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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S 2015 INTEGRATED RESOURCE PLAN.	**CASE NO. PAC-E-15-04**
	COMMENTS OF THE COMMISSION STAFF

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its attorney of record, Neil Price, Deputy Attorney General, and in response to the Notice of Modified Procedure issued in Order No. 33299 on May 12, 2015, submits the following comments.

BACKGROUND

On March 31, 2015, PacifiCorp dba Rocky Mountain Power ("Rocky Mountain," "PacifiCorp," or "Company") filed its 2015 Integrated Resource Plan ("IRP") with the Commission pursuant to the Commission's rules and in compliance with the biennial IRP filing requirements mandated in Order No. 22299.

PacifiCorp files an IRP on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. PacifiCorp's 2015 IRP represents its 13th comprehensive plan submitted to state regulatory commissions.

PacifiCorp states that the projected load forecast continues to decline beyond 2019 in relation to projected loads used in the Company's 2013 IRP and 2013 IRP Update. The Company cites reduced residential class load forecast due to increased energy efficiency, including continued phase-in of the Energy Independence and Security Act federal lighting standards, and lower energy response to economic growth as the main drivers of lower forecasted load.

Order No. 22299 requires the Company to submit a biennial "Resource Management Report." This order requires this report to give balanced consideration to supply and demand resources when formulating resource plans and procuring resources. The Company typically submits its IRP in compliance with this requirement. The Company states that this IRP reflects continued alignment efforts with the Company's annual ten-year business planning process. The Company's IRP 2015-2024 Action Plan is provided as Attachment A.

The Commission has previously noted that acceptance of the IRP should not be interpreted as endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition contained in the plan.

STAFF ANALYSIS

Staff reviewed the Company's 2015 IRP and notes that there have been substantial changes to the Company's resource strategy since its 2013 IRPs.[1] The Company states that these changes were made in response to uncertainty about the EPA's proposed interpretations of §111(d) of the Clean Air Act, EPA Regional Haze Requirements, and requirements of state specific Renewable Portfolio Standards (RPS). Staff believes that these uncertainties greatly complicate PacifiCorp's planning process. However, Staff also believes that the Company's flexible approach, which considers a broad array of scenarios and potential resource portfolios, is appropriate.

In general, the alternative resource portfolios considered by PacifiCorp decrease the Company's reliance on coal, either by decommissioning existing coal-fired plants, or by converting them to use natural gas, with a net decrease in generation capacity by 2024. In its 2013 IRP, the Company planned to meet the resulting capacity shortfall using market purchases. The Company's 2015 IRP preferred portfolio is somewhat less dependent on market purchases. Instead, the Company relies on Class 2 DSM energy management programs to meet anticipated capacity needs.

[1] The Company issued both an initial IRP and a revised IRP in 2013.

The Company states that recent increases in natural gas supplies have exerted downward pressure on natural gas prices, making conversion of some of its coal-fired base units to natural gas economically viable; however, the Company cautions that long-term natural gas price volatility may pose a long-term risk. Class 2 DSM programs include non-dispatchable, firm energy savings such as those achieved through installation of energy efficient equipment, appliances, lighting, and construction. Although typically associated with energy efficiency programs, Class 2 DSM programs can also reduce capacity needs if they reduce energy use during periods of system peak demand.

Capacity Load and Resource Balance with Existing Resources

PacifiCorp develops its load and resource balance by comparing its obligations with the capabilities of its existing resources. Capacity Position is the difference between the Company's ability and its obligation to supply power at system coincident peak loads. Because it is calculated assuming existing resources (including commitments and contracts), the Capacity Position is the Company's forecasted capacity shortfall absent any new resource acquisition on its part. Front Office Transactions (FOTs) are short-term firm market purchases.

Capacity Position *= (Existing Resources + Available FOTs) - (Obligation + Reserves)*

In previous IRPs, FOTs were considered separately as a type of market purchase, and not explicitly included in the computation of capacity position. The Company defines its existing resources, obligation, and reserves as follows.

Existing Resources *= Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Class 1 DSM - Firm Sales - Non-Owned Reserves*

Obligation *= Load - Interruptible Contracts - Existing Class 2 DSM*

Reserves *= Obligation x Planning Reserve Margin = Obligation x 13%*[2]

Between 2015 and 2024, the Company expects that existing generation capacity will decrease 4.6% from 10,156 MW to 9,692 MW. Existing thermal capacity will decrease from

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[2] Staff notes that the Company's stated 13% Planning Reserve Margin (PRM) is approximate.

8,905 MW to 8,670 MW, hydro from 894 MW to 740 MW, and renewables from 357 MW to 282 MW. Firm purchases will decrease from 818 MW to 277 MW, and purchases from qualifying facilities will vary between 255 MW and 488 MW. Decreases in generation capacity, firm purchases, and purchases from qualifying facilities will be partially offset by decreases in firm sales from 942 MW in 2015 to 222 MW in 2024. Non-owned reserves will remain constant at 41 MW, and beginning in 2016, interruptible contracts will remain a constant 175 MW.

Staff notes that the Company has changed the way that it values its DSM programs in its 2015 IRP. Class 1 DSM programs include firm, fully dispatchable and scheduled capacity programs such as the Company's 170 MW irrigation load management program in Idaho. In previous IRPs, Class 1 DSM capacity savings were subtracted from the Company's obligation. In the current IRP, these are considered to be a resource. PacifiCorp's existing Class 1 DSM programs will account for a constant 323 MW of capacity between 2015 and 2024. Because Class 1 DSM savings are no longer deducted from the Company's obligation, the net effect is a small increase (42.6 MW) in required reserves, and a concomitant decrease in capacity position. Between 2015 and 2024, PacifiCorp's existing Class 2 DSM programs will account for a 110 MW reduction in its capacity obligation.

The Company anticipates a 0.89% annual increase in system coincident peak demand between 2015 and 2024. Staff notes that the Company's system-wide capacity position may exceed available FOTs beginning in 2020. Table 1 summarizes PacifiCorp's system-wide resources, obligations, reserves, capacity position, and available FOTs.

System	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Resources (MW)	10568	10043	10143	10217	10144	10124	10486	10446	10458	10425
Obligation (MW)	10104	9930	10089	10225	10333	10452	10569	10674	10788	10832
Reserves (MW)	1333	1310	1331	1349	1363	1378	1393	1407	1422	1428
Obligation + Reserves (MW)	11437	11240	11420	11573	11696	11830	11963	12081	12210	12259
Capacity Position (MW)	(869)	(1,197)	(1,277)	(1,356)	(1,552)	(1,706)	(1,477)	(1,635)	(1,752)	(1,834)
Available FOTs (MW)	1670	1670	1670	1670	1670	1670	1670	1670	1670	1670

Table 1: System Capacity Position with Existing Resources (Volume I, Tables 1.2 & 5.14)

The Company's territory is divided into two balancing areas. Its west balancing area (PACW) comprises service territories in Oregon, California, and Washington. The Company's east balancing area (PACE) includes service territories in Wyoming, Utah, and Idaho. Staff observes that the capacity deficit in its east balancing area already exceeds available front office transactions (Table 2), while there are no capacity deficits in its west balancing area.

East Balancing Area	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Resources (MW)	7033	6880	6976	7031	7026	7018	7462	7453	7439	7396
Obligation (MW)	6935	6729	6854	6960	7047	7135	7200	7281	7370	7392
Reserves (MW)	921	894	910	924	935	947	955	966	977	980
Obligation + Reserves (MW)	7855	7623	7764	7885	7982	8081	8155	8247	8347	8372
Capacity Position (MW)	(823)	(743)	(789)	(853)	(957)	(1,064)	(693)	(794)	(908)	(976)
Available FOTs (MW)	318	318	318	318	318	318	318	318	318	318

Table 2: East Balancing Area Capacity Position with Existing Resources (Volume 1, Table 5.14)

Resource Portfolio Selection

PacifiCorp uses its resource portfolio selection process to determine resource mixes that enable it to meet its load obligations at the least cost. The Company analyzes the effects of different resource mixes under different scenarios using its Planning and Risk (PaR) assessment tool and its System Optimizer (SO) tool. The Company recently implemented an updated version of its Enterprise Portfolio Management (EPM) model, which improves efficiency of the PaR and SO tools.

PacifiCorp's 2015 IRP resource portfolio selection process considered 34 core case scenarios, as well as 15 additional scenarios used to determine model sensitivity. Core case scenarios included four different regional haze policies, five different §111(d) policies, CO_2 prices, the impact of four different Class 2 DSM programs, and two different FOT availability assumptions. Using its PaR, SO, and EPM tools, the Company identified models having the least cost and least risk. From the resulting short list, it conducted further analyses to select its preferred portfolio.

The Company states that a major 2015 IRP analysis highlight was development of a planning framework to address cost, risk, and uncertainty associated with the U.S. Environmental Protection Agency's (EPA) proposals to regulate CO_2 under §111(d) of the Clean Air Act. These proposals have not yet been finalized, and some alternatives currently being discussed could have a large impact on selection of the Company's preferred resource portfolio. To this end, the Company has developed a new spreadsheet-based tool, 111(d) Scenario Maker, that enables it to study the effects of §111(d) policy and compliance uncertainties.

Another factor driving the 2015 IRP process is compliance with EPA Regional Haze Requirements, which has required assessment of compliance alternatives for the coal-fired Wyodak, Naughton Unit 3, Dave Johnson Unit 4, and Cholla Unit 4 power plants. EPA Regional Haze Requirements apply to a variety of airborne pollutants that restrict visibility, but particularly to those affecting visibility in U.S. national parks, wilderness areas, and some international parks. Under the EPA's Regional Haze program, each state submits a State Implementation Plan (SIP). Currently, the Company is awaiting EPA approval of some SIPs prior to determining the best strategies for assuring compliance of selected coal-fired power plants. Options being considered for these plants include Selective Catalytic Reduction (SCR), which reduces nitrogen oxide (NO_x) emissions; bag houses, which reduce particulate emissions; natural gas conversion, which reduces CO_2, NO_x, and particulate emissions; and decommissioning.

A renewable resource portfolio standard (RPS) requires electricity retailers to include specified amounts of renewable energy in their portfolios. Three states in the Company's territory (California, Oregon, and Washington) have mandated RPS requirements. Utah has implemented an RPS goal. PacifiCorp has considered these requirements and goals in its 2015 IRP process.

Preferred Resource Portfolio

Currently, the Company derives 50.3% of its system coincident peak power from pulverized coal, 25.1% from natural gas, 7.6% from hydroelectric power, and 6.9% from purchases (Volume I, Table 5.2). The Company obtains the remaining 10.1% from a combination of DSM, renewables, purchases from qualifying facilities, and interruptible contracts. PacifiCorp's total capacity is 11,810 MW.

Under the Company's preferred portfolio, power obtained from pulverized coal will decrease to 44% in 2024, primarily due to conversion of Naughton Unit 3 to natural gas in 2018. By 2034, this percentage will fall to 24%, due primarily to closure of the Company's coal-fired Naughton Units 1 and 2 in 2029. Between 2018 and 2024, contributions from natural gas and market purchases will remain relatively constant. The Company plans to acquire new natural gas fired plants beginning in 2029, and anticipates that the peak capacity contribution of natural gas will increase to 40% by 2034. The Company states that approximately 2,800 MW of existing coal generation will either be retired or converted to use natural gas by 2034.

Under its preferred portfolio, the Company anticipates that the contribution from renewables (solar) will increase from 3.0% to 6.0% in 2015 and 2016, and remain relatively constant thereafter. The capacity contribution from its Class 2 DSM programs will account for the majority of peak capacity growth between 2015 and 2024, and will be a major component thereafter. Class 2 DSM's capacity contribution will increase from 3.7% to 9% between 2015 and 2024, and to 14% by 2034.

PacifiCorp believes that the market for FOTs is favorable. However, growth in energy efficiency savings will reduce the need for FOTs through the first ten years of the planning horizon. The Company states that, on average, 2015 IRP preferred portfolio FOTs are down 16% from the 2013 IRP Update and down 29% when compared to the 2013 IRP preferred portfolio. Staff observes that these statements may be true when assessing its east and west balancing areas together. However, as mentioned earlier, the capacity deficit in the Company's east balancing area currently exceeds available FOTs.

Planning Reserve Margins and Resource Sufficiency

The Company estimates resource sufficiency for both planning reserves and operating reserves as part of its IRP process. These assessments are detailed in the Company's most recent IRP, the 2015 IRP, specifically Volume II, Appendix F (Flexible Resource Needs Assessment) and Appendix I (Planning Reserve Margin (PRM) Study).

PacifiCorp claims that it will exceed its 13% target planning reserve margin through 2019 and fall short of its target planning reserve margin in 2020. However, the Company anticipates that expiration of an existing exchange contract will increase system capacity and allow the Company to exceed its 13% target planning reserve margin in 2021 and 2022. PacifiCorp estimates that it will be at least 82 MW and 165 MW below its target planning reserve margin in 2023 and 2024, respectively. The 13% target planning reserve margin is calculated as projected load less distributed generation, less existing Class 2 DSM energy efficiency savings, and less interruptible load.

Energy Imbalance Market and Transmission Investments

If PacifiCorp's system resources are insufficient to meet reserve obligations, additional resources and associated investments or purchases would be required. Staff believes benefits associated with participating in the EIM may reduce the Company's reserve obligations (See Company Response No. 6, bullet 1) and could thereby reduce future resource needs. However, existing transmission limits between PACE and PACW generally limit these benefits to PACW only. Staff suggests the Company assess market access issues in its's IRP to allow expansion of EIM benefits to both PACE and PACW.

Staff understands that transmission system investments identified by the Company as part of the IRP planning process may be mitigated by development of new or modified grid operation procedures and/or by adding transmission projects to the 10-year capital transmission improvement plan. For example, PacifiCorp continues to support transmission permitting efforts for Energy Gateway West (Segments D and E), Energy Gateway South (Segment F), Boardman to Hemingway (Segment H), and a line from Walla Walla to McNary, while participating in regional and the interregional transmission planning efforts with the Northern Tier Transmission Group (NTTG), the Western Electricity Coordination Council (WECC), and the FERC order 1000 Interregional Coordination Group. Staff believes that regional plan comparisons through an effective interregional coordination process can, ultimately, lead to more efficient long-term planning processes across the Western United States and Canada. Staff also believes that both an efficiency of scale and cooperative, co-ownership of transmission assets that reduce the cost of complying with contingency requirements can be achieved through these efforts. Moreover, improvements in operational efficiency ensure that existing resources are better utilized and may allow postponement of costly future transmission investments.

Staff believes that the Company should compare its transmission plans as outlined in the IRP to planning efforts of regional transmission groups to assure efficient and prudent compliance with operational and long-term transmission planning and reliability requirements.

Load and Resource Balance

In its acceptance of the Company's 2013 IRP, the Commission directed the Company "to increase its efforts toward achieving higher levels of cost-effective DSM" and "to present clear and quantifiable metrics governing its actions regarding decisions to implement or decline energy efficiency programs."

Staff notes the Company's reliance on Class 2 DSM energy savings programs to meet its capacity obligations. By 2024, the Company anticipates deriving 6.1 GWh (9%) of its energy obligation, and 1.0 GW (9.0%) of capacity obligation from Class 2 DSM energy savings programs. To put this in perspective, this is nine times the capacity reduction that the Company obtains from its existing Class 2 DSM programs (110 MW), and is greater than the combined capacity of its two largest coal fired plants, Hunter Unit 3 and Huntington Unit 1. By 2034, under the Company's preferred portfolio, Class 2 DSM savings will be 10.9 GWh. The Company states that for its 2015 IRP, it used an accelerated Class 2 DSM acquisition scenario that exceeded energy savings estimates in its 2013 IRP by 59%. The Company also notes that the accelerated scenario is "both speculative and hypothetical," but did not provide an assessment of the specific risks associated with it. Nevertheless, Staff believes the Company's Class 2 DSM energy savings target to be achievable, and supports the Company's aggressive program to obtain Class 2 DSM resources.

According to the Company, its Class 2 DSM programs are primarily targeted at reducing energy consumption, so a program's ability to reduce system peak demand is dependent on the types of energy savings programs adopted by the Company. For example, a program that encourages energy efficient heating might reduce energy use, but have no impact on the capacity obligation of a summer peaking utility like PacifiCorp. The Company's 2015 IRP emphasizes the process for selecting Class 2 DSM programs based on their ability to reduce energy use, but describes no mechanism for assuring their contribution to reducing peak load. Given the 2015 IRPs reliance on Class 2 DSM capacity reductions, Staff believes that the Company should include a thorough explanation of the effects of these programs for both energy and capacity reduction in its 2017 IRP.

Staff notes inconsistencies between some of the text, tables, and figures used to discuss DSM related capacity reductions. Part of this difficulty arises because the 2015 IRP often does not discriminate between the name plate/capacity reduction and the system peak reduction of Class 2 DSM programs. Class 2 DSM name plate/capacity reduction is computed without regard to the timing of that reduction, and is not necessarily coincident with the system's peak. For purposes of analyzing capacity position, only a Class 2 DSM program's system coincident peak reduction is useful. The effect of using name plate/capacity reduction rather than system coincident peak reduction is to exaggerate, often by 50% or more, the apparent capacity contribution of energy efficiency programs. Given the increased importance of Class 2 DSM programs to the Company's capacity position, Staff would like to see the Company provide a more detailed explanation describing how the Company will assure that these programs meet the energy and capacity targets in its next IRP.

Staff analyzed the Company's preferred portfolio plan for converting/decommissioning selected coal fired plants. According to the Company, this plan is sensitive to assumptions about natural gas price and the EPA's final rules for interpreting §111(d). The 2015 IRP includes extensive discussions of these risks and issues surrounding them. Given these uncertainties, Staff believes that the Company's preferred portfolio plan for reducing the energy contribution of coal, and increasing the energy contribution of natural gas to both be reasonable.

As noted earlier, Washington, Oregon, California, and Utah have renewable portfolio standards requirements/goals that constrain the energy options available to the Company. The Multi-State Allocation Protocol assigns the differential costs of RPS's to those states that cause these costs to be incurred, thereby protecting Idaho customers from subsidizing the RPS requirements of other states.

The 2015 IRP includes a summary of a wind integration study conducted by the Company. Over the next two years, the Company also plans to double the amount of energy that it obtains from solar power, from 3% to about 6% of its system load. Given its increased reliance on solar power, Staff believes that it would be appropriate for the Company to conduct a solar integration study for inclusion in the Company's 2017 IRP.

STAFF RECOMMENDATIONS

The Commission has previously noted that acceptance of the IRP should not be interpreted as endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition contained in the plan. After reviewing PacifiCorp's 2015 IRP, Staff believes that the Company's 2015 IRP gives balanced consideration to supply and demand resources, and that it satisfies the requirements of Commission Order Nos. 25260 and 22299. Subsequent IRPs are expected to address current resource needs with more accurate information prior to final resource decisions being made. Based on these considerations, Staff recommends that the Commission acknowledge the Company's 2015 IRP filing.

Respectfully submitted this 7th day of August 2015.

Neil Price
Deputy Attorney General

Technical Staff: Johanna Bell
Mike Morrison

i:umisc:comments/pace15.4npjbmm comments

ATTACHMENT A – **2015-2024 IRP ACTION PLAN**

1. **Renewable Resource Actions**

- Pursue unbundled REC request for proposals (RFP) to meet its state renewable portfolio standard (RPS) compliance requirements.

- Issue annual RFPs seeking current-year or forward-year vintage unbundled RECs to meet Washington and California renewable portfolio standard targets through 2017.

- Defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA's draft 111(d) rule. The Company asserts that it has a projected bank balance extending out through 2027.

- Issue quarterly reverse RFPs through 2016 to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.

- Secure bids from 2013 RFPs seeking up to 7 MW of capacity from qualifying solar systems to meet Oregon's 2020 solar capacity standard.

2. **Firm Market Purchase Actions**

- Acquire short-term on-peak firm market purchase deliveries from 2015 through 2017.

- Balance month and day-ahead competitive price brokered transactions.

- Balance month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE).

- Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.

3. **DSM Actions**

- Class 1 DSM: Pursue a west-side irrigation load control pilot beginning 2016.
- Class 2 DSM: Acquire the following cost-effective Class 2 DSM resources targeting annual system energy and capacity selections from the preferred portfolio:
  - *2015*– 551 MW of Annual Incremental Energy (GWh) and 133 MW of Annual Incremental Capacity;
  - *2016*– 584 MW of Annual Incremental Energy and 139 MW of Annual Incremental Capacity;
  - *2017*– 616 MW of Annual Incremental Energy and 146 MW of Annual Incremental Capacity;
  - *2018*– 634 MW of Annual Incremental Energy and 146 MW of Annual Incremental Capacity.

4. **Coal Resource Actions**

- Naughton Unit 3: Issue RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016. Possibly update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.

- Dave Johnston Unit 3: Wyoming currently appealing 10 Circuit ruling the portion of EPA's final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. If EPA's final FIP is upheld, the Company is committed to shutting down Dave Johnston Unit 3 by the end of 2027. If EPA's final FIP is or will be modified, the Company will evaluate alternative compliance strategies.

- Wyodak: Continue appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak. Compliance deadline for SCR under the FIP is currently stayed by the court. If EPA's final FIP is upheld (with a modified schedule that reflects the final stay duration), the Company will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations.

- Cholla Unit 4: Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by April 2025.

5. **Transmission Actions**

- Continue permitting for the Energy Gateway transmission plan. Near-term targets for Segments D, E, and F include the continued funding of the required federal agency permitting environmental consultant; continue to support the federal permitting process by providing information and participating in public outreach.

- For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.

- Continue to implement the Walla Walla to McNary project construction plan with 2017 expected in-service date. Continue to support permitting process.

ATTACHMENT B – **Summary of IRP Standards and Guidelines for Idaho:**[1]

- **Filing Requirements and Frequency:** Submit "Resource Management Report" (RMR) on planning status biennially. Also file the following progress reports at least annually: (1) conservation, (2) low-income programs, (3) lost opportunities, and (4) capability building.
- **Commission Approval or Acceptance:** Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.
- **Focus:** 20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. The RMR is to address risks and uncertainties; and to emphasize clarity, understandability, resource capabilities and planning flexibility.
- **Elements:** The RMR is to discuss analyses considered including: load forecast uncertainties; known or potential changes to existing resources; equal consideration of demand and supply side resource options; contingencies for upgrading, optioning and acquiring resources at optimum times; and report on existing resource stack, load forecast and additional resource menu.

[1]Order 22299 Electric Utility Conservation Standards and Practices, January, 1989, as restated by the Company in the 2015 IRP, Table B.1.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 7th DAY OF AUGUST 2015, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-15-04, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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