Application No. 18-04-002
Exhibit PAC/100
Witness: Etta Lockey and Steve McDougal

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of Etta Lockey and Steve McDougal

Clean Version

Policy and Allocation Methodology

ERRATA

December 2018

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ATTACHED EXHIBITS

Q. Who is sponsoring the testimony in this Exhibit?

A. This testimony is sponsored by Ms. Etta Lockey and Mr. Steve McDougal, both of whom sponsored direct testimony in I. 17-04-019 which has been combined with this docket. Ms. Lockey and Mr. McDougal are adopting the identified portions of the Rebuttal Testimony of Scott D. Bolton, served as Exhibits PAC/100, PAC/101, PAC/102, PAC/103, and PAC/104.

I. PURPOSE OF TESTIMONY (ETTA LOCKEY)

Q. What is the purpose of your testimony in this proceeding?

A. My testimony provides an overview of PacifiCorp's general rate case filing proposing a modest $1.06 million increase to PacifiCorp's base electric rates. I also address the regulatory policy issues raised by this filing, including PacifiCorp's proposal to reinstitute shorter depreciation lives for the company's coal-fired resources and the company's proposed new allocation methodology for system costs, the 2017 Inter-jurisdictional Allocation Protocol (2017 Protocol). Finally, my testimony introduces other witnesses providing testimony on behalf of PacifiCorp.

II. OVERVIEW OF PACIFICORP'S FILING (ETTA LOCKEY)

Q. Please describe PacifiCorp's filing.

A. PacifiCorp is filing its first general rate case since 2011.[1] Since that time, the company, and indeed the electricity sector have undergone significant changes driven by public policy, emerging and maturing technologies, and new levels of customer engagement. PacifiCorp has managed this transition without losing focus on

[1] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, Application (A.) 09-11-015 (filed November 20, 2009).

maintaining the affordability of essential electricity services for its approximately 45,000 customers in its heavily rural and economically challenged service territory. This filing updates costs to serve California customers by requesting a modest increase of approximately $1.06 million, or a 0.9 percent net increase, to its base electric rates in California.

This modest increase is evidence of the cost-conscious and prudent actions taken by PacifiCorp to control its costs and provide safe and reliable energy to its customers at a fair price. A significant driver of the increase requested in this case are the costs associated with regulations adopted in R.15-05-006 designed to mitigate the risk of catastrophic fires attributed to overhead utility equipment.[2] Despite that significant driver, PacifiCorp's diligence in managing its costs has allowed the company to propose to accelerate depreciation for its coal-fired generation resources and invest in a clean energy future, while keeping rates relatively flat for its customers.

Q. Upon what test year is the rate increase request based?

A. As described in the testimony of Ms. Shelley E. McCoy, the rate increase is based on a forecast test period of the 12 months ending December 31, 2019, and certain specific adjustments based on known and measurable capital additions.

Q. What are the primary factors driving the overall rate increase?

A. As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its California service territory while

[2] *See Order Instituting Rulemaking to Develop and Adopt Fire Threat Maps and Fire Safety Regulations*, Decision (D.) 17-12-024 (December 21, 2017).

balancing cost, risk, and state energy policy objectives. PacifiCorp's proposed rate increase is due to a combination of factors, including increased operating expenses, company investments in generation, transmission, and distribution, the recent changes to the federal tax code, and the new fire safety regulations adopted in R.15-05-006, among other items.

PacifiCorp is in the process of transitioning to a clean energy future by investing in additional capacity from renewable resources. The test period in this case includes a portion of significant new renewable energy and infrastructure investments, known as Energy Vision 2020,[3] to serve customers from more clean energy resources, as part of PacifiCorp's long-term plan to build an energy future that is increasingly reliable, decreases greenhouse gas emissions, while maintaining affordability for its customers. One key component of Energy Vision 2020 is expanding the amount of wind power serving PacifiCorp customers with its repowering project to increase the capacity of certain existing wind-generation facilities.

PacifiCorp also seeks to mitigate current risks by increasing flexibility to address changing carbon policy. Specifically, PacifiCorp is proposing to accelerate depreciation on coal-fired resources so that all coal facilities will be fully depreciated by 2029 or earlier. I discuss the basis for PacifiCorp's accelerated depreciation proposal for coal-fired resources later in my testimony.

PacifiCorp is also seeking recovery of its prior investments to reduce emissions in compliance with environmental requirements. Mr. Chad A. Teply

[3] *See* http://www.pacificorp.com/es/energy-vision-2020.html.

discusses the company's 2012-2013 investment decisions on selective catalytic reduction (SCR) systems installed in accordance with state and federal environmental compliance requirements for Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. The SCR systems reduce oxides of nitrogen (NO_X) emissions.

While the proposed revenue requirement includes the company's generation, distribution, and transmission investments occurring for the benefits of the system, the proposed revenue requirement also includes two major investments in PacifiCorp's California service territory. Mr. Richard A. Vail discusses the construction of a new Lassen distribution substation to replace the aging Mt. Shasta substation and Mr. David M. Lucas presents PacifiCorp's deployment of advanced metering infrastructure in its California service territory.

Q. Is PacifiCorp seeking an increase to its currently authorized Return on Equity (ROE) in this proceeding?

A. No. PacifiCorp is not proposing any change to its currently authorized ROE. Based on recent changes to the federal tax code and the evidence provided in the testimony and exhibits of Ms. McCoy, PacifiCorp will earn a ROE in California of 10.08 percent for the test period. This return is less than the company's currently authorized 10.6 percent ROE, which is the ROE requested by the company and supported by the testimony of Mr. Kurt G. Strunk in this proceeding. An overall price increase of approximately $1.06 million or 0.9 percent is required to produce the 10.6 percent ROE necessary to maintain PacifiCorp's financial integrity while making the necessary capital investments to transition to a cleaner energy future.

Q. Please provide an overview of PacifiCorp's repowering proposal for certain of its wind facilities.

A. PacifiCorp's wind repowering project is part of a plan to deliver more renewable generation along with long-term savings for customers. This is the type of investment required to transition a system the size of PacifiCorp's away from coal-fired generating plants and towards a clean-energy future. PacifiCorp's repowering effort was designed to lead this transition. The economic benefits of repowering—zero fuel-cost energy and Production Tax Credits (PTC)—will reduce the Energy Cost Adjustment Clause (ECAC) offset rate that will be effective January 1, 2019, which aligns with the rates effective in this proceeding. Over the first 10 years of the lives of the proposed project, federal PTC benefits drive net customer benefits across all nine price-policy scenarios presented in PacifiCorp's 2017 IRP.[4] PacifiCorp's repowering effort is discussed in the testimonies of Mr. Rick T. Link and Mr. Timothy J. Hemstreet.

Q. Will the company incur other costs in 2019?

A. Yes. The repowering project included in the company's 2019 revenue requirement is part of PacifiCorp's Energy Vision 2020 effort. PacifiCorp will be making additional investments in 2019 related to new wind generation and transmission upgrades to deliver energy from new and repowered wind generation to customers. These additional investments will be financed, in part, during 2019, but will not go into service until after the test-year in this proceeding.

[4] http://www.pacificorp.com/es/irp.html.

Q. Are the cost increases facing PacifiCorp unique in the industry?

A. No. There is a significant interest in finding cost effective ways to transition to cleaner energy resources and maintain compliance with federal and state environmental requirements. PacifiCorp's efforts to meet environmental requirements and develop cost effective opportunities to transition its system away from coal, with only a modest increase to rates, has allowed PacifiCorp to maintain competitive prices measured against other utilities in California. PacifiCorp's current and proposed rates are presented in the testimony of Ms. Judith M. Ridenour.

Q. What portion of the requested increase is related to net power costs?

A. The company is not requesting authorization to recover any revenue requirement related to net power costs in this filing. PacifiCorp collects net power costs through its ECAC, which is updated each August and collected through rate schedule ECAC-94. In compliance with the ECAC mechanism, PacifiCorp will file an application to set its 2019 ECAC rates by August 1, 2018.

Q. What has PacifiCorp done to mitigate the rate increase requested in this proceeding?

A. PacifiCorp has taken several steps to mitigate this rate increase request. First, PacifiCorp has proactively and aggressively controlled its costs. PacifiCorp's repowering project will qualify for an additional 10 years of federal PTCs, resulting in net benefits to customers. Additionally, repowering will reset the 30-year depreciable life of the assets and reduce run-rate operating costs, while increasing production capacity. PacifiCorp's SCR system projects were also implemented under budget and met all environmental compliance deadlines. Finally, as discussed in the direct testimony of Ms. Nikki L. Kobliha, PacifiCorp has been successful in securing favorable interest rates for recent bond issuances that directly benefit customers.

Q. Does PacifiCorp's rate increase include the impacts of the federal tax legislation, formally titled "To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018", H.R. 1 (Tax Cuts and Jobs Act)?[5]

A. Yes. PacifiCorp's 2019 rate case revenue requirement includes the forecasted impact of the Tax Cuts and Jobs Act. The impacts of the Tax Cuts and Jobs Act is discussed in the direct testimony of Ms. McCoy.

Q. How is PacifiCorp addressing the 2018 impacts of the Tax Cuts and Jobs Act?

A. On December 28, 2017, PacifiCorp filed an application to establish a memorandum account to track the expected income tax impacts associated with the Tax Cuts and Jobs Act. PacifiCorp does not currently have a detailed estimate on the impacts of the Tax Cuts and Jobs Act for 2018. PacifiCorp expects to know more once its 2017 results of operations are complete, and can be used as a proxy for 2018. PacifiCorp expects to complete this estimate mid-2018. Once PacifiCorp can estimate the 2018 impact of the Tax Cuts and Jobs Act, PacifiCorp will develop an amortization proposal.

Q. Does this filing address the California Public Utilities Commission's (Commission) direction to begin incorporating a risk-based decision-making process into PacifiCorp's general rate case?

A. Yes. In this filing PacifiCorp has taken steps to begin incorporating a risk-based

[5] Signed into law on December 22, 2017.

decision making process as required by D.14-12-025.[6] The testimony of Mr. Brett S. Allsup addresses the safety risks that PacifiCorp faces in its system and operations, and explains how it plans to manage, mitigate, and minimize those risks.

III. COST RECOVERY MECHANISMS (ETTA LOCKEY)

Q. Please describe the cost-recovery mechanisms currently authorized for PacifiCorp.

A. In PacifiCorp's 2005 General Rate Case, PacifiCorp was authorized to implement three cost-recovery mechanisms that operate outside the three-year cycle for general rate case proceedings.[7] The Commission authorized PacifiCorp to implement an ECAC to recover its volatile energy costs in a timely and efficient manner. In addition to the ECAC, the Commission authorized for PacifiCorp a Post Test Year Adjustment Mechanism (PTAM) for Major Capital Additions that allows the company to recover the California–allocated share of reasonable costs related to any plant additions greater than $50 million on a total-company basis, and an annual PTAM Attrition Factor adjustment that allows the company to adjust base rates for changes in inflation with an offsetting productivity factor of 0.5 percent. The PTAM Attrition Factor adjustment was effective on January 1 of the years when PacifiCorp did not file a general rate case.

[6] *Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities,* D.14-12-025 (December 9, 2014).
[7] *In the Matter of the Application of PACIFICORP (U 901-E) for an Order Authorizing a General Rate Increase and Implementation of an Energy Cost Adjustment Clause and a Post Test-Year Adjustment Mechanism*, D.06-12-011 (December 18, 2018).

Q. Have these mechanisms been effective?

A. Yes. These mechanisms have allowed PacifiCorp to adjust its rates incrementally as the cost of serving customers changes, providing for recovery of prudently-incurred costs, and typically providing customers with small and gradual rate changes. The mechanisms also result in an efficient use of PacifiCorp and Commission resources to avoid the expense and effort of processing large litigated cases. PacifiCorp works closely with the Office of Ratepayer Advocates to communicate frequently and in advance of the PTAM filings. As a result, PacifiCorp's PTAM filings have been processed expeditiously and efficiently by the Commission.

These mechanisms also provide benefits to customers when PacifiCorp's costs decrease. PacifiCorp's 2016, 2017, and 2018 ECAC applications included a request for a rate decrease, reflecting lower loads across the company's system, and lower wholesale prices for electricity and natural gas. This illustrates that mechanisms like the ECAC and PTAM provide benefits to both PacifiCorp and its customers by providing accurate and timely recovery (or return) of costs prudently incurred by the company.

Q. Will PacifiCorp continue to use the mechanisms in 2019 and beyond?

A. Yes. The Commission's order in the 2011 Rate Case did not include any limitations on the continuation of the ECAC or the PTAM for Major Capital Additions. As such, PacifiCorp intends to continue to recover net power costs through the annual ECAC mechanism. The company will continue to make an annual filing on August 1 of each year for rate changes effective January 1 of the next calendar year.

PacifiCorp also intends to continue to utilize the PTAM for Major Capital Additions. The current filing includes forecast cost data and in-service dates for capital projects scheduled to be completed through calendar year 2019. As new, eligible plant additions are placed in service prior to the January 1, 2019 rate effective date of this proceeding, or after December 31, 2019, PacifiCorp plans to use the PTAM to add the California-allocated costs of these projects to rates based on actual cost data and in-service dates. Any material difference between the actual data and the forecast data included in the rate case will be adjusted following approval of the PTAM filings. Present revenues will also be updated to reflect the increase in rates, thereby reducing the revenue requirement increase requested in this proceeding.

The Commission authorized continuation of the PTAM Attrition Factor adjustment in PacifiCorp's 2011 Rate Case[8] and in the subsequent decisions modifying its decision in that case.[9] In PacifiCorp's 2011 Rate Case, the PTAM Attrition Factor adjustment was authorized for use in setting rates for 2012 and 2013,[10] and extended to years 2014 through 2017.[11] PacifiCorp respectfully requests that the PTAM Attrition Factor adjustment be authorized for setting rates in the

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[8] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.10-09-010 (September 3, 2010).
[9] *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.12-10-006 (October 17, 2012); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.13-07-026 (July 31, 2013); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.14-06-018 (June 13, 2014); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.15-12-018 (December 7, 2015); and *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.16-09-046 (October 3, 2016).
[10] D.10-09-010.
[11] D.12-10-006; D.13-07-026; D.14-06-018; D.15-12-018; and D.16-09-046.

calendar years between general rate cases on a going-forward basis, based on the same formula and applied to the same rate elements as was used for calculating the adjustment for calendar year 2011, and approved in D.10-09-010.

IV. ACCELERATED DEPRECIATION OF COAL RESOURCES (ETTA LOCKEY)

Q. What is PacifiCorp's accelerated depreciation proposal?

A. To provide greater resource planning flexibility as California implements state and federal environmental policies, the company recommends that the Commission return PacifiCorp's coal-fired resources to their pre-2008 depreciable lives. This would accelerate the current depreciation schedules for coal-fired resources currently in California rates, and more closely aligns the depreciable lives for those resources in PacifiCorp's California, Oregon, and Washington service territories. The proposed depreciation schedules reflect the shorter depreciation lives California used before PacifiCorp's 2007 depreciation study. This change will provide greater resource planning flexibility for PacifiCorp and its customers as California implements state environmental policies described below. Exhibit PAC/101 includes a comparison of the current and proposed depreciable lives for PacifiCorp's coal-fired resources.

Q. Why does PacifiCorp propose to reinstate shorter depreciation schedules on its coal-fired resources?

A. The electric industry in undergoing a significant transformation, including the treatment of coal-based generation and greenhouse gas emissions. Currently in California, the depreciation schedules for PacifiCorp's coal-fired resources reflect depreciable lives ending between 2027 and 2046.[12]

It is reasonable to manage state climate policy risk by aligning depreciation schedules and returning to the shorter depreciable lives previously approved by the Commission. The shorter depreciable life for these resources provides the Commission, the company, and customers additional flexibility in resource planning to address state and federal environmental policies, mandates, and legislation.

This is also consistent with PacifiCorp's actions in its most recent depreciation study where it accelerated the retirement of the Carbon coal plant in Utah by five years to comply with United States Environmental Protection Agency (EPA) regulations. PacifiCorp concluded that retiring the Carbon plant in 2015 was the least-cost alternative while accounting for risk and uncertainty.

Q. Is PacifiCorp presenting a depreciation study in support of its recommendation in this case?

A. No. PacifiCorp's proposal is not based on a change in technical depreciation assumptions, methodologies, or calculations. Instead, PacifiCorp is seeking a policy-based change in the depreciable lives of one set of assets—coal-fired generation resources—based on new and proposed laws and regulations that may impact the useful lives of these assets. Reducing depreciable lives now mitigates future customer risk associated with coal-fired generation, and provides PacifiCorp additional flexibility to respond to existing and emerging environmental regulations.

[12] Exhibit PAC/101.

Q. What value is provided by more closely aligning the depreciation rates in California, Oregon, and Washington?

A. Aligning coal plant depreciation rates in PacifiCorp's western service territories makes it easier for the company to implement environmental or regulatory policies adopted by California, Oregon, and Washington. California, Oregon, and Washington have a long history of collaboration to encourage the reduction of greenhouse gas emissions. In 2006, the Commission, Public Utility Commission of Oregon, and Washington Utilities and Transportation Commission executed the Western Public Utility Commissions' Joint Action Framework on Climate Change (Joint Action Framework). In the Joint Action Framework, the commissions agreed to a statement of shared principles on climate change and to work cooperatively to implement the shared principles.[13] More recently, in February 2016, the governors of California, Oregon, and Washington, along with governors from 14 other states signed the "Governors' Accord for a New Energy Future."[14] Through this accord, California, Oregon, and Washington have committed to diversify energy generation and expand clean energy sources by, among other commitments, working together to facilitate the transition away from coal and towards a cleaner resource mix. By shortening the depreciation schedules for the company's coal-fired resources now, the company can more effectively implement state policies common to all of PacifiCorp's western service territories.

[13] Exhibit PAC/102.
[14] Exhibit PAC/103, Bolton/1.

V. 2017 PROTOCOL (ETTA LOCKEY)

Q. Is PacifiCorp proposing a new inter-jurisdictional allocation methodology in this proceeding?

A. Yes. My testimony describes and supports the 2017 Protocol, agreed to among PacifiCorp and the signatories to the 2017 Protocol (referred to individually as a Party or collectively as the Parties). The 2017 Protocol describes the multi-jurisdictional allocation methodology that will be used by the company in all rate proceedings filed in California until a new protocol is proposed.[15]

Q. Are you also sponsoring an exhibit to your testimony?

A. Yes. Exhibit PAC/104 presents the 2017 Protocol with all of its appendices.

<u>Brief History of PacifiCorp's Multi-State Process (MSP)</u>

Q. Please provide a brief history of the events that gave rise to the 2017 Protocol.

A. In 2002 PacifiCorp filed applications in each of its six jurisdictions to create a process to consider issues related to its status as a multi-jurisdictional utility. Following years of discussions and negotiations, the Revised Protocol was agreed to by the Parties and approved by the commissions in California, Idaho, Oregon, Utah, and Wyoming. The Revised Protocol allocated costs among PacifiCorp's jurisdictions and ensured that the company operated its generation and transmission system on an integrated basis to achieve a least cost-least risk resource portfolio, while allowing each state to independently establish its ratemaking policies. The Revised Protocol was approved

[15] The 2017 Protocol was approved by the state commissions in Idaho, Oregon, Utah, and Wyoming for use starting January 1, 2017.

by the Commission in PacifiCorp's 2011 Rate Case and is the allocation methodology that is currently in effect for California.

Thereafter, subsequent and substantial discussions occurred to address various concerns raised by stakeholders in different states that resulted in the development of the 2010 Protocol. The 2010 protocol is a simplified version of the revised protocol intended to reduce unintended variations in the allocation of actual revenue requirement compared to the forecast used in the development of the revised protocol. The 2010 Protocol was approved by the commissions in Idaho, Oregon, Utah and Wyoming. Differing applications amongst states of both the Revised Protocol and 2010 Protocol resulted in PacifiCorp being unable to fully recover all of its prudently incurred costs.

One of the terms of 2010 Protocol was a specified termination date. The Parties to the 2010 Protocol agreed that it would only be used for regulatory filings made before January 1, 2017. Knowing that it would take some time to develop a new allocation methodology, the MSP standing committee (a committee consisting of one member or delegate from each commission) and MSP Broad Review Workgroup (BRWG)[16] started collaborating in November 2012 to come up with potential solutions acceptable to all Parties in the context of an allocation methodology, including the performance of various studies by PacifiCorp at the request of the Standing Committee.

Q. Who participated in the MSP meetings?

A. The MSP meetings were typically attended by in excess of 50 individuals in person or

[16] The BRWG is now referred to as the MSP Workgroup under the 2017 Protocol.

by teleconference, representing 18 entities from the states of Idaho, Oregon, Utah, Washington, and Wyoming. These included representatives of state commission policy staff, advocacy staff, industrial customers, and consumer groups.

Q. Did stakeholders from California participate in the MSP?

A. Not for the entire process. Representatives from the Commission participated in the May 1, 2015 forum, but did not continue their participation through the negotiations. PacifiCorp's inter-jurisdictional allocation methodologies are considered in the course of the company's general rate case cycle in California, and prior approval is generally not required.

Q. Who are the signatories to the 2017 Protocol?

A. The Parties signing the 2017 Protocol include: PacifiCorp, Public Utility Commission of Oregon Staff, the Citizens' Utility Board of Oregon, the Idaho Public Utilities Commission Staff, Utah Division of Public Utilities, Utah Office of Consumer Services, Wyoming Office of Consumer Advocate, Wyoming Industrial Energy Consumers, and the Wyoming Public Service Commission Staff.

Q. Did the BRWG establish principles to guide their review of inter-jurisdictional cost allocation alternatives?

A. Yes, the BRWG developed principles and criteria to guide their review of allocation alternatives. The four key criteria that the allocation method should incorporate were to:

1. Maintain state sovereignty by not impeding states from pursuing policy directives or flexibility in establishing class allocation or rate design;

2. Provide an equitable solution for PacifiCorp and all states based on principles of cost causation;
3. Be sustainable by promoting rate stability and avoiding unreasonable or inappropriate cost shifts; and
4. Promote administrative ease.

Q. Do you believe the 2017 Protocol meets these requirements?

A. Yes. The 2017 Protocol generally accomplishes these requirements. During negotiations, however, some Parties requested that the 2017 Protocol be designed as a short-term methodology until impacts of the EPA rules governing carbon pollution from existing power plants under section 111(d) of the Clean Air Act (Rule 111(d)) and other issues could be better understood. Based on this feedback, the initial term of the 2017 Protocol is for two years with the option of a one year extension.

Q. How did Parties address the equity issue with the 2017 Protocol?

A. Through extensive negotiations with the Parties, an Equalization Adjustment was added to the 2017 Protocol to account for inconsistent implementation of PacifiCorp's allocation methodologies, and to allow the company a better opportunity to recover its costs.

Q. Does the 2017 Protocol allow PacifiCorp an opportunity to collect all of its prudently incurred costs?

A. Not entirely. The Equalization Adjustment mitigates the issues caused by inconsistent implementation of PacifiCorp's allocation methodologies, but it does not fully provide the company the ability to recover all its costs.

Q. Why was PacifiCorp willing to agree to a method that didn't allow it to recover all of its cost?

A. PacifiCorp agreed to the 2017 Protocol for two primary reasons. Most importantly, because this was an interim solution, it provided the company and its stakeholders time to explore more durable solutions to address state-specific energy and environmental policy impacts on allocations. Second, the company appreciated the BRWG good faith approach to implement an Equalization Adjustment which significantly reduced the short-fall the company was experiencing under both the Revised Protocol and 2010 Protocol.

Q. Does the 2017 Protocol contain provisions for continued dialogue among the states?

A. Yes. The Parties have committed to hold an annual public meeting to which all seated commissioners from each jurisdiction where PacifiCorp provides retail service are invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues (Commissioner Forums), beginning in January 2017. At the first Commissioner Forum, commissioners were invited to discuss and make recommendations regarding extension of the 2017 Protocol and other inter-jurisdictional allocation issues that may arise.

In addition, 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 the company and its customers, state resource policies, or the development of a regional independent system operator, in order to inform discussions at the Commissioner Forum.

<u>Overview of 2017 Protocol</u>

Q. Please provide an overview of the 2017 Protocol.

A. The 2017 Protocol was negotiated as an integrated, interdependent agreement. All sections were discussed, resulting in a negotiated agreement based on the entirety of the language.

Q. How was the 2017 Protocol developed?

A. The 2017 Protocol was largely developed using the 2010 Protocol as the starting point and further refining areas within that methodology to arrive at the new agreement and allocation methodology. A major focus was on arriving at a single allocation methodology that all of the Parties could support that made progress towards reducing the allocation shortfall resulting from differences in the application of the 2010 Protocol. This resulted ultimately in the development of an Equalization Adjustment, that when combined with the Embedded Cost Differential (ECD), produces the 2017 Protocol Adjustment. The 2017 Protocol Adjustment is added to each state's annual revenue requirement. This modification to PacifiCorp's prior allocation methodologies is intended to reduce unintended ECD variations due to non-uniform implementation of those prior allocation methodologies. Other changes were made to address direct access treatment, the duration of the 2017 Protocol, and process issues.

<u>Detailed Discussions of Sections I to XIV of the 2017 Protocol (STEVE MCDOUGAL)</u>

Q. Please describe each section of the 2017 Protocol Agreement.

A. The 2017 Protocol has 14 sections that contain the terms and conditions agreed to by the Parties through the negotiations. Section I provides an introduction to the 2017

Protocol. Section I makes it clear that the 2017 Protocol is not intended to prejudge the prudence of any costs or abrogate a State commission's right and/or obligation to determine fair, just, and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that commission. The parties and state commissions are also not prohibited from considering any changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates. The 2017 Protocol also does not prohibit the establishment of different allocation policies and procedures for purposes of allocation of costs and revenues within a State to different customers or customer classes.

Section II discusses the effective period and expiration of the 2017 Protocol.

Section III identifies the classification of resources between Demand-Related, meaning capital and fixed costs or revenues incurred or received in order to be prepared to meet the maximum demand imposed upon PacifiCorp's system, or Energy-Related, costs and revenues that vary based on the amount of energy delivered to customers.

Section IV discusses the allocation of resource costs and wholesale revenues. Resources are assigned to one of two categories of inter-jurisdictional allocation: State Resources or System Resources. State Resources refer to those resources that accommodate jurisdiction-specific policy. Costs for these resources are assigned to a specific jurisdiction. There are four types of State Resources: Demand-side Management Programs; Portfolio Standards; Qualifying Facility (QF) Contracts; and Jurisdiction-Specific Initiatives. System Resources are all other resources and are allocated across all jurisdictions. This allocation methodology includes an Equalization Adjustment to be applied to each State's revenue requirement, as specifically identified in Section XIV of the 2017 Protocol.

Section V includes a commitment by PacifiCorp to submit filings seeking authorization from the state commissions prior to filing for approval from the Federal Energy Regulatory Commission (FERC) of the re-functionalization of facilities as transmission or distribution. This section also identifies the cost allocation for transmission costs and revenues as 75 percent Demand-Related and 25 percent Energy-Related.

Section VI states that distribution-related expenses and investments are directly assigned to the State in which the related facilities are located where possible. Costs that cannot be directly assigned are allocated based on the factors in Appendix B to the 2017 Protocol.

Section VII addressed the allocation of administrative and general costs. Such costs are allocated based on the factors in Appendix B to the 2017 Protocol.

Section VIII provides that any Special Contracts—contracts between PacifiCorp and one of its retail customers based on specific circumstances of the customer—will be included in load-based dynamic allocation factors identified in Appendix D to the 2017 Protocol.

Section IX states that any loss or gain from the sale of a company-owned resource or transmission asset would be allocated among the States based on the allocation factor used to allocate the fixed costs of the resource or asset at the time of the sale. The 2017 Protocol reserves to each State commission the authority to determine the appropriate allocation between PacifiCorp's customers and shareholders.

Section X addresses the treatment of loads lost to alternative energy suppliers through State direct access or other programs.

Section XI identifies the treatment of changes in retail load.

Section XII includes a commitment that the company will plan and acquire resources on a system-wide least cost, least-risk basis, with prudently incurred investments reflected in rates consistent with the laws and regulations in each State.

Section XIII outlines the parameters for interpretation and governance. Section XIII also provides for a Commissioner Forum to be held annually and an MSP Workgroup, similar to the BRWG, open to any interested stakeholders. Proposals for new inter-jurisdictional allocation procedures, including any modifications proposed to the 2017 Protocol, can be submitted by any Party or commission using the 2017 Protocol.

Section XIV contains additional, State-specific terms. These additional terms include the State-specific Equalization Adjustment negotiated by the parties. This section also identifies specific commitments by PacifiCorp regarding general rate case timing during the effective period of the 2017 Protocol.

The 2017 Protocol also includes a set of appendices providing defined terms and specific details regarding allocation factors and their derivations.

<u>Term of 2017 Protocol</u>

Q. What is the effective period in the 2017 Protocol?

A. The 2017 Protocol was intended to be used in all PacifiCorp rate proceedings filed after December 31, 2016, through December 31, 2018, in Idaho, Oregon, Utah, and Wyoming, with an optional one-year extension. The state commissions in Idaho, Oregon, Utah, and Wyoming subsequently approved the one-year extension, making the 2017 Protocol effective until December 31, 2019.

Q. Why was the 2017 Protocol intended to be a three-year inter-jurisdictional allocation methodology?

A. The 2017 Protocol was intended to be a transitional allocation mechanism while the impacts of EPA's Rule 111(d) and other multi-jurisdictional issues are better understood and analyzed. The term of 2017 Protocol also provided an opportunity for PacifiCorp to analyze alternative allocation methods in light of the changing electric industry in the Western United States.

Q. For what term is PacifiCorp requesting Commission approval to use the 2017 Protocol?

A. PacifiCorp requests that the Commission approve the use of the 2017 Protocol for all rate proceedings filed starting January 1, 2018, until a new allocation methodology is approved by the Commission. This would align allocation methodologies across five of PacifiCorp's six states while the company develops a more durable allocation solution that addresses diverging state resource policies.

Q. Will PacifiCorp be proposing revisions to the 2017 Protocol at the end of its term?

A. PacifiCorp is currently engaged in the development of a durable solution to its allocation issues that will address the interests of each state while continuing to provide the benefits of PacifiCorp's system to customers. PacifiCorp has presented a proposal to its stakeholders in the MSP workgroup that would assign fixed portions of generation resources to serve the company's retail load in each state. Participants from all states, including California, have been actively involved in this round of the MSP. PacifiCorp's proposal would allow PacifiCorp to accommodate each state's energy policies without adversely impacting customers in other states. This solution, however, is at least a couple of years away because of the significant changes being discussed in the MSP. Accordingly, PacifiCorp requests that the Commission approve the use of the 2017 Protocol until PacifiCorp proposes a new inter-jurisdictional allocation methodology.

Q. Will PacifiCorp be filing any other rate applications this year?

A. Yes. PacifiCorp expects to file its annual ECAC filing in August. Rates in both this proceeding and the ECAC will become effective January 1, 2019. PacifiCorp will use the 2017 Protocol for the ECAC offset rate so both rates are based on the same inter-jurisdictional allocation methodology.

<u>Resource Classification and Cost and Revenue Allocation</u>

Q. How does the 2017 Protocol allocate costs and revenues?

A. Resources fixed costs, wholesale contracts, and short-term firm purchases and sales are classified as 75 percent Demand-Related and 25 percent Energy-Related. Non-firm purchases and sales and fuel expenses are classified as 100 percent Energy-Related. This allocation balances the impact of demand and load on system costs.

Q. What is the difference between State Resources and System Resources?

A. State Resources include four defined types of resources that are dependent on specific state policy. Accordingly, it is appropriate to allocate the benefits and costs associated with these resources to a particular jurisdiction on a situs basis. System Resources include the substantial majority of PacifiCorp's resources, and contribute to retail service across the company's entire multi-jurisdictional service territory.

Q. What types of resources are included in State Resources?

A. There are four types of State Resources. The first type of State Resource is demand-side management programs. These programs may include incentives for energy efficiency and demand response to reduce load. Costs associated with these programs are assigned on a situs basis to the jurisdiction in which the investment is made. Benefits from demand-side management programs are reflected in the load-based dynamic allocation factors.

The second type of State Resource includes resources acquired to comply with a jurisdiction's mandated resource portfolio standard, adopted through legislative enactment or by a regulatory commission. The portion of costs associated with portfolio standards that exceed the costs PacifiCorp would have otherwise incurred acquiring comparable resources (resources with similar capacity factors, start-up costs, and other output and operating characteristics) are assigned on a situs basis to the jurisdiction adopting the portfolio standard.

The third type of State Resource includes QF contracts executed under the requirements of the Public Utility Regulatory Policies Act (PURPA). PURPA requires that a public utility agree to purchase energy from certain cogeneration and small renewable energy generating facilities that meet the definition of a QF under PURPA. State commissions set the prices for each public utility under its jurisdiction for power purchase agreements under PURPA. The 2017 Protocol assigns the costs associated with QF contracts on a system basis, unless a portion of the QF costs exceed what PacifiCorp would have otherwise incurred acquiring comparable resources (resources with similar capacity factors, start-up costs, and other output and operating characteristics) which would then be assigned on a situs basis to the jurisdiction that approved the contract.

The final type of State Resource includes any resources acquired in accordance with an initiative adopted by a specific jurisdiction. Any such resource is assigned on a situs basis to the jurisdiction adopting the initiative. Examples of these jurisdiction-specific initiatives include certain incentive programs, net-metering tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

Q. Does the 2017 Protocol alter PacifiCorp's resource planning responsibility or a commission's authority?

A. No. Section XII provides that 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, and approved by that State's commission consistent with such laws and regulations.

<u>Embedded Cost Differential</u>

Q. Explain the use of the ECD in the 2017 Protocol?

A. As a result of negotiations, the Parties agreed that the ECD would continue as a component of the 2017 Protocol as modified and incorporated into an overall 2017 Protocol Adjustment that will be included in each State's revenue requirement.[17] The

[17] In the Revised Protocol the ECD is referred to as the Hydro Endowment.

ECD is fixed for Wyoming, Idaho, and California; for Utah it is zero; and for Oregon, it is dynamic with a floor and a cap, for the duration of the 2017 Protocol. This treatment of the ECD during the term of the 2017 Protocol eliminates or mitigates unintended allocation consequences that occurred under the 2010 Protocol.

The ECD in the 2017 Protocol is referred to as the Baseline ECD. For California and Wyoming, the Baseline ECD was established using the data, as filed by the company on March 3, 2015, in the 2015 Wyoming general rate case (Docket 20000-469-ER-15). Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in the 2017 Protocol. Idaho's Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's Baseline ECD is zero consistent with its 2010 Protocol agreement.

Q. Please describe the 2017 Protocol Adjustment and how it is implemented.

A. For the period that the 2017 Protocol remains in effect, a 2017 Protocol Adjustment will be added to each State's annual revenue requirement. The 2017 Protocol Adjustment is the sum of the 2017 Protocol Baseline ECD and the 2017 Protocol Equalization Adjustment.

Q. Please explain the 2017 Protocol Equalization Adjustment.

A. The Equalization Adjustment is a fixed dollar adjustment to be applied to each state's revenue requirement as specified in Section XIV of the 2017 Protocol. Parties to the 2017 Protocol negotiated an annual Equalization Adjustment totaling $9.074 million that represents the sum of approximately two-tenths of one percent of each state's annual revenue requirement. The Equalization Adjustment is intended to recognize differences among the states' implementation of PacifiCorp's allocation methodology respective to the treatment of the ECD adjustment (i.e. fixed ECD, dynamic ECD, or no ECD). The result of the 2017 Protocol Equalization Adjustment is to equitably share the allocation shortfall resulting from differences in the implementation of PacifiCorp's allocation methodology, while analysis continues on the development of a more permanent allocation method.

Q. What is the amount of the 2017 Protocol Adjustment that will be added to each state's annual revenue requirement?

A. California's 2017 Protocol Adjustment is zero because its Equalization Adjustment exactly offsets its Baseline ECD, Idaho's is $0.986 million, Utah's is $4.4 million and Wyoming's is a credit of $0.251 million. Because Oregon's Baseline ECD is dynamic but capped between specified ranges its 2017 Protocol Adjustment will be between $5.6 million to $7.9 million credit.

<u>Cost Allocations</u>

Q. How are transmission costs and revenues allocated under the 2017 Protocol?

A. Costs associated with transmission assets and firm wheeling expenses are classified as 75 percent Demand-Related and 25 percent Energy-Related. These costs are allocated based on a system generation factor. Non-firm wheeling expenses and revenues are allocated on a system energy factor. The system generation factor and system energy factors are described in the appendices to the 2017 Protocol.

Q. How are distribution costs assigned under the 2017 Protocol?

A. Distribution-related expenses and investments are directly assigned to the state where they are located where possible. There are certain distribution expenses and investments that cannot be directly assigned. For the costs that cannot be directly assigned, they will be allocated consistent with the factors identified in Appendix B to the 2017 Protocol.

Q. Can the company reclassify its facilities between transmission and distribution?

A. Yes. The classification of facilities as transmission or distribution depends on how the facility is used, and may change over time. Any such reclassification is generally done following an analysis by the company, using tests adopted by FERC. The company has committed in the 2017 Protocol to seek review and authorization of any such reclassification with the state commissions before filing any request to approve a reclassification of facilities with FERC.

Q. How does the 2017 Protocol allocate administrative and general costs?

A. Appendix B provides for the specific allocation of administrative and general costs, general plant costs, and intangible plant costs consistent with the factors in Appendix B to the 2017 Protocol.

Q. How does the 2017 Protocol address special contracts?

A. The 2017 Protocol provides that revenues associated with special contracts—meaning contracts between the company and a particular customer based on the specific circumstances of that customer and approved by the State commission—will be included in each State's revenues (situs assigned). Load under the special contract is included in the load-based dynamic allocation factors defined in Appendix D.

Q. Will PacifiCorp allocate any gain or loss from a sale of a resource or transmission asset based on the factors used to allocate the cost associated with that resource or transmission asset for ratemaking purposes?

A. Yes. The allocation of any loss or gain from the sale of a company-owned resource or transmission asset will be allocated based on the allocation factor used to allocate fixed costs at the time of its sale. Each State commission will determine the allocation of any loss or gain between the company's customers and shareholders in accordance with its jurisdictional authority.

Changes to PacifiCorp Load

Q. Does the 2017 Protocol include a provision to address changes in load due to changes in the company's retail service territory?

A. Yes. Section XI addresses the treatment of changes to load as a result of: condemnation or municipalization; the 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 the gain or loss of large customers. These changes would be reflected in changes to the load-based dynamic allocation factors. The load-based dynamic allocation factors are calculated using the states' monthly energy usage and/or contribution to monthly system coincident peak. The allocation of costs and benefits arising from a merger, sale, or acquisition involving more than five percent of system load would be considered on a case-by-case basis in the course of any approval proceedings in each state.

The 2017 Protocol also addresses Oregon's direct access program for large customers and the potential transfer of electricity service to an alternative electricity supplier in Utah under Utah Code Annotated Section 54-3-32. These programs affect a state's load relative to other states, and, thereby, have the potential to impact allocations. The company has committed to inform the State commission and MSP participants if any state adopts laws or regulations governing customer access to alternative electricity suppliers.

<u>Governance (ETTA LOCKEY)</u>

Q. What is the purpose of the annual Commissioner Forums?

A. During the term of the 2017 Protocol, PacifiCorp agreed to analyze alternative allocation methods including corporate structure alternatives, divisional allocation methodologies, alternative system allocation methodologies, potential implications of the EPA's Rule 111(d), and possible formation of a regional independent system operator. PacifiCorp conducted these analyses and presented them at the 2017 Commissioner Forum. As a result of that analysis, PacifiCorp began looking at an alternative proposal that would allow the company to meet the resource policy goals of each state, while maintaining the benefits of system dispatch.

PacifiCorp believes that annual Commissioner Forums are an appropriate way to keep commissioners and participants informed, and that they will be an opportunity for all Parties to discuss progress on a more durable allocation methodology. The company anticipates that all MSP participants will remain engaged in the process of analyzing the results of these studies, and that continuing to engage in this type of collaboration is in the best interests of the participants and PacifiCorp's customers. PacifiCorp is significantly encouraged by the participation of Commission representatives.

Q. Is there an opportunity for interested stakeholders to raise issues with the 2017 Protocol?

A. Yes. Any participant or state commission using the 2017 Protocol for inter-jurisdictional allocation purposes may submit proposals for a new inter-jurisdictional allocation procedure or change to the 2017 Protocol. Any such proposal must be provided to the company so that PacifiCorp can distribute the proposal to the other Parties and State commissions and initiate discussions. The Party or State commission proposing the modification or new inter-jurisdictional allocation procedure must, consistent with its legal obligations, attempt to present the proposal to the Commissioner Forum or MSP Workgroup and negotiate a resolution in good faith.

Commission Review of Approval of the 2017 Protocol

Q. Why should California approve the 2017 Protocol?

A. One of the primary objectives of PacifiCorp's MSP was to develop a consistent allocation methodology to be used by all states. Through this process the Parties determined that it is in everyone's best interest, including PacifiCorp's customers, to support a new protocol governing inter-jurisdictional allocation procedures. The 2017 Protocol is designed to provide PacifiCorp, state commissions, and other interested Parties a transitional allocation method while the company more fully analyzed its multi-jurisdictional issues. Through the MSP, the Parties negotiated a balanced agreement with reasonable solutions to issues raised by the company and stakeholders. The Parties agreed to support the 2017 Protocol with the intent to continue to achieve equitable resolutions to multi-jurisdictional allocation issues that are in the public interest.

Q. Are the terms of the 2017 Protocol for California reasonable compared to the terms for other states?

A. Yes. The 2017 Protocol represents a fair, just, and reasonable approach to PacifiCorp's inter-jurisdictional allocation issues while the company develops a more durable solution. The Equalization Adjustment is equivalent between states representing approximately two-tenths of one percent of each state's annual revenue requirement. While the Equalization Adjustment does not provide full recovery to the company, it is a reasonable approach considering the interim nature of the 2017 Protocol.

Q. What process does PacifiCorp propose for the Commission review of this Application?

A. PacifiCorp proposes that the Commission will review and approve the 2017 Protocol in this proceeding. The Commission opened a separate investigation to explore PacifiCorp's system operations and planning, and current allocation methodology.[18] No parties to that proceeding have challenged PacifiCorp's current allocation methodology or proposed a different allocation methodology. Participants to PacifiCorp's MSP conducted significant analysis and review since November 2012 as the BRWG considered many options. This analysis enabled the MSP participants to confidently negotiate the 2017 Protocol. PacifiCorp believes that the result was a 2017 Protocol that is fair to all states.

[18] *Order Instituting Investigation to determine whether PacifiCorp (U901-E) engages in least-cost planning on a control area basis and whether PacifiCorp's Inter-Jurisdictional Cost Allocation Protocol results in just and reasonable rates in California*, Investigation 17-04-019 (May 8, 2017).

Q. What action do you recommend the Commission take with respect to the 2017 Protocol?

A. I recommend that the Commission find that the 2017 Protocol is in the public interest and request that the Commission approve all the terms and conditions of the 2017 Protocol for determining rates in this and future proceedings in its order in this docket.

VI. INTRODUCTION OF WITNESSES (ETTA LOCKEY)

Q. Please list the PacifiCorp witnesses and provide a brief description of their testimony.

A. **Kurt G. Strunk**, Director, National Economic Research Associates, testifies concerning PacifiCorp's cost of equity. He presents support for the requested authorized ROE of 10.6 percent to account for the risks and operating challenges that PacifiCorp faces as a vertically integrated electric investor owned utility (Exhibit PAC/200).

Nikki L. Kobliha, Chief Financial Officer, describes the calculation of PacifiCorp's capital structure, costs of debt and preferred stock (Exhibit PAC/300).

Chad A. Teply, Senior Vice President, Strategy & Development, supports the prudence and necessity of certain major capital projects on coal-fired generation resources within the PacifiCorp generation portfolio, including the required installation of SCR systems on Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2, in accordance with state and federal environmental compliance requirements for the individual units (Exhibit PAC/400).

Rick T. Link, Vice President, Resource & Commercial Strategy, describes the economic analysis performed in 2012 that supported the company's decisions to install SCR emission control systems on Units 3 and 4 of the Jim Bridger generating plant, the economic analysis that shows PacifiCorp's decision to upgrade, or "repower", certain wind resources, and summarizes PacifiCorp's assessment of the wind repowering project in its 2017 Integrated Resource Plan (Exhibit PAC/500).

Timothy J. Hemstreet, Director, Renewable Energy Development, provides the technical information supporting PacifiCorp's decision to repower certain wind facilities (Exhibit PAC/600).

Richard A. Vail, Vice President, Transmission, describes significant capital investment projects for new distribution and transmission systems (Exhibit PAC/700).

David M. Lucas, Vice President, Transmission & Distribution Operations, presents an overview of PacifiCorp's investment in advanced metering infrastructure in the state of California (Exhibit PAC/800).

Michael G. Wilding, Director, Net Power Costs & Regulatory Strategy, presents PacifiCorp's proposal to modify the ECAC to include updates to PTCs and start-up fuel costs (Exhibit PAC/900).

Brett S. Allsup, Director, Engineering Strategy & Cost Control, describes PacifiCorp's risk management process to implement a risk-based investment decision making framework (Exhibit PAC/1000).

Shelley E. McCoy, Manager, Revenue Requirement, addresses the calculation of the company's California-allocated revenue requirement based on the forecast test period of 12 months ending December 31, 2019, excluding net power costs (Exhibit PAC/1100).

Robert M. Meredith, Manager, Pricing & Cost of Service, describes PacifiCorp's functionalized class revenue requirement and supporting marginal cost-of-service study based on the forecast test period of 12 months ending December 31, 2019 (Exhibit PAC/1200).

Judith M. Ridenour, Pricing & Cost of Service Specialist, presents PacifiCorp's proposed rate spread, proposed rate design, and proposed revised tariffs (Exhibit PAC/1300).

Q. Does this conclude your direct testimony?

A. Yes.