Docket No. UE 263
Exhibit PAC/500
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

March 2013

DIRECT TESTIMONY OF RICHARD A. VAIL

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am Vice President of Transmission for PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering (Electric Power Systems Focus) from Portland State University. My experience spans more than 18 years in the electric utility business and electric power industry in general. I have working experience and have had management responsibility for a number of functional organizations at PacifiCorp including Substation Engineering, Planning Technologies, Standards Engineering, Cost Estimating, Project Services, Capital Planning, Maintenance Policy, Maintenance Planning, Investment Planning, Risk Planning and Asset Strategy, Reliability Standards, Asset Management, and most recently Transmission Services and Transmission System and Area Planning.

Q. What are your responsibilities as Vice President of Transmission?

A. I am responsible for transmission planning activities required to support PacifiCorp's existing and future bulk transmission system and to ensure a safe and reliable transmission system that provides adequate service to our customers.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the mandatory system reliability and performance requirements with which the Company must comply, and to support the test year costs associated with capital investments in the Company's transmission system. These investments include the new Black Rock Substation in Millard County, Utah; the interconnection to the new Lake Side 2 natural gas-fired generating plant (Lake Side 2) near Vineyard, Utah; system reinforcements needed to interconnect new data facilities near Prineville, Oregon; and transmission system upgrades needed to provide voltage support to the system connected to the Carbon generating facility in central Utah.

Q. What is the capital investment for the projects described in your testimony?

A. The capital investment for the major transmission projects described in my testimony is $69.2 million on a total-company basis. These projects are included as part of the Oregon revenue requirement in this case and are referenced in the direct testimony and exhibits of Mr. Gary W. Tawwater.

Q. Will these investments be considered "used and useful" before the test period for this case?

A. Yes. My testimony will demonstrate that these were prudent investments that benefit our customers, the projects are on schedule for completion, and the projects will be used and useful before the test year for this proceeding.

RELIABILITY REQUIREMENTS

Q. Please describe the mandatory reliability standards and criteria with which the Company is required to comply.

A. PacifiCorp plans, designs, and operates its transmission system to meet or exceed North American Electric Reliability Corporation (NERC) standards for the Bulk Electric Systems and Western Electricity Coordinating Council (WECC) regional standards and criteria. The NERC standards are federal law stated in 18 CFR Part 40 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC standards and criteria are deemed necessary for the WECC Region to meet or exceed NERC standards. There are currently more than 100 approved NERC standards with which the Company must comply. The following standards dictate the minimum levels of transmission system reliability, redundancy, and performance required for transmission facilities:

- NERC TPL-001 System Performance Under Normal Conditions[1]
- NERC TPL-002 System Performance Following Loss of a Single Bulk Electric System (BES) Element[2]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[3]
- NERC TPL-004 System Performance Following Extreme BES Events[4]
- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[5]

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[1] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf.
[2] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[3] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf.
[4] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[5] TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at: http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20thru%20004-WECC-1-CR%20-%20System%20Performance%20Criteria.pdf.

- TPL 002-WECC-1-CR System Performance Criteria Following Loss of a Single BES Element
- TPL 003-WECC-1-CR System Performance Criteria Following Loss of Two or More BES
- TPL 004-WECC-1-CR System Performance Criteria Following Extreme BES Events
- NERC TOP-002 Normal Operations Planning[6]
- NERC TOP-004 Transmission Operations[7]
- NERC TOP-007 Reporting SOL and IROL Violations[8]

Q. Please discuss further how these standards and criteria influence the timing of the investments included in this case.

A. These mandatory standards require the Company to have a forward-looking transmission plan of action to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system operations (all system elements in service) and during system contingencies (where elements of the transmission system are out of service), both planned or otherwise. NERC Transmission Planning Standard TPL 002 states (emphasis added):

> **A. Introduction**
> **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that *meet specified performance requirements with sufficient lead time*, and continue to be modified or upgraded as <u>*necessary to meet present and future system needs.*</u>
>
> **B. Requirements**
> **R1.** The Planning Authority and Transmission Planner shall each demonstrate through valid assessment that its portion of the interconnected

[6] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[7] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[8] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf.

transmission *system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions* as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.
R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R2. When System simulations indicate an *inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1*, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
R2.1.1. *Including a schedule for implementation.*
R2.1.2. *Including a discussion of expected required in-service dates of facilities.*
R2.1.3. *Consider lead times necessary to implement plans.*

The Company is required to have both short-term and long-term transmission plans to reliably meet all expected current and forecasted customer electrical demands. The requirement to have these plans and meet current and forecasted customer demand is not optional for the Company. The Company is audited every three years by NERC and WECC. The next audit is scheduled for May 2013.

BLACK ROCK SUBSTATION

Q. Please describe the Black Rock Substation investment included in this case.

A. The Black Rock Substation is a new 230-69 kilovolt (kV) substation in Millard County, Utah, with a scheduled in-service date of May 1, 2013, and cost of $19.1 million on a total-company basis. This project consists of looping in and out the existing Pavant-Gonder 230 kV transmission line and the Delta-Graymont

69 kV transmission line, installing a 75 megavolt ampere (MVA) 230-69 kV load tap changing transformer, and changing the relay settings on the 46-46 kV regulator at the Delta Substation to enable forward and reverse power operation.

Q. Why is the Black Rock Substation investment needed?

A. The Black Rock Substation investment is needed to meet load growth and reliability needs and to maintain compliance with the mandatory system reliability and performance requirements described above. Currently, the Company's contractual obligation in the area served by the Pavant Substation exceeds what the system can provide. The Company performed a five-year study to address these contracted loads under multiple scenarios based on current and projected demand. This study showed that meeting current and projected maximum contracted load at the Pavant Substation resulted in a range of outcomes, including low voltages across the entire 46 and 69 kV systems during N-0 conditions, system deficiencies during summer peak beginning in 2012, and dropped loads during N-1 conditions (estimated for 2012 at approximately 47 MW of load served from Pavant in the Delta area). The Black Rock Substation was determined to be the least-cost option to provide voltage support to the area under N-0 conditions (i.e., normal system conditions) and to help solve problems under N-1 conditions (i.e., system performance following the loss of a single BES element).

Q. What are the system benefits associated with the Black Rock Substation?

A. The Black Rock Substation provides several system benefits, including:

- Decreased loading on the Pavant 230-46 kV transformers, providing redundancy in case of the loss of the other transformer;

- Improved voltage on the 46 and 69 kV systems to handle additional load growth in the area;
- Reduced loading on the Pavant to McCornick 46 kV line to 46 percent of its 25 MVA steady state rating, reducing the risk of load shedding in the Delta area; and
- Enabling of the 46 kV lines from Pavant to McCornick and Pavant to Delta to operate under N-1 operation upon the loss of one another.

Q. Will the Black Rock Substation investment be used and useful before the test period for this case?

A. Yes. When the Black Rock Substation is placed into service, in May 2013, the project will be part of the interconnected transmission system and will be fully used and useful.

LAKE SIDE 2 INTERCONNECTION

Q. Please describe the Lake Side 2 interconnection investment included in this case.

A. The investments included in this case for interconnection of Lake Side 2 (approximately $18.5 million total-company basis) consist primarily of the following:

- Construction of a new 345 kV point of interconnection substation (Steel Mill Substation);
- Looping in and out the existing 345 kV Camp Williams/Emery transmission line;
- Configuring the point of interconnection substation to accommodate a six breaker ring bus layout with three breakers installed for this project;
- Installing a control house, metering, communication, and protection and control equipment at the new point of interconnection substation; and
- Deploying required equipment replacement, control modifications, and communications upgrades at the Camp Williams, Emery, Sigurd, Dynamo,

and Timp substations, and at the Salt Lake City and Portland control centers.

Q. Why is the Lake Side 2 interconnection investment needed?

A. PacifiCorp Energy, the interconnection customer, made a formal request for interconnection of the new Lake Side 2 to PacifiCorp's existing Camp Williams-Hunter/Emery 345kV transmission line, which is adjacent to the existing Lake Side generating facility. The interconnection must be completed in May 2013 to provide electrical back feed approximately one year ahead of the generation plant in-service date. The interconnection substation must be engineered, designed, and constructed to meet all applicable PacifiCorp, NERC, and WECC mandatory reliability standards as described above.

Q. Is the Lake Side 2 interconnection investment in the Steel Mill Substation included in this case part of the interconnection facilities dedicated to Lake Side 2?

A. No. The Steel Mill Substation investment included in this case is located separately and remote from Lake Side 2 site and is an integral part of the 345kV transmission system serving both the generating unit and the Company's customers. Interconnection facilities that would be considered an integral part of the generating unit include those physically located on the Lake Side 2 site, such as the generator step up unit transformers (GSUs) and associated plant substation facilities and facilities interconnecting to the Steel Mill Substation included in this case. These facilities, installed and owned by PacifiCorp Energy, will be placed in service coincident with Lake Side 2 and are included as part of the costs included in the proposed separate tariff rider discussed in the testimony of Ms. Joelle R. Steward.

Q. What are the benefits associated with the Lake Side 2 interconnection investment?

A. The Company is required under its Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff to provide transmission service and generator interconnection service to all customers on a non-preferential, non-discriminatory basis. Per the Company's binding FERC interconnection agreement with PacifiCorp Energy, the Project must be completed in May 2013. Additionally, Lake Side 2 is part of the Company's acknowledged integrated resource plans and will provide benefits to all of PacifiCorp's native load customers.

Q. Will the Lake Side 2 interconnection investment be used and useful before the test period for this case?

A. Yes. When the Steel Mill Substation is placed into service in May 2013, the facility will be part of the interconnected transmission system and will be fully used and useful.

NEW OREGON DATA CENTER CUSTOMER SYSTEM REINFORCEMENTS

Q. Please describe the customer system reinforcements included in this case.

A. The customer's system reinforcements in this case are approximately $18.3 million on a total-company basis and consist primarily of the following:

- Expansion of 115 kV ring bus at Houston Lake Substation for 115 kV feed to the customer's new substation and new 115 kV transmission line between Ponderosa and Houston Lake Substations;

- Installation of metering equipment, 115 kV CT/PT combined metering units and metering bypass structure at Houston Lake Substation for feed to the customer's new substation;
- Construction of approximately 400 feet of 115 kV line from Houston Lake Substation to the customer's new substation;
- Installation of second 230-115 kV, 250 MVA transformer at Ponderosa Substation; expand Ponderosa Substation 115 kV ring bus to accommodate second transformer position and new Ponderosa-Houston Lake 115 kV line;
- Provision of funding to Bonneville Power Administration (BPA) for new 230 kV bus position at BPA Ponderosa Substation for interconnection of Company's new 230-115 kV transformer;
- Construction of new 115 kV line on a new right-of-way between Ponderosa and Houston Lake Substations, approximately 7.7 miles long;
- Modification of existing Ponderosa to Prineville 115 kV line at crossing with new line to achieve line separation and clearance;
- Replacement of 230 kV line relays at Pilot Butte Substation; and
- Replacement of four 12.47 kV circuit breakers and two sets of 115 kV fuses at Prineville Substation to accommodate increased system fault duty.

Q. Why are the new Oregon data center system reinforcements needed?

A. The customer has requested network service for its new Oregon Data Centers II and III, located adjacent to its existing Oregon Data Center I in the Tom McCall Industrial Park southwest of Prineville, Oregon. The customer system reinforcements are required to support interconnection of the new Oregon Data Centers II and III, which together represent 80 MVA of new customer load, and to maintain compliance with the mandatory system reliability and performance requirements described above, specifically NERC TPL-001 and TPL-002.

Q. What are the system benefits associated with these system reinforcements?

A. These investments are required for the interconnection and reliable service to the new data centers, absent these reinforcements, this new customer load could not be reliably interconnected or served and the Company would not meet its obligation to serve electric customers.

Q. Will the Oregon data center system reinforcements be used and useful to serve customers before the test period for this case?

A. Yes. When the project is placed into service in 2013, the facility will be part of the interconnected transmission system and will be fully used and useful.

CARBON VOLTAGE SUPPORT

Q. Please describe the Carbon voltage support investments included in this case.

A. The Carbon voltage support investments included in this case (approximately $13.2 million on a total-company basis), include the following:

- Removal of the 46 kV Carbon switching substation and replacement of the existing alternate station service feed to the 138 kV switching station with a new feed;
- Installation of two 138 kV 15 megavolt ampere reactive (MVAR) capacitor banks at the Mathington Substation;
- Expansion of the Mathington Substation for the static volt-ampere reactive (VAR) compensator (SVC); and
- Design/installation of one 138 kV +85 MVAR and -15 MVAR SVC; and modified communications and protection and control equipment at multiple locations across the Company's system.

Q. Why are the Carbon voltage support investments needed?

A. The Carbon generating facility is anticipated to be retired by April 15, 2015, to comply with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards. To enable this facility to be retired as scheduled, and to maintain compliance with the mandatory system reliability and performance requirements described above, transmission system upgrades must be in place to provide voltage support necessary for continued reliable operation of the Carbon-Price-Vernal transmission grid area.

Q. What are the system benefits associated with the Carbon voltage support investments?

A. The Carbon voltage support investments will allow the Company to comply with NERC and WECC standards while continuing to provide reliable transmission service to the Carbon-Price-Vernal area following Carbon's retirement.

Q. Does this conclude your direct testimony?

A. Yes.