- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	DOCKET NO. 17-035-61 ORDER

ISSUED: October 30, 2020

SYNOPSIS

We approve an export credit rate for customer generation of 5.969 cents/kWh in summer rates and 5.639 cents/kWh in winter rates. These rates represent an avoided energy component of 2.439 cents/kWh in summer rates (June through September) and 2.109 cents/kWh in winter rates (October through May), plus total avoided generation, transmission, and distribution capacity costs of 3.53 cents/kWh.

Though some statutes describe jurisdiction to regulate the business of public utilities in broad terms,[1] our regulatory purview "does not encompass any and all considerations of interest to the public."[2] Our primary responsibility is to set rates based on the utility's cost of service. Accordingly, we have accepted and adopted every component of the export credit rate for which any party provided substantial evidence of a quantifiable impact on the utility's cost of service. We decline certain parties' invitation to incorporate components unrelated to utility ratemaking. While we recognize the importance of environmental considerations, carbon policy, economic

[1] Utah Code Ann. § 54-4-1.

[2] *Ellis-Hall Consultants, LLC v. Public Service Commission of Utah*, 2014 UT 52, ¶ 22. The quoted text pertains to the Court's conclusion that our statutory mandate to set avoided cost rates under the Public Utility Regulatory Practices Act that are in "the public interest" does not permit us to consider all considerations of interest to the public. While this matter concerns our authority in a different statutory context, we find the Court's reasoning persuasive and anticipate the Court would apply similar constraints on our regulatory purview with respect to setting an export credit rate. *See infra* at n.8.

development, and public health, these matters fall within the regulatory ambit of other government agencies. We will not appropriate those agencies' authority or pretend to their essential expertise by adopting a boundless view of our own in the context of utility ratemaking.

We have approved annual updates to the export credit rate, and have invited comments on the timing, procedure, and substance of those updates. We anticipate issues like market prices and updates to capacity contribution values will play a role in the updates, and we also recognize the opportunity to update the export credit rate in the event that carbon or environmental requirements allow the utility to avoid quantifiable costs through customer generation.

The highest and best use of customer generation is for the customer to avoid the purchase of electricity. For that use, customers avoid the full retail rate of electricity, a rate that includes variable and fixed costs. That highest and best use should incentivize customers to size their systems to take full advantage of the benefits of avoiding electricity purchases. Additionally, the export credit rate we order will provide meaningful compensation to those customers for their excess generation.

We decline to adopt the utility's proposed application fee, and direct the utility to apply to Schedule 137 the tiered application fee currently in place for Schedule 136. We decline to approve a time of use element in the export credit rate or interval netting of excess generation and accordingly, we also decline to adopt the utility's proposed metering fee. The value of a customer's monthly excess generation will be netted against the energy portion of the customer's monthly bill.

For the time being, we are retaining the annual expiration of accrued credits. We look forward to future evaluation of annual expiration based on data from customers who are compensated through the export credit rate.

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1. Background

This docket commenced on December 1, 2017 with an application filed by Rocky Mountain Power (RMP). The application followed a September 29, 2017 order ("2017 Order") by the Public Service Commission of Utah (PSC) approving a settlement stipulation in a separate but related docket.[3] The current docket was separated into two phases, the first of which concluded with a PSC order issued on July 10, 2018. This order addresses the docket's second phase, during which testimony and evidence were presented by RMP, the Division of Public Utilities (DPU), the Office of Consumer Services (OCS), Utah Clean Energy (UCE), Vivint Solar, Inc. ("Vivint"), Vote Solar (VS), Utah Solar Energy Association ("Utah SEA"), and Salt Lake City Corporation ("SLC").

2. Rate Elements Advocated by Parties

In Phase II we are considering a proposed rate structure for customer generation (CG) that includes an export credit rate (ECR) for excess customer-generated electricity as well as other rate structure details including fees and operational elements.

RMP proposed an ECR consisting of avoided energy costs with differentials based on summer/winter generation and peak/off-peak generation. RMP proposed adjustments for line

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[3] *Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114.

losses and integration costs, net billing of a customer's excess generation against usage, annual updates to the ECR, and one-time fees for CG customers: a $150 application fee and a $160 metering fee. The DPU and OCS generally supported that structure proposed by RMP with some variations.

The remaining parties, to varying degrees, advocated for additional components to increase the ECR such as avoided capacity costs and ancillary, community, and environmental benefits. Those parties generally opposed RMP's proposed fees and annual expiration of credits, supported netting of excess generation on an hourly or greater basis, and supported various scenarios for locking in the ECR for individual customers on a long-term basis. Some parties supported a return to a "kWh for kWh" credit structure for CG, or for any new rates to be implemented gradually over time.

The details and nuances of these positions were presented in written testimony and discussed at the hearing. We will not attempt to summarize those further here, but we discuss them in this order as necessary to make our findings, conclusions, and decisions.

3. Findings of Fact, Conclusions of Law, and Decisions

a. We are implementing a CG rate structure ("Schedule 137"), including an ECR, that meets the requirements of Utah Code Title 54, Chapter 15, Net Metering of Electricity ("NM Statute"). Accordingly, it is not necessary at this time to conclude whether or not compliance with the NM Statute is mandatory in connection with Schedule 137.

RMP's net metering program was implemented and regulated by the PSC under the NM Statute. The NM Statute permits RMP to discontinue the net metering program after customer generation reaches a specified cumulative generating capacity, and permits the PSC to adjust that specified cumulative generating capacity.[4] Our 2017 Order approved a cap for the net metering program and a grandfathering period for customers whose interconnection applications were approved prior to that cap. Our 2017 Order also approved a transition program ("Schedule 136") for customers who submit an interconnection application prior to the earlier of the date a specified customer generation capacity is reached, or the date this order is issued.

This order establishes the parameters for Schedule 137 to govern electricity generated by customers who submit an interconnection application on or after its effective date. Schedule 137 operates independent of both the grandfathered and transition customers. The stipulation we approved in our 2017 Order appears to be premised on establishing Schedule 136 and ultimately Schedule 137 without the NM Statute governing those Schedules, but the stipulation does not explicitly state that legal outcome. In our 2017 Order, we did not make any conclusion of law regarding the applicability of the NM Statute to Schedule 136.

Similarly, it is unnecessary at this time to conclude whether Schedule 137 operates pursuant to, or independent of, the NM Statute. Regardless of whether the NM Statute's requirements apply to customers who take service under Schedule 137, we conclude our approval of Schedule 137, including an ECR, complies with those requirements.

Specifically, in this proceeding we have evaluated whether "costs that [RMP] or other customers will incur" from CG operating under Schedule 137 "will exceed the benefits" of that CG, or vice-versa.[5] We are approving a structure within Schedule 137 "in light of [those] costs

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[4] Utah Code Ann. § 54-15-103(2) and (3).
[5] Utah Code Ann. § 54-15-105.1(1).

and benefits."[6] Regardless of the specific legal applicability of the NM Statute to Schedule 137, the NM Statute represents the most salient state policy to guide our consideration of a just and reasonable CG rate structure and we conclude our findings herein satisfy the statute's requirements.[7]

All parties have advocated various rate components and operational elements that impact the ECR and other aspects of Schedule 137 and have provided evidence and testimony regarding the costs and benefits attributable to the individual rate components and operational elements. In this proceeding we have evaluated all costs and benefits advocated by all parties.

Our evaluation requires us to consider both the evidence supporting each cost and benefit advocated by a party, and the relevance of each cost and benefit. With respect to relevance, we conclude that for purposes of establishing Schedule 137, we should evaluate the costs and benefits that accrue to RMP and its customers in their capacity as ratepayers of RMP. Accordingly, we conclude that Schedule 137 should be based on costs and benefits that have a direct and quantifiable impact on RMP's cost of service. We conclude that costs and benefits that do not impact RMP's cost of service in a direct and quantifiable way are not relevant to the rate structure we are approving in this order.[8] We evaluate the costs, benefits, and Schedule 137 rate

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[6] Utah Code Ann. § 54-15-105.1(2).

[7] Pursuant to both our 2017 Order and the settlement stipulation we approved in the 2017 Order, both grandfathered and transition customers are continuing under the CG compensation structure established in the settlement stipulation without our having completed the statutory evaluation of the costs and benefits of the grandfathered and transition rate structures. No party has advocated for the discontinuation of the grandfathered and transition rate structures.

[8] More than thirty years ago, the Utah Supreme Court articulated our primary responsibilities to regulate utilities like RMP to ensure reliable service at a reasonable, non-discriminatory cost. *Garkane Power Ass'n v. Public Service Comm'n*, 681 P.2d 1196, 1207 (1984). If we were to base the ECR on costs and benefits that do not impact RMP's cost of service, we would be

elements advocated by the parties to this docket pursuant to those conclusions. If a cost, benefit, or rate structure component advocated by a party meets this relevance standard, we move forward to an evaluation of evidence addressing it.

b. We find that it is just and reasonable to update the ECR annually, without providing long-term price guarantees to Schedule 137 customers.

We find that annually updating the ECR is just and reasonable. Energy and capacity prices can change each year; no party argued otherwise. Some parties argued for individual Schedule 137 customers to lock in their ECR for a long-term period at the time of interconnection. Those parties supported that position with arguments about the need for potential CG customers to calculate the ultimate return on their CG investment, but we conclude those policy arguments are not relevant to RMP's cost of service. Additionally, a CG customer who wants to lock in a long-term value for the customer's generation could choose to sell their power to RMP under the Public Utility Regulatory Policies Act (PURPA). Schedule 37 is RMP's process for purchasing power from small generators, and there is no minimum capacity

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assuming authority that has not been legislatively delegated to us. For example, environmental regulation in Utah generally rests with the Department of Environmental Quality. Absent more specific statutory direction, we would be appropriating that agency's authority if we attempted to establish an ECR to promote or compensate environmental attributes in the absence of a direct and quantifiable impact on RMP's cost of service. While statutes such as Utah Code Ann. § 54-4-1 employ broad jurisdictional language, we conclude that it would be inappropriate to exercise that jurisdiction out of context from the more specific boundaries and contours outlining our authority, and the authority of other state agencies in Utah, established by both statute and case law. This conclusion is also supported by recent legislation in 2019 implementing a similar standard in a different context, the Community Renewable Energy Act. That Act codifies as state policy the premise that when we consider rates for participants under the Community Renewable Energy Act, we "shall take into account any quantifiable benefits to the qualified utility, and the qualified utility's customers, including participating customers in their capacity as ratepayers of the qualified utility, excluding costs or benefits that do not directly affect the qualified utility's costs of service." Utah Code Ann. § 54-17-904(4)(c).

requirement under that schedule. A CG customer who desires a long-term locked in price could choose Schedule 37 as long as the customer is also willing to accept the accompanying long-term obligations and requirements imposed by the Federal Energy Regulatory Commission.

We decline to approve a long-term price guarantee for Schedule 137 customers without accompanying long-term contractual and generation obligations. We find that annual updates to the ECR will keep that rate most accurate in context of changing market conditions. These updates will differ significantly from general rate cases, which evaluate total utility revenue requirements, cost of capital, and rate design. ECR annual updates will instead focus on the narrow issues related to the values represented in the ECR and other elements of Schedule 137. These updates will not directly impact the rates an RMP customer pays for electricity service from RMP, but instead will only impact the compensation Schedule 137 participants receive for their excess electricity. We invite any interested person to file comments on the potential timing, procedure, and scope of these annual updates on or before February 8, 2021, and to file reply comments on or before March 22, 2021.

c. Calculating the avoided energy component of the ECR with average locational marginal price data from the Western Energy Imbalance Market (EIM) operated by the California Independent System Operator, is a reasonable and transparent method.

No party alleged that avoided energy is not a relevant component of the ECR or that it does not impact RMP's cost of service. We conclude that avoided energy is relevant and should be the initial component of the ECR.

RMP proposed a method for calculating CG avoided energy using a single year, 2021 projection through the proprietary modeling software RMP uses for other purposes. VS proposed a method using market prices at three eastern energy hubs utilized by RMP based on the top 10% of load hours according to RMP's official forward price curve. Vivint originally proposed calculating the avoided energy component of the ECR with average locational marginal price data from the EIM. All three of these parties provided testimony and evidence in support of their proposed method, although in surrebuttal testimony Vivint updated its position to support the method originally proposed by VS. Other parties also expressed their preferences for one of those methods, and some of those preferences evolved to some degree during the various stages of testimony.

With annual updates to the ECR, we find that the general method that was originally proposed by Vivint, with the modifications to that method presented on surrebuttal by RMP, is the most reasonable. It does not require use of any proprietary software, and EIM price data is publicly available and transparent. It is also a more accurate method of calculating short-term compensation than using a forward price curve. A forward price curve is valuable in contexts such as resource planning and establishing prices for long-term fixed contracts with obligations from both the utility and generator. But as OCS witness Philip Hayet succinctly stated, "forecasts are not error free."[9] Recent EIM prices, on the other hand, reflect actual market prices within a specified time frame. Customers receiving an ECR updated annually using recent EIM prices will be more reasonably compensated based on the prices RMP in fact paid for energy during the most recently comparable time period.

[9] Rebuttal Testimony of Philip Hayet on behalf of the OCS, July 15, 2020, 20:443.

VS criticized RMP's load research study, its proposed method for calculating avoided energy, and the DPU for its reliance on that load research study. Because we are not adopting the method for calculating avoided energy that RMP originally presented in its application, and because the other components of the ECR we are adopting in this order also do not rely on RMP's load research study, it is not necessary for us to make any findings with respect to that study.[10]

RMP recommended that the EIM prices originally proposed by Vivint should be adjusted, arguing that Vivint incorrectly removed adders (generally negative for Utah prices) relating to greenhouse gas costs and transmission congestion. We find that these adjustments proposed by RMP are reasonable because the transmission congestion and greenhouse gas adders generally result in higher EIM prices in California, and the EIM prices we use to calculate the ECR should reflect prices paid by Utah customers through the EIM. For these reasons, we find the EIM-calculated avoided energy cost presented by RMP in its surrebuttal testimony, with the line losses adjustment we have described below, is a just and reasonable basis for the avoided energy component of the ECR.

i. We find that using a summer and winter ECR is reasonable, but we find that it is premature to include peak and off-peak pricing or to approve RMP's proposed metering fee.

No party contested RMP's proposed differential ECR rate for summer and winter, and we approve and adopt that ECR component with summer pricing from June through September, and

[10] RMP's proposed method of calculating avoided energy costs based on EIM pricing uses Schedule 136 customer census data, and we find RMP's use of that data to be reasonable and supported by substantial evidence.

winter pricing from October through May. However, we decline at this time to adopt a peak and off-peak component into the ECR. We have not yet adopted and approved mandatory time of use rates for RMP's residential[11] customers. We recognize that the ECR is not the same as a rate for customer purchases of utility service, and that nothing inherently prevents us from incorporating peak and off-peak pricing in the ECR without doing so in other customer rates. We also recognize RMP's assertion that peak and off-peak ECR pricing more accurately reflects the individual characteristics of Schedule 137 customers.

Nevertheless, peak and off-peak pricing comes with a cost, as represented in RMP's proposed metering fee. And the delta between the peak and off-peak ECR pricing proposed by RMP is relatively modest. Based on the record in this docket, we are unable to find that the benefits of peak and off-peak ECR pricing justify the additional metering cost. Therefore, we decline to approve both the peak and off-peak component of the ECR, and RMP's proposed metering fee. We recognize that even without a peak and off-peak ECR, metering costs are not necessarily zero. However, RMP testified that without a peak and off-peak ECR, and without interval netting which we are also declining to impose in this order, Schedule 137 metering needs would be equivalent to the metering needs that existed under Schedule 135, which did not include any metering fee beyond the metering component included in the customer charge of the monthly bill that RMP residential customers paid then and now. Peak and off-peak ECR compensation could be re-evaluated in the future if advanced metering deployment changes.

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[11] We have approved time of use rates for large general service customers, but different policy considerations apply to those customers than those that apply to Schedule 137.

ii. We conclude that line losses are a relevant component of the ECR, and we find that line losses should include secondary line transformer losses.

All parties agreed that line losses represent an appropriate component of the ECR. We find that line losses reflect an impact on cost-of-service, and conclude that the issue is relevant to the ECR.

Vivint's original avoided energy proposal included an avoided line loss component embedded into the avoided energy rate. We find that based on the record in this docket, the EIM prices used by Vivint do not reflect the full value of all appropriate line losses.

The remaining primary difference between parties on this issue involves whether or not secondary line transformer losses should be included in the ECR. We find that the record supports the inclusion of secondary line transformer losses. Specifically, we find inadequate data in the record to support RMP's assertion that exported energy must be transformed before flowing to another customer. We find it intuitively likely for some exported energy to flow to another customer on the same secondary line. Accordingly, in the absence of more specific data identifying the frequency with which exported energy does and does not flow to a customer on the same secondary line (data that we recognize may be elusive), we find that the avoided line loss value proposed by VS, with the adjustment OCS recommended to apply the line losses to a one-year estimate of avoided energy costs rather than a 20-year levelized calculation, is both just and reasonable. We find the OCS adjustment is necessary and reasonable in context of our decision to update the ECR annually.

iii. We conclude that integration costs are a relevant ECR component and we find substantial evidence to support an adjustment to the ECR to reflect these costs.

RMP proposed that the ECR should be adjusted downward to reflect integration costs necessary to hold flexible resources to accommodate fluctuations in the system's load and resource balance. RMP argues this cost is necessary because CG is not under RMP's control. While some parties disputed RMP's evidence, no party alleged that RMP's proposed integration costs, if established by evidence, are not a component of cost-of-service, and accordingly we conclude this is a relevant ECR component for which we should evaluate the adequacy of the evidence.

We find that RMP's flexible reserve study provides substantial evidence of the necessary reserve requirements attributable to the aggregate variations from resources (including solar) that do not follow dispatch signals. This study therefore captured the benefits based on the aggregate variation of the diversity that exists among that category of resources. Though the flexible reserve study included only utility scale solar resources, we find that utility scale solar is a reasonable proxy for estimating integration costs for CG solar. RMP's calculation of a percent variability value for CG exports based on aggregate Schedule 136 exports provides evidence for our finding that CG integration costs are likely higher, but at least equal to, the integration costs for utility scale solar identified in the flexible reserve study. We expect the integration cost component of the ECR should be adjusted in future annual updates to reflect new resources that are in operation.

iv. We approve the avoided energy component of the ECR as 2.439 cents/kWh in summer rates, and 2.109 cents/kWh in winter rates.

For the reasons we have discussed, we approve the avoided energy component of the ECR as 2.439 cents/kWh in summer rates, and 2.109 cents/kWh in winter rates. We calculate that amount starting with the proposed avoided energy rates based on EIM pricing that RMP presented in its surrebuttal testimony. We have adjusted those rates to exclude the peak and off-peak differential, and adjusted them upward to reflect the calculations by the OCS to include secondary line losses.[12]

d. We conclude that avoided capacity costs are a relevant component of the ECR, and we approve a total avoided capacity cost (including avoided generation, transmission, and distribution capacity) for the ECR of 3.53 cents/kWh.

We conclude that avoided capacity costs, if quantified and calculated correctly, reflect a reduction to RMP's cost-of-service that result from CG. Accordingly, we conclude that avoided capacity costs are relevant ECR components for which we should evaluate the sufficiency of the evidence.

Most objections from parties to avoided capacity costs generally focus on the non-firm nature of CG, and the lack of control RMP has over those resources. We find, though, that aggregate CG output is an output on which RMP has chosen to rely in its integrated resource planning (IRP) process. CG does not provide firm capacity, but the record includes substantial

[12] The OCS proposed a 0.043 cents/kWh adjustment to the avoided energy cost RMP proposed in rebuttal testimony. The avoided energy cost RMP proposed in surrebuttal testimony included an amount for secondary line losses. When we reduce the OCS adjustment to account for RMP's proposed secondary line loss increment on surrebuttal and average that amount weighted between summer and winter rates, we calculate the OCS adjustment to be 0.0323 cents/kWh in summer rates, and 0.0279 cents/kWh in winter rates.

evidence that aggregate CG output reduces load sufficient to impact RMP's need to invest in future capacity.

i. We approve the capacity contribution value proposed by VS and apply it to each avoided capacity cost.

An initial difference in position, primarily between RMP and VS, applies to each component of a potential avoided capacity cost. VS advocates for a capacity contribution value significantly higher than the one presented by RMP in its surrebuttal testimony.[13] The two methods are calculated differently, but one significant difference is that the capacity contribution values advocated by VS include only resources currently operating, while RMP's proposed capacity contribution values include planned future resources. We find that difference to be most pertinent in deciding which capacity contribution factor to apply to avoided capacity costs.

We have approved capacity contribution values for use in calculating the rates to be paid to qualifying facilities under PURPA. However, PURPA rates include long-term contracts with levelized pricing. In that context, future resources planned in the IRP are an intuitive component of capacity contribution values. Additionally, PURPA rates often deal with energy and capacity separately.

The ECR we are approving, on the other hand, will be updated annually and will integrate energy and capacity components into one payment to CG customers. The annual updates provide us the opportunity to adjust capacity contribution values as new resources are added to the system. We find and conclude that any avoided capacity costs we include in the

[13] While RMP's position is that avoided capacity costs should not be part of the ECR, on surrebuttal RMP presented an alternate capacity contribution value to apply to avoided capacity costs.

ECR will better reflect the current impact of Schedule 137 on RMP's cost of service if they are calculated with an avoided capacity contribution value that reflects only currently operational resources. Accordingly, we approve the capacity contribution values proposed by VS.

ii. We apply an annual carrying charge of 7.82% to all of the proposed avoided capacity costs.

VS and Vivint were the only parties who provided methodologies to calculate generation, transmission, and distribution avoided capacity costs. Both of those parties applied a carrying charge of 9.39% based on a study filed in 2018 by PacifiCorp with the California Public Utilities Commission. We find that number does not represent the current cost of equity and debt for RMP in Utah. We find that the number proposed by RMP witness Daniel J. MacNeil in his rebuttal testimony, 7.82%,[14] more accurately reflects RMP's current cost of equity and debt in Utah, and that we should apply that number to the generation, transmission, and distribution avoided capacity costs.

iii. We approve the generation, transmission, and distribution avoided capacity costs proposed by VS, as adjusted to one-year calculations and using the appropriate carrying charge. This results in an addition of 3.53 cents/kWh to the ECR.

VS and Vivint were the only parties who provided methodologies for calculating generation, transmission, and distribution avoided capacity costs. The criticism of those costs generally focused on the non-firm nature of CG and the lack of control of CG output by RMP.

[14] Rebuttal Testimony of Daniel J. MacNeil, July 15, 2020, 39-40:830-836.

For the reasons we described previously, we find those criticisms do not warrant rejection of these avoided costs.[15]

We find that substantial evidence exists in the record to support the three avoided capacity costs proposed by VS. The only alternative methods were proposed by Vivint, a party that ultimately supported the VS methods. Having rejected the criticisms of avoided capacity costs generally, we find that the best evidence before us of the value of those avoided costs was provided by VS.

Adjusted to one-year calculations and for what we have found to be the more appropriate carrying charge, we approve an avoided generation capacity cost of 2.31 cents/kWh, an avoided transmission capacity cost of 0.91 cents/kWh, and an avoided distribution capacity cost of 0.31 cents/kWh.

e. We conclude that avoided fuel price hedging is a relevant potential ECR component that could impact RMP's cost of service, but we find that the evidence in this docket is insufficient to include that value in the ECR.

Fuel price hedging costs are a component of RMP's cost of service. Therefore, if CG were found to reduce those costs, that would be an appropriate component of the ECR. The record and evidence in this docket, though, are insufficient to include that component. The only

[15] While RMP and the OCS expressed some conceptual support for an avoided generation capacity cost, they rejected outright any avoided capacity cost for transmission or distribution. However, the arguments against all three types of avoided capacity costs were premised on the same concept that we have found not to be a basis to reject these costs: the non-firm nature of CG and the lack of control of CG output by RMP. While there was some anecdotal discussion of additional wear and tear CG could cause to the distribution system, the record evidence is insufficient to find that the avoided distribution capacity should be adjusted in any quantifiable amount. And finally, we cannot accept the OCS recommendation to reduce avoided generation capacity by 25% or 50% without additional evidence of the source of those two proposed percentages.

evidence in support of a quantified fuel hedging price savings to RMP as a result of CG is a 2011 published study of utilities in the Northwestern United States. The data is dated and is not specific to PacifiCorp's current hedging program or to the RMP territory in Utah. In particular, there was no evidence in the record of how CG would impact RMP's energy balancing account, or the process currently in place to evaluate fuel price hedging in the context of that balancing account. Accordingly, we decline to include an avoided fuel price hedging component in the ECR.

f. We conclude that all other proposed components of the ECR do not impact RMP's cost of service, and therefore we decline to approve them.

Various parties advocate for the following values to be included in the ECR (or given a "placeholder" for future consideration): avoided carbon compliance, ancillary benefits, community benefits, grid support services, reliability and resilience, health benefits from reduced air pollution, benefits from reduced carbon emissions, social benefits of reduced carbon emissions, avoided fossil fuel life cycle benefits, and local economic benefits. We conclude that none of these proposed ECR components have been demonstrated to impact RMP's cost of service, and that they are therefore not relevant to our establishment of an ECR.

We recognize that many of these proposed ECR components have societal value, and in some cases parties have quantified that value. But without an impact on cost of service, we decline to appropriate jurisdiction that properly belongs to other agencies who have more direct authority over and expertise related to these areas of policy. We do not set policy for the state of Utah on carbon, environmental regulations, social policy, or economic development.

We recognize that some of those issues may impact RMP's cost of service in the future. Some parties have advocated for a "placeholder" zero value, but we find that unnecessary considering annual updates to the ECR. For example, if a carbon cost is imposed on RMP in the future, then the ECR can be adjusted to reflect the extent to which CG avoids that cost. If the costs of a current or future environmental regulation can be shown to be avoided by CG, then the ECR can be adjusted to reflect that avoided cost.

g. We approve netting a customer's ECR value earned against energy costs incurred on the customer's monthly bill.

We have declined to conclude in this order whether the NM Statute applies to Schedule 137. However, if it does, Utah Code Ann. § 54-15-104(1) provides support for netting excess generation on the CG customer's monthly bill.

Several parties have advocated for netting an individual's generation on an hourly basis. We discussed previously in this order that we have rejected RMP's proposed metering fee because we did not find the benefits of the peak and off-peak rates to justify that cost. Therefore, there is no guarantee that all Schedule 137 customers will have meters capable of hourly netting.

But more importantly, hourly netting (or any netting interval) simply does not have a basis or justification in a cost of service setting. Most of the testimony on the issue focused on what would be more convenient or understandable to customers. While we find netting a customer's ECR values against energy charges on the customer's monthly bill to be simple and intuitive, we consider it unnecessary to consider whether some other netting interval might be more understandable, even though that seems unlikely. Cost of service principles dictate that Schedule 137 customers should receive the ECR for each kWh they actually export to the grid.

Netting the values of a customer's ECRs earned against the customer's energy charges on the monthly bill accomplishes that objective.

h. Some parties have advocated for the elimination of the annual expiration of accrued credits for excess customer-generated electricity. We find and conclude that the appropriate response to that request is: not yet.

We have declined to conclude in this order whether the NM Statute applies to Schedule 137. However, if it does, then this issue is settled. Annual expiration is codified in Utah Code Ann. § 54-15-104(3)(a)(ii).

Moving from a "kWh for kWh" net metering regime to one where Schedule 137 customers will be compensated for the value of their excess generation raises the legitimate policy issue of whether annual expiration still remains appropriate. Some parties discussed annual expiration as providing an important disincentive for a customer to over-size a CG system. The ECR should now accomplish that incentive because the highest and best use of CG, and the use that brings the greatest benefit to CG participants, is the energy they consume and thereby avoid purchasing from RMP.

Nevertheless, we are mindful that if we were to eliminate annual expiration of accrued credits at this time, we would do so without any experience with how the ECR will influence the size of future CG systems. Given how challenging it would be to walk back from such a change, we consider it more reasonable to defer a decision on discontinuing annual expiration of credits until the effects of the ECR on system size can be evaluated empirically. For now, accrued credits will expire coincident with the regularly scheduled meter reading for the month of March (or October for irrigation customers).

We have not yet established the timing, procedure, and scope of annual updates to the ECR. However, we fully plan and expect that the first annual update will include an evaluation of whether annual expiration of accrued credits should be eliminated.

i. We decline to approve RMP's proposed application fee, and we direct RMP to utilize the tiered application fee currently in place for Schedule 136.

We previously approved the current, tiered application fee in Schedule 136 as a just and reasonable fee. RMP has proposed establishing a flat application fee of $150 for Schedule 137. While RMP has provided substantial evidence that the proposed $150 fee reflects the actual aggregate costs of processing applications, RMP has not provided sufficient evidence that the proposed $150 fee reflects the cost of service for individual applicants. In other words, we previously approved the tiered application fee for Schedule 136 on the premise that it costs RMP more to process the applications of some customers than it does to process others. There is simply insufficient evidence in the record to establish that is no longer the case. Accordingly, we will apply to Schedule 137 the existing application fee regime for Schedule 136. Like other issues in this order, the application fee could be revisited in future dockets.

j. We decline to return to a "kWh for kWh" netting regime for Schedule 137.

While some parties have advocated for a return to the "kWh for kWh" netting regime that existed under Schedule 135, we conclude that the stipulation we approved in our 2017 order contemplated moving from that regime to one based on an ECR as a financial value, not as a traded kWh. We recognize the stipulation did not preclude a value identical or similar to the average retail rate for electricity, but the findings and conclusions we have made in this order lead to a lower ECR. Accordingly, we find and conclude that to provide Schedule 137 participants an ECR in excess of what we are approving in this order would constitute a subsidy to ECR participants from other RMP customers, would not reflect the utility's cost of service, and therefore would be neither just nor reasonable.

ORDER

1. We approve an ECR of 5.969 cents/kWh in summer rates (June through September) and 5.639 cents/kWh in winter rates (October through May), with no time of use differential.
2. Schedule 137 customers' excess generation will be netted monthly in connection with billing for RMP-supplied energy.
3. Accrued bill credits will expire annually coincident to the regularly-scheduled meter reading in the month of March (or October for irrigation customers).
4. We decline to approve RMP's proposed metering fee and application fee, but we approve application to Schedule 137 of the tiered application fee currently in place for Schedule 136.
5. RMP shall file revised tariff sheets to implement this order.
6. We invite any interested person to file comments on the potential timing, procedure, and scope of annual updates to Schedule 137 on or before February 8, 2021, and to file reply comments on or before March 22, 2021.
7. In accordance with the stipulation we approved in our 2017 Order, the transitional program ends today, the date this order is issued. RMP shall file tariff sheets that reflect this date appropriately in both Schedule 136 and 137.

DATED at Salt Lake City, Utah, October 30, 2020.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#316191

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this written Order by filing a written request with the PSC within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC does not grant a request for review or rehearing within 30 days after the filing of the request, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on October 30, 2020, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Email:

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