BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of PACIFICORP, dba PACIFIC POWER, Petition for Approval of the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol.	ORDER

DISPOSITION: 2017 PROTOCOL ADOPTED

I. INTRODUCTION

PacifiCorp, dba Pacific Power, seeks approval of its 2017 Protocol to update the company's inter-jurisdictional allocation methodology. In this order, we accept the 2017 Protocol as filed, and announce that we will open an investigation into the company's allocation issues in the fall of 2016.

II. BACKGROUND

PacifiCorp provides retail electric service in six western states (California, Idaho, Oregon, Washington, Wyoming, and Utah), and the multi-state process (MSP) allows the company to work with its states to develop an allocation protocol to divide total system costs among the states.[1] The protocols are intended to better afford the company an opportunity to recover its cost-of-service by having a consistent cost allocation methodology used by the states for which PacifiCorp provides retail service.

The 2017 Protocol is fourth in a series of protocols. The modified accord was the first allocation protocol followed by the Revised Protocol,[2] and then the 2010 Protocol.[3] Oregon, Utah, Wyoming, and Idaho approved the past protocols but have implemented

[1] The protocols are used in future rate cases to determine how the company's generation, transmission, and distribution costs and wholesale revenues are allocated among the utility's service territories.
[2] Order No. 05-021 (Jan 12, 2005).
[3] Order No. 11-244 (Jul 5, 2011).

them differently.[4] The 2010 Protocol expires at the end of 2016, and upon expiration, the default for Oregon is to revert back to the Revised Protocol.

The 2017 Protocol is signed by Commission Staff, and the Citizens' Utility Board of Oregon (CUB), as well as parties from Utah, Idaho, and Wyoming. Other parties participating in the proceeding include: the Industrial Customers of Northwest Utilities (ICNU), Noble Americas Energy Solutions (Noble Solutions), and Northwest and Intermountain Power Producers Coalition (NIPPC).[5]

III. DISCUSSION

A. Positions of the Signatories

As signatories to the 2017 Protocol, PacifiCorp, Staff, and CUB support the 2017 Protocol as a reasonable short-term, non-precedential inter-jurisdictional allocation approach that allows parties to continue working towards a permanent solution, while providing some certainty for PacifiCorp. The signatories explain that the 2017 Protocol was developed using the 2010 Protocol as a starting point, with an equalization adjustment to reduce the company's allocation shortfall which is present under the 2010 Protocol.

The signatories contend the 2017 Protocol is in the public interest and emphasize three key benefits. First, they explain that the agreement continues the hydro endowment, which will ensure that Oregon customers continue to benefit from northwest hydro resources.[6] The hydro endowment benefits to Oregon are provided through the embedded cost differential (ECD), and it reflects the difference between the cost of the hydro facilities and the cost of all other company resources in service prior to 2005.

Second, the 2017 Protocol requires PacifiCorp to continue to analyze alternative allocation methods including divisional allocation methodologies. PacifiCorp agreed to complete these studies by March 31, 2017, or pay a financial penalty. CUB and Staff requested these studies and believe they are important for future negotiations.

Finally, the 2017 Protocol contains a general rate case stay-out period that prevents PacifiCorp from filing a rate case before February 28, 2017 (with a corresponding January 1, 2018, effective date).[7] CUB believes the rate case stay-out provides some value to customers because new capital investments, including emissions investments that were identified, but not acknowledged, in the 2013 IRP will be subject to regulatory lag before they can be put into rates in 2018. Staff believes that the value of this provision reflects delaying a relatively small rate increase for one year, pointing to low inflation, stable rate base, and reduced cost of capital.

[4] California considers the allocation methodology in a general rate case cycle. Washington uses a Western Control Area methodology that is similar to a control area split. Utah sets the embedded cost differential to zero.
[5] PacifiCorp, Staff, CUB, ICNU, and Noble Solutions filed testimony. A hearing was held. All parties, including NIPPC, filed briefs.
[6] *See* Appendix A, PAC/101, Dalley/31.
[7] The company agreed to the same stay-out period in Idaho, and a shorter stay-out period in Utah.

ICNU, Noble Solutions, and NIPPC are not signatories to the agreement and request that we modify or clarify certain provisions of the 2017 Protocol. We address these contested issues below.

B. Contested Issues

1. Equalization Adjustment, Limited Duration, Divisional Split Analysis, and Rate Case Stay-out

To address the shortfall that PacifiCorp experienced under the 2010 Protocol, the parties negotiated an annual total equalization adjustment of $9.07 million, with $2.6 million allocated to Oregon. This amount represents approximately two-tenths of one percent of Oregon's annual revenue requirement.[8] Other states have similar impacts.

ICNU argues that the equalization adjustment should be reduced because SB 1547 could result in a material increase to Oregon rates during the term of the 2017 Protocol and outside of a general rate case.[9] ICNU asks that the adjustment be reduced until the company's next general rate case, when a holistic review of the company's entire revenue requirement, including expired PTCs, can be performed.

Staff and ICNU maintain that the majority of the allocation shortfall is due to Utah choosing to treat costs as rolled-in, without any form of ECD. They note that PacifiCorp agreed in its 1988 merger stipulation that shareholders would bear this type of shortfall. Thus, Staff does not believe that the equalization adjustment should be viewed as a remedy for the allocation shortfall, but rather should be considered a one-time concession that was part of negotiations for the 2017 Protocol.

PacifiCorp maintains that a change to any term of the 2017 Protocol would alter the balance struck between the parties and subject the 2017 Protocol to risk of modification in another jurisdiction, or even unravel the 2017 Protocol entirely.

2. ECD or Hydro Endowment

The 2017 Protocol modifies Oregon's current ECD by instituting a floor of $8.238 million and a cap of $10.5 million for the first general rate case filed under the 2017 Protocol. If the company files a second general rate case using the 2017 Protocol, the cap increases to $11 million. The company maintains that the floor and cap on Oregon's ECD are reasonable because they are in line with its projections of $8.2 million

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[8] *See* Appendix A, PAC/101, Dalley/14 for a table that summarizes the state-specific impacts of the 2017 Protocol. *See* also PAC/100, Dalley/25-26 for the mechanics of the deferral and the planned tariff filing to credit Oregon customers the balance of the OATT revenue deferral (from docket UE 246) net of the 2017 equalization adjustment.

[9] Senate Bill 1547, Oregon Leg. 2016 Regular Session. *See generally* PacifiCorp's Opening Brief at 16 (May 26, 2016) (stating that SB 1547 allows PacifiCorp to remove production tax credits (PTCs) from rates as they expire without the need for a general rate case).

for 2016, $8.7 million for 2017, and $10 million for 2018.[10] The company, CUB, and Staff all compare these figures to the Revised Protocol (2005), which would have provided approximately $7 million.

ICNU opposes the cap on the hydro endowment. ICNU maintains that it is not appropriate to limit the benefits Oregon customers receive through the hydro endowment, particularly in an interim agreement, when Oregon customers bear the majority of the costs of the company's northwest hydro systems. ICNU believes that Oregon's ECD could potentially be almost twice as much as proposed in the 2017 Protocol. ICNU also believes the purpose of the cap is to move Oregon closer to Utah's preferred methodology of fully rolled-in cost allocation.

CUB explains that it is very committed to permanently preserving the hydro endowment and believes the 2017 Protocol largely preserves the ECD. CUB states that it is sympathetic to ICNU's concerns, but ultimately CUB points to Staff's testimony showing that the hydro endowment has decreased over the last ten years, that it is unlikely that the endowment will exceed the cap, and there is a real possibility that it could be below the floor.[11] CUB supports the floor and cap as a reasonable compromise that protects all parties.

PacifiCorp responds that ICNU uses outdated data to exaggerate the hydro endowment value.[12] PacifiCorp states that the parties negotiated the floor to recognize and balance Oregon customers' investments in hydro facilities, and the cap to mitigate risk of under-recovery for PacifiCorp.

3. Direct Access

a. New Policies

Noble Solutions and NIPPC continue to advocate for changes to PacifiCorp's five-year program, and ask us to clarify that the 2017 Protocol does not limit our ability to revise direct access programs through future rules or orders.[13] The 2017 Protocol states "to the extent Oregon adopts new laws or regulations regarding Oregon Direct Access Programs, Oregon's treatment of loads lost * * * may be re-determined * * *." NIPPC is concerned that this language does not include "laws, regulations, or *orders*." NIPPC asks us to clarify that we are not limiting our ability to revise direct access programs. Noble Solutions states that, in docket UE 267, PacifiCorp relied on the 2010 Protocol to defeat a reasonable five-year program, and Noble Solutions believes we must clarify that the 2017 Protocol will not impede further development of direct access programs.

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[10] For comparison, PacifiCorp's last general rate case in docket UE 263 used a 2014 forecast test year and the ECD was a credit of $8.8 million. In 2015, Oregon ECD was a credit of $7.6 million. PacifiCorp Opening Brief at 13.

[11] CUB Opening Brief at 12 (May 26, 2016) (citing Staff/200, Kaufman/4 and Staff/202).

[12] PacifiCorp's Opening Brief at 11-12 (stating that ICNU used 2013 data from less precise foundational studies, and the updated calculations use data from a Wyoming rate case that is more accurate and more recent).

[13] NIPPC did not file testimony, but supports Noble Solutions' testimony.

PacifiCorp responds that these requests are unclear, and that addressing hypothetical changes to direct access programs in Oregon or in other states is unnecessary because the 2017 Protocol allows parties to reconvene to discuss any necessary modifications due to changed regulatory circumstances.[14] Staff believes that the Commission retains full discretion over the allocation treatment of loads lost to direct access in Oregon, and it is unnecessary to speak to what the Commission may or may not do in the future.

b. Other States

ICNU submits that the critical issue in this docket is to ensure that we understand that we have the authority to adopt consistent treatment between loads lost to direct access programs in Oregon and loads lost to direct access programs in other states. ICNU states that the 2017 Protocol does not explicitly describe how loads lost to direct access programs in other states will be handled, and that we may need to prevent cost shifting in the event that a large customer switches to direct access in Utah.

Staff construes the 2017 Protocol to allow us to unilaterally choose to include or exclude any state's direct access load.

PacifiCorp responds that none of the parties to this proceeding contest ICNU's interpretation. However, PacifiCorp opposes ICNU's request, arguing that it is premature and circumvents language in the 2017 Protocol that commits PacifiCorp to informing all parties should any state adopt or change direct access programs, and the language that allows parties to reconvene to discuss any necessary modifications due to changed regulatory circumstances.

c. Voluntary Renewable Energy Tariff (VRET)

Noble Solutions and NIPPC ask us to reaffirm that "VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access."[15] Noble Solutions is concerned that PacifiCorp would have a competitive advantage with a company-owned VRET product that spreads stranded costs across the entire system, instead of being situs-assigned to Oregon customers for a ten-year period, as is the case with the direct access five-year opt-out program.

In response, PacifiCorp states that this clarification is premature because the company does not currently have a VRET. Thus, Staff concludes that we retain the discretion to determine how VRET load is treated as part of a VRET proceeding, and need not decide the issue as part of the 2017 Protocol.

[14] PacifiCorp Opening Brief at 16-17 (citing PAC/100, Dalley/23).
[15] *In the Matter of Voluntary Renewable Energy Tariffs for Non-Residential Customers,* Docket No. UM 1690, Order No. 15-045 at 2 (Dec 15, 2015).

IV. COMMISSION RESOLUTION

We have considered the parties' concerns outlined above, and we will accept the 2017 Protocol as filed. We recognize that the parties put significant time and effort into the 2017 Protocol, that Utah has already adopted it, and that our Staff and CUB support it. The 2017 Protocol explains a process going forward for the company to analyze alternative allocation methods and present these issues to the MSP workgroup and discuss them at Commissioner forums.

We will use the 2017 Protocol in PacifiCorp rate proceedings filed from December 31, 2016 through December 31, 2018. We do not intend to adopt the one-year extension contemplated in the 2017 Protocol.[16]

We treat the 2017 Protocol as a contested stipulation, and we review the terms of any stipulation for reasonableness and accord with the public interest.[17] Overall, we find that the 2017 Protocol is, on balance, in the public interest because it is a short-term agreement between numerous stakeholders from different jurisdictions that is generally consistent with the status quo of the 2010 Protocol. The 2017 Protocol meets our previously-established standards for the protocols,[18] and sets out an allocation methodology to allow the company an opportunity to recover its prudently incurred costs. It also provides for equitable sharing by evenly distributing the equalization adjustment among the states that participate in the protocol.[19] The 2017 Protocol was negotiated over three years and agreed to by the parties in four jurisdictions before it was filed, unlike the 2010 Protocol.

In addition, we will open a new investigation into PacifiCorp's inter-jurisdictional allocation so that we can conduct detailed analyses on a reasonable allocation method for the company and its Oregon customers. We will continue to work within the process identified in the 2017 Protocol with the MSP workgroup and the Commissioner forums. However, to ensure that we can fully analyze Oregon-specific issues, we will simultaneously work on our own investigation. Oregon will be facing new and unique allocation issues due to the passage of SB 1547 which, in part, requires the removal of coal resources from Oregon rates by 2030. A new investigation will allow us to analyze impacts of SB 1547. A new investigation will also allow us to independently explore

[16] The 2017 Protocol states that it may be extended for a one-year period if the state commissions act by March 31, 2017.

[17] *In re PacifiCorp, Transition Adjustment, Five-Year Cost of Service Opt-out,* Docket UE 267, Order No. 15-060 at 4 (Feb 24, 2015) ("[w]e clarify that we do not defer to, and are not bound by the terms of any stipulation. Although we encourage parties to resolve disputes informally, we must review the terms of any stipulation for reasonableness and accord with the public interest. We also affirm that, as set out in OAR 860-001-0350, we may adopt or reject a stipulation in its entirety, or adopt it with modifications to its terms.").

[18] Order No. 02-193 (Mar 26, 2002) (the order initiating this docket identified three goals for the MSP, (1) allow PacifiCorp an opportunity to recover its prudently incurred costs, (2) ensure that Oregon's share of costs is equitable, and (3) meet the public interest standard).

[19] Order No. 05-021 at 6 (the equitable sharing goal was met because Oregon, along with the other five states, pays an appropriate share of its costs).

approaches consistent with cost-causation principles and that make sense for Oregon customers.

We do not adopt any of the parties' proposed changes to the 2017 Protocol. We briefly address the requested changes, and our reasoning, below.

We do not adopt ICNU's request to reduce the $2.6 million annual equalization adjustment in light of increased revenues the company will receive after passage of SB 1547. Although the general rate-case stay out provision and the company's commitment to perform allocation studies may not justify the equalization adjustment, we find that retention of the hydro endowment provides benefits that exceed the equalization adjustment. We also decline to reduce the equalization adjustment in light of PTC revenues, because we do not see the direct connection between the company's inter-jurisdictional shortfall, the equalization adjustment, and net power costs accounting that occurs in the company's annual transition adjustment mechanism (TAM) filings, which now includes PTC costs. In part, this is because the parties have not fully explained the cause of the shortfall, beyond pointing to Utah and Oregon's different implementation of the ECD.

We decline to adopt ICNU's request to remove the $8.238 million floor and the $10.5 million[20] cap from the ECD because we do not believe these parameters are expected to harm customers, when considered as part of this short-term, multi-state compromise. The company has provided ECD projections for Oregon for the term of the 2017 Protocol, and these projections (from $8.2 to $10.0 million)[21] are within the ECD limits in the 2017 Protocol. The company has explained that it is using more recent and robust data than ICNU's projections. We concur with Staff and the company that it is unlikely the ECD projections will meet or exceed the cap.

We do not adopt any changes to the direct access language in the 2017 Protocol. All parties appear satisfied with the 2017 Protocol's treatment of direct access load, insofar as load associated with the one- or three-year program will be included in the load-based dynamic allocation factors for all resources with transition payments situs assigned to Oregon.[22] The same treatment applies to the five-year program during the period covered by transition cost payments, after which the load is excluded from load-based dynamic allocation factors. We limit our decision here to the 2017 Protocol's language describing this treatment.

Regarding the parties' concerns, we agree with PacifiCorp that we do not need to make anticipatory findings on future changes to direct access. This is a short-term protocol and we can address any issues when, and if, they arise. The 2017 Protocol contains considerable language recognizing the necessary flexibility of the regulatory process to address changed or unforeseen circumstances.[23] We further agree with Staff that the 2017 Protocol does not limit our authority over direct access allocation. Regarding

[20] The cap increases to $11.0 million if a second rate case is filed using the 2017 Protocol.
[21] PAC/200, McDougal/7.
[22] The load-based dynamic allocation factors are calculated using the states' monthly energy usage.
[23] Appendix A, PAC/101, Dalley/3-4.

NIPPC's concern over the 2017 Protocol language omitting the term "Commission orders", this omission does not limit or bind our authority over direct access programs.

Finally, we do not address the recommendations regarding the VRET program because we have recently closed that proceeding.[24]

IV. ORDER

IT IS ORDERED that:

1. The 2017 Protocol, attached as Appendix A, is adopted; and

2. We will open a new investigation by the end of November 2016 into PacifiCorp's inter-jurisdictional allocation.

Made, entered, and effective AUG 23 2016.

Lisa D. Hardie
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

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[24] *In re Voluntary Renewable Energy Tariffs for Nonresidential Customers,* Docket No. UM 1690, Order No. 16-251 (Jul 5, 2016) (closing the VRET docket because the utilities are not moving forward with VRET proposals).

2017 Protocol

2017 Protocol

I. Introduction:

This 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (the "2017 Protocol") is the result of general agreement that has been reached between representatives of PacifiCorp (or the "Company") and certain Commission staff members, consumer advocates and other interested parties from Idaho, Oregon, Utah, and Wyoming (collectively referred to as the "Parties" or individually as a "Party") regarding issues arising with regards to the 2010 Protocol, PacifiCorp's status as a multi-jurisdictional utility and future inter-jurisdictional allocation procedures.

The 2010 Protocol expires at midnight on December 31, 2016. The Parties have determined that it is in their best interest or the interest of PacifiCorp's customers to support a new protocol governing inter-jurisdictional allocation procedures. This 2017 Protocol is designed to provide PacifiCorp, State Commissions, and other interested Parties a transitional allocation method while the impacts of the United States Environmental Protection Agency (EPA) rules governing carbon pollution from existing power plants under section 111(d) of the Clean Air Act (111(d)) and other multi-jurisdictional issues are better understood and can be more fully analyzed for their allocation impacts on PacifiCorp and each State. During the term of the 2017 Protocol, PacifiCorp will analyze alternative allocation methods including but not limited to: corporate structure alternatives, divisional allocation methodologies, alternative system allocation methodologies, potential implications of the EPA's final Rule 111(d), and possible formation of a regional independent system operator. PacifiCorp will present its analyses of these issues to the Multi-State Protocol or MSP Workgroup and discuss them at Commissioner Forums.

During the term of the 2017 Protocol, PacifiCorp commits that its generation and transmission system will continue to be planned and operated prudently on an integrated basis designed to achieve a least cost/least risk resource portfolio for PacifiCorp's customers. This commitment will not prevent PacifiCorp from filing for and requesting State Commission approval to participate in a regional independent system operator organization.

The 2017 Protocol describes inter-jurisdictional allocation policies and procedures, which, if applied by each of the States for rate proceedings filed after December 31, 2016, or as otherwise agreed to in Section XIV, are intended to better afford, than would otherwise be the case, PacifiCorp a reasonable opportunity to meet the goal of recovering its prudently incurred cost of service.

The apportionment, assignment, or allocation of a particular expense or investment, or allocation of a share of an expense or investment, to a State under the 2017 Protocol is not intended to and will not prejudge the prudence of those costs. Nothing in the 2017 Protocol is intended to abrogate a State Commission's right and/or obligation to: (1) determine fair, just, and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that Commission; (2) consider the impact of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedures for purposes of allocation of costs and revenues within that State to different customers or customer classes.

Parties who support the 2017 Protocol do so with the intent to continue to achieve equitable resolutions to multi-jurisdictional allocation issues that are in the public interest. A Party's support of the 2017 Protocol will not, however, in any manner negate the necessary flexibility of the regulatory process to address changed or unforeseen circumstances, including but not limited to changes in laws or regulations, and a Party's support of the 2017 Protocol will not bind or be used against that Party if a Party concludes that the 2017 Protocol no longer produces results that are just, reasonable, and in the public interest, or provides the Company with the opportunity to recover its prudently incurred cost of service. Support of the 2017 Protocol will not be deemed to constitute an acknowledgement by any Party of the validity or invalidity of any particular method, theory, or principle of regulation, cost recovery, cost of service, or rate design, and no Party will be deemed to have agreed that any particular method, theory, or principle of regulation, cost recovery, cost of service, or rate design employed or implied in the 2017 Protocol is appropriate for resolving any other issues.

The 2017 Protocol describes how the costs and revenues, including wholesale transactions, associated with PacifiCorp's generation, transmission, and distribution systems will be assigned or allocated among its six state jurisdictions.

Terms that are capitalized in the 2017 Protocol are either defined in the 2017 Protocol or set forth in Appendix A.

A table identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation is included as Appendix B.

The algebraic derivation of each allocation factor is contained in Appendix C.

A description and numeric example of how Special Contracts and related discounts will be reflected in rates is set forth in Appendix D.

Additional terms specific to each State, including an Equalization Adjustment, are reflected in Section XIV.

II. Effective Period and Expiration:

The Parties agree to support Commission adoption or use of the 2017 Protocol in all PacifiCorp rate proceedings filed after December 31, 2016, or as otherwise agreed to by Parties in Section XIV, up to and including December 31, 2018.

The 2017 Protocol will expire December 31, 2018, unless all State Commissions that approved the 2017 Protocol determine, by no later than March 31, 2017, that the term of the 2017 Protocol will be extended by an optional one-year extension through December 31, 2019. In determining whether the 2017 Protocol should or should not be extended, each State Commission can take such steps or provide such processes for public input as that Commission determines to be necessary or appropriate under applicable State laws.

A Commissioner Forum will be held annually, beginning in January 2017, to discuss inter-jurisdictional allocation issues and whether the 2017 Protocol should be extended for an additional one-year term, as described above.

III. Classification of Resources:

All Resource Fixed Costs, Wholesale Contracts, and Short-term Firm Purchases and Firm Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All Non-Firm Purchases and Sales will be classified as 100 percent Energy-Related.

IV. Allocation of Resource Costs and Wholesale Revenues:

Resources will be assigned to one of two categories for inter-jurisdictional allocation purposes: State Resources or System Resources. A complete description of allocation factors to be used is set forth in Appendix B.

There are four types of State Resources. The remaining types of Resources are System Resources, which constitute the substantial majority of PacifiCorp's Resources. Benefits and costs associated with each category and type of Resource will be assigned or allocated to Jurisdictions on the following basis:

A. State Resources

Benefits and costs associated with the four types of State Resources will be assigned as follows:

1. Demand-Side Management ("DSM") Programs: Costs associated with DSM Programs, including Class 1 DSM Programs, will be assigned on a situs basis to the Jurisdiction in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors.

2. Portfolio Standards: Costs associated with Resources acquired to comply with a Jurisdiction's Portfolio Standard adopted, either through legislative enactment or a State's Commission, the portion of which exceeds the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the Jurisdiction adopting the Portfolio Standard.

3. Qualifying Facility Contracts: Costs associated with Qualifying Facility Contracts, the portion of which exceeds the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources will be assigned on a situs basis to the Jurisdiction that approved the contract.

4. Jurisdiction-Specific Initiatives: Costs and benefits associated with Resources acquired in accordance with a Jurisdiction-specific initiative will be assigned on a situs basis to the Jurisdiction adopting the initiative.

This includes, but is not limited to, the costs and benefits of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

B. System Resources

All Resources that are not State Resources are System Resources and will be allocated as follows:

1. Generally, all Fixed Costs associated with System Resources and all costs incurred under Wholesale Contracts will be allocated based upon the System Generation ("SG") Factor.
2. Generally, all Variable Costs associated with System Resources will be allocated based upon the System Energy ("SE") Factor.
3. Revenues received by PacifiCorp under Wholesale Contracts will be allocated based upon the SG Factor.

C. Equalization Adjustment

The 2017 Protocol includes an Equalization Adjustment to be applied to each State's revenue requirement, as summarized in Section XIV, for purposes of ratemaking proceedings filed prior to the expiration of the 2017 Protocol. The Equalization Adjustment recognizes differences among the States in the 2010 Protocol Agreement implemented in each State and the respective treatment of the embedded cost differential ("ECD") adjustment – i.e. Baseline ECD, Dynamic ECD, or no ECD. The 2017 Protocol with the Equalization Adjustment is designed to allow PacifiCorp the opportunity to equitably allocate revenue requirement components in rate recovery proceedings in the States.

V. Re-functionalization and Allocation of Transmission Costs and Revenues

Before filing any request to approve a reclassification of facilities as transmission or distribution with FERC, PacifiCorp will submit filings seeking review and authorization of any such reclassification with the State Commissions. The cost responsibility for any assets reclassified under FERC policy will be assigned or allocated consistent with other assets in the relevant function.

Costs associated with transmission assets, and firm wheeling expenses and revenues, will be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated based upon the SG Factor. Non-firm wheeling expenses and revenues will be allocated based upon the SE Factor. In the event that PacifiCorp joins a regional independent system operator, the allocation of transmission costs and revenues may be reevaluated and revised as provided for in Section XIII.

VI. Assignment of Distribution Costs:

All distribution-related expenses and investment that can be directly assigned will be directly assigned to the State where they are located. Those costs that cannot be directly assigned will be allocated consistent with the factors set forth in Appendix B.

VII. Allocation of Administrative and General Costs:

Administrative and General Costs, General Plant costs, and Intangible Plant costs will be allocated consistent with the factors set forth in Appendix B.

VIII. Allocation of Special Contracts:

Revenues associated with Special Contracts will be included in State revenues, and loads of Special Contract customers will be included in Load-Based Dynamic Allocation Factors as appropriate (see Appendix D). Special Contracts may or may not include Customer Ancillary Service Contract attributes. Load curtailments and buy-through arrangements will be handled as appropriate (see Appendix D).

IX. Allocation of Gain or Loss from Sale of Resources or Transmission Assets:

Any loss or gain from the sale of a Company-owned Resource or transmission asset will be allocated based upon the allocation factor used to allocate the Fixed Costs of the Resource or the transmission asset at the time of its sale. Each Commission will determine the appropriate allocation of loss or gain allocated to that Jurisdiction as between customers and PacifiCorp shareholders.

X. State Programs Regarding Access to Alternative Electricity Suppliers:

A. Treatment of Oregon Direct Access Programs:

This Section describes treatment of loads lost to Oregon Direct Access Programs during the term of the 2017 Protocol.

1. Customers electing PacifiCorp's one- and three-year Oregon Direct Access Programs – The load of customers electing to be served on PacifiCorp's one- and three-year Oregon Direct Access Programs will be included in the Load-Based Dynamic Allocation Factors for all Resources, and the transition cost payments from these customers will be situs assigned to Oregon.

2. Customers electing PacifiCorp's five year opt-out program under the Oregon Direct Access Program – The treatment will be consistent with Order No. 15-060, as clarified through Order No. 15-067, of the Oregon Public Utility Commission in Docket UE 267, and Oregon Schedule 296, which allow Oregon Direct Access Program

Customers to permanently opt-out of cost-of-service rates after payment of ten years of transition costs in Oregon. During the ten-year period for which Oregon Direct Access Customers are paying transition costs, the Oregon Direct Access Customers' loads will be included in Load-Based Dynamic Allocation Factors, and the transition cost payments from these customers will be situs-assigned to Oregon. At the end of the 10-year period covered by the transition cost payments, the loads of the Oregon Direct Access Customers will be excluded from Load-Based Dynamic Allocation Factors. Thereafter, if an Oregon Direct Access Customer elects to return to Oregon cost-of-service rates by providing four-years notice under Schedule 267, its load will be included in Load-Based Dynamic Allocation Factors at the time the customer returns to Oregon cost of service rates.

3. To the extent Oregon adopts new laws or regulations regarding Oregon Direct Access Programs, Oregon's treatment of loads lost to Oregon Direct Access Programs may be re-determined in a manner consistent with the new laws and regulations. In the event Oregon adopts such new laws or regulations, the Company will inform the State Commissions and the Parties of the same.

B. Utah Eligible Customer Program:

If, pursuant to Utah Code Annotated Section 54-3-32, an eligible customer in Utah transfers service to a non-utility energy supplier, the Public Service Commission of Utah will make determinations under Utah law as contemplated therein. The Company will inform the State Commissions and the Parties of the Public Service Commission of Utah's determinations.

C. Other State Actions:

In the event any State adopts laws or regulations governing customer access to alternative electricity suppliers, the Company will inform the State Commissions and the Parties of the same.

XI. Loss or Increase in Load:

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale, or acquisition of new service territory that involves less than five percent of system load, realignment of service territories, changes in economic conditions, or gain or loss of large customers will be reflected in changes in the Load-Based Dynamic Allocation Factors. The allocation of costs and benefits arising from merger, sale, or acquisition transactions proposed by the Company involving more than five percent of system load will be considered on a case-by-case basis in the course of Commission approval proceedings.

XII. Commission Regulation of Resources:

PacifiCorp will plan and acquire new Resources on a system-wide least-cost, least-risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each State, as approved by individual State Commissions.

XIII. Interpretation and Governance:

A. Issues of Interpretation

If questions of interpretation of the 2017 Protocol arise during rate proceedings, audits of results of PacifiCorp's operations, or both, Parties will attempt, consistent with their legal obligations, to resolve them in good faith in light of the language of the 2017 Protocol and the intent of the Parties.

B. Commissioner Forum

A Commissioner Forum will be held annually beginning January 2017 to discuss the 2017 Protocol and other inter-jurisdictional allocation issues that may arise. All seated commissioners from each Jurisdiction will be invited to participate in all Commissioner Forums.

Each Commissioner Forum will be a public meeting and all interested parties will be allowed to attend. Prior to attending a Commissioner Forum, each Commission can take such steps and provide such process for public input as the Commission determines to be necessary or appropriate under applicable State laws.

At the Commissioner Forum, commissioners will be invited to discuss and may make recommendations regarding extension of the 2017 Protocol and other inter-jurisdictional allocation issues that may arise.

C. MSP Workgroup

The MSP Workgroup will be open to any utility regulatory agency, customer, and other person or entity potentially affected by inter-jurisdictional allocation procedures that expresses an interest in participating. The MSP Workgroup may create sub-committees to investigate, evaluate, or make recommendations as to specified issues. MSP Workgroup meetings may be held in person or by telephone.

The Company will promptly convene one or more MSP Workgroup meetings: (i) to discuss the possibility of a new inter-jurisdictional allocation agreement if any Commission indicates that the 2017 Protocol should not be extended pursuant to Section II or as a result of new developments pursuant to Section X, (ii) to discuss an inter-jurisdictional allocation issue identified by any Commission, or (iii) to discuss any other inter-jurisdictional allocation issue raised by any interested stakeholders. MSP Parties will work in good faith to achieve resolution of any issues brought before the MSP Workgroup.

Before each annual Commissioner Forum, PacifiCorp will convene an MSP Workgroup meeting for the purpose of discussing and monitoring emerging inter-jurisdictional allocation issues facing PacifiCorp and its customers, the status and implications of Rule 111(d), or the development of a regional independent system operator, in order to inform discussions at the Commissioner Forum. PacifiCorp will provide reasonable staffing and resources to provide minutes of any MSP Workgroup meeting, coordinate MSP Workgroup activities and conduct studies and analysis as agreed to by the MSP Workgroup, and as suggested by the Commissioner Forum.

D. Proposals for New Inter-Jurisdictional Allocation Procedures

Proposals for new inter-jurisdictional allocation procedures, including any changes to the 2017 Protocol, ranging from minor modifications to major modifications, may be submitted by any Party or any Commission utilizing the 2017 Protocol. Proposals shall be provided to the Company for the purpose of circulating the proposals to the other Parties and State Commissions and initiating discussions to attempt to address and resolve specific concerns.

If any Party intends to propose a new inter-jurisdictional allocation procedure, the Party will attempt, consistent with their legal obligations, to: (1) bring that proposal to the Commissioner Forum or the MSP Workgroup and (2) resolve the proposal in good faith.

A Party's initial support or acceptance of the 2017 Protocol will not bind or be used against that Party if unforeseen or changed circumstances, including new developments pursuant to Section X, cause that Party to conclude that the 2017 Protocol no longer produces just and reasonable results, reasonable cost recovery for the Company, or is not in the public interest. Before a Party asks a Commission to deviate from the terms of the 2017 Protocol, the Parties, will be invited by the Company to enter into a discussion, or series of discussions, to attempt to address and resolve their concerns at MSP Workgroup meetings and/or a Commissioner Forum, consistent with any applicable legal obligations.

E. Interdependency among Commission Approvals

The 2017 Protocol has been developed by the Parties as an integrated, interdependent, organic whole. Support by any Party or Commission of the 2017 Protocol is expressly conditioned upon similar support of the 2017 Protocol by the Commissions of at least the States of Idaho, Oregon, Utah, and Wyoming, without material alteration. If a Commission materially deletes, alters, or conditions approval of the 2017 Protocol, Parties shall promptly meet and discuss the implications of the material alteration, and will have the opportunity to accept or reject continued support of the 2017 Protocol in light of such action.

XIV. <u>Additional State-Specific Terms:</u>

For the period that the 2017 Protocol remains in effect, a 2017 Protocol Adjustment will be added to each State's annual revenue requirement. For California, Idaho, Utah, and Wyoming, the 2017 Protocol Adjustment is the sum of the Baseline ECD and the Equalization Adjustment. For Oregon, the 2017 Protocol Adjustment is the sum of the Baseline ECD, which is dynamic with the parameters described in paragraph three below, and the Equalization Adjustment. The Parties agree to an annual Equalization Adjustment of $9.074 million, with specific State-by-State 2017 Protocol Adjustment impacts as summarized in this table:

Revenue Requirement ($000)	Total Company	California	Oregon	Utah	Idaho	Wyoming
2017 Protocol Baseline ECD **	(9,578)	(324)	(8,238) *	0	836	(1,851)
2017 Protocol Equalization Adjustment	9,074	324	2,600	4,400	150	1,600
2017 Protocol Adjustment		(0)	(5,638)	4,400	986	(251)

* Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in paragraph 3 below. For the other states, the 2017 Protocol Baseline ECD is fixed and does not change over time.
** 2017 Protocol Baseline ECD amounts shown in the table for California, Oregon, and Wyoming are based on the test year data as filed by the Company in the 2015 Wyoming general rate case (Docket 20000-469-ER-15) on March 3, 2015. The amount for Idaho's 2017 Protocol Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement.

State specific implementation is summarized below:

1. California's 2017 Protocol Adjustment is zero.
2. The Idaho Parties and PacifiCorp agree to an annual Idaho 2017 Protocol Adjustment of $0.986 million to be added to Idaho's 2017 Protocol revenue requirement. Idaho's Equalization Adjustment is $0.150 million. The Idaho 2017 Protocol Adjustment shall be included in base rates through a general rate case beginning January 1, 2018, or to the extent that a case is filed so the rate effective date is later than that date, the Equalization Adjustment shall be deferred on a monthly basis ($12,500 per month) from January 1, 2018, forward as a regulatory asset until the rate effective date of PacifiCorp's next Idaho general rate case at which time (1) the deferred costs and (2) the ongoing impact of Idaho's 2017 Protocol Adjustment shall be included in rates.
3. The Public Utility Commission of Oregon Staff ("Commission Staff"), the Citizens' Utility Board of Oregon ("CUB"), and PacifiCorp ("Oregon Parties"), agree to an Oregon Equalization Adjustment of $2.6 million. The Oregon Parties agree that Oregon's Equalization Adjustment of $2.6 million annually (or $216,667 monthly) be deferred from January 1, 2017, until the 2017 Protocol Equalization Adjustment is reflected in base rates through the Company's next general rate case. The Oregon Parties agree that the 2017 Protocol Equalization Adjustment deferral will be reflected as a debit (reduction to the existing credit balance to be returned to customers) in the Open Access Transmission Tariff ("OATT") revenue deferral account originally established through docket UE 246.[1] The Parties agree that the Company will file a new tariff to return to

[1] As a result of the stipulation and Commission Order No. 12-493 in docket UE-246, the Company filed for, and the Commissiou approved the Company's application to defer incremental OATT revenues from January 1, 2013, until

(Continued...)

Oregon customers the balance of the OATT revenue deferral, net of the 2017 Protocol Equalization Adjustment deferral, within 60 days of an Oregon Commission order approving of the 2017 Protocol. The Company commits to continued evaluation of alternative inter-jurisdictional allocation methods, including consideration of corporate structure alternatives, divisional allocation methodologies, and potential implications of the Environmental Protection Agency's final Rule 111(d), and possible formation of a regional independent system operator. The Company will distribute or present the results of its analysis, based on information available, no later than March 31, 2017. If PacifiCorp does not distribute or present the results of its analysis on or before March 31, 2017, for each month the analysis is not provided after that date $216,667 will be credited to the OATT revenue deferral balance unless otherwise waived by the Commission for good cause. The Company agrees that during the effective period of this agreement regarding the 2017 Protocol, the Company will not have any pending general rate case that requests rates effective before January 1, 2018. Oregon Parties may file for deferrals during the general rate case stay-out period, but such filings will be subject to the Commission's guidelines for deferrals established in docket UM 1147, unless otherwise authorized by the Commission. This provision will not alter the operation or application of existing or new rate adjustment mechanisms authorized by the Commission, including but not limited to PacifiCorp's Transition Adjustment Mechanism, the Power Cost Adjustment Mechanism, and the Renewable Adjustment Clause. The Oregon Parties agree that for the duration of the 2017 Protocol, Oregon's results of operations reports

(...continued)
these revenues are reflected in base rates. Commission Order Nos. 13-045, 14-023, and 15-020 approved the Company's applications to defer these incremental revenues for 2013, 2014, and 2015, respectively.

and general rate case filings will reflect a Dynamic ECD calculated consistent with the 2010 Protocol inter-jurisdictional allocation methodology with the parameters as described below:

- For the Company's first Oregon general rate case filing under the 2017 Protocol (which will be effective no earlier than January 1, 2018), the Dynamic ECD value for Oregon will be set at a level no less than $8.238m (the baseline value of Oregon's ECD used to negotiate each State's contribution to the 2017 Protocol Equalization Adjustment), and will be capped at $10.5 million; and
- If the 2017 Protocol is extended to 2019, and the Company files a second Oregon general rate case using the 2017 Protocol, the Dynamic ECD in that general rate case filing will be set at a level no less than $8.238m and will be capped at $11.0 million. The Dynamic ECD provisions apply only to the 2017 Protocol as an integrated agreement and do not in any way limit or compromise any party's ability to argue for a different ECD or hydro endowment calculation in any future inter-jurisdictional allocation methodologies.

The Oregon Parties agree that unless there is formal action by the Public Utility Commission of Oregon to adopt an alternate allocation methodology by January 1, 2019, or unless the 2017 Protocol is extended through 2019 under the terms of the 2017 Protocol, PacifiCorp will use the Revised Protocol allocation method for general rate case filings in Oregon after January 1, 2019. The Oregon Parties have negotiated this settlement as an integrated agreement. If the Public Utility Commission of Oregon rejects all or any material portion of this agreement or imposes additional material conditions in approving this agreement, any of the Oregon Parties are entitled to withdraw from the settlement. If the Public Utility Commission of Oregon rejects the 2017 Protocol, this agreement terminates upon the date of the order rejecting the 2017 Protocol.

4. The Utah Parties and PacifiCorp agree to an annual Utah Equalization Adjustment of \$4.4 million and a 2017 Protocol Adjustment of the same amount. The Company agrees that it will not file a Utah general rate case or major plant addition case prior to May 1, 2016, and new rates will not be effective prior to January 1, 2017. Utah's 2017 Protocol Adjustment shall be included in base rates through a general rate case with rates effective beginning on or after January 1, 2017. To the extent that a Utah general rate case or major plant addition case is filed with a rate effective date later than that date, Utah's Equalization Adjustment shall be deferred on a monthly basis, (\$366,667 per month), from January 1, 2017, forward as a regulatory asset until the rate effective date of PacifiCorp's next Utah general rate case at which time (1) the deferred costs and (2) the ongoing impact of Utah's 2017 Protocol Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Utah Equalization Adjustment is proposed for inclusion in rates.

5. The Wyoming Parties and PacifiCorp agree to an annual credit for Wyoming's 2017 Protocol Adjustment of \$0.251 million to be netted against Wyoming's 2017 Protocol revenue requirement. If the Company does not file a general rate case prior to January 1, 2017, Wyoming's Equalization Adjustment of \$1.6 million annually shall be deferred, as a regulatory asset, on a monthly basis, (\$133,333 per month), beginning July 1, 2017, until the rate effective date of PacifiCorp's next Wyoming general rate case, at which time (1) the deferred costs and (2) Wyoming's ongoing impact of the 2017 Protocol

Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

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CITIZENS UTILITY BOARD OF OREGON Bob Jenks *Executive Director of Citizens Utility Board of Oregon*	UTAH DIVISION OF PUBLIC UTILITIES Chris Parker *Director of Utah Division of Public Utilities*
UTAH OFFICE OF CONSUMER SERVICES Michelle Beck *Director of Utah Office of Consumer Services*	UTAH ASSOCIATION OF ENERGY USERS Gary Dodge *Attorney for Utah Association of Energy Users*

Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

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Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

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Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

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Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

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WYOMING OFFICE OF CONSUMER ADVOCATE Ivan Williams Ivan Williams *Senior Counsel of Wyoming Office of Consumer Advocate*	WYOMING INDUSTRIAL ENERGY CONSUMERS Robert M. Pomeroy, Esq. Thorvald A. Nelson, Esq. *Attorneys for Wyoming Industrial Energy Consumers*
WYOMING PUBLIC SERVICE COMMISSION STAFF Darrell Zlomke *Commission Administrator for Wyoming Public Service Commission*	

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*This signature does not represent the position of any Wyoming Public Service Commission Commissioner or any Commission staff not directly involved with the negotiations leading to this Settlement Agreement (the "2017 Protocol").

2017 Protocol – Appendix A
Defined Terms

2017 Protocol - Appendix A

Defined Terms

For purposes of this 2017 Protocol, these terms will have the following meanings:

"2010 Protocol" means the PacifiCorp inter-jurisdictional allocation method that was approved by the Idaho, Oregon, Utah, and Wyoming Commissions in 2012 to apply to all PacifiCorp rate proceedings filed after each commission's approval and before December 31, 2016.

"2017 Protocol Adjustment" means the result of netting the 2016 Baseline ECD against the $9.074 million Equalization Adjustment for each State's revenue requirement as specified in Section XIV of the 2017 Protocol. The 2017 Protocol Adjustment is intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in the 2010 Protocol inter-jurisdictional allocation procedures utilized by such States.

"Administrative and General Costs" means costs included in FERC accounts 920 through 935.

"Class 1 DSM Programs" means DSM Programs designed to reduce peak loads.

"Coincident Peak" means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using a historic test period Coincident Peak is based upon actual, metered load data adjusted for normalized weather conditions and in States using future test periods Coincident Peak is based upon forecasted normalized loads, in both cases adjusted as appropriate for interruptibility of Special Contracts.

"Commission" means a utility regulatory commission in a Jurisdiction.

"Commissioner Forum" means an annual public meeting held in January of each year beginning in 2017 to which all seated commissioners from each Jurisdiction will be invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues.

"Company" means PacifiCorp.

"Comparable Resource" means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

"Customer Ancillary Service Contracts" means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company's system.

"Demand-Related" means capital and other Fixed Costs or revenues incurred or received by the Company in order to be prepared to meet the maximum demand imposed upon its system.

"Demand-Side Management Programs" or "DSM Programs" means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.

"Embedded Cost Differential" or "ECD" means the sum of (1) PacifiCorp's total production costs of Pre-2005 Resources expressed in dollars per megawatt-hour compared to the Hydro-Electric Resources forecasted production costs expressed in dollars per megawatt-hour multiplied by the Hydro-Electric Resources megawatt-hours of production, and (2) the differential between the Pre-2005 Resources dollars per megawatt-hour compared to Mid-Columbia Contracts forecasted costs in dollars per megawatt-hour multiplied by the Mid-Columbia Contracts megawatt-hours.

- "Baseline ECD" means the amount of the ECD for each State to be used in the determination of the 2017 Protocol Adjustment. For the states of California, and Wyoming, their Baseline ECD amounts are based on the test year data, as filed by the Company in the 2015 Wyoming General Rate Case (Docket 20000-469-ER-15, Exhibit SRM-2), on March 3, 2015. Idaho's Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement. For Oregon, the Baseline ECD is dynamic with the parameters described in paragraph three of Section XIV.

- "Dynamic ECD" means the ECD components are updated to the test period utilized in the filing.

"Energy-Related" means costs and revenues, such as fuel costs and transmission costs, or sales revenues that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred or received by the Company in order to meet its energy requirements.

"Equalization Adjustment" means a fixed dollar adjustment to be applied to each State's revenue requirement as reflected in Section XIV of the 2017 Protocol intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in current inter-jurisdictional allocation procedures utilized by such states.

"FERC" means the Federal Energy Regulatory Commission.

"Fixed Costs" means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

"General Plant" means capital investment included in FERC accounts 389 through 399.

"Hydro-Electric Resources" means Company-owned hydro-electric plants located in Oregon, Washington or California.

"Intangible Plant" means capital investment included in FERC accounts 301 through 303.

"Jurisdiction" means any one of the six states where the Company provides retail service.

"Load-Based Dynamic Allocation Factor" means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

"Mid-Columbia Contracts" means the various power sales agreements between PacifiCorp and Public Utility District No. 2 of Grant County, PacifiCorp and Douglas County Public Utility District, and PacifiCorp and Chelan County Public Utility District, specifically: the

Power Sales Contract with Public Utility District No. 2 of Grant County dated May 22, 1956; the Power Sales Contract with Public Utility District No. 2 of Grant County dated June 22, 1959; the Priest Rapids Project Product Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Additional Products Sales Agreement with Public Utility District No. 2 of Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Power Sales Contract with Douglas County Public Utility District dated September 18, 1963; the Power Sales Contract with Chelan County Public Utility District dated November 14, 1957 and all successor contracts thereto.

"Multi-State Protocol Workgroup" or "MSP Workgroup" means a group consisting of utility regulatory agencies, customers and others potentially affected by inter-jurisdictional allocation procedures who desire to participate in a cooperative workgroup context and who agree to comply with reasonable confidentiality and other procedures adopted by the MSP Workgroup.

"Non-Firm Purchases and Sales" means transactions at wholesale that are not Wholesale Contracts or Short-Term Purchases and Sales.

"Oregon Direct Access Customers" means Oregon retail electricity consumers that procure electricity from a supplier other than PacifiCorp under an Oregon Direct Access Program.

"Oregon Direct Access Program" means Oregon laws, regulations and orders that permit PacifiCorp's Oregon retail consumers to purchase electricity directly from a supplier other than PacifiCorp.

"Portfolio Standard" means a law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

"Pre-2005 Resources" means Resources (other than Mid-Columbia Contracts and Hydro-Electric Resources) that were part of the Company's integrated system prior to January 1, 2005.

"Qualifying Facility Contracts" means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

"Resources" means Company-owned and leased generating plants and mines, Wholesale Contracts, Short-Term Firm Purchases and Firm Sales and Non-firm Purchases and Sales.

"System Energy Factor" or "SE Factor" - refer to Appendix B.

"System Generation Factor" or "SG Factor" - refer to Appendix B.

"Short-Term Firm Purchases and Firm Sales" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

"Special Contract" means a contract entered between PacifiCorp and one of its retail customers with prices, terms, and conditions based on the specific circumstances of that customer. Special Contracts may account for Customer Ancillary Services Contract attributes.

"State" means any state that is utilizing the 2017 Protocol for inter-jurisdictional allocation purposes, and is intended to include the states of California, Idaho, Oregon, Utah, or Wyoming.

"State Resources" means Resources whose costs are assigned to a single jurisdiction to accommodate jurisdiction-specific policy preferences.

"System Resources" means Resources that are not State Resources and whose associated costs and revenues are allocated among all States on a dynamic basis.

"Variable Costs" means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

"Wholesale Contracts" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm long-term power and/or energy at wholesale or Customer Ancillary Service Contracts as discussed in Appendix D.

2017 Protocol – Appendix B

Allocation Factor Applied to each Component of Revenue Requirement

2017 Protocol - Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
453	Water Sales		
		Common	SG
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG
		Other - Common	SO
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
		Customer Related	CN
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
		Customer Related	CN
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Customer Service Deposits	CN
		Direct assigned - Jurisdiction	S
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Remaining Steam Plants	SG
501	Fuel Related		
		Remaining steam plants	SE
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	SG
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
556	System Control & Load Dispatch		
		Other Expenses	SG
557	Other Expenses		
		Direct assigned - Jurisdiction	S
		Other Expenses	SG
		Cholla Transaction	SGCT
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Steam Plants	SG
403NP	Nuclear Depreciation		
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403HP	Hydro Depreciation		
		Pacific Hydro	SG
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Storage Battery Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S
403GP	General Depreciation		
		Distribution	S
		Remaining Steam Plants	SG
		Mining	SE
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	SG
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		System Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining related	SE
		General	SO
		Production / Transmission	SG
		Depreciation	SCHMDEXP
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJD
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
		Distribution	SNPD
		Production, Other	SGCT
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	SG
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD
		Customer Related	CN
State Income Taxes			
40911	State Income Taxes		
		Income Before Taxes	CALCULATED
40911		Renewable Energy Tax Credit	SG
40910		FIT True-up	S
40910		Renewable Energy Tax Credit	SG
		PMI	SE
		Foreign Tax Credit	SO
Steam Production Plant			
310 - 316			
		Steam Plants	SG
Nuclear Production Plant			
320-325			
		Nuclear Plant	SG
Hydraulic Plant			
330-336			
		Pacific Hydro	SG
		East Hydro	SG
Other Production Plant			
340-346			
		Other Production Plant	S
		Other Production Plant	SG
TRANSMISSION PLANT			
350-359			
		Transmission Plant	SG
DISTRIBUTION PLANT			
360-373			
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
399	Coal Mine		
		Remaining Mining Plant	SE
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
		Generation / Transmission	SG
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
128	Pensions		
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Steam Production Plant	SE
152	Fuel Stock - Undistributed		
		Steam Production Plant	SE
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE
25319	Provo Working Capital Deposit		
		Mining Plant	SE
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		Production - Common	SG
		General	SO
		Distribution	SNPD
		Production, Other	SG
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SG
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production, Other	SGCT
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SG
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
141		Notes Receivable	SO
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
		Accounts Payable	SE
		Accounts Payable	SG
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
230		Other Deferred Credits - Misc	SE
254105		ARO Reg Liability	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Notes Receivable		
		Employee Loans - Hunter Plant	SG
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
		Other Production	SG
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
254105	FAS 143 ARO Regulatory Liability		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
230	Asset Retirement Obligation		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25398	S02 Emissions		SE
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
254	Regulatory Liabilities		
		Regulatory Liabilities	S
		Regulatory Liabilities	SE
		Insurance Provision	SO
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
		Depreciation	TAXDEPR
		Depreciation	SCHMDEXP
		System Gross Plant	GPS
		Contribution in Aid of Construction	CIAC
		Mining	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Production, Other	SGCT
		Property Tax	GPS
		Mining Plant	SE
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	SG
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Steam Plants	SG
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	SG
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
		Mining Plant	SE
108MP	Mining Plant Accumulated Depr.		
		Mining Plant	SE
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Steam Plants	SG
111GP	Accum Prov for Amort-General		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	SG
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Mining Plant	SE

2017 Protocol - Appendix C
Allocation Factors
Algebraic Derivations

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor derivations:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity ("SC")

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy ("SE").

In defining the System Generation ("SG") factor, the weighting of 75 percent System Capacity, 25 percent System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor ("SC")

$$SCi = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i = **System Capacity Factor** for jurisdiction i.
TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor ("SE")

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i = **System Energy Factor** for jurisdiction i.
$TAEi_j$ = Temperature Adjusted Input Energy of jurisdiction i in month j.

System Generation Factor ("SG")

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i = **System Generation Factor** for jurisdiction i.
SC_i = System Capacity for jurisdiction i.
SE_i = System Energy for jurisdiction i.

Division Generation - Pacific Factor ("DGP")

$$DGP_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.
SG_i^* = SG_i if i is a Pacific jurisdiction, otherwise
$SG_i^* = 0$.
SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor ("DGU")

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.
SG_i^* = SG_i if i is a Utah jurisdiction, otherwise
$SG_i^* = 0.$
SG_i = System Generation for jurisdiction i.

System Net Plant - Distribution Factor ("SNPD")

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

System Gross Plant - System Factor ("GPS")

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$ = **Gross Plant - System Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor ("SNP")

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i = **System Net Plant Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.
$ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

System Overhead - Gross Factor ("SO")

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_oi - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i = **System Overhead - Gross Factor** for jurisdiction i.
PP_i = Gross Production Plant for jurisdiction i.
PT_i = Gross Transmission Plant for jurisdiction i.
PD_i = Gross Distribution Plant for jurisdiction i.
PG_i = Gross General Plant for jurisdiction i.
PI_i = Gross Intangible Plant for jurisdiction i.
PP_{oi} = Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi} = Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi} = Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi} = Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi} = Gross Intangible Plant for jurisdiction i allocated on a SO factor

Income Before Taxes Factor ("IBT")

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

$IBTi$ = **Income before Taxes Factor** for jurisdiction i.
$TIBTi$ = Total Income before Taxes for jurisdiction i.

Bad Debt Expense Factor ("BADDEBT")

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$	=	**Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$	=	Balance in Account 904 for jurisdiction i.

Customer Number Factor ("CN")

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:

CN_i	=	**Customer Number Factor** for jurisdiction i.
$CUST_i$	=	Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction ("CIAC")

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:

$CIAC_i$	=	**Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$	=	Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions ("SCHMD")

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M - Deductions (SCHMD) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant ("TROJP")

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning ("TROJD")

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

Tax Depreciation ("TAXDEPR")

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$	=	**Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$	=	Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction's total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense ("DITEXP")

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$	=	**Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$	=	Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

Deferred Tax Balance ("DITBAL")

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

2017 Protocol – Appendix D
Special Contracts

2017 Protocol - Appendix D
Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

2017 Protocol - Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

	Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1 **Loads**					
2 Jurisdictional Loads - No Interruptible Service					
3 Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4 Jurisdictionel Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actuel Interruptions					
7 Jurisdictional Sum of 12 monthly CP demend (MW)		71,700	24,000	35,700	12,000
8 Jurisdictionel Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Speciel Contract Customer Revenue and Load - Non Interruptible Service					
11 Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12 Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13 Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14					
15 Speciel Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16 Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17 Discount for Ancillery Services				-	
18 Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19 Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20 Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21					
22 System Cost Sevings from Interruption		$4,000,000			
23					
24 **Allocation Factors**					
25 No Interruptible Service					
26 SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27 SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28 SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actuel Physical Interruptions)					
31 SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32 SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33 SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
36	**No Interruptible Service**				
37					
38 **Cost of Service**					
39 Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40 Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41 Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42					
43 **Revenues**					
44 Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45 **Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46					
47					
48	**With Interruptible Service**				
49					
50 **Cost of Service**					
51 Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52 Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53 Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54					
55 **Revenues**					
56 Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57 **Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

2017 Protocol - Appendix D - Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17	Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18	Net Cost to Spacial Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Intarruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service & Ancillary Service Contract**					
49						
50	**Cost of Service**					
51	Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52	Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53	Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54	Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56						
57	**Revenues**					
58	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**