PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

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VIA ELECTRONIC FILING

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

RE: Docket UE-191023—Pacific Power & Light Company's Comments

PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company) provides these responses to the questions set forth in the Notice of Opportunity to file written comments issued on January 15, 2020, in Docket UE-191023, a rulemaking relating to Clean Energy Implementation Plans (CEIPs) and compliance with the Clean Energy Transformation Act (CETA). The Company appreciates this opportunity to provide information and looks forward to continued discussions with the Washington Utilities and Transportation Commission (Commission) and other stakeholders.

1. CETA stresses the need to maintain system reliability and resource adequacy. RCW 19.405.060(1)((a)(iii) requires that the specific actions taken in a CEIP be consistent with the utility's resource adequacy requirements. What information should utilities include about their system reliability and resource adequacy in the CEIP? For example, should the utilities include detailed information about the resource mix it plans to use to meet system reliability and resource adequacy and how each resource type contributes?

   PacifiCorp already addresses system reliability and resource adequacy in each Integrated Resource Plan (IRP) filing in Appendix F, Flexible Reserve Study. In the 2019 IRP filing, PacifiCorp also engaged in an extensive reliability assessment as set forth in Appendix R, Coal Studies.

   The Company suggests that the most appropriate place to continue to address resource adequacy is as part of the IRP development process because the IRP results in a resource portfolio that meets reliability requirements over a 20-year planning period. This longer planning horizon allows a utility to make resource decisions to address reliability and adequacy. The CEIP will necessarily reflect these planning decisions because it will function as the short-term (four year) implementation plan that results from the IRP process. In recognition of this relationship and to the extent possible, PacifiCorp recommends coordinating the rules to avoid requirements that create duplicative obligations for the IRP, CEIP, and Clean Energy Action Plan (CEAP).

2. RCW 19.405.060(1) requires that by January 1, 2022, and every four years thereafter, each electric investor-owned utility must develop and submit to the Commission a four-year CEIP for the standards established under RCW 19.405.040(1) and 19.405.050(1). The plan must

propose specific targets for energy efficiency, demand response, and renewable energy. The plan must also propose interim targets for meeting the standard in RCW 19.405.040(1) prior to 2030 and between 2030 and 2045.

a. Should the rules provide that specific targets must be defined cumulatively for each four year period, or identified annually, within the four year compliance period?

PacifiCorp would prefer that interim targets be defined on a four-year cumulative compliance period. Annual targets may be problematic if a ramp-up period is necessary; a four-year target provides greater flexibility for plan implementation.

b. Should the Commission require utilities to identify interim targets by resource type or some other metric(s), such as percentage of sales to customers from nonemitting generation and renewable resources?

In resource planning, PacifiCorp identifies proxy resources, which may not reflect resource types and locations emerging from a subsequent request for proposals (RFP) process. While proxy resources do provide a target with regard to the scope of an RFP, a key goal of both resource planning and the RFP design is to ensure that all requirements and constraints are met while using selection processes that do not prejudge the outcome. For reasons of flexibility therefore, interim targets based on percentage of overall sales would be preferable to interim targets based on resource type if only one target is used; however, PacifiCorp emphasizes the need for flexibility and suggests that allowing a utility to satisfy requirements using either metric may be appropriate.

c. Should the Commission require that interim targets be defined cumulatively or annually for the years prior to 2030? For the years between 2030 and 2045?

PacifiCorp recommends that interim targets be set in a way that allows maximum flexibility leading up to 2030 including setting targets cumulatively. For the period between 2030 and 2045, please refer to PacifiCorp's response to 5c below.

3. RCW 19.405.060(1)(c) requires the Commission to approve, reject, or approve with conditions the CEIP and associated targets after a hearing. With conditional approval, the Commission may recommend or require more stringent targets. Are there circumstances in which the Commission can and should recommend, rather than require, more stringent targets? If so, when should the Commission recommend more stringent targets and on what basis could and should the Commission not require more stringent targets?

PacifiCorp recommends that if a utility-filed CEIP is approved with conditions as allowed by RCW 19.405.060(1)(c), that the conditions serve as recommendations rather than requirements. The targets specified in a CEIP may be based on inputs from other long-term or intermediate-term planning processes such as the IRP or CEAP. In PacifiCorp's case, planning is conducted system-wide across multiple states and the

system is operated as a single entity. As a result, it would be very challenging for PacifiCorp to incorporate mandatory conditions imposed on the CEIP. Instead, PacifiCorp suggests that any conditions placed on PacifiCorp's CEIPs be in the form of a recommendation to allow for flexibility for the utility to seek a compliance path that leads to the best outcome for all of PacifiCorp's customers while also meeting the objectives of the recommendations from the Commission. Any requirements or mandatory directives are better implemented through a subsequent IRP process.

4. RCW 19.405.060(1)(c) allows the Commission to periodically adjust or expedite timelines when considering a utility's CEIP or interim targets. A common Commission practice is to respond to a motion to adjust timelines from any party with standing in a proceeding at any time or after hearing a compliance item at an open meeting.

    a. What criteria should the Commission take into account in making changes to timelines?

    Before establishing criteria for timeline changes, in general, it would be helpful to have a longer-term perspective and focus in evaluating CEIPs and targets. Changing the CEIP to meet modified interim targets or expedited timelines may impact how efficiently and cost-effectively a utility can achieve compliance. It will be important to maintain a long-term perspective in any evaluation of whether it is appropriate to adjust targets or expedite the timeline associated with a CEIP.

    When adjusting timelines, the Commission should also take into account the impact that the timeline will have on other long- and intermediate-term utility planning processes. For instance, PacifiCorp will alternately file either the CEIP or the CEAP every two years. PacifiCorp will continue to prepare and file the IRP on a two-year cycle. If there is a change to the timeline, it could impact the ability to prepare and file other planning and compliance processes. Changes that occur late in the process may not be able to be incorporated into the analysis for the next filing.

    In addition, PacifiCorp requests additional clarity in the rules regarding how and when the timeline could be adjusted. It would be helpful to have a comment period specifically to request any adjustments to the timeline.

    b. When should the Commission consider adjusting or expediting the timeline? How should the Commission interpret the term "periodically?"

    When adjusting timelines, the Commission should take into account the impact the timeline change will have on the CEAP, IRP, resource procurement, and other related long-term planning processes. The benefit of expediting or otherwise changing the timeline should be weighed against the impact that the timeline adjustment would cause.

c. Who bears the burden of demonstrating that adjusting or expediting the timeline can or cannot be achieved in a manner consistent with RCW 19.405.060(1)(c)(i)-(iv)?

The burden for demonstrating that adjustments to the timeline can be achieved consistent with RCW.19.404.060(1)(c)(i)-(iv) should be borne by the entity proposing the timeline modification.

5. What level of additional detail, if any, should the specific CEIP targets include beyond the statutory language?

a. For energy efficiency, the target required by the Energy Independence Act, RCW 19.285.040(1)(a), follows methods consistent with those of the Pacific Northwest Power and Conservation Council and only considers first year savings. Should the energy efficiency target in the CEIP be based on cumulative savings, savings projected over the lifetimes of measures implemented in a given program year, or capacity savings?

Energy efficiency targets for the Energy Independence Act (EIA) are established using first year savings. The economic assessment performed to demonstrate compliance with WAC 480-109-100 (8) incorporates the multi-year impacts of the measures implemented in a given year and includes the benefits of capacity savings. The impacts of cumulative savings from energy efficiency are accounted for by regularly re-assessing first year saving opportunities (Conservation Potential Assessment) and incorporating this information into each IRP cycle, which uses updated load forecasts. Prior energy efficiency activity is reflected in reduced loads in subsequent IRPs. For consistency and alignment with EIA and regional efforts, this approach should be used to develop the energy efficiency targets for the CEIP.

b. For demand response (DR):

i. How should the Commission develop a cost test to identify cost-effective demand response, as referenced in the Commission's draft rules under WAC 480-100-610(12)(e) (See Integrated Resource Plan Rulemaking, Docket UE-190698, Staff Discussion Draft Rules (Nov. 20, 2019))?

Demand response resources should be identified in a conservation potential assessment with cost effective selections identified through the IRP process. Washington demand response resources selected by the IRP are by definition cost effective. Additional costs tests, similar to the standard practice tests used for conservation/energy efficiency could be developed for demand response in Washington. Adopting such test(s) has the potential to provide additional guidance into planning and selecting demand side resources using the process described above. Should the Commission consider adopting or developing demand response tests(s), the Company recommends beginning with work that is available in other jurisdictions, including the California Public Utilities

Commission (CPUC) Distributed Energy Resource Avoided Cost Framework, Appendix A Demand Response Cost Effectiveness Protocols.

ii. Should demand response potential be considered only within a utility's service territory or encompass the utility's entire balancing authority?

Demand response opportunity and potential is customer specific. The current practice of planning for demand response through the Conservation Potential Assessment and selecting it through the IRP on a state basis should continue. The current practice of planning and selecting distributed resources, such as demand response for each state within the PacifiCorp system should continue.

c. For renewable energy:

i. How should the utility calculate its target? Should it be a glide path to 2030, glide path to 2045, or both?

The regulations should provide utilities sufficient flexibility to determine their trajectory to 2045 and calculate their own interim targets in their individual CEIPs. This flexibility allows each uniquely positioned utility to maintain pace with emerging and maturing technologies and take advantage of customer-focused energy transformation opportunities, all while continuing to maintain reliability of their systems. PacifiCorp would support an interim guardrail across compliance period three to ensure utilities are on path to the 2045 target. Specifically, the Company recommends a guardrail that requires utilities to calculate the use of electricity from renewable resources and non-emitting electric generation in an amount equal to 90 percent of total retail sales during the period spanning January 1, 2038 through December 31, 2041.

ii. How should the utility consider and account for the Energy Independence Act renewable targets, as referenced in RCW 19.285.040, and nonemitting resources, as referenced in RCW 19.405.040(1)(a)(ii), when calculating the utility's renewable target under CETA?

Eligible renewable resources (RCW 19.205.030 (12)) forecast to be used to comply with the EIA should also qualify for demonstration of compliance with the forecast compliance periods under CETA. The renewable energy certificates associated with these resources are retired in WREGIS, preventing double counting or selling off of these attributes. Because the EIA and CETA have different underlying retail sales assumptions (average of previous two years versus four-year compliance period), the EIA-achieved target may not map directly to 15 percent per year under CETA, but would likely be in that range. In addition, resources that meet the definition of non-emitting resources under RCW 19.405.020 (28), should be included toward the renewable target calculation.

6. Should the CEIP contain time ranges for the acquisition of capacity resources, or deadlines for acquisition?

   PacifiCorp requests as much flexibility as possible for the acquisition of capacity resources under the CEIP. This would give the utilities the best chance to acquire the necessary resources at a competitive price, and incorporate new resources into its system in the most beneficial way possible. In addition, PacifiCorp is concerned that setting a "deadline" that is publicly known could adversely impact the procurement process.

7. What guidance (content and form) should the Commission provide to ensure utilities employ robust, equitable, and inclusive public involvement in drafting CEIPs?

   PacifiCorp would appreciate Commission guidance through the form of utility-filed outreach plans that are subject to public comment. For example, at the beginning of the CEIP drafting process, utilities could submit an outreach plan that provides:

   - Scheduled outreach and feedback sessions
   - Plans to seek input from stakeholders who may be less familiar with regulatory processes or who are historically less involved in regulatory processes
   - Comment process, including how comments may be submitted through either formal (written comment) or less formal (listening session or community event) settings.

   Following submittal of the outreach plan, staff and other regulatory stakeholders would be able to provide comments suggesting any additional public outreach that should be considered to ensure that the drafting process is robust, equitable, and inclusive.

8. Given the need for utilities to integrate their integrated resource plan (IRP), clean energy action plan (CEAP), and CEIP, what procedural outline should utilities' public involvement follow and what components (*e.g.*, advisory groups, workshops, comment periods, etc.) should be included? How should a CEIP public engagement and public involvement process emulate or differ from the proposed rules in the IRP rulemaking (See Integrated Resource Plan Rulemaking, Docket UE-190698, Staff Discussion Draft Rules at 17 (Nov. 20, 2019)) or the conservation planning process in WAC 480-109-110 and WAC 480-109-120? Please describe in detail.

   PacifiCorp already engages in a robust public input process for its integrated resource planning. As CETA is considered an extension of resource planning, PacifiCorp intends to add the CEAP and CEIP as topics to be discussed in its existing public input process. Flexibility to allow each utility to address this need based on their own resources and needs would be appreciated because it would allow utilities like PacifiCorp that already have established public input processes to leverage this practice and continue to engage with stakeholders in a way that is familiar and effective.

9. Would a requirement for a utility to file a draft CEIP for public input be useful or problematic if the plan were to be litigated? Please explain why or why not.

The requirement to file a draft CEIP would be problematic for PacifiCorp. PacifiCorp prefers a robust and inclusive public input process as the CEIP is prepared, with opportunities for questions and feedback throughout. Generally, a significant portion of the analysis is already complete by the time a draft document is prepared, drafted, and submitted. At the later stages of analysis, the ability to incorporate significant changes in response to feedback is more limited.

10. The Commission uses a planning and reporting cycle for conservation under the Energy Independence Act described in WAC 480-109-120. Should Commission rules similarly describe the level and frequency of reporting for demonstrating compliance with RCW 19.405.030, 040, and 050?

    It is not necessary for the Commission's rules to dictate a rigid reporting schedule for progress toward the CEIP targets outside of the statutory requirements. Rather, PacifiCorp recommends that the Commission require specific and targeted reporting on an as-needed basis that is tailored to each utility's CEIP in an order. Whenever possible, the Commission should consider eliminating duplicative reporting burdens by including information that can be used for multiple purposes in a single report.

    In recent years, the Commission has made efforts to streamline old processes to reduce unnecessary "check-the-box" activities that add workload without providing commensurate benefits. PacifiCorp supports keeping routine processes to a minimum. Lastly, informational progress reporting should not, in itself, serve as the vehicle for reopening a utility's Commission-approved CEIP, unless it is progress reporting directed by the Commission under Section 9.

11. Regarding the frequency of filings:
    a. Should utilities regularly file reports on their progress toward meeting compliance metrics?
    b. Does or should the frequency of the filings depend on the existence of a rate plan?

       Regular progress or compliance reports are not always the most beneficial filings. As stated above, PacifiCorp recommends that the Commission require specific and targeted reporting on an as-needed basis that is tailored to each utility's Commission-approved CEIP. If interim reporting is adopted, the frequency of such reporting should not exceed once every two years to allow for procurement cycles to flow into the utility's resource mix. More frequent reporting would create unnecessary reporting burden with little benefit. Whenever possible, the Commission should consider eliminating duplicative reporting burdens by including information that can be used for multiple purposes in a single report.

12. How must a utility demonstrate to the Commission that the utility has eliminated coal-fired resources from its allocation of electricity beginning in 2026, as required in RCW 19.405.030?

PacifiCorp requests that the Commission allow that utilities demonstrate compliance with the requirement to eliminate coal-fired resources from the allocation of electricity through the filing of an annual attestation. This would minimize administrative burden on all stakeholders, and mirrors PacifiCorp's current compliance process in other states (*e.g.,* California Emissions Performance Standard attestation required pursuant to Decision 07-01-039, Section 5.2).

13. If the Commission has four years of investment information from a utility when approving its CEIP:
    a. How often should the Commission require the utility to update the investment plans to reflect changing information?

       PacifiCorp requests that a utility be required to update the investment plans to reflect changing information only when there is a material and significant change to PacifiCorp's planned investment. Through the IRP, CEAP, and CEIP, there will be regular investment and planning updates from the utilities to the Commission, and preparing a supplement to the CEIP outside of the typical filing cycle could create significant administrative burden.

    b. May the updates be informational filings, or should they be formal filings subject to Commission approval?

       Per PacifiCorp's response to part a. of this question, updates to the CEIP investment plan should reflect significant and material changes to the planned investment, and would likely not be a regular occurrence. As such, acknowledgement or approval of the change would be appropriate.

14. RCW 80.28.410 allows utilities to defer costs incurred in connection with major projects in the CEAP or that are identified in bids for resource acquisition. How should the Commission interpret "major projects" in this context? What metric should the utility use to identify major projects? How should these projects be included in the CEIP?

    The Commission already has processes in place that allow utilities to request deferred accounting treatment on an as-needed basis. The Commission has the discretion to grant a utility's request for deferred accounting in consideration of the utility's specific circumstances and need. PacifiCorp recommends that the Commission continue to use existing practices for investments under CEAPs.

15. RCW 80.28.410 provides for the deferral of both the capital and the variable costs for new resources. Through the power cost adjustment mechanisms (PCAM), utilities recover only the variable power costs of resources. How should costs for new resources be treated in the PCAM in light of the additional deferral allowed under RCW 80.28.410?

a. Should the Commission require changes to the utilities' power cost adjustment mechanisms to match the cost of new resources with the benefits in compliance with the statute?

Yes. Utility PCAMs should allow for all the variable costs and benefits of renewable resources to flow through to customers. The capital costs should be deferred for inclusion in customer rates until an appropriate proceeding like a general rate case or a separate capital cost recovery mechanism outside of the PCAM. A PCAM without deadbands and sharing bands coupled with the existing ability to defer the capital costs is the most accurate, simple, and efficient way to match these costs and benefits. Additionally certain generation-related benefits like production tax credits (PTC) should be included in the PCAM.[1]

b. During the period of deferral allowed under Chapter RCW 80.28.410(1) for a new energy resource, should the Commission provide deferral within the power cost adjustment mechanism for the difference between the hourly marginal costs of power production (or purchases) used to set the authorized power cost in effect during the deferral and the variable costs of the new energy resource not deferred under RCW 80.28.410(2)? If not, please explain why not? If so, should this change be requested as part of the CEIP, or through a separate proceeding?

No, the calculation described above relies on overly simplistic assumptions. For example, in a system as large, diverse, and disparate as PacifiCorp's, identifying the marginal resource that would be displaced is not straightforward. Additionally, this method does not adequately capture the variable costs associated with adding renewable resources to the system, will potentially overestimate the benefits, and is based on a forecast net power costs (NPC) rather than actual NPC. The solution suggested by PacifiCorp above in part a, which removes the deadbands and sharing bands from the PCAM, efficiently and accurately provides customers the full amount of actual benefits of new renewable resources.

c. During the period of deferral allowed under Chapter RCW 80.28.410(1) for a capacity resource, should the Commission provide an adjustment to the deferral within the power cost adjustment mechanism for the lower power costs resulting from the addition of a lower heat rate generation unit to the utility's portfolio? If not, please explain why not? If so, should this change be requested as part of the CEIP, or through a separate proceeding?

No, a PCAM without deadbands and sharing bands would allow customers to receive the actual benefits associated with capacity resources making any sort of adjustment unnecessary. A PCAM without deadbands and sharing bands is the most accurate,

[1] PacifiCorp is proposing to exclude PTC from the deadbands and sharing bands in its current general rate case. *See WUTC v. PacifiCorp dba Pacific Power & Light Co*, Docket No. UE-191024, Direct Testimony of Michael G. Wilding, Exhibit MGW-1CT at 66-67 (Dec. 13, 2019).

simple, and efficient way to ensure customers receive the benefits of a new renewable or capacity resource. This method avoids unnecessary complexity that could have potential unintended consequences.

16. RCW 19.405.090 provides that upon its own motion or at the request of the utility, and after a hearing, the Commission may issue an order relieving the utility of its administrative penalty obligation, if certain conditions are met. Does the Commission need to provide more guidance on the application of penalties and waivers of penalties in rule? If yes, please describe what additional guidance should the Commission provide.

PacifiCorp requests the Commission consider providing additional guidance around how a utility would demonstrate inability to comply with reliability standards, or what the six-month progress report would look like in the event of exemption.

17. RCW 19.405.040(8) states:

In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

a. Please provide a list of costs and benefits (*e.g.*, public health, pollution) that the Commission should consider when determining a utility's compliance with RCW 19.405.040(8).

The Commission should consider costs and benefits that are within the control of a utility. For example, reduction of emissions from company-operated generation facilities is a public benefit that a utility can control. Reductions of wood smoke or PM 2.5 at customer homes directly attributable to the installation of heat pumps such as those quantified in the August 20, 2018 report by Abt should also be considered as a quantifiable benefit. Other public health benefits may prove difficult to measure or are likely to be outside the control of a utility.

b. Please provide a list of which geographic areas, populations, customer demographics, or other factors the Commission should consider when determining a utility's compliance with RCW 19.405.040(8).

As a guiding principle, factors used to assess compliance should be those associated with customers within the utility service territory and be in compliance with existing consumer information protection statutes. Types of information and their sources the Commission should consider include, but are not limited to: income from third party sources (such as US Census), self-reported data on English as second language, self-reported data on rent versus own, and utility data on energy usage in addition to data available from Department of Health and Department of Commerce. This list is not

intended to be exhaustive.

18. In the Commission's IRP rulemaking in Docket UE-190698, many stakeholders commented that the Commission should determine compliance with RCW 19.405.040(8) as part of the CEIP process. If the Commission were to do so, what types of guidance on RCW 19.405.040(8) compliance should the Commission provide in its CEIP rules? If the Commission were to provide guidance on RCW 19.405.040(8) compliance in a form other than rules (*e.g.*, an interpretive and policy statement), what type of guidance should the Commission provide? Please be as specific as possible in your responses.

    PacifiCorp requests guidance on what would determine compliance with the "equitable distribution of benefits" portions of the law through the form of a Commission policy statement. In particular, PacifiCorp would appreciate guidance on what data and/or information should be submitted as part of the compliance determination process.

19. Should a utility's demonstration of compliance with the requirements in RCW 19.405.040(8) include qualitative data, quantitative data, or both? Please explain your response. If you recommend qualitative data, which of the following approaches for approximating hard-to-quantify impacts are most appropriate: (a) service territory-specific studies; (b) studies from other service territories; (c) proxies; (d) alternative thresholds; or (e) or another approach? Does your response depend on a particular factual scenario? If so, please describe the scenario and explain why the approach you recommend is best suited for that scenario.

    Generally, PacifiCorp agrees with the potential qualitative methods listed in sections a-e above. There will likely need to be a combination of qualitative methods used for utilities to comply with the "equitable distribution" portions of the law.

    Regarding quantitative data, PacifiCorp recognizes that "equitable distribution of benefits" may be a subjective determination, at least in the early compliance periods. To the extent that quantitative data is available, PacifiCorp prefers that the data is based on actual investments and should be developed in collaboration with the Department of Health and Department of Commerce rulemakings.

20. Please provide any existing data sources or methodologies of which you are aware for quantifying non-energy costs and benefits, and other equity-related impacts.

    PacifiCorp is not currently aware of methodologies used to quantify equity-related impacts.

21. How should the Commission interpret RCW 19.405.060(1)(c)(iii)? How are the requirements in that statute different than the requirements in RCW 19.405.040(8)?

    PacifiCorp suggests creating consistent requirements for compliance with RCW 19.405.060(1)(c)(iii) and RCW 19.405.040(8). It appears that the intent of both sections is similar and by creating a consistent set of requirements, the review process for the

Commission will be lessened, reporting by utilities won't be duplicative, and confusion for members of the public and other stakeholders will be reduced.

22. RCW 19.405.060(3) requires an electric investor-owned utility to use its weather-adjusted sales revenue to customers as reported in its most recent Commission basis report (CBR) as part of its incremental cost calculation. Each investor-owned utility is different in how it reports its weather-adjusted sales revenues and adjusts its sales for "weather."

    a. Should the Commission standardize its CBR rules to be able to effectively implement the incremental cost calculation requirements in RCW 19.405.060(3)? If so, please describe how the Commission should revise those rules.

    It is not necessary for the Commission to standardize CBR rules. Synchronizing the reports between the different utilities will not likely have a significant impact to an incremental cost calculation. Companies should continue to use the methodologies that were approved in its last general rate case.

    b. Can the Commission allow each utility to use a different weather normalization method and still create a consistent methodology for calculating incremental cost?

    Please see the company's response to subsection a. above.

23. RCW 19.405.060(3)(a) states that an electric investor-owned utility complies with its Clean Energy Implementation Plan if, over a four-year compliance period, the utility's average incremental cost to comply with RCW 19.405.040 and 19.405.050 increases by two percent over the utility's weather-adjusted sales revenue.

    a. If a utility relies on the incremental cost compliance option as detailed in RCW 19.405.060(3)(a), when should the Commission determine whether the utility has achieved the incremental cost threshold for compliance? For example, should the Commission determine the utility's compliance based on a forecast, at the time the utility files its Clean Energy Implementation Plan, based on actual data at the conclusion of the four-year period or through interim reporting, or a combination of these options?

    The Commission should evaluate the utilities' compliance based on the forecast incremental cost for the compliance period, as filed in the companies' CEIPs, beginning January 1, 2030. An after-the-fact review could result in unintentional rate impacts with no vehicle for mitigation.

    b. If the Commission allows a utility to forecast its reliance on the incremental cost of compliance option, and the utility's actual incremental costs increase more or less than two percent averaged over the four-year period, would a true-up mechanism be allowed and necessary to reconcile the differences between the actual and the forecasted incremental cost?

The Commission has the flexibility to implement different ratemaking mechanisms. However, unlike true-up mechanisms that exist for net power costs, which identifies a specific set of Federal Energy Regulatory Commission accounts that are appropriate for true-up, a true-up mechanism for the incremental cost of compliance may include a significant number of variable and capital costs that are recovered through base rates. A single true-up mechanism is not appropriate, customers will face the actual incremental costs of compliance when the fixed and variable costs of compliance are reflected in base rates, NPC, or any other specific recovery mechanism.

24. When using the incremental cost compliance option, RCW 19.405.060(3)(a) requires all of a utility's costs to be directly attributable to the actions necessary to comply with RCW 19.405.040 and RCW 19.405.050. How should the Commission require a utility to demonstrate that such actions were "directly attributed and necessary" for the utility to take only to comply with CETA?

    The utilities should demonstrate their actions were directly attributed and necessary by using a forecast retail sales basis for calculating its CETA requirement that subtracts its forecast renewable portfolio standard retail sales requirement under the EIA for the four-year compliance period. This methodology is simple and ensures a calculation of costs that appropriately excludes purchases and investments that would not be incurred if not for CETA.

25. RCW 19.405.060(3)(b) states that if a utility relies on subsection (a) (incremental cost as a basis of compliance), the utility must demonstrate that it has "maximized investments in renewable resources and nonemitting electric generation prior to using alternative compliance options." In what type of proceeding should the Commission require a utility to demonstrate that it has maximized investments in renewable resources and nonemitting electric generation? What documentation should the Commission require the utility to provide?

    The CEIP seems to be the best forum for the Commission to determine whether the utility has demonstrated that it has maximized investments before using alternative compliance options. PacifiCorp requests Commission guidance, and potentially a workshop, on what it means to "maximize" investments in this context.

26. How should the utility address investment planning and cost recovery in its CEIP?

    Cost recovery can continue to be handled using the methods available to the Commission. The CEIP does not need to impose new requirements for utility investment planning and cost recovery. Utility investment planning can still occur through the IRP and traditional utility investment planning processes. These cost can then be recovered through appropriate cost recovery mechanisms including general rate cases and specific regulatory mechanisms like the PCAM. In previous comments to the Commission, PacifiCorp has proposed a regulatory mechanism to recover the capital costs of increased

investments in renewable resources, and such a mechanism could be helpful to recover these costs.

27. How could a utility's CEIP be used to set rates prospectively? Would using a CEIP to set rates prospectively be in the public interest? Please explain your answer.

CETA authorizes the Commission to determine rates for "up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates."[2] Given the flexibility granted under the new law, an approach that allows for identifiable investments to be incorporated into rates could be in the public interest. Just like an IRP, a utility CEIP could be another tool to help identify those investments, which could then be included in rates through a general rate case or other specific regulatory mechanism. PacifiCorp has two specific regulatory mechanisms in California and Oregon that allow the inclusion of those investments outside a general rate case.

In California, PacifiCorp has a Post Test Year Adjustment Mechanism (PTAM), which allows for the timely recovery of "prudently incurred cost increases related to inflation, new plant, general operating cost increases, unforeseen events, and changes in capital structure."[3] The PTAM allows for cost recovery of major capital addition to plant-in-service that are greater than $50 million on a total-company basis.[4] PacifiCorp submits an advice letter containing significant information about the proposed capital addition to the CPUC. This filing is open to protest and is reviewed by the Energy Division of the CPUC. PacifiCorp's process in California allows for significant capital investments to be included in rates with minimal regulatory lag.

The Renewable Adjustment Clause (RAC) in Oregon allows for recovery of prudently incurred costs "to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage."[5] The RAC is specifically authorized by statute and was adopted by the legislature to ensure minimal regulatory lag for resource acquisitions associated with compliance with the state's renewable portfolio standard. This process allows for the creation of an automatic adjustment mechanism (separate tariff) for the incremental costs and capital that is necessary for investment in renewable energy sources. The automatic adjustment clause is updated annually and continues until the incremental costs are included in base rates during a general rate case.

Both of these mechanisms have provided benefits for customers and enabled PacifiCorp to respond nimbly and efficiently to resource opportunities. These efficient and flexible

[2] RCW 80.04.250.
[3] *In Re PacifiCorp*, Case No. A. 05-11-022, D. 06-12-011 at 3 (Dec. 14, 2006).
[4] *In Re PacifiCorp*, Case No. A. 05-11-022, D. 06-12-011 at Attachment A §2.3.2 (Dec. 14, 2006).
[5] ORS 469A.120.

cost recovery mechanism could work well in Washington to allow efficient cost recovery for renewable and transmission resources.

28. Which elements of a CEIP should a utility recover through general rate cases? Which elements of a CEIP are appropriate for a cost recovery mechanism?

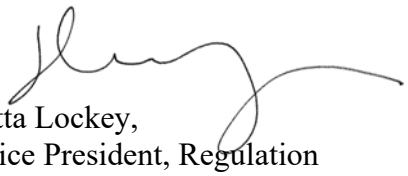
    Increased flexibility is necessary to ensure that utilities can find the best approach that allows for increased renewable investment while mitigating customer impacts. It is not appropriate to narrow the scope of a general rate case to identify specific elements for a cost recovery mechanism. A cost recovery mechanism should simply be another tool for utilities and the Commission to find a flexible an efficient approach to incorporating increased investment in renewable resources and transmission for customers.

29. Should the Commission require a utility to provide in its CEIP (a) information on program budgets related to incremental programs for compliance with CETA; (b) descriptions of, and details about, capital budgeting for all investment; or (c) both?

    Consistent with any capital investment that a utility makes, CEIP and CETA-related investments can be reviewed through general rate cases and other cost recovery mechanisms. In addition, it may be premature to require detailed budget information as part of the CEIP since it might not be available at the time of filing.

PacifiCorp is committed to fully participate in this proceeding and looks forward to continuing to work with the Commission and stakeholders through this process.

Sincerely,



Etta Lockey,
Vice President, Regulation