PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Received
Records Management
12/03/20 15:33
State Of WASH.
UTIL. AND TRANSP.
COMMISSION

December 3, 2020

VIA ELECTRONIC FILING

Mark L. Johnson
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

RE: Dockets UE-191023 and UE-190698 (consolidated) Rulemaking to consider adoption of rules to implement chapter 19.405 RCW and revisions to chapter 80.28 RCW

The Washington Utilities and Transportation Commission (Commission) issued a Notice of Opportunity to Submit Written Comments on its draft rules considering the meaning of "use" and implications for utility resource planning, and more specifically the potential impacts of two proposed sets of rules. PacifiCorp appreciates the opportunity to comment and share its views on how the Clean Energy Transformation Act (CETA) can be implemented efficiently and within the larger regional energy markets.

INTRODUCTION

Washington utilities—both publicly-owned and investor-owned—participate in regional energy markets and are connected to the western interconnection. States throughout the western interconnect are increasingly prioritizing renewable development and decreased reliance on emitting resources. The Commission can and should develop rules that implement CETA to prioritize benefits to Washington customers and meet Washington's policy objectives without sacrificing the customer benefits of utilities' participation in current and future regional wholesale energy markets. However, this cannot be achieved without coordination across states and in conjunction with a broader regional dialogue regarding the intersection of state renewable energy and emissions policies with regional wholesale electricity markets. While market design will likely evolve to align with state policies, it is not realistic to expect that a regional multi-state market will perfectly reflect each state's individual preferences and policies. PacifiCorp urges the Commission to consider its implementation of CETA in this context. The proposed rules submitted by the utilities, as reflected in Attachment A to the Notice, enable utilities to deliver major transformations in utility resource portfolios in the most cost-effective, efficient ways possible, and also support the robust, functioning wholesale markets that will be necessary to meet CETA's objectives.

While Staff's request for comments focuses on the word "use," PacifiCorp suggests that a broader view of the issue would be more helpful. "Use" is a single word, used just one time in the relevant sections of CETA, in a complicated compliance paradigm that stretches over at least three sections of CETA. There are ways to interpret "use" that seem reasonable or persuasive in isolation, but make little sense in the context of those sections, and of the law more generally.

1. Do the rules provided in Attachment A or B allow CETA to be enforced as an offset program?

- **a. If no, which portion of the rule language prevents CETA compliance from functioning as an offset program?**
- **b. If yes, which portion of the rule language permits CETA compliance to function as an offset program?**

Neither the rules set forth in Attachments A and B, nor the language of CETA, support the enforcement or operation of CETA as an offset program. PacifiCorp understands the premise of this question to be that CETA could operate as an "offset program" insofar as renewable or non-emitting generation used to comply with CETA may cause someone else, somewhere else, to reduce the output of their electric generation, and presumably their greenhouse gas emissions. The assumption being, PacifiCorp understands, that any wholesale sale of renewable or non-emitting electricity results in greenhouse gas emissions reductions somewhere on the electric grid other than on the system of the utility that originally produced the energy. PacifiCorp does not agree with this premise nor is there any statutory support for this interpretation.

No part of CETA refers to the law as an offset program, nor to it operating or being enforced as one. Further, nothing in CETA requires that emissions reductions resulting from CETA must occur within the same utility portfolio in which renewable or non-emitting energy is produced. In fact, nothing in CETA requires that emissions reductions must result from energy used for compliance. Staff should not read this significant requirement into a statute that lacks either implicit or explicit support for such an interpretation.

Second, to effectively be enforced as an offset program, PacifiCorp anticipates—similar to other carbon offset programs—that the emissions reductions associated with each wholesale energy sale of renewable or non-emitting energy would need to be real, specific, identifiable, and quantifiable. This is the standard applied to emissions reductions associated with energy transformation projects used for alternative compliance under CETA.[1] PacifiCorp also anticipates that it would need to be demonstrated where any emissions reductions occurred. PacifiCorp is not aware of any method that may be used to verify the specific location or verifiable quantity of emissions reductions associated with an individual megawatt-hour of renewable or non-emitting electricity. In addition, PacifiCorp does not agree with the assumption that each wholesale sale of energy from a particular utility's long-term generation portfolio necessarily results in *off-system* emissions reductions. PacifiCorp's experience in the energy imbalance market (EIM) has been that greater market participation, and larger numbers of shorter-term transactions, resulted in *on-system* emissions reductions. In 2016, following a year of experience in the EIM, PacifiCorp realized a step-change reduction in its system emissions that has been sustained through 2020. PacifiCorp therefore does not agree that each wholesale sale of energy necessarily results in emissions reductions somewhere other than the participating utility's system.

---

[1] RCW 19.405.040(2).

The most significant difference between the rules in Attachment A and those in Attachment B is that the rules in Attachment B would require a demonstration of ownership of electricity used for compliance that would require that the electricity was not transferred to another entity either via sale or other transfer. As will be discussed in greater detail below, for reliability as well as to reduce costs for customers, PacifiCorp generally does not transact on a resource-specific basis and would not have a method to demonstrate resource-specific compliance with the Attachment B rules on a transactional or contractual basis.

Nonetheless, even if such a demonstration could be made, it would not support the implementation of CETA as an offset program because it would not facilitate the specific location of any emissions reductions associated with a specific wholesale sale of electricity. Similarly, Attachment A would not support the enforcement or implementation of CETA as an offset program.

2. Do the rules in Attachment A or B allow a utility to produce renewable electricity in excess of the amount required to serve its load and use the RECs from that excess renewable electricity, sold off system, to cover periods of load in which more than 20 percent of its load is served by GHG emitting resources as a means of complying with RCW 19.405.040(1)(b)(ii)?4 For example, can a utility comply with the 80 percent requirement through buying 1000 MWh of hydroelectricity in excess of its load service needs in every hour of the day during the spring runoff and resell that power while retaining the nonpower attributes for compliance?

This question does not reflect how utilities prudently plan to serve load on a long- and short-term basis, how and why utilities engage in short-term market transactions, or how utilities are most likely to plan to comply with CETA. Notably, the legislature intentionally directs utilities to average their renewable and non-emitting procurement and generation over a four-year compliance period without regard for short-term wholesale energy transactions.

While CETA and Attachment A allows this flexibility, it is highly unlikely that PacifiCorp would deliberately employ a strategy of over-procurement and subsequent wholesale sales as a means to comply with CETA as set forth in the example above. The example provided, or any similar transaction, assumes a utility would buy a large amount of energy in excess of its needs, when the likely resale value for that energy is either very low or even negative (as is common in spring in the Northwest). It would also put the utility far out of load-resource balance, relatively close to the operating hour, and would require the utility to be engaging in speculative energy transactions with the sole upside being CETA compliance. The utility would be taking a serious risk of financial loss and an inability to sell that power, which could create reliability problems for the entire region and, more likely, renewable curtailment during this period. This strategy would be contrary to accepted and prudent energy supply management practices and potentially very costly and risky for customers.

In reality, load-serving entities do not procure resources or energy that are not going to be used or usable to serve load. The more realistic, and somewhat analogous, possibility is that a utility could produce (inclusive of market purchases) more or less energy than its retail electric load over the course of any given interval, whether that is five minutes, an hour, a month, or even a full four-year CETA compliance period. But the utility could retain RECs generated when its production of renewables exceeds its total demand. This is a benefit and intentional feature of the integrated western interconnection, as it allows utilities to ensure reliability and seek least-cost dispatch on a systemwide basis. It also results in cost savings, reduced renewable curtailments, optimization of available tax incentives, and efficiencies for customers when a portion of energy produced is sold to wholesale buyers.

The rules in Attachment A allow for this sort of transaction and are consistent with CETA. In contrast, the restriction in the Attachment B rules that electricity used for compliance must not be subsequently sold or transferred is not supported by CETA. Attachment B's rules are unsupportable because they violate the basic structure of RCW 19.405.040(1), which sets the policy that "all retail sales of electricity to Washington retail electric customers be *greenhouse gas neutral* by January 1, 2030" (emphasis added). A utility "must demonstrate its compliance with this standard" "for each four year compliance period," meaning that greenhouse gas neutrality must be accomplished over that period. If a utility retains a REC for CETA compliance but sells the underlying electricity as unspecified, the REC still represents a greenhouse gas neutral sale to Washington retail electric customers as long as the REC is used in the same compliance period as when the sale of the underlying electricity is made.

3. Attachment A states in (2)(C)(ii)(4) that the delivery of resources used for compliance may occur at "another point of delivery designated by an electric utility for the *purpose of subsequent delivery to the utility* [emphasis added]."

a. Does the term "purpose of subsequent delivery" mean that the electricity must be delivered to the utility, or only that it was intended to be delivered?

The electricity must be delivered to the utility.

b. What constitutes "delivery to the utility"?

Delivery to the utility means that the utility has received the energy and associated non-power attributes. This could be demonstrated through a variety of means, including long-term contractual arrangements.

4. How will the suggested rules in Attachment A and B affect long-term portfolio planning and acquisition?

a. CETA requires that all of a utility's load be served by renewables or nonemitting resources by 2045. Do the rules in Attachment A or B support this objective? Do they allow compliance with the 2030 goal in a manner that diverges from the 2045 goal?

The rules in Attachment A are consistent with CETA and intentionally allow utilities flexibility in meeting the 2030 requirement while technology, state policy, and electricity markets evolve to meet the 2045 goal. The rules in Attachment A align with and support the 2045 objective. Under Attachment A, PacifiCorp will be required to procure a quantity of renewable or non-emitting energy equal to 80 percent of its Washington retail electric load over the course of a multi-year compliance period. There is no financial incentive for PacifiCorp to procure this quantity of energy for any reason other than to serve load. In fact, meeting the 2030 policy on a least-cost basis creates an incentive for utilities to match electricity procurement with load as much as possible – this includes driving incentives for storage and other technologies that may be employed during periods of low renewable or non-emitting energy production. The fact that each resource procured does not serve a specific utility's load on a minute-by-minute basis does not mean that the procurement of such significant quantities of renewable and non-emitting energy is misaligned with or subverts the 2045 goal.

The rules in Attachment B are not consistent with CETA and do not support the 2045 goal. Meeting the 2045 goal will take much more than traditional renewable and non-emitting resource procurement—it will take evolutions in storage and battery technology, smart grid developments, state and federal policies that support these objectives, and, importantly, greater development of regional markets to integrate significant penetrations of variable renewable energy. By effectively putting restrictions and disincentives on wholesale energy sales, the rules in Attachment B go the opposite direction. Restricting and disincentivizing utilities' ability to fully engage in short-term balancing transactions and unilaterally driving inefficiencies into the market will isolate Washington from the rest of the regional market, drive inefficiency and over-procurement, and ultimately frustrate the long-term ability of Washington to be a leader in the transformation of the Western electric grid.

The rules in Attachment B may also frustrate long-term planning because it will become much more difficult to predict the quantity of resource procurement needed for compliance. The quantity of wholesale sales over a given time period is dependent upon many variable factors including market conditions, as well as weather and load patterns. Utilities count on short-term balancing transactions to smooth out this variability though the quantity of such transactions can change significantly as the planning horizon is shortened. To account for this uncertainty, utilities would be incentivized to acquire greater quantities of resources than are needed to meet load and CETA compliance. A policy that drives over-procurement is ultimately inconsistent with the 2045 goal, which should be focused on right-sizing a decarbonized electric grid with load service.

Rather than adopt rules that are likely to result in unintended consequences and unnecessary disruptions in the ability of utilities to participate in regional markets, the Commission should engage in a regional dialogue with other state policy makers and market participants. Washington's policies should not be adopted in a vacuum. The Commission should also consider the consequences of states, with similar goals to Washington's, also adopting restrictions on wholesale electricity sales. Such a situation is likely to become untenable quickly. A regional dialogue can engage issues of market design and how to effectively decarbonize the Western grid in parallel with market development. This dialogue has been initiated as part of the

Western Interconnection Regional Electricity Dialogue (WIRED) initiative, with Washington already taking a leading role.[2]

b. Do the suggested rules in Attachment A or B support a long-term resource portfolio plan that matches the production of renewable electricity with the utility's load and has sufficient transmission service between the point of injection of its planned source of renewable electricity and the utility's load to enable the renewable electricity to serve that load?

Yes, the rules in Attachment A support this objective. While the rules in Attachment A do not require an explicit matching of resource procurement to load, the rules cannot be read in isolation from how utilities engage in long-term resource planning. The lack of an explicit matching requirement does not mean that utilities' will be able to somehow procure energy with no nexus or tie to load-service. As discussed in response to question two, under least-cost, least-risk planning requirements, utilities' procurement is rooted in load-service—there will not be an ability to comply with CETA separately from these planning requirements.

The rules in Attachment A further require that the energy procured is deliverable to a utility's system. If energy is delivered to PacifiCorp's system, it is deliverable to load. Any required interconnected or transmission service requirements would need to be met to meet this deliverability standard.

Attachment A and Attachment B do not appear to be materially different in this regard.

5. Could the Energy Imbalance Market (EIM) provide a prorated share of the attributes of the resources that provided energy in a market interval to the loads that received energy in that market interval?

Currently, resource attributes are not transacted in the EIM. Some attribute allocation methodologies could theoretically be developed but would likely require significant coordination and agreement among all market participants and any relevant state regulators to agree upon the methodology of allocating those attributes and how and to whom those attributes are compensated. To work, it is likely that market participants would be required to bid in all of the attributes associated with all of the energy they are bidding into the market. If only some sub-set of attributes are bid into the market, there may be inequities across market participants or jurisdictions, which would require an agreed-upon methodology to re-allocate those attributes.

The California Independent System Operator (CAISO) is unlikely to have the authority to require entities to bid in all of their attributes, and market participants may be reluctant to do so, particularly if those attributes are needed for their own jurisdictional compliance needs. Furthermore, the nature of these changes would likely require substantial changes to CAISO's rules and procedures, Best Practice Manuals, and tariff changes all of which would likely not

[2] The WIRED initiative is a collaborative effort of the Center for the New Energy Economy (CNEE), the Western Electric Industry Leaders (WEIL) Group, and many of the western governors' energy policy advisors. More information regarding this effort can be found here: https://cnee.colostate.edu/repowering-western-economy/.

only require extensive stakeholder engagement but also likely result in significant incremental software and process update costs that would need to be fairly allocated. In addition, a methodology would have to be granular enough to allocate attributes to specific market participants. The current method of resource-specific attribution to California load in the EIM for purposes of cap-and-trade compliance does not allocate resources to specific entities but rather identifies resources delivered to California load within the CAISO boundary (*i.e.*, it does not identify specific resources delivered to PacifiCorp's California load). Further, because other states are not electrically separated on a basis roughly consistent with geographic state boundaries, the current approach to allocating resources to California is not expandable to multiple states. Given the complexity, any attribute-allocation methodology in the EIM would likely have to be an out-of-market solution that allocates attributes on some type of pro rata basis.

A key principle for designing emissions accounting and tracking frameworks should be to avoid administratively burdensome, complex accounting approaches unless they are likely to achieve demonstrably better outcomes. A market solution that involves some type of attribute allocator is an example of an unnecessarily complex and burdensome approach, which would not deliver any better outcome than well-tested, existing methods. The rules in Attachment A require utilities to transform their portfolios of long-term resources used to serve load, while avoiding unnecessarily complex modifications to wholesale energy market design.

As noted above, PacifiCorp encourages Washington to engage in regional dialogues on these topics.

a. **If EIM loads were to receive the attributes of the generators providing energy in the market, should constraints in the dynamic transfer capacity be incorporated into the calculation of the distribution of those attributes to load? Is it possible to reflect those constraints in the distribution of attributes to locational loads?**

See response above.

b. **If EIM loads could receive the attributes of the generators providing energy in the market, is there a means of allocating those attributes by a bid price mechanism?**

See response above.

6. Energy serving load in a day-ahead market (DAM) is unspecified. If the DAM bid awards were mostly surplus hydro, would the loads receiving energy from the DAM only receive unspecified energy under the rules in Attachments A and B? Does this mean that a utility that was a net buyer from the DAM at a time of excess hydroelectric generation would only receive unspecified power?

Yes. While day-ahead markets vary, in general a utility that is a net buyer from a DAM would only receive unspecified power, regardless of the generation sold into the market at that time. Notably, if a hypothetical Washington utility had only hydroelectric generation and was a net *seller* of that generation, under Attachment B it would presumably lose the associated RECs (or other non-energy attributes) for the purpose of CETA compliance. This illustrates why the rules in Attachment B risk undermining utilities' participation in markets: market purchases are an essential component of utilities' real-time and day-ahead operations and deliver efficiencies unobtainable within a single system. However, the rules in Attachment B encourage utilities to rely only on their own systems, even if doing so creates inefficiencies and does not necessarily result in better environmental outcomes.

It is unclear whether this question is referring to the California Independent System Operator's existing day-ahead market (CAISO DAM) or the potential for the expansion of the current day-ahead market to the EIM footprint. PacifiCorp will assume the latter, that the question refers to the potential extended day-ahead market (EDAM). The EDAM market design is still in its formative stages and therefore the response to this question makes assumptions regarding how the market will be designed.

PacifiCorp anticipates that the EDAM, consistent with the DAM and CAISO's real time market, surplus energy would not be identified on a resource- or fuel type-specific basis. Furthermore, as noted above, energy awards in the EIM, and likely the EDAM, are not accompanied by associated fuel type attributes.

7. Rules in Attachment B, part (2)(b), state that a utility must make a demonstration that the electricity used for compliance was generated by the utility or acquired by the utility with the nonpower attributes and not resold.

a. How would a utility make such a demonstration?

As explained above, to ensure reliability and to reduce costs for all customers, PacifiCorp's wholesale energy sales are almost exclusively done on a system basis. There is no transactional or contractual basis to identify the specific resources from which energy was sold across the compliance period. There is no ability for PacifiCorp to attribute a specific market purchase or sale to Washington load or Washington allocated resources.

PacifiCorp recommends that the Commission avoid interpreting Attachment B as forcing utilities to transact on a resource-specific basis. This would require vast modifications to how business is currently conducted and is likely to decrease reliability while significantly increasing costs. This requirement is more likely to cause Washington utilities' isolation from the market rather than drive such fundamental changes to a regional marketplace in which all market participants would have to agree. As noted herein, the Commission should avoid unnecessary and complex solutions that frustrate CETA's goals and do not result in significant incremental benefits.

b. How would power generated and purchased by the utility be identified as sold, which documents would be used, and what process would be followed to reconcile purchases and sales?

See response to 7.a.

c. How would Commission staff conduct audits under this proposal?

See response to 7.a.

8. Please explain how double counting is prevented under the suggested rules in Attachment A and B?

PacifiCorp understands the main concern around double-counting to be the re-sale of specified energy, sold on the basis of its non-emitting attribute, where the associated REC continues to be held for CETA compliance. This practice is easily prevented using existing market and regulatory mechanisms.

The Western Renewable Energy Generation Information System (WREGIS) helps ensure that no double counting has occurred by tracking and retiring RECs and bringing transparency to REC markets. WREGIS, however, does not currently track whether the zero-emissions attribute of the REC has been reported as part of a greenhouse gas program in a regional area.

As an example, California's Cap-and-Trade Program requires the reporting of emissions characteristics of resources regardless of the disposition of any associated attributes.
There are two ways that double-counting could potentially occur for imports into California:

(1) *Bilateral specified source contracts* between an entity that imports energy into California and a Washington utility in which the Washington utility resold the power but retains the REC for CETA compliance *and* the resource's emission rate is used by the importing entity to comply under California's cap-and-trade program.

(2) *EIM Renewable Participating Resources* where RECs are owned by or sold to a Washington utility and retained for CETA compliance and the electric output of the resource is "deemed delivered" into California *and* the resource's emission rate is by the importing entity to comply under California's cap-and-trade program.

These are the solutions that would address the potential scenarios:

(1) *In the bilateral contract scenario*: if the Washington utility makes a specified contract, the Washington utility will need to prove they will not also count those RECs for CETA compliance. Proof is provided by documentation through contracts or other supporting documentation all specified sales to California; supporting WREGIS documentation; and, a review of documentation by the appropriate auditing body to assure the REC is not being used for CETA compliance.

(2) In the EIM scenario: If a Washington utility sells its power through the EIM, or purchases power from an independent power producer participating in the EIM, it will need to prove the energy has not been "deemed" to be delivered into California to prevent double

counting. Proof is provided through review of EIM settlements for deemed-delivered resources to assure they are not part of a utility's CETA compliance.

Attachment A addresses these situations and include the following language to address double counting: *"Nonpower attributes used to satisfy compliance with RCW 19.405.040(1)(a)(ii) may not be double counted. If a utility claiming a renewable resource or nonemitting generation as provided in subsection (1) sells or transfers ownership of the electricity in a transaction that contractually specifies the generation source, it may not use the nonpower attributes associated with that specified-source sale of electricity for compliance with RCW 19.405.040(1)(a)(ii)."*

Attachment B also appears to prohibit double counting by disallowing RECs associated with any resale of electricity from being used for CETA compliance. This is not necessary to avoid double counting because unspecified sales would not be classified as zero-emitting under the California cap-and-trade program nor would a buyer be able to "claim" a zero-emitting attribute if the energy is sold on an unspecified basis.

CONCLUSION

PacifiCorp appreciates the opportunity to provide comments on draft rules considering the meaning of "use" and implications for utility resource planning, as well as the potential impacts of two proposed sets of rules in Attachment A and B. PacifiCorp looks forward to continuing to participate as these discussions and issues are reviewed developed further.

Sincerely,

/s/

Etta Lockey
Vice President, Regulation
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
(503) 813-5701
etta.lockey@pacificorp.com