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Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

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Chapter 3

Direct Testimony of Steven R. McDougal

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# CHAPTER 3

## PACIFICORP'S INTER-JURISDICTIONAL ALLOCATION METHODOLOGIES

**Testimony of Steven R. McDougal**

### A. INTRODUCTION

PacifiCorp's recent inter-jurisdictional allocation protocols are the result of the currently ongoing, broad-stakeholder Multi-State Process (MSP), which began in 2002. The MSP is a collaborative effort to develop solutions to the company's multi-state utility challenges. The MSP Workgroup, open to representatives from state commission staff, consumer representatives, and other stakeholders, meets to discuss emerging issues related to allocations among the six states served by PacifiCorp. As discussed in the testimony of Etta Lockey (Chapter 1), the MSP Workgroup is currently meeting monthly to discuss a new approach to address differing energy policies among the states while maintaining the substantial benefits of PacifiCorp's diverse system and access to multiple markets.

The MSP includes periodic commissioner forums where state commissioners can discuss issues raised in the MSP Workgroup and provide guidance for future meetings. This collaborative effort has resulted in inter-jurisdictional cost allocation protocols that fairly allocate system costs based on relative load in each state. To date, this has resulted in just and reasonable rates for each state, including California, because the load percentage is calculated based on the test year used in the filing. By using a system allocation approach, each state has shared in both system costs, and in the benefits of being part of a larger integrated system. While this has been a reasonable approach to date, PacifiCorp does not believe this approach is sustainable going forward because of changes in the industry, customer demands, and diverging state energy policies.

**B. HISTORY OF THE MSP**

Inter-jurisdictional issues are not new to PacifiCorp. PacifiCorp's predecessor, Pacific Power & Light (PP&L) began operating as an integrated system in 1973, serving portions of California, Montana, Oregon, Washington, and Wyoming. PP&L's first cost allocation methodology was the 1986 Note 1 Methodology.

The current MSP began in 2002, with PacifiCorp filing 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 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (Revised Protocol) was agreed to by the stakeholders 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 specified allocation factors for each component of PacifiCorp's revenue requirement, identified costs as system or situs, and created an Embedded Cost Differential (ECD) to address cost differences between hydro resources and other resources. System generation and transmission costs were allocated using a weighted load-based allocation factor called the System Generation (SG) factor. The SG factor is calculated as 75 percent of the System Capacity factor and 25 percent of the System Energy factor. The System Capacity factor is calculated using the ratio of each states contribution to the PacifiCorp system 12 monthly coincident peaks. The System Energy (SE) factor is each state's energy divided by the system total energy.

After adoption of the Revised Protocol, MSP discussions continued and, partially in response to various concerns raised by stakeholders, the 2010 Inter-Jurisdictional Cost Allocation Protocol (2010 Protocol) was developed by PacifiCorp. The 2010 Protocol was agreed to by Idaho, Oregon, Utah, and Wyoming on September 15, 2010, [1] and was designed to allocate PacifiCorp's costs among its jurisdictions in an equitable manner, ensure PacifiCorp plans and operate its generation and transmission system on a six-state integrated basis that achieved a least cost-least risk resource portfolio for customers, allow each state to independently establish its ratemaking policies, and provide PacifiCorp with the opportunity to recover its prudently-incurred costs.

One of the terms of 2010 Protocol was a specified termination date. The states that agreed to use the 2010 Protocol agreed that it would only be used for regulatory filings made before January 1, 2017. Knowing that it would take time to develop a new allocation methodology, the MSP standing committee (a committee consisting of one member or delegate from each commission) and the stakeholder workgroup 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 the company at the request of the standing committee.

In 2014 and 2015, PacifiCorp and stakeholders became concerned that consensus on a long-term allocation methodology may not be possible given the uncertainty facing the industry, generally, and the company, in particular, at the time. The potential impacts of the U.S. Environmental Protection Agency's clean power plan rules were not fully known at the time. Additionally, PacifiCorp was entering the California Independent System Operator

[1] PacifiCorp inter-jurisdiction allocation methodologies are considered in the course of the company's general rate case cycle in California.

(CAISO) Energy Imbalance Market (EIM), and starting to explore the potential of joining a regional ISO as a participating transmission owner. As a result, a consensus emerged in the MSP Workgroup and Commissioner Forum discussions that an interim methodology would provide time to address some of the uncertainty facing the utility.

In 2015, PacifiCorp and most of the MSP stakeholders agreed to the PacifiCorp 2017 Inter-Jurisdictional Cost Allocation Protocol (2017 Protocol).[2] As an interim agreement, the 2017 Protocol was substantially similar to the 2010 Protocol, with the only differences being the calculation of the embedded cost differential and the addition of the 2017 Protocol Equalization Adjustment. It was originally a two-year agreement, with an option for an additional one-year extension, which has been exercised by all four states that approved use of the 2017 Protocol.[3] The 2017 Protocol was a fully negotiated agreement incorporating certain state-specific provisions. The state-specific terms in the 2017 Protocol included an Equalization Adjustment to address PacifiCorp's under-collection under the different interpretation and regulatory treatment among the states in the calculation of the ECD. The Equalization Adjustment provided for an offset to the ECD for each state. The Equalization Adjustment mitigated the issues caused by inconsistent implementation of the 2010 Protocol but did not fully provide the Company the ability to recover all its costs. The 2010 Protocol included a fixed ECD amount for each state using a levelized projection of the ECD. Only Idaho approved the use of the levelized amount, with Utah deciding to use zero, and

[2] Only two stakeholders participating in the MSP did not agree to the 2017 Protocol: the Industrial Customers of Northwest Utilities in Oregon; and the Utah Association of Energy Users in Utah. Both groups represented large, industrial customers. All of the residential consumer advocates participating in the MSP agreed to the 2017 Protocol.

[3] The state commissions in Idaho, Oregon, Utah, and Wyoming all approved the one-year extension of the 2017 Protocol in 2017, making the 2017 Protocol the allocation methodology for those states through December 31, 2019.

Wyoming, Oregon, and California using a dynamically allocated ECD, resulting in PacifiCorp not having the opportunity to recover all of its prudently incurred costs. The 2017 Protocol Equalization adjustment was a negotiated amount intended to address this issue.

The MSP meetings were typically attended by more than 50 individuals in person or by teleconference, representing 18 entities from the states of Idaho, Oregon, Utah, Washington, and Wyoming. These included representatives of state commission policy staffs, advocacy staffs, industrial customers, and consumer groups. Representatives from the California Commission participated in the May 1, 2015 forum, but did not continue their participation through the negotiations. Likewise, representatives from Washington participated in early discussions, but the Washington Utilities and Transportation Commission has adopted a specific allocation methodology for PacifiCorp. Representatives from Washington, however, have engaged in all of the MSP discussions during 2017.

## C. INTER-JURISDICTIONAL COST ALLOCATION METHODOLOGIES

### 1. The Revised Protocol

In California, PacifiCorp has historically filed for approval of the inter-jurisdictional allocation protocol in conjunction with its general rate case (GRC) by proposing the inter-jurisdictional allocation protocol in place in other states at the time of filing. In Application (A.) 05-11-022, PacifiCorp proposed using the Revised Protocol to determine revenue requirement for all rate-related filings made in California. The Revised Protocol was adopted in the July 7, 2006 settlement in which parties agreed that the revenue requirement in the GRC, Energy Cost Adjustment Clause, and Post-Test Year Adjustment Mechanism should be based on the Revised Protocol. The commission approved the settlement agreement with the agreed upon allocation methodology in D.06-12-011 on December 14, 2006.

In A.09-11-015, PacifiCorp's last GRC, PacifiCorp proposed to continue using the Revised Protocol to determine revenue requirement for all rate-related filings in California. The commission approved an all-party settlement on September 2, 2010, which approved the continued use of the Revised Protocol for calculating revenue requirement in all rate-related filings.

PacifiCorp's California customers pay a proportionate share of PacifiCorp's system costs based on the relative usage of PacifiCorp's assets used to serve its California service area. PacifiCorp allocates system-wide costs, primarily generation and transmission costs, based on contribution to system peak (demand-related) and annual energy usage to determine the state's cost causation on the system. Each state's contribution to the 12 monthly system peaks is weighted 75 percent demand-related and the state's annual energy usage is weighted 25 percent energy-related in the development of the SG factor which is used to allocate generation and transmission costs to align with the causation of those costs.

As an example, in the Company's most recent Catastrophic Event Memorandum Account (CEMA) filing, A.17-04-023, the Company incurred $185,382 in capital costs and $638,758 in expense for repairs to the Company's transmission system. While these assets are located in California, because they are transmission and benefit all of PacifiCorp's customers, California customers were only allocated that state's SG share of the costs, $3,255 for the capital and $11,215 of the expense.

Under Revised Protocol, the cost of Company-owned generation, including its thermal (i.e. natural gas and coal plants), hydro and wind, are allocated by the SG factor for capital and O&M. PacifiCorp's transmission assets are also allocated using the SG factor.

Fuel costs are allocated on an SE factor. The SE factor is calculated as each states percentage of total energy usage during the year.

PacifiCorp's only owned generation resource added since the 2011 test year GRC was Lake Side 2, a 631 megawatt natural gas-fired, combined cycle power plant, total investment of approximately $671 million. Transmission assets added to since PacifiCorp's 2011 test year GRC are identified in Table 2.

Table 2: Transmission Resources Added Since 2011 Test Year California GRC

| Transmission Resources Added After 2011 CA GRC | | |
|---|---|---|
| **Resource** | **Year Added** | **Total Investment (millions)** |
| Clover Transmission Substation | 2013 | $ 63.7 |
| Mona-to-Oquirrh Transmission Project | 2013 | $ 347.5 |
| Sigurd-to-Red Butte | 2015 | $ 338.0 |

Based on calendar year 2016 historical loads, PacifiCorp's system allocated costs were approximately 1.6 percent to California, 26.6 percent to Oregon, 8.2 percent Washington, 5.9 percent Idaho, 42.7 percent to Utah, and 15.0 percent to Wyoming. Distribution related costs are assigned 100 percent situs assigned to each state.[4]

Since the company's last California GRC, the inter-jurisdictional allocation methodology adopted in other states has been modified, as discussed above, but there has been limited participation from California stakeholders. The company is planning to propose the 2017 Protocol in its next GRC, to be filed in 2018 with a 2019 test-year.[5]

[4] These calculations are the same under either the Revised Protocol of 2017 Protocol.
[5] At the time the company files its next GRC, there is unlikely to be resolution amongst the states in the MSP process as to the replacement cost allocation methodology for the 2017 Protocol.

**2. The 2017 Protocol**

The 2017 Protocol is currently in use in Idaho, Oregon, Utah, and Wyoming.[6] The differences between the 2017 Protocol and the Revised Protocol allocation method approved for use in California include the removal of seasonal factors, the calculation of the ECD, and the addition of an equalization adjustment.

Allocation of Specific Costs under the 2017 Protocol

a) System Resources

Generation resources are considered system resources, unless they meet a definition for regional or state specific resources below. PacifiCorp allocates system resources based on each state's contribution to system peak and annual energy usage or their cost causation to the system. Each state's contribution to the twelve monthly system peaks is weighted 75 percent and the state's annual energy usage is weighted 25 percent in the development of the SG factor. This factor is used to allocate generation and transmission costs to states aligning with the cost causation of these costs.

b) Regional Resources

There are no Regional resources under the 2017 Protocol.

[6] *In the matter of PacifiCorp DBA Rocky Mountain Power*, Idaho Public Utilities Commission (IPUC) Case No. PAC-E-15-16, Order No. 33623 (October 14, 2016), extension approved by *In the matter of PacifiCorp DBA Rocky Mountain Power*, IPUC Case No. PAC-E-17-01, Order No. 33726 (March 8, 2017); *In the matter of PacifiCorp, dba Pacific Power*, Public Utility Commission of Oregon (OPUC) Docket No. UM 1050, Order No. 16-319 (August 23, 2016), extension approved by *In the matter of PacifiCorp, dba Pacific Power*, OPUC Docket No. UM 1050, Order No. 17-124 (March 29, 2017); *In the matter of Rocky Mountain Power*, Public Service Commission of Utah (UPSC) Docket No. 15-035-86, Order (June 23, 2016), extension approved by *In the matter of Rocky Mountain Power*, UPSC Docket No. 17-035-06, Order (March 23, 2017); *In the matter of Rocky Mountain Power*, Public Service Commission of Wyoming (WPSC) Docket No. 20000-486-EA-15, Record No. 14304, Order (November 1, 2016), extension approved in *In the matter of Rocky Mountain Power*, WPSC Docket No. 20000-510-EA-17, Record No. 14644 (July 7, 2017).

c) Seasonal Resources

There are no seasonal resources under the 2017 Protocol. The 2017 Protocol does not include the seasonal factors previously included in the Revised Protocol. Under the Revised Protocol, seasonal factors were used to allocate Simple-Cycle Combustion Turbines (SCCTs), seasonal contracts, Cholla unit 4, and the seasonal expense contract associated with Cholla 4 under the Revised Protocol. The seasonal factors were eliminated from the 2010 Protocol because of the immaterial impact they had on allocations. The seasonal allocation factors allocated approximately three one hundredths of a percent more of a very limited set of assets to California. The 2017 Protocol was based on the 2010 Protocol with only limited modifications, as such it also did not include seasonal factors.

d) State Resources

Cost associated with Demand-Side Management (DSM) Programs are assigned on a situs basis to the state in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to coincident peaks, are reflected in the load-based dynamic allocation factors.

The portion of costs associated with resources acquired to comply with a state's portfolio standards, adopted either through legislative enactment or a State's Commission, that exceeds the costs PacifiCorp would have otherwise incurred are assigned on a situs basis to the state adopting the Portfolio Standard.

e) Qualifying Facilities

All current Qualified Facility contracts are system allocated, similar to all other generation resources. Under the 2017 Protocol, if a state were to determine that a portion of the contract exceeds the costs PacifiCorp would have otherwise incurred acquiring comparable resources, that portion would be assigned on a situs basis to the state that approved the contract.

f) Administrative and General Costs

Administrative and general cost are allocated using the System Overhead factor that allocates costs similar to how system generation is allocated. The System Overhead factor is the ratio of gross plan allocated to each state.

g) ECD and the 2017 Protocol Equalization Adjustment

The ECD was a component of the Revised Protocol. The calculation looked at the embedded cost of: 1) the west hydro generation resources; 2) Mid-Columbia contracts; and 3) Qualifying Facility contracts entered into before June 1, 2004. The prior three items were compared to the embedded cost of all other generation including purchased power. Because of the volatility in the ECD associated with purchased power and the impact of new resources, the calculation was changed in the 2010 Protocol to eliminate QF contracts and, instead of comparing to all other generation, the 2010 Protocol compared hydro and mid-C contracts to specific generation resources acquired before 2005.

The 2017 Protocol further changed the ECD to eliminate future volatility by using a fixed amount for all jurisdictions, including California. For California, the fixed amount is a credit of $324,000. The fixed amount for California, Oregon, and Wyoming was based on the test year data as filed by the company in the 2015 Wyoming GRC (Docket 20000-469-ER-15) on March 3, 2015.

The 2017 Protocol Adjustment also includes a 2017 Protocol equalization adjustment. The equalization adjustment was added to the ECD through negotiations with stakeholders to address continued under-recovery by the company. The Equalization Adjustment mitigates the issues caused by inconsistent implementation of the 2010 Protocol, but does not fully provide the company the ability to recover all its costs. Per the equalizing adjustment, each state and PacifiCorp accepted some responsibility for the inconsistencies leading to under-recovery. For California, the Equalization Adjustment in the 2017 Protocol is a debit of $324,000, which will result in a combined 2017 Protocol Adjustment of zero if the Commission approves the 2017 Protocol in PacifiCorp's upcoming GRC. In comparison, the Revised Protocol increased California's revenue requirement by $1.3m in the last California rate case. Table 1, below, summarizes the impacts of the 2017 Protocol Adjustment.

Table 1: 2017 Protocol ECD and Equalization Adjustment

| 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.

### 3. The West Control Area Allocation Methodology

In 2007, PacifiCorp agreed to use the West Control Area Inter-Jurisdictional Allocation Methodology (WCA) in Washington for a five-year evaluation period.[7] The WCA isolates the costs and revenues associated with assets located in PacifiCorp's west balancing authority area (PACW), and allocates to Washington a proportionate share of the costs and revenues based primarily on Washington's relative contribution to demand and

[7] *Washington Utilities and Transportation Commission v. PacifiCorp D/B/A pacific Power & Light Co.*, Docket UE-061546, Order 08 (June 21, 2017).

energy requirements. The WCA includes loads, generation, and transmission assets and wholesale contracts for facilities located in California, Oregon, and Washington. It also includes transmission and generation assets located outside of California, Oregon, and Washington that are electrically located in PACW. The WCA excludes all loads and assets located within PacifiCorp east balancing authority area (PACE).

The WCA, however, does not reflect the actual operations of the company. As discussed in the joint testimony of Joseph P. Hoerner and Shayleah J. LaBray, PacifiCorp operates all of its assets as an integrated system, dispatched from a central control center. Power is purchased, sold, and transferred between PACW and PACE to serve PacifiCorp's entire retail load on a least cost basis. PacifiCorp's geographically diverse system benefits California customers because of the enhanced flexibility in dispatching power, enhanced system reliability, load peaking diversity, and greater access to wholesale markets.

The WCA is also inconsistent with how PacifiCorp finances its investments. PacifiCorp finances its operations on a total-company basis. PacifiCorp's credit rating benefits from the company's six-state service territory, reducing overall debt costs and benefiting customers. PacifiCorp's mortgage on its long-term assets are also backed by all of PacifiCorp's system assets.

The differences between company operations and ratemaking under the WCA create unnecessary inconsistencies. As an example, the Washington Utilities and Transportation Commission recently approved the transfer of certain transmission assets between PacifiCorp and Idaho Power Company.[8] The transfer allowed PacifiCorp to more fully utilize its system and rights across Idaho Power Company transmission system. Following the transfer,

[8] *In the matter or Pacific Power & Light Co.*, Docket UE-144136, Order 01 (September 24, 2015).

PacifiCorp sought to include the costs of the new assets in rates. The WUTC found that despite the undisputed fact that the facilities were used and useful, they did not provide an incremental benefit to Washington customers under the WCA.[9] As a result, in Washington, PacifiCorp was required to continue to charge its Washington customers for assets the company had previously transferred to Idaho Power Company, but was prohibited from including owned assets that are used and useful in the delivery of electricity to the PACW load.

Applying the WCA implemented in Washington would not result in more just and reasonable electric rates to PacifiCorp's California customers than either the Revised Protocol or 2017 Protocol. The WCA method does not reflect the way the company operates on a system basis nor does it comply with cost causation principles. The WCA would remove from California rates several plants that have been found to be used and useful in prior California GRCs. Inconsistencies between operations and the WCA would separate rates from actual costs of operation, and create a perverse incentive to locate resources in higher cost areas simply to increase rate recovery.

## D. DEPRECIABLE LIVES OF COAL PLANTS

Differing depreciation lives used by the states also impact retail rates. The coal asset depreciation schedules used in the company's last two depreciation studies were the same for all states except Oregon, which has adopted shorter depreciable lives than the other states. Depreciable lives for PacifiCorp's coal plants are shown in Table 3. In 2008, Oregon did not approve extending the depreciable lives of PacifiCorp's coal generation assets, resulting in coal plant lives shorter than PacifiCorp's other states. Washington also recently elected to

[9] *Washington Utilities and Transportation Commission v. Pacific Power & Light Co.*, Docket UE-152253, Order 12 at ¶216 (September 1, 2016).

increase depreciation expense to reduce the coal plant balances. In doing so, Washington matched the Oregon depreciation lives to, in part, respond to environmental and market pressures on existing coal-fired generation.[10] PacifiCorp plans to propose accelerated depreciation for its coal plants in its next California GRC to be filed in 2018.

Table 3: PacifiCorp Coal Plant Depreciable Lives

| | **End of Depreciable Life** | |
|---|---|---|
| **Plant** | **CA/ID/UT/WY** | **OR/WA** |
| CHOLLA | 2042 | 2028 |
| COLSTRIP | 2046 | 2032 |
| CRAIG | 2034 | 2026 |
| DAVE JOHNSTON | 2027 | 2023 |
| HAYDEN | 2030 | 2023 |
| HUNTER | 2042 | 2029 |
| HUNTINGTON | 2036 | 2030 |
| JIM BRIDGER | 2037 | 2025 |
| NAUGHTON | 2029 | 2028 |
| WYODAK | 2039 | 2026 |

The differing depreciable lives do not currently impact California customers. Under the Revised Protocol and the 2017 Protocol, one state's depreciation rates don't impact other states. PacifiCorp's coal generation assets have not been fully depreciated in any states to date. Accordingly, all states are paying their share of the fixed and variable costs associated with that generation.

When customers in a particular state with shorter depreciable lives pay off all of the depreciation expense for an asset, those customers would then only pay, for example, their share of variable costs or the incremental costs of other capital improvements related to ongoing maintenance or environmental compliance. If state policy, however, restricts the type of generation used to serve customers within that state, after paying off the full

[10] *Washington Utilities and Transportation Commission v. Pacific Power & Light Co.*, Docket UE-152253, Order 12 at ¶51 (September 1, 2016).

allocation of fixed costs there is a potential future impact to other states because any incremental fixed or variable costs would then be allocated among a smaller set of jurisdictions. This scenario could occur in 2030 as a result of Oregon Senate Bill 1547. Oregon Senate Bill 1547 prohibits costs from coal generation in retail electric rates in Oregon. The company, as part of MSP has proposed a coal plant re-alignment that would enable Oregon to implement its state law while mitigating that impact on other states.

## E. IMPACT OF INTER-JURISDICTIONAL ALLOCATION METHODOLOGIES ON RATES

These allocations form the basis for rate filings in each jurisdiction. Retail rates, however, also include situs allocated costs and state specific rate adjustments in final retail rates. Each state's rates are also impacted significantly by the weighting of customer classes (i.e. whether it is mainly residential versus industrial and rural versus urban service territory), and by state policy decisions such as the level of DSM. Accordingly, comparisons of actual retail rates between states is not meaningful.

## F. ALTERNATIVE CORPORATE STRUCTURES OR COST ALLOCATIONS ANALYZED DURING THE MSP

During 2016, PacifiCorp, at the request of stakeholders in the MSP Workgroup, analyzed whether an alternative corporate structure, specifically a separation into two separate electric utilities separately serving load in California, Oregon, and Washington from load in Idaho, Utah, and Wyoming, could be accomplished without increasing costs to customers. That analysis, however, indicated that costs would likely increase for all customers due to likely increases in financing costs, property and income tax expense, and administrative and general costs, along with requiring additional resources and increase reliance on market purchases. Furthermore, to avoid early redemption penalties and meet the mortgage bond requirements would require a transition spanning multiple decades.

PacifiCorp's current MSP discussions, however, are exploring an alternative approach that would allow each state to implement resource policies, without adversely impacting customers in other states. PacifiCorp believes the alternative being developed in the MSP Workgroup could provide a long-term allocation solution for all parties.

**G. INTER-JURISDICTIONAL ALLOCATION IMPACTS ON COMPLIANCE WITH CALIFORNIA GREENHOUSE GAS POLICIES**

The inter-jurisdictional allocation methodology is a method of allocating costs between states and does not impact PacifiCorp compliance with California Greenhouse Gas (GHG) policies in any of PacifiCorp's states. PacifiCorp's resource planning incorporates various GHG state policy requirements. PacifiCorp's compliance with GHG policies are specifically addressed in the testimony of Mary M. Wiencke (Chapter 4) and PacifiCorp's resource planning process is addressed in the testimony of Joseph P. Hoerner and Shayleah J. LaBray (Chapter 2). PacifiCorp plans and operates on a system basis, incorporating the compliance aspects of various state policies into its costs of operations. Any costs incurred to implement a discrete, state specific policy are assigned to the state that implemented the policy. As the company complies with federal and state policies and operational efficiencies are achieved, including the benefits of the energy imbalance market (EIM), California is allocated its share of these items through the allocation methodology.

**H. BENEFITS OF PACIFICORP'S DIVERSE SYSTEM**

PacifiCorp's diverse and expansive system provides benefits to all of PacifiCorp's customers, and does not shift any burdens to customers in any one state without associated benefits. The merger of PP&L with Utah Power and Light was approved by all six state commissions based on the company's demonstration of customer benefits from operational efficiencies. Many of those efficiencies were similar to what is being achieved today by the

EIM. The basis for all the allocation methodologies used since the merger was to align cost causation and benefits so customers appropriately pay their share of costs and receive the associated benefits.

PacifiCorp's system diversity provided significant benefits to customers immediately after the merger and those benefits continue to flow to customers today. As the bilateral energy market developed in the Western Interconnection, PacifiCorp's access to trading hubs from the Pacific Northwest to the Rocky Mountains to the Desert Southwest providing additional benefits to net power costs. PacifiCorp's entry into the EIM and interconnection to utilities across the interconnection has provided additional benefits to all of PacifiCorp's customers. Given the system benefits, there is not any cost shifting to California customers without commensurate sharing of benefits.

## I. CONCLUSION

PacifiCorp's inter-jurisdictional cost allocation methodology has resulted in just and reasonable rates for the benefit of PacifiCorp's customers in California. Its diverse and expansive system provides benefits to all of PacifiCorp's customers, and does not shift any burdens to customers in any one state without associated benefits.