this case?

A. Yes.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Division of Public Utilities of the Utah Department of Commerce (the Division).

Q. What is the purpose of your testimony?

A. My testimony provides comments in response to the direct testimony of intervenors in Rocky Mountain Power's (RMP or the Company) rate application. The intervenors provided direct testimony related to that of RMP witness Robert M. Meredith on the subjects of the embedded cost-of-service study (ECOSS), the marginal cost-of-service study (MCOSS) and rate design. I focus on comments pertaining to the ECOSS, but add comments related to the rate implications where appropriate. I provide responses to the direct testimony of Mr. Ron Nelson, Director of Strategen Consulting, who appeared on behalf of the Utah Office of Consumer Services (OCS). I also provide a brief comment in response to the direct testimony of Ms. Sarah Wright, who appears on behalf of Utah Clean Energy (UCE), a non-profit public interest organization of which she is the Executive Director.

Q. Should we make any inferences about your views on various intervenors' direct testimony, in whole or in part, if you do not comment on them in this testimony?

A. No, lack of a comment, on a portion of testimony or an entire submission, indicates neither support nor opposition.

Q. How is your testimony organized?

A. I provide comments on the testimony of each witness mentioned above, in the order listed.

ISSUES ASSOCIATED WITH OFFICE OF CONSUMER SERVICES WITNESS NELSON'S DIRECT TESTIMONY

Q. Do you agree with OCS witness Nelson's perspective on RMP's production cost classification methodology, specifically the 75/25 demand/energy classification rule?

A. Yes. I agree with his analysis and support his views at lines 653-660 that the time is approaching when this rule should be reviewed, and alternative methods of production cost classification be considered.

Q. Do you agree with witness Nelson's views on classification of production costs for purposes of equity and accuracy?

A. Not entirely. Witness Nelson suggests that RMP consider alternative methods of production cost classification at lines 725-746. I agree that RMP should at some point investigate alternatives to its agreed 75/25 demand/energy division and find his suggestions sensible. As mentioned above, I believe that RMP should be allowed to recommend a preferred approach from the full range of production cost classification alternatives as set out in the NARUC Cost Allocation Manual (or in alternative sources of methods). Specifically, the Public Service Commission of Utah (PSC) does not need to require RMP to provide an alternative ECOSS utilizing the probability of dispatch model in preference to others. I note that the probability of dispatch simulation method does not appear to take account of generation costs associated with planning reserves or, for that matter, operating reserves carried in real time.

Q. Do you agree with witness Nelson's views on transmission cost classification, namely a willingness to consider some of these costs as energy-related?

A. I disagree with his arguments in lines 701-723, but acknowledge that utilities can justify classifying transmission cost as partly energy-related. For example, his first argument pertains to moving power from remote generators to load centers. While his approach suggests that such transmission lines should be classified as energy-related, I would rely on the fact that utilities sometimes treat such transmission lines as extensions of the generation function and functionalize them as generation. At that point, whatever classification rule that the utility applies to generation costs also applies to those transmission assets. More generally, the NARUC Cost Allocation Manual gives weight to classification of transmission as demand-related, which suggests at least that RMP should be permitted discretion in its transmission classification methods and not be forced into adopting a method that includes a high proportion of energy-related classification.

Q. Do you agree with witness Nelson's argument that the subfunctionalization of production and transmission costs into fixed and variable costs indirectly produces a departure from the 75/25 demand/energy split, and offers RMP a chance of shifting costs in the direction of demand and away from energy?

A. The argument does not appear to be conclusive. At lines 460 to 499, he first states that the subfunctionalizing of production and transmission costs has no effect on ECOSS results (lines 464-465). However, he then states that this subfunctionalizing "shifts energy related costs into demand related costs, and demand related costs into fixed charges" (lines 483-485). Witness Nelson then alleges that this process has an ulterior motive associated with these shifts: to recover fixed costs more fully through fixed charges. (My inference from lines 504-505).

Q. Did you find apparent contradictions elsewhere?

A. Perhaps. There is certainly a difference between the argument of RMP witness Meredith and that of OCS witness Nelson. In principle, if subfunctionalizing occurs following classification of production and transmission costs into demand- and energy-related (the 75/25 D/E split), then the demand and energy shares should be preserved. Meredith's direct testimony at lines 74-89 appears to indicate that this is what happens. Alternatively, if subfunctionalization occurs before classification, then the 75/25 split is not assured, but witness Meredith does not adopt this line of argument.

However, witness Nelson constructs an example in his Figure 1 at line 1371 purporting to demonstrate that the subfunctionalization process results in shifted costs, as he previously claimed, so that cost-based energy in all rates is greater that the energy share produced by the fixed/variable split. This issue deserves further discussion.

Q. What other rate implications does witness Nelson draw from his cost misapplication conclusion?

A. He states that the subfunctionalizing of production and transmission costs leads to RMP's rate unbundling strategy. (Lines 1198-1217). Costs are grouped into delivery, fixed supply and variable supply. Basic, demand, and energy charges are used to collect required revenue. However, unlike traditional COS studies, there is no one-to-one mapping of cost causes to retail charges, which, in his view, complicates an understanding of the link between costs and prices. Delivery charges are collected via fixed and demand charges. Fixed supply charges are recovered via demand and energy charges and variable supply charges are recovered via energy pricing.

Q. In your view is this a valid criticism?

A. Not necessarily. It makes sense that delivery costs should be collected by a combination of customer and demand charges (distribution using both types and transmission using demand only). Recovery of production supply charges via demand and energy charges seems sensible as well. However, witness Nelson's criticism of the use of the fixed/variable split as unnecessary may be valid.

Q. Does witness Nelson draw any other conclusions regarding costs from his analysis of subfunctionalization?

A. Yes. He also concludes that the fixed/variable approach, when applied to distribution costs, shifts costs in the direction of demand-related cost and away from energy-related cost. (Line 1347-1355.) The path to this conclusion lies through his analysis of the unbundling of pricing built on subfunctionalization of production and transmission costs. By combining all distribution costs into the delivery cost category, he alleges that RMP has created an opportunity to shift some distribution costs from the demand-related to the customer-related classification. Thus, rate unbundling appears to work backward into distribution cost classification.

Q. Do you have any other comments on the fixed/variable subfunctionalization issue?

A. Yes. This issue appears to reflect differences between RMP and the OCS on the extent to which cost ought to be considered fixed. Witness Nelson mentions this concern at lines 1297-1315. While RMP's perspective appears to be closer to that of wholesale markets in which most costs aside from the commodity itself and related O&M are fixed, witness Nelson encourages us to view more costs as variable given a longer-term perspective. In the former case, energy-related costs are limited to a short list and energy prices should be low, while in the latter case, energy prices should bear a much higher share of the cost recovery burden.

Q. Do you have any concerns about witness Nelson's advocacy of a "beneficiary pays" methodology regarding AMI? This argument appears in lines 343-388.

A. Yes. The use of a beneficiary pays approach to AMI cost recovery appears worthy of consideration in that meters are now a vehicle for recording amount consumed in shorter intervals (usually 15 minutes or an hour) than an entire billing period. This enables measurement and billing of customer demand response to price signals of system conditions. He argues that, because all customers benefit from customers' demand response, they should bear some of the cost of the metering that makes demand response possible.

However, it is likely that the measurement of such benefits would be complicated and open to dispute. Furthermore, the reduction in cost responsibility for the class with AMI would not distinguish between those who provide the benefits and those who do not. Additionally, if all classes are eventually covered by AMI, the utility would then have to compute the average responsiveness of each class in order to allocate the putative value of demand response. The direction and magnitude of benefit flows would be quite uncertain. As well, the value of such benefits can change significantly over time. Would variation in the value of demand response benefits over time and across customers be adequately and accurately recognized?

Additionally, I believe that it would be preferable to allocate AMI costs according to traditional cost causation and then to recognize the benefits of demand response through payments or rebates to customers who respond based on retail prices that reflect wholesale market conditions and the degree of actual response. Dynamic pricing products such as real-time pricing, critical-peak pricing, and peak-time rebate are established tariffs that perform exactly this task. Under this approach, all customers pay equally for the meters associated with their class, but only those customers who opt to be served under a demand response tariff and then actually undertake demand response to high prices would receive payment for that response, and that payment would be based on the value of their response.

Q. Do you agree with the recommendation that AMI costs be functionalized as shared equally among the production, transmission, and distribution functions? (Please see lines 837-843, and lines 903-906).

A. No. The first reason has to do with my disagreement with the application of the beneficiary pays methodology to this cost allocation problem. The second reason is that there appears to be no cost-based approach to the proposed functional split into equal thirds. AMI benefits are related predominantly to mitigation of peak loads, which suggests recognition of capacity costs on the margin. AMI-based infrastructure effects on capacity cost savings will accrue to production and transmission, and not significantly to distribution. Distribution systems, at an individual level, are characterized by capital indivisibility: cost functions of distribution facilities are discrete, with large increments in capacity. (This is particularly the case when load decreases; the investment function is highly asymmetric). I do not recommend that the equal sharing rule be adopted in the next rate case, as recommended by witness Nelson at lines 909-910.

Q. Do you agree with witness Nelson's view that AMI costs not be included in the current rate case?

A. No. His argument pertains to COVID-19's impact and does not pertain exclusively to AMI costs, although the recommendation is mentioned in the AMI section immediately above at lines 914-915. Witness Nelson argues appropriately that COVID-19 will have effects on load profiles and revenues that are not recognized in the RMP filing. However, he then argues that this constitutes grounds for "minimizing changes in revenue apportionment and design." This issue is larger than my topic here, which is simply to suggest that AMI costs, if pertaining to used and useful plant and equipment, belong in revenue requirements. Ironically, arguing for minimizing change might be interpreted to suggest that such costs be included and allocated in a traditional manner, according to a customer allocator.

Q. Do you agree with witness Nelson's arguments against increasing the residential class single-family customer charge, including its objections on the basis of miscalculated customer-related cost to serve?

A. No. Witness Nelson offers three reasons for rejecting most of RMP's proposed increase. First, he argues that the bill impacts associated with the combination of reducing the number of tiers of the residential energy charge and increasing customer-related costs are so large that the change should not be pursued. Second, he states that the fixed/variable methodology issue calls into question the cost basis of the customer charge increase. Third, he objects to recovery of line transformer costs via the customer charge. I will not discuss the first issue, which is associated with rate design and the rate at which bills can change in response to a change in rate structure.

Regarding the second, costing methodology issue, if witness Nelson's argument is deemed persuasive, then the size of the customer charge increase would be reduced, because fewer costs will have been classified as customer-related than RMP currently wishes. Regarding the third issue, line transformer cost treatment, the standard approach to cost classification of FERC Account 368 (Line Transformers) is to classify costs as partly demand-related and partly customer-related and to use statistical methods to determine the shares.[1] In the case of residential ratemaking, the customer share should be included in the customer charge, and it is a matter of ratemaking discretion what demand-related costs, if any, are included in the customer charge. Arguing that all line transformer costs belong in the energy charge appears excessive.

<u>ISSUES ASSOCIATED WITH UTAH CLEAN ENERGY WITNESS WRIGHT'S DIRECT TESTIMONY</u>

[1] NARUC, *Electric Utility Cost Allocation Manual*, Table 6-1, p. 87.

Q. Do you have any comments with respect to the direct testimony of UCE witness Wright?

A. Yes. At lines 89-94 of her testimony, Ms. Wright provides a recommendation that the PSC investigate permitting communities to own street lighting assets currently owned by RMP. I agree that such an action may be worthy of further study with respect to cost effectiveness. However, my focus is on the cost of service implications of such a change. Street lighting services consist of three components: 1) the street lights, fixtures, and related assets; 2) maintenance services; and 3) the provision of electricity services. In theory, these could be unbundled and the first two procured competitively, presuming that the barriers to market entry by potential vendors are not unduly burdensome. (Evidence suggests that only a few entrants are necessary in order to satisfy the conditions for workably competitive markets). Even if markets prove not to be workably competitive, service unbundling might help to clarify costs and provide the means to improve pricing of street lighting services.

Such an approach does not necessarily imply significant changes in cost allocation methodology. Street lighting customers who take energy services only, would still be allocated their share of production and transmission services. Street lighting facilities sold to communities would be removed from rate base, (albeit with issues relating to book vs. market value). O&M expenses allocated to class, including street lighting will need review. Communities that terminate maintenance service will stop paying for such costs and utility costs will be reduced. The result will be allocated costs for each component of service: distribution costs in the form of unit demand and customer costs, production and transmission costs in the form of unit demand and energy costs. Pricing structure for each service would be a matter of utility discretion, subject to PSC review.

Q. Does this conclude your testimony?

A. Yes, it does.