Witness OCS – 5D

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. 20-035-04**
	)	
	)	**Phase II Direct Testimony of**
	)	**Ron Nelson**
	)	**On behalf of the**
	)	**Office of Consumer Services**
	)	

September 15, 2020

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I. INTRODUCTION

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

A. My name is Ron Nelson. I am a Director with Strategen Consulting. My business address is Suite 400, 2150 Allston Way, Berkeley, California 94704.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Utah Office of Consumer Services ("OCS").

Q. PLEASE DESCRIBE YOUR FORMAL EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Currently, I am a Director at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have worked with consumer advocates, trade associations, non-profits, and commissions on issues related to cost of service modeling, rate design, grid modernization, distributed energy resource ("DER") valuation and integration, and performance-based regulation ("PBR").

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led the Office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics and a Minor in Mathematics from Western Washington University.

Q. HAVE YOU TESTIFIED IN SIMILAR REGULATORY PROCEEDINGS PREVIOUSLY?

A. Yes. I have testified in 18 proceedings in Minnesota, Pennsylvania, Oklahoma, Illinois, New Hampshire, and Ohio. The issues covered in these proceedings include marginal and embedded cost of service studies, revenue apportionment, rate design, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, distributed energy resource (DER) interconnection, DER compensation, DER integration, and smart inverter specifications.

I have also assisted with testimonies and regulatory analysis in Hawai'i, Washington D.C., Maryland, Minnesota, Massachusetts, California, North Carolina, and the Federal Energy Regulatory Commission ("FERC"). The issues covered in these proceedings include electric vehicle rate design and infrastructure, wholesale market tariff design, cost-benefit analysis, community-based solar programs, rate design, cost and rate unbundling, integrated resource planning, energy storage integration, and DER interconnection.

A summary of my resume is attached as Exhibit OCS 5.1D.

Q. DO YOU HAVE OTHER RELEVANT EXPERIENCE RELATED TO EVALUATING DO YOU HAVE OTHER RELEVANT EXPERIENCE RELATED TO EVALUATING RMP'S PROPOSALS IN THIS CASE?

A. Yes. I am currently serving as the Hawai'i Public Utilities Commission ("Hawai'i Commission") subject matter expert and technical advisor for its advanced rate design, Docket No. 2019-0323. This docket is examining alterations and improvements to residential, low and moderate income, commercial and industrial, electric vehicle, and other tariff rate designs. Among other things, I am advising the Hawai'i Commission on cost and rate unbundling, which is an important issue in this case. Additionally, I am advising the Hawai'i Commission on how to develop customer class tariffs for charging of utility services, while efficiently compensating DERs through other distinct tariff or programs.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE UTAH PUBLIC SERVICE COMMISSION ("PSC")?

A. No.

II. PURPOSE AND RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to evaluate and review Rocky Mountain Power's ("RMP") application for a rate increase in the State of Utah and to make recommendations in the areas of embedded cost of service, rate design, and advanced metering infrastructure ("AMI") business case.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS AND WORKPAPERS RELATED TO YOUR DIRECT TESTIMONY.

A. In addition to my resume, I have attached the following exhibits and workpapers:

- Exhibit OCS 5.2D consists of responses to data requests referenced in this testimony and the attached exhibits.
- Workpaper OCS 5.1D includes summaries of each of the modified Embedded Cost of Service Study ("ECOSS") models I present.
- Workpaper OCS 5.2D compares RMP's unbundled rate components to cost-based rate components estimated within RMP's ECOSS.

- Workpaper OCS 5.3D is a bill impact analysis of RMP's proposed residential rates.
- Workpaper OCS 5.4D includes my analysis of RMP's AMI costs and benefits.

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF YOUR ANALYSIS AND RECOMMENDATIONS REGARDING RMP'S PROPOSED ECOSS.

A. RMP's proposed ECOSS relies on numerous traditional assumptions and methodologies that do not reflect the current power system transition. As the penetrations of renewable energy and advanced technologies, such as advanced grid functionality and AMI, become common, the ECOSS needs to be updated with more appropriate and modern assumptions and methods. RMP's proposed ECOSS has failed to do so.

To the extent that the PSC relies on an ECOSS for revenue apportionment and rate design in this case, I recommend that the PSC rely on a modified ECOSS that is more reflective of the modern power system. Specifically, I recommend modifications to the (1) classification and allocation of production and transmission costs, (2) subfunctionalization of the primary and secondary distribution, and (3) functionalization of meters.

Lastly, I strongly urge the PSC to reject RMP's proposed subfunctionalization of production and transmission costs into fixed and variable costs. RMP's proposed subfunctionalization is, in fact, not a subfunctionalization step because it has no impact on class cost allocation. Instead, RMP's proposed subfunctionalization of fixed and variable cost is an attempt to inject a rate design step into the ECOSS. The practical implication is that RMP designs rates based on information that is not derived from the ECOSS and is therefore not cost-based. Approving such a methodology would go against decades of ratemaking precedent, not only in Utah but in the entire United States.

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF YOUR ANALYSIS AND RECOMMENDATIONS REGARDING RMP'S RESIDENTIAL RATE DESIGN PROPOSALS.

A. RMP proposes to separate the residential class into single and multi-family tariffs and recommends rate designs for each. RMP's recommended rate designs result in inequitable bill impacts with 70 percent of customers with lower consumption (less than 1,000 kWh) realizing rate increases of over 9 percent, while 30 percent of higher consumption customers (above 1,000 kWh) receive over a 10 percent rate decrease during the summer months. To help address these significant bill impacts, I recommend that the single-family customer charge be increased by only $1 to $7.

I agree with RMP's proposal to create a multi-family tariff and its proposed customer charge of $6. However, I make recommendation for how RMP could improve upon the new multi-family residential offering in its next rate case.

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF YOUR ANALYSIS AND RECOMMENDATIONS REGARDING RMP'S PROPOSED C&I RATE DESIGN.

A. I provide analysis of RMP's proposed interruptible tariff, Schedule 35, pilot. Utility administered pilots should have a clear objective, evaluation process (i.e., performance target and/or metric), reporting requirements, and plan for what happen after the pilot (e.g., scale or revise the offerings). Most importantly, every pilot should clearly identify the benefits it will create for ratepayers. RMP's Schedule 35 pilot does not have many, if any, of these important components. In Section V.C, I provide recommendations to improve RMP's proposed schedule 35 pilot and recommend the PSC require that RMP develop a more effective pricing pilot in the future.

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF YOUR ANALYSIS AND RECOMMENDATIONS REGARDING RMP'S PROPOSED AMI PROJECT.

A. RMP's proposed AMI project includes spending similar to what other utilities and regulators have referred to as grid modernization investments. While RMP is requesting cost recovery associated with key grid modernization investments, its proposed AMI project is myopically focused on providing meter reading cost reduction benefits. By narrowly focusing the AMI project on meter reading savings, RMP is foregoing any discussion or development of a comprehensive and transparent grid modernization strategy that better leverages demand-side resources, allows the utility and third-parties to provide new energy services, and improves load flexibility. RMP's AMI project is solely focused on how grid modernization investments can provide utility and shareholder benefits as opposed to leveraging grid modernization to provide cost-effective, customer-centric solutions for ratepayers.

Unsurprisingly, RMP's own cost-benefit analysis ("CBA") indicates that the AMI project is not cost effective.[1] RMP's AMI project would eliminate full-time employees and create negative net benefits for ratepayers, while increasing profitability for RMP and its shareholders. The AMI project is clearly unreasonable and should be forcefully rejected by the PSC.

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[1] RMP's CBA omits important assumptions, such as carrying charges and the evaluation period. Reasonable inputs for these assumptions result in net negative benefits.

Should RMP request AMI or grid modernization related cost recovery in the future, I recommend the following:

- provide clear guidance to RMP on the substance that needs to be in future AMI or grid modernization cost recovery requests;

- require RMP to file an advanced rate design roadmap and updated CBA the next time it files for AMI, or grid modernization related, cost recovery; and,

- consider a demand response target or requirement as part of any AMI program that gets approved.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the next section, I discuss and analyze RMP's cost studies. In Section IV, I discuss revenue apportionment. In Section V, I provide analysis and recommendations related to rate design. In Section VI, I analyze RMP's AMI project, In Section VII, I conclude my testimony and provide a summary of my recommendations.

III. COST OF SERVICE STUDIES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I highlight the deficiencies of RMP's embedded cost of service study (ECOSS) methods. Specifically, I provide analysis on RMP's proposed production and transmission subfunctionalization, distribution subfunctionalization, the classification and allocation of production costs, and advanced metering infrastructure ("AMI") functionalization. I also briefly review RMP's marginal cost of service study ("MCOSS").

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. Before I begin discussing the methods utilized by RMP within the ECOSS, I provide a discussion of the economic incentives that can influence decision-making within the ECOSS modeling process. Then, in Section III.B, I provide background on how to conduct a ECOSS and the associated objectives. In Section III.C, I provide my analysis of RMP's proposed ECOSS and recommend numerous modifications to their study. In Section III.D, I provide my conclusions and recommendation on the ECOSS. Finally, in Section III.E, I provide my analysis of RMP's proposed Marginal Cost of Service Study ("MCOSS").

A. The Influence of Economic Incentives on Cost of Service Studies

Q. BEFORE YOU DISCUSS THE DETAILS OF THE COSS, PLEASE EXPLAIN HOW ECONOMIC INCENTIVES MAY INFLUENCE COST STUDIES.

A. When evaluating cost studies, and the rate designs they inform, decision-makers should consider how the economic incentives of for-profit investor-owned utilities ("IOUs") can impact assumptions within utility-sponsored cost of service studies.

In a perfect world, corporate profit maximization would align with the objectives of those corporations' customers. However, that is not the case for IOUs. It is important for decision-makers to understand how IOUs' economic incentives may not align with public policy goals and ratepayer interests, so that decision-makers can evaluate cost of service modeling and rate design proposals more effectively.

Q. PLEASE PROVIDE EXAMPLES OF WHERE A UTILITY'S ECONOMIC INCENTIVES MAY NOT ALIGN WITH POLICY GOALS OR RATEPAYER INTERESTS.

A. There are two interrelated issues that can impact the utilities' perspective when conducting cost studies.

First, the price elasticity, or sensitivity, of demand for electricity differs across customer groups. The elasticity of demand measures how much a consumer changes their electricity consumption given a change in its price. Because large customers have more elastic demand than residents, large customers will decrease their demand for electricity more than residents following an equivalent price change, all else constant. This relationship means that utilities can benefit financially from shifting costs from large to residential customers. This presents the utility with an incentive to shift subjective cost allocations (and there are many in cost studies) to classes with less elastic demand by increasing their rates.[2]

Second, third-party services act as substitutes for utility services. Traditionally, electric utilities have had few competitors (e.g. other utilities or natural gas as a fuel alternative) and never have utilities faced competition on the distribution system. Currently, technological improvements, such as solar plus storage, are providing service opportunities that compete with those provided by the utility. The presence of this competition impacts utility incentives in many ways, potentially prompting them to take actions to make their services more cost competitive through otherwise inefficient rate design changes.

Q. HOW DO THE ECONOMIC INCENTIVES OF A UTILITY IMPACT COST STUDIES IN PRACTICE?

A. The utility perspective is largely informed by its economic incentives. For this reason, when subjective determinations are made within a cost of service study or rate design, utilities are likely to make assumptions that benefit their bottom line – as would any for-profit business in a similar position. This can be especially problematic in cost studies and rate design because each process involves numerous subjective assumptions.

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[2] *See* generally James C. Bonbright, Albert L. Danielsen, & David Kamerschen, Principles of Public Utility Rates (2d ed. 1988).

Q. WHY ARE YOU HIGHLIGHTING THESE PERVERSE ECONOMIC INCENTIVES FOR DECISION-MAKERS?

A. My goal is to ensure that decision-makers understand the economic incentives that influence the perspectives a utility presents in regulatory proceedings and when it constructs cost of service models. My goal is not, however, to demonize the utility, which is simply responding to the regulatory framework and the resulting economic incentives in which RMP operates.

B. Objectives & Background

i. Traditional Embedded Cost of Service Study Methodology

Q. WHAT IS THE PURPOSE OF AN ECOSS?

A. The purpose of an ECOSS, or a class cost of service study ("COSS") as referred to by RMP, is to categorize costs into bundled cost categories to inform rate design, and to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs to inform class revenue apportionment.

Q. HOW IS A TRADITIONAL ECOSS PERFORMED?

A. An ECOSS has three steps:

1. Functionalize costs into various categories.

2. Classify costs as related to energy/commodity, demand/capacity, or customers.
3. Allocate costs to the various customer classes using allocators related to energy, demand/capacity, or customer characteristics.

The principles of cost causation and beneficiary pays are used throughout the ECOSS to determine the most appropriate functionalization, classification, and allocation of costs. Cost causation dictates that the user who incurred, or caused, a cost must pay for it. Conversely, beneficiary pays dictates that all of those who benefit from an investment must pay for its costs – in other words, "costs follow benefits."[3] Incorporating the beneficiary pays principle at the retail level is a more modern concept, but is reflected in some traditional cost classification and allocation approaches.

Q. HOW ARE COSTS FUNCTIONALIZED?

A. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission (FERC). These accounts divide costs by various

[3] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, FERC Order 1000, Docket No. RM10-23-000, at 358 (July 21, 2011), available at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf. *See Also* Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual,* at 18. Montpelier, VT: Regulatory Assistance Project. (hereinafter "RAP Manual")

cost functions, such as generation, transmission, and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs.

Many utilities also subfunctionalize costs, which often aligns with different voltage levels. For example, distribution costs can be subfunctionalized into primary and secondary voltages. The purpose of subfunctionalization is to reflect cost causation or beneficiaries more granularly.

Q. HOW ARE COSTS THEN CLASSIFIED?

A. Cost causation is used to classify whether each cost is a commodity-, demand-, or customer-related cost. Energy costs relate to a customer class' energy usage, measured in kilowatt-hours (kWh). Capacity costs relate to a customer class' contribution to peak demand within the system, measured in kilowatts (kW). Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity. Specifically, the National Association of Regulatory Utility Consumers Electric Manual (NARUC Electric Manual) defines customer costs as "costs that are directly related to the number of customers served."[4] In other words, the utility incurs customer costs based

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[4] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January, 20 (1992). (hereinafter "NARUC Manual")

on the number of customers on its system, rather than based on the amount of energy they consume or when they consume it.

Q. HOW ARE COSTS ALLOCATED ONCE THEY HAVE BEEN CLASSIFIED?

A. Costs are allocated to customer classes based on each class' contribution to each classified cost. For example, if RMP spends the same amount of time and money on each customer location, regardless of class, then it is appropriate to allocate that cost based on the number of customer locations. This result stems from the fact that the number of customer locations, rather than customers' electricity consumption, causes costs to be incurred.

Q. HOW SHOULD AN ECOSS ANALYSIS BE USED IN A RATE CASE?

A. Parties and the PSC should exercise caution when using an ECOSS model to inform revenue apportionment or rates, as it is an inherently imprecise tool. Every cost analyst makes numerous subjective determinations that will dramatically impact the results of the study. In my testimony, I suggest several reasonable alternative approaches to the methods that RMP has chosen and demonstrate their impact on the results. Ultimately, the ECOSS I recommend is better supported by economic theory and power system engineering. While I acknowledge that no ECOSS is perfect, I explain the reasons that certain approaches are more reasonable and should therefore be considered by the PSC when determining revenue apportionment and rate design.

ii. ECOSS in a changing power system

Q. ARE THERE ANY CURRENT INDUSTRY TRENDS IMPACTING TRADITIONAL METHODS USED WITHIN THE ECOSS?

A. Yes. Technology and cost responsibility are changing rapidly to meet evolving market demands and to further state policy goals. For example, PacifiCorp's recent all-source request for proposals[5] and its participation in the Western Energy Imbalance Market ("EIM")[6] signal a change in resource makeup and a movement toward shared grid services, each leading to much higher integration of distributed and large-scale renewable energies.

Technological advances are impacting the services provided on the power grid and how they are created, which requires a cost analyst to re-evaluate cost allocation issues that may previously have been considered settled. For example, the increase in variable resources on RMP's system makes the timing of grid services and the availability of grid flexibility

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[5] PacifiCorp's 2020 All-Source Request for Proposals. https://www.pacificorp.com/suppliers/rfps/all-source-rfp.html.
[6] "About". Western Energy Imbalance Market. https://www.westerneim.com/Pages/About/default.aspx.

increasingly important. Modern ECOSS and rate design need to adapt to reflect this changing value by creating and improving temporal cost allocations. Doing so may increase time-varying volumetric cost recovery by classifying larger portions of costs as energy related which will incentivize load flexibility.

Q. PLEASE PROVIDE ANOTHER EXAMPLE OF HOW TRADITIONAL COST CAUSATION HAS CHANGED DUE TO TECHNOLOGICAL ADVANCES.

A. Investment in advanced metering infrastructure ("AMI") serves as an illustrative example. Traditional analog meters simply recorded customer consumption, serving only the individual customer using the meter, and therefore were classified as a customer cost. AMI, however, enables information transfer and action to reduce line losses and lower peak demand, in turn yielding generation, transmission, and distribution system benefits. Customers across those system levels should pay for these services, rather than only the customer who hosts the meter. This is a dramatic departure from the traditionally understood cost responsibility for meters. I discuss this issue in more detail later in my testimony.

Q. WHAT DOES THE AMI EXAMPLE HIGHLIGHT ABOUT THE PRINCIPLE OF COST CAUSATION?

A. Over reliance on a traditional interpretation of the cost causation principle may not result in equitable cost functionalization, classification, and allocation. In the AMI example, traditional cost causation would indicate that the customer who needs a meter incurs the meter cost and therefore should pay for all of it. However, the principle of “beneficiary pays” better accommodates the nuances of AMI benefits and costs explained above. This principle supplements cost causation by recognizing that those who benefit from the cost are not always those who cause it. Costs should be assigned to all beneficiaries.

C. Concerns with Rocky Mountain Power’s ECOSS approach

Q. WHAT DO YOU DISCUSS IN THIS SECTION AND WHY IS IT IMPORTANT?

A. I discuss RMP’s methods for functionalizing, classifying, and allocating electric system costs. For each ECOSS step, I discuss my concerns with RMP’s ECOSS approach. Specifically, I discuss the following topics:

- Subfunctionalization of production and transmission costs
- Subfunctionalization of distribution costs
- Classification of production and transmission costs
- Functionalization of AMI

For each of the above topics, I recommend modifications to RMP’s ECOSS.

i. Subfunctionalization of production and transmission costs

Q. HOW DOES RMP FUNCTIONALIZE COSTS?

A. RMP functionalizes system costs into five categories: production (or generation), transmission, distribution, retail, and miscellaneous.

Q. HAS RMP MADE ANY CHANGES TO ITS FUNCTIONALIZATION APPROACH?

A. Yes. RMP has added a new subfunctionalization step that breaks the production and transmission functions each into four additional categories, for a total of eight categories:

- Demand-Related - Fixed
- Energy-Related - Fixed
- Demand-Related - Variable
- Energy-Related - Variable

Q. HOW DOES RMP SUBFUNCTIONALIZE PRODUCTION AND TRANSMISSION COST CATEGORIES?

A. RMP "split" production and transmission costs into "Fixed and Variable costs" in order to help "facilitate the unbundling of rates."[7]

[7] Meredith Direct at 4.

Q. IS THE SUBFUNCTIONALIZATION OF PRODUCTION AND TRANSMISSION COSTS INTO FIXED AND VARIABLE COSTS AN ACCEPTED ECOSS METHOD?

A. No. It is not supported by any cost manual that I am aware of nor has any state commission approved or utility proposed this form of subfunctionalization—it is unprecedented. The reason that it is not supported by a cost manual or any other industry reference is because RMP is not subfunctionalizing costs.

Traditional subfunctionalization is most frequently used to differentiate costs by voltage levels to reflect cost causation more granularly.[8] RMP's proposal does not reflect cost causation – or even claim to – which undermines the very purpose of functionalization.

Q. DOES RMP DEFINE ITS "FIXED" AND "VARIABLE" SUBFUNCTIONALIZED CATEGORIES?

A. RMP explains that variable supply includes the costs in its Energy Balancing Account, and that fixed supply includes the production function except net variable power costs. [9] The EBA is a rider, which has no

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[8] Lawrence Vogt (2013). Electricity Pricing: Engineering Principles and Methodologies. For example, the subfunctionalization of primary and secondary distribution. Another example is initial functionalization of production, transmission, distribution, and retail.

[9] Meredith Direct at 17.

economic definition and can change over time. RMP does not specify everything that the EBA includes, nor does it provide any analytical methodology for including costs in the EBA. Therefore, there is no general definition of the terms fixed and variable, nor is an economic or accounting definition offer by the Company.

The fixed and variable subfunctions represent entire categories of costs without an analytical definition. Significant costs that are reasonably considered variable could be omitted from the EBA rider. Without a clear analytical methodology, they cannot be investigated to see whether they are accurately accounted for.

The issue of injecting subjectively categorized fixed and variable costs into the ECOSS demonstrates why subfunctionalization is most frequently based on power system engineering and not rate design—power system characteristics are objective while rate design objectives are not.[10] It is clear when a customer takes service at transmission or secondary voltage. It is not clear, what costs are fixed and variable because it is a subjective and unclear definition that is unrelated to power system engineering.

[10] Exceptions to traditional methods of subfunctionalizing costs are emerging due to the transition toward a more modern and technologically advanced power system. These exceptions, however, are driven largely by substitution effects created through advanced technologies, not an analyst's desire to influence rate design outcomes.

Q. WHAT ARE THE PRIMARY SHORTCOMINGS OF RMP'S SUBFUNCTIONALIZATION OF PRODUCTION AND TRANSMISSION?

A. There are multiple shortcomings associated with RMP's proposal to subfunctionalize production and transmission costs.

First, RMP's subfunctionalization approach has no impact on the results of the ECOSS. RMP's proposed subfunctionalization does not impact total class cost allocation nor does it affect classification or allocation. This fact, again, demonstrates that it is not a subfunctionization approach—every other subfunctionalization step in the ECOSS impacts class cost allocation. For this reason, the additional subfunctionalization step only adds confusion to the ECOSS.

Second, RMP is proposing to insert a rate design approach into its ECOSS. Inserting a rate design approach clearly violates best practices for cost modeling and predetermines rate design decisions. Cost studies are supposed to inform rate design—not the other way around. Allowing RMP to insert rate design preferences into the ECOSS will blur the lines between costs and policy determinations made within the rate design process.

Third, RMP's subfunctionalization method creates confusing results. The practical implication of RMP's proposed change is that cost components used to inform rate design are different from those found in the ECOSS. Instead of using the energy, demand, and customer cost components, RMP relies on fixed and variable cost components to inform rate design. The result of this approach is that RMP's method shifts energy related costs into demand related costs, and demand related costs into fixed charges. This aligns with RMP's economic incentive to collect more revenues through demand and customer charges. However, informing rate design based on the subfunctionalized cost components contradicts the results of the ECOSS which has been the basis of rate design for decades in states.[11] No commission in the United States has used the approach recommended by RMP in this proceeding to inform rates.

Lastly, using RMP's subfunctionalized ECOSS results to inform rates will lead to rates that are not based on cost. The ECOSS has traditionally bundled rates into the categories of energy, demand, and customer related to costs so that these cost components can be used to inform energy, demand, and customer rate components. State commissions have used this traditional ratemaking approach for over 100 years. Using RMP's subjectively subfunctionalized fixed and variable costs to inform rates, will deviate from cost-based rates.

[11] Some states rely on the results of marginal costs studies to set rates.

Q. WHAT OBJECTIVE DO YOU BELIEVE RMP IS ATTEMPTING TO ACHIEVE WITH THE SUBFUCTIONALIZATION OF PRODUCTION AND TRANSMISSION INTO FIXED AND VARIABLE COSTS?

A. RMP is attempting to work around the cost of service study to achieve its own rate design preferences.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS MATTER?

A. I recommend that the Commission require RMP to remove the subfunctionalization step within the ECOSS for compliance filings in this case and in future rate cases.

ii. Subfunctionalization of distribution costs

Q. DOES RMP SUBFUNCTIONALIZE DISTRIBUTION COSTS?

A. Yes. RMP splits distribution plant into primary and secondary subfunctions for FERC accounts 364-368.

Q. HOW DOES RMP DETERMINE WHICH EQUIPMENT IS PRIMARY OR SECONDARY?

A. RMP does not explain in testimony its methodology for determining whether distribution infrastructure is primary or secondary. In Data Request OCS 8.21, RMP was asked to “provide a detailed explanation of the data and method used to determine the split between secondary and primary distribution for FERC accounts 364-368." In response, RMP provided only a spreadsheet of a limited number of account costs categorized as primary and secondary and the explanation: "these percentages are based upon a 10-year average of material issues from stores."[12] Not only did RMP fail to explain its subfunctionalization methodology; it failed to explain its data.[13] Without a transparent, quantitative explanation of the costs in the spreadsheet and why they were included, there is no way to know if RMP's primary/secondary split calculations are accurate. RMP did not meet its burden to demonstrate that its method was reasonable.

Q. WHY IS SUBFUNCTIONALIZATION OF PRIMARY AND SECONDARY DISTRIBUTION EQUIPMENT AN IMPORTANT ISSUE?

A. The distinction between primary and secondary distribution infrastructure is important because it could alter cost allocation, particularly for residential customers. If larger portions of the distribution system are found to be secondary related, more costs are borne by the residential class. For example, a 10 percent increase in primary classification for

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[12] OCS 8.21.
[13] OCS 16.21.

FERC accounts 365, 366, and 367 (overhead conductors and underground conductors and conduits) reduces RMP's estimated revenue deficiency for the residential class from 12.78 percent to 12.12 percent.[14] Because RMP did not meet its burden to demonstrate the split of secondary and primary distribution, I include the 10 percent adjustment as a sensitivity within my recommended model.

Q. WHAT DO YOU RECOMMEND THAT THE PSC DO ON THIS ISSUE?

A. The PSC should require RMP to provide additional information on the methodology and the inputs used to justify the split between secondary and primary. This information should include:

1. the data set from which RMP sampled;
2. a description of the data and how it is tracked; and
3. the criteria RMP uses to select costs from the original data set.

iii. Classification of production and transmission costs

Q. HOW DOES RMP CLASSIFY PRODUCTION COSTS?

A. RMP classifies production plant and non-fuel expenses as 75 percent demand-related and 25 percent energy-related. Fuel costs are classified as 100 percent energy related.

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[14] Workpaper OCS 5.1D.

Q. WHAT ARE THE IMPLICATIONS OF CLASSIFYING COSTS THIS WAY?

A. There are two implications. First, from a cost allocation perspective, a higher portion of energy costs are allocated to large energy consuming customer classes (i.e., industrial customers), while demand costs are allocated to customer classes will lower load factors and spiker demand (e.g., residential class). Second, from a rate design perspective, for larger customer classes with demand charges, classifying production costs as demand-related means collecting those costs through a demand charge, while classifying as energy-related means collecting through a volumetric rate.

Q. DO YOU HAVE CONCERNS WITH RMP'S CLASSIFICATION OF PRODUCTION COSTS?

A. Yes. I am concerned with the fact that this allocation approach treats all production resources the same. Regardless of whether the plant is a solar facility, gas turbine, or coal generator, RMP will classify it as 75 percent demand and 25 percent energy.

Q. WHY IS IT PROBLEMATIC TO TREAT ALL PRODUCTION COSTS THE SAME WAY?

A. Treating all production costs in a uniform way fails to acknowledge that investment in different resources reflects specific needs on the power system. Those specific needs indicate whether the plant costs are energy- or capacity-related. For example, peaker plants are generally built to meet capacity reliability need while baseload is built to meet energy need. Renewable resources are generally built to meet energy need and displace the need for other fuel sources – and they do not necessarily provide firm capacity during peak grid demand. RMP therefore should not classify production costs uniformly without evaluating the specific mix of production plant resources on its system.

Q. IS RMP'S CLASSIFICATION METHOD RESPONSIVE TO THE CHANGING POWER SYSTEM TRENDS?

A. No. RMP's blunt and high-level 75 percent demand and 25 percent energy (75/25) approach fails to reflect modern changes in the utility's generation resource mix. The 75/25 ratio likely classifies far fewer costs as energy-related than other, more reasonable, methods would.

Additionally, as technology advances and the power system requires more flexibility, temporal costs become increasing important. For this reason, classifying and allocating production costs based on temporal characteristics may be more efficient and equitable. For example, temporal cost allocation acknowledges that, with high-levels of renewable energy on the grid, load profiles are more important than load factors. This is demonstrated through the growing issue of addressing peaks and low-load conditions during shoulder months as opposed to the traditional focus of meeting peak in summer months in grids with high renewables. As with many more traditional cost allocation approaches, temporal cost allocation would likely lead to higher portion of production being classified and/or allocated as energy-related and result in improved cost components for rate design purposes.

Q. WHAT JUSTIFICATION DOES RMP PROVIDE FOR THE 75/25 CLASSIFICATION APPROACH?

A. RMP explains that "the methodology used in this study for the classification and allocation of generation and transmission costs is consistent with the 2010 Protocol inter-jurisdictional allocation method recently approved by the Utah Public Service Commission."[15]

Q. HAVE PARTIES PROPOSED ALTERNATE PRODUCTION CLASSIFICATION METHODOLOGIES BEFORE?

A. Yes. In numerous previous rate cases, parties proposed alternate classification or allocation methods for generation and/or transmission.

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[15] Exhibit RMP_(RMM-3) at 7.

Those parties acknowledged that it was not necessary to maintain consistency between interjurisdictional and class methods, particularly since the interjurisdictional method results from a multistate compromise.

Q. HAS THE PSC PROVIDED GUIDANCE ON THE STANDARD OF REVIEW FOR ADVOCATING ALTERNATE PRODUCTION CLASSIFCIATIONS?

A. Yes. The PSC previously denied request to deviate from the 75/25 classification and stated: "Any party who would like to propose an alternative to the approved methods must provide analysis to demonstrate the proposed method is also appropriate and viable at the interjurisdictional level. This analysis must include a level of detail to determine the impacts to Utah and other states in the PacifiCorp system of a proposed change in classification and allocation methods." [16]

Q. DO YOU PROVIDE ANALYSIS AT THE INTER-JURISCTIONAL LEVEL AND REGARDING IMPACT ON OTHER STATES?

A. No. My understanding is that the inter-jurisdictional allocation method within the 2020 Protocol is moving away from dynamic allocations toward fixed allocations. According the RMP:

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[16] Phase I Order on Revenue Requirement and Cost of Service using June 2010 Forecast Test Period. Rocky Mountain Power 2009 General Rate Case. Docket No. 09-035-23 at 123.

> the 2020 Protocol represents a fundamental shift in how RMP proposes to address inter-jurisdictional cost allocation, with the ultimate goal of moving away from dynamic allocation factors and a common generation resource portfolio to a cost-allocation protocol with fixed allocation factors for generation resources and state specific resource portfolios.[17]

This fundamental change would appear to obviate the necessity for such analysis because, among other reasons, RMP is moving to a state-specific cost allocation approach. I am not an expert on the inter-jurisdictional allocation method nor am I involved in the ongoing discussions and analysis. However, it seems apparent that as the system evolves into a new allocation method, it would be a good time to re-evaluate the allocations within this jurisdiction to reflect the energy transition currently underway.

Q. DO ALL THE OTHER STATES IN PACIFICORP'S JURISDICTION USE THE SAME CLASSIFICATION APPROACH?

A. No. In response to Data Request OCS 8.3, RMP indicated that the 75/25 approach is not used in California or Oregon.

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[17] *See* Docket No. 19-035-42, Order Approving 2020 Protocol at 7, issued April 15, 2020. "According to RMP,"

Q. ARE YOU AWARE OF OTHER COMMISSIONS THAT ALSO UTILIZE DIFFERENT CLASSIFICATION APPROACHES FOR JURISDICTION AND RETAIL PURPOSES?

A. Yes. One example is the Minnesota Public Utilities Commission.

Q. WHY IS IT IMPORTANT TO PROPERLY CLASSIFY PRODUCTION COSTS?

A. Accurate cost classification is important because the production function accounts for approximately 40 percent of RMP's rate base and 66 percent of total operating expenses.[18] Correctly classifying these significant costs as demand or energy is an equity issue, because it affects how costs are allocated among customer classes.

Q. CAN YOU DEMONSTRATE THAT HIGHER DEMAND-RELATED CLASSIFICATION IMPOSES MORE COSTS ON RESIDENTIAL CUSTOMERS?

A. Yes. I modified RMP's ECOSS model to reflect a 40 percent demand and 60 percent energy ("40/60") classification of production and transmission. The 40/60 split better balances the demand and energy related characteristics of RMP's current and future system. For example, RMP

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[18] COS UT GRC 2020.

has significant hydro and renewable generations that are not appropriately considered 75 percent demand related. Even RMP's baseload plants, such as coal facilities, would be inappropriate to classify at the 75 percent demand related level. The 40/60 split better reflects cost causation and is, therefore, more reasonable.

The 40/60 split changes class cost allocation significantly. The cost responsibility for the residential class fell from the initial cost-based rate increase of 12.78 percent to 8.31 percent, or over approximately 35 percent. While general service over 1 MW and general service with high voltage cost-base rate increase responsibility went up by 3 percent and 6 percent, respectively.[19]

Table 1: ECOSS Results with 40/60 Production and Transmission Classification

Schedule No.	Description	RMP Proposed ECOSS	40/60 ECOSS Results	Cost Allocation Change
1	Residential	12.78%	8.31%	-4.47%
6	General Service - Large	-2.57%	-2.49%	0.08%
8	General Service - Over 1 MW	-0.59%	2.57%	3.16%
7,11,12	Street & Area Lighting	-22.28%	-14.75%	7.53%
9	General Service - High Voltage	7.16%	13.48%	6.32%
10	Irrigation	5.65%	11.03%	5.37%
15	Traffic Signals	-4.64%	-0.56%	4.08%
15	Outdoor Lighting	-31.54%	-15.53%	16.01%
23	General Service - Small	-4.53%	-5.06%	-0.54%
SpC	Customer 1	15.38%	22.70%	7.32%
SpC	Customer 2	0.23%	23.25%	23.03%

[19] Workpaper OCS 5.1D.

	Total Utah Jurisdiction	5.05%	5.05%	N/A

Q. TABLE 1 ALSO INCLUDES AN ALTERATION TO THE CLASSIFICATION OF TRANSMISSION. WHY IS IT REASONABLE TO CLASSIFY LARGE AMOUNTS OF TRANSMISSION AS ENERGY?

A. Transmission systems do not only serve to meet peak demand with reserve capacity. Transmission systems in fact serve to lower energy costs in several ways – and therefore should be proportionally classified as energy-related: 1) they move large amounts of power from remote baseload or renewable generation, trading off expensive transmission costs against the high operating cost of power plants sited closer to a load center; 2) transmission systems are designed to allow large energy transfers between neighboring utilities; 3)) transmission systems are designed to minimize energy losses over long periods of high load (ex: using high voltage infrastructure), rather than just for short periods of peak demand.[20]

RMP's transmission system reflects many of the above energy related design attributes. RMP's transmission connects its load centers to remote coal plants in Wyoming, Arizona, and Colorado, and hydro assets in the Northwest. A significant amount of the costly, high-voltage

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[20] RAP Manual at 138.

infrastructure serves to connect consumers with this remote and inexpensive baseload generation.[21] Therefore, it is reasonable to include transmission in the above sensitivity analysis of 40 percent demand and 60 percent energy classification for RMP's production and transmission functions.

Q. HOW DO YOU RECOMMEND THAT RMP MORE ACCURATELY AND EQUITABLY CLASSIFY PRODUCTION PLANT?

A. There are several classification approaches presented in industry literature that would more specifically and accurately classify RMP's production costs to align with its planning needs and data. More reasonable approaches include the equivalent peaker method and methods that classify costs based on time-differentiated cost causation, such as probability of dispatch.[22]

The probability of dispatch model is superior to most, if not all, approaches because it allows for time-differentiated cost allocation. It involves building a utility's load curve and matching the cost of the units that run in each hour to the kWh use of each customer class in each hour.

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[21] RAP Manual at 138-139.
[22] RAP Manual at 19.

Costs can be recovered through demand and energy charges that reflect the resources under the hourly load curve.[23]

Like any ECOSS approach, the probability of dispatch method requires a cost analyst to make various decisions and therefore their execution must still be deemed reasonable.

Q. DID YOU CALCULATE ANY ALTERNATIVE ALLOCATION METHODOLOGIES?

A. No. Given the Commission's previous rulings, the resources were not expended to conduct these analyses.

Q. HOW DO YOU RECOMMEND THAT THE PSC TREAT PRODUCTION AND TRANSMISSION CLASSIFICATION?

A. In this case, the PSC should consider the alternative ECOSS results, presented in Section III.D, when informing the appropriate revenue apportionment between customer classes and rate designs.

The PSC should require RMP to provide an alternative ECOSS that utilizes the probability of dispatch approach discussed above.

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[23] NARUC Manual at 62.

iv. Classification and allocation of distribution costs

Q. HOW DOES RMP CLASSIFY DISTRIBUTION SYSTEM COSTS?

A. Distribution function costs are considered demand-related, except for meters and services, which are considered customer-related. This is referred to as the basic customer approach for classification of the distribution system. I support the use of this classification approach.

v. Functionalization of AMI costs

Q. WHAT DO YOU DISCUSS IN THIS SECTION?

A. I discuss the functionalization, classification, and allocation of advanced metering infrastructure (AMI) and recommend an alternate functionalization for RMP's AMI equipment. Before I discuss AMI functionalization, I need to explain how traditional meters have traditionally been classified and allocated in cost of service studies and explain why traditional thinking should no longer apply to advanced meters.

Q. HOW HAVE METERS TRADITIONALLY BEEN CLASSIFIED WITHIN COST OF SERVICE STUDIES?

A. According to the NARUC Electric Manual, the costs of meters, or FERC account 370, "are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment."[24]

Q. WHY ARE LARGE-USAGE CUSTOMERS' METERS MORE EXPENSIVE?

A. Large customers' meters are more expensive for many reasons, but generally larger-usage customers' meters have additional functionalities enabled when compared to residential meters.

Q. WHAT WERE THE DIFFERENCES IN FUNCTIONALITY?

A. At the time the NARUC Electric Manual was written—over two-and-a-half decades ago—most residential and small business customers had "dumb meters." Dumb meters only measured energy use and required meter readers to drive to the physical location of the meter to obtain a reading. On the other hand, large-usage customers had meters that measured demand-related requirements and sometimes recorded energy consumption on time intervals such as every 15 minutes (as opposed to residential energy measurement that had just one aggregate reading every month).

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[24] NARUC Manual at 97.

Q. WHAT IS THE REASONING BEHIND THE TWO RECOMMENDED CLASSIFICATIONS IN THE NARUC ELECTRIC MANUAL?

A. The functionality of the meters drove the cost causation. Large customers were on more advanced rate designs that required additional metering functionality such as measuring demand. The additional metering functionality increased the expense of the meter.

Q. WHY DOES CLASSIFYING METERS AS DEMAND RELATED ALIGN WITH COST CAUSATION?

A. Meters that can measure demand, or more granular interval data, can be used to mitigate demand-related costs through price signals. For example, large customer classes often have demand charges and TOU rates. Demand charges incent customers to have higher load factors in order to reduce the costs caused to the power system, while TOU rates encourage load shifting. For this reason, the NARUC Electric Manual finds it reasonable to classify meters as demand because of the enhanced functionality associated with advanced metering.

Q. HOW DOES RMP CLASSIFY METERS?

A. RMP classifies meters as customer related.[25]

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[25] Meredith Direct at 7.

Q. IS RMP PROPOSING CHANGES TO ITS METERING IN THIS CASE?

A. Yes. RMP has proposed the Utah AMI project, which will begin to roll out AMI throughout its Utah service territory.

Q. ARE THE COSTS OF RMP'S AMI DIRECTLY CAUSED BY THE NUMBER OF CUSTOMERS?

A. No. A large portion of the cost of AMI should be to avoid future production and transmission related investments.

Q. WHAT TYPE OF ENHANCED FUNCTIONALITY DOES THE AMI HAVE COMPARED TO STANDARD METERS?

A. Compared to standard meters, AMI has enhanced functionality related to both energy and demand. For example, RMP's AMI could enable it to offer advanced time-based customer rates. Time-based rates can encourage load shifting, which reduces energy costs, and load flexibility, which can reduce peak load and therefore demand costs. Each of these functionalities can decrease the need for future generation and transmission investments, which are together 100 percent energy and capacity related.

Q. HOW DO YOU RECOMMEND RMP TREAT AMI IN THE ECOSS?

A. Because RMP's AMI capabilities can create benefits by avoiding energy- and demand-related costs across multiple electric system functions, changing the functionalization of meters would better reflect cost causation and the beneficiary pay principles. I recommend that RMP functionalize metering costs as 1/3 production, 1/3 transmission, and 1/3 distribution.

Q. WHY IS IT REASONABLE TO FUNCTIONALIZE AMI AS PARTIALLY PRODUCTION AND TRANSMISSION?

A. The practical implication of functionalizing AMI as production and transmission is that AMI costs are then classified and allocated the same as production and transmission assets and are correspondingly allocated to customer classes. Assigning AMI costs as though they are production and transmission assets is reasonable because AMI is an advanced technology that can act as a substitute for production and transmission investments. For example, AMI should be used to increase the amount of demand response on RMP's system, which should necessarily lead to a reduction in production and transmission investments. These avoided investments would have been allocated the same way I am suggesting AMI be allocated---through the production and transmission functions. Said more simply, the customers that benefit from the AMI investments—

through decreased production and transmission investments—should equitably share in the cost of AMI.

Q. HOW DOES MODIFYING THE FUNCTIONALIZATION OF AMI CHANGE THE ECOSS RESULTS?

A. Table 2, below, displays the results of modifying the functionalization of AMI. In general, the modified functionalization results in slightly lower cost allocations to less energy and demand intensive customers and vice versa.

Table 2: ECOSS Results with AMI Costs[26]

Schedule No.	Description	OCS Percentage Change from Current Revenues	RMP Percentage Change
1	Residential	12.46%	12.78%
6	General Service - Large	-2.35%	-2.57%
8	General Service - Over 1 MW	-0.29%	-0.59%
7,11,12	Street & Area Lighting	-22.18%	-22.28%
9	General Service - High Voltage	7.52%	7.16%
10	Irrigation	5.56%	5.65%
15	Traffic Signals	-6.26%	-4.64%
15	Outdoor Lighting	-31.64%	-31.54%
23	General Service - Small	-4.80%	-4.53%
SpC	Customer 1	15.81%	15.38%
SpC	Customer 2	0.55%	0.23%
	Total Utah Jurisdiction	5.05%	5.05%

Q. HOW DID YOU ACHIEVE THIS CHANGE?

[26] Workpaper OCS 5.1D.

A. I removed two thirds of RMP's meter costs from the distribution function and divided it amongst the production and transmission functions instead.

It is important to note that the functionalization approach that I recommend is an actual functionalization step, as opposed to the subfunctionalization approach proffered by RMP. The table above demonstrates that re-functionalizing AMI has an impact on class cost allocation as any functionalization or subfunctionalization step should.

Q. DO YOU HAVE REFERENCES TO SUPPORT YOUR RECOMMENDATION?

A. Yes. I have already described how the NARUC Electric Manual supports classifying advanced meters differently than dumb meters. The Rocky Mountain Institute and Regulatory Assistance Project (RAP) have also previously acknowledged that AMI reduces energy and demand costs. [27] Most recently, RAP's cost allocation manual expressed that the cost of AMI systems are "largely justified by services other than billing" and listed several metering benefits beyond measuring customer usage. Therefore,

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[27] "In some situations, a portion of AMI (and other smart-grid infrastructure) costs may be appropriately recovered through energy or demand charges." *See* Rocky Mountain Institute, A Review of Alternative Rate Designs: Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers, 54 (2016).
"[The] additional cost of smart [also known as AMI] meters is justified by many benefits beyond the simple measurement of usage . . . and this additional cost is not properly considered customer related." *See* Regulatory Assistance Project. Smart Rate Design for a Smart Future, Appendix A at A-4.

"[AMI] costs must be allocated over a wider range of activities, either by functionalizing part of the costs to generation, distribution and so on or reflecting those functions in classification or the allocation factor."[28] While the functionalization that I recommend is subjective to a degree, it better reflects the nature of this modern investment.

Q. IS THERE NON-METER EQUIPMENT AS PART OF RMP'S AMI ROLLOUT?

A. Yes. RMP's AMI project includes information technology infrastructure for data collection and processing.

Q. HOW ARE THESE COSTS LIKELY CLASSIFIED?

A. Customer accounts expenses such as meter reading are functionalized as retail and allocated using customer factors.

Q. HOW DO YOU RECOMMEND THAT AMI IT COSTS BE CLASSIFIED?

A. Given that these technologies enable the same broad functionality and electric system benefits as advanced meters, I recommend that they be similarly functionalized as 1/3 production, 1/3 transmission, and 1/3 distribution. However, I did not incorporate this modification into an

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[28] RAP Manual at 157.

alternative ECOSS due to the complexity of re-coding RMP's model. Therefore, I recommend that the Commission require RMP to make this change in its next rate case.

Q. HOW DOES YOUR ECOSS AMI RECOMMENDATIONS ALIGN WITH YOUR LATER SECTIONS ABOUT AMI?

A. In section VI., I discuss AMI utilization and programs. I conclude there that RMP should not include AMI costs in this rate case. However, given that RMP *has* proposed to include its AMI costs, I have addressed the ECOSS treatment of AMI costs to ensure comprehensive treatment of AMI issues.

vi. Other concerns: COVID-related impacts

Q. DO YOU BELIEVE THAT COVID-19 HAS IMPACTED RMP'S COST OF SERVICE?

A. Yes. COVID-19 has significantly impacted nearly all aspects of life around the country, including the load profiles of electricity consumers. Load profiles are a primary input into the ECOSS because they represent each class' contribution to cost causation within the model. While I acknowledge that the timing of RMP's filing was too early to have a full picture of the impact, the fact that the ECOSS does not reflect COVID's impact on customer loads strongly indicates that the study is inaccurate.

Q. WILL COVID IMPACTS MEANINGFULLY IMPACT CUSTOMER CLASS LOAD PROFILES?

A. Yes. In addition to the immediate effects of quarantining and sheltering in place, COVID-19 has widespread economic ramifications that will alter consumption behavior. These economic consequences will likely have a significant impact that varies both within and between customer classes. For example, commercial electricity usage in Utah dropped 13 percent in April and 11 percent in May due to the economic impacts of COVID-19.[29] These significant changes in load would impact the ECOSS were inputs to be updated.

Q. HAS RMP UPDATED ITS SALES AND LOAD DATA SINCE THE PANDEMIC BEGAN?

A. No.

Q. WHY IS THIS ISSUE IMPORTANT?

A. When the ECOSS fails to reflect current grid circumstances, it likely does not allocate costs accurately. For this reason, it may not be reasonable to make significant revenue apportionment and rate design changes based

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[29] Michael D. Vanden Berg. "Energy News: Impacts of the COVID-19 Pandemic on Utah's Energy Industry." The Utah Geological Survey. August 25, 2020. https://geology.utah.gov/map-pub/survey-notes/energy-news/energy-news-impacts-of-the-covid-19-pandemic-on-utahs-energy-industry/.

heavily on an ECOSS with this severe of a shortcoming, especially considering the circumstances ratepayers are currently facing.

Q. ARE THERE OTHER COST DRIVERS THAT COULD BE AFFECTED BY COVID?

A. In addition to utility sales and load shapes, COVID will likely affect fuel costs, capital costs, labor costs, and uncollectible accounts, among other things.

Q. HOW DO YOU RECOMMEND THAT THE PSC ADDRESS COVID COST OF SERVICE IMPACTS?

A. The PSC should consider the fact that COVID-19 has likely made the results of the ECOSS unreliable and inaccurate. For that reason, in this rate case the PSC should prioritize minimizing changes in revenue apportionment and rate design. Gradualism will help ensure sound revenue apportionment and rate design principles during this period of great instability and uncertainty.

D. ECOSS Conclusions and Recommendations

Q. WHAT IS YOUR IMPRESSION OF RMP'S PROPOSED ECOSS?

A. RMP's proposed ECOSS does not reflect the technology that is currently being placed on the power system, such as renewable energy and AMI.

Not updating the methods used within the ECOSS to reflect modern cost of service principles, will lead to inequitable cost estimates and rates between and within customer classes.

Importantly, RMP's proposal to subfunctionalize costs into fixed and variable costs is an attempt to inject rate design principles into a cost of service study. It will result in rates that are not cost-based. This approach should be clearly and forcefully rejected by the PSC.

Q. CAN YOU PLEASE PRESENT THE RESULTS OF YOUR ALTERNATIVE ECOSS MODEL?

A. Yes. The table presents ECOSS results with the following alterations: (1) production and transmission classified as 40 percent demand and 60 percent energy related; (2) a 10 percent adjustment to the subfunctionalization of primary and secondary distribution, and (3) a re-functionalization of meters.

Table 3: OCS and RMP Final ECOSS Results[30]

Schedule No.	Description	OCS Percentage Change from Current Revenues	RMP Percentage Change
1	Residential	7.30%	12.78%
6	General Service - Large	-1.48%	-2.57%
8	General Service - Over 1 MW	3.59%	-0.59%
7,11,12	Street & Area Lighting	-14.58%	-22.28%
9	General Service - High Voltage	13.87%	7.16%

[30] Workpaper OCS 5.1D.

10	Irrigation	12.17%	5.65%
15	Traffic Signals	-1.76%	-4.64%
15	Outdoor Lighting	-15.46%	-31.54%
23	General Service - Small	-5.69%	-4.53%
SpC	Customer 1	23.18%	15.38%
SpC	Customer 2	23.70%	0.23%
	Total Utah Jurisdiction	5.05%	5.05%

Q. WHAT DO YOU RECOMMEND REGARDING RMP'S PROPOSED ECOSS?

A. I recommend that the PSC consider these issues when apportioning revenue and designing rates. I discuss the rate design implications of these issues in the next section. Specifically, I have recommended that the PSC:

1. Require RMP to remove the ECOSS step that subfunctionalizes production and transmission into fixed and variable categories within the ECOSS.
2. Require RMP to provide additional information on its methodology and data inputs for subfunctionalizing distribution costs into primary and secondary.
3. Consider my modified ECOSS results, presented within Section III.D, when informing revenue apportionment between customer classes and rate designs.

4. Require RMP to provide an alternate ECOSS utilizing the probability of dispatch classification method in its next rate case.
5. Prioritize rate gradualism and fairness due to the impact COVID has likely had on the ECOSS model inputs and results.
6. Metering costs should be functionalized to reflect the characteristics of AMI. Specifically, meters should be functionalized as 1/3 production, 1/3 transmission, and 1/3 distribution.

E. Concerns with Rocky Mountain Power's MCOSS approach

Q. WHAT DO YOU DISCUSS IN THIS SECTION AND WHY IS IT IMPORTANT?

A. I discuss RMP's Marginal Cost of Service Study. RMP agreed to conduct the study after the 2014 rate case, although the results are only for informational purposes. It is nonetheless important to review the MCOSS findings and methodology as they reflect and reinforce trends around RMP's general decision-making in cost studies.

Q. HOW DOES AN MCOSS DIFFER FROM AN EMBEDDED COSS?

A. Rather than using historic service costs to assign cost responsibility among customer classes, an MCOSS is forward-looking. The MCOSS determines the resources required for RMP to produce one additional unit of electricity or serve one new customer in the test year.

Q. HAVE YOU REVIEWED RMP'S MCOSS?

A. Yes, I have done so at a high level.

Q. DO YOU HAVE CONCERNS WITH RMP'S MCOSS?

A. Yes, I am concerned with RMP's treatment of marginal distribution costs, specifically RMP's choice to classify certain system components as customer-related, and the methodology used for doing so.

Q. PLEASE EXPLAIN.

A. RMP classifies distribution cost into three components:[31]

1. demand-related ($/kW/year) = additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system
2. commitment-related ($/customer/year) = the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system
3. billing-related ($/customer/year) = billing and customer service related costs.

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[31] Meredith Direct at 67

Thus, commitment and billing costs will be classified as customer related. While it is common practice to consider billing costs customer-related, RMP has made a subjective decision to include pole, conductor, and transformer costs in this category.

Q. HOW DOES RMP CALCULATE TRANSFORMER COMMITMENT COSTS?

A. RMP created a least squares regression of installed cost versus size of RMP's commonly installed transformers. The slope of the regression, or the change in cost per change in capacity, defines the demand-related costs. The intercept of the regression, or the cost when modeled capacity is zero, defines the commitment costs. This method is known in industry literature as the minimum-intercept or zero-intercept method and relies on the idea that the customer-related cost of a line transformer can be found by simulating a hypothetical no-load piece of equipment.[32]

Q. WHAT ARE YOUR CONCERNS WITH THIS APPROACH?

A. The zero-intercept approach is problematic for several reasons, including that it is abstract and unrealistic and varies dramatically based on a

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[32] NARUC Manual at 92.

utility's subjectively-chosen statistical methods and equipment data.[33] The zero-intercept approach has recently been rejected by Commissions in Colorado and Illinois.[34]

This classification approach is inconsistent with RMP's class COSS. In the class COSS, meters and services are considered customer-related and all other costs considered demand-related.[35] Clearly, far more than meters and services have been assigned to customer rather than demand in the MCOSS. This inconsistency, along with the unsupported classification method, discredit the results of RMP's MCOSS.

Q. HOW DO YOU RECOMMEND THAT THE PSC TREAT THE MCOSS?

A. I do not recommend that RMP's MCOSS be used to inform revenue apportionment or rate design.

IV. REVENUE APPORTIONMENT

Q. HOW DID RMP APPORTION ITS REVENUE REQUIREMENT AMONG CUSTOMER CLASSES?

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[33] RAP Manual at 148.
[34] RAP Manual at 145.
[35] Meredith Direct at 7

A. RMP set a rate spread midpoint at 4.9 percent and then decided how far above or below 4.9 percent to place every customer class, approximately based on its cost of service results. RMP produced the below rate spread:

Customer Class	Proposed Rate Change
Residential	6.9%
Commercial and Industrial	
Schedule 23	1.9%
Schedule 6	3.9%
Schedule 8	3.9%
Schedule 9	4.9%
Irrigation	4.9%
Lighting Schedules	-21.4%

Q. ARE THERE ANY UNIQUE CIRCUMSTANCES RELATED TO THE REVENUE REQUIREMENT AT THIS POINT IN THE RATE CASE?

A. Yes. While RMP has requested an increase in revenue of approximately $95 million, the OCS has recommended a decrease of approximately $59 million. The disparity between the two parties is significant and unusually large. From a revenue apportionment perspective, under the current circumstances, whether an analyst is allocating a rate decrease or increase to classes may impact the recommended approach.

Q. HOW MAY APPROACHES TO APPORTIONING REVENUE, OR RATE SPREAD, TO CLASSES DIFFER UNDER A RATE DECREASE AND INCREASE?

A. There are many ways that the principles may differ when decreasing or increasing rates. I will discuss two. First, while gradualism for rate increases is always important, it may be less so when apportioning rate decreases. For example, an analyst may recommend larger decreases for classes that are significantly overpaying, such as the lighting classes and Schedule 23, but would keep revenue apportionment increases more strongly clustered around the overall increase. In application, gradual rate increases result in assigning classes with increases that do not significantly vary from the overall increase. Gradualism preserves inter-class equity and acknowledges the uncertainty within every cost study.

Second, the level to which an analyst relies on ECOSS results could also vary. Most times that revenue requirements are significantly revised from direct to surrebuttal testimony, the ECOSS is not updated. Not updating an ECOSS with a significantly revised revenue requirement creates a situation where revenue apportionment is based on stale and inaccurate cost information. For example, RMP's proposed ECOSS has the costs of RMP's AMI project, which has been delayed, and I recommend being rejected. The OCS has proposed numerous other similar adjustments that are not reflected in either RMP or my modified ECOSS. For this reason, as disparities from the proposed revenue to the ultimately approved revenues increase, the less useful ECOSS results become.

Q. ARE THERE OTHER UNIQUE CIRCUMSTANCES THAT THE PSC SHOULD CONSIDER WHEN DETERMINING REVENUE APPORTIONMENT?

A. Yes. As discussed above, the economic impacts of COVID have likely changed customer class load profiles significantly. Because customer class load profiles are critical inputs in to the ECOSS, these changes call into question the accuracy of RMP's proposed ECOSS and its usefulness for informing revenue apportionment and rate design.

Q. DURING TIMES WITH EXCESSIVE UNCERTAINTY AND POOR DATA QUALITY, HOW DO YOU RECOMMEND THAT REVENUE BE APPORTIONED TO CUSTOMER CLASSES?

A. I recommend that the PSC prioritize equity. One way to do this is to assign all classes the same directional increase or decrease in rates, while allowing the magnitude of the increase or decrease to vary amongst customer classes. Requiring that all customers shared the burden of rate increases, or in the benefits of rate decreases, is one way to support inter-class equity and reduce the potential for customer confusion. And, as discussed above, gradualism is an important principle, especially when the quality of the underlying data is suspect.

Q. WHAT IS YOUR RECOMMENDATION FOR REVENUE APPORTIONMENT?

A. My recommendation is to follow the principles I have outlined in this section. Due to the circumstances explained above, I will provide a more specific revenue apportionment recommendation in surrebuttal. That will allow me to factor into my analysis whether the revenue requirement differences have narrowed and evaluate any updated data that RMP provides.

V. RATE DESIGN

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I highlight the deficiencies of RMP's rate design methods, specifically its unbundling approach, residential rates, and C&I interruptible load pilot

A. Rate Unbundling

Q. PLEASE EXPLAIN WHY YOU ADDRESS RATE UNBUNDLING IN THIS SECTION.

A. I address RMP's rate unbundling proposal as part of rate design because RMP has introduced its unbundling method as a tool for altering ratemaking.[36]

Q. WHAT IS RATE UNBUNDLING?

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[36] Meredith Direct at 17.

A. Rate unbundling is creating a rate determinant on a customer's bill. However, the general term "unbundling" is used to describe many processes within the cost study and rate design process.

Q. WHAT IS THE TRADITIONAL PURPOSE OF RATE UNBUNDLING?

A. Rate unbundling emerged with utility restructuring. Unbundling was used as a way to remove competitive services from bundled regulated utilities, and then facilitate competition between third parties by allowing the service to be sold separately.

Q. WHAT ARE SOME OF THE EMERGENT OBJECTIVES THAT RATE UNBUNDLING MAY BE USED TO ACHIEVE?

A. The emergence of DERs has led to theoretical proposals suggesting that each service offered by a utility should be separately priced (i.e., unbundled).[37] These unbundled rate structures would result in numerous additional billing determinants on customer bills in an attempt to price each discrete utility service.

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[37] Overcast, Edwin H. Smart Rates for Smart Utilities: Creating a New Customer Paradigm with Enhanced Pricing of Utility Services. Black & Veatch.

Q. DOES THE METHOD OR PURPOSE OF RMP'S PROPOSED RATE UNBUNDLING ALIGN WITH TRADITIONAL OR EMERGENT APPROACHES TO RATE UNBUNDLING?

A. No. In fact, RMP's unbundling methodology is unprecedented and illogical. Specifically, in a vertically integrated regulatory framework, an unbundled ECOSS component should map directly to an unbundled rate component.[38] However, RMP's rate components contradict the cost allocations produced by its own ECOSS resulting in rates that are not cost-based. This suggests that the purpose of RMP's subfunctionalization in the ECOSS, and RMP's ultimate rate unbundling, are both attempts to justify a fabricated rate design.

I strongly disagree with RMP's production and transmission subfunctionalization and unbundled rate design approach. The remainder of this section explains, in depth, the many theoretical and practical shortcomings of RMP's unbundling approach.

i. Company's Proposal and Justification

Q. PLEASE DESCRIBE RMP'S UNBUNDLING PROPOSAL.

A. As previously described, RMP has proposed to subfunctionalize the production and transmission functions into the categories demand and

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[38] There may be circumstances, such as with ancillary service quantification, that direct mappings would be arguable.

energy and then again into “fixed” and “variable” in its ECOSS. RMP then translates these new ECOSS cost categories into three rate design categories:[39]

- Delivery (includes the distribution, retail, and miscellaneous functions and most of the transmission function)
- Fixed supply (includes the production function excluding net variable power costs which are in the Energy Balancing Account (“EBA”), which includes the cost of fuel, wholesale transactions, and production tax credits)
- Variable supply (includes the costs in the EBA, which includes net variable power costs and production tax credits)

RMP then transforms those categories into three rate components:

- basic charge
- demand charge
- energy charge.

Delivery costs are recovered through monthly customer charges and kW charges; fixed supply costs are recovered through demand and energy rates; and variable supply costs are recovered through energy charges.

Q. WHY HAS RMP PROPOSED RATE UNBUNDLING?

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[39] Meredith Direct at 17.

A. RMP justifies its rate unbundling proposal as providing "greater transparency between cost of service and rate design" and "making it easier for regulators and stakeholders to better analyze and understand the different aspects of utility costs."[40]

Q. DID YOU FIND THAT THE RATE UNBUNDLING APPROACH ACHIEVED RMP'S CLAIMED OBJECTIVES?

A. No. The rate unbundling approaches does not achieve the intended objectives. The unbundling proposal convolutes the translation from ECOSS to rate design. It is utterly unclear from testimony – and requires a great deal of scrutiny of RMP's pricing model, which takes time that regulators do not always have available – to ascertain how RMP goes from its new "delivery" subfunction to its basic customer charge, or from its "fixed supply" and "variable supply" to volumetric rates. RMP's rate unbundling does not improve transparency and creates an unclear relationship between the ECOSS and rate design.

Q. HAS RMP'S PROPOSED UNBUNDLING CONCEPT BEEN USED BEFORE?

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[40] Meredith Direct at 17.

A. No. The use of three rate design categories (delivery, fixed supply, and variable supply) is not utilized in any of RMP's other jurisdictions.[41] Additionally, RMP cannot name any other electric utility in the United States that uses this unbundling concept.[42] Nor can RMP cite any publications that recommend the subfunctionalization that RMP has proposed.[43]

Q. DOES RMP CLAIM THAT IT HAS UNBUNDLED ITS RATES BEFORE?

A. Yes. RMP's direct testimony says "The Company unbundles its rates in Oregon, Wyoming, and California"[44] when it introduces the unbundling proposal, just eight lines before describing the three unbundled categories: delivery, variable supply, and fixed supply.

However, when asked in discovery about the specific unbundling in these three states, RMP responded that: "The Company does not unbundle its rates in Oregon, Wyoming, and California into the same three categories it has proposed for Utah."[45] For this reason, I found RMP's testimony on the unbundling practices used in other states be misleading.

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[41] OCS 8.6
[42] OCS 8.7
[43] OCS 8.1
[44] Meredith Direct at 17.
[45] OCS 8.6.

ii. Theoretical Premise

Q. DOES RMP JUSTIFY ITS FIXED AND VARIABLE SUPPLY DISTINCTION FOR RATE DESIGN?

A. No. As explained earlier in section 3.C.i, RMP does not transparently define "fixed" or "variable" from an economics, or any other, perspective. RMP similarly fails to provide an analytical basis for its rate components that are based on fixed and variable supply.

Q. DOES DISTINGUISHING BETWEEN FIXED AND VARIABLE COSTS PROVIDE USEFUL INFORMATION FOR RATE DESIGN?

A. No. RMP's theoretical premise for unbundling – categorizing between fixed and variable costs – is subjective and misconstrues cost subfunctionalization. The fixed versus variable distinction is an antiquated approach that often treats fuel and other short-term costs as variable (to be collected through kWh charges) and other investments as fixed (to be collected based on demand or number of customers). Indeed, this is how RMP applies the concept to rate design.[46] Not only does this approach mischaracterize investment decisions in the modern power system, but it also over-emphasizes short-term costs.

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[46] "Cost causation principles would support recovery of generation fixed costs through demand rates". *See* Meredith Direct at 19.

Q. HOW DOES THE FIXED VERSUS VARIABLE APPROACH MISCHARACTERIZE INVESTMENT DECISIONS IN THE MODERN POWER SYSTEM?

A. In the modern power system, traditional fixed and variable costs no longer serve set purposes and will not reflect cost causation if categorized as such for rate design. For example, wind and solar facilities would traditionally be considered fixed investments with very little variable cost. Informing rate design through the fixed and variable paradigm may lead to recovering wind and solar resources completely through system demand charges. However, utilities often invest in wind and solar to avoid fuel costs, which are traditionally considered variable.

When using the fixed versus variable paradigm, RMP relies on this outdated binary distinction to identify the type of cost and then lets that determination decide why the money was spent, rather than deciding – and charging customers accordingly – based on the way the investment was actually used.

Q. HOW DOES THE FIXED VERSUS VARIABLE APPROACH OVER-EMPHASIZE SHORT-TERM COSTS?

A. Assigning only a narrow set of fuel and power costs to variable supply restricts the costs used to inform rate design to short time period. This approach disregards the fact that a number of so-called “fixed” costs can in fact vary over a multi-year time horizon and can, over that time, be affected by energy consumption – therefore qualifying as energy-related. Imposing such a strict fixed and variable time horizon ignores the economic reality that all costs vary in the long run. Indeed, utilities plan their investments on a multi-year time horizon. Therefore, broadly calling non-fuel investments “fixed” misrepresents the realities of modern system planning.

Finally, and most importantly, using the fixed versus variable approach to inform rate design does not maximize benefits for ratepayers. The fixed versus variable approach is a backward-looking rate design approach. Basing forward-looking rates, on a backward-looking cost approach, has important unintended consequences. The primary consequence is that it will not lead to cost-minimization as the resulting rate design incents customer consumption with a low volumetric rate component, all else constant. The increased consumption can lead to increase capital expenditures at all levels of the power system and therefore increase future rates for ratepayers.

iii. Practical Implications

Q. WHAT ARE THE PRACTICAL IMPLICATIONS OF RMP’S UNBUNDLING PROPOSAL?

A. I will highlight three implications of RMP’s unbundling proposal:

1. It allows RMP to deviate from ECOSS results when designing rates;
2. It shifts energy charges to demand charges; and
3. Designing rate with the goal of influencing renewable energy programs is likely to lead unintended consequences.

Q. HOW DOES UNBUNDLING ENABLE RMP TO WORK AROUND THE COSS?

A. The rate unbundling proposal allows RMP to deviate from the 75/25 demand and energy classification of production and transmission costs within the ECOSS. By subfunctionalizing the production and transmission functions into fixed and variable demand and energy – *separately* from the classification that assigns each function 75 percent demand and 25 percent to energy– RMP is able to sidestep the predetermined classification ratio when translating its COSS into rate designs.

RMP uses the costs from its unbundled categories “delivery”, “fixed supply”, and “variable supply” to set rates, rather than its classified energy and demand costs.[47] By “unbundling” fixed and variable costs, RMP effectively gives itself an alternate framework for categorizing costs as related to energy or demand when designing rates. In fact, RMP has explicitly stated that “what the Company considers to be variable supply

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[47] UT Pricing Model GRC2020.xls

costs is not the same as what it considers to be energy-related."[48] Therefore, although RMP formally classifies production and transmission costs according to jurisdictional protocol, it uses unbundling to carefully avoid translating that part of the COSS results into rates. RMP's rate unbundling proposal subverts decades of regulatory precedent.[49]

Q. ARE THERE OTHER WAYS THAT THE PROPOSED RATE UNBUNDLING ALLOWS RMP TO WORK AROUND THE COSS?

A. Yes. RMP's rate unbundling allows it to deviate from the distribution classification in the COSS. Although the COSS indicates that the only distribution infrastructure that should be considered customer-related is meters and services, the brand new, unbundled "delivery" category includes the entire distribution function.[50] This allows RMP to pick and choose more distribution components to include in basic customer charge in rate design, which RMP has done for the residential class. These examples demonstrate that, instead of increasing transparency, RMP's

[48] OCS 8.8.

[49] To be clear, RMP is changing a ratemaking precedent where results from a cost of service study are used to inform rate designs. RMP's attempt to alter the ratemaking process with rate unbundling relies on a work around to the 75/25 classification split for production and transmission, which is also a long-standing precedent. I am challenging the 75/25 split as well but do so transparently. Of the two distinct precedents, changing the ratemaking process is far more concerning because this change would be unprecedented within the United States, while classification of production and transmission.

[50] UT Pricing Model GRC2020.xls

rate bundling is being covertly used to make significant rate design changes.

Q. HOW DOES RATE UNBUNDLING SHIFT ENERGY CHARGES TO DEMAND CHARGES?

A. As explained earlier, RMP uses its rate unbundling approach to collect production and transmission “variable supply” and “fixed supply” costs in rates, instead of the costs classified traditionally as “energy” and “demand”. A side-by-side comparison of these costs reveals RMP’s orchestrated shift away from cost collection through volumetric components.

Figure 1: Comparison of cost-based energy to unbundled variable supply rate components[51]

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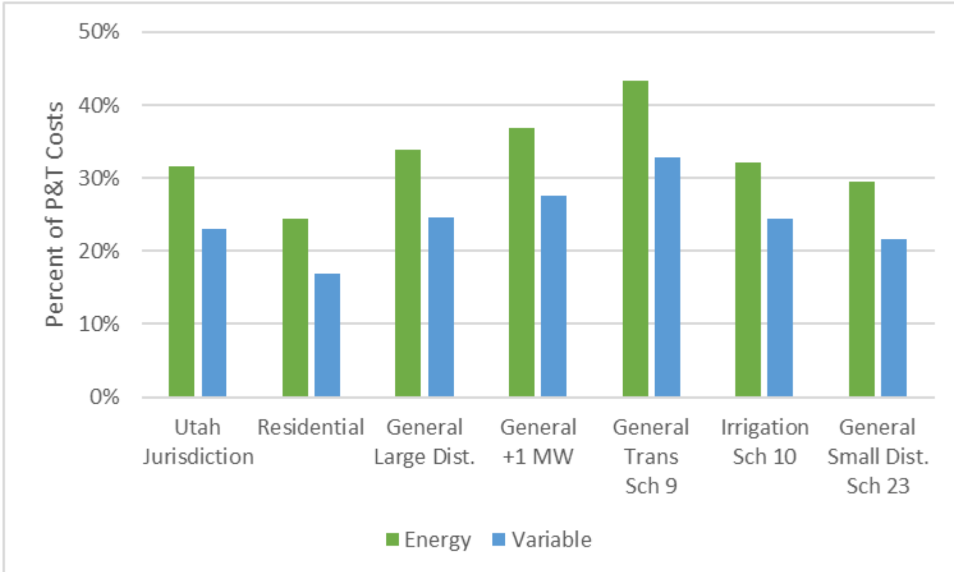
[51] Workpaper OCS 5.2D.



The figure above demonstrates that for each customer class (including those not shown above), the production and transmission costs that RMP subfunctionalized as variable supply are significantly lower than the costs RMP classified as energy.[52] Correspondingly, the costs subfunctionalized as fixed supply are greater than the costs classified as demand. General Service distribution customers, for example, would see a 9 percent decrease from cost-based kWh rates under RMP's rate unbundling. RMP relies on variable supply costs to inform kWh its rate proposals, which reduces the kWh component below the cost basis indicated within RMP's ECOSS.

[52] The energy classification percentages do not equal exactly 25% because they may include other things such as fuel costs that are classified 100% energy.

Q. WHY IS IT CONCERNING THAT UNBUNDLING SHIFTS ENERGY CHARGES TO DEMAND CHARGES?

A. There are few reasons why shifting collection from energy charges to demand charges concerns me.

First, it will increase energy consumption since price signals associated with incremental energy use will be much lower, all else constant. Increasing consumption will likely lead to increased investment by the utility and ultimately increase rates.

Second, lowering kWh and increasing demand charges may lead to less flexible load. Collecting revenues through relatively higher time-varying rate designs would better incent flexibility and therefore align better with the technologies that are going onto the grid (e.g., renewable energy, energy storage, and AMI).

Lastly, it changes the ratemaking process by moving away from cost-based rates as determined within the ECOSS. Approving RMP's methodology would provide RMP with a much higher degree of control over the design of rate components because rate components would no longer be informed by the ECOSS, but instead by the costs that RMP subjectively and opaquely determines to be fixed or variable.

Q. RMP NOTES THAT RATE UNBUNDLING WILL HELP WITH RENEWABLE ENERGY PROGRAM DESIGN. [53] **HOW DO YOU RESPOND TO THIS IDEA?**

A. First, rates for general customer tariffs should not be designed with external renewable energy programs in mind. This will likely lead to unintended consequences. Also, RMP provides no evidence supporting their assertion of how rate unbundling, and more specifically its proposed rate unbundling design, will help with any renewable program design.

Q. DO YOU FIND IT APPROPRIATE TO DESIGN RATES WITH THE GOAL OF IMPACTING COMPENSATION FOR DERS OR RENEWABLE ENERGY PROGRAMS?

A. No. Rates should be designed to provide customers with an efficient price signal based on the services they are receiving at that time. Rates should not be designed with DER compensation in mind. Doing so will result in an over-emphasis of the utility’s revenue stability and an under-emphasis of incenting positive behavior through price signals. This is the case with RMP’s rate design proposals. If RMP believes that DERs are not compensated equitably, they should create a distinct pathway to compensate them, not use primary customer class tariffs.

[53] Meredith Direct at 17.

iv. Recommendation

Q. HOW DO YOU RECOMMEND THE PSC ADDRESS RMP'S RATE UNBUNDLING PROPOSAL?

A. Allowing RMP to base rates off its rate unbundling approach is a move away from cost-based rate design. This would be a significant and unprecedented approach to design rates.

I recommend that the PSC reject RMP's rate unbundling proposal. In the next rate case, the PSC should require RMP to inform rate based on cost and not inform rate on its rate unbundling methodology.

B. Residential Rate Design

Q. WHAT RATE CHANGES HAS RMP PROPOSED FOR ITS RESIDENTIAL CUSTOMER CLASS?

A. RMP has proposed to assign different prices to multi-family and single-family customers for the monthly customer charge. It proposes maintaining the existing $6 monthly customer charge for the former customer type and raising it to $10 for the latter. RMP also proposes eliminating its minimum charge and the third tier of its inclining energy block rates while updating the seasons for its remaining tiered blocks.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY ON RESIDENTIAL RATE DESIGN?

A. I provide analysis and recommendation related to the appropriate customer charges and segmentation of the residential class into single and multi-family tariffs.

Q. DO YOU HAVE CONCERNS WITH RMP'S PROPOSED CUSTOMER CHARGE AND THE JUSTIFICATION USED TO SUPPORT IT?

A. Yes. I have the following concerns, each of which I will discuss in further detail:

1. The bill impacts created with RMP's proposed customer charge increase, in combination with reducing the number of inverted block rate ("IBR") tiers, are very significant.
2. Use of the fixed versus variable distinction is inappropriate for rate design.
3. Recovering transformer costs in the customer charge is unreasonable.
4. While I find RMP's recommendation reasonable to segment the residential class into single and multi-family tariffs, I discuss how to improve the multi-family offering.

I end with my recommendations on the appropriate customer charges for the single and multi-family residential tariffs.

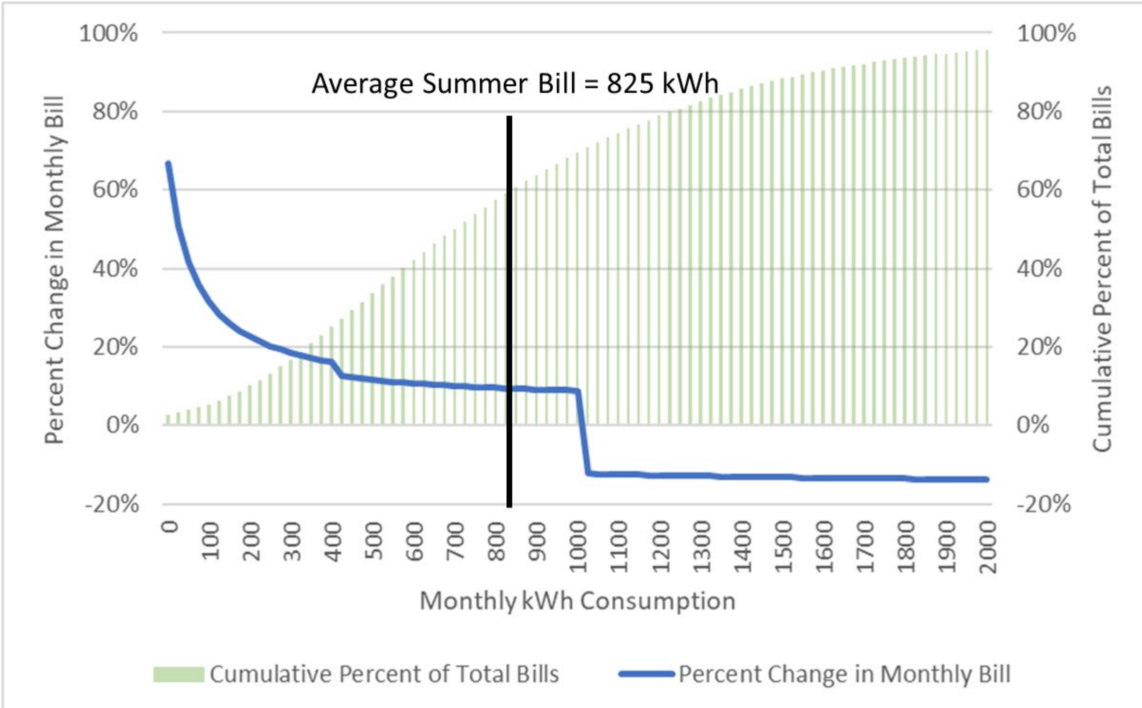
i. RMP's Proposal Creates Excessive Bill Impacts for Most Residential Customers

Q. HOW DOES RMP'S PROPOSED RATE DESIGN AFFECT RESIDENTIAL BILLS?

A. RMP's proposed rate design increases average summer monthly bills under 1,000 kWh by over 9 percent and lowers bills for consumers over 1,000 kWh by over 10 percent. The bill increase affects approximately 70 percent of residential customers while the decrease affects approximately 30 percent. The graph below demonstrates the impact of RMP's proposal on monthly residential bills up to 2,000 kWh.

Figure 2: RMP's proposed rate design bill impacts by percentage increase and proportion of customers impacted[54]

[54] Workpaper OCS 5.3D.



Due to the seasonal nature of RMP's rates, Figure 2 represents summer impacts (June-September), for simplicity. The blue, horizontal line represents the percentage change in current single-family bills and corresponds to the left y-axis. The x-axis shows average monthly summer consumption.[55] The green bars represent a cumulative distribution curve that indicates the percentage of residential customers who consume at or below each kWh level throughout the summer.[56] The percentages associated with the cumulative distribution are presented on the right y-

[55] The average consumption was created using data from 2019.

[56] Due to data limitations, the blue bill impact line represents single-family residential bills, while the green cumulative frequency distribution of customer bill count includes all residential customers.

axis. Finally, the vertical post indicates average monthly summer consumption. Importantly, approximately 60 percent of residential customers consume less than average and would experience a rate increase of over 9.5 percent.

Figure 2, above, demonstrates that RMP's proposal to increase the basic customer charge, while at the same time reducing the number of IBR tiers from three to two, significantly shifts cost recovery to lower consuming residents and creates very large bill impacts for small consumers. While low consuming customers could see a 20 percent rate increase, high consumption customers (over 1,000 kWh) will realize *a rate decrease of over 10 percent*. Residential customers who consume under 250 kWh a month (or about 12.5 percent) will experience a 20% or greater increase in their average monthly summer bills, while 50% of residential customers will experience a 10% or higher increase in their average monthly summer bills.

RMP's proposal creates inequitable bill impacts within the residential class by assigning significant rate increases to low use customers (which constitutes 70 percent of residential customers) and assigning significant rate decreases to high consumption users.

ii. Fixed versus Variable Costs

Q. HOW DOES RMP USE THE FIXED VERSUS VARIABLE DISTINCTION IN RATE DESIGN?

A. As with its unbundling proposal, RMP uses the idea of fixed costs in residential rate design, explaining that the "residential basic charge should include the fixed costs associated with customer service, billing, and the local infrastructure… ."[57]

Q. WHAT IS YOUR CONCERN WITH RMP'S DISTINCTION OF "FIXED COSTS"?

A. As explained earlier, the concept is outdated and does not align with how the power system is modernizing. By assuming that costs are fixed and therefore need to be recovered through a fixed charge, RMP is implicitly assuming that once installed equipment will not need to be replaced due to capacity overload. This assumption is unsupported and likely untrue for some of the equipment deemed fixed, such as transformers.

iii. Line Transformers are Not Customer-Specific Costs

Q. WHAT ARE YOUR CONCERNS WITH INCLUDING TRANSFORMERS IN THE CUSTOMER CHARGE?

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[57] Meredith Direct at 19.

A. Only customer-specific costs should be collected through a customer charge, which line transformers are not. Customer-specific costs are unaffected by demand and energy use and are equitable to collect through a fixed charge.

Q. WHY DOES RMP INCLUDE TRANSFORMERS IN ITS BASIC CUSTOMER CHARGE?

A. RMP claims that it is appropriate to include line transformers in the monthly customer service charge for a few reasons. RMP first supports its position by arguing that the cost of line transformers is unaffected by changes in customer energy usage, saying that "a customer's conservation efforts…will not lower the Company's cost of line transformers."[58]

Q. DO YOU FIND THIS ARGUMENT TO HOLD TRUE?

A. No. The Regulatory Assistance Project points out that transformer usage correlates to the lifetime (and therefore the cost) of the equipment:

> A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.[59]

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[58] Meredith Direct at 21.
[59] RAP Manual at 148.

Since the frequency of transformer replacement is linked to its customers' load shapes, line transformer cost can be closely related to customer demand. Contrary to RMP's claims, conservation efforts could indeed lower costs if that conservation were targeted at reducing local distribution peaks. Conservation efforts could also increase the number of customers that can be served on one transformer.

Q. COULD LOAD SHAPE BECOME EVEN MORE COST-CAUSATIVE INTO THE FUTURE?

A. Yes. If EV adoption takes place as RMP predicts, it is likely to lead to more severe transformer overload in the future as EV customers likely charge their vehicles during the existing residential peak. This trend will make individual customers' load shape even more impactful on transformer costs. If the cost of line transformers is applied equally on a per-customer basis, rather than based on the impact of individual demand during distribution peaks, there will be a significant equity issue as other customers cross-subsidize those EV customers.

Q. WHY ELSE DOES RMP INCLUDE TRANSFORMERS IN ITS CUSTOMER CHARGE?

A. RMP also argues that line transformers should be included in the basic customer charge because the cost of a transformer does not increase proportionally to customer size. RMP explains that transformers come in capacities of 10, 25, and 50 KVA but that the installed cost difference between the latter two sizes is only 7 percent. Those economies of scale evidently suggest that installed cost is "not driven entirely by size."[60] However, when the incremental capacity of a transformer jumps from 25 to 50 KVA, the cost of a new one is also certainly "not driven entirely by" incremental customer count, either.

RMP additionally argues that line transformers should be included in the basic customer charge because that charge should include "the local infrastructure that is located geographically close to the customer and is dedicated to serving one or a small number of customers"[61] It could be reasonable to assign transformers to the customer charge if the equipment were utilized by only one customer, but RMP's average line transformer serves 6.48 customers. Even single-family transformers serve an average 5.63 customers.[62] This infrastructure is clearly not specific to an individual customer in the majority of cases.

Q. DO YOU BELIEVE LINE TRANSFORMERS SHOULD BE INCLUDED IN THE CUSTOMER CHARGE?

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[60] Meredith Direct at 21.
[61] Meredith Direct at 19.
[62] Exhibit RMP___(RMM-6) - Basis for Cust Svc Chg.

A. No. Increasing the fixed customer charge with transformer cost is a step in the wrong direction. RMP should be focusing on moving toward time-varying rates to improve efficiency and equity. Time-varying rates are more cost reflective and give customers more control over their bill. Fixed charges do the opposite.

Q. WHY SHOULD ONLY CUSTOMER-SPECIFIC COSTS BE COLLECTED FROM CUSTOMERS THROUGH THE CUSTOMER CHARGE?

A. Only customer-specific costs should be collected through the customer charge. The reasoning is again about equity (avoiding intra-class subsidy) and sending efficient price signal for energy efficiency and conservation. Additionally, collecting only customer-specific costs through the customer charge leaves demand related costs to be collected through time-of-use rates, which would send a better price signal to customers and therefore encourage consumption that reflects the true conditions on the electric grid.

Q. HOW MUCH ARE CUSTOMER-SPECIFIC COSTS FOR RESIDENTS?

A. Using my ECOSS approach, the cost of meters, services, the retail function, and the miscellaneous function are $7.90 for both single-family and multi-family customers.[63] Although RMP acknowledges that meters and services costs "are generally lower for serving multi-family dwellings," but that they do not have the data to differentiate.[64]

iv. Multi-Family Rate Proposal

Q. WHAT HAS RMP PROPOSED FOR MULTI-FAMILY RATE DESIGN?

A. RMP has proposed to split the customer service charge into different prices for single-family and multi-family customers: $10 for single-family and $6 for multi-family. The difference is based on the differing cost of line transformers to serve the two customer groups.

Q. DO YOU FIND CREATING A SEPARATE MULTI-FAMILY TARIFF TO BE REASONABLE?

A. I agree conceptually with distinguishing between single- and multi-family residential customers. However, RMP should broaden the cost distinction beyond the groups' line transformer costs (particularly given that line transformer costs should not be in a basic customer charge in the first place, per my testimony above). RMP notes that it could only analyze the difference in costs related to transformers, and not the cost differences for

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[63] Exhibit RMP___(RMM-6) - Basis for Cust Svc Chg. RMP's approach leads to $8.46 of customer-specific costs.

[64] Meredith Direct at 20.

meters and services due to data availability.[65] RMP should collect more information and further the distinction between the two groups.

Q. WHAT ADDITIONAL DATA SHOULD RMP COLLECT?

A. RMP should begin collecting data on load differences and differences in infrastructure requirements between the sub-classes, such as service line and secondary distribution infrastructure requirements. I recommend that the PSC require RMP to provide this, as well as other information the utility identifies as being useful, in its next rate case.

v. Customer Charge Recommendation

Q. WHAT CUSTOMER CHARGE DO YOU RECOMMEND FOR THE SINGLE AND MULTI-FAMILY RESIDENTIAL CLASS TARIFFS?

A. For single-family residents, I recommend a basic customer charge of $7. For multi-family, I agree with RMP's recommendation of $6.

Q. WHY DO YOU RECOMMEND THESE CHARGES?

A. Just as RMP did in its proposal, I used the customer-related costs to inform my customer charge proposal. I also took into consideration the bill impacts of the other proposed rate changes, including RMP's elimination

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[65] Meredith Direct at 20.

of its highest tiered energy block. As I explained in the section above, these impacts include increased costs for low volumetric users. It would cause significant rate shock to increase the customer charge in addition to the other proposed changes. Along the same lines, I prioritize gradualism due to the challenging economic circumstances many ratepayers are facing due to COVID.

Q. ARE THERE ADDITIONAL REASONS THAT RMP SHOULD AVOID SIGNIFICANT RATE CHANGES AT THIS TIME?

A. RMP's proposed AMI rollout will enable additional, potentially more beneficial, rate offerings in the future.

C. C&I Interruptible Load Pilot (Schedule 35)

Q. WHAT HAS RMP PROPOSED FOR ITS C&I SCHEDULE 35 PILOT ("INTERRUPTIBLE TARIFF" OR "SCHEDULE 35")?

A. The proposed pilot would enable large customers to reduce their load during periods of high market prices or grid stress, in exchange for demand charge credits ($1/kW) and energy credits ($0.20/kWh). The participating customers would nominate their interruptible load level and would have to reduce their consumption to that level whenever RMP calls interruption events (ex: if a customer that typically consumes 10 MW chose to be interruptible down to 7 MW, it would need to shed 3 MW during each event).

RMP would call up to 100 hours of events each calendar year – each with a minimum one-hour duration – and would be able to call an event for up to three consecutive hours each day. Participating customers would have at least 30 minutes to reduce their load after receiving notice.[66] Participants would pay a $90 monthly administrative fee and cover any necessary cost to upgrade their metering equipment.

Q. WHY HAS RMP PROPOSED THE C&I INTERRUPTIBLE LOAD PILOT?

A. RMP explains that large customers represent the greatest per meter opportunity for load flexibility, i.e. bill reduction in exchange for load shifting to low-cost periods, and that large customers are sophisticated energy users who can respond to complex pricing structures.[67]

Q. HOW DID RMP DETERMINE CREDIT PRICES FOR THE INTERRUPTIBLE LOAD PILOT?

A. RMP used real-time prices from the EIM. For energy credits, it determined that $0.20/kWh would be appropriate because the EIM exceeds $200/MWh under 100 times a year, meaning that RMP would be

[66] Meredith Direct at 49-50.
[67] Meredith Direct at 49.

incentivized to call an event during that limited set of hours. For demand charge credits, RMP again used EIM prices to determine that the value of the hours exceeding $200/MWh equated to $0.89/kW-month. RMP rounded the demand charge up to $1 to make the savings "sufficiently attractive" to large non-residential customers and to account for capacity value that might be additional to the energy credit.[68]

Q. HOW DOES RMP PROPOSE TO EVALUATE THE INTERRUPTIBLE LOAD PILOT?

A. RMP does not propose a specific evaluation process. RMP refers to potential learnings throughout its proposal.[69] However, RMP offers no objective criteria, metrics, reporting requirements, or any other objective framework from which to evaluate the pilot.[70]

For example, in its responses to Data Requests OCS 8.15 and 16.17, RMP stated that it will evaluate the "cost-effectiveness of the pilot" but, after a request for exactly how it will measure cost-effectiveness, RMP failed to provide any information that could be used to measure program cost-effectiveness. Additionally, RMP indicated that it would

[68] Meredith Direct at 51.
[69] E.g., "(E)xperience operating the proposed pilot program can help determine an appropriate capacity value … (and) … even if no customers ultimately enroll in either program, the Company will learn that the pilots are not sufficiently attractive to entice participation." Meredith Direct at 51 and 58.
[70] See RMP's Response to Data Request OCS 8.15 and 16.17.

measure the success of the program "based upon its communications with customers." The subjective evaluation approach suggested by RMP will not provide useful information and will leave the success of the program to be directly determined by the utility and by the customers receiving a discounted rate. Simply said, RMP's pilot framework does not follow best practices.[71]

Q. WHAT PROCESS DOES RMP PROPOSE FOR PROGRAM DEVELOPMENT AFTER THE PILOT?

A. Like RMP's lack of evaluation criteria, the proposal also lacks clarity on the pilot's progression towards a scaled offering, such as a standard tariff, or further development of a modified offering. However, RMP seems to assume that the pilot will extend multiple years, saying: "after the first year, availability on both programs would be on a first-come, first-served basis."[72] RMP anticipates requesting future program expansion "depending upon how well the pilots perform at providing both RMP and customers with meaningful value."[73] However, RMP provides no metric for what meaningful value might be, nor when that value would be measured.

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[71] Peter Cappers and C. Anna Spurlock (2020). A handbook for designing, implementing, and evaluating successful pilots. Lawrence Berkley National Laboratory. Prepared for the Office of Electricity Delivery and Energy Reliability.
[72] Meredith Direct at 58.
[73] Meredith Direct at 58.

Q. WHAT ARE YOUR HIGH-LEVEL CONCERNS WITH RMP'S PROPOSED SCHEDULE 35?

A. My primary concern is that the load on Schedule 35 will not provide meaningful value to ratepayers through the deferral or replacement of utility resources or utilization of the interruptible load (i.e., the likelihood that interruption will be called is incredibly low and economic curtailment is not required). This concern suggests that in practice Schedule 35 may simply be a rate decrease for large customers as opposed to a useful demand response resource.

A secondary concern is the fact that RMP is piloting an interruptible load tariff – a tariff type and technology that has existed for decades.[74] Pilots should test new technologies, business models, and pricing constructs. Pilots are often unnecessary when a solution has been proven by numerous other utilities. While this tariff and pricing structure may be new to RMP (although even that is unclear), the concept is not. For this reason, RMP should have a clear plan for integrating and scaling the tariff to provide value to ratepayers – but RMP does not. This reinforces my concern that Schedule 35 is merely a rate discount and not a serious service offering.

[74] E.g., Interruptible tariffs are present in California and many MISO states, including Minnesota.

Given these concerns, I recommend multiple improvements to the pilot specifics and framework. First, I recommend that the PSC require an improved framework for pilot programs moving forward. Second, I recommend an adjusted discount. Finally, I recommend that the PSC adopt multiple reporting requirements related to the pilot.

i. RMP's pilot framework should be improved

Q. HOW COULD RMP'S PILOT FRAMEWORK BE IMPROVED?

A. There are many ways that RMP could improve its pilot framework. I offer the following methods to improve future pilots but do not consider this a comprehensive list of potentially beneficial improvements.

First, RMP needs to provide a clear description of the product, service, or offering that it is testing. In testimony, RMP described the interruptible tariff as increasing load flexibility. There are many types of load flexibility and each type has a different value to the grid. Exploring different types of flexibility and their value is important. However, testing flexibility and value requires more carefully defined services than what RMP has provided. RMP's proposed interruptible tariff is more accurately described as economic curtailment and emergency load balancing and frequency regulation services.[75] These forms of flexibility have a lower

[75] See RMP's Response to Data Request OCS 16.18.

value to ratepayers than, for example, a dispatchable demand response program that displaces a future capacity need.

Second, the objectives of the pilot should be clearly identified and directly linked to providing ratepayer benefits. For example, RMP claims that one of the objectives of the Interruptible Tariff is to determine whether there is a capacity value associated with the tariff. However, RMP does not have a framework for determining whether the Interruptible Tariff achieves this objective. One way to demonstrate that the Interruptible Tariff provides capacity value is to incorporate the resource into RMP's integrated resource plan, similar to other utilities.[76] Clearly identified objectives with direct links to ratepayer benefits should be required for every RMP pilot moving forward.

Third, evaluation criteria – including performance targets and/or metrics – should be included within each pilot proposal. In the current proposal, RMP "hopes to develop (metrics) as it gains experience with the pilot."[77] Developing metrics after the pilot proposal does not follow best practice and demonstrates a lack of forethought on the value that the offering will provide ratepayers. Performance targets and/or metrics are central to providing clear and actionable insights and should be required prior to approval of any pilot.

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[76] E.g., Xcel Energy and Minnesota Power in Minnesota.
[77] See RMP's Response to Data Request OCS 8.15, 16.15, and 16.17.

Lastly, I recommend that each pilot have a plan for scaling the piloted service offering or, at a minimum, a description of what RMP plans to do if the pilot is successful. RMP has provided no detail on how this pilot could be scaled or improved based on its results.

ii. The interruptible discount should reflect the service provided

Q. WHAT ARE SOME OF THE SHORTCOMINGS OF RMP'S APPROACH TO CALCULATING THE ENERGY AND DEMAND DISCOUNTS?

A. The primary issue is that RMP derived the demand discount from real-time energy prices, not from a tangible capacity value. Additionally, RMP's claim that there is a capacity value associated with a product that has a maximum duration of three hours lacks support. For that reason, if the pilot is approved, I recommend rounding down the demand-related credit to $0.50/kW. With that said, I may support an alteration or addition to the pilot that productively explored right-sizing incentives, if one were proposed.

I request that RMP provide additional analysis to complement its Exhibit RMP__(RMM-10) in rebuttal in order to compare the $0.50/kW and $1/kW discount levels. Specifically, I request that RMP provide 10 different customer types with differing load shapes and load factors. As currently provided, Exhibit RMP__(RMM-10) only evaluates the discount on one specific customer, which may not be representative of participating customers.

iii. The PSC should adopt reporting requirements

Q. HOW COULD THE PSC TAKE STEPS TOWARD IMPROVING THE INTERRUPTIBLE TARIFF PILOT FRAMEWORK?

A. The PSC could adopt an initial set of reporting requirements.

Q. WHAT REPORTING REQUIREMENTS DO YOU RECOMMEND?

A. I recommend the following annual report requirements:

- All intervals when energy prices are above $200/kWh;
- Interruptions by event, customer, interval, and a narrative for each event describing the reason for interruption;
- Amount of capacity enrolled by month;
- For each event, the amount of curtailment called and the amount curtailed within the required timeline;
- The price of energy during the top 400 15-minute intervals and a narrative explaining why economic curtailment was not called during intervals that exceed $200/kWh;
- Annual program costs; and
- Annual cost saving and a narrative explaining the methodology for estimating savings.

Q. WHAT ACTIONS DO YOU RECOMMEND THE PSC TAKE ON RMP'S SCHEDULE 35 PROPOSAL?

A. I recommend that the PSC require RMP to file a compliance filing that provides the information in Section V.C.i, adopt the discount alteration of $0.50/kW, and adopt the reporting requirements in Section V.C.iii.

Additionally, I recommend that the PSC require RMP provide similar information for each future pilot.

D. C&I Critical Peak Pricing

Q. WHAT IS CRITICAL PEAK PRICING?

A. A critical peak price is an event-based rate component that can be added to most, if not all, rate structures to incent flexible load during times of system stress. Characteristics of a critical peak pricing components can include a significant kWh rate (often between $0.50/kWh and $1/kWh), a limit on the number of events and event hours per year, and a limit to duration an event can last. For example, a critical peak pricing component could be added to RMP's Schedule 8 tariff that was $0.75/kWh with the constraints that the utility could call 15 day ahead events that could not last longer than 5 hours.

Q. WHAT IS THE PURPOSE OF CRITICAL PEAK PRICING?

A. The purpose of critical peak pricing is to incent flexible load through price signals. Critical peak prices are distinct from the pilots that RMP is proposing because the critical peak pricing component is designed to collect peaking capacity costs, at a minimum, to reflect that system peaks cause future capacity additions. RMP's pilots focus on real-time or near-real-time pricing circumstances.

Q. HAVE OTHER UTILITIES IMPLEMENTED CRITICAL PEAK PRICING FOR LARGE CUSTOMERS?

A. Yes. There have been numerous pilots and some utilities have included a critical peak pricing component within default large customer tariffs.

Q. DO YOU HAVE A RECOMMENDATION RELATED TO CRITICAL PEAK PRICING?

A. Yes. For each customer class with demand over 1 MW, the PSC should order RMP to evaluate a critical peak pricing pilot in its next rate case, since this type of program has a better track record of delivering transparent benefits to other ratepayers.

<u>VI. ADVANCED METERING INFRASTRUCTURE (AMI)</u>

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide an analysis of RMP's AMI project as discussed in the testimony of Witness Curtis B. Mansfield. In Section VI.A, I discuss the additional process and details needed for the PSC to comprehensively evaluate the reasonableness of RMP's AMI project proposal. In Section VI.B, I analyze and comment on RMP's cost-benefit analysis ("CBA"). Finally, in Section VI.C, I provide my recommendations related to RMP's AMI project.

Q. HOW DOES THIS SECTION OF YOUR TESTIMONY RELATE TO THE DIRECT TESTIMONY OF OCS WITNESS DONNA RAMAS?

A. Ms. Ramas recommended that the costs of the AMI project not be included within the test year, based on the project not being used and useful during the test year. I recommend that the AMI project proposal be rejected based on the analysis within this section. Therefore, my conclusion to reject the AMI project is consistent with, but distinct from, Ms. Ramas's recommendation.

Q. PLEASE SUMMARIZE RMP'S AMI PROJECT PROPOSAL.

A. RMP's Utah AMI Project would construct an AMI field area network which would enable remote reading of 790,000 existing AMR meters, and on-site replacement of approximately 175,000 existing meters to Itron smart meters. The effort would fully automate and retrieve hourly meter reading data each day.[78]

Q. WHAT IS THE TIMELINE FOR THE AMI PROJECT?

A. The AMI project was initially going to be completed by the end of 2022. Due to COVID RMP has delayed the start of the AMI project until the end of 2022.[79]

Q. WHAT ARE THE SPECIFIC INVESTMENTS THAT RMP IS INCLUDING WITHIN THE AMI PROJECT?

A. RMP proposes to invest in multiple grid modernization assets within the AMI project including (1) a field area network ("FAN"), a meter data management system ("MDMS"), (3) website alterations, (4) an outage detection system, and (5) AMI.

Q. WHAT ARE THE PRIMARY OBJECTIVES OF RMP'S AMI PROJECT?

A. RMP is attempting to improve outage management, enable RMP to remotely connect and disconnect electric service, lower operating costs (i.e., reducing manual metering reading operations), provide customers

[78] Mansfield Direct at 24.
[79] See RMP's Response to Data Request OCS 11.1.

with some additional consumption data, and lay a foundation for future smart grid investments, including "customer facing energy efficiency applications and rate design."[80]

Q. HOW IS RMP ROLLING OUT AMI TO CUSTOMERS?

A. RMP claims that it is utilizing a controlled rollout of AMI, along with the installation of a FAN, to improve cost-effectiveness. The FAN would read existing AMR meters, and allow RMP to depreciate the additional existing meters before replacing them.[81] RMP did not include any analysis of alternative rollout scenarios.

Q. WHAT IS YOUR OPINION OF RMP'S AMI PROJECT PROPOSAL?

A. RMP has failed to develop a business case for its AMI project that demonstrates benefits will be created for ratepayers. Most importantly, the AMI project is not cost-effective—RMP's own cost-benefit analysis shows negative net benefits. It is unclear why RMP is in a rush to rollout AMI in an untraditional manner when the approach will not provide positive net benefits to its customers and the current automatic meter reading (AMR) meters have 10 to 15 years before they will be fully depreciated.

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[80] Mansfield Direct at 25.
[81] Mansfield Direct at 29

RMP has framed the proposed AMI investment as a project that will provide meter reading savings and some additional data to its customers. However, AMI and the other complementary investments are key investments for grid modernization. By narrowly focusing the AMI project on meter reading savings, RMP is foregoing any discussion or development of a comprehensive and transparent grid modernization strategy that better leverages demand-side resources, allows the utility and third-parties to provide new energy services, and improves load flexibility. RMP's AMI project is solely focused on how grid modernization investments can provide utility and shareholder benefits as opposed to leveraging grid modernization to provide cost-effective, customer-centric solutions for ratepayers. Moreover, by embracing such a narrow and short-sighted approach to its proposed AMI project – and, by extension, grid modernization more broadly – RMP's grid modernization investments place unreasonable risk and financial burden on customers with almost assuredly no opportunity for customers to realize quantitative or qualitative benefits.

Many states have dedicated entire proceedings to ensure that utility strategies for grid modernization are in-line with state policies and regulatory goals and that they provide tangible benefits to ratepayers. Articulating a comprehensive and cohesive strategy is critical because grid modernization investments are significant, technologically complex, and need to be sequenced such that risks are minimized and benefits are maximized for ratepayers.[82] For example, while RMP proposes to invest millions in AMI and an MDMS, it would not be able to offer advanced rate designs for most customers because it has not invested in or updated its customer service system.[83] This example demonstrates that "AMI is a highly technical investment that requires integration with other utility systems and its value depends on how it is implemented and utilized."[84]

The overall goal of the PSC should be to ensure RMP is deploying modern grid investments pursuant to an appropriate priority and sequence, and at an optimal pace to ensure that these strategic investments:

- cost-effectively maximize planning and asset flexibility;
- minimize the risk of redundancy and obsolescence;
- deliver customer benefits; and
- enable more efficient DER and renewable energy integration.[85]

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[82] *See* "What do regulators want most from grid modernization proposals? A compelling business case." Authored by Rhode Island Public Utilties Commissioner Abigail Anthony. Published September 9, 2020. Available at: https://www.utilitydive.com/news/what-do-regulators-want-most-from-grid-modernization-proposals-a-compellin/584845/

[83] See RMP's Response to OCS Data Request 18.4

[84] AMI In Review, Office of Electricity US Department of Energy (2020). Available at: https://www.smartgrid.gov/voices_of_experience

[85] Hawai'i PUC Docket No. 2016-0087.

The information that RMP provided in its filing and through discovery is wholly inadequate for the PSC to determine the reasonableness of the proposed AMI project investments. In fact, the information provided by RMP *is* adequate for the PSC to determine that its proposed AMI project investments are *unreasonable.*

Q. WHAT DO YOU DISCUSS IN THE REMAINDER OF THIS SECTION?

A. The remainder of this section focuses on the process and components that are missing from RMP's AMI project, and how the information that was provided should be improved before the PSC approves any similar proposals. I begin with a review of RMP's CBA.

A. Additional process and detail should be required before RMP's AMI project is approved

Q. WHAT KEY STEPS DID RMP OMIT WITH ITS AMI PROJECT PROPOSAL?

A. Most importantly, RMP's AMI project does not create net benefits. It's unclear why RMP would propose a project of this magnitude while not creating benefits for ratepayers. One of the primary reasons the AMI project is not cost-effective is that RMP myopically focused the project to create meter reading benefits. RMP's AMI project is ill-conceived and does not begin to address the multitude of issues involved with an AMI rollout.

RMP's AMI project will increase customer rates for ratepayers—creating negative net benefits—while benefiting shareholders with increases in rate base and lower operational costs by eliminating full-time jobs. While I acknowledge that RMP's AMI project was developed pre-COVID, eliminating employees with a project that creates negative net benefits is clearly unreasonable, doing so during a global pandemic is unacceptable.

Q. DID RMP INCLUDE ANY INFORMATION THAT IT GATHERED FROM STAKEHOLDERS OR CUSTOMERS TO HELP INFORM THE AMI PROJECT?

A. RMP does not appear to have conducted significant, or any, stakeholder and customer outreach to determine what direct customer benefits are desired and potentially cost-effective. According to a recent report from the US Department of Energy, this is a critical misstep when deploying AMI; "Not surprisingly, commissions, advocates, and other parties emphasize() that they want to know how the consumer – not just the utility – will benefit directly and recognized that intangible benefits can be a significant factor for an AMI business case."[86] Direct customer benefits,

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[86] AMI In Review, Office of Electricity US Department of Energy (2020). Available at: https://www.smartgrid.gov/voices_of_experience

along with intangible benefits, were not only left out of RMP's testimony on the AMI project, they seem to have been largely disregarded.[87]

Q. WHAT TYPES OF DIRECT AND INTANGIBLE CUSTOMER BENEFITS SHOULD BE CONSIDERED WHEN DEPLOYING AMI AND OTHER GRID MODERNIZATION INVESTMENTS?

A. There are entire publications addressing the new products and services, operational improvements, and analytics that can be created with AMI.[88] I will touch briefly on (1) advanced rate design, (2) data access, (3) planning and operational improvements, and (4) DER integration.

i. Advanced Rate Design Roadmap

Q. WHAT INFORMATION DID RMP PROVIDE RELATED TO ADVANCED RATE DESIGN?

A. RMP mentions that the AMI project will "position" RMP to establish new rate structures utilizing "the new granular level of data and customer transparency."[89] In discovery, RMP acknowledges that the AMI project will not allow RMP to implement advanced rate designs, nor do they have a

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[87] See RMP's Response to Data Request OCS 18.16.

[88] "Voice of Experience | Leveraging AMI Networks and Data". U.S. Department of Energy. March 15, 2019. https://www.smartgrid.gov/document/VOE_Leveraging_AMI_Networks_Data

[89] Mansfield Direct at 30.

plan or timeline for doing so. I found RMP's testimony on this issue to be misleading at best and disingenuous at worst.

Q. WHY SHOULD DYNAMIC RATE OFFERINGS ACCOMPANY AMI DEPLOYMENT?

A. Advanced metering technology enables energy interval data, load forecasting, and two-way communication between the utility and end-users. These are critical functionalities for developing rate designs that allow customers to manage their energy use more effectively and respond to price signals, thereby aligning their behavior with grid needs. The full value of AMI investment is realized only when customers can do so.

Q. HOW DO YOU RECOMMEND THAT THE PSC DIRECT RMP TO ENSURE THIS VALUE?

A. The PSC should direct RMP to develop a succinct Advanced Rate Design Roadmap that describes how and when RMP will leverage the technological capabilities of advanced meters to create beneficial rate structures that serve both customer and grid needs.

Q. WHAT WOULD AN ADVANCED RATE DESIGN ROADMAP INCLUDE?

A. It should briefly describe RMP's plans to offer advanced rate designs and programs – including time-varying rates and demand response – with considerations for low-income customer participation. It should outline enrollment mechanisms for convenient customer participation, implementation plans including customer education and outreach, and evaluation plans for monitoring, verifying, and improving advanced rate design effectiveness.

Additionally, RMP should include a description and cost estimate of the technological investments and upgrades that will be required to enable the different types of advanced rate designs. For example, RMP may already have the technology available to implement critical peak pricing for large customer but not the technology to implement peak-time rebates. This type of information is useful because it suggests the critical peak pricing could be cost-effectively implemented in the near term, while a similar rate design, peak-time rebates, would cost more and take longer to implement.

Q. HAVE OTHER STATE COMMISSIONS REQUIRED THAT UTILITIES FILE SIMILAR ADVANCED RATE DESIGN INFORMATION?

A. This requirement and approach is very similar to that taken by the Hawai'i Commission in Docket No. 2018-0141, where it approved the Hawaiian Electric Companies' grid modernization investments, including AMI, but made a portion of cost recovery contingent upon HPUC acceptance of an

Advanced Rate Design Strategy.[90] Additionally, the Minnesota and New Hampshire Public Utilities Commissions have ordered Xcel Energy and Liberty Utilities to provide similar information.[91]

ii. Data Access Framework

Q. WHAT IS A DATA ACCESS FRAMEWORK, IN THE AMI CONTEXT?

A. AMI deployment produces energy usage data that can enable operational benefits for utilities and energy savings for consumers. However, these achievements require that the AMI data be available and usable to various parties, particularly the consumer. A data access framework, as described by the New York Department of Public Service, is a set of uniform and consistent data access policies following the principle of useful access to useful energy-related data.[92]

Q. WHY IS DATA ACCESS IMPORTANT?

A. Data access is necessary for enabling conscious consumption, grid innovation, and policy objectives. Customers in particular must have easy, secure access to their energy usage information in order to save energy

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[90] In re Application for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, to Defer Certain Computer Software Development Costs, Etc., Docket No. 2018-0141, Decision and Order No. 36320, at 50-53, filed March 25, 2019.

[91] *See* MN PUC Docket No. 19-666. *See Also* Docket No. DE 19-064. Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities. Petition for Permanent Rate Increase.

[92] NY DPS. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. CASE 20-M-0082 – In the Matter of Strategic Use of Energy Related Data. May 29, 2020.

and money through personal actions, smart technologies, or energy management service providers. The full value of AMI cannot be realized without ensuring that customers can access their energy data and can benefit from its use.

Q. DOES RMP DISCUSS DATA ACCESS?

A. RMP explains that customers will be able to log into RMP's website to see graphs depicting their hourly, daily, weekly, and monthly consumption. Customers will also be able to interactively target a chosen billing threshold and receive notifications if they are projected to exceed that amount.[93]

Q. SHOULD RMP'S CUSTOMER DATA ACCESS BE IMPROVED?

A. Yes. The data that is currently available and that would be made available through the AMI project does not provide actionable data that is easy to access. Customers should certainly have access to both present and historic downloadable usage data. Critically, that data should be made available in a standardized format such as Green Button Connect (Green Button).

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[93] Mansfield Direct at 31.

Q. WHAT IS GREEN BUTTON?

A. The Green Button initiative, started at the U.S. Department of Energy, allows customers to download their energy data through a green button on their utility's website. Utilities voluntarily adopt this consensus industry standard, in turn enabling and incentivizing "software developers and other entrepreneurs to build innovative applications, products and services which will help consumers manage energy use."[94] According to the DOE, RMP has committed to implementing Green Button; therefore, I would expect RMP to utilize the Green Button standard for its customer data access.

Green Button *Connect My Data* (CMD) is the energy-industry standard for enabling easy access to, and secure sharing of, utility-customer energy data. Utilities providing standards-based Green Button customer-consumption and billing data can provide customers new data-driven services, programs, and platforms; digitally empowering customers with the ability to securely transfer their data to third-party solution providers who can further assist them in monitoring and managing energy usage.[95]

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[94] "Green Button". https://www.energy.gov/data/green-button#:~:text=Green%20Button%20Connect%20My%20Data%20is%20a%20new%20capability%20which,in)%20customer%20consent%20and%20control.

[95] Green Button *Connect My Data* (CMD) Standard: The Industry Standard for Securely Accessing and Sharing Energy Usage and Water Data, Green Button Alliance, *available at* https://www.greenbuttonalliance.org/assets/docs/Collateral/2020-04%20Green%20Button%20CMD%20and%20Certification%20Data%20Sheet.pdf

Green Button CMD is an open-data standard to unlock easy access to utility interval usage and billing data – providing easy, seamless access for software applications. Green Button CMD enables utility customers to authorize third-party solutions to quickly and securely obtain interval meter data and enables an accurate and detailed level of analysis to inform energy management decision-making – while ensuring customer data are protected and their privacy is maintained. The Green Button standard ensures data integrity and accuracy, eliminates the need for manual data entry and, for some building-energy managers, it significantly simplifies the data-collection and reporting process across multiple utilities and jurisdictions.

Q. WHAT ARE SOME COMPLICATIONS ASSOCIATED WITH DATA ACCESS THAT SHOULD BE ADDRESSED PRIOR TO AMI APPROVAL?

A. There are several data access considerations that must be accounted for, including protecting information technology (IT) and data systems against cyber risks, safeguarding customer privacy and sensitive data, and preserving customers' control and consent over their energy usage data.[96]

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[96] NY DPS. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. CASE 20-M-0082 – In the Matter of Strategic Use of Energy Related Data. May 29, 2020.

In fact, RMP may already be experiencing these types of difficulties. In response to data request OCS 11.1, RMP indicated that the AMI project has been delayed due to “cyber security” issues.

Q. WHAT DATA ACCESS FEATURES DO YOU BELIEVE MUST ACCOMPANY RMP’S AMI DEPLOYMENT?

A. Customers and third parties should have reasonable access to AMI data. Customers should be able to use Green Button Connect My Data, which allows them to “automate the secure transfer (of) their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control.”[97] In addition to this standardized and vetted national format for data sharing, additional rules may need to be developed through a separate proceeding or in the next rate case to establish robust management of cybersecurity and privacy risks.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO DATA ACCESS?

A. The deployment of AMI offers significant operational benefits and the potential for significant energy savings for consumers. A major lesson

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[97] “Green Button”. https://www.energy.gov/data/green-button#:~:text=Green%20Button%20Connect%20My%20Data%20is%20a%20new%20capability%20which,in)%20customer%20consent%20and%20control.

from prior state deployments of AMI is that full realization of consumer benefits from efficiency or time-shifting of usage will not occur unless consumers have convenient access to their own energy data made available by advanced meters. It is also critical that such policies are timely and consistently implemented. I would recommend that any potential future approval of an AMI investment must be informed and guided by a sound grid modernization strategy and should only be approved conditioned on ensuring that consumers receive their share of the benefits of AMI, including access to the energy data generated by their advanced meters, along with accompanying cost information.

More specifically, to ensure that customers have functional, secure access to new data-enabled technologies and services to help them save energy and money, and otherwise realize value from an AMI deployment, I would recommend the PSC require of RMP the following:

1. Provide consumers easy access to the best available information about their energy usage.
2. Provide customers and authorized third parties with access to historic billing information in a machine-readable, automated manner.
3. Provide consumers and third parties with rate information in standardized, machine-readable formats.

4. The customer authorization process should be easy for consumers to use and require the least number of steps.

5. Provide a set of open data access standards that would create the ability for third parties to access sets of customer energy use data, either aggregated or anonymized.[98]

iii. Planning and operational improvements

Q. DO ASPECTS OF PLANNING AND OPERATIONAL IMPROVEMENTS NEED TO BE FURTHER EXPLORED BY RMP?

A. Yes. The original business cases for implementing AMI typically focused on the cost savings that could be achieved from avoided truck rolls and the end of manual meter reading. Now more than a decade since smart meters hit the industry, utilities have learned that the value of AMI goes far beyond logging energy usage. It is important to understand, however, that additional value streams cannot be achieved by merely installing the network and meters; they require integration with other systems and investments in time, equipment, and resources. None of which appear to be a part of RMP's proposal.

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[98] *See* Minnesota Public Utilities Commission, Docket No. M-19-5050, "Minnesota CUB's Notice of Petition and Petition to Adopt Open Data Standards," filed August 6, 2019.

Q. WHAT ARE SOME OF THE OPERATIONAL AND PLANNING BENEFITS THAT A UTILITY COULD REALIZE THROUGH AMI IF IT WERE TO AVOID AN APPROACH OF MERELY INSTALLING THE NETWORK AND METERS, BUT THOUGHTFULLY INTEGRATED THE FOUNDATIONAL AMI INVESTMENT WITH SOLUTIONS THAT ALLOW THE DATA TO BE ANALYZED, VISUALIZED AND PAIRED WITH OTHER DATA?

A. The following table outlines how utilities are using AMI beyond meter reading:

Activity	**Uses**
Monitoring and managing operating conditions	• Improved power quality • Validation of voltage compliance • Visualizing the data/increased system visibility • Volt/Var optimization (VVO) and conservation voltage reduction (CVR) • Switching analysis
Capacity planning	• Load forecasting and projected growth • Equipment investments and upgrades (e.g., distribution transformers, substations transformers, etc.) • Line loss studies • Circuit phase load balancing
Model validation	• Validation of the primary circuit model • GIS and network connectivity corrections • Meter to transformer mapping/transformer load management (TLM) • Phase identification and mapping
Distributed energy and resource management	• Identifying unregistered customer-owned systems • Determining DER capacity • Informing policy

Asset monitoring and diagnostics	• Proactive maintenance • Identifying over and underloaded transformers • Identifying bad distribution voltage regulators and distribution capacitors • Identifying hot sockets
Outage management	• Verifying outages through meter pings • Estimating restoration times • Service order automation through remote connect/disconnect • Identifying outage locations • Determining cause of outage • Customer communications • Determine fire-caused outage using temperature data • Identifying which phase of wires are down
Measuring and verification	• Reduce/eliminate estimated reads • Revenue protection • Reliability metrics • Demand response verification/thermostat programs • Demand response and load shifting for EV charging • Enables new rate options (e.g., time of use and prepay)
Identifying unsafe working conditions	• Identifying unregistered PV installations • Identifying downed live conductors

The level to which RMP will be able to achieve the operational and planning benefits is unclear. However, it is certain that RMP has not shared a plan that discusses these potential benefits and whether this functionality is or is not cost-effective for ratepayers.

B. RMP's Cost-Benefit Analysis is insufficient

Q. DID RMP CONDUCT A CBA RELATED TO ITS AMI PROJECT?

A. Yes. RMP projects $77.9 million in capital costs and $4.3 million in operation and maintenance (O&M) costs, with an additional $2.8 million annually in O&M costs following AMI implementation. A projected $7.8 million in annual savings are related to reduced meter reading costs, including driving, overtime labor, and handheld device maintenance.[99]

Q. HOW SHOULD CBAs BE USED WHEN EVALUATING GRID MODERNIZATION AND AMI INVESTMENTS?

A. CBAs are tools to evaluate many grid modernization investments, but these analyses are not suited well for evaluating all the costs and benefits associated with grid modernization. For example, the benefits of advanced rate designs and new DR programs can be difficult to accurately estimate because of the variations associated with their implementation and results. On the other hand, quantifying the costs and benefits of the operational and system benefits included within RMP's CBA is comparatively straight forward.

Q. WHAT IS YOUR HIGH-LEVEL RESPONSE TO RMP'S CBA?

A. The usefulness of RMP's CBA is extremely limited due to its sole focus on meter reading. Foregoing this critical limitation, the CBA lacks clarity

[99] Mansfield Direct at 28-29.

around many important assumptions, such as the time horizon the calculation is taking place and assumed cost of capital. The CBA also omits important investments that will be needed to enable what most stakeholders would consider pivotal AMI functionality, such as TOU rate designs. Specifically, the CBA omits the "significant" overhaul that RMP's customer service system will be require before billing customers on advanced rates will be possible. The magnitude of this cost has not been provided by RMP.[100]

Q. EVEN WITHOUT THE COSTS ASSOCIATED WITH THE CUSTOMER SERVICE SYSTEM, DO THE BENEFITS OF THE AMI PROPOSAL OUTWEIGH ITS COSTS?

A. No. The net present value (NPV) of the proposal is -\$25 to -\$50 million, depending on the time horizon and assumed cost of capital used in the calculation. A cost-benefit ratio should be greater than 1, but RMP's AMI project ratio is 0.8.[101] RMP does not acknowledge in testimony that the benefits of its proposal do not outweigh the costs.

Q. COULD AMI YIELD BENEFITS THAT RMP HAS NOT TAKEN ADVANTAGE OF?

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[100] See RMP's Response to Data Request OCS 18.14.
[101] Workpaper OCS 5.4D.

A. Yes. RMP could realize several potential value streams from its proposed AMI, but it has not included plans to do so.

Q. HOW DO YOU RECOMMEND THAT RMP IMPROVE UPON ITS COST-BENEFIT RATIO?

A. I recommend that the PSC require RMP to develop a more comprehensive CBA that incorporates, to the extent reasonable, operational and system benefits and costs as well as direct customer benefits.

The remainder of this section provides detail some of the many issues that were not reflected within RMP's CBA.

C. Recommendations related to AMI and grid modernization investments

Q. WHAT ACTION DO YOU RECOMMEND THE PSC TAKE WITH RESPECT TO RMP'S AMI PROJECT?

A. I have multiple recommendations related to the AMI project.

First, I recommend the PSC reject RMP's AMI project without prejudice.

Second, I recommend that the PSC provide clear guidance to RMP on the substance that needs to be in future AMI or grid modernization cost recovery requests.

Third, I recommend that the PSC require RMP to file an advanced rate design roadmap and updated CBA the next time it files for AMI, or grid modernization related, cost recovery.

Lastly, I recommend that the PSC consider a demand response target or requirement as part of any AMI program that gets approved. Adopting a demand response requirement concomitantly with approval of AMI (at whatever date that is) demonstrates the PSC's commitment to tangible and customer facing benefits being created with grid modernization investments. The process for developing the demand response requirement could begin with approval of AMI or in RMP's next rate case.

Demand response requirements are in development or have been approved in Rhode Island, Minnesota, New York, and Hawai'i.[102]

Q. WITH RESPECT TO YOUR SECOND RECOMMENDATION, DO YOU HAVE ANY RECOMMENDATIONS FOR THE GUIDANCE THAT THE PSC SHOULD PROVIDE TO RMP WHEN FILING FOR FUTURE AMI OR GRID MODERNIZATION COST RECOVERY?

[102] *See* Rhode Island Public Utilities Commission Docket 4770, MN PUC Docket No. 17-401, NY PSC 14-M-0101, and Hawai'i PUC Docket No. 2018-0088.

A. Yes. The following is a modified framework utilized by another state commission.[103]

RMP, informed by stakeholder input, must consider and address the following:

1. Definition and guiding principles. RMP must consider and provide a specific preliminary definition and guiding principles of its AMI and grid modernization investments.

2. Current status of the electric grid. RMP and stakeholders need to assess and better understand the present status of the electric grid to better inform which steps must be taken to achieve the State's energy goals.

3. Grid architecture and interoperability. There is a need to assess a RMP specific grid architecture that can actively shape the evolution of the State's electric grid rather than to passively allow grid evolution in a bottom up- manner. In addition, open standards and interoperability must be viewed as foundational components of the integrated grid.

4. Grid-facing technologies. RMP must solicit and facilitate discussion regarding the capabilities of a modern distribution network, the status of technologies required to enable these capabilities, the

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[103] Hawaii PUC Docket No. 2016-0087, Order 34281 at 6-8.

regulatory changes that may be necessary to facilitate the development of a modern distribution network, and the steps that RMP should take to integrate relevant technologies in a cost effective- manner.

5. Customer-facing technologies. RMP, in conjunction with stakeholders, must assess how customer facing- technologies, practices, and strategies can be used to (a) enable customers to manage their electric usage more efficiently and enable maximum customer cost savings; (b) enable customers to harness their electric loads as a responsive resource to meet grid service needs; and (c) further integrate resources such as DER, including energy storage devices and electric vehicles.

6. Pace of implementation. RMP must address the sequence and pace of grid modernization infrastructure investments, including both grid facing and customer facing- technologies.

7. Costs and benefits. RMP and stakeholders should examine what might constitute an appropriate framework to evaluate the cost effectiveness of grid modernization technologies and practices, including an evaluation of hard- to- -quantify impacts such as improved reliability, increased customer choice, and reduced environmental impacts.

8. Flexibility and resilience. RMP should consider how grid modernization investments can be designed and implemented to cost effectively- meet the dual goals of enhancing grid flexibility and resilience.

9. Health, cybersecurity, data access and privacy. RMP must proactively address the myriad issues related to health, cybersecurity, data access and privacy.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE PSC.

A. My recommendations pertaining to the ECOSS and MCOSS are as follows:

- Require RMP to remove the ECOSS step that subfunctionalizes production and transmission into fixed and variable categories within the ECOSS.
- Require RMP to provide additional information on the methodology and the inputs used to justify the split between secondary and primary distribution. This information should include:
    - the data set from which RMP sampled;
    - a description of the data and how it is tracked; and

    - the criteria RMP uses to select costs from the original data set.
- Require RMP to provide an alternate ECOSS utilizing the probability of dispatch classification method in its next rate case.
- Prioritize rate gradualism and fairness due to the impact COVID has likely had on the ECOSS model inputs and results.
- Functionalize metering costs to reflect the characteristics of AMI. Specifically, meters should be functionalized as 1/3 production, 1/3 transmission, and 1/3 distribution.
- Consider my modified ECOSS results, presented within Section III.D, when informing revenue apportionment between customer classes and rate designs.
- Do not rely on RMP's proposed MCOSS to inform revenue apportionment or rate design.

My recommendations pertaining to residential rate design are as follows:

- Reject RMP's rate unbundling proposal. In the next rate case, the PSC should require RMP to inform rates based on cost and not inform rates on its rate unbundling methodology.
- Approve RMP's proposed multi-family residential tariff.

- In RMP's next rate case, require the utility to provide additional cost information to further differentiate the multi-family from the single-family residential tariff.
- For single-family residents, I recommend a basic customer charge of $7. For multi-family, I agree with RMP's recommendation of $6.

My recommendations pertaining to C&I rate design are as follows:

- For the current Schedule 35 pilot proposal and future proposals, require RMP to utilize a clear framework that, at a minimum, clearly defines what is assessed, the objective of pilot, the ratepayer benefits that will be created, how success will be measured, and describe what happens after the pilot (e.g., a plan for scaling the offering).
- Regarding RMP's proposed Schedule 35 pilot, round down the demand-related credit to $0.50/kW.
- Regarding RMP's proposed Schedule 35 pilot, adopt the reporting requirements in Section V.C.iii.
- In RMP's next rate case, for each customer class with demand over 1 MW, the PSC should order RMP to evaluate a critical peak pricing pilot.

My recommendations pertaining to RMP's proposed AMI project are as follows:

- Reject RMP's AMI project without prejudice.
- Provide clear guidance to RMP on the substance that needs to be in future AMI or grid modernization cost recovery requests. A detailed example of such guidance is provided in Section VI.C.
- Require RMP to file an advanced rate design roadmap and updated CBA the next time it files for AMI, or grid modernization related, cost recovery.
- Consider a demand response target or requirement as part of any AMI program approval. Adopting a demand response requirement concomitantly with approval of AMI (at whatever date that is) demonstrates the PSC's commitment to tangible and customer facing benefits being created with grid modernization investments. The process for developing the demand response requirement could begin with approval of AMI or in RMP's next rate case.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.