ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

January 6, 2014

VIA E-MAIL AND US MAIL

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

Re: FERC Docket No. ER14-835-000—PacifiCorp Cost-Based Rate Schedule

PacifiCorp participates as a seller in the western wholesale energy markets under authorization granted it by the Federal Energy Regulatory Commission (FERC) in its Volume No. 12 market-based rate authority. In contrast, wholesale energy sales by NV Energy in the Nevada Power Company and Sierra Pacific Power Company balancing authority areas must be made in accordance with its FERC-filed cost-based rate. When NV Energy became a PacifiCorp affiliate through common control by MidAmerican Energy Holdings Company on December 19, 2013, NV Energy's cost-based rate restriction also became applicable to PacifiCorp for its sales in the Nevada Power Company and Sierra Pacific Power Company balancing authority areas. In order to facilitate such sales, on December 24, 2013, PacifiCorp filed with the FERC a proposed cost-based rate schedule.

As noted in the attached FERC filing, PacifiCorp's proposed cost-based rate schedule will act as an amendment to the WSPP Schedule Q, establishing a mechanism to allow PacifiCorp to negotiate rates for short-term transactions up to the ceiling rates set forth therein. Service under this schedule is voluntary and available to wholesale customers located within the areas subject to the NV Energy cost-based rate. The proposed cost-based rate schedule was developed consistent with FERC precedent.

Informal questions should be directed to Dave Taylor, Manager, Utah Regulatory Affairs, at (801) 220-2923.

Sincerely,

Jeffrey K. Larsen / PBD

Jeffrey K. Larsen
Vice President, Regulation and Government Affairs

Enclosures

Gibson, Dunn & Crutcher LLP

1050 Connecticut Avenue, N.W.
Washington, DC 20036-5306
Tel 202.955.8500
www.gibsondunn.com

William R. Hollaway, Ph.D.
Direct: +1 202.955.8592
Fax: +1 202.530.9534
whollaway@gibsondunn.com

December 24, 2013

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *PacifiCorp*, Docket No. ER14-_____-000
<u>Cost-Based Rate Schedule</u>

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission (the "Commission" or "FERC"), 18 C.F.R. Part 35, PacifiCorp hereby submits for filing with the Commission an application for a Cost-Based Rate Schedule ("CB Rate Schedule") for PacifiCorp. Once accepted, this CB Rate Schedule will apply, among other things, to sales by PacifiCorp to its affiliates Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific," and together with Nevada Power, the "NVE Utilities").

Upon acceptance by the Commission of this stand-alone CB Rate Schedule, this CB Rate Schedule will be submitted to WSPP, Inc., so that it can be included in Schedule Q of the WSPP Agreement. As authorized by past Commission orders,[1] once the stand-alone rate schedule is accepted by the Commission, PacifiCorp will request WSPP, Inc. to submit a ministerial filing to revise the WSPP Agreement to incorporate this rate schedule into Schedule Q of the WSPP Agreement, with an effective date as of the date that the Commission accepts PacifiCorp's stand-alone CB Rate Schedule. In order to permit potential customers the ability to make purchases under the CB Rate Schedule as soon as possible, PacifiCorp respectfully requests waiver of the Commission's prior notice filing requirement to make the proposed CB Rate Schedule effective December 25, 2013 (*i.e.*, one day after the date of filing).

---

[1] *See, e.g., Western Systems Power Pool*, 126 FERC ¶ 61,193 (2009).

I. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications concerning the above-captioned proceeding should be addressed to the following persons:[2]

Jeffery B. Erb
Assistant General Counsel
Assistant Corporate Secretary
PacifiCorp Energy – Commercial & Trading Division
825 NE Multnomah, Suite 600
Portland, Oregon 97232
Tel: (503) 813-5029
Fax: (503) 813-6761
jeff.erb@pacificorp.com

William R. Hollaway, Ph.D.
Brandon C. Johnson
Jennifer C. Mansh
Gibson, Dunn & Crutcher, LLP
1050 Connecticut Ave., NW
Washington, DC 20036
Tel: (202) 955-8500
Fax: (202) 530-9534
whollaway@gibsondunn.com
bcjohnson@gibsondunn.com
jmansh@gibsondunn.com

II. DOCUMENTS SUBMITTED WITH THIS FILING

This filing consists of:

- This Transmittal Letter;
- Attachment A, clean rate schedule sheets (note that this is a new schedule and, therefore, no redlines are submitted with this filing);
- Attachment B, cost justification schedules for the *Units Most Likely to Participate Methodology*; and
- Attachment C, a list of PacifiCorp's principal wholesale customers that would potentially take service under the proposed CB Rate Schedule once it is incorporated into Schedule Q of the WSPP Agreement.

III. THE DATE ON WHICH PACIFICORP REQUESTS THE TARIFF SHEETS BECOME EFFECTIVE

PacifiCorp respectfully requests that the proposed CB Rate Schedule become effective on December 25, 2013 (*i.e.*, one day after the date of filing). PacifiCorp is filing this CB Rate Schedule to enable short-term sales by PacifiCorp in the Nevada Power and Sierra Pacific balancing authority areas ("BAAs") now that PacifiCorp is an affiliate of Nevada Power and Sierra Pacific. PacifiCorp requests that this CB Rate Schedule become effective December 25, 2013 to enable PacifiCorp to make any needed sales in the Nevada Power and Sierra Pacific

[2] PacifiCorp requests a waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2013), to the extent necessary to permit more than two persons to be included on the official service list on their behalf in this proceeding.

BAAs to meet needs in those BAAs at cost-based rates at the earliest possible date following this filing.

IV. THE NAMES AND ADDRESSES OF THOSE TO WHOM THIS FILING HAS BEEN SENT

Pursuant to Section 35.2(e) of the Commission's regulations, PacifiCorp is serving a copy of this filing to those listed below.

Carolyn E. Tanner, Esq.
Public Utilities Commission of Nevada
1150 E. William Street
Carson City, NV 89701
Tel: (775) 684-6188
ctanner@puc.nv.gov

Eric Witkoski, Esq.
Office of the Nevada Attorney General
Bureau of Consumer Protection
100 North Carson Street
Carson City, Nevada 89701
Tel: (775) 684-1180
EWitkoski@ag.nv.gov

Maria Salinas
Energy Division, Tariff Unit
California Public Utilities
Commission
505 Van Ness Avenue
San Francisco, CA 94102
Tel: (415) 703-1329
mas@cpuc.ca.gov
edtariffunit@cpuc.ca.gov

Jean D. Jewell
Angie Velasquez
Idaho Public Utilities Commission
472 West Washington Street
Boise, ID 83702
Tel: (208) 334-0338
Jean.jewell@puc.idaho.gov
Angie.velasquez@puc.idaho.gov

Kathy Williams
Oregon Public Utility Commission
PO Box 1088
Salem, OR 97308
Tel: (503) 378-2118
kathy.williams@state.or.us
puc.filingcenter@state.or.us

Gary Widerburg
Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84114
Tel: (801) 530-6713
gwiderburg@utah.gov
psc@utah.gov

Steven V. King
Washington Utilities and
Transportation Commission
1300 S. Evergreen Park Drive
PO Box 47250
Olympia, WA 98504
Tel: (360) 664-1160
sking@utc.wa.gov

Chris Petrie
Mary Kiser
Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, WY 82002
Tel: (307) 777-5763
Chris.petrie@wyo.gov
Mary.kiser@wyo.gov

A copy of this filing has also been sent to PacifiCorp's principal wholesale customers for which cost-based sales under these rate schedules would be applicable upon ultimate incorporation into Schedule Q of the WSPP Agreement, as listed in Attachment C. A copy of this filing has also been sent to WSPP, Inc.

V. BACKGROUND

The proposed CB Rate Schedule would establish an "up to" cost-based rate platform for short-term wholesale power sales that is comparable in all material respects to other such rate schedules that have been accepted by the Commission. PacifiCorp does not presently have on file "up to" cost-based rates for sales under the WSPP Agreement. Thus, the proposed CB Rate Schedule will not supersede, supplement, or otherwise change the provisions of any rate schedule now on file for PacifiCorp.

Historically, PacifiCorp has had market-based rate ("MBR") authority for wholesale sales in all BAAs, including the BAAs operated by Nevada Power and Sierra Pacific. However, on December 19, 2013, MidAmerican completed its previously announced merger of NV Energy, Inc. ("NVE"), the parent company of Nevada Power and Sierra Pacific, and Silver Merger Sub, Inc., a subsidiary of MidAmerican (the "NVE Merger"). The NVE Merger was approved by the Commission under Section 203 of the Federal Power Act by order dated December 19, 2013.[3] Following the NVE Merger, NVE became an indirect wholly owned subsidiary of MidAmerican and PacifiCorp became affiliated with each of Nevada Power and Sierra Pacific. Neither Nevada Power nor Sierra Pacific has market-based rate authority for wholesale sales within its own BAA, and each of the NVE Utilities has restrictions in its own MBR tariff to mitigate market-based rate sales in its own BAA. Accordingly, PacifiCorp filed amendments to its MBR Tariff on December 20, 2013, to adopt restrictions on market-based rate sales in the NVE Utilities' BAAs (the "Mitigated Areas").[4]

Once PacifiCorp's MBR Tariff amendments are approved by the Commission, PacifiCorp will not have market-based rate authority for wholesale sales within the Mitigated Areas of its new affiliates Nevada Power and Sierra Pacific. Furthermore, effective on the closing of the merger, PacifiCorp is no longer making MBR sales to Nevada Power and Sierra Pacific under its MBR Tariff. The CB Rate Schedule will allow PacifiCorp the opportunity to make short-term wholesale sales to Nevada Power, Sierra Pacific, and other entities within the Mitigated Areas under the WSPP Agreement, capped at a cost-based rate ceiling.

VI. BASIS FOR CB RATE SCHEDULE

The CB Rate Schedule would apply to voluntary, short-term (less than one year) wholesale sales of power. It would allow PacifiCorp to negotiate rates for short-term transactions up to the ceiling rates set forth therein. The Commission has held that sellers have

---

[3] *See Silver Merger Sub, Inc., et al.*, 145 FERC ¶ 61,261 (2013) ("NVE Merger Order").

[4] *See MidAmerican Energy Co., et al.*, Docket No. ER14-725-000, *et al.*, Amendments to Market-Based Rate Tariffs (filed Dec. 20, 2013).

flexibility in designing ceiling rates under cost-based tariffs.[5] The rate cap proposed under the CB Rate Schedule includes a capacity (demand) charge calculated using a well-established methodology – the *Units Most Likely To Participate* stacking methodology. The demand rate cap is accompanied by an energy charge of up to 110 percent of PacifiCorp's variable cost, which is the standard energy charge for cost-based rate caps of this nature.

The rate schedule, rate design and cost justification for the CB Rate Schedule is consistent with similar cost-based rate tariffs (and associated evidentiary submissions) accepted for filing by the Commission.[6] The CB Rate Schedule reflects the Commission's longstanding practice of permitting cost-based (cost-justified) rate ceilings that include a contribution to seller's fixed costs for transactions of less than one year.[7]

---

5 *See e.g., Illinois Power Co.,* 57 FERC ¶ 61,213, at p. 61,699 (1991) ("Illinois Power") (explaining that the Commission's "approach to pricing of off-system sales is not that inflexible. Many pricing structures for off-system sales are acceptable."); *Consumers Energy Co.,* 80 FERC ¶ 61,283, at p. 62,009 (1997) (citing *Illinois Power*); *Detroit Edison Co.,* 78 FERC ¶ 61,149, at p. 61,628 (1997) (citing *Illinois Power*).

6 *See Westar Energy, Inc.*, Letter Order in Docket No. ER11-3233-000 (issued May 26, 2011) (accepting cost-based rate schedule for Schedule Q of the WSPP Agreement); *Nevada Power Co. and Sierra Pacific Power Co.*, 133 FERC ¶ 61,005 (2010) and *Nevada Power Co.*, Letter Order in Docket No. ER11-1832-000 (issued Nov. 23, 2010) (accepting cost-based rate schedule for Schedule Q of the WSPP Agreement). *See also Arizona Public Service Co.*, Letter Order in Docket Nos. ER07-23-000 and ER07-23-001 (issued Dec. 6, 2006) (accepting cost-based rate schedule for Schedule Q of the WSPP Agreement); *Carolina Power & Light Co.*, 113 FERC ¶ 61,130, P 23 (2005) ("CP&L's proposal to base its capacity ceiling rates for short-term power sales, including sales of one week or less, on the embedded costs of the CP&L units that are most likely to be used to provide the service is sufficiently supported and consistent with Commission precedent); *MidAmerican Energy Co.*, 114 FERC ¶ 61,280, PP 15, 18 (2006) (mandating cost-based rates), 117 FERC ¶ 61,178 (approving cost-based rates); *Duke Power, a Division of Duke Energy Corporation*, 113 FERC ¶61,192 (2005), 115 FERC ¶ 61,042 (2006); *AEP Power Marketing, Inc.*, et al., 112 FERC ¶ 61,047, 113 FERC ¶ 63,027 (2005), and Letter Order in Docket Nos. ER96-2495-026, et seq.; and *Southern Energy Services, Inc.*, 125 FERC ¶ 61,393 (2008).

7 *See, e.g., Western Systems Power Pool*, 122 FERC ¶ 61,139, at P 31 (2008). *See also Detroit Edison Co.,* 78 FERC ¶ 61,149, at pp. 61,268-69 (accepting tariff permitting rate negotiations under cost-based ceilings provided for demand and energy charges for hourly, daily, weekly, and monthly transactions); *Illinois Power,* 57 FERC ¶ 61,213, at p. 61,699 (explaining that "the Commission allows utilities to include in their rates an amount above incremental costs to provide a contribution to fixed costs. Utilities use this margin to reduce the rates of system customers who have already paid the costs of the generating resources."); *Florida Power & Light Co.,* 33 FERC ¶ 61,116, at p. 61,248 (1985) (explaining that "[t]he Commission will generally permit rates for coordination services to recover, in addition to variable costs, an amount up to the contribution to fixed costs that would have been made by requirements customers using the same facilities."); *Wisconsin Public Service Corp.,* 25 FERC ¶ 61,101, at p. 61,325 (1983) (concluding that while interruptible loads do not require "capacity additions, they nevertheless benefit from the existing capacity and should pay a portion of its costs.")

VII. SUMMARY OF SERVICES, RATES, AND CHARGES

The CB Rate Schedule for PacifiCorp is attached hereto as Attachment A. Service under the CB Rate Schedule is voluntary and will be available to wholesale customers located within the Mitigated Areas. Any agreement under the proposed CB Rate Schedule would be limited by its terms to transactions with a term of less than one year. The CB Rate Schedule would permit PacifiCorp to charge rates for short-term transactions up to a ceiling rate. The ceiling rate in the CB Rate Schedule is the sum of a demand charge, an energy charge, and transmission expenses incurred directly in connection with a transaction.

A. Demand Component of Rate

The demand component of the ceiling rate in the CB Rate Schedule is determined using the *Units Most Likely to Participate Methodology* (Attachment B).

The Fixed Charge Rate developed for PacifiCorp (Attachment B) uses the FERC standard methodology and 2012 actual costs primarily from PacifiCorp's FERC Form 1, as shown in Attachment B. The Rate of Return on Equity ("ROE") employed in the capital structure is 9.8%. This ROE is a system-weighted average of the ROEs approved and authorized by the six state utility commissions that regulate PacifiCorp, as shown in Attachment B. The use of this ROE is appropriate for this filing and will help to expedite the review and approval process and eliminate the need to undertake a costly ROE study. Other data used to develop the rate comes primarily from PacifiCorp's FERC Form 1.

For the *Units Most Likely to Participate Methodology*, the demand component of the ceiling rate in the CB Rate Schedule is based on the weighted cost of the PacifiCorp generation resources that are deemed likely to participate in the sales transactions, as established pursuant to the Commission's well-established methodology. To determine these "likely resources," PacifiCorp performed a "stacking analysis" under which generating resources are stacked in ascending order based on fuel costs per MWh. The resources located in the stack between the minimum and maximum monthly PacifiCorp peak loads are selected as the likely resources.

The total annual cost (in $/kW) of each likely resource was then calculated by applying a fixed charge rate to the resource's installed costs per kW, and adding the actual fixed operation and maintenance expenses per kW for each resource. The available capacity for each likely resource was determined by subtracting the resource's capacity factor, or "Plant Factor," from its availability factor and multiplying by the resource's nameplate capacity. The annual charges for each of the likely resources are weighted by the amount of available capacity from each resource to arrive at the total demand charge.[8]

---

[8] For purchased resources, the purchased capacity (kW) was used as the nameplate capacity, the energy charges per MWh were used to include the resource in the stack, and the demand charges per kW were used as the total annual cost in $/kW.

The calculation details and cost data supporting the development of the fixed charge rate and the weighted costs of the selected units-most-likely are provided in Attachment B of this filing and are consistent with the Commission's stack analysis calculation spreadsheet available on the Commission's website.[9] The data used in Attachment B are actual costs that come primarily from PacifiCorp's 2012 FERC Form 1, as shown in Attachment B.

B. Energy Component of Rate

The energy component of the ceiling rate is based on incremental cost principles and provides compensation for out-of-pocket System Incremental Costs that would not have otherwise been incurred, plus a 10 percent adder for difficult-to-quantify costs.[10]

System Incremental Costs means all reasonably forecasted costs of such power and/or energy and which otherwise would not have been incurred by PacifiCorp including, but not limited to, costs associated with fuel, labor, variable operation and maintenance, start-up, shut-down, fuel handling, taxes or other similar government impositions, regulatory commission charges, emission allowances, and other environmental compliance costs.

If PacifiCorp enters into purchased power transactions specifically for the purpose of reselling such power hereunder, the rates shall not exceed the sum of the following:

(i) PacifiCorp's out-of-pocket costs of purchasing such capacity and/or energy, including all related charges incurred for transmission service, ancillary services, transmission losses, and any applicable taxes or other similar governmental impositions; and

(ii) $1.00 per megawatt-hour multiplied by the total megawatt hours scheduled.

C. Transmission Component of Rate

The transmission component reflects a pass-through of transmission service charges directly incurred in connection with a given transaction. It includes all charges incurred for transmission service, ancillary services, and transmission losses.

D. Summary of Rate Components

---

[9] *See* Stacking of Generating Units to Determine the Units Likely to Participate in Short Term Power Sales, *available at* http://www.ferc.gov/industries/electric/gen-info/mbr.asp (under "Quick Links," follow "Blank Stack Analysis" hyperlink).

[10] The Commission has consistently recognized that the 10 percent adder provides for "recovery of difficult-to-quantify costs for services that are provided on an intermittent basis." *MidAmerican Energy Co.*, 114 FERC ¶ 61,280, at P 37 & n. 36 (2006) (citing *PacifiCorp*, 54 FERC ¶ 61,296, at p. 61,853, *reh'g denied*, 55 FERC ¶ 61,461 (1991)).

In summary, the proposed ceiling rates for sales from PacifiCorp's generating resources under the CB Rate Schedule (as set forth in Attachment A) are the sum of:

(i) a demand charge associated with the term of the transaction;

(ii) 110 percent of the System Incremental Costs of a transaction; and

(iii) out-of-pocket transmission expenses, including all charges incurred for transmission service, ancillary services, and transmission losses,

The hourly and daily demand charges are based on a sixteen-hour day and a five-day week. As a result, the maximum hourly and daily demand components are subject to the required daily and weekly rate caps.[11]

The proposed ceiling rate when power is purchased for resale under the CB Rate Schedule (as set forth in Attachment A) is the sum of:

(i) out-of-pocket costs of purchasing such capacity and/or energy plus a $1.00 per megawatt-hour adder; and

(ii) out-of-pocket transmission expenses, including all charges incurred for transmission service, ancillary services, and transmission losses.

VIII. WAIVER OF FILING REQUIREMENTS

To the extent that this filing fails to contain any information otherwise required for technical compliance with the Commission's regulations, PacifiCorp respectfully requests that compliance with such regulations be waived.

IX. CONCLUSION

The proposed CB Rate Schedule (including the ceiling rates summarized above) have been developed in accordance with Commission precedent and are consistent in all material respects with comparable arrangements that have been accepted by the Commission as just and reasonable. Accordingly, PacifiCorp respectfully requests that the Commission accept the CB Rate Schedule, without suspension, hearing, condition, or modification, to be effective as of December 25, 2013.

---

[11] It is not possible at this time to estimate with the requisite degree of accuracy the quantity of service or the resulting revenues that would be associated with this initial rate filing, and as a result no such estimates are provided with the attached submission. *See* 18 C.F.R. § 35.12(b)(1).

Thank you for your consideration of this matter. If you have any questions regarding the instant filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

William R. Hollaway, Ph.D.
Brandon C. Johnson
Jennifer C. Mansh
GIBSON DUNN & CRUTCHER, LLC
1050 Connecticut Ave., NW
Washington, DC 20036-5306

Counsel for PacifiCorp

Enclosures

ATTACHMENT A

Proposed New
Cost-Based Rate Schedule for PacifiCorp

COST-BASED RATE SCHEDULE
FOR
PACIFICORP

Determination of Ceiling Rates Applicable to Cost-Based Sales Made by PacifiCorp

1. The following rates shall be applicable to any cost-based sale of power and/or energy made by PacifiCorp (1) pursuant to the applicable terms and conditions of the WSPP Agreement, including under Service Schedule A (Economy Energy Service), Service Schedule B (Unit Commitment Service), and Service Schedule C (Firm Capacity/Energy Sale or Exchange Service), (2) at a delivery point located within the Nevada Power Company balancing authority area or the Sierra Pacific Power Company balancing authority area, and (3) for a term of less than one year.

2. The rates for any cost-based power and/or energy sale made by PacifiCorp pursuant to the applicable terms and conditions of the WSPP Agreement from PacifiCorp's generating resources shall not exceed the following:

(i) Maximum Demand Charge:

The Maximum Demand Charge shall be capped using the following methodology:

Units Most Likely To Participate Methodology	
Monthly	Up to $11,317/MW
Weekly	Up to $2,612/MW
Daily	Up to $522/MW, provided, however, that the Daily rate of $522/MW shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2,612/MW.
Hourly	Up to $32.64/MW, provided, however, that the hourly rate of $32.64/MW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum daily demand charge of $522/MW, and also not exceed the product of the number of kilowatts sold for a week multiplied by the maximum weekly demand charge of $2,612/MW.

(ii) Energy Charge of 100% of SIC, plus up to 10% of SIC; and

(iii) All charges incurred for transmission service, ancillary services, and transmission losses.

3. If PacifiCorp enters into a purchased power transaction specifically for the purpose of reselling such power hereunder, the rates shall not exceed the sum of the following:

(i) PacifiCorp's out-of-pocket costs of purchasing such capacity and/or energy, including all related charges incurred for transmission service, ancillary services, transmission losses and any applicable taxes or other similar governmental impositions; and

(ii) $1.00 per megawatt-hour multiplied by the total megawatt-hours scheduled.

4. System Incremental Costs ("SIC") means all reasonably forecasted costs of such power and/or energy and which otherwise would not have been incurred by PacifiCorp including, but not limited to, costs associated with fuel, labor, variable operation and maintenance, start-up, shut-down, fuel handling, taxes or other similar governmental impositions, regulatory commission charges, emission allowances and other environmental compliance costs.

5. Purchasers in cost-based transactions shall also be responsible for any taxes, purchased power costs, and for any other costs incurred by PacifiCorp in fulfilling its obligations for the provision of power and/or energy under the WSPP Agreement, which cost would otherwise not have been incurred, had such service not been provided.

ATTACHMENT B

Cost Justification Schedules

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

III) Calculate weighted annual cost and rates for the participating generating plants -- FERC Stack.

(1) Plant No.	(2) Plant	EAF[1]	(3) Available Capacity[2]	(4) Cumulative Avail. Cap.	(5) Expected Ptcp.	(6) Installed Cost/kW	(7) Operation and Maintenance	(8) Fixed Charge Rate (FCR = 1 for PP)	(9) Weighted Annual Demand Cost
1	Cholla	89%	61,597	61,597	0.1037	$ 1,275	$ 38.98	0.1139	$ 21.35
2	Jim Bridger	88%	298,816	360,413	0.5030	$ 692	$ 13.44	0.1139	$ 52.91
3	Portland General Electric Company	69%	-	360,413	-	$ -	$ -	1.0000	$ -
4	Hayden	90%	17,138	377,551	0.0288	$ 1,056	$ 33.91	0.1139	$ 4.97
5	J Bar 9 Ranch, Inc.	8%	-	377,551	-	$ -	$ -	1.0000	$ -
6	Tri-State Generation and Transmission Association, Inc.	84%	7,968	385,519	0.0134	$ 254	$ -	1.0000	$ 4.06
7	Oregon State University	1%	-	385,519	-	$ -	$ -	1.0000	$ -
8	Public Utility District No. 1 of Douglas County (s)	27%	-	385,519	-	$ -	$ -	1.0000	$ -
9	Tesoro Refining and Marketing Company	11%	-	385,519	-	$ -	$ -	1.0000	$ -
10	Kennecott Utah Copper LLC	16%	-	385,519	-	$ -	$ -	1.0000	$ -
11	Wasatch Integrated Waste Management District	7%	-	385,519	-	$ -	$ -	1.0000	$ -
12	Rock River 1, LLC	31%	-	385,519	-	$ -	$ -	1.0000	$ -
13	Yakima-Tieton Irrigation District	49%	-	385,519	-	$ -	$ -	1.0000	$ -
14	Harold Foster & Robert Walker	49%	-	385,519	-	$ -	$ -	1.0000	$ -
15	Sunnyside Cogeneration Associates	92%	-	385,519	-	$ -	$ -	1.0000	$ -
16	US Magnesium LLC	41%	-	385,519	-	$ -	$ -	1.0000	$ -
17	Ballard Hog Farms Inc.	68%	-	385,519	-	$ -	$ -	1.0000	$ -
18	RES Ag - Oak Lea LLC	68%	-	385,519	-	$ -	$ -	1.0000	$ -
19	City of Portland, Portland Water Bureau	19%	-	385,519	-	$ -	$ -	1.0000	$ -
20	Hermiston	94%	130,650	516,168	0.2199	$ 617	$ 33.22	0.1139	$ 24.29
21	Idaho Falls, City of	35%	-	516,168	-	$ -	$ -	1.0000	$ -
22	Hermiston Generating Company, L.P.	94%	77,957	594,125	0.1312	$ 162	$ -	1.0000	$ 22.67
23	Roseburg Forest Products Company	14%	-	594,125	-	$ -	$ -	1.0000	$ -

Subtotal Weighted Annual Demand Cost	$ 130.25	
Losses (4.26%)	$ 5.55	
Total Weighted Annual Demand Cost	$ 135.80	
Annual Demand Charge	$ 135,801	$/MW
Monthly Demand Charge	$ 11,317	$/MW
Weekly Demand Charge	$ 2,612	$/MW
Daily Demand Charge	$ 522	$/MW
Hourly Demand Charge	$ 32.64	$/MW

Note 1 - 5-year average EAF of PacifiCorp owned generating resources from 2008 to 2012 PacifiCorp Equivalent Availability reports. EAF of dispatchable PPAs from NERC Generating Unit Statistical Brochu
EAF of non-dispatchable resources is equal to the Plant Factor, resulting in zero available capacity.

Note 2 - Available capacity is determined as (EAF - PF) * Name Plate Capacity of each unit. The sum of the max nameplate capacities of the units with Available Capacity is equal to 2,568 MW, while the band between the minimum and the maximum monthly peak loads, used for calculating the 'Units Most Likely' list, is 2,494 total MW.

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

Min Monthly Peak	7337
Max Monthly Peak	9831

I) Stacking of generating plants according to fuel expense [col. (7)].

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)	(12)
Plant No.	Plant	Plant Type Plant Type[1]	Total Cost (p402,17)[2,6]	Fuel Expense dollars (p402/3, 20)[3,6]	Generation kWh (p402/3, 12)[4]	Fuel Expense $/kWh (5) / (6)	Max Name Plate Rating kW (p402/3, 5)		Accum. Name Plate Capacity kW	Name Plate $/kW (4) / (8)	Plant Factor	Participating Plant (FERC Stack)[5]
1	Ashton	H	35,512,686	-	1,903,000	-	6,700		6,700	5,300	0.0324	0
2	Bend	H	1,335,093	-	3,344,000	-	1,110		7,810	1,203	0.3439	0
3	Big Fork	H	7,373,547	-	33,426,000	-	4,150		11,960	1,777	0.9195	0
4	Black Cap	Solar	74,986	-	585,000	-	2,000	8	13,960	37	0.0334	0
5	Blundell	G	120,495,392	-	268,542,000	-	38,100		52,060	3,163	0.8046	0
6	Camas Co-Gen	S	34,450,540	-	78,036,000	-	61,500		113,560	560	0.1448	0
7	Clearwater No. 1	H	6,997,199	-	50,701,000	-	15,000		128,560	466	0.3859	0
8	Clearwater No. 2	H	18,503,724	-	54,153,000	-	26,000		154,560	712	0.2378	0
9	Copco No. 1	HS	9,941,054	-	85,352,000	-	20,000		174,560	497	0.4872	0
10	Copco No. 2	H	16,063,008	-	109,416,000	-	27,000		201,560	595	0.4626	0
11	Cutler	HS	30,236,233	-	50,408,000	-	30,000		231,560	1,008	0.1918	0
12	Dunlap Ranch 1	W	239,618,218	-	387,973,000	-	111,000	8	342,560	2,159	0.3990	0
13	Eagle Point	H	1,861,057	-	17,897,000	-	2,810		345,370	662	0.7271	0
14	East Side	H	1,991,695	-	-	-	3,200		348,570	622	-	0
15	Fall Creek	H	1,395,011	-	10,432,000	-	2,200		350,770	634	0.5413	0
16	Fish Creek	H	15,759,774	-	42,829,000	-	11,000		361,770	1,433	0.4445	0
17	Foote Creek	W	36,515,908	-	85,137,000	-	32,150	8	393,920	1,136	0.3023	0
18	Fountain Green	H	597,630	-	-	-	160		394,080	3,735	-	0
19	Glenrock	W	201,049,749	-	314,476,000	-	99,000	8	493,080	2,031	0.3626	0
20	Glenrock III	W	87,388,684	-	119,142,000	-	39,000	8	532,080	2,241	0.3487	0
21	Goodnoe Hills	W	183,027,132	-	221,156,000	-	94,000	8	626,080	1,947	0.2686	0
22	Grace	HS	17,433,531	-	82,593,000	-	33,000		659,080	528	0.2857	0
23	Granite	H	5,234,569	-	6,406,000	-	2,000		661,080	2,617	0.3656	0
24	GrowPro, Inc.	PP	-	12	-	-	76	7 8	661,156	-	-	0
25	Gunlock	H	683,045	-	1,489,000	-	750		661,906	911	0.2266	0
26	High Plains	W	219,515,480	-	315,879,000	-	99,000	8	760,906	2,217	0.3642	0
27	Iron Gate	HS	24,399,794	-	100,757,000	-	18,000		778,906	1,356	0.6390	0
28	JC Boyle	HS	34,068,973	-	240,436,000	-	97,980		876,886	348	0.2801	0
29	Last Chance	H	2,809,625	-	3,833,000	-	1,730		878,616	1,624	0.2529	0
30	Leaning Juniper 1	W	175,690,243	-	190,905,000	-	100,500	8	979,116	1,748	0.2168	0
31	Lemolo No. 1	HS	24,101,992	-	166,546,000	-	31,990		1,011,106	753	0.5943	0
32	Lemolo No. 2	H	48,897,523	-	207,037,000	-	38,500		1,049,606	1,270	0.6139	0
33	Marengo	W	239,478,535	-	358,669,000	-	140,400	8	1,190,006	1,706	0.2916	0
34	Marengo II	W	129,148,793	-	177,552,000	-	70,200	8	1,260,206	1,840	0.2887	0
35	McFadden Ridge I	W	56,961,391	-	94,789,000	-	28,500	8	1,288,706	1,999	0.3797	0
36	Merwin	HS	83,539,418	-	657,225,000	-	136,000		1,424,706	614	0.5517	0
37	Olmsted	H	232,720	-	19,185,000	-	10,300		1,435,006	23	0.2126	0
38	Oneida	HS	13,917,934	-	32,971,000	-	30,000		1,465,006	464	0.1255	0
39	Oregon Institute of Technology	PP	-	-	-	-	280	7 8	1,465,286	-	-	0
40	Paris	H	432,494	-	2,434,000	-	720		1,466,006	601	0.3859	0
41	Pioneer	H	11,000,932	-	15,091,000	-	5,000		1,471,006	2,200	0.3445	0
42	Prospect No. 1	H	2,531,526	-	20,393,000	-	3,760		1,474,766	673	0.6191	0
43	Prospect No. 2	H	40,002,547	-	238,047,000	-	32,000		1,506,766	1,250	0.8492	0
44	Prospect No. 3	H	8,343,868	-	37,518,000	-	7,200		1,513,966	1,159	0.5948	0
45	Prospect No. 4	H	2,365,524	-	3,833,000	-	1,000		1,514,966	2,366	0.4376	0
46	Rolling Hills	W	201,829,100	-	292,022,000	-	99,000	8	1,613,966	2,039	0.3367	0
47	Sand Cove	H	933,722	-	1,326,000	-	800		1,614,766	1,167	0.1892	0

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

Min Monthly Peak	7337
Max Monthly Peak	9831

I) Stacking of generating plants according to fuel expense [col. (7)].

(1) Plant No.	(2) Plant	(3) Plant Type Plant Type[1]	(4) Total Cost (p402,17)[2,6]	(5) Fuel Expense dollars (p402/3, 20)[3,6]	(6) Generation kWh (p402/3, 12)[4]	(7) Fuel Expense $/kWh (5) / (6)	(8) Max Name Plate Rating kW (p402/3, 5)		(9) Accum. Name Plate Capacity kW	(10) Name Plate $/kW (4) / (8)	(11) Plant Factor	(12) Participating Plant (FERC Stack)[5]
48	Seven Mile Hill	W	200,758,039	-	342,192,000	-	99,000	[8]	1,713,766	2,028	0.3946	0
49	Seven Mile Hill II	W	42,010,209	-	72,558,000	-	19,500	[8]	1,733,266	2,154	0.4248	0
50	Slide Creek	H	25,929,627	-	96,627,000	-	18,000		1,751,266	1,441	0.6128	0
51	Soda	HS	14,970,992	-	20,023,000	-	14,000		1,765,266	1,069	0.1633	0
52	Soda Springs	HS	92,172,529	-	50,541,000	-	11,000		1,776,266	8,379	0.5245	0
53	St. Anthony	H	1,337,279	-	-	-	500		1,776,766	2,675	-	0
54	Stairs	H	1,626,626	-	4,803,000	-	1,000		1,777,766	1,627	0.5483	0
55	Swift No. 1	HS	146,204,068	-	809,468,000	-	240,000		2,017,766	609	0.3850	0
56	Toketee	HS	17,907,710	-	263,788,000	-	42,500		2,060,266	421	0.7085	0
57	Veyo	H	893,125	-	1,030,000	-	500		2,060,766	1,786	0.2352	0
58	Wallowa Falls	H	2,887,127	-	5,611,000	-	1,100		2,061,866	2,625	0.5823	0
59	Weber	H	2,962,109	-	15,100,000	-	3,850		2,065,716	769	0.4477	0
60	West Side	H	468,574	-	1,810,000	-	600		2,066,316	781	0.3444	0
61	Yale	HS	60,995,100	-	702,744,000	-	134,000		2,200,316	455	0.5987	0
62	Wyodak	S	445,288,396	19,828,875	1,990,902,000	0.010	289,700		2,490,016	1,537	0.7845	0
63	Dave Johnston	S	995,934,041	58,092,617	4,906,422,000	0.012	816,800		3,306,816	1,219	0.6857	0
64	Public Utility District No. 1 of Douglas County	PP	-	3,263,025	245,509,000	0.013	56,000		3,362,816	-	0.5005	0
65	Huntington	S	824,779,006	95,307,621	6,744,160,000	0.014	996,000		4,358,816	828	0.7730	0
66	Colstrip	S	221,923,196	15,728,446	1,099,064,000	0.014	155,600		4,514,416	1,426	0.8063	0
67	Craig	S	175,413,982	22,290,729	1,344,729,000	0.017	172,100		4,686,516	1,019	0.8920	0
68	Grant PUD	PP	-	2,360,557	135,994,000	0.017	22,000	[8]	4,708,516	-	0.7057	0
69	Douglas County, Inc.	PP	-	177,038	10,143,000	0.017	6,250	[7,8]	4,714,766	-	0.1853	0
70	Hunter Unit No. 2	S	313,089,099	31,803,729	1,820,865,000	0.017	294,500		5,009,266	1,063	0.7058	0
71	Hunter Unit No. 1	S	387,041,540	53,314,799	2,904,129,000	0.018	457,700		5,466,966	846	0.7243	0
72	Hunter Unit No. 3	S	532,972,587	52,721,821	2,849,599,000	0.019	495,600		5,962,566	1,075	0.6564	0
73	Deseret Generation & Transmission Cooperative	PP	18,968,825	13,026,114	679,693,000	0.019	100,000		6,062,566	190	0.7759	0
74	Carbon	S	132,570,769	25,897,410	1,287,240,000	0.020	188,600		6,251,166	703	0.7791	0
75	Lacomb Irrigation District	PP	-	75,330	3,642,000	0.021	1,180	[7,8]	6,252,346	-	0.3523	0
76	Naughton	S	768,007,014	105,801,044	5,056,959,000	0.021	707,200		6,959,546	1,086	0.8163	0
77	Cholla	S	527,862,468	59,141,031	2,703,937,000	0.022	414,000		7,373,546	1,275	0.7456	1
78	Jim Bridger	S	1,068,978,479	203,151,812	9,250,668,000	0.022	1,545,100		8,918,646	692	0.6835	1
79	Portland General Electric Company	PP	-	270,000	12,024,000	0.022	2,000	[7,8]	8,920,646	-	0.6863	1
80	Hayden	S	85,988,054	11,686,571	488,619,000	0.024	81,400		9,002,046	1,056	0.6852	1
81	J Bar 9 Ranch, Inc.	PP	-	1,607	67,000	0.024	100	[7,8]	9,002,146	-	0.0765	1
82	Tri-State Generation and Transmission Association, Inc	PP	6,351,000	2,894,270	113,858,000	0.025	25,000		9,027,146	254	0.5199	1
83	Oregon State University	PP	-	9,984	386,000	0.026	6,500	[7,8]	9,033,646	-	0.0068	1
84	Public Utility District No. 1 of Douglas County (s)	PP	-	2,367,669	88,266,000	0.027	38,000	[7,8]	9,071,646	-	0.2652	1
85	Tesoro Refining and Marketing Company	PP	-	845,991	25,014,000	0.034	25,000	[7,8]	9,096,646	-	0.1142	1
86	Kennecott Utah Copper LLC	PP	-	1,921,698	56,610,000	0.034	39,340	[7,8]	9,135,986	-	0.1643	1
87	Wasatch Integrated Waste Management District	PP	-	32,530	948,000	0.034	1,600	[7,8]	9,137,586	-	0.0676	1
88	Rock River 1, LLC	PP	-	4,793,270	135,098,000	0.035	49,000	[7,8]	9,186,586	-	0.3147	1
89	Yakima-Tieton Irrigation District	PP	17,281	251,416	6,864,000	0.037	1,600	[8]	9,188,186	11	0.4897	1
90	Harold Foster & Robert Walker	PP	-	31,620	857,000	0.037	200	[7,8]	9,188,386	-	0.4892	1
91	Sunnyside Cogeneration Associates	PP	10,621,050	15,945,696	418,433,000	0.038	52,000	[8]	9,240,386	204	0.9186	1
92	US Magnesium LLC	PP	-	5,154,841	128,736,000	0.040	36,000	[7,8]	9,276,386	-	0.4082	1
93	Ballard Hog Farms Inc.	PP	302	2,431	60,000	0.041	10	[8]	9,276,396	30	0.6849	1
94	RES Ag - Oak Lea LLC	PP	-	41,694	1,015,000	0.041	170	[7,8]	9,276,566	-	0.6816	1

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

Min Monthly Peak	7337
Max Monthly Peak	9831

I) Stacking of generating plants according to fuel expense [col. (7)].

(1) Plant No.	(2) Plant	(3) Plant Type Plant Type[1]	(4) Total Cost (p402,17)[2,6]	(5) Fuel Expense dollars (p402/3, 20)[3,6]	(6) Generation kWh (p402/3, 12)[4]	(7) Fuel Expense $/kWh (5) / (6)	(8) Max Name Plate Rating kW (p402/3, 5)			(9) Accum. Name Plate Capacity kW	(10) Name Plate $/kW (4) / (8)	(11) Plant Factor	(12) Participating Plant (FERC Stack)[5]
95	City of Portland, Portland Water Bureau	PP	-	2,015	49,000	0.041	30	7	8	9,276,596	-	0.1865	1
96	Hermiston	GT	172,412,531	47,631,026	1,149,724,000	0.041	279,600			9,556,196	617	0.4694	1
97	Idaho Falls, City of	PP	-	2,900,829	68,969,000	0.042	22,500	7	8	9,578,696	-	0.3499	1
98	Hermiston Generating Company, L.P.	PP	36,089,626	48,441,607	1,146,891,000	0.042	223,000			9,801,696	162	0.5871	1
99	Roseburg Forest Products Company	PP	-	1,559,074	36,743,000	0.042	30,000	7	8	9,831,696	-	0.1398	1
100	Shoshone Irrigation District	PP	188,293	434,781	10,185,000	0.043	2,600		8	9,834,296	72	0.4472	0
101	Draper Irrigation Company	PP	-	2,698	63,000	0.043	511	7	8	9,834,807	-	0.0141	0
102	Eurus Combine Hills I, LLC	PP	-	4,922,879	108,721,000	0.045	41,000	7	8	9,875,807	-	0.3027	0
103	CER Generation II, LLC	PP	5,208,000	12,478,140	272,791,000	0.046	200,000			10,075,807	26	0.1557	0
104	United States Air Force at Hill Air Force Base	PP	-	654,845	14,227,000	0.046	2,457	7	8	10,078,264	-	0.6610	0
105	Cottonwood Hydro, LLC	PP	-	141,210	2,994,000	0.047	1,110	7	8	10,079,374	-	0.3079	0
106	Weber County	PP	-	238,529	5,022,000	0.047	950	7	8	10,080,324	-	0.6035	0
107	Simplot Phosphates LLC	PP	494,000	3,991,543	79,938,000	0.050	10,000		8	10,090,324	49	0.9125	0
108	Meadow Creek Project Company LLC	PP	-	1,509,603	29,683,000	0.051	119,700	7	8	10,210,024	-	0.0283	0
109	C Drop Hydro, LLC	PP	-	135,034	2,619,000	0.052	1,100	7	8	10,211,124	-	0.2718	0
110	Lake Side	GT	356,733,564	149,162,596	2,890,938,000	0.052	591,300			10,802,424	603	0.5581	0
111	Roseburg LFG Energy, LLC	PP	-	592,655	11,411,000	0.052	1,600	7	8	10,804,024	-	0.8141	0
112	Currant Creek	GT	373,369,290	111,149,193	2,132,523,000	0.052	566,900			11,370,924	659	0.4294	0
113	Stahlbush Island Farms, Inc.	PP	-	428,422	8,213,000	0.052	1,600	7	8	11,372,524	-	0.5860	0
114	Cameron A. Curtiss	PP	-	5,284	101,000	0.052	75	7	8	11,372,599	-	0.1537	0
115	Duane Wiggins Hydro, Inc.	PP	-	787	15,000	0.052	20	7	8	11,372,619	-	0.0856	0
116	Spanish Fork Wind Park 2, LLC	PP	-	2,555,950	48,703,000	0.052	18,900	7	8	11,391,519	-	0.2942	0
117	O.J. Power Company	PP	-	36,019	684,000	0.053	2,260	7	8	11,393,779	-	0.0345	0
118	City of Preston Idaho	PP	-	135,558	2,557,000	0.053	400	7	8	11,394,179	-	0.7297	0
119	Lower Valley Energy, Inc.	PP	-	58,928	1,107,000	0.053	760	7	8	11,394,939	-	0.1663	0
120	Commercial Energy Management Inc.	PP	-	100,966	1,877,000	0.054	900	7	8	11,395,839	-	0.2381	0
121	Dry Creek LLC	PP	-	552,993	10,268,000	0.054	4,000	7	8	11,399,839	-	0.2930	0
122	Jake Amy	PP	-	94,429	1,724,000	0.055	490	7	8	11,400,329	-	0.4016	0
123	Chehalis	GT	340,450,692	47,149,887	849,938,000	0.055	593,300			11,993,629	574	0.1635	0
124	Mountain Wind Power, LLC	PP	-	9,522,713	171,518,000	0.056	60,900	7	8	12,054,529	-	0.3215	0
125	Mink Creek Hydro LLC	PP	-	493,901	8,861,000	0.056	3,180	7	8	12,057,709	-	0.3181	0
126	Wolverine Creek Energy, LLC	PP	-	10,027,514	178,431,000	0.056	64,500	7	8	12,122,209	-	0.3158	0
127	Power County Wind Park North, LLC	PP	-	3,979,854	70,382,000	0.057	22,500	7	8	12,144,709	-	0.3571	0
128	Georgetown Irrigation Company	PP	-	114,462	2,023,000	0.057	410	7	8	12,145,119	-	0.5633	0
129	Power County Wind Park South, LLC	PP	-	3,664,717	64,743,000	0.057	22,500	7	8	12,167,619	-	0.3285	0
130	Nicholson's Sunny Bar Ranch	PP	-	107,012	1,870,000	0.057	350	7	8	12,167,969	-	0.6099	0
131	Marsh Valley Hydro Electric Company	PP	-	292,280	5,083,000	0.058	1,780	7	8	12,169,749	-	0.3260	0
132	CDM Hydroelectric Company	PP	-	1,634,850	28,427,000	0.058	6,000	7	8	12,175,749	-	0.5408	0
133	Ingram Warm Springs Ranch Partnership	PP	-	70,730	1,224,000	0.058	950	7	8	12,176,699	-	0.1471	0
134	Birch Power Company, Inc.	PP	-	888,603	15,362,000	0.058	2,650	7	8	12,179,349	-	0.6618	0
135	Cargill, Incorporated	PP	-	292,708	4,946,000	0.059	1,700	7	8	12,181,049	-	0.3321	0
136	George DeRuyter & Sons Dairy	PP	14,014	416,932	6,710,000	0.062	800		8	12,181,849	18	0.9575	0
137	Evergreen BioPower, LLC	PP	-	2,158,175	34,659,000	0.062	10,000	7	8	12,191,849	-	0.3957	0
138	Middle Fork Irrigation District	PP	-	1,572,734	25,232,000	0.062	5,000	7	8	12,196,849	-	0.5761	0
139	Oregon Environmental Industries, LLC	PP	-	1,376,978	22,079,000	0.062	3,200	7	8	12,200,049	-	0.7876	0
140	Chevron U.S.A. Inc.	PP	-	2,894,381	45,768,000	0.063	17,000	7	8	12,217,049	-	0.3073	0
141	Three Buttes Windpower, LLC	PP	-	21,681,288	340,033,000	0.064	99,000	7	8	12,316,049	-	0.3921	0

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

Min Monthly Peak	7337
Max Monthly Peak	9831

I) Stacking of generating plants according to fuel expense [col. (7)].

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)	(11)	(12)
Plant No.	Plant	Plant Type Plant Type[1]	Total Cost (p402,17)[2, 6]	Fuel Expense dollars (p402/3, 20)[3, 6]	Generation kWh (p402/3, 12)[4]	Fuel Expense $/kWh (5) / (6)	Max Name Plate Rating kW (p402/3, 5)		Accum. Name Plate Capacity kW	Name Plate $/kW (4) / (8)	Plant Factor	Participating Plant (FERC Stack)[5]
142	Mountain Wind Power II, LLC	PP	-	14,574,484	227,793,000	0.064	79,800	7 8	12,395,849	-	0.3259	0
143	Farmers Irrigation District	PP	-	1,578,289	24,377,000	0.065	4,800	7 8	12,400,649	-	0.5797	0
144	Loyd Fery	PP	-	22,539	348,000	0.065	40	7 8	12,400,689	-	0.9932	0
145	Top of The World Wind Energy LLC	PP	-	43,898,356	665,128,000	0.066	200,200	7 8	12,600,889	-	0.3793	0
146	Ward Butte Windfarm, LLC	PP	-	1,194,858	17,718,000	0.067	6,600	7 8	12,607,489	-	0.3065	0
147	Oregon Trail Windfarm, LLC	PP	-	1,763,384	26,111,000	0.068	9,900	7 8	12,617,389	-	0.3011	0
148	Four Corners Windfarm, LLC	PP	-	1,926,532	28,521,000	0.068	10,000	7 8	12,627,389	-	0.3256	0
149	Sand Ranch Windfarm, LLC	PP	-	1,646,437	24,317,000	0.068	9,900	7 8	12,637,289	-	0.2804	0
150	Four Mile Canyon Windfarm, LLC	PP	-	1,758,543	25,965,000	0.068	10,000	7 8	12,647,289	-	0.2964	0
151	Pacific Canyon Windfarm, LLC	PP	-	1,344,769	19,839,000	0.068	8,250	7 8	12,655,539	-	0.2745	0
152	Wagon Trail, LLC	PP	-	520,842	7,682,000	0.068	3,300	7 8	12,658,839	-	0.2657	0
153	Big Top, LLC	PP	-	260,709	3,844,000	0.068	1,650	7 8	12,660,489	-	0.2659	0
154	Butter Creek Power, LLC	PP	-	888,593	13,093,000	0.068	4,950	7 8	12,665,439	-	0.3019	0
155	Lower Valley Energy, Inc.	PP	-	396,577	5,822,000	0.068	940	7 8	12,666,379	-	0.7070	0
156	Rough & Ready Lumber Company	PP	-	559,319	8,196,000	0.068	1,280	7 8	12,667,659	-	0.7310	0
157	Biomass One, L.P.	PP	-	8,725,321	127,571,000	0.068	30,000	7 8	12,697,659	-	0.4854	0
158	Mountain Energy, Inc.	PP	-	6,574	96,000	0.068	50	7 8	12,697,709	-	0.2192	0
159	Finley BioEnergy, LLC	PP	-	2,342,922	34,089,000	0.069	4,800	7 8	12,702,509	-	0.8107	0
160	Swalley Irrigation District	PP	-	145,570	2,115,000	0.069	1,000	7 8	12,703,509	-	0.2414	0
161	Threemile Canyon Wind I, LLC	PP	-	1,566,514	22,740,000	0.069	10,000	7 8	12,713,509	-	0.2596	0
162	City of Albany	PP	-	57,170	829,000	0.069	500	7 8	12,714,009	-	0.1893	0
163	Roush Hydro Inc.	PP	-	20,510	297,000	0.069	75	7 8	12,714,084	-	0.4521	0
164	City of Hurricane	PP	-	138,717	1,928,000	0.072	1,000	7 8	12,715,084	-	0.2201	0
165	Public Utility District No. 2 of Grant County	PP	104,746	4,234,461	58,852,000	0.072	14,000	8	12,729,084	7	0.4799	0
166	Bell Mountain Hydro, LLC	PP	-	76,989	1,027,000	0.075	290	7 8	12,729,374	-	0.4043	0
167	Thayn Hydro LLC	PP	83,116	231,688	2,768,000	0.084	300	8	12,729,674	277	1.0533	0
168	Central Oregon Irrigation District	PP	608,150	4,846,859	52,300,000	0.093	5,900	8	12,735,574	103	1.0119	0
169	Santiam Water Control District	PP	13,632	152,919	1,609,000	0.095	200	8	12,735,774	68	0.9184	0
170	The Town of the City of Buffalo	PP	23,310	185,095	1,888,000	0.098	200	8	12,735,974	117	1.0776	0
171	Gadsby Peakers	GT	80,657,121	9,415,092	94,391,000	0.100	181,100		12,917,074	445	0.0595	0
172	Slate Creek Hydro Company, Inc.	PP	120,921	844,985	7,970,000	0.106	2,400	8	12,919,474	50	0.3791	0
173	Falls Creek H.P. Limited Partnership	PP	255,074	2,197,882	19,554,000	0.112	3,600	8	12,923,074	71	0.6201	0
174	Deschutes Valley Water District	PP	567,894	3,232,576	28,734,000	0.113	5,800	8	12,928,874	98	0.5655	0
175	Sprague Hydro, LLC	PP	55,233	304,346	2,577,000	0.118	500	8	12,929,374	110	0.5884	0
176	Gadsby Steam	S	82,778,915	14,231,285	120,348,000	0.118	251,600		13,180,974	329	0.0546	0
177	Box Canyon Limited Partnership	PP	271,905	1,843,813	15,586,000	0.118	2,900	8	13,183,874	94	0.6135	0
178	Eagle Point Irrigation District	PP	45,865	423,858	3,574,000	0.119	800	8	13,184,674	57	0.5100	0
179	Douglas County	PP	83,226	905,218	7,179,000	0.126	800	8	13,185,474	104	1.0244	0
180	Ralphs Ranch, Inc.	PP	-	28,892	215,000	0.134	100	7 8	13,185,574	-	0.2454	0
181	Paul Luckey	PP	-	38,030	282,000	0.135	50	7 8	13,185,624	-	0.6438	0
182	City of Walla Walla	PP	138,980	1,986,857	13,637,000	0.146	2,000	8	13,187,624	69	0.7784	0
183	Solwatt LLC	PP	-	103,662	443,000	0.234	306	7 8	13,187,930	-	0.1653	0
184	Joseph Community Solar LLC	PP	-	159,880	667,000	0.240	422	7 8	13,188,352	-	0.1804	0
185	Black Hills	PP	300,000	204,302	10,000	20.430	100,000	8	13,288,352	3	0.0000	0

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

Min Monthly Peak	7337
Max Monthly Peak	9831

I) Stacking of generating plants according to fuel expense [col. (7)].

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Max Name	Accum.			
				Fuel Expense	Generation	Fuel Expense	Plate Rating	Name Plate	Name Plate	Plant	Participating
Plant	Plant	Plant Type	Total Cost	dollars	kWh	$/kWh	kW	Capacity	$/kW	Factor	Plant
No.		Plant Type[1]	(p402,17)[2,6]	(p402/3, 20)[3,6]	(p402/3, 12)[4]	(5) / (6)	(p402/3, 5)	kW	(4) / (8)		(FERC Stack)[5]

Note 1: Parenthetical letter designations are as follows; G = Geothermal, GT = Gas Turbines, H = Hydro, HS = Hydro Storage PP = Purchased Power Agreement, S = Steam, and W = Wind. Steam plants use coal, gas and/or oil for fuel, see Form 1 for details.

Note 2: Plant (Types) showing "PP" are from pages 327.x, column j.

Note 3: Plant (Types) showing "PP" are from pages 327.x, column k. Plant Numbers 180 and 181, Joseph Community Solar LLC and Solwatt LLC, Fuel Expense has been set at $230/MWh, as per their contracts

Note 4: Plant (Types) showing "PP" are from pages 327.x, column g.

Note 5: Insert a "1" next to the unit expected to participate. Power for "off-system sales" will only be provided after native load requirements are met.
reported on page 401b of Form 1. Load for PacifiCorp's combined system comes from its Load Report, Section IV, Total 401b Load. Participating plants will generally be those ranked above an Accumulated Name Plate Capacity that equals or exceeds the Minimum Peak shown below:
Min. Peak (MW) 7,337 Max. Peak (MW) 9,831; Min: FERC Form 1, 401b, 32, Max: FERC Form 1, 401b, 35.

Note 6: The following adjustments were made to the Total Costs and Fuel Expense costs associated with the listed PPAs:

1) CER Generation II, LLC: Include $12,478,140 in FF1 reported Other charges to the Fuel Expense $ column (5) – O&M and fuel for West Valley.
2) Deseret Generation & Transmission: included $3,936,927 of FF1 reported Other Charges to Total Cost column (4) as part of demand charge – they are the fixed O&M charges paid under PPA starting at $2.76/kw-mn and escalating at 2.5% per year.
3) Idaho Falls (Gem State): included $2,900,829 in FF1 reported Other charges to the Fuel Expencse $ column (5) – O&M charges for PAC share of Gem State.
4) Joseph Community Solar – Energy Charges reports $159,880 instead of FF1 reported $20,484.
5) Portland General Electric (Cove Replacement): include $270,000 in FF1 reported Other charges to the Fuel Expense column (5) - O&M for Cove replacement project.
6) Douglas PUD (Wells PSA): include $3,263,025 in FF1 reported Other charges to the Fuel Expense column 5 - it is the Take/Pay cost for Wells PSA.
7) Grant PUD (14 MW contract): include in Fuel Expense column (5) the $206,201 in "Other Charges" – it is the "Ancillary Services" part of the billing charges
8) Solwatt Solar – Energy Charges reports $103,662 instead of FF1 reported $15,862.

Note 7: Billing demand not included in column D of FERC Form 1, pg 327; obtained the contractual MW from the contract.

Note 8: Non-dispatchable resources, EAF will equal the plant factor. Additionally, Hydro generation that is "run-of-river" is also non-dispatchable but is not distinguished from other Hydro in this report.

Demand and VOM Charge Calculation Using Annual Fixed Charge Rate

(Based on FERC Form No. 1 Data from 2012)

II] Demand related O&M expenses by generating plant.

	(1) Plant No.	(2) Plant (Type)	(3) Max Name Plate Rating kW	(4) Operations Supervision & Engineering (p402-19)	(5) Coolant & Water (p402-21)	(6) Steam Expenses (p402-22)	(7) Hydrolic Expenses (p402-22)	(8) Electric Expenses (p402-25)	(9) Miscellaneous Steam/Nuclear Expenses (p402-26)	(10) Miscellaneous Hydrolic Power Generation Exp (p402-26)	(11) Rents (p402-27)	(12) Maintenance of Structures (p402-30)	(13) Maintenance of Misc. Steam/Nuclear (p402-33)	(14) Total	(15) O&M $/kW
1	Cholla	S	414,000	1,650,019	-	8,412,343	-	828,656	2,003,022	-	-	629,121	2,615,209	16,138,370	$ 38.98
2	Jim Bridger	S	1,545,100	15,997,364	-	3,812,213	-	307	(12,061,776)	-	237,500	10,093,311	2,690,211	20,769,130	$ 13.44
3	Portland General Electric Company	PP	2,000	-	-	-	-	-	-	-	-	-	-	-	$ -
4	Hayden	S	81,400	179,935	-	952,473	-	329,863	430,372	-	-	409,933	457,559	2,760,135	$ 33.91
5	J Bar 9 Ranch, Inc.	PP	100	-	-	-	-	-	-	-	-	-	-	-	$ -
6	Tri-State Generation and Transmission Association, Inc.	PP	25,000	-	-	-	-	-	-	-	-	-	-	-	$ -
7	Oregon State University	PP	6,500	-	-	-	-	-	-	-	-	-	-	-	$ -
8	Public Utility District No. 1 of Douglas County (s)	PP	38,000	-	-	-	-	-	-	-	-	-	-	-	$ -
9	Tesoro Refining and Marketing Company	PP	25,000	-	-	-	-	-	-	-	-	-	-	-	$ -
10	Kennecott Utah Copper LLC	PP	39,340	-	-	-	-	-	-	-	-	-	-	-	$ -
11	Wasatch Integrated Waste Management District	PP	1,600	-	-	-	-	-	-	-	-	-	-	-	$ -
12	Rock River 1, LLC	PP	49,000	-	-	-	-	-	-	-	-	-	-	-	$ -
13	Yakima-Tieton Irrigation District	PP	1,600	-	-	-	-	-	-	-	-	-	-	-	$ -
14	Harold Foster & Robert Walker	PP	200	-	-	-	-	-	-	-	-	-	-	-	$ -
15	Sunnyside Cogeneration Associates	PP	52,000	-	-	-	-	-	-	-	-	-	-	-	$ -
16	US Magnesium LLC	PP	36,000	-	-	-	-	-	-	-	-	-	-	-	$ -
17	Ballard Hog Farms Inc.	PP	10	-	-	-	-	-	-	-	-	-	-	-	$ -
18	RES Ag - Oak Lea LLC	PP	170	-	-	-	-	-	-	-	-	-	-	-	$ -
19	City of Portland, Portland Water Bureau	PP	30	-	-	-	-	-	-	-	-	-	-	-	$ -
20	Hermiston	GT	279,600	-	-	-	-	9,287,696	-	-	-	-	-	9,287,696	$ 33.22
21	Idaho Falls, City of	PP	22,500	-	-	-	-	-	-	-	-	-	-	-	$ -
22	Hermiston Generating Company, L.P.	PP	223,000	-	-	-	-	-	-	-	-	-	-	-	$ -
23	Roseburg Forest Products Company	PP	30,000	-	-	-	-	-	-	-	-	-	-	-	$ -

PacifiCorp
Annual Fixed Charge Rate Calculation
(Based on FERC Form No. 1 Data from 2012)

I) Determine Rate of Return Contribution.

A) Develop Common Stock Component

			PacifiCorp
Proprietary Capital	(112, 16, c)	$	7,644,054,942
Less: Preferred Stock	(112, 3, c)	$	40,733,100
Acc. 216.1	(112, 12, c)	$	157,299,053
Common Stock		$	7,446,022,789

B) Determine Consolidated Cost of Capital

		Year End Balance	Ratio	Cost	Weighted Weighted Cost
Long Term Debt[1]	$	6,806,057,103	47.62%	5.31%	2.53% ("WCLTD")
Preferred Stock[1]	$	40,733,100	0.28%	5.03%	0.01%
Common Stock[2]	$	7,446,022,789	52.10%	9.80%	5.11%
Total	$	14,292,812,992	100.00%		7.65% ROR

		PacifiCorp
Where: Long Term Debt (112, 24, c) =	$	6,806,057,103
LTD Interest (117, 62 through 66, c) =	$	361,338,060
Preferred Dividends (118, 29, c) =	$	(2,049,846)

II) Determine Production O&M Expense Contribution.

			PacifiCorp
C) Total Power Production Exp.	(321, 80, b)	$	2,142,943,722
D) Purchased Power Expenses[3]	(321, 76, b less 327, "Total", j)	$	459,198,761

E) Energy Related:

Acc. 501 Fuel	(320, 5, b)	$	768,997,788
Acc. 503 Stm./Other Srcs.	(320, 7, b)	$	3,937,027
Acc. 504 Stm. Tfd. (Cre)	(320, 8, b)	$	-
Acc. 510 Mnt. S&E	(320, 15, b)	$	6,378,884
Acc. 512 Mnt. Blr. Plt.	(320, 17, b)	$	107,992,173
Acc. 513 Mnt. Elect. Plt.	(320, 18, b)	$	35,012,328
Acc. 518 Fuel	(320, 25, b)	$	-
Acc. 528 Mnt. S&E	(320, 35, b)	$	-
Acc. 530 Mnt. Reac. Plt.	(320, 37, b)	$	-

Acc. 531 Mnt. Elect. Plt.	(320, 38, b)	$	-
Acc. 544 Mnt. Elect. Plt.	(320, 56, b)	$	1,974,573
Acc. 547 Fuel	(321, 63, b)	$	364,507,540
Total		$	1,288,800,313

F) Total Production Plant (205, 46, g) $ 10,942,646,469

G) Consolidated Production O&M Contribution

$$\frac{(C - D - E)}{F} \quad 0.036092$$

III) Determine Production-Related A&G Expense Contribution.

			PacifiCorp
H) Production Wages Expense	(354, 20, b)	$	140,994,569
I) A&G Wages Expense	(354, 27, b)	$	43,097,996
J) Total Wages Expense	(354, 28, b)	$	363,265,480
K) Total A&G related O&M	(323, 197, b)	$	188,239,678

L) Consolidated, Production-Related, A&G Contribution

$$\frac{H}{(J - I)} \times \frac{K}{F} \quad 0.007576$$

IV) Determine Production-Related Depreciation Expense Contribution.

		PacifiCorp
M) Production Depreciation Expense (336, 2 through 6, b)	$	291,378,673

N) Determine Consolidated Depreciation Rate and Production Plant Life

i) Determine Consolidated Depreciation Rate ("r")

$$\frac{M}{F} \quad 0.026628$$

ii) Determine Production Plant Life ("n")

$$\frac{1}{r} \quad 37.55$$

O) Determine Consolidated, Production-Related, Depreciation Contribution ("d")

$$\frac{ROR}{(1 + ROR)^{n} - 1} \quad 0.005126$$

V) Determine Other Taxes Expense Contribution.

			PacifiCorp
P) Other Taxes (Electric Only)	(114, 14, c)	$	160,882,952
Q) Electric Plant in Service	(207, 104, g)	$	23,734,237,296

R) Consolidated, Production-Related, Other Taxes Contribution

$$\frac{P}{Q} \qquad 0.006779$$

VI) Determine Composite Income Tax Expense Contribution.

S) Determine "CTR"

CTR = 1 - (((1 - SIT) x (1 - FIT) / (1 - SIT x FIT x p)) = 37.95%

where FIT =	35.00%
SIT =	4.54%
p =	0

T) CIT Contribution

(CTR / (1 - CTR)) * (ROR + d - r) * (1 - (WCLTD/ROR)) = 0.022510

VII) Determine ADIT Offset Contribution.

U) Calculate ADIT.

			PacifiCorp
ADIT Account 190	(234, 8, c)	$	648,219,005
ADIT Account 282	(275, 2, k)	$	3,796,825,280
ADIT Account 283	(277, 9, k)	$	728,061,162
Total ADIT (Acc. 190 - Acc. 282 - Acc. 283)		$	(3,876,667,437)

V) ADIT Contribution

(U / Q) x (ROR + CIT) = (0.016169)

VIII) Determine General Plant Contribution.

W) Determine Intangible and General Plant

		PacifiCorp
Intangible and General Plant (205, 5, g and 207, 99, g)	$	2,213,568,219

X) General Plant Contribution

((H / (J - 1)) * W * (R + ROR + O + T + V)) / F =	0.008438	

IX) Determine M&S Contribution.

			PacifiCorp
Y) Determine Prod. M&S	(227, 1 and 7, c)		$ 363,688,990
Z) Determine M&S Contribution (Y / F) x ROR		0.002542	

X) Determine Cash Working Capital Contribution.

AA) Determine Cash Working Capital Contribution

((C-D-Acc. 501-Acc. 518-Acc. 547)/8*(ROR+T))/	0.000622	

XI) Determine Production Fixed Charge Rate

I) Rate of Return Contribution.	0.076479
II) O&M Expense Contribution.	0.036092
III) A&G Expense Contribution.	0.007576
IV) Depreciation Expense Contribution.	0.005126
V) Other Taxes Expense Contribution.	0.006779
VI) Composite Income Tax Expense Contribution.	0.022510
VII) ADIT Offset Contribution.	(0.016169)
VIII) General Plant Contribution.	0.008438
IX) M&S Contribution.	0.002542
X) Cash Working Capital Contribution.	0.000622

Fixed Charge Rate (Use for system avg. fuel sales)	0.149995
Fixed Charge Rate Less O&M (Use for all other sales)	0.113903

XII) Notes

Note 1 - Information used to calculate the cost as follows:
Long Term Debt cost = Long Term Interest / Long Term Debt
Preferred Stock cost = Preferred Dividends / Preferred Stock

Note 2 - Common Stock cost shall be equal to 9.8%, which is the system weighted average ROE authorized by state utility commissions.

Jurisdiction	Annual MWH*	Percent	Authorized Return on Equity	Effective Date	Weighted Authorized Return on Equity
CALIFORNIA	919,114	1.56%	10.60%	Jan-07	0.17%
OREGON	14,537,470	24.68%	9.80%	Jan-13	2.42%
WASHINGTON	4,493,393	7.63%	9.50%	Dec-13	0.72%
UTAH	25,106,695	42.62%	9.80%	Oct-12	4.18%
IDAHO	3,738,889	6.35%	9.90%	Dec-10	0.63%
WYOMING	10,110,540	17.16%	9.80%	Oct-12	1.68%
TOTAL	58,906,100	100.00%			9.80%

* Annual temperature normalized 2012 retail load in the jurisdictions that PacifiCorp serves.

Note 3 - Demand charge expenses included in Account 555 (327, "Total", j) remain part of the FCR. Amounts that are energy and/or fuel charge related need to be removed from the FCR calculation. This amount is determined as follows:

Form 1 (321, 76, b)	$ 535,586,277
Less: Amount remaining in FCR	$ 76,387,516
Amount removed from FCR	$ 459,198,761

ATTACHMENT C

Principal Wholesale Customers for the Proposed New Cost-Based Rate Schedule

POTENTIAL CUSTOMER LIST – PACIFICORP

Fallon, City of
Attn: Steven King
55 W. Williams Avenue
Fallon, NV 89406
Phone: (775) 423-3550
Fax: (775) 423-3550
E-Mail: falonlaw2@cccomm.net

Mt. Wheeler Power, Inc.
Attn: Randy Ewell
1600 Great Basin Blvd.
P.O. Box 151000
Ely, NV 89315-1000
Phone: (775) 289-8981 ext 139
E-Mail: mwprandy@mwpower.net

Truckee Donner Public Utility District
Attn: Stephen Hollabaugh
11570 Donner Pass Road
P.O. Box 309
Truckee, CA 96160-0309
Phone: (530) 582-3934
Fax: (530) 587-1189
E-Mail: Stephenhollabaugh@tdpud.org

Wells Rural Electric
Attn: Clay Fitch
P.O. Box 365
1451 Humboldt
Wells, NV 89835
Phone: (775) 752-3328
E-Mail: cfitch@wrec.coop

Boulder City, City of
Attn: Ned Shamo
401 California Avenue
P.O. Box 61350
Boulder City, NV 89006
Phone: (702) 293-9231
E-Mail: nshamobenv@earthlink.net

Pacific Gas & Electric Company-Utility
Attn: Sandra Duncan
77 Beale Street, room 1369
San Francisco, CA 94105-1814
Phone: (415) 973-2796
Fax: (415) 973-7043
E-Mail: SMD2@pge.com

Bonneville Power Administration
Attn: Scott Wiley
905 NE 11th Avenue
Portland, OR 97208-3621
Phone: (503) 230-3877
Fax: (503) 230-3621
E-Mail: sdwiley@bpa.gov

Harney Electric
Attn: Randy Whitaker
1326 Hines Blvd
Burns, OR 97720
Phone (541) 573-2061
E-Mail: randy.whitaker@harneyelectric.org

Colorado River Commission of Nevada
Attn: Gail Bates
555 Washington Avenue, Suite 3100
Las Vegas, NV 89101-1065
Phone: (702) 691-5228
Fax: (702) 691-5222
E-Mail: gbates@crc.nv.gov

Southern Nevada Water Authority
Attn: Scott Krantz
100 City Parkway Suite 700
Las Vegas, NV 89106
Phone: (702) 691-5240
Fax: (702) 691-5220
E-Mail: scott.krantz@snwa.com

POTENTIAL CUSTOMER LIST – PACIFICORP CONTINUED

Lincoln County Power District No. 1
Attn: Dave Luttrell
HC 74-Box 101
Pioche, NV 89043
Phone: (702) 595-9705
E-Mail: david_luttrell@earthlink.net

Valley Electric Association
Attn: Thomas Husted
P.O. Box 237
800 E. Highway 372
Pahrump, NV 89041-0237
Phone: (775) 727-2139
E-Mail: tomh@vea.coop

Overton Power District No. 5
Attn: Delmar Leatham
P.O. Box 395
615 N. Moapa Valley Blvd
Las Vegas, NV 89119
Phone: (775) 397-2512 ext 3020
E-Mail: dleatham@opd5.com

Nevada Power Company
Attn: Thomas Woodworth
6226 West Sahara Avenue
Las Vegas, NV 89146
Phone: (702) 402-5694
E-Mail: TWoodworth@nvenergy.com

Sierra Pacific Power Company
Attn: Thomas Woodworth
6226 West Sahara Avenue
Las Vegas, NV 89146
Phone: (702) 402-5694
E-Mail: TWoodworth@nvenergy.com

Shell Energy North America (US), L.P.
Attn: James Davitt
Two Houston Center
909 Fannin, Plaza Level 1
Houston, TX 77010-1014
Phone: (713) 230-3414
Fax: (858) 320-2684
E-Mail: j.davitt@shell.com

Morgan Stanley Capital Group, Inc.
Attn: James McLellan
2000 Westchester Avenue
Purchase, NY 10575
Phone: (914) 225-1433
Fax: (914) 225-9297
E-Mail: James.McLellan@MorganStanley.com

Northern California Power Agency
Attn: David Dockham
651 Commerce Drive
Roseville, CA 95678-6420
Phone: (916) 781-4256
Fax: (916) 781-4252
E-Mail: dave.dockham@ncpa.com

POTENTIAL CUSTOMER LIST – PACIFICORP CONTINUED

Truckee Donner PUD
Attn: Sara Owens
11570 Donner Pass Road
Truckee, California 96161
Phone: (530) 582-3956
E-Mail: saraowens@tdpud.org

Arizona Public Service Company
Attn: Fred Contreras
400 N. 5th Street
Mail Station 9831
Phoenix, AZ 85004
Phone: (602) 250-2892
Fax: (602) 250-3238
E-Mail: federico.contreras@aps.com

WAPA –Sierra Nevada Region
Attn: Sonja Anderson
114 Parkshore Drive
Folsom, CA 95630
Phone: (916) 353-4421
Fax: (916) 985-1931
E-Mail: sanderso@wapa.gov

Utah Associated Municipal Power System
Attn: Marshall Empey
155 North 400 West Suite 480
Salt Lake City, UT 84103
Phone: (801) 214-6405
Fax: (801) 561-2687
E-Mail: marshall@uamps.com

Arizona Electric Power Cooperative
Attn: Walter Bray
P.O. Box 670
Benson, AZ 85602-0670
Phone: (520) 583-5201
Fax: (520) 586-5279
E-Mail: wbray@ssw.coop