PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Pacific Power |
Rocky Mountain Power
825 NE Multnomah
Portland, OR 97232

April 15, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: *PacifiCorp*, Docket No. ER19-_________-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (2012), Part 35 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, 18 C.F.R. Part 35 (2018), and Order No. 714[1] regarding electronic filing of tariff submittals, PacifiCorp hereby tenders for filing a revised version of the General Transfer Agreement ("GTA") between Bonneville Power Administration ("BPA") and PacifiCorp, Eleventh Revised Rate Schedule No. 237.[2]

1. Background and Reason for Filing

PacifiCorp and BPA are parties to the GTA, a pre-Order No. 888[3] legacy agreement originally executed on May 4, 1982. The GTA is a reciprocal transfer agreement that allows BPA to use PacifiCorp's transmission facilities to deliver energy to BPA's customers at various points of delivery, and, conversely, allows PacifiCorp to use BPA's transmission facilities to deliver energy to PacifiCorp's customers at various points of delivery. In light of this reciprocal arrangement under which each party is both providing and taking transmission service, the GTA is effectively between the merchant and transmission functions of both parties.

On June 19, 2017, in Docket No. ER17-1867, PacifiCorp filed the prior version of the GTA, designated as Ninth Revised Rate Schedule No. 237. The Commission accepted the filing, via letter order dated August 15, 2017, with an effective date of January 1, 2017.[4]

---

1 Electronic Tariff Filings, Order No. 714, 124 FERC ¶ 61,270 (2008).

2 The GTA was originally executed in 1982 and is not available in a full plain text version. Therefore, PacifiCorp is filing only the proposed exhibits in full plain text version. The Commission has accepted the previous eTariff version of this agreement when it was filed in a similar manner. *See, e.g., PacifiCorp*, Letter Order, Docket No. ER15-354-000 (Dec. 30, 2014).

3 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

4 *PacifiCorp*, Letter Order, Docket No. ER17-1867-000 (August 15, 2017)

This filing reflects amendments to Exhibit D – Transfer Charges, Sole Use-of-Facilities Charges, and Loss Factors ("Exhibit D"), which has been revised to retroactively update a transfer charge associated with the Klondike 69kV delivery point that is charged by BPA's transmission function to PacifiCorp's merchant function. Exhibit D in the Eleventh Revised Rate Schedule No. 237 updates the transfer charge for the Klondike point of delivery effective January 1, 2019. PacifiCorp, is submitting the revisions to Exhibit D of the GTA for filing with the Commission.

The charge at issue in the amendments to Exhibit D reflects BPA's costs to serve PacifiCorp's load by transferring power from BPA's De Moss Substation over Wasco Electric Cooperative, Inc.'s ("Wasco") transmission facilities to Wasco's Klondike 69 kV point of delivery. Wasco charges BPA for the transfer service, and BPA passes on these costs to PacifiCorp under Exhibit D of the GTA, the Klondike 69 kV point of delivery charge. Wasco updates the charge annually and applies the updated charge retroactively to January 1 of the calendar year for which the updated charge applies. Wasco notifies BPA of any updates to the charge; BPA then notifies PacifiCorp of the updated charge. Because the Klondike 69 kV point of delivery charge is assessed by Wasco and passed through by BPA's transmission function to PacifiCorp's merchant function, PacifiCorp believes that this charge itself does not reflect a rate or charge within the Commission's jurisdiction. Nevertheless, PacifiCorp has traditionally filed updates to Exhibit D of the GTA reflecting changes to the Klondike 69 kV point of delivery charge with the Commission because other terms and conditions of the GTA govern the provision of Commission-jurisdictional services, and because the GTA is on file with the Commission.

Concurrently with this filing, PacifiCorp is also filing with the Commission a revised version of the GTA with amendments to the same Exhibit D charge, which PacifiCorp has requested be designated as its Tenth Revised Rate Schedule No. 237. As discussed further in the transmittal letter for the concurrent filing of PacifiCorp's Tenth Revised Rate Schedule No. 237, an inadvertent administrative error on the part of BPA and outside of the control of PacifiCorp delayed BPA's notification to PacifiCorp of the updated charge applicable in 2018. Accordingly, PacifiCorp is tendering for filing its Tenth Revised Rate Schedule No. 237 and Eleventh Revised Rate Schedule No. 237 concurrently.

2. Effective Date and Request for Waiver

For the revision contemplated to the GTA in the Eleventh Revised Rate Schedule No. 237, PacifiCorp requests an effective date of January 1, 2019. Because the changes to the Klondike 69 kV point of delivery charge are not related to any FERC-jurisdictional service, and because the timing of the update to the charge are outside the control of PacifiCorp, PacifiCorp respectfully requests that applicable notice requirements be waived, and the Eleventh Revised Rate Schedule No. 237 be deemed effective on January 1, 2019.

To the extent that any other filing requirement in Part 35 of the Commission's regulations is not satisfied by this filing and the materials enclosed herewith, PacifiCorp respectfully requests waiver of such requirements.

3. Designation

PacifiCorp respectfully requests that the amended version of the GTA attached herewith be designated as PacifiCorp Eleventh Revised Rate Schedule No. 237.

4. Enclosures

The following enclosures are attached hereto:

Enclosure 1	General Transfer Agreement between BPA and PacifiCorp, to be designated as PacifiCorp Eleventh Revised Rate Schedule No. 237;
Enclosure 2	Redline of Ninth Revised Rate Schedule No. 237 as compared to the Eleventh Revised Rate Schedule No. 237[5]

5. Communications

All communications and correspondence regarding this filing should be forwarded to the following persons:

Andrew C. Mayer
Senior Counsel
PacifiCorp
825 N.E. Multnomah, Suite 1800
Portland, OR 97232
(503) 813-6442
Andrew.Mayer@PacifiCorp.com

Thomas C. Woodworth
Assistant General Counsel
PacifiCorp
825 N.E. Multnomah, Suite 1800
Portland, OR 97232
(503) 813-5356
Tom.Woodworth@PacifiCorp.com

6. Notice

Pursuant to 18 C.F.R. § 35.2(e), a copy of this filing is being served by e-mail on the following:

[5] As discussed above, PacifiCorp is submitting this filing concurrently with a separate filing containing amendments to the same charge in Exhibit D of the GTA, which PacifiCorp request be designated as its Tenth Revised Rate Schedule No. 237. Because the Tenth Revised Rate Schedule has not yet been accepted for filing by the Commission, PacifiCorp is providing with this filing a redline of the Eleventh Revised Rate Schedule No. 237 that shows against the version of the GTA currently on file with FERC, the Ninth Revised Rate Schedule No. 237.

Dan Yokota
Transfer Services Manager
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
dryokota@bpa.gov

Eric Carter
Senior Transmission Account Executive
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98662
ehcarter@bpa.gov

Joseph Hoerner
Vice President, Energy Supply Management
PacifiCorp Energy Supply Management
825 NE Multnomah St., Suite 600
Portland, OR 97232
Joseph.Hoerner@PacifiCorp.com

Rick Vail
Vice President, Transmission
PacifiCorp
825 NE Multnomah St. , Suite 1600
Portland, OR 97232
Richard.Vail@PacifiCorp.com

Public Utility Commission
of Oregon
550 Capitol Street N.E., Suite 215
Salem, OR 97301-2551
PUC.FilingCenter@state.or.us

Washington Utilities and Transportation
Commission
1300 S Evergreen Park Dr. SW
Olympia, WA 98504-7250
records@utc.wa.gov

If you have any questions, or if I can be of further assistance, please do not hesitate to contact me.

Respectfully Submitted,

/s/ Andrew C. Mayer
Andrew C. Mayer
Attorney for PacifiCorp

Contract No. DE-MS79-82BP90049

5-3-82

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

Index to Sections

This GENERAL TRANSFER AGREEMENT, executed May 4, 1982, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFIC POWER & LIGHT COMPANY (Company), a corporation of the State of Maine,

W I T N E S S E T H :

WHEREAS Bonneville and the entities named in Exhibit B (Bonneville's Customers) have entered into power sales contracts providing for the delivery of firm power and energy to such customers at various points of delivery in part by transfer over Company facilities; and

WHEREAS the parties hereto have executed agreements which provide that Bonneville or the Company, as the case may be, transfer electric power and energy to the Company or Bonneville's Customers at various points of delivery described in Exhibits B and C and now desire to replace such agreements in accordance with a letter agreement (Contract No. DE-MS79-82BP90924), with a single agreement; and

WHEREAS the parties, on August 9, 1973, executed an exchange agreement (Contract No. 14-03-29245, which as amended or replaced is called "Exchange Agreement") providing, among other matters, for an exchange energy account (Exchange Account), measurement and scheduling arrangements, and points of delivery; and

WHEREAS the parties hereto have agreed to a reciprocal transfer service philosophy which is recognized in this agreement and to consolidate and add various provisions to allow more frequent review of charges and loss factors in a manner consistent with the review of transmission rate schedules; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Agreements. Contract No. 14-03-001-10010, as amended, Contract No. 14-03-001-10662, as amended, Contract No. 14-03-001-11343, as amended, Contract No. 14-03-001-11477, as amended, Contract No. 14-03-001-13386, as amended, Contract No. 14-03-001-13395, Contract No. 14-03-001-14609, Contract No. 14-03-17532, as amended, Contract No. 14-03-37030, Contract No. 14-03-47929, as amended, Contract No. 14-03-56743, as amended, Contract No. 14-03-75629, Contract No. 14-03-77652, Contract No. 14-03-84718, Contract No. 14-03-86605, as amended, Contract No. 14-03-86620, as amended, and Contract No. DE-MS79-79BP90043 are hereby terminated as of the effective date hereof, but all liabilities accrued thereunder shall be and are hereby preserved until satisfied.

2. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution, and shall terminate on the earlier of the following:

(a) 2400 hours on the date of termination of the Exchange Agreement, or

(b) the time of the termination of all deliveries hereunder.

3. Exhibits. Exhibits A through H are made a part of this agreement. The Company shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to Bonneville's Customers or Bonneville, as the case may be, at points of delivery specified in Exhibit B, and each of Bonneville's Customers or Bonneville, as the case may be, shall be the "Transferee" mentioned therein. Bonneville shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to the Company at points of delivery specified in Exhibit C, and the Company shall be the "Transferee" mentioned therein. All references to "the Administrator" in such exhibits are changed to "Bonneville."

4. Revision of Exhibits.

(a) Exhibits B, C, D, and H shall be revised at:

(1) any time by mutual agreement of the parties to add or remove points of delivery;

(2) the time specified by the party receiving transfer service in a written notice to the Transferor to remove any point of delivery specified in Exhibits B or C, as the case may be, but not before the expiration of 1 year from 2400 hours on the date notice is received by the Transferor; or

(3) the time specified by the Transferor in a written notice to the party receiving transfer service to remove any point of delivery in the situation where the facilities used to perform the transfer service are surplus to the needs of the Transferor, but not before the expiration of 3 years from 2400 hours on the date such notice is received by the party receiving transfer service.

(b) Exhibit F contains the methodology for calculating Transfer Charges and Sole Use of Facility Charges listed in Exhibit D and shall be used by both parties. This methodology is an application of Bonneville's UFT-2 rate schedule. The UFT-2 rate schedule is included as a part of Exhibit G. Any change to the methodology described in Exhibit F shall require mutual approval of the parties; however such methodology shall be periodically reviewed by the parties upon the request of either party to consider modifications. Such modifications shall not be allowed more often than once in each 3-year period and shall be applicable to both parties. The values of the variables I, R, and D used in the methodology are expected to change from time to time and such changes shall not be deemed to be a change in the methodology. Bonneville waives its right to unilaterally change its rates provided in Exhibit F pursuant to section 37 of Exhibit A, Equitable Adjustment of Rates Section, insofar as it applies to this contract.

(c) The charges and Loss Factors specified in Exhibit D and factors in Exhibit H shall be revised pursuant to section 19 of Exhibit A, Adjustment for Change of Conditions Section, upon mutual agreement of the parties. The Transferor shall submit notice of such revision including justification for any such revision 90 days prior to the date the revision is requested to be effective. The party receiving transfer service shall review such information and shall not unreasonably withhold agreement to change the affected Exhibit. Any Loss Factor, Transfer Charge, or Sole Use of Facilities Charge shall be reviewed if requested by either party, but such review shall not be required more often than once in any 12-month period for any point of delivery; and if parameters used to calculate such factors or charges have changed, the parties shall not unreasonably withhold their agreement to change the affected Exhibits.

(d) Upon any change in methodology or charges pursuant to this section, the Transfer Charges and Sole Use of Facilities Charges specified in Exhibit D or any subsequent charges specified in this agreement shall be recalculated accordingly and the parties shall prepare a revised Exhibit D incorporating the new charges. A revised Exhibit D shall also be prepared to incorporate any change in Loss Factors pursuant to this section. Such revised Exhibit D shall be substituted for the Exhibit D then in effect and shall become effective as of the effective date of such new methodology or charges.

5. Provisions Relating to Delivery. Electric power and energy shall be made available by the Transferor at all times during the term hereof at the points of delivery described in Exhibits B and C, in the amount of the Transferee's requirements at such points and at the approximate voltages specified therefor. Amounts of electric energy, Integrated Demands therefor, and varhours delivered at such points during each month shall be determined from measurements made by meters installed at the locations and in the circuits specified in Exhibits B and C. Such amounts shall be increased for losses as determined by the parties hereto and specified in Exhibit D (Loss Factors). Such Loss Factors reflect all losses from the point of metering to the point of replacement specified in Exhibit B or C. Losses shall be determined on an incremental basis and the Transferee shall be assessed the incremental losses so determined. On or before July 1 of each year each party shall furnish the other party a five year forecast of the maximum demand for each of the points of delivery described in Exhibits B or C, as the case may be.

6. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the party receiving transfer service shall make electric power and energy available to the Transferor during each month in the term hereof, at the points of replacement specified in Exhibit B or C as the case may be. Such electric power and energy to be made available by the party receiving transfer service shall be computed by

increasing metered amounts, determined as provided in Exhibit B or C for each point of delivery, by the Loss Factors specified in Exhibit D.

The party receiving transfer service shall make available to the Transferor each hour in each month during the term hereof the amount of electric energy which is estimated to be the amount, so increased for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor as provided in the Exchange Agreement.

7. Payment for Transfer of Power.

(a) For the use of Transferor services and facilities in transferring electric power and energy hereunder, the party receiving transfer service shall pay the Transferor each month in the term hereof an amount equal to the sum for all points of delivery of the greater of (1) or (2) below for each point of delivery:

(1) the product of the Transfer Charge for each point of delivery and the Transfer Demand for that month for such point of delivery after increasing such Transfer Demand by one percent for each one percent or major fraction thereof by which the average power factor, at which electric energy is delivered at the point of delivery hereunder during each month, is less than 95 percent lagging; or

(2) the largest product obtained by multiplying the Transfer Demand of each of the 11 immediately preceding months by the respective Transfer Charge for each such month.

(b) The "Transfer Charge" for each point of delivery mentioned in subsection (a) above shall be as shown in Exhibit D. Transfer Charges shall be determined pursuant to Exhibit F.

(c) The "Transfer Demand" mentioned in subsection (a) above shall be the largest of the Integrated Demands, increased by the Loss Factors specified in Exhibit D, at which electric energy is delivered by the Transferor hereunder during such month, determined as provided in Exhibits B or C, as the case may be, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency conditions.

(d) For determining power factor in subsection (a)(1) above, metered amounts shall be adjusted for losses between the point of metering and the point of delivery. These losses shall be calculated from factors contained in Exhibit H which are different from the Loss Factors contained in Exhibit D.

8. Payment for Sole Use of Facilities. In addition to the payment due the Transferor in accordance with section 7, the party receiving transfer service shall pay the Transferor each month the amounts specified in Exhibit D under "Sole Use of Facilities Charge" for sole use of facilities by the party receiving transfer service. Sole Use of Facilities Charges shall be determined pursuant to Exhibit F.

9. Payment of Bills.

(a) The Company shall reimburse Bonneville in accordance with applicable provisions of Exhibit E by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section.

(b) Bonneville shall reimburse the Company for services hereunder within 30 days following its receipt of an itemized statement of payments due pursuant to sections 7 and 8 hereof by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section. If the Company is unable to render Bonneville a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill.

10. <u>Removal of Existing Facilities, Termination of Charges, and Installation of Additional Facilities</u>.

(a) The parties shall exchange any necessary data and confer from time to time to determine the necessity for removal of existing facilities and for installation of additional facilities to enable the parties to fulfill their obligations hereunder. If the parties cannot agree on the need for addition or removal of facilities, the Transferor shall make such determination. The Transferor agrees to provide additional facilities at the Transferor's expense as required to serve the combined load growth of both parties; <u>provided, however</u>, that the Transferee may provide such facilities at the Transferee's expense, subject to mutual agreement of the parties and appropriate credit to the Transferee, if the Transferee can do so at less total expense to both parties. Any facilities provided by the Transferee shall be compatible with the specifications of the Transferor. The cost and ownership of such new facilities shall be reflected in the next amendment of the charges contained in Exhibit D in accordance with the methodology contained in Exhibit F.

(b) Upon removing or installing facilities as determined in subsection (a) above, the parties shall include such revisions in this agreement, including the applicable contract terms and termination charges, if any, by executing new Exhibits B, C, or D, as appropriate. Such new exhibit shall replace the existing exhibit on the effective date specified therein.

(c) The party receiving transfer service shall pay the Transferor an appropriate mutually agreeable termination charge to the extent that the capacity of such facilities which were provided to enable the transfer service would be excess to the Transferor's needs as a consequence of any of the following:

(1) the parties agree to remove facilities pursuant to subsection (a) above;

(2) a point of delivery is terminated pursuant to section 4(a)(1) or 4(a)(2); or

(3) this agreement is terminated as provided in section 2.

(d) If additional facilities must be constructed or installed by either party pursuant to subsection (a) above, a reasonable period of time shall be allowed for such construction or installation.

11. Ratification of Interim Agreement. During the period commencing:

(a) July 1973 to July 1, 1981, the parties hereto have provided each other services as described in Exhibit G and the settlement therefor shall be as specified therein;

(b) July 1, 1981, to the effective date of this agreement, the parties hereto have provided each other services as described herein and in Exhibit G and payment therefor shall be as specified in Exhibit G, except that the points of delivery and charges contained in Attachment 1 to Exhibit G are hereby replaced by the points of delivery and charges contained in Exhibits B, C, and D hereto, effective as of the dates specified in such exhibits. Some of the services covered by the retroactive provisions of this section were also covered by provisions of contracts which are being terminated pursuant to section 1 hereof (Prior Contracts). In such cases, the provisions and charges contained herein shall supercede the provisions and charges of such Prior Contracts and any payments made for such services subsequent to June 30, 1981, pursuant to such Prior Contracts shall be credited against payments due hereunder for such services. All liabilities accrued pursuant to Exhibit G shall be and are hereby preserved until satisfied.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By ______________________
Bonneville Assistant Adminstrator
for Power Management

PACIFIC POWER & LIGHT COMPANY

By ______________________
Title Vice President
Date May 4, 1982

ATTEST:
By ______________________
Title Assistant Secretary
Date May 4, 1982

(WP-PCI-1185c)

EXHIBIT A

GWP Form-3 (7-27-77)

GENERAL WHEELING PROVISIONS

Index to Sections

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in the agreement to which these General Wheeling Provisions are an exhibit shall be deemed to be a part hereof for the purpose of determining the meaning of any provision contained herein. If a provision in such agreement is in conflict with a provision contained herein, the former shall prevail

(b) Nothing contained in this agreement shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this agreement:

(a) the words "Contractor", "Utility" or "Borrower" as used herein shall mean the party to this agreement other than the Administrator;

(b) the word "month" shall mean the period commencing at the time when the meters mentioned in this agreement are read by the Administrator and ending approximately 30 days thereafter when a subsequent reading of such meters is made by the Administrator;

(c) the words "Integrated Demand" shall mean the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour;

(d) the words "System" or "Facilities" shall mean the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

3. Prior Demands. In determining any credit demand mentioned in, or money compensation to be paid under this agreement for any month, Integrated Demands at which electric energy was delivered by the Transferor at points of delivery mentioned herein for the account of the other party to this agreement prior to the date upon which the agreement takes effect shall be considered in the same manner as if this agreement had been in effect.

4. Measurements. Except as it is otherwise provided in section 7 hereof, each measurement of each meter mentioned in this agreement shall be the measurement automatically recorded by such meter, but if not so recorded, shall be the measurement as determined by the parties hereto.

If it is provided in this agreement that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by representatives designated by the parties to such agreement. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such changes in conditions.

5. Measurements and Installation of Meters. The Administrator may at any time install a meter or metering equipment of the Government to make the measurements required for any computation or determination mentioned in this agreement, and if so installed such measurements shall be used thereafter in such computation or determination.

6. Tests of Meters. Each party to this agreement will, at its expense, test its meters mentioned in this agreement at least once every two years, and, if requested to do so by the other party, will make additional tests or inspections of such meters, the expense of which will be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in section 7 hereof. Each party will give reasonable notice of the time when any such test or inspection is to be made to the other party, who may have representatives present at such test or inspection. Meters found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering.

(a) If any meter mentioned in this agreement fails to register, or if the measurement made by such meter during a test made as provided in section 6 hereof varies by more than one percent from the measurement made by the standard meter used in such test, adjustment shall be made correcting all measurements made by such inaccurate meter during the period hereinafter stated. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, of any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this agreement for (1) the actual period during which such inaccurate measurements were made if such period can be determined, or (2) if not, the period immediately preceding a tes of such inaccurate meter which is equal to one-half the time from the date of the last preceding test of such meter; provided, however, that the period for which such recomputations are to be made shall not exceed six months.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto within 30 days after the recomputation is made; provided, however, that the other party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this agreement.

8. Character of Service. Unless otherwise specifically provided for in the agreement, electric power and energy made available pursuant to this agreement shall be in the form of three-phase current, alternating at a frequency of approximately 60 hertz.

9. Point of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this agreement that the amounts of electric energy and varhours, delivered at any point of delivery, and of the Integrated Demands for such electric energy, for any period,

shall be the amounts thereof determined by combining deliveries at two or more metering points coincidentally:

(a) the amounts of electric energy and varhours so delivered at such point of delivery during such period shall be the sums computed by adding together the amounts of electric energy and varhours, respectively, which flow during such period at such metering points, determined as provided in this agreement; and

(b) the amount of each Integrated Demand for such electric energy at such point of delivery shall be the sum computed by adding together the Integrated Demands for such hour at such metering points, determined as provided in this agreement.

11. Suspension of Deliveries. The other party to this agreement may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this agreement. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. The Transferor may temporarily interrupt or reduce deliveries of electric power and energy to the Transferee if he determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the Transferor's System. Except in case of emergency and in order that the Transferee's operations will not be unreasonably interfered with, the Transferor will give the Transferee advance notice of any such interruption or reduction, the reason therefor, and the probable duration thereof.

13. Uncontrollable Forces.

(a) Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

(b) The term "Uncontrollable Forces" means:

(1) Strikes affecting the operation of either party's System or other Facilities upon which such operation is completely dependent; or

(2) Such of the following events as either party, by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(i) Events, reasonably beyond the control of the party having jurisdiction thereof, causing failure, damage, or destruction of any such system or facilities. The word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such System or Facilities; or

(ii) Floods which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such system or facilities.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces, as defined in section 13 hereof, on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid, to the Transferor shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Payments due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree. Under contracts included in this procedure all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

In applying the above formula, the meter for measurement of reactive kilovolt-ampere-hours will be ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this agreement, no adjustment will be made for power factor at any point of delivery described in this agreement while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 lagging.

17. Permits.

(a). If by the terms of any contract between the parties any equipment or facilities of a party to this agreement are, or are to be, located on the property of the other at any point of delivery provided in this agreement, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this agreement and to remove such equipment and facilities at the expiration of said term, together with the right of ingress to and egress from the location thereof at all reasonable times in such term is hereby granted by the other party.

(b) Each party shall have the right to read, at all reasonable times, any and all meters mentioned in this agreement which are installed on the property of the other.

(c) If by the terms of any contract between the parties either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modifications which may affect the duties of the other party in regard to such equipment, and furnish the other party accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed by a party to this agreement on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and, to the extent agreed upon by the parties, all other salvable facilities which are installed by such party on the property of the other. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this agreement to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this agreement, such factor will be changed in a manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this agreement to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Arbitration. If the parties do not agree on the determination of any question of fact hereinafter stated, such determination will be made by arbitratio The party calling for arbitration shall serve notice in writing on the other party setting forth in detail the question or questions to be arbitrated and the arbitra appointed by such party. The other party shall, within ten days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator withi said ten days, or in case the two so appointed fail for ten days to agree upon and appoint a third, the party calling for the arbitration, upon five days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second or third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators, and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, and all other costs incurred in connection with the arbitration shall be paid equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be: (a) the determination of the measurements to be made by the parties hereto pursuant to section 4 hereof; (b) the correction of the measurements to be made as provided in section 7 hereof; (c) the amount of reduction in charges mentioned in section 14 hereof; (d) the duration of the interruption or equivalent interruption mentioned in section 14 hereof; (e) whether changes in conditions mentioned in section 19 hereof have occurred, and if so, the change to be made in the factor mentioned; (f) whether an increase or decrease in load or change in load factor mentioned in section 31 hereof is unusual; (g) any fact mentioned in sections 29 and 33 hereof; (h) whether an abnormal nonrecurring demand occurred and the amount and time therec (i) and the acceptable level of harmonics mentioned in section 34 hereof.

21. Contract Work Hours and Safety Standards. This agreement, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (40 U.S.C. 327-333), is subject to the following provisions and to all other applicable provisions and exceptions of such Act and the regulations of the Secreta of Labor thereunder.

(a) Overtime requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers, mechanics, apprentices, trainees, watchmen, and guards shall require or permit any laborer, mechanic, apprentice, trainee, watchman or guard in any workweek in which he is employed on such work to work in excess of eight hours in any calendar day or in excess of 40 hours in such workweek on work subject to the provisions of the Contract Work Hours and Safety Standards Act unless such laborer mechanic, apprentice, trainee, watchman, or guard receives compensation at a rate not less than one and one-half times his basic rate of pay for all such hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, whichever is the greater number of overtime hours.

(b) Violation; liability for unpaid wages; liquidation of damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for his unpaid wages. In addition, such Contractor and subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer, mechanic, apprentice, trainee, watchman, or guard employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed on such work in excess of eight hours or in excess of his standard workweek of 40 years without payment of the overtime wages required by subsection (a).

(c) Withholding for unpaid wages and liquidated damages. The Administrator may withhold from the Government Prime Contractor, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in the provisions of subsection (b) above.

(d) Subcontracts. The Contractor shall insert subsections (a) through (d) of this section in all subcontracts, and shall require their inclusion in all subcontracts of any tier.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for three years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. (The following clause is applicable unless this agreement is exempt under the rules, regulations and relevant orders of the Secretary of Labor [41 CFR, ch. 60].)

During the performance of this agreement, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or workers' representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractdor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions, including sanctions for noncompliance; provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

24. Reports. The other party to this agreement will furnish the Administratc such information as is necessary for making any computation required for the purposes of this agreement, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

25. Assignment of Agreement. This agreement shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this agreement; provided, however, that neither such agreement nor any interest therein shall be transferred or assigned by either party to any party other than the United States or an agency thereof without the written consent of the other; provided, further, that the consent of the Administrator is hereby given to any security assignment which may be required under terms of any mortgage, trust, or security agreement made by and between the Utility and any mortgage, trustee, or secured party, as security for bonds or other indebtedness of such Utility, present or future; such mortgagee, trustee, or secured party may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Utility.

26. Waiver of Default. Any waiver at any time by any party to this agreement of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such agreement, shall not be considered a waiver with respect to any subsequent default or matter.

27. Notices and Computation of Time. Any notice required by this agreement to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

28. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this agreement or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this agreement if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS AGREEMENT

29. Balancing Phase Demands. The Administrator may, at any time during the term of this agreement, require the Transferee to make such changes as are necessary on its system to balance the phase currents at any point of delivery so that the current on any one phase shall not exceed the current on any other phase at such point by more than ten percent.

30. Adjustment for Unbalanced Phase Demands. If the Transferee fails to make promptly the changes mentioned in section 29 hereof, the Administrator, at the Transferee's expense, may determine, for each month thereafter until such changes are made, that the registered demand of the Transferee at the point of delivery in question is equal to the product obtained by multiplying by three the largest of the Integrated Demands of the Transferee on any phase at such point during such month. This section shall not apply with respect to any point of delivery where the current required to be supplied at such point is other than three-phase current.

31. Changes in Demands or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Administrator of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

32. Inspection of Transferee's Facilities. The Administrator may, but shall not be obligated to, inspect the Transferee's electric installation at any time, but such inspection, or failure to inspect, shall not render the Government, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this agreement. The Administrator shall observe written operating instructions posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

33. Electric Disturbances.

(a) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(b) If both parties to this agreement are parties to the Agreement Limiting Liability Among Western Interconnected Systems, their relationship with respect to system damages shall be governed by that Agreement.

(c) During such time as a party to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this agreement shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (a)(2) above.

(d) If one of the parties to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this agreement shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (a)(2) above, and such failure contributed to the loss, injury or damage.

(e) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this agreement.

34. Harmonic Control. Each party shall design, construct, operate, maintain, and use its electric system in accordance with good engineering practices to minimize to acceptable levels the production of harmonic currents and voltages injected or coupled into the other party's facilities.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS AGREEMENT

35. Protection of the Transferor. Protection is or will be afforded to the Government or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by the Administrator and each third party Transferee named in this agreement: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Purchaser's Facilities.

RELATING ONLY TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

36. Approval of Agreement. This agreement shall not be binding on the parties thereto if it is not hereafter approved by the Administrator of the Rural Electrification Administration and any other entity from whom the Borrower borrows under an indenture which requires the lender's approval; provided, however, that the Borrower shall notify the Administrator of any such entity prior to the Administrator's execution of this agreement. If so approved it shall be effective at the time stated in the section of this agreement entitled "Term of Agreement."

APPLICABLE ONLY IF THE ADMINISTRATOR IS THE TRANSFEROR

37. Equitable Adjustment of Rates.

(a) As used in this section, the words "Rate Adjustment Date" shall mean any date designated by the Administrator after the date a new rate schedule is available for the class, quality, and type of service covered by this agreement; provided, however, that a Rate Adjustment Date shall not occur more frequently than once in any 12-month period. The Administrator may file with the Federal Power Commission or its successor for approval of a revised or new rate when he determines such revised or new rate is necessary to reflect the cost of the class, quality, and type of service covered by this agreement. The Administrator shall provide the Transferee with his then proposed schedule or schedules, supporting data, and a statement reflecting the effects of the proposed schedule or schedules on the charges specified in this agreement no less than 90 days prior to filing a proposed schedule or schedules with the Federal Power Commission or its successor, unless shorter periods are agreed upon by the parties hereto. The rate schedule in effect under this agreement on the Rate Adjustment Date shall continue in effect until the next Rate Adjustment Date on which revised or new rate schedules shall have been proposed by the Administrator and confirmed and approved by the Federal Power Commission or its successor.

(b) The Transferee shall pay the Administrator for the service made available under this agreement during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period which would be incorporated in a new agreement for service of the class, quality, and type provided for in this agreement, and in accordance with the terms hereof and of the General Transmission Rate Schedule Provisions incorporated or referred to in such rate schedule. If at the beginning of such period more than one rate is available for the class, quality, and type of service covered by this agreement, the Transferee shall, prior to 30 days after the later of the effective date of such rate or the date of approval of such rate by the Federal Power Commission or its successor, notify the Administrator in writing which of such rates the Transferee elects to have applied under this agreement during such period. If the Transferee fails to make such election, the Administrator shall determine the applicable rate. Such election by the Transferee or determination by the Administrator shall be applied as of the beginning of the first billing month following the effective date of such rate.

Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
City of Ashland
Effective Date: November 1, 1994

Points of Delivery for Bonneville

This Revision No. 1 adds the Mountain Avenue Point of Delivery.

1. ASHLAND POINT OF DELIVERY:

   Location: the point in the PacifiCorp's Ashland Substation where the 12.5 kV facilities of the PacifiCorp and the City of Ashland are connected.

   Voltage: 12.5 kV.

   Metering: in the PacifiCorp's Ashland Substation, in the 12.5 kV circuit over which such electric power and energy flows.

   Point of Replacement: The point in Meridian Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

2. OAK KNOLL POINT OF DELIVERY:

   Location: the point in the PacifiCorp's Oak Knoll Substation where the 12.5 kV facilities of the PacifiCorp and the City of Ashland are connected.

   Voltage: 12.5 kV.

   Metering: in PacifiCorp's Oak Knoll Substation, in the 12.5 kV circuit over which such electric power and energy flows.

   Point of Replacement: the point in Meridian's Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

3. MOUNTAIN AVENUE POINT OF DELIVERY:

   Location: the point in PacifiCorp's Oak Knoll-Ashland 115 kV line where Bonneville's 115 kV Mountain Avenue Tap line is connected.

   Voltage: 115 kV.

   Metering: in Bonneville's Mountain Avenue Substation, in the 12.5 kV circuit over which electric power and energy flows.

Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
City of Ashland
Effective Date: November 1, 1994

Point of Replacement: the point in Meridian Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________
Senior Customer Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 31, 1995

PACIFICORP

By ______________________

Title Manager, Customer Contract Administration
Name Colin Persichetti
(Print/Type)

Date February 7, 1995

(VS9-MPSD-3608e)

Exhibit B, Table 2, Revision No. 4
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Yakama Power
Effective 2400 hours on April 5, 2017

Points of Delivery for Bonneville

This revision documents the transfer of the White Swan point of delivery from Benton REA to Yakama Power.

WHITE SWAN POINT OF DELIVERY:

Location: the point in Yakama Power's White Swan Substation where the facilities of Yakama Power and Company are connected.

Voltage: 115 kV.

Metering: In the Yakama Power White Swan Substation, in the 115 kV circuit over which such electric power and energy flows.

Meter Adjustment: The Yakama Power White Swan meter reading will be adjusted by deducting Yakama Power's Hawk Road meter point, plus demand losses of 1.0163% and energy losses of 1.0170%. (NOTE: See Network Agreement between PacifiCorp and BPA to serve Yakama Power)

Point of Replacement: the point outside the Government's Moxee Switching Station where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	PACIFICORP
By [signature]	By [signature]
Name: Dan Yokota	Name: Rick Vail
Date: 2/6/17	Date: 2/2/17

Exhibit B, Table 3, Revision No. 2
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Cowlitz County
Public Utility District
Effective at 2400 hours on
February 1, 1993

Point of Delivery for Bonneville

This revision adds the Ariel Point of Delivery.

ARIEL POINT OF DELIVERY:

Location: the point in Cowlitz PUD's Ariel Substation where the 115 kV facilities of the Company and Cowlitz PUD are connected.

Voltage: 115 kV.

Metering: the point in Cowlitz PUD's Ariel Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: the point on the north side of the Kalama River at structure No. 1/1 of the Government's Cardwell-Cowlitz transmission line where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Walter E Pollock
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By Dennis P Steinberg

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Exhibit B, Table 4
Contract No. DE-MS79-82BP90049
Transferor: Company
Transferee: Bonneville
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. PENDLETON POINT OF DELIVERY:

Location: in the Government's Pendleton Substation where the 69 kV facilities of the Government and the Company are connected;

Voltage: 69 kV;

Metering: in the Government's Pendleton Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 5, Revision No. 2
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
Central Electric Cooperative
Effective Date: July 1, 1991

Points of Delivery for Bonneville

This Revision No. 2 establishes an effective date of July 1, 1991 for this Point of Delivery.

PILOT BUTTE POINT OF DELIVERY

Location: the point in PacifiCorp's Pilot Butte Substation where the 69 kV facilities of the Cooperative are connected;

Voltage: 69 kV;

Metering: in PacifiCorp's Pilot Butte Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in PacifiCorp's Pilot Butte Substation where the 230 kV facilities of the parties are connected.

Revision No. 1
Exhibit B, Table 6
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
Public Utility District No. 1
of Clark County, Washington
Effective at 2400 hours on
September 30, 1996

POINTS OF DELIVERY FOR BONNEVILLE

This revision deletes the Chelatchie and View 115 kV Points of Delivery. This table is left blank for future use.

ACCEPTED:

PACIFICORP

By Brian D. Sickels

Name Brian D. Sickels
(Print/Type)

Title Vice President

Date December 31, 1996

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By

Manager, Transmission
and Reserve Services

Name Patrick G. McRae
(Print/Type)

Date December 13, 1996

(PBLLAN-PST-W:\PSC\PM\CT\90049B_1.DOC)

Exhibit B, Table 7
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Basin Electric Cooperative, Inc. and
Umatilla Electric Cooperative
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

PILOT ROCK POINT OF DELIVERY:

Location: the point in the Company's 12.5 kV Pilot Rock circuit where the facilities of the Company and Umatilla are connected:

Voltage: 12.5 kV;

Metering: on the second pole from the point of interconnection between the facilities of the Company and Umatilla, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 8
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Power Cooperative Association, Inc.
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

UKIAH POINT OF DELIVERY:

Location: the point in the Company's Pilot Rock Substation where the Company's 69 kV facilities and Columbia Power's Ukiah 69 kV line leased by Bonneville are connected;

Voltage: 69 kV;

Metering: in Columbia Power's Ukiah Substation, in the 25 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 9, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Columbia Rural
Electric Association, Inc.
Effective at 2400 hours on December 31, 2012

POINTS OF DELIVERY FOR BONNEVILLE

This revision deletes the Dayton Point of Delivery. Table 9 will be left blank.

ACCEPTED;

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________ for

Name: **Todd E. Miller,**
Manager, Transfer Services

Date December 13, 2012

ACCEPTED;

PACIFICORP

By Natalie Hocken

Name: Natalie Hocken

Title: SVP, Transmission + System Operations

Date 12/19/12

Exhibit B, Table 10, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Douglas Electric Cooperative, Inc.
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Point of Replacement.

LOOKINGGLASS POINT OF DELIVERY

Location: The point in Bonneville's Lookingglass Substation where the 69 kV facilities of the Parties are connected;

Voltage: 69 kV;

Metering: In Bonneville's Lookingglass Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: The point in the Dixonville 500 kV Substation where the Parties jointly owned facilities connect with PacifiCorp owned facilities.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves

Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 11, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:

Effective at 2400 hours
April 30, 2000

Points of Delivery for Bonneville

This revision deletes the Hanna Point of Delivery. Table 11 will be left blank.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves
Date 6/22/00

PACIFICORP

By ______________________

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 12, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Hood River Electric Coop.
Effective at 2400 hours on December 31, 2012

This revision changes the name of the Point of Delivery from Woody Guthrie Point of Delivery to Willard Johnson Point of Delivery

POINTS OF DELIVERY FOR BONNEVILLE

WILLARD JOHNSON POINT OF DELIVERY:

Location: the point on the Company's 69 kV Powerdale-Dee transmission line where Hood River Electric's Willard Johnson Substation is connected;

Voltage: 69 kV;

Metering: In Hood River Electric's Willard Johnson Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected.

ACCEPTED;

PACIFICORP

By Natalie L Hocken

Name: Natalie L Hocken

Title: SVP, Transmission & System Operations

Date December 19, 2012

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By [signature] for

Name: Todd E. Miller,

Title: Manager, Transfer Services

Date: December 13, 2012

Exhibit B, Table 13, Revision No.4
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Public Utility District No. 1
of Klickitat County
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision corrects the Point of Replacement.

BINGEN POINT OF DELIVERY

Location: The point where Klickitat PUD's Bingen Substation connects to PacifiCorp's Powerdale-Condit 69 kV transmission line;

Voltage: 69 kV;

Metering: In Klickitat PUD's Bingen Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: The point at Bonneville's Bald Mountain Substation where the 69 kV facilities of PacifiCorp and Bonneville are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves
Date 6/22/00

PACIFICORP

By [signature]

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 14, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Lane Electric Cooperative, Inc.
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Location and Point of Replacement.

DORENA POINT OF DELIVERY

Location: The point where Bonneville's 115 kV transmission line serving Bonneville's Dorena Substation is connected to PacifiCorp's Village Green-Drain Tap 115 kV transmission line;

Voltage: 115 kV;

Metering: In Bonneville's Dorena Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: The point where Bonneville's Martin Creek-Drain Tap 115 kV transmission is connected with PacifiCorp's Village Green-Drain Tap 115 kV transmission line.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves

Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 15, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Oregon Metallurgical Corp (Oremet)
Effective 0000 hours on September 16, 2005

Point of Delivery for Bonneville

This revision deletes the OREMET 12.5 kV Point of Delivery. This Table is left blank for future use.

ACCEPTED;

PACIFICORP

By K Houston

Name Kenneth Houston
(Print/Type)

Title Director, Transmission

Date 2-10-06

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper
Manager,
Transmission and Reserve Services

Name Anne E. Draper
(Print/Type)

Date 26 September 05

Exhibit B, Table 16, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Effective at 2400 hours on
February 1, 1993

Points of Delivery for Bonneville

This revision deletes the Alvey 115 kV Point of Delivery. This Table is left blank for future use.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Walter E. Pollock
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By Dennis P. Steinberg

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Revision No. 1, Exhibit B, Table 17
POINTS OF DELIVERY FOR BONNEVILLE

This revision adds the Nehalem Tap Point of Delivery.

1. EFFECTIVE DATE. This exhibit revision shall take effect at 2400 hours on January 28, 1999.

2. TRANSFEROR. PacifiCorp (Company).

3. BONNEVILLE'S CUSTOMER. Tillamook People's Utility District (Tillamook).

4. POINT(S) OF DELIVERY

   (a) Garibaldi Point of Delivery

   Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which the Government's 115 kV Garibaldi tap line is connected;

   Voltage: 115 kV;

   Metering: in the Government's Garibaldi Substation, in the 24.9 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

   (b) Mohler Point of Delivery

   Location: the point on the Company's Astoria-Tillamook 115 kilovolt (kV) transmission line at which the Government's Mohler Substation is connected;

   Voltage: 115 kV;

   Metering: in the Government's Mohler Substation in the 24.9 kV circuits over which such electric power and energy flows;

   Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

   (c) Nehalem Tap Point of Delivery

   Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which Tillamook's Nehalem Tap 115 kV transmission line is connected;

Voltage: 115 kV;

Metering: in Tillamook's Nehalem Substation, in the 24.9 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

PACIFICORP

By ______________________

Name Donald N. Furman
(Print/Type)

Title Vice President Transmission Systems

Date 4-29-99

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________
Manager, Power Business Line Transmission and Reserve Services

Name Patrick G. McRae
(Print/Type)

Date 4/13/99

(PBLLAN-PSB/5-W:\PSC\PM\CT\90049B17.DOC) 04/06/99

Points of Delivery for Bonneville

This Revision No. 4 establishes an effective date of April 5, 2017 for the following points of Delivery.

1. MALIN POINT OF DELIVERY:

   Location: the point in the Malin Substation where the 230 kV Facilities of PacifiCorp and Bonneville are connected;

   Voltage: 230 kV;

   Metering: in Surprise Valley's Canby Switching Station, in the 69 kV circuit over which such electric power and energy flows;

   Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

2. ALTURAS POINT OF DELIVERY:

   Location: the point outside PacifiCorp's Alturas Substation where the 12.5 kV facilities of PacifiCorp and Surprise Valley are connected;

   Voltage: 12.5 kV;

   Metering: outside of PacifiCorp's Alturas Substation, in the 12.5 kV circuit over which such electric power and energy flows;

   Exception: the potential and current transformers are owned by PacifiCorp;

   Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

3. AUSTIN POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Austin Switching Station where the 69 kV facilities of PacifiCorp and Surprise valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Austin Switching Station, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

4. CEDARVILLE POINT OF DELIVERY:

Location: the point in the vicinity of Bonneville's 115/69 kV Cedarville Junction Substation where the 115 kV facilities of PacifiCorp and Bonneville are connected;

Voltage: 115 kV;

Metering: in Bonneville's Cedarville Junction Substation, in the 69 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be reduced by the amounts of demand and energy, adjusted for losses, registered on meters in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which electric power and energy flows to PacifiCorp;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

5. DAVIS CREEK POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 115 kV facilities of PacifiCorp and Bonneville are connected;

Voltage: 115 kV;

Metering: in Surprise Valley's Davis Creek Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

6. LAKEVIEW 69 KV POINT OF DELIVERY:

Location; the point in which the vicinity of Surprise valley's Lakeview Switching Station where the 69 kV facilities of PacifiCorp and Surprise Valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Lakeview Switching Station, in the 69 kV circuit over which such electric power and energy flows; provided, however, if the output of the Paisley geothermal facility is being delivered outside of Surprise Valley's system, metering at the Lakeview Switching Station shall be adjusted upwards in the amount of the metered output of the Paisley geothermal facility measured at the Paisley resource plus losses, which shall be 1.9%.

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

ACCEPTED:

UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	PACIFICORP
By: [signature]	By: [signature]
Name: Dan Yokota	Name: Rick Vail
Date: 2/2/17	Date: 2/2/17

Points of Delivery for Bonneville

HAT ROCK POINT OF DELIVERY:

Location: the point where the Government's Hat Rock Substation is connected to the Company's McNary-Walla Walla 230 kV transmission line;

Voltage: 230 kV;

Metering: in the Government's Hat Rock Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the parties are connected;

Switching Facilities:

(a) The Company has elected to operate said McNary-Walla Walla 230 kV transmission line in a manner which required Bonneville to install major switching facilities, suitable to the Company, at said Hat Rock point of delivery. Bonneville installed such switching facilities, to enable continued service to Umatilla at Hat Rock.

(b) The Company, at Government expense shall:

(1) operate and maintain the two 230 kV disconnect switches adjacent to the Hat Rock point of delivery in the same manner in which it maintains similar facilities of its own and furnish any parts necessary for such maintenance; and

(2) remove said switches and associated materials which can be removed without damage to Company property, when no longer required to provide service at said Hat Rock point of delivery, deliver said switches and salvable materials to such location as Bonneville shall designate, and restore the Company's transmission facilities to their original configuration, subsequent to such removal.

(c) The Company shall submit an itemized statement of charges for materials furnished and services performed, as specified in section (b), including a reasonable allowance for overheads, within 20 days after the end of the month in which they were incurred, and Bonneville shall pay such charges within 30 days after receipt of said statement;

(d) Title to and ownership of the two 230 kV disconnect switches and related salvable materials installed by Bonneville shall be in the Government at all times.

Exhibit B, Table 20
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Wasco Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

WARM SPRINGS POINT OF DELIVERY:

Location: the point in the Company's Warm Springs Substation where the 69 kV facilities of the Company and facilities leased by the Government are connected;

Voltage: 69 kV;

Metering: in the Kah-Nee-Ta Substation leased by the Government, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Redmond Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
West Oregon Electric Cooperative, Inc.
Effective at 2400 hours on February 1, 1993

Points of Delivery for Bonneville

Revision No. 1 removes the Necanicum Junction Point of Delivery.

1. OLNEY POINT OF DELIVERY:

   Location: at the point near Olney, Oregon, where 12.5 kV facilities of the Company and West Oregon Electric Cooperative are connected.

   Voltage: 12.5 kV.

   Metering: at the point of delivery in the 12.5 kV circuit over which such electric power and energy flows.

   Point of Replacement: the point in the Company's Astoria Switching Station where the 115 kV facilities of the parties are connected.

2. NECANICUM POINT OF DELIVERY:

Location: at the point between structures 25/2 and 25/3 of the Company's Tillamook-Astoria 115 kV line where the 115 kV facilities of West Oregon Electric Cooperative and the Company are connected.

Voltage: 115 kV.

Metering: in West Oregon Electric Cooperative's Necanicum Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: the point in the Government's Clatsop Substation where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA

Department of Energy
Bonneville Power Administration

By Walter E. Pollock
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By Dennis P. Steinberg

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Exhibit B, Table 22, Revision No.3
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Emerald People's Utility District
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Powerline Point of Delivery to reflect the second tap into Power line Substation.

1. CRESWELL POINT OF DELIVERY

   Location: at the point in the Company's Alvey-Village Green 115 kV transmission line between structure 5/9 and 6/9 where the facilities of the Company and the Government are connected.

   Voltage: 115 kV.

   Metering: in Emerald's Creswell Substation, in the 20.8 kV circuit over which such electric power and energy flows.

   Exception: losses in Exhibit D include an adjustment for losses between the point of delivery and the point of metering.

   Point of Replacement: in the Government's Alvey Substation where the 115 kV facilities of the parties are connected.

2. POWERLINE POINT OF DELIVERY

   Location: the points in the Company's Diamond Hill-Coburg 69 kV line at structures 12/9 and 12X/9 where the facilities of the Government and Company are connected.

   Voltage: 69 kV.

   Metering: in Emerald's Powerline Substation, in the 20.8 kV circuits over which such power and energy flows.

   Exception: losses in Exhibit D include an adjustment for losses between the point of delivery and the points of metering.

   Point of Replacement: in the Governments Alvey Substation where the 230 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	PACIFICORP
By: Anne E. Draper	By: [signature]
Name: Anne E. Draper Manager, Transmission Acquisition and Reserves	Name: Donald N. Furman Vice President
Date: 6/22/00	Date: June 20, 2000

Transferor: Bonneville
Transferee: PacifiCorp
Effective Date: November 1, 2009

EXHIBIT C, REVISION NO. 8
POINTS OF DELIVERY FOR THE COMPANY

This Exhibit C, Revision No. 8 accomplishes the following: (1) adds the Klondike 69 kV Point of Delivery (POD); (2) updates the description for the Location of all PODs and, (3) reformats Exhibit C to reflect the current standard format. The Effective Date of this Revision No. 8 shall be retroactive to November 1, 2009, to coincide with the date the Klondike 69 kV POD was deleted from Exhibit C.

1. ALVEY 115 KV - PAC

Location: the point in the Transmission Provider's[1] J.P. Alvey[2] substation, where the 115 kV facilities of the Transmission Provider and PacifiCorp[3] are connected;

Voltage: 115 kV;

Metering: in the Government's Alvey Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Alvey Substation where the 230 kV facilities of the Company and Bonneville are connected;

Exception: Company load metered at Alvey Line 4 will be adjusted by subtracting Emerald PUD load metered at Creswell adjusted for losses between the Creswell meter and the Alvey Substation 115 kV bus.

2. CEDARVILLE JUNCTION 69 KV - SURP

Location: the point in the vicinity of the Transmission Provider's Cedarville Junction substation, where the 69 kV facilities of the Transmission Provider and Surprise Valley Electrification Corporation[4] are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Cedarville Junction Substation where the 115 kV facilities of the Parties are connected.

[1] The Transmission Provider is also referred to as both the "Government" and "Bonneville" in this contract, its amendments and exhibits.
[2] Alvey Substation
[3] PacifiCorp is also referred to as the "Company" in this contract, its amendments and exhibits.
[4] Surprise Valley

3. **DALREED 230 KV**

Location: the point near structure 37/3 of the Transmission Provider's McNary-Jones Canyon 230 kV transmission line where the facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 230 kV;

Metering: in the Company's Dalreed Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the Parties are connected.

4. **KLONDIKE 69 KV**

Location: the point near Wasco Electric Cooperative's Klondike Substation where the 69 kV facilities of PacifiCorp and Wasco Electric Cooperative are connected;

Voltage: 69 kV;

Metering: in the Company's Klondike-Willow Creek Line in the 69 kV circuit over which such electric power flows;

Exception: the Company is served by transfer over Wasco Electric Cooperative, Inc. (Wasco) facilities. The terms and conditions of the transfer are specified in Contract No. 14-03-47930 between Wasco and the Government;

Point of Replacement: the point in the Government's De Moss Substation where the 69 kV facilities of the Government and Wasco are connected[5].

[5] Pursuant to Network Integration Transmission Service Agreement No. 09TX-14534, the Government delivers electric power to its De Moss Substation where it is transferred over to Wasco's facilities for delivery to the Company's facilities. Wasco charges the Government for the transfer service, and the Government passes Wasco's transfer charge through to the Company under the transfer charge for the Klondike 69 kV POD.

5. **KNAPPA TAP 115 KV**

Location: the point near structure 37/4 of the Transmission Provider's Longview-Astoria 115 kV transmission line where the facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 115 kV;

Metering: in the Company's Knappa-Svenson Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the instrument transformers are owned by the Company;

Point of Replacement: the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

6. **FERN HILL 115 KV**

Location: the point near PacifiCorp's Fern Hill Substation where the 115 kV facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 115 kV;

Metering: in the Company's Fern Hill Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: losses in Exhibit D include an adjustment for losses between the Point of Delivery and the Point of Metering;

Point of Replacement: the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

7. **VANSYCLE TAP 69 KV - PAC**

Location: the point in the Transmission Provider's Walla Walla-Pendleton 69 kV transmission line where the 69 kV tap line facilities of the Vansycle Ridge Windfarm are connected;

Voltage: 69 kV;

Metering: in the Vansycle Windfarm Substation, in the 69 kV circuit over which such electric power and energy flows;

Exception: losses in Exhibit D include an adjustment for losses between the Point of Delivery and the Point of Metering;

Point of Replacement: the point in the Government's Walla Walla Substation where the 69 kV facilities of the Parties are connected.

8. **SIGNATURES**

The Parties have executed this Exhibit as of the last date indicated below.

PACIFICORP		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	[signature]	By:	Kimberly D. Gilliland
Name:	Stefan A. Bird *(Print/Type)*	Name:	for Kenneth H. Johnston *(Print/Type)*
Title:	SVP Commercial + Trading	Title:	Transmission Account Executive
Date:	5/23/14	Date:	05/09/2014

(W:\TMC\CT\PacifiCorp\Revisions\90049_ExC_R8.doc)

EXHIBIT D, REVISION NO. 26
TRANSFER CHARGES, SOLE USE-OF-FACILITIES CHARGES, AND LOSS FACTORS

This Exhibit D, Revision No. 26 (Revision) updates the Transfer Charge associated with the Klondike 69 kV Point of Delivery.

EFFECTIVE DATE: This exhibit revision shall be effective on the date approved by FERC. Once effective, changes to the Transfer Charge for the Klondike 69kV Point of Delivery (POD) are retroactive to January 1, 2019.

Point of Delivery	Transferor	Transfer Charge ($/kW/mo)	Sole Use-of-Facilities Charge ($/mo)	Loss Factors Peak	Loss Factors Energy
Alvey 115 kV (Line 4)	Bonneville	0.1067	0	1.0034	1.0014
Cedarville Junction	Bonneville	0.5470	0	1.0019	1.0008
Dalreed	Bonneville	0.0580	0	1.0059	1.0023
Fern Hill	Bonneville	0.0998	0	1.0056	1.0091
Klondike 69 kV	Bonneville	1.345[1]	0	1.0341[2]	1.0136
Knappa Tap	Bonneville	0.1783	0	1.0127	1.0110
Vansycle Tap	Bonneville	1.3009	0	1.0190	1.0190
Ashland (City of Ashland)	PacifiCorp	1.3869	0	1.0196	1.0111
Oak Knoll (City of Ashland)	PacifiCorp	1.8900	0	1.0245	1.0138
Mt. Avenue (City of Ashland)	PacifiCorp	1.0368	0	1.0124	1.0084
White Swan (Yakama)	PacifiCorp	1.1204	0	1.0317	1.0234
Pilot Butte (Central Electric)	PacifiCorp	0.6489	0	1.0050	1.0024
Ariel (Cowlitz)	PacifiCorp	0.1197	0	1.0384	1.0221
Pilot Rock (Columbia Basin and Umatilla)	PacifiCorp	0.8423	0	1.1151	1.0661
Ukiah (Columbia Power)	PacifiCorp	0.2989	0	1.0887	1.0553
Lookingglass (Douglas)	PacifiCorp	1.6083	4,183	1.0786	1.0429
Creswell (Emerald)	PacifiCorp	0.1869	0	1.0063	1.0053
Powerline (Emerald)	PacifiCorp	1.6066	0	1.0224	1.0157
Willard Johnson (Hood River)	PacifiCorp	0.4347	0	1.0573	1.0309
Bingen (Klickitat)	PacifiCorp	0.2372	0	1.0169	1.0111
Dorena (Lane)	PacifiCorp	0.0000	1,559	1.0069	1.0072

---

[1] Under Contract No. 14-03-47930, Wasco Electric Cooperative, Inc. (Wasco) updates the Transfer Charge the Government pays Wasco to transfer power from the Government's De Moss Substation over Wasco's 69 kV transmission facilities to Wasco's Klondike 69 kV Point of Delivery (POD). Wasco charges the Government for the transfer service and updates its charges annually. The Government passes Wasco's Transfer Charge through to the Company under the Transfer Charge for the Klondike 69 kV POD. After Wasco updates the charge to the Government, the Government applies this change retroactively to January 1 of the calendar year for which Wasco updated its charges (in the case of this Revision No. 26 to Exhibit D, January 1, 2019). Despite that this is a charge from Wasco passed through by the Government's transmission function to the Company's merchant function, it is incorporated into this Agreement which also governs the provision of FERC-jurisdictional services by the Company's transmission function to the Government's merchant function, and is therefore on file with FERC and subject to FERC approval.

[2] Because the incremental loss calculation for the network did not fairly represent actual losses, an average system loss of 2 percent was used. The other loss component is for transformation losses in the Company's facilities, as metering is located on the low side of the transformer.

Point of Delivery	Transferor	Transfer Charge ($/kW/mo)	Sole Use-of-Facilities Charge ($/mo)	Loss Factors Peak	Loss Factors Energy
Garibaldi (Tillamook)	PacifiCorp	0.1160	0	1.0241	1.0140
Mohler (Tillamook)	PacifiCorp	0.2996	0	1.0452	1.0268
Nehalem Tap (Tillamook)	PacifiCorp	0.3602	0	1.0513	1.0285
Alturas (Surprise Valley)	PacifiCorp	1.3503	0	1.1796	1.1146
Austin (Surprise Valley)	PacifiCorp	3.8109	0	1.1005	1.0654
Cedarville (Surprise Valley)	PacifiCorp	2.2194	0	1.0406	1.0389
Davis Creek (Surprise Valley)	PacifiCorp	5.5103	0	1.2974	1.1910
Lakeview 69 kV (Surprise Valley)	PacifiCorp	5.7468	325	1.1011	1.0662
Malin (Surprise Valley)	PacifiCorp	0.4126	0	1.0416	1.0271
Hat Rock (Umatilla)	PacifiCorp	0.3993	0	1.0113	1.0099
Pendleton (Umatilla)	PacifiCorp	0.0405	110	1.0105	1.0061
Warm Springs (Wasco)	PacifiCorp	6.0632	0	1.2108	1.1115
Necanicum (West Oregon)	PacifiCorp	1.0431	0	1.0471	1.0337
Olney (West Oregon)	PacifiCorp	1.9403	0	1.6743	1.3385

SIGNATURES

This Revision may be executed in several counterparts, all of which taken together will constitute one single agreement, and the Revision may be executed and delivered electronically. The parties have executed this Revision as of the last date indicated below.

PACIFICORP

By: Joseph Hoerner Digitally signed by Joseph Hoerner Date: 2019.04.02 10:33:11 -07'00'

Title: VP. Energy Supply Management

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Eric H. Carter Digitally signed by ERIC CARTER Date: 2019.03.22 12:29:16 -07'00'

Title: Senior Transmission Account Executive

If opting out of the electronic signature:

By: ______________________________

Name: ______________________________
(Print/Type)

Title: ______________________________

Date: ______________________________

General Transmission Rate Schedule Provisions:

FOR SET A TRANSMISSION SCHEDULES

1. Interpretation. The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. Bonneville Service Area. The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the BPA wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. Availability of Transmission Service. Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identifed in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. Billing Details.

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

5. Definitions. Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

a. Agreement: The transmission agreement to which this exhibit is attached.

b. Connection Point: Refers collectively to the following:

(1) Point of Integration (POI): Connection points where a non-Federal project is integrated with the FCRTS.

(2) Point of Delivery (POD): Connection points where power is delivered to a customer from the FCRTS. The power may be Federal or non-Federal.

(3) Point of Exchange (POE): Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. Electric Power (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. Firm Transmission Service: Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. Interest and Amortization Ratio: The annual interest and amortization costs of the Federal Columbia River Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

f. Main Grid: That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

g. Main Grid Delivery Terminal: 230 kV Terminal Facilities associated with a Point of Delivery.

h. Main Grid Distance: The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

i. Main Grid Integration Terminal: The Main Grid Terminal Facilities located at the Point of Integration.

j. Main Grid Miscellaneous Facilities: Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

k. Main Grid Terminal: Terminal facilities on the Main Grid adjacent to the Secondary System.

l. NonFirm Transmission Service: Service for which BPA will accept power only when it determines excess capacity is available. Once BPA accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

m. Ratchet Demand: The maximum past or present demand established during the previous 11 billing months based on the highest scheduled demand during that time.

n. Secondary System: That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

o. Secondary System Delivery Terminal: A Point of Delivery from a Main Grid substation at 115 kV or 69 kV, or a terminal located at a Point of Delivery from the Secondary System.

p. Secondary System Distance: The number of circuit miles of Secondary System transmission lines between the Main Grid and the Point of Delivery or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

q. Secondary System Integration Terminal: The first Terminal Facility in the Secondary System.

r. Secondary System Intermediate Terminal: The final Terminal Facilities in the Secondary System.

s. Secondary Transformation: Transformation from Main Grid to Secondary System facilities.

Exhibit F

Contract No. DE-MS79-82BP90049
Pacific Power & Light Company
Effective at 2400 hours on
June 30, 1981

Methodology for Calculating Transfer Charges and Sole Use of Facilities Charges

The Transfer Charge is the monthly charge per kilowatt of transfer demand as transfer demand is defined in the contract of which this exhibit is a part. The Transfer Charge is equal to one-twelfth of the sum of the Annual Costs of all facilities used in providing the service hereunder divided by the sum of the yearly non-coincidental peak demands as determined in (c) below. The Annual Costs of each facility are defined as the product of: (1) the capital cost of such facility as determined in (a) below; and (2) the Annual Cost Ratio as determined in (b) below. The Transfer Charge is therefore calculated from the formula:

$$\frac{\text{sum of } (I \times R) \text{ for all applicable facilities}}{D} \times 1/12$$

where:

I = Capital cost of such facility as determined in (a) below,
R = Annual Cost Ratio as determined in (b) below,
D = The sum of the yearly non-coincidental peak demands as determined in (c) below.

(a) Capital cost of each such facility as in the most recently published plant investment records of the parties hereto.

(b) Annual Cost Ratio for each such Bonneville facility using the most recent system average cost factors, or Annual Cost Ratio for each such Company facility which incorporates the most recent rate of return approved by the ~~Idaho Public Utility Commission, the Montana Public Service Commission, the~~ Oregon Public Utility Commission~~, or the Washington Utilities and Transportation Commission, as the case may be, for facilities located in the respective states.~~ The Annual Cost Ratio used herein includes the operation and maintenance component defined as "B" in the UFT-2 rate schedule.

(c) The yearly noncoincidental peak demands of all users of such facilities, as determined in part by use of power flows agreed to by both parties and in part by forecasted peaks agreed to by both parties that are different from those used in the power flows. Since the noncoincidental peaks may occur at different times it may not be possible to include both in the same power flow. The parties shall initially use power flows, which are already existing as of January 1, 1982, which are based on 1981-82 Operating Year forecasted peak. Unless the parties subsequently agree to a different method, the following method shall be used to update power flows:

(1) the initial power flows shall be used through December 31, 1983 or such other date as agreed by the parties;

(2) new power flows shall then be prepared which shall use parameters forecasted to exist 2 years from the date that the power flow is prepared;

(3) such new power flows shall then be the basis for transfer charges for 3 years;

(4) every third year the procedure in (2) above shall be repeated and such new power flows shall be used for 3 years.

Sole Use of Facilities Charge

The Sole Use of Facilities Charge is the transfer charge where a party has sole use of a facility. In such cases the charge is expressed in dollars per month and is calculated as:

sum of (I x R) for all applicable facilities x 1/12

using the same quantities defined above.

EXHIBIT G

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

In reply refer to: PCI

OFFICE OF THE ADMINISTRATOR

FEB 26 1982

Contract No. DE-MS79-82BP90924

Mr. Robert W. Moench
Senior Vice President
Pacific Power & Light Company
Portland, Oregon 97204

Dear Mr. Moench:

During the past year, representatives of Pacific Power & Light Company (PP&L) and Bonneville Power Administration (BPA) have been meeting from time to time to reach settlement on transfer services to BPA's Hanna, Lookingglass, and Surprise Valley loads for the period from July 1973 to the present as well as other outstanding issues related to transfer services rendered to both parties. At meetings on February 23 and 24, 1982, agreement was reached between PP&L and BPA on certain of these issues. There are other issues, as well as final details of future charges for transfer services provided each other, which are yet to be resolved. BPA and PP&L, however, agree that final resolution of all remaining issues will be greatly facilitated as a result of these recent meetings and the agreement of principles upon which many of these decisions were made.

In accordance with these recent discussions, BPA and PP&L agree to the following terms and conditions:

A. <u>Settlement for services rendered prior to July 1, 1981</u>.

1. BPA shall pay PP&L $5,300,000 for transfer service provided by PP&L to BPA's Surprise Valley, Hanna, and Lookingglass loads from July 1973 through 2400 hours on June 30, 1981. The amount of the payment was computed using a fixed rate of .5 mill per kWh, a UFT methodology equivalent to BPA's approved UFT-1 rate methodology, and a transfer amount of 7,639,784,496 kWh.

2. BPA shall pay PP&L $319,789 for transfer service of the Lost Creek Project generation for the period from July 6, 1977, through October 1, 1978.

3. Payment pursuant to subsections 1 and 2 above shall be made in three equal payments, such payments shall be made at 30-day intervals. The first such payment shall be made within 30 days of receipt of an invoice for the full amount due. There shall be no interest paid on such payments.

4. BPA agrees to reimburse PP&L 62,000 MWh for losses which PP&L incurred during the period commencing at 2400 hours on June 30, 1973 and continuing through 2400 hours on June 30, 1981. Delivery of such energy will be made, to the extent possible, in equal hourly increments during the period commencing at 2400 hours on June 30, 1982 and continuing through 2400 hours on June 30, 1983.

B. <u>Settlement for services rendered subsequent to July 1, 1981</u>.

1. <u>Payment</u>

a. BPA shall pay PP&L each month in the amounts specified in Attachment 1, within 30 days of receipt of billing.

b. BPA shall pay PP&L the actual cost of the line transposition required on the Buckley-Summer Lake line. Such cost is estimated to be $40,000. BPA and PP&L shall execute an appropriate trust agreement for this transaction.

c. PP&L shall pay BPA an monthly charge of $32,100 from 2400 hours on November 30, 1981 through the date of Commercial Operation of the Buckley-Summer Lake-Malin line for the right to remove PP&L's 230 kV Malin phase shifter. Such monthly charge shall resume at 2400 hours on August 31, 1985, as established pursuant to Contract No. DE-MS79-79BP90091, unless BPA determines that, such date should be extended based upon studies done in a manner similar to those done in originally establishing such dates. PP&L shall, in consideration for the above and as mutually agreed upon by the parties, extend the period of time for which BPA shall have west to east transmission rights on PP&L's Summer-Lake - Midpoint line.

2. <u>Calculation of Charges - Specific Provisions</u>

a. Mile Hi - Alturas 115 kV line

(1) For the period of time from 2400 hours on June 30, 1981 to the date of energization of BPA's proposed 230 kV Malin - Alturas line, BPA shall pay charges calculated as if power flowed from Mile Hi to the Davis Creek, Cedarville, and Alturas Points of Delivery.

(2) For the period of time from the date of energization of BPA's proposed 230 kV Malin - Alturas line until 2400 hours on December 31, 1991 BPA shall pay charges calculated as if power flowed from Alturas to the Cedarville, Davis Creek, and Lakeview 69 kV points of delivery.

(3) Commencing at 2400 hours on December 31, 1991 BPA will pay charges calculated as if power flowed from Alturas to the Cedarville and Davis Creek points of delivery.

b. Transfer charges for service to the Hanna, Lookingglass, and Ashland Loads shall be calculated based on a Fairview point of replacement. These charges shall include payment to PP&L for BPA's use of the Government's Fairview - Reston 230 kV line for which PP&L is currently paying an exclusive use charge.

c. Following energization of the Buckley-Summer Lake - Malin 500 kV line and the 230 kV Malin-Alturas line, the point of replacement for transfer service to BPA's Surprise Valley Electrification load shall be the Malin 500 kV bus. BPA will pay UFT-2 charges for use of PP&L's's 500-230 kV Malin transformer. If BPA agrees that a second 500-230 kV transformer is a reasonable addition to provide reliable service to area loads and when PP&L adds such transformer, charges for such transformer shall be included in the UFT-2 calculations for the use of PP&L's Malin 500-230 kV facilities.

C. General Transfer Agreement.

1. Services rendered subsequent to July 1, 1981 shall be pursuant to the terms and conditions of the proposed General Transfer Agreement (draft dated September 10, 1980); provided, however, that charges and payments shall be based upon the amounts of electric power and energy delivered at the specified points of delivery adjusted for losses to the point of replacement.

2. BPA and PP&L agree that the General Transfer Agreement to be executed pursuant to subsection 3 below shall provide that the parties reciprocally apply the methodology contained in BPA's UFT - 2 rate schedule or its successor for transfer services rendered pursuant to the General Transfer Agreement. BPA and PP&L shall share in the cost of the unused capacity of facilities. This payment reflects the transferor's acceptance of the responsibility to provide additional facilities as required to serve the load growth of the parties.

3. The parties agree to execute the General Transfer Agreement no later than 60 days subsequent to the date of execution of this agreement.

D. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution and shall continue in effect until 2400 hours on the date of execution of the General Transfer Agreement, except that all obligations incurred hereunder shall be preserved until satisfied.

If the above listed conditions are acceptable to you, please countersign this letter and return it to me. BPA will then initiate the appropriate actions to implement these arrangements.

Sincerely,

/s/ Peter T. Johnson

Administrator

PACIFIC POWER & LIGHT COMPANY

By /s/ Robert W. Moench

Title Senior Vice President

Date March 4, 1982

Enclosure:
Points of Delivery and Charges
UFT - 2 Rate Schedule

ATTEST:
By /s/ Sally A. Nofziger

Title Assistant Secretary

(WP-PCI-1057c)

Attachment 1
Contract No. DE-MS79-82BP90924
Pacific Power & Light Company
Effective at 2400 hours on
June 30, 1981

POINTS OF DELIVERY AND CHARGES

Points of Delivery	Charges: Fixed	Charges: Variable
1. Surprise Valley		
Austin		$1.20/kW/Mo.
Alturas	$242.00/mo.	$5.06/kW/Mo.
Canby		$.90/kW/Mo.
Cedarville		$3.37/kW/Mo.
Davis Creek		$2.31/kW/Mo.
Lakeview 69kV		$1.62/kW/Mo.
2. Looking Glass	$2,617.00/Mo.	$.530/kW/Mo.
3. Hanna	$6,141.00/Mo.	$.189/kW/Mo.
4. City of Ashland 1/ Ashland	$8,554.00/Mo.	$.526/kW/Mo.
Oak Knoll	$4,019.00/Mo.	$.526/kW/Mo.

1/ This point of delivery shall be effective at 2400 hours on February 27, 1982.

(WP-PCI-1057c)

SCHEDULE UFT - USE-OF-FACILITIES TRANSMISSION.

SECTION 1. Availability: This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. This schedule is not appropriate for new agreements for service over the Integrated Network Segment, or the PNW-PSW Intertie Segment.

SECTION 2. Rates: The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specified facilities. Such Annual Cost shall be determined in accordance with Section 3.

SECTION 3. Determination of Transmission Rate:

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and are used to transmit electric power and energy thereunder:

1. Capital cost of each such facility as specified in the most recently published plant investment records of BPA which are issued in support of the Federal Columbia River Power System financial statement.

2. Annual Interest and Amortization Ratios for each such facility using the most recent system average cost factors developed from actual Interest and Amortization costs for specific categories of FCRTS facilities and from data included in the financial statement.

3. Operation, maintenance, administrative and general, and general plant costs of such facilities using the most recent system average costs for specific categories of FCRTS facilities.

4. The yearly noncoincidental peak demands of all users of such facilities.

B. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each of the FCRTS facilities used. The Annual Cost per kilowatt of each facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{(I \times R) + B}{D}$$

Where B = Operation, maintenance, administrative and general, and general plant cost of such facility as determined in A.3.

I = Capital cost of such facility as determined in A.1.

R = Annual Interest and Amortization Ratio for such facility as determined in A.2.

D = The sum of the yearly noncoincidental demands on the facility as determined in A.4.

The Annual Co per kilowatt of facilities ..sted in the Agreement which are owned by another entity, and used by BPA for making deliveries to the Transferee, shall be determined from the costs specified in the Agreement between BPA and such other entity.

SECTION 4. Determination of Transmission Demand: Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. the Ratchet Demand.

SECTION 5. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Exhibit H, Revision No. 3
Contract No. DE-MS79-82BP90049
PacifiCorp
Effective at 2400 hours on
June 30, 2000

Factors for Determining Power Factor

Revises the Factors for all listed Points-of-Delivery except Dalreed, Klondike and Knappa Tap. Deletes Chelatchie, View, Gilmer, Glenwood and Hanna. Adds Ashland, Oak Knoll, Mt. Avenue, Pilot Butte, Ariel, Pilot Rock, Creswell, Powerline, Nehalem, Alturas and Olney.

Point-of-Delivery	Reactive Factor (X)%	Energy Adj. Factor (Z)	Constant kvarh Reactive Adj. (Y)	
Dalreed	7.2	1.008	+	214,182
Klondike	0.37	1.003	-	140,890
Knappa Tap	12.35	1.0113	+	32,726
Ashland	15.58	1.0067		0
Oak Knoll	20.58	1.0100		0
Mt. Avenue	2.57	1.0041		28,747
White Swan	4.17	1.0095	+	70,416
Pilot Butte	9.66	1.0024		0
Ariel	1.62	1.0052	+	10,402
Pilot Rock	0.37	1.0003		0
Ukiah	4.15	1.0107	+	48,221
Dayton	1.67	1.0074	+	24,841
Creswell	4.49	1.0040	+	10,023
Powerline	3.03	1.0035	+	7,427
Woody Guthrie	4.32	1.0033	+	11,917
Bingen	6.42	1.0051	+	56,847
Dorena	2.95	1.0066	+	39,564
Ormet	25.23	1.0134		0
Mohler	2.56	1.0054	+	7,123
Garibaldi	6.31	1.0034	+	20,019
Nehalem	5.24	1.0035	+	20,019
Alturas	9.07	1.0051		0
Davis Creek	1.82	1.0214	+	50,842
Cedarville	6.74	1.0087	+	44,021
Hat Rock	8.93	1.0083	+	589,162
Warm Springs	2.10	1.0074	+	26,383
Necanicum	4.15	1.0184	+	31,057
Olney	0.04	1.0002		0

PACIFICORP

By:

Name: Donald N. Furman

Title: Vice President

Date: June 20, 2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By:

Name: Anne E. Draper

Title: Manager, Transmission Acquisition and Reserves

Date: 6/22/00

EXHIBIT I, REVISION NO. 1
SETTLEMENT OF DEVIATIONS

This Exhibit I, Revision No. 1 sets out the bandwidth for "Normal" and "Excessive Monthly" energy "Deviations," as defined below, and prescribes the rates at which such Deviations will be settled between PacifiCorp and the Bonneville Power Administration (Bonneville), both of which may be referred to individually, as a Party, or collectively as the Parties. This Exhibit I is hereby made part of the General Transfer Agreement (DE-MS79-82BP90049) between the Parties and shall be changed only upon the mutual written consent of each Party.

1. Deviation means the difference during a single month between scheduled and actual delivery of energy to Bonneville or PacifiCorp loads.

    a. A positive deviation occurs where a Party's total monthly actual load was less than that Party's total monthly delivered energy across all of its checkout transaction point types.
    b. A negative deviation occurs where a Party's total monthly actual load was more than that Party's total monthly delivered energy across all of its checkout transaction point types.

2. Normal Deviations are Deviations that are less than or equal to the bandwidth of each Party established below:

    a. Normal Deviation for Bonneville: Less than or equal to 1000 MWh in a month.
    b. Normal Deviation for PacifiCorp: Less than or equal to 500 MWh in a month.

3. Excessive Monthly Deviations are Deviations that exceed a Party's Normal Deviation bandwidth in a month.

4. A Party's deviation level (Normal or Excessive) will be calculated on a monthly basis by netting out all of a Party's positive deviations during a month against all of a Party's negative deviations during a month.

5. All deviations (Normal and Excessive) will initially be settled on a monthly basis at $2.50/MWh.

6. In November of each year, the Parties will review and settle any Excessive Monthly Negative Deviations from the previous September through August period at the Excessive Monthly Negative Deviation Adjustment Price described below.

    a. Excessive Monthly Negative Deviation Adjustment Price:

Excessive Monthly Negative Deviation Adjustment Price	=	(Monthly Market Price - $2.50/MWh) * Excessive Negative Deviation (MWh) for the month.
Where:		
Monthly Market Price	=	Unless modified pursuant to section 6(b) below, the Monthly Market Price shall mean the monthly average of the Intercontinental Exchange (ICE) Mid-C Day Ahead weighted average of the peak and off-peak prices for each day of the month. The ICE firm Day Ahead market prices (for both HLH and LLH) used in the calculations will be limited to a minimum of $0/MWh.
Excessive Monthly Negative Deviation	=	A negative deviation (as defined above in 1.b), that is Excessive (as defined above in section 3).

b. Alternative Index Because of Market Disruption Event.

(1) If a Market Disruption Event occurs on any one or more days in the month, then either Party may provide notice in writing to the other Party of the Market Disruption Event. In such case, the Parties shall mutually agree upon a substitute index that most closely applies to energy and energy deliveries under this agreement (considering applicable factors and the intent of the Parties, including such factors as delivery point, firmness of electricity, and general acceptance and use of such index by market participants), or such other substitute index as the Parties may agree.

(2) If the Parties are unable to so agree within 30 days after the foregoing notice is given, the Parties may agree to refer the matter to a mediator to choose a substitute index based on the criteria in (b)(1) above.

(3) Pending agreement on or determination of the substitute index, the Party entitled to a settlement payment based on the index shall specify an interim index or pricing method, acting reasonably, and amounts so credited based on such interim index or pricing method shall be adjusted retroactively, to reflect the selected substitute

index, to the date the Party provided the notice in writing referred to above.

(4) If there is no daily index price published for the peak and/or off-peak period of a day or series of days in a month, and neither Party provides notice of the Market Disruption Event, the Monthly Market Price will be calculated using the remaining days in the month that have both the peak and off-peak prices published.

(5) "Market Disruption Event" means, with respect to the ICE Index, any of the following events:

(i) the failure of the ICE Index to announce, publish or make available the specified index or information necessary for determining the ICE index Price for a particular day;

(ii) the failure of trading to commence on a particular day or the permanent discontinuation or material suspension of trading in the relevant market specified for determining the ICE index;

(iii) the temporary or permanent discontinuance or unavailability of the ICE index;

(iv) a material change in the formula for or the method of determining the index by the index publisher or a material change in the composition of the ICE Index.

[Signatures to Follow]

The Parties have executed this Exhibit as of the last date indicated below.

PACIFICORP

By: Rick Vail

Name: Rick Vail

Title: Vice President, Transmission

Date: 2/22/17

By: Joseph H

Name: Joeseph Hoerner

Title: Vice President, Energy Supply Management

Date: 2-24-17

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Dan Y

Name: Dan Yokota

Title: Manager, Transfer Services

Date: 2/22/17

Contract No. DE-MS79-82BP90049

5-3-82

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

Index to Sections

- -

This GENERAL TRANSFER AGREEMENT, executed May 4, 1982, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFIC POWER & LIGHT COMPANY (Company), a corporation of the State of Maine,

W I T N E S S E T H :

WHEREAS Bonneville and the entities named in Exhibit B (Bonneville's Customers) have entered into power sales contracts providing for the delivery of firm power and energy to such customers at various points of delivery in part by transfer over Company facilities; and

WHEREAS the parties hereto have executed agreements which provide that Bonneville or the Company, as the case may be, transfer electric power and energy to the Company or Bonneville's Customers at various points of delivery described in Exhibits B and C and now desire to replace such agreements in accordance with a letter agreement (Contract No. DE-MS79-82BP90924), with a single agreement; and

WHEREAS the parties, on August 9, 1973, executed an exchange agreement (Contract No. 14-03-29245, which as amended or replaced is called "Exchange Agreement") providing, among other matters, for an exchange energy account (Exchange Account), measurement and scheduling arrangements, and points of delivery; and

WHEREAS the parties hereto have agreed to a reciprocal transfer service philosophy which is recognized in this agreement and to consolidate and add various provisions to allow more frequent review of charges and loss factors in a manner consistent with the review of transmission rate schedules; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Agreements. Contract No. 14-03-001-10010, as amended, Contract No. 14-03-001-10662, as amended, Contract No. 14-03-001-11343, as amended, Contract No. 14-03-001-11477, as amended, Contract No. 14-03-001-13386, as amended, Contract No. 14-03-001-13395, Contract No. 14-03-001-14609, Contract No. 14-03-17532, as amended, Contract No. 14-03-37030, Contract No. 14-03-47929, as amended, Contract No. 14-03-56743, as amended, Contract No. 14-03-75629, Contract No. 14-03-77652, Contract No. 14-03-84718, Contract No. 14-03-86605, as amended, Contract No. 14-03-86620, as amended, and Contract No. DE-MS79-79BP90043 are hereby terminated as of the effective date hereof, but all liabilities accrued thereunder shall be and are hereby preserved until satisfied.

2. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution, and shall terminate on the earlier of the following:

(a) 2400 hours on the date of termination of the Exchange Agreement, or

(b) the time of the termination of all deliveries hereunder.

3. Exhibits. Exhibits A through H are made a part of this agreement. The Company shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to Bonneville's Customers or Bonneville, as the case may be, at points of delivery specified in Exhibit B, and each of Bonneville's Customers or Bonneville, as the case may be, shall be the "Transferee" mentioned therein. Bonneville shall be the "Transferor" as that term is used in Exhibit A when transferring electric power and energy to the Company at points of delivery specified in Exhibit C, and the Company shall be the "Transferee" mentioned therein. All references to "the Administrator" in such exhibits are changed to "Bonneville."

4. Revision of Exhibits.

(a) Exhibits B, C, D, and H shall be revised at:

(1) any time by mutual agreement of the parties to add or remove points of delivery;

(2) the time specified by the party receiving transfer service in a written notice to the Transferor to remove any point of delivery specified in Exhibits B or C, as the case may be, but not before the expiration of 1 year from 2400 hours on the date notice is received by the Transferor; or

(3) the time specified by the Transferor in a written notice to the party receiving transfer service to remove any point of delivery in the situation where the facilities used to perform the transfer service are surplus to the needs of the Transferor, but not before the expiration of 3 years from 2400 hours on the date such notice is received by the party receiving transfer service.

(b) Exhibit F contains the methodology for calculating Transfer Charges and Sole Use of Facility Charges listed in Exhibit D and shall be used by both parties. This methodology is an application of Bonneville's UFT-2 rate schedule. The UFT-2 rate schedule is included as a part of Exhibit G. Any change to the methodology described in Exhibit F shall require mutual approval of the parties; however such methodology shall be periodically reviewed by the parties upon the request of either party to consider modifications. Such modifications shall not be allowed more often than once in each 3-year period and shall be applicable to both parties. The values of the variables I, R, and D used in the methodology are expected to change from time to time and such changes shall not be deemed to be a change in the methodology. Bonneville waives its right to unilaterally change its rates provided in Exhibit F pursuant to section 37 of Exhibit A, Equitable Adjustment of Rates Section, insofar as it applies to this contract.

(c) The charges and Loss Factors specified in Exhibit D and factors in Exhibit H shall be revised pursuant to section 19 of Exhibit A, Adjustment for Change of Conditions Section, upon mutual agreement of the parties. The Transferor shall submit notice of such revision including justification for any such revision 90 days prior to the date the revision is requested to be effective. The party receiving transfer service shall review such information and shall not unreasonably withhold agreement to change the affected Exhibit. Any Loss Factor, Transfer Charge, or Sole Use of Facilities Charge shall be reviewed if requested by either party, but such review shall not be required more often than once in any 12-month period for any point of delivery; and if parameters used to calculate such factors or charges have changed, the parties shall not unreasonably withhold their agreement to change the affected Exhibits.

(d) Upon any change in methodology or charges pursuant to this section, the Transfer Charges and Sole Use of Facilities Charges specified in Exhibit D or any subsequent charges specified in this agreement shall be recalculated accordingly and the parties shall prepare a revised Exhibit D incorporating the new charges. A revised Exhibit D shall also be prepared to incorporate any change in Loss Factors pursuant to this section. Such revised Exhibit D shall be substituted for the Exhibit D then in effect and shall become effective as of the effective date of such new methodology or charges.

5. Provisions Relating to Delivery. Electric power and energy shall be made available by the Transferor at all times during the term hereof at the points of delivery described in Exhibits B and C, in the amount of the Transferee's requirements at such points and at the approximate voltages specified therefor. Amounts of electric energy, Integrated Demands therefor, and varhours delivered at such points during each month shall be determined from measurements made by meters installed at the locations and in the circuits specified in Exhibits B and C. Such amounts shall be increased for losses as determined by the parties hereto and specified in Exhibit D (Loss Factors). Such Loss Factors reflect all losses from the point of metering to the point of replacement specified in Exhibit B or C. Losses shall be determined on an incremental basis and the Transferee shall be assessed the incremental losses so determined. On or before July 1 of each year each party shall furnish the other party a five year forecast of the maximum demand for each of the points of delivery described in Exhibits B or C, as the case may be.

6. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the party receiving transfer service shall make electric power and energy available to the Transferor during each month in the term hereof, at the points of replacement specified in Exhibit B or C as the case may be. Such electric power and energy to be made available by the party receiving transfer service shall be computed by

increasing metered amounts, determined as provided in Exhibit B or C for each point of delivery, by the Loss Factors specified in Exhibit D.

The party receiving transfer service shall make available to the Transferor each hour in each month during the term hereof the amount of electric energy which is estimated to be the amount, so increased for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor as provided in the Exchange Agreement.

7. Payment for Transfer of Power.

(a) For the use of Transferor services and facilities in transferring electric power and energy hereunder, the party receiving transfer service shall pay the Transferor each month in the term hereof an amount equal to the sum for all points of delivery of the greater of (1) or (2) below for each point of delivery:

(1) the product of the Transfer Charge for each point of delivery and the Transfer Demand for that month for such point of delivery after increasing such Transfer Demand by one percent for each one percent or major fraction thereof by which the average power factor, at which electric energy is delivered at the point of delivery hereunder during each month, is less than 95 percent lagging; or

(2) the largest product obtained by multiplying the Transfer Demand of each of the 11 immediately preceding months by the respective Transfer Charge for each such month.

(b) The "Transfer Charge" for each point of delivery mentioned in subsection (a) above shall be as shown in Exhibit D. Transfer Charges shall be determined pursuant to Exhibit F.

(c) The "Transfer Demand" mentioned in subsection (a) above shall be the largest of the Integrated Demands, increased by the Loss Factors specified in Exhibit D, at which electric energy is delivered by the Transferor hereunder during such month, determined as provided in Exhibits B or C, as the case may be, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency conditions.

(d) For determining power factor in subsection (a)(1) above, metered amounts shall be adjusted for losses between the point of metering and the point of delivery. These losses shall be calculated from factors contained in Exhibit H which are different from the Loss Factors contained in Exhibit D.

8. Payment for Sole Use of Facilities. In addition to the payment due the Transferor in accordance with section 7, the party receiving transfer service shall pay the Transferor each month the amounts specified in Exhibit D under "Sole Use of Facilities Charge" for sole use of facilities by the party receiving transfer service. Sole Use of Facilities Charges shall be determined pursuant to Exhibit F.

9. Payment of Bills.

(a) The Company shall reimburse Bonneville in accordance with applicable provisions of Exhibit E by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section.

(b) Bonneville shall reimburse the Company for services hereunder within 30 days following its receipt of an itemized statement of payments due pursuant to sections 7 and 8 hereof by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section. If the Company is unable to render Bonneville a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill.

10. Removal of Existing Facilities, Termination of Charges, and Installation of Additional Facilities.

(a) The parties shall exchange any necessary data and confer from time to time to determine the necessity for removal of existing facilities and for installation of additional facilities to enable the parties to fulfill their obligations hereunder. If the parties cannot agree on the need for addition or removal of facilities, the Transferor shall make such determination. The Transferor agrees to provide additional facilities at the Transferor's expense as required to serve the combined load growth of both parties; provided, however, that the Transferee may provide such facilities at the Transferee's expense, subject to mutual agreement of the parties and appropriate credit to the Transferee, if the Transferee can do so at less total expense to both parties. Any facilities provided by the Transferee shall be compatible with the specifications of the Transferor. The cost and ownership of such new facilities shall be reflected in the next amendment of the charges contained in Exhibit D in accordance with the methodology contained in Exhibit F.

(b) Upon removing or installing facilities as determined in subsection (a) above, the parties shall include such revisions in this agreement, including the applicable contract terms and termination charges, if any, by executing new Exhibits B, C, or D, as appropriate. Such new exhibit shall replace the existing exhibit on the effective date specified therein.

(c) The party receiving transfer service shall pay the Transferor an appropriate mutually agreeable termination charge to the extent that the capacity of such facilities which were provided to enable the transfer service would be excess to the Transferor's needs as a consequence of any of the following:

(1) the parties agree to remove facilities pursuant to subsection (a) above;

(2) a point of delivery is terminated pursuant to section 4(a)(1) or 4(a)(2); or

(3) this agreement is terminated as provided in section 2.

(d) If additional facilities must be constructed or installed by either party pursuant to subsection (a) above, a reasonable period of time shall be allowed for such construction or installation.

11. Ratification of Interim Agreement. During the period commencing:

(a) July 1973 to July 1, 1981, the parties hereto have provided each other services as described in Exhibit G and the settlement therefor shall be as specified therein;

(b) July 1, 1981, to the effective date of this agreement, the parties hereto have provided each other services as described herein and in Exhibit G and payment therefor shall be as specified in Exhibit G, except that the points of delivery and charges contained in Attachment 1 to Exhibit G are hereby replaced by the points of delivery and charges contained in Exhibits B, C, and D hereto, effective as of the dates specified in such exhibits. Some of the services covered by the retroactive provisions of this section were also covered by provisions of contracts which are being terminated pursuant to section 1 hereof (Prior Contracts). In such cases, the provisions and charges contained herein shall supercede the provisions and charges of such Prior Contracts and any payments made for such services subsequent to June 30, 1981, pursuant to such Prior Contracts shall be credited against payments due hereunder for such services. All liabilities accrued pursuant to Exhibit G shall be and are hereby preserved until satisfied.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy

By ______________________
Bonneville Assistant Adminstrator for Power Management

PACIFIC POWER & LIGHT COMPANY

By ______________________

Title Vice President

Date May 4, 1982

ATTEST:

By ______________________

Title Assistant Secretary

Date May 4, 1982

(WP-PCI-1185c)

EXHIBIT A

GWP Form-3 (7-27-77)

GENERAL WHEELING PROVISIONS

Index to Sections

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in the agreement to which these General Wheeling Provisions are an exhibit shall be deemed to be a part hereof for the purpose of determining the meaning of any provision contained herein. If a provision in such agreement is in conflict with a provision contained herein, the former shall prevail

(b) Nothing contained in this agreement shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. . As used in this agreement:

(a) the words "Contractor", "Utility" or "Borrower" as used herein shall mean the party to this agreement other than the Administrator;

(b) the word "month" shall mean the period commencing at the time when the meters mentioned in this agreement are read by the Administrator and ending approximately 30 days thereafter when a subsequent reading of such meters is made by the Administrator;

(c) the words "Integrated Demand" shall mean the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour;

(d) the words "System" or "Facilities" shall mean the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

3. Prior Demands. In determining any credit demand mentioned in, or money compensation to be paid under this agreement for any month, Integrated Demands at which electric energy was delivered by the Transferor at points of delivery mentioned herein for the account of the other party to this agreement prior to the date upon which the agreement takes effect shall be considered in the same manner as if this agreement had been in effect.

4. Measurements. Except as it is otherwise provided in section 7 hereof, each measurement of each meter mentioned in this agreement shall be the measurement automatically recorded by such meter, but if not so recorded, shall be the measurement as determined by the parties hereto.

If it is provided in this agreement that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by representatives designated by the parties to such agreement. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such changes in conditions.

5. Measurements and Installation of Meters. The Administrator may at any time install a meter or metering equipment of the Government to make the measurements required for any computation or determination mentioned in this agreement, and if so installed such measurements shall be used thereafter in such computation or determination.

6. Tests of Meters. Each party to this agreement will, at its expense, test its meters mentioned in this agreement at least once every two years, and, if requested to do so by the other party, will make additional tests or inspections of such meters, the expense of which will be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in section 7 hereof. Each party will give reasonable notice of the time when any such test or inspection is to be made to the other party, who may have representatives present at such test or inspection. Meters found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering.

(a) If any meter mentioned in this agreement fails to register, or if the measurement made by such meter during a test made as provided in section 6 hereof varies by more than one percent from the measurement made by the standard meter used in such test, adjustment shall be made correcting all measurements made by such inaccurate meter during the period hereinafter stated. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, of any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this agreement for (1) the actual period during which such inaccurate measurements were made if such period can be determined, or (2) if not, the period immediately preceding a tes of such inaccurate meter which is equal to one-half the time from the date of the last preceding test of such meter; provided, however, that the period for which such recomputations are to be made shall not exceed six months.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto within 30 days after the recomputation is made; provided, however, that the other party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this agreement.

8. Character of Service. Unless otherwise specifically provided for in the agreement, electric power and energy made available pursuant to this agreement shall be in the form of three-phase current, alternating at a frequency of approximately 60 hertz.

9. Point of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this agreement that the amounts of electric energy and varhours, delivered at any point of delivery, and of the Integrated Demands for such electric energy, for any period,

shall be the amounts thereof determined by combining deliveries at two or more metering points coincidentally:

(a) the amounts of electric energy and varhours so delivered at such point of delivery during such period shall be the sums computed by adding together the amounts of electric energy and varhours, respectively, which flow during such period at such metering points, determined as provided in this agreement; and

(b) the amount of each Integrated Demand for such electric energy at such point of delivery shall be the sum computed by adding together the Integrated Demands for such hour at such metering points, determined as provided in this agreement.

11. Suspension of Deliveries. The other party to this agreement may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this agreement. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. The Transferor may temporarily interrupt or reduce deliveries of electric power and energy to the Transferee if he determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the Transferor's System. Except in case of emergency and in order that the Transferee's operations will not be unreasonably interfered with, the Transferor will give the Transferee advance notice of any such interruption or reduction, the reason therefor, and the probable duration thereof.

13. Uncontrollable Forces.

(a) Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

(b) The term "Uncontrollable Forces" means:

(1) Strikes affecting the operation of either party's System or other Facilities upon which such operation is completely dependent; or

(2) Such of the following events as either party, by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(i) Events, reasonably beyond the control of the party having jurisdiction thereof, causing failure, damage, or destruction of any such system or facilities. The word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such System or Facilities; or

(ii) Floods which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such system or facilities.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces, as defined in section 13 hereof, on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid, to the Transferor shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Payments due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree. Under contracts included in this procedure all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

In applying the above formula, the meter for measurement of reactive kilovolt-ampere-hours will be ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this agreement, no adjustment will be made for power factor at any point of delivery described in this agreement while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 lagging.

17. Permits.

(a). If by the terms of any contract between the parties any equipment or facilities of a party to this agreement are, or are to be, located on the property of the other at any point of delivery provided in this agreement, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this agreement and to remove such equipment and facilities at the expiration of said term, together with the right of ingress to and egress from the location thereof at all reasonable times in such term is hereby granted by the other party.

(b) Each party shall have the right to read, at all reasonable times, any and all meters mentioned in this agreement which are installed on the property of the other.

(c) If by the terms of any contract between the parties either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modifications which may affect the duties of the other party in regard to such equipment, and furnish the other party accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed by a party to this agreement on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and, to the extent agreed upon by the parties, all other salvable facilities which are installed by such party on the property of the other. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this agreement to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this agreement, such factor will be changed in a manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this agreement to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Arbitration. If the parties do not agree on the determination of any question of fact hereinafter stated, such determination will be made by arbitratio The party calling for arbitration shall serve notice in writing on the other party setting forth in detail the question or questions to be arbitrated and the arbitra appointed by such party. The other party shall, within ten days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator withi said ten days, or in case the two so appointed fail for ten days to agree upon and appoint a third, the party calling for the arbitration, upon five days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second or third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators, and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, and all other costs incurred in connection with the arbitration shall be paid equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be: (a) the determination of the measurements to be made by the parties hereto pursuant to section 4 hereof; (b) the correction of the measurements to be made as provided in section 7 hereof; (c) the amount of reduction in charges mentioned in section 14 hereof; (d) the duration of the interruption or equivalent interruption mentioned in section 14 hereof; (e) whether changes in conditions mentioned in section 19 hereof have occurred, and if so, the change to be made in the factor mentioned; (f) whether an increase or decrease in load or change in load factor mentioned in section 31 hereof is unusual; (g) any fact mentioned in sections 29 and 33 hereof; (h) whether an abnormal nonrecurring demand occurred and the amount and time therec (i) and the acceptable level of harmonics mentioned in section 34 hereof.

21. Contract Work Hours and Safety Standards. This agreement, to the extent that it is of a character specified in the Contract Work Hours and Safety Standards Act (40 U.S.C. 327-333), is subject to the following provisions and to all other applicable provisions and exceptions of such Act and the regulations of the Secreta of Labor thereunder.

(a) Overtime requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers, mechanics, apprentices, trainees, watchmen, and guards shall require or permit any laborer, mechanic, apprentice, trainee, watchman or guard in any workweek in which he is employed on such work to work in excess of eight hours in any calendar day or in excess of 40 hours in such workweek on work subject to the provisions of the Contract Work Hours and Safety Standards Act unless such laborer mechanic, apprentice, trainee, watchman, or guard receives compensation at a rate not less than one and one-half times his basic rate of pay for all such hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, whichever is the greater number of overtime hours.

(b) Violation; liability for unpaid wages; liquidation of damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for his unpaid wages. In addition, such Contractor and subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer, mechanic, apprentice, trainee, watchman, or guard employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed on such work in excess of eight hours or in excess of his standard workweek of 40 years without payment of the overtime wages required by subsection (a).

(c) Withholding for unpaid wages and liquidated damages. The Administrator may withhold from the Government Prime Contractor, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in the provisions of subsection (b) above.

(d) Subcontracts. The Contractor shall insert subsections (a) through (d) of this section in all subcontracts, and shall require their inclusion in all subcontracts of any tier.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for three years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. (The following clause is applicable unless this agreement is exempt under the rules, regulations and relevant orders of the Secretary of Labor [41 CFR, ch. 60].)

During the performance of this agreement, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Administrator setting forth the provisions of this Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Administrator, advising the labor union or workers' representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractdor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Administrator and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (g) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as the Administrator may direct as a means of enforcing such provisions, including sanctions for noncompliance; <u>provided, however</u>, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the Administrator, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

24. Reports. The other party to this agreement will furnish the Administratc such information as is necessary for making any computation required for the purposes of this agreement, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

25. Assignment of Agreement. This agreement shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this agreement; provided, however, that neither such agreement nor any interest therein shall be transferred or assigned by either party to any party other than the United States or an agency thereof without the written consent of the other; provided, further, that the consent of the Administrator is hereby given to any security assignment which may be required under terms of any mortgage, trust, or security agreement made by and between the Utility and any mortgage, trustee, or secured party, as security for bonds or other indebtedness of such Utility, present or future; such mortgagee, trustee, or secured party may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Utility.

26. Waiver of Default. Any waiver at any time by any party to this agreement of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such agreement, shall not be considered a waiver with respect to any subsequent default or matter.

27. Notices and Computation of Time. Any notice required by this agreement to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

28. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this agreement or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this agreement if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS AGREEMENT

29. Balancing Phase Demands. The Administrator may, at any time during the term of this agreement, require the Transferee to make such changes as are necessary on its system to balance the phase currents at any point of delivery so that the current on any one phase shall not exceed the current on any other phase at such point by more than ten percent.

30. Adjustment for Unbalanced Phase Demands. If the Transferee fails to make promptly the changes mentioned in section 29 hereof, the Administrator, at the Transferee's expense, may determine, for each month thereafter until such changes are made, that the registered demand of the Transferee at the point of delivery in question is equal to the product obtained by multiplying by three the largest of the Integrated Demands of the Transferee on any phase at such point during such month. This section shall not apply with respect to any point of delivery where the current required to be supplied at such point is other than three-phase current.

31. Changes in Demands or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Administrator of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

32. Inspection of Transferee's Facilities. The Administrator may, but shall not be obligated to, inspect the Transferee's electric installation at any time, but such inspection, or failure to inspect, shall not render the Government, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this agreement. The Administrator shall observe written operating instructions posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

33. Electric Disturbances.

(a) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(b) If both parties to this agreement are parties to the Agreement Limiting Liability Among Western Interconnected Systems, their relationship with respect to system damages shall be governed by that Agreement.

(c) During such time as a party to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this agreement shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (a)(2) above.

(d) If one of the parties to this agreement is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this agreement shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (a)(2) above, and such failure contributed to the loss, injury or damage.

(e) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this agreement.

34. Harmonic Control. Each party shall design, construct, operate, maintain, and use its electric system in accordance with good engineering practices to minimize to acceptable levels the production of harmonic currents and voltages injected or coupled into the other party's facilities.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS AGREEMENT

35. Protection of the Transferor. Protection is or will be afforded to the Government or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by the Administrator and each third party Transferee named in this agreement: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Purchaser's Facilities.

RELATING ONLY TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

36. Approval of Agreement. This agreement shall not be binding on the parties thereto if it is not hereafter approved by the Administrator of the Rural Electrification Administration and any other entity from whom the Borrower borrows under an indenture which requires the lender's approval; provided, however, that the Borrower shall notify the Administrator of any such entity prior to the Administrator's execution of this agreement. If so approved it shall be effective at the time stated in the section of this agreement entitled "Term of Agreement."

APPLICABLE ONLY IF THE ADMINISTRATOR IS THE TRANSFEROR

37. Equitable Adjustment of Rates.

(a) As used in this section, the words "Rate Adjustment Date" shall mean any date designated by the Administrator after the date a new rate schedule is available for the class, quality, and type of service covered by this agreement; provided, however, that a Rate Adjustment Date shall not occur more frequently than once in any 12-month period. The Administrator may file with the Federal Power Commission or its successor for approval of a revised or new rate when he determines such revised or new rate is necessary to reflect the cost of the class, quality, and type of service covered by this agreement. The Administrator shall provide the Transferee with his then proposed schedule or schedules, supporting data, and a statement reflecting the effects of the proposed schedule or schedules on the charges specified in this agreement no less than 90 days prior to filing a proposed schedule or schedules with the Federal Power Commission or its successor, unless shorter periods are agreed upon by the parties hereto. The rate schedule in effect under this agreement on the Rate Adjustment Date shall continue in effect until the next Rate Adjustment Date on which revised or new rate schedules shall have been proposed by the Administrator and confirmed and approved by the Federal Power Commission or its successor.

(b) The Transferee shall pay the Administrator for the service made available under this agreement during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period which would be incorporated in a new agreement for service of the class, quality, and type provided for in this agreement, and in accordance with the terms hereof and of the General Transmission Rate Schedule Provisions incorporated or referred to in such rate schedule. If at the beginning of such period more than one rate is available for the class, quality, and type of service covered by this agreement, the Transferee shall, prior to 30 days after the later of the effective date of such rate or the date of approval of such rate by the Federal Power Commission or its successor, notify the Administrator in writing which of such rates the Transferee elects to have applied under this agreement during such period. If the Transferee fails to make such election, the Administrator shall determine the applicable rate. Such election by the Transferee or determination by the Administrator shall be applied as of the beginning of the first billing month following the effective date of such rate.

Points of Delivery for Bonneville

This Revision No. 1 adds the Mountain Avenue Point of Delivery.

1. ASHLAND POINT OF DELIVERY:

Location: the point in the PacifiCorp's Ashland Substation where the 12.5 kV facilities of the PacifiCorp and the City of Ashland are connected.

Voltage: 12.5 kV.

Metering: in the PacifiCorp's Ashland Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: The point in Meridian Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

2. OAK KNOLL POINT OF DELIVERY:

Location: the point in the PacifiCorp's Oak Knoll Substation where the 12.5 kV facilities of the PacifiCorp and the City of Ashland are connected.

Voltage: 12.5 kV.

Metering: in PacifiCorp's Oak Knoll Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: the point in Meridian's Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

3. MOUNTAIN AVENUE POINT OF DELIVERY:

Location: the point in PacifiCorp's Oak Knoll-Ashland 115 kV line where Bonneville's 115 kV Mountain Avenue Tap line is connected.

Voltage: 115 kV.

Metering: in Bonneville's Mountain Avenue Substation, in the 12.5 kV circuit over which electric power and energy flows.

Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
City of Ashland
Effective Date: November 1, 1994

Point of Replacement: the point in Meridian Substation where PacifiCorp's 230/500 kV facilities interconnect with PacifiCorp's and Bonneville's jointly owned 500 kV 3rd AC Intertie facilities.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________
Senior Customer Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 31, 1995

PACIFICORP

By ______________________

Title Manager, Customer Contract Administration

Name Colin Persichetti
(Print/Type)

Date February 7, 1995

(VS9-MPSD-3608e)

Exhibit B, Table 2, Revision No. 4
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Yakama Power
Effective 2400 hours on April 5, 2017

Points of Delivery for Bonneville

This revision documents the transfer of the White Swan point of delivery from Benton REA to Yakama Power.

WHITE SWAN POINT OF DELIVERY:

Location: the point in Yakama Power's White Swan Substation where the facilities of Yakama Power and Company are connected.

Voltage: 115 kV.

Metering: In the Yakama Power White Swan Substation, in the 115 kV circuit over which such electric power and energy flows.

Meter Adjustment: The Yakama Power White Swan meter reading will be adjusted by deducting Yakama Power's Hawk Road meter point, plus demand losses of 1.0163% and energy losses of 1.0170%. (NOTE: See Network Agreement between PacifiCorp and BPA to serve Yakama Power)

Point of Replacement: the point outside the Government's Moxee Switching Station where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By [signature]
Name: Dan Yokota
Date: 2/6/17

PACIFICORP

By [signature]
Name: Rick Vail
Date: 2/2/17

Exhibit B, Table 3, Revision No. 2
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Cowlitz County
Public Utility District
Effective at 2400 hours on
February 1, 1993

Point of Delivery for Bonneville

This revision adds the Ariel Point of Delivery.

ARIEL POINT OF DELIVERY:

Location: the point in Cowlitz PUD's Ariel Substation where the 115 kV facilities of the Company and Cowlitz PUD are connected.

Voltage: 115 kV.

Metering: the point in Cowlitz PUD's Ariel Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: the point on the north side of the Kalama River at structure No. 1/1 of the Government's Cardwell-Cowlitz transmission line where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Walter E. Pollock
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By Dennis P. Steinberg

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Exhibit B, Table 4
Contract No. DE-MS79-82BP90049
Transferor: Company
Transferee: Bonneville
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

1. PENDLETON POINT OF DELIVERY:

Location: in the Government's Pendleton Substation where the 69 kV facilities of the Government and the Company are connected;

Voltage: 69 kV;

Metering: in the Government's Pendleton Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Exhibit B, Table 5, Revision No. 2
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
Central Electric Cooperative
Effective Date: July 1, 1991

Points of Delivery for Bonneville

This Revision No. 2 establishes an effective date of July 1, 1991 for this Point of Delivery.

PILOT BUTTE POINT OF DELIVERY

Location: the point in PacifiCorp's Pilot Butte Substation where the 69 kV facilities of the Cooperative are connected;

Voltage: 69 kV;

Metering: in PacifiCorp's Pilot Butte Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in PacifiCorp's Pilot Butte Substation where the 230 kV facilities of the parties are connected.

Revision No. 1
Exhibit B, Table 6
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
Public Utility District No. 1
of Clark County, Washington
Effective at 2400 hours on
September 30, 1996

POINTS OF DELIVERY FOR BONNEVILLE

This revision deletes the Chelatchie and View 115 kV Points of Delivery. This table is left blank for future use.

ACCEPTED:

PACIFICORP

By Brian D. Sickels

Name Brian D. Sickels
(Print/Type)

Title Vice President

Date December 31, 1996

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By
Manager, Transmission
and Reserve Services

Name Patrick G. McRae
(Print/Type)

Date December 13, 1996

(PBLLAN-PST-W:\PSC\PM\CT\90049B_1.DOC)

Exhibit B, Table 7
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Basin Electric Cooperative, Inc. and
Umatilla Electric Cooperative
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

PILOT ROCK POINT OF DELIVERY:

Location: the point in the Company's 12.5 kV Pilot Rock circuit where the facilities of the Company and Umatilla are connected:

Voltage: 12.5 kV;

Metering: on the second pole from the point of interconnection between the facilities of the Company and Umatilla, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 8
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Columbia Power Cooperative Association, Inc.
Effective at 2400 hours on June 30, 1981

Points of Delivery for Bonneville

UKIAH POINT OF DELIVERY:

Location: the point in the Company's Pilot Rock Substation where the Company's 69 kV facilities and Columbia Power's Ukiah 69 kV line leased by Bonneville are connected;

Voltage: 69 kV;

Metering: in Columbia Power's Ukiah Substation, in the 25 kV circuit over which such electric power and energy flows;

Point of Replacement: the points in the Government's Roundup Substation where the 69 kV facilities of the parties are connected.

Exhibit B, Table 9, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Columbia Rural
Electric Association, Inc.
Effective at 2400 hours on December 31, 2012

POINTS OF DELIVERY FOR BONNEVILLE

This revision deletes the Dayton Point of Delivery. Table 9 will be left blank.

ACCEPTED;

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________ for

Name: **Todd E. Miller,**
Manager, Transfer Services

Date December 13, 2012

ACCEPTED;

PACIFICORP

By Natalie Hocken

Name: Natalie Hocken

Title: SVP, Transmission + System Operations

Date 12/19/12

Exhibit B, Table 10, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Douglas Electric Cooperative, Inc.
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Point of Replacement.

LOOKINGGLASS POINT OF DELIVERY

Location: The point in Bonneville's Lookingglass Substation where the 69 kV facilities of the Parties are connected;

Voltage: 69 kV;

Metering: In Bonneville's Lookingglass Substation, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: The point in the Dixonville 500 kV Substation where the Parties jointly owned facilities connect with PacifiCorp owned facilities.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves

Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 11, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:

Effective at 2400 hours
April 30, 2000

Points of Delivery for Bonneville

This revision deletes the Hanna Point of Delivery. Table 11 will be left blank.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves

Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 12, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Hood River Electric Coop.
Effective at 2400 hours on December 31, 2012

This revision changes the name of the Point of Delivery from Woody Guthrie Point of Delivery to Willard Johnson Point of Delivery

POINTS OF DELIVERY FOR BONNEVILLE

WILLARD JOHNSON POINT OF DELIVERY:

Location: the point on the Company's 69 kV Powerdale-Dee transmission line where Hood River Electric's Willard Johnson Substation is connected;

Voltage: 69 kV;

Metering: In Hood River Electric's Willard Johnson Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Hood River Substation where the 115 kV facilities of the parties are connected.

ACCEPTED;

PACIFICORP

By Natalie L Hocken

Name: Natalie L Hocken

Title: SVP, Transmission & System Operations

Date December 19, 2012

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By [signature] for

Name: Todd E. Miller,

Title: Manager, Transfer Services

Date: December 13, 2012

Exhibit B, Table 13, Revision No.4
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Public Utility District No. 1
of Klickitat County
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision corrects the Point of Replacement.

BINGEN POINT OF DELIVERY

Location: The point where Klickitat PUD's Bingen Substation connects to PacifiCorp's Powerdale-Condit 69 kV transmission line;

Voltage: 69 kV;

Metering: In Klickitat PUD's Bingen Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: The point at Bonneville's Bald Mountain Substation where the 69 kV facilities of PacifiCorp and Bonneville are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves
Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 14, Revision No.1
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Lane Electric Cooperative, Inc.
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Location and Point of Replacement.

DORENA POINT OF DELIVERY

Location: The point where Bonneville's 115 kV transmission line serving Bonneville's Dorena Substation is connected to PacifiCorp's Village Green-Drain Tap 115 kV transmission line;

Voltage: 115 kV;

Metering: In Bonneville's Dorena Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: The point where Bonneville's Martin Creek-Drain Tap 115 kV transmission is connected with PacifiCorp's Village Green-Drain Tap 115 kV transmission line.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper

Name Anne E. Draper
Manager, Transmission Acquisition and Reserves

Date 6/22/00

PACIFICORP

By

Name Donald N. Furman
Vice President

Date June 20, 2000

Exhibit B, Table 15, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Oregon
Metallurgical Corp (Oremet)
Effective 0000 hours on
September 16, 2005

Point of Delivery for Bonneville

This revision deletes the OREMET 12.5 kV Point of Delivery. This Table is left blank for future use.

ACCEPTED;

PACIFICORP

By K Houston

Name Kenneth Houston
(Print/Type)

Title Director, Transmission

Date 2-10-06

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Anne E. Draper
Manager,
Transmission and Reserve
Services

Name Anne E. Draper
(Print/Type)

Date 26 September 05

Exhibit B, Table 16, Revision No. 1
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Effective at 2400 hours on
February 1, 1993

Points of Delivery for Bonneville

This revision deletes the Alvey 115 kV Point of Delivery. This Table is left blank for future use.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ______________________
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By ______________________

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Revision No. 1, Exhibit B, Table 17
POINTS OF DELIVERY FOR BONNEVILLE

This revision adds the Nehalem Tap Point of Delivery.

1. EFFECTIVE DATE. This exhibit revision shall take effect at 2400 hours on January 28, 1999.

2. TRANSFEROR. PacifiCorp (Company).

3. BONNEVILLE'S CUSTOMER. Tillamook People's Utility District (Tillamook).

4. POINT(S) OF DELIVERY

(a) Garibaldi Point of Delivery

Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which the Government's 115 kV Garibaldi tap line is connected;

Voltage: 115 kV;

Metering: in the Government's Garibaldi Substation, in the 24.9 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

(b) Mohler Point of Delivery

Location: the point on the Company's Astoria-Tillamook 115 kilovolt (kV) transmission line at which the Government's Mohler Substation is connected;

Voltage: 115 kV;

Metering: in the Government's Mohler Substation in the 24.9 kV circuits over which such electric power and energy flows;

Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

(c) Nehalem Tap Point of Delivery

Location: the point on the Company's Astoria-Tillamook 115 kV transmission line at which Tillamook's Nehalem Tap 115 kV transmission line is connected;

Voltage: 115 kV;

Metering: in Tillamook's Nehalem Substation, in the 24.9 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Tillamook Substation where the 115 kV facilities of the parties are connected.

PACIFICORP

By ____________________

Name Donald N. Furman
(Print/Type)

Title Vice President Transmission Systems

Date 4-29-99

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By ____________________
Manager, Power Business Line Transmission and Reserve Services

Name Patrick G. McRae
(Print/Type)

Date 4/13/99

(PBLLAN-PSB/5-W:\PSC\PM\CT\90049B17.DOC) 04/06/99

Points of Delivery for Bonneville

This Revision No. 4 establishes an effective date of April 5, 2017 for the following points of Delivery.

1. MALIN POINT OF DELIVERY:

Location: the point in the Malin Substation where the 230 kV Facilities of PacifiCorp and Bonneville are connected;

Voltage: 230 kV;

Metering: in Surprise Valley's Canby Switching Station, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

2. ALTURAS POINT OF DELIVERY:

Location: the point outside PacifiCorp's Alturas Substation where the 12.5 kV facilities of PacifiCorp and Surprise Valley are connected;

Voltage: 12.5 kV;

Metering: outside of PacifiCorp's Alturas Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the potential and current transformers are owned by PacifiCorp;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

3. AUSTIN POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Austin Switching Station where the 69 kV facilities of PacifiCorp and Surprise valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Austin Switching Station, in the 69 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

4. CEDARVILLE POINT OF DELIVERY:

Location: the point in the vicinity of Bonneville's 115/69 kV Cedarville Junction Substation where the 115 kV facilities of PacifiCorp and Bonneville are connected;

Voltage: 115 kV;

Metering: in Bonneville's Cedarville Junction Substation, in the 69 kV circuit over which such electric power and energy flows;

Exception: the metered amounts of demand and energy shall be reduced by the amounts of demand and energy, adjusted for losses, registered on meters in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which electric power and energy flows to PacifiCorp;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

5. DAVIS CREEK POINT OF DELIVERY:

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 115 kV facilities of PacifiCorp and Bonneville are connected;

Voltage: 115 kV;

Metering: in Surprise Valley's Davis Creek Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

6. LAKEVIEW 69 KV POINT OF DELIVERY:

Location; the point in which the vicinity of Surprise valley's Lakeview Switching Station where the 69 kV facilities of PacifiCorp and Surprise Valley are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Lakeview Switching Station, in the 69 kV circuit over which such electric power and energy flows; provided, however, if the output of the Paisley geothermal facility is being delivered outside of Surprise Valley's system, metering at the Lakeview Switching Station shall be adjusted upwards in the amount of the metered output of the Paisley geothermal facility measured at the Paisley resource plus losses, which shall be 1.9%.

Point of Replacement: the point where Bonneville's Buckley-Summer Lake 500 kV transmission line and PacifiCorp's Summer Lake-Malin 500 kV transmission line are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: ______________________

Name: Dan Yokota

Date: 2/2/17

PACIFICORP

By: ______________________

Name: Rick Vail

Date: 2/2/17

Points of Delivery for Bonneville

HAT ROCK POINT OF DELIVERY:

Location: the point where the Government's Hat Rock Substation is connected to the Company's McNary-Walla Walla 230 kV transmission line;

Voltage: 230 kV;

Metering: in the Government's Hat Rock Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the parties are connected;

Switching Facilities:

(a) The Company has elected to operate said McNary-Walla Walla 230 kV transmission line in a manner which required Bonneville to install major switching facilities, suitable to the Company, at said Hat Rock point of delivery. Bonneville installed such switching facilities, to enable continued service to Umatilla at Hat Rock.

(b) The Company, at Government expense shall:

(1) operate and maintain the two 230 kV disconnect switches adjacent to the Hat Rock point of delivery in the same manner in which it maintains similar facilities of its own and furnish any parts necessary for such maintenance; and

(2) remove said switches and associated materials which can be removed without damage to Company property, when no longer required to provide service at said Hat Rock point of delivery, deliver said switches and salvable materials to such location as Bonneville shall designate, and restore the Company's transmission facilities to their original configuration, subsequent to such removal.

(c) The Company shall submit an itemized statement of charges for materials furnished and services performed, as specified in section (b), including a reasonable allowance for overheads, within 20 days after the end of the month in which they were incurred, and Bonneville shall pay such charges within 30 days after receipt of said statement;

(d) Title to and ownership of the two 230 kV disconnect switches and related salvable materials installed by Bonneville shall be in the Government at all times.

Exhibit B, Table 20
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Wasco Electric
Cooperative, Inc.
Effective at 2400 hours on
June 30, 1981

Points of Delivery for Bonneville

WARM SPRINGS POINT OF DELIVERY:

Location: the point in the Company's Warm Springs Substation where the 69 kV facilities of the Company and facilities leased by the Government are connected;

Voltage: 69 kV;

Metering: in the Kah-Nee-Ta Substation leased by the Government, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Redmond Substation where the 69 kV facilities of the parties are connected.

(WP-PCI-1185c)

Points of Delivery for Bonneville

Revision No. 1 removes the Necanicum Junction Point of Delivery.

1. OLNEY POINT OF DELIVERY:

   Location: at the point near Olney, Oregon, where 12.5 kV facilities of the Company and West Oregon Electric Cooperative are connected.

   Voltage: 12.5 kV.

   Metering: at the point of delivery in the 12.5 kV circuit over which such electric power and energy flows.

   Point of Replacement: the point in the Company's Astoria Switching Station where the 115 kV facilities of the parties are connected.

2. NECANICUM POINT OF DELIVERY:

Location: at the point between structures 25/2 and 25/3 of the Company's Tillamook-Astoria 115 kV line where the 115 kV facilities of West Oregon Electric Cooperative and the Company are connected.

Voltage: 115 kV.

Metering: in West Oregon Electric Cooperative's Necanicum Substation, in the 12.5 kV circuit over which such electric power and energy flows.

Point of Replacement: the point in the Government's Clatsop Substation where the 115 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA

Department of Energy
Bonneville Power Administration

By Walter E. Pollock
Assistant Administrator for Power Sales

Name Walter E. Pollock
(Print/Type)

Date April 16, 1993

PACIFICORP

By Dennis P. Steinberg

Title Vice President

Name Dennis P. Steinberg
(Print/Type)

Date April 28, 1993

(VS10-PMTT-3579e)

Exhibit B, Table 22, Revision No.3
Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville Customer:
Emerald People's Utility District
Effective at 2400 hours
June 30, 2000

Points of Delivery for Bonneville

This revision revises the Powerline Point of Delivery to reflect the second tap into Power line Substation.

1. CRESWELL POINT OF DELIVERY

   Location: at the point in the Company's Alvey-Village Green 115 kV transmission line between structure 5/9 and 6/9 where the facilities of the Company and the Government are connected.

   Voltage: 115 kV.

   Metering: in Emerald's Creswell Substation, in the 20.8 kV circuit over which such electric power and energy flows.

   Exception: losses in Exhibit D include an adjustment for losses between the point of delivery and the point of metering.

   Point of Replacement: in the Government's Alvey Substation where the 115 kV facilities of the parties are connected.

2. POWERLINE POINT OF DELIVERY

   Location: the points in the Company's Diamond Hill-Coburg 69 kV line at structures 12/9 and 12X/9 where the facilities of the Government and Company are connected.

   Voltage: 69 kV.

   Metering: in Emerald's Powerline Substation, in the 20.8 kV circuits over which such power and energy flows.

   Exception: losses in Exhibit D include an adjustment for losses between the point of delivery and the points of metering.

   Point of Replacement: in the Governments Alvey Substation where the 230 kV facilities of the parties are connected.

ACCEPTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Anne E. Draper

Name: Anne E. Draper
Manager, Transmission Acquisition and Reserves
Date: 6/22/00

PACIFICORP

By: [signature]

Name: Donald N. Furman
Vice President
Date: June 20, 2000

Transferor: Bonneville
Transferee: PacifiCorp
Effective Date: November 1, 2009

EXHIBIT C, REVISION NO. 8
POINTS OF DELIVERY FOR THE COMPANY

This Exhibit C, Revision No. 8 accomplishes the following: (1) adds the Klondike 69 kV Point of Delivery (POD); (2) updates the description for the Location of all PODs and, (3) reformats Exhibit C to reflect the current standard format. The Effective Date of this Revision No. 8 shall be retroactive to November 1, 2009, to coincide with the date the Klondike 69 kV POD was deleted from Exhibit C.

1. **ALVEY 115 KV - PAC**

Location: the point in the Transmission Provider's[1] J.P. Alvey[2] substation, where the 115 kV facilities of the Transmission Provider and PacifiCorp[3] are connected;

Voltage: 115 kV;

Metering: in the Government's Alvey Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Alvey Substation where the 230 kV facilities of the Company and Bonneville are connected;

Exception: Company load metered at Alvey Line 4 will be adjusted by subtracting Emerald PUD load metered at Creswell adjusted for losses between the Creswell meter and the Alvey Substation 115 kV bus.

2. **CEDARVILLE JUNCTION 69 KV - SURP**

Location: the point in the vicinity of the Transmission Provider's Cedarville Junction substation, where the 69 kV facilities of the Transmission Provider and Surprise Valley Electrification Corporation[4] are connected;

Voltage: 69 kV;

Metering: in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's Cedarville Junction Substation where the 115 kV facilities of the Parties are connected.

---

[1] The Transmission Provider is also referred to as both the "Government" and "Bonneville" in this contract, its amendments and exhibits.
[2] Alvey Substation
[3] PacifiCorp is also referred to as the "Company" in this contract, its amendments and exhibits.
[4] Surprise Valley

3. **DALREED 230 KV**

Location: the point near structure 37/3 of the Transmission Provider's McNary-Jones Canyon 230 kV transmission line where the facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 230 kV;

Metering: in the Company's Dalreed Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement: the point in the Government's McNary Substation where the 230 kV facilities of the Parties are connected.

4. **KLONDIKE 69 KV**

Location: the point near Wasco Electric Cooperative's Klondike Substation where the 69 kV facilities of PacifiCorp and Wasco Electric Cooperative are connected;

Voltage: 69 kV;

Metering: in the Company's Klondike-Willow Creek Line in the 69 kV circuit over which such electric power flows;

Exception: the Company is served by transfer over Wasco Electric Cooperative, Inc. (Wasco) facilities. The terms and conditions of the transfer are specified in Contract No. 14-03-47930 between Wasco and the Government;

Point of Replacement: the point in the Government's De Moss Substation where the 69 kV facilities of the Government and Wasco are connected[5].

[5] Pursuant to Network Integration Transmission Service Agreement No. 09TX-14534, the Government delivers electric power to its De Moss Substation where it is transferred over to Wasco's facilities for delivery to the Company's facilities. Wasco charges the Government for the transfer service, and the Government passes Wasco's transfer charge through to the Company under the transfer charge for the Klondike 69 kV POD.

5. **KNAPPA TAP 115 KV**

Location: the point near structure 37/4 of the Transmission Provider's Longview-Astoria 115 kV transmission line where the facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 115 kV;

Metering: in the Company's Knappa-Svenson Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: the instrument transformers are owned by the Company;

Point of Replacement: the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

6. **FERN HILL 115 KV**

Location: the point near PacifiCorp's Fern Hill Substation where the 115 kV facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 115 kV;

Metering: in the Company's Fern Hill Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception: losses in Exhibit D include an adjustment for losses between the Point of Delivery and the Point of Metering;

Point of Replacement: the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

7. **VANSYCLE TAP 69 KV - PAC**

Location: the point in the Transmission Provider's Walla Walla-Pendleton 69 kV transmission line where the 69 kV tap line facilities of the Vansycle Ridge Windfarm are connected;

Voltage: 69 kV;

Metering: in the Vansycle Windfarm Substation, in the 69 kV circuit over which such electric power and energy flows;

Exception: losses in Exhibit D include an adjustment for losses between the Point of Delivery and the Point of Metering;

Point of Replacement: the point in the Government's Walla Walla Substation where the 69 kV facilities of the Parties are connected.

8. **SIGNATURES**

The Parties have executed this Exhibit as of the last date indicated below.

PACIFICORP		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:		By:	Kimberly D. Gilliland
Name:	Stefan Bird *(Print/Type)*	Name:	for Kenneth H. Johnston *(Print/Type)*
Title:	SVP Commercial + Trading	Title:	Transmission Account Executive
Date:	5/23/14	Date:	05/09/2014

(W:\TMC\CT\PacifiCorp\Revisions\90049_ExC_R8.doc)

EXHIBIT D, REVISION NO. ~~24~~26
TRANSFER CHARGES, SOLE USE-OF-FACILITIES CHARGES, AND LOSS FACTORS

This Exhibit D, Revision No. ~~24~~26 (Revision) updates the Transfer Charge associated with the Klondike 69 kV Point of Delivery.

EFFECTIVE DATE: This exhibit revision shall be effective on the date approved by FERC. Once effective, changes to the Transfer Charge for the Klondike 69kV Point of Delivery (POD) are retroactive to January 1, ~~2017~~2019.

		Transfer Charge	Sole Use-of-Facilities Charge	Loss Factors	
Point of Delivery	**Transferor**	**($/kW/mo)**	**($/mo)**	**Peak**	**Energy**
Alvey 115 kV (Line 4)	Bonneville	0.1067	0	1.0034	1.0014
Cedarville Junction	Bonneville	0.5470	0	1.0019	1.0008
Dalreed	Bonneville	0.0580	0	1.0059	1.0023
Fern Hill	Bonneville	0.0998	0	1.0056	1.0091
Klondike 69 kV	Bonneville	1.345~~149~~[1]	0	1.0341[2]	1.0136
Knappa Tap	Bonneville	0.1783	0	1.0127	1.0110
Vansycle Tap	Bonneville	1.3009	0	1.0190	1.0190
Ashland (City of Ashland)	PacifiCorp	1.3869	0	1.0196	1.0111
Oak Knoll (City of Ashland)	PacifiCorp	1.8900	0	1.0245	1.0138
Mt. Avenue (City of Ashland)	PacifiCorp	1.0368	0	1.0124	1.0084
White Swan (Yakama)	PacifiCorp	1.1204	0	1.0317	1.0234
Pilot Butte (Central Electric)	PacifiCorp	0.6489	0	1.0050	1.0024
Ariel (Cowlitz)	PacifiCorp	0.1197	0	1.0384	1.0221
Pilot Rock (Columbia Basin and Umatilla)	PacifiCorp	0.8423	0	1.1151	1.0661
Ukiah (Columbia Power)	PacifiCorp	0.2989	0	1.0887	1.0553
Lookingglass (Douglas)	PacifiCorp	1.6083	4,183	1.0786	1.0429
Creswell (Emerald)	PacifiCorp	0.1869	0	1.0063	1.0053
Powerline (Emerald)	PacifiCorp	1.6066	0	1.0224	1.0157
Willard Johnson (Hood River)	PacifiCorp	0.4347	0	1.0573	1.0309
Bingen (Klickitat)	PacifiCorp	0.2372	0	1.0169	1.0111
Dorena (Lane)	PacifiCorp	0.0000	1,559	1.0069	1.0072
Garibaldi (Tillamook)	PacifiCorp	0.1160	0	1.0241	1.0140
Mohler (Tillamook)	PacifiCorp	0.2996	0	1.0452	1.0268
Nehalem Tap (Tillamook)	PacifiCorp	0.3602	0	1.0513	1.0285
Alturas (Surprise Valley)	PacifiCorp	1.3503	0	1.1796	1.1146
Austin (Surprise Valley)	PacifiCorp	3.8109	0	1.1005	1.0654
Cedarville (Surprise Valley)	PacifiCorp	2.2194	0	1.0406	1.0389

[1] Under Contract No. 14-03-47930, Wasco Electric Cooperative, Inc. (Wasco) updates the Transfer Charge the Government pays Wasco to transfer power from the Government's De Moss Substation over Wasco's 69 kV transmission facilities to Wasco's Klondike 69 kV Point of Delivery (POD). Wasco charges the Government for the transfer service~~,~~ and updates its charges annually. ~~t~~The Government passes Wasco's Transfer Charge through to the Company under the Transfer Charge for the Klondike 69 kV POD. After Wasco updates the charge to the Government, the Government applies this change retroactively to January 1 of the calendar year for which Wasco updated its charges (in the case of this Revision No. 26 to Exhibit D, January 1, 2019). Despite that this is a charge from Wasco passed through by the Government's transmission function to the Company's merchant function, it is incorporated into this Agreement which also governs the provision of FERC-jurisdictional services by the Company's transmission function to the Government's merchant function, and is therefore on file with FERC and subject to FERC approval.

[2] Because the incremental loss calculation for the network did not fairly represent actual losses, an average system loss of 2 percent was used. The other loss component is for transformation losses in the Company's facilities, as metering is located on the low side of the transformer.

Point of Delivery	Transferor	Transfer Charge ($/kW/mo)	Sole Use-of-Facilities Charge ($/mo)	Loss Factors Peak	Loss Factors Energy
Davis Creek (Surprise Valley)	PacifiCorp	5.5103	0	1.2974	1.1910
Lakeview 69 kV (Surprise Valley)	PacifiCorp	5.7468	325	1.1011	1.0662
Malin (Surprise Valley)	PacifiCorp	0.4126	0	1.0416	1.0271
Hat Rock (Umatilla)	PacifiCorp	0.3993	0	1.0113	1.0099
Pendleton (Umatilla)	PacifiCorp	0.0405	110	1.0105	1.0061
Warm Springs (Wasco)	PacifiCorp	6.0632	0	1.2108	1.1115
Necanicum (West Oregon)	PacifiCorp	1.0431	0	1.0471	1.0337
Olney (West Oregon)	PacifiCorp	1.9403	0	1.6743	1.3385

SIGNATURES

This Revision may be executed in several counterparts, all of which taken together will constitute one single agreement, and the Revision may be executed and delivered electronically. The parties have executed this Revision as of the last date indicated below.

PACIFICORP

By: *s/ Joseph P. Hoerner*

Joseph P. Hoerner
2019.04.02~~2017.05.10~~ ~~08:18:29~~10:33:11-07'00'

Title: Vice President, Energy Supply Mgmt

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: *s/ Eric H. Carter*

Digitally signed by ~~ehc2532@bud.bpa.gov~~ ERIC CARTER
Date:2019.03.22~~2017.04.26~~ ~~11:17:58~~12:29:16-07'00'

Title: Senior Transmission Account Executive

If opting out of the electronic signature:

By: ____________________________

Name: ____________________________
(Print/Type)

Title: ____________________________

Date: ____________________________

General Transmission Rate Schedule Provisions:

FOR SET A TRANSMISSION SCHEDULES

1. Interpretation. The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. Bonneville Service Area. The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the BPA wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. Availability of Transmission Service. Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identifed in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. Billing Details.

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

5. Definitions. Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

a. Agreement: The transmission agreement to which this exhibit is attached.

b. Connection Point: Refers collectively to the following:

(1) Point of Integration (POI): Connection points where a non-Federal project is integrated with the FCRTS.

(2) Point of Delivery (POD): Connection points where power is delivered to a customer from the FCRTS. The power may be Federal or non-Federal.

(3) Point of Exchange (POE): Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. Electric Power (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. Firm Transmission Service: Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. Interest and Amortization Ratio: The annual interest and amortization costs of the Federal Columbia River Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

f. Main Grid: That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

g. Main Grid Delivery Terminal: 230 kV Terminal Facilities associated with a Point of Delivery.

h. Main Grid Distance: The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

i. Main Grid Integration Terminal: The Main Grid Terminal Facilities located at the Point of Integration.

j. Main Grid Miscellaneous Facilities: Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

k. Main Grid Terminal: Terminal facilities on the Main Grid adjacent to the Secondary System.

l. NonFirm Transmission Service: Service for which BPA will accept power only when it determines excess capacity is available. Once BPA accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

m. Ratchet Demand: The maximum past or present demand established during the previous 11 billing months based on the highest scheduled demand during that time.

n. Secondary System: That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

o. <u>Secondary System Delivery Terminal</u>: A Point of Delivery from a Main Grid substation at 115 kV or 69 kV, or a terminal located at a Point of Delivery from the Secondary System.

p. <u>Secondary System Distance</u>: The number of circuit miles of Secondary System transmission lines between the Main Grid and the Point of Delivery or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

q. <u>Secondary System Integration Terminal</u>: The first Terminal Facility in the Secondary System.

r. <u>Secondary System Intermediate Terminal</u>: The final Terminal Facilities in the Secondary System.

s. <u>Secondary Transformation</u>: Transformation from Main Grid to Secondary System facilities.

Methodology for Calculating Transfer Charges and Sole Use of Facilities Charges

The Transfer Charge is the monthly charge per kilowatt of transfer demand as transfer demand is defined in the contract of which this exhibit is a part. The Transfer Charge is equal to one-twelfth of the sum of the Annual Costs of all facilities used in providing the service hereunder divided by the sum of the yearly non-coincidental peak demands as determined in (c) below. The Annual Costs of each facility are defined as the product of: (1) the capital cost of such facility as determined in (a) below; and (2) the Annual Cost Ratio as determined in (b) below. The Transfer Charge is therefore calculated from the formula:

$$\frac{\text{sum of } (I \times R) \text{ for all applicable facilities}}{D} \times 1/12$$

where:

I = Capital cost of such facility as determined in (a) below,
R = Annual Cost Ratio as determined in (b) below,
D = The sum of the yearly non-coincidental peak demands as determined in (c) below.

(a) Capital cost of each such facility as in the most recently published plant investment records of the parties hereto.

(b) Annual Cost Ratio for each such Bonneville facility using the most recent system average cost factors, or Annual Cost Ratio for each such Company facility which incorporates the most recent rate of return approved by the ~~Idaho Public Utility Commission, the Montana Public Service Commission, the~~ Oregon Public Utility Commission~~, or the Washington Utilities and Transportation Commission, as the case may be, for facilities located in the respective states.~~ The Annual Cost Ratio used herein includes the operation and maintenance component defined as "B" in the UFT-2 rate schedule.

(c) The yearly noncoincidental peak demands of all users of such facilities, as determined in part by use of power flows agreed to by both parties and in part by forecasted peaks agreed to by both parties that are different from those used in the power flows. Since the noncoincidental peaks may occur at different times it may not be possible to include both in the same power flow. The parties shall initially use power flows, which are already existing as of January 1, 1982, which are based on 1981-82 Operating Year forecasted peak. Unless the parties subsequently agree to a different method, the following method shall be used to update power flows:

(1) the initial power flows shall be used through December 31, 1983 or such other date as agreed by the parties;

(2) new power flows shall then be prepared which shall use parameters forecasted to exist 2 years from the date that the power flow is prepared;

(3) such new power flows shall then be the basis for transfer charges for 3 years;

(4) every third year the procedure in (2) above shall be repeated and such new power flows shall be used for 3 years.

Sole Use of Facilities Charge

The Sole Use of Facilities Charge is the transfer charge where a party has sole use of a facility. In such cases the charge is expressed in dollars per month and is calculated as:

sum of (I x R) for all applicable facilities x 1/12

using the same quantities defined above.

EXHIBIT G

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

FEB 26 1982

In reply refer to: PCI

Contract No. DE-MS79-82BP90924

Mr. Robert W. Moench
Senior Vice President
Pacific Power & Light Company
Portland, Oregon 97204

Dear Mr. Moench:

During the past year, representatives of Pacific Power & Light Company (PP&L) and Bonneville Power Administration (BPA) have been meeting from time to time to reach settlement on transfer services to BPA's Hanna, Lookingglass, and Surprise Valley loads for the period from July 1973 to the present as well as other outstanding issues related to transfer services rendered to both parties. At meetings on February 23 and 24, 1982, agreement was reached between PP&L and BPA on certain of these issues. There are other issues, as well as final details of future charges for transfer services provided each other, which are yet to be resolved. BPA and PP&L, however, agree that final resolution of all remaining issues will be greatly facilitated as a result of these recent meetings and the agreement of principles upon which many of these decisions were made.

In accordance with these recent discussions, BPA and PP&L agree to the following terms and conditions:

A. Settlement for services rendered prior to July 1, 1981.

1. BPA shall pay PP&L $5,300,000 for transfer service provided by PP&L to BPA's Surprise Valley, Hanna, and Lookingglass loads from July 1973 through 2400 hours on June 30, 1981. The amount of the payment was computed using a fixed rate of .5 mill per kWh, a UFT methodology equivalent to BPA's approved UFT-1 rate methodology, and a transfer amount of 7,639,784,496 kWh.

2. BPA shall pay PP&L $319,789 for transfer service of the Lost Creek Project generation for the period from July 6, 1977, through October 1, 1978.

3. Payment pursuant to subsections 1 and 2 above shall be made in three equal payments, such payments shall be made at 30-day intervals. The first such payment shall be made within 30 days of receipt of an invoice for the full amount due. There shall be no interest paid on such payments.

4. BPA agrees to reimburse PP&L 62,000 MWh for losses which PP&L incurred during the period commencing at 2400 hours on June 30, 1973 and continuing through 2400 hours on June 30, 1981. Delivery of such energy will be made, to the extent possible, in equal hourly increments during the period commencing at 2400 hours on June 30, 1982 and continuing through 2400 hours on June 30, 1983.

B. Settlement for services rendered subsequent to July 1, 1981.

1. Payment

a. BPA shall pay PP&L each month in the amounts specified in Attachment 1, within 30 days of receipt of billing.

b. BPA shall pay PP&L the actual cost of the line transposition required on the Buckley-Summer Lake line. Such cost is estimated to be $40,000. BPA and PP&L shall execute an appropriate trust agreement for this transaction.

c. PP&L shall pay BPA an monthly charge of $32,100 from 2400 hours on November 30, 1981 through the date of Commercial Operation of the Buckley-Summer Lake-Malin line for the right to remove PP&L's 230 kV Malin phase shifter. Such monthly charge shall resume at 2400 hours on August 31, 1985, as established pursuant to Contract No. DE-MS79-79BP90091, unless BPA determines that, such date should be extended based upon studies done in a manner similar to those done in originally establishing such dates. PP&L shall, in consideration for the above and as mutually agreed upon by the parties, extend the period of time for which BPA shall have west to east transmission rights on PP&L's Summer-Lake - Midpoint line.

2. Calculation of Charges - Specific Provisions

a. Mile Hi - Alturas 115 kV line

(1) For the period of time from 2400 hours on June 30, 1981 to the date of energization of BPA's proposed 230 kV Malin - Alturas line, BPA shall pay charges calculated as if power flowed from Mile Hi to the Davis Creek, Cedarville, and Alturas Points of Delivery.

(2) For the period of time from the date of energization of BPA's proposed 230 kV Malin - Alturas line until 2400 hours on December 31, 1991 BPA shall pay charges calculated as if power flowed from Alturas to the Cedarville, Davis Creek, and Lakeview 69 kV points of delivery.

(3) Commencing at 2400 hours on December 31, 1991 BPA will pay charges calculated as if power flowed from Alturas to the Cedarville and Davis Creek points of delivery.

b. Transfer charges for service to the Hanna, Lookingglass, and Ashland Loads shall be calculated based on a Fairview point of replacement. These charges shall include payment to PP&L for BPA's use of the Government's Fairview - Reston 230 kV line for which PP&L is currently paying an exclusive use charge.

c. Following energization of the Buckley-Summer Lake - Malin 500 kV line and the 230 kV Malin-Alturas line, the point of replacement for transfer service to BPA's Surprise Valley Electrification load shall be the Malin 500 kV bus. BPA will pay UFT-2 charges for use of PP&L's's 500-230 kV Malin transformer. If BPA agrees that a second 500-230 kV transformer is a reasonable addition to provide reliable service to area loads and when PP&L adds such transformer, charges for such transformer shall be included in the UFT-2 calculations for the use of PP&L's Malin 500-230 kV facilities.

C. General Transfer Agreement.

1. Services rendered subsequent to July 1, 1981 shall be pursuant to the terms and conditions of the proposed General Transfer Agreement (draft dated September 10, 1980); provided, however, that charges and payments shall be based upon the amounts of electric power and energy delivered at the specified points of delivery adjusted for losses to the point of replacement.

2. BPA and PP&L agree that the General Transfer Agreement to be executed pursuant to subsection 3 below shall provide that the parties reciprocally apply the methodology contained in BPA's UFT - 2 rate schedule or its successor for transfer services rendered pursuant to the General Transfer Agreement. BPA and PP&L shall share in the cost of the unused capacity of facilities. This payment reflects the transferor's acceptance of the responsibility to provide additional facilities as required to serve the load growth of the parties.

3. The parties agree to execute the General Transfer Agreement no later than 60 days subsequent to the date of execution of this agreement.

D. Term of Agreement. This agreement shall be effective at 2400 hours on the date of execution and shall continue in effect until 2400 hours on the date of execution of the General Transfer Agreement, except that all obligations incurred hereunder shall be preserved until satisfied.

If the above listed conditions are acceptable to you, please countersign this letter and return it to me. BPA will then initiate the appropriate actions to implement these arrangements.

Sincerely,

/s/ Peter T. Johnson

Administrator

Enclosure:
Points of Delivery and Charges
UFT - 2 Rate Schedule

PACIFIC POWER & LIGHT COMPANY

By /s/ Robert W. Moench

Title Senior Vice President

Date March 4, 1982

ATTEST:
By /s/ Sally A. Nofziger

Title Assistant Secretary

(WP-PCI-1057c)

Attachment 1
Contract No. DE-MS79-82BP90924
Pacific Power & Light Company
Effective at 2400 hours on
June 30, 1981

POINTS OF DELIVERY AND CHARGES

Points of Delivery	Charges: Fixed	Charges: Variable
1. Surprise Valley	$242.00/mo.	
Austin		$1.20/kW/Mo.
Alturas		$5.06/kW/Mo.
Canby		$.90/kW/Mo.
Cedarville		$3.37/kW/Mo.
Davis Creek		$2.31/kW/Mo.
Lakeview 69kV		$1.62/kW/Mo.
2. Looking Glass	$2,617.00/Mo.	$.530/kW/Mo.
3. Hanna	$6,141.00/Mo.	$.189/kW/Mo.
4. City of Ashland 1/ Ashland	$8,554.00/Mo.	$.526/kW/Mo.
Oak Knoll	$4,019.00/Mo.	$.526/kW/Mo.

1/ This point of delivery shall be effective at 2400 hours on February 27, 1982.

(WP-PCI-1057c)

SCHEDULE UFT - USE-OF-FACILITIES TRANSMISSION.

SECTION 1. Availability: This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. This schedule is not appropriate for new agreements for service over the Integrated Network Segment, or the PNW-PSW Intertie Segment.

SECTION 2. Rates: The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specified facilities. Such Annual Cost shall be determined in accordance with Section 3.

SECTION 3. Determination of Transmission Rate:

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and are used to transmit electric power and energy thereunder:

1. Capital cost of each such facility as specified in the most recently published plant investment records of BPA which are issued in support of the Federal Columbia River Power System financial statement.

2. Annual Interest and Amortization Ratios for each such facility using the most recent system average cost factors developed from actual Interest and Amortization costs for specific categories of FCRTS facilities and from data included in the financial statement.

3. Operation, maintenance, administrative and general, and general plant costs of such facilities using the most recent system average costs for specific categories of FCRTS facilities.

4. The yearly noncoincidental peak demands of all users of such facilities.

B. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each of the FCRTS facilities used. The Annual Cost per kilowatt of each facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{(I \times R) + B}{D}$$

Where B = Operation, maintenance, administrative and general, and general plant cost of such facility as determined in A.3.

I = Capital cost of such facility as determined in A.1.

R = Annual Interest and Amortization Ratio for such facility as determined in A.2.

D = The sum of the yearly noncoincidental demands on the facility as determined in A.4.

The Annual Co per kilowatt of facilities ..sted in the Agreement which are owned by another entity, and used by BPA for making deliveries to the Transferee, shall be determined from the costs specified in the Agreement between BPA and such other entity.

SECTION 4. Determination of Transmission Demand: Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. the Ratchet Demand.

SECTION 5. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Exhibit H, Revision No. 3
Contract No. DE-MS79-82BP90049
PacifiCorp
Effective at 2400 hours on
June 30, 2000

Factors for Determining Power Factor

Revises the Factors for all listed Points-of-Delivery except Dalreed, Klondike and Knappa Tap. Deletes Chelatchie, View, Gilmer, Glenwood and Hanna. Adds Ashland, Oak Knoll, Mt. Avenue, Pilot Butte, Ariel, Pilot Rock, Creswell, Powerline, Nehalem, Alturas and Olney.

Point-of-Delivery	Reactive Factor (X)%	Energy Adj. Factor (Z)	Constant kvarh Reactive Adj. (Y)	
Dalreed	7.2	1.008	+	214,182
Klondike	0.37	1.003	-	140,890
Knappa Tap	12.35	1.0113	+	32,726
Ashland	15.58	1.0067		0
Oak Knoll	20.58	1.0100		0
Mt. Avenue	2.57	1.0041		28,747
White Swan	4.17	1.0095	+	70,416
Pilot Butte	9.66	1.0024		0
Ariel	1.62	1.0052	+	10,402
Pilot Rock	0.37	1.0003		0
Ukiah	4.15	1.0107	+	48,221
Dayton	1.67	1.0074	+	24,841
Creswell	4.49	1.0040	+	10,023
Powerline	3.03	1.0035	+	7,427
Woody Guthrie	4.32	1.0033	+	11,917
Bingen	6.42	1.0051	+	56,847
Dorena	2.95	1.0066	+	39,564
Ormet	25.23	1.0134		0
Mohler	2.56	1.0054	+	7,123
Garibaldi	6.31	1.0034	+	20,019
Nehalem	5.24	1.0035	+	20,019
Alturas	9.07	1.0051		0
Davis Creek	1.82	1.0214	+	50,842
Cedarville	6.74	1.0087	+	44,021
Hat Rock	8.93	1.0083	+	589,162
Warm Springs	2.10	1.0074	+	26,383
Necanicum	4.15	1.0184	+	31,057
Olney	0.04	1.0002		0

PACIFICORP

By: ______________________

Name: Donald N. Furman

Title: Vice President

Date: June 20, 2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Anne E. Draper

Name: Anne E. Draper

Title: Manager, Transmission Acquisition and Reserves

Date: 6/22/00

EXHIBIT I, REVISION NO. 1
SETTLEMENT OF DEVIATIONS

This Exhibit I, Revision No. 1 sets out the bandwidth for "Normal" and "Excessive Monthly" energy "Deviations," as defined below, and prescribes the rates at which such Deviations will be settled between PacifiCorp and the Bonneville Power Administration (Bonneville), both of which may be referred to individually, as a Party, or collectively as the Parties. This Exhibit I is hereby made part of the General Transfer Agreement (DE-MS79-82BP90049) between the Parties and shall be changed only upon the mutual written consent of each Party.

1. Deviation means the difference during a single month between scheduled and actual delivery of energy to Bonneville or PacifiCorp loads.

   a. A positive deviation occurs where a Party's total monthly actual load was less than that Party's total monthly delivered energy across all of its checkout transaction point types.
   b. A negative deviation occurs where a Party's total monthly actual load was more than that Party's total monthly delivered energy across all of its checkout transaction point types.

2. Normal Deviations are Deviations that are less than or equal to the bandwidth of each Party established below:

   a. Normal Deviation for Bonneville: Less than or equal to 1000 MWh in a month.
   b. Normal Deviation for PacifiCorp: Less than or equal to 500 MWh in a month.

3. Excessive Monthly Deviations are Deviations that exceed a Party's Normal Deviation bandwidth in a month.

4. A Party's deviation level (Normal or Excessive) will be calculated on a monthly basis by netting out all of a Party's positive deviations during a month against all of a Party's negative deviations during a month.

5. All deviations (Normal and Excessive) will initially be settled on a monthly basis at $2.50/MWh.

6. In November of each year, the Parties will review and settle any Excessive Monthly Negative Deviations from the previous September through August period at the Excessive Monthly Negative Deviation Adjustment Price described below.

   a. Excessive Monthly Negative Deviation Adjustment Price:

Excessive Monthly Negative Deviation Adjustment Price	=	(Monthly Market Price - $2.50/MWh) * Excessive Negative Deviation (MWh) for the month.
Where:		
Monthly Market Price	=	Unless modified pursuant to section 6(b) below, the Monthly Market Price shall mean the monthly average of the Intercontinental Exchange (ICE) Mid-C Day Ahead weighted average of the peak and off-peak prices for each day of the month. The ICE firm Day Ahead market prices (for both HLH and LLH) used in the calculations will be limited to a minimum of $0/MWh.
Excessive Monthly Negative Deviation	=	A negative deviation (as defined above in 1.b), that is Excessive (as defined above in section 3).

b. Alternative Index Because of Market Disruption Event.

(1) If a Market Disruption Event occurs on any one or more days in the month, then either Party may provide notice in writing to the other Party of the Market Disruption Event. In such case, the Parties shall mutually agree upon a substitute index that most closely applies to energy and energy deliveries under this agreement (considering applicable factors and the intent of the Parties, including such factors as delivery point, firmness of electricity, and general acceptance and use of such index by market participants), or such other substitute index as the Parties may agree.

(2) If the Parties are unable to so agree within 30 days after the foregoing notice is given, the Parties may agree to refer the matter to a mediator to choose a substitute index based on the criteria in (b)(1) above.

(3) Pending agreement on or determination of the substitute index, the Party entitled to a settlement payment based on the index shall specify an interim index or pricing method, acting reasonably, and amounts so credited based on such interim index or pricing method shall be adjusted retroactively, to reflect the selected substitute

index, to the date the Party provided the notice in writing referred to above.

(4) If there is no daily index price published for the peak and/or off-peak period of a day or series of days in a month, and neither Party provides notice of the Market Disruption Event, the Monthly Market Price will be calculated using the remaining days in the month that have both the peak and off-peak prices published.

(5) "Market Disruption Event" means, with respect to the ICE Index, any of the following events:

(i) the failure of the ICE Index to announce, publish or make available the specified index or information necessary for determining the ICE index Price for a particular day;

(ii) the failure of trading to commence on a particular day or the permanent discontinuation or material suspension of trading in the relevant market specified for determining the ICE index;

(iii) the temporary or permanent discontinuance or unavailability of the ICE index;

(iv) a material change in the formula for or the method of determining the index by the index publisher or a material change in the composition of the ICE Index.

[Signatures to Follow]

The Parties have executed this Exhibit as of the last date indicated below.

PACIFICORP

By: Rick Vail

Name: Rick Vail

Title: Vice President, Transmission

Date: 2/22/17

By: Joseph H

Name: Joeseph Hoerner

Title: Vice President, Energy Supply Management

Date: 2-24-17

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: Dan Y

Name: Dan Yokota

Title: Manager, Transfer Services

Date: 2/22/17